



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

Chenchao Lu
Counsel
T: (610) 666-2255 | F: (610) 666-8211
Chenchao.Lu@pjm.com

March 9, 2018

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

*Re: PJM Interconnection, L.L.C., Docket No. ER18-988-000
Proposed Changes to Incremental Auction Rules*

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d (2000), and the Federal Energy Regulatory Commission's ("Commission") Regulations, 18 C.F.R. Part 35 (2011), PJM Interconnection, L.L.C. ("PJM") hereby submits proposed revisions to PJM's Open Access Transmission Tariff ("Tariff")¹ and the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA").² Specifically, as further explained below, PJM proposes to (1) release excess capacity commitments at a Sell Offer price equal to the relevant Base Residual Auction ("BRA") clearing price, (2) replace the current practice of allocating uncleared PJM Incremental Auction ("IA") Sell Offer MWs as Excess Commitment Credits ("ECCs") with an excusal process for capacity commitments up to the uncleared PJM Sell Offer

¹For the purpose of this filing, capitalized terms not defined herein shall have the meaning as contained in the PJM Open Access Transmission Tariff or the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region.

² PJM recognizes that the Commission initiated a section 206 proceeding in Docket No. EL14-48-000 to investigate and facilitate the development of revised capacity replacement rules. As such, PJM is making a concurrent informational filing in Docket EL14-48-000, which will inform the Commission of this filing. As the Commission recently explained, the existence of a section 206 proceeding on the same subject does not preclude a section 205 filing. See *Monongahela Power Company, et al.*, 162 FERC ¶ 61,129, at PP 93-95 (2018). Based on the problem statement and issue charge that was approved by the Markets and Reliability Committee, there may be additional reforms that will be proposed to address this issue, during a second phase of the stakeholder process. However, the Incremental Auction Senior Task Force voted to defer the continuation of further replacement capacity reform discussions until after the Commission rules on this filing. Thus, PJM does not definitively know whether the Section 206 proceeding is still needed until the Commission acts on this filing.

megawatt (“MW”) quantity that remains after the Final Incremental Auction, (3) reduce the number of IAs from three to two, and (4) revise the triggers that determine the MW quantity of PJM Buy Bids and/or Sell Offers in the IAs.

Under the Commission approved capacity market construct known as the Reliability Pricing Model (“RPM”), PJM conducts a BRA three years in advance of a Delivery Year to secure commitments of identifiable physical resources sufficient to satisfy projected load.³ Thereafter, the First, Second and Third IAs are conducted twenty, ten, and three months prior to the start of the Delivery Year, respectively. Each IA provides an opportunity for Capacity Market Sellers to sell available capacity and purchase replacement capacity, as well as a means for PJM to secure additional commitments of capacity or release sellers from prior capacity commitments based on updated reliability requirements.⁴

Historically, the clearing prices of IAs have been consistently and significantly lower than the clearing prices of the relevant BRA, as shown below. This pattern of low IA prices relative to the BRA price has two significant adverse impacts. First, it creates an environment in which Sell Offers in the BRA can be made with a high level of confidence that commitments can be replaced in an associated IA with little likelihood of economic loss and a high likelihood of profit. Such expectations may act to encourage BRA Sell Offers that have little or no reasonable expectation of physical delivery. Second, while load in PJM receives the proceeds of a release of excess capacity commitments in an IA, the load continues to pay the original BRA commitment at the BRA clearing price for the entire annual Delivery Year period. Therefore, as an example, if PJM releases excess capacity commitments in an IA at a price of 40% of the BRA price, then

³ Tariff, Attachment DD, section 5.4(a).

⁴ Tariff, Attachment DD, section 5.4(c).

PJM load will in effect pay 60% of the BRA clearing price to a Capacity Market Seller of a Capacity Resource that no longer has a commitment, as a result of the buyout in the IA, to provide any of the reliability and energy benefits it otherwise would have been required to provide. In fact, the Capacity Resource may not even physically exist because it may have retired, canceled, or delayed its in-service date, or worse, potentially had very little expectation of physical delivery when it was initially offered in the BRA.

The existing rules regarding PJM's release of excess capacity commitments in each IA play a considerable role in this persistent outcome⁵ and the proposed market rules in this filing are designed to address these issues. PJM proposes that these revisions be applicable to the BRA and associated IAs starting with the 2021/2022 Delivery Year and requests that the Commission issue its order accepting the enclosed revisions by no later than May 8, 2018, sixty (60) days from the date of this filing, with an effective date of May 8, 2018 for all revisions.

I. BACKGROUND

On March 10, 2014, PJM submitted proposed tariff revisions designed to discourage speculative offers from being submitted in the capacity auctions ("2014 Filing").⁶ Among the proposed tariff revisions of the 2014 Filing were changes to rules regarding the conduct of the IAs, particularly as they relate to PJM's participation in the IAs.⁷ Thereafter, the Commission

⁵ For the purpose of the IAs and throughout this discussion, excess capacity commitment means the MW quantity reduction in the PJM Region Reliability Requirement due to an updated PJM Region forecasted peak load that is lower than the forecasted peak load value used in the BRA. This clarification is made so that one does not mistakenly interpret excess capacity commitment as referred to throughout this discussion to mean the quantity that PJM may procure in a BRA above the target Reliability Requirement due to the use of a sloped VRR Curve in each BRA.

⁶ PJM Interconnection, L.L.C., Docket No. ER14-1461-000 (filed March 10, 2014).

⁷ Some of the other changes proposed in the 2014 Filing include, among others, requiring planned generation resources to support Sell Offers with a project development schedule, requiring facilities study agreement as a condition to offer into an RPM Auction, establishing a charge on all replacement capacity transactions, elimination

issued an Order on May 9, 2014 denying PJM's proposed revisions while agreeing that PJM's existing tariff provisions may encourage speculative Sell Offers to be submitted into PJM's RPM Auctions and undermine the long term reliability of the PJM Region.⁸ More particularly, while the Commission agreed with PJM that offers into the RPM Auction should not be speculative,⁹ it found that the proposal was beyond what was reasonable to ensure that offers are supported by physical resources.¹⁰ Consequently, the Commission initiated a separate proceeding under section 206 of the Federal Power Act, 16 U.S.C. § 824e (2000), in Docket No. EL14-48-000 and ordered a technical conference and comment procedure to "facilitate the development of a just and reasonable solution."¹¹

Since that time, PJM requested the Commission to defer action on the technical conference and comment procedure on three separate occasions in order to allow PJM to develop a fuller record of the results from additional IAs under the Capacity Performance construct. While the section 206 proceeding was deferred, the PJM Markets and Reliability Committee ("MRC") endorsed a new problem statement¹² and accompanying issue charge¹³ to review the general structure of the IAs and determine whether modifications are necessary on November 17, 2016. More particularly, the problem statement sought a solution that would appropriately

of two IAs, and increasing Capacity Resource Deficiency Charges. In contrast to the broad changes proposed in the 2014 Filing, the instant filing is much more limited and narrowly focused, as more fully discussed herein.

⁸ See *PJM Interconnection, L.L.C.*, 147 FERC ¶ 61,108, at P 2 (2014) ("2014 Order").

⁹ *Id.* at P 69.

¹⁰ *Id.* at P 73.

¹¹ *Id.* at P 74.

¹² The problem statement is available at:

<http://pjm.com/~media/committeesgroups/committees/mrc/20161117/20161117-item-07-incremental-auction-sales-problem-statement.ashx>.

¹³ The issue charge is available at: <http://pjm.com/~media/committees-groups/committees/mrc/20161117/20161117-item-07-incremental-auction-sales-issue-charge.ashx>.

compensate load for reducing capacity commitments in the IAs. Thereafter, PJM and its stakeholders engaged in an extensive and vigorous stakeholder process to design a solution that correctly values capacity in the IAs. This filing represents the culmination of PJM and its stakeholders' efforts to develop a set of narrowly tailored market rules that more appropriately value excess capacity commitments. In doing so, these rules will provide significant mitigation of the persistent pattern of low IA price results and address the concern that such a pattern may be encouraging BRA Sell Offers that have little or no reasonable expectation of physical delivery.

II. REVISED MARKET RULES ARE NECESSARY TO ENSURE COMMITMENTS ARE FOR IDENTIFIABLE PHYSICAL RESOURCES AND TO PROVIDE GREATER VALUE TO LOAD FROM THE BASE RESIDUAL AUCTION.

A. RPM Requires Commitments Based on Physical Resources.

The underlying purpose of the RPM Auction is to procure sufficient commitments of physical resources to reliably meet the needs of electric consumers within the PJM region. Commitments in the RPM Auction need to be physically available for PJM dispatch to either produce energy or reduce consumption of energy at peak times or during emergency conditions. Further, a high degree of forward certainty on the delivery of Capacity Resources is critical to ensuring long term reliability and an effective and efficient transmission planning process because of RPM's tight integration with PJM's Regional Transmission Expansion Planning Process. To achieve this goal, PJM obtains commitments of identifiable physical resources to meet resource adequacy needs three years forward through the BRA.

Subsequent to the BRA, the current rules require PJM to run three IAs associated with the Delivery Year. The IAs were intended for the purpose of providing a means for a Capacity Market Seller that cannot honor its BRA capacity commitment due to unforeseen physical

circumstances¹⁴ to avoid a deficiency penalty while maintaining the level of capacity committed in the BRA. PJM's current market rules do not protect against, and may in fact incentivize, speculative behavior. Specifically, the current rules allow Capacity Market Sellers to take on a commitment in the BRA with the opportunity to replace such BRA commitments in the IAs likely at a profit. This can encourage Capacity Market Sellers to offer in the BRA resources that have little or no reasonable expectation of physical delivery. Such an outcome defeats the long term resource adequacy objective of the RPM by distorting price signals on the value of capacity that RPM is designed to disclose.

B. A Persistent Pattern of IA Prices That are Below BRA Prices Provide Incentive for Offers to be Made in the Base Residual Auction with Little Expectation of Physical Delivery.

IA prices have been persistently below the corresponding BRA prices. The current IA market rules that this filing proposes to reform have been a significant contributor to this consistent trend. As explained in the attached affidavit of Mr. Jeffrey D. Bastian, PJM's Manager of Capacity Market Operations, "the average cost to purchase replacement capacity across the twenty-one IAs conducted since the three-IA format was first implemented for the 2012/2013 Delivery Year has been only 40.7% of the value assigned to those capacity commitments by the BRA."¹⁵ This is shown in Table 1, which Mr. Bastian explains, "compares the clearing prices in the BRA and corresponding IAs on a MW-weighted basis for all cleared IA

¹⁴ The need to purchase replacement Capacity Resources may arise for any reason, including but not limited to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences. See Tariff, Attachment DD, section 5.4(d).

¹⁵ Affidavit of Jeffrey D. Bastian on behalf of PJM Interconnection, L.L.C., at ¶ 9 (Attached hereto) ("Bastian Affidavit")

buy bids in all areas.”¹⁶ Mr. Bastian also notes that, as shown in Table 1, when focusing on the six Delivery Years for which all three IAs have been conducted, “the weighted average replacement cost has ranged from 16.2% to 72.5%¹⁷ of the BRA value of those capacity commitments.”¹⁸

Table 1: Weighted-Average IA Replacement Cost relative to BRA Capacity Values

| Delivery Year | # of IAs | Cleared Buy Bids | | | |
|---------------|----------|------------------|--------------------|------------------|----------------------|
| | | MW | BRA Value (\$/Day) | IA Cost (\$/Day) | IA Cost vs BRA Value |
| 2012/2013 | 3 | 9,346.4 | \$611,014 | \$99,200 | 16.2% |
| 2013/2014 | 3 | 13,649.2 | \$1,461,507 | \$412,800 | 28.2% |
| 2014/2015 | 3 | 14,008.5 | \$1,819,935 | \$488,731 | 26.9% |
| 2015/2016 | 3 | 11,979.4 | \$2,058,554 | \$1,492,561 | 72.5% |
| 2016/2017 | 3 | 16,636.8 | \$1,526,192 | \$828,800 | 54.3% |
| 2017/2018 | 3 | 12,414.3 | \$1,538,809 | \$667,501 | 43.4% |
| 2018/2019 | 2 | 7,254.1 | \$1,263,498 | \$214,309 | 17.0% |
| 2019/2020 | 1 | 3,992.0 | \$398,425 | \$139,101 | 34.9% |
| Total | 21 | 89,280.7 | \$10,677,934 | \$4,343,004 | 40.7% |

Thus, not only is the average cost to procure replacement capacity in an IA very low relative to the corresponding BRA price, but the pattern is consistent. The consistently low IA prices provide an incentive to submit BRA Sell Offers with little or no expectation of physical delivery. That is because Capacity Market Sellers can reliably expect an opportunity to buy out of their BRA commitment – avoiding all capacity availability, energy offer and performance

¹⁶ Bastian Affidavit at ¶ 9.

¹⁷ Mr. Bastian notes that the 72.5% value occurred in the 2015/2016 Delivery Year. For that Delivery Year, PJM sought and received approval of a waiver to not release excess capacity commitment in the 3rd IA. PJM observed that in the 3rd IA for the 2015/2016 Delivery Year, the cost to procure replacement capacity was 98.5% of the corresponding BRA value. *Id.* at ¶ 9

¹⁸ Bastian Affidavit at ¶ 9.

requirements – at IA prices that are substantially less than the price they will receive for clearing in the BRA while retaining a large portion of the payment associated with having cleared the BRA.

C. Observed Replacement of BRA Commitments Shows Higher Rate of Replacement for Resource Types Having Most Uncertainty of Three-Year Forward Physical Capability.

PJM’s Independent Market Monitor (“IMM”) recently produced an updated report that analyzed RPM replacement rates by Capacity Resource type.¹⁹ Using data from IMM’s updated report, Table 2 shows the MW quantity of replaced commitment and the replacement rate (shown as a percent of replaced MW quantity versus total MW quantity cleared in all auctions) by Delivery Year²⁰ and by category of resource type.

Table 2: Replacement Rate by Capacity Resource Type

| Delivery Year | Internal In-Service Generation | | | Internal Planned Generation | | | External Generation | | | Demand Resource | | |
|----------------|--------------------------------|--------------|--------------|-----------------------------|--------------|--------------|---------------------|-------------|--------------|-----------------|--------------|--------------|
| | Cleared MW | Replaced MW | Replace Rate | Cleared MW | Replaced MW | Replace Rate | Cleared MW | Replaced MW | Replace Rate | Cleared MW | Replaced MW | Replace Rate |
| 2012/13 | 127,361 | 7,056 | 5.5% | 2,999 | -67 | -2.2% | 1,517 | 123 | 8.1% | 8,753 | 2,265 | 25.9% |
| 2013/14 | 141,713 | 8,083 | 5.7% | 4,020 | 480 | 11.9% | 2,429 | 479 | 19.7% | 10,780 | 3,314 | 30.7% |
| 2014/15 | 138,240 | 6,314 | 4.6% | 3,275 | -27 | -0.8% | 3,678 | 812 | 22.1% | 14,943 | 6,732 | 45.0% |
| 2015/16 | 146,096 | 6,662 | 4.6% | 5,432 | 859 | 15.8% | 5,353 | -160 | -3.0% | 15,775 | 5,151 | 32.7% |
| 2016/17 | 147,893 | 6,143 | 4.2% | 9,112 | 2,342 | 25.7% | 7,761 | 2,938 | 37.9% | 13,285 | 4,820 | 36.3% |
| 2017/18 | 148,243 | 5,881 | 4.0% | 13,574 | 4,162 | 30.7% | 4,981 | 264 | 5.3% | 11,871 | 3,871 | 32.6% |
| Average | 141,591 | 6,690 | 4.7% | 6,402 | 1,291 | 20.2% | 4,286 | 743 | 17.3% | 12,568 | 4,359 | 34.7% |

As demonstrated in Table 2, Demand Resources show the highest replacement rate on average among the different categories. Internal Planned Generation Capacity Resources and External Resources show considerable variability to the extent they replace a BRA capacity

¹⁹ “Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2016,” available at <http://www.pjm.com/-/media/committees-groups/task-forces/iastrf/20180119/20180119-item-03a-imm-report-capacity-replacement-activity.ashx>. This report was recently filed in Docket Nos. EL14-48-000 and ER14-1461-001 by the IMM on December 30, 2016.

²⁰ The data shows the replacement quantities on the June 1 start date of the relevant Delivery Year.

commitment. Nonetheless, in some years, these two resource categories have also replaced capacity in the IAs at high rates. As Mr. Bastian explains, “Demand Resources, External Resources, and Planned Generation Capacity Resources show the highest replacement rate on average among the different resource categories. This is indicative of Capacity Market Sellers submitting Sell Offers that have a heightened degree of uncertainty in the BRA. This is because at the time of the BRA, Planned Generation Capacity Resources will still be in development and Demand Resources likely will not have all of their end-users identified and under contract.”²¹

Although the commitment replacement rate of Existing Generation Capacity Resources is low relative to the other resource types on an absolute basis, large quantities of Existing Generation Capacity Resource commitments are also replaced. The large quantity of replaced commitments of Existing Generation Capacity Resources is associated in some instances with generation that cleared in a BRA and subsequently deactivated prior to the start of the BRA Delivery Year. Therefore, Capacity Market Sellers that submit BRA Sell Offers of Existing Generation Capacity Resources, resources that physically exist at the time of the BRA Sell Offer, are also confronted with the need to assess their reasonable expectation to physically delivery on a BRA commitment at the time a BRA Sell Offer is submitted.

The observed high level of purchases of replacement capacity in the IAs indicates that some Capacity Market Sellers are submitting Sell Offers that have a heightened degree of uncertainty into the BRA. As previously discussed, Sell Offers from such Capacity Resources can distort the price signals on the value of capacity that RPM is designed to disclose and are ultimately detrimental to the long term resource adequacy and reliability objective of RPM.

²¹ Bastian Affidavit at ¶ 11. The requirements for RPM participation by External Generation Capacity Resources have changed considerably over this period of time; and current requirements to participate eliminate much of the uncertainty that existed prior to the 2017/2018 Delivery year.

D. Existing Rules Regarding PJM's Release of Excess Capacity Commitment Significantly Contribute to the Persistent Disparity Between BRA and IA Clearing Prices

Existing rules pertaining to PJM's release of excess capacity commitment in the IAs significantly contribute to the persistent disparity between the BRA and corresponding IA clearing prices. When the updated IA reliability requirement decreases from the reliability requirement used in the BRA, existing rules direct PJM to release this excess capacity commitment through a PJM Sell Offer of a MW quantity equal to the change in reliability requirement and at a price that is based on the updated VRR Curve Decrement. This requirement has resulted in PJM releasing a substantial amount of excess capacity commitments into the IAs at a low prices relative to the BRA clearing price, often times at zero, which has negatively influenced the IA clearing prices.

Table 3: Source of Supply and Cost of Cleared IA Buy Bids²²

| Delivery Year | Cleared Buy Bid MW | IA Cost vs BRA Value | Cleared Participant Sell Offer MW | | Cleared Net PJM Sell Offer MW | |
|-----------------------|--------------------|----------------------|-----------------------------------|---------------------|-------------------------------|---------------------|
| | | | MW | % of Cleared Supply | MW | % of Cleared Supply |
| 2012/2013 | 9,346 | 16.2% | 4,930.0 | 52.7% | 4,416.4 | 47.3% |
| 2013/2014 | 13,649 | 28.2% | 7,087.6 | 51.9% | 6,562.0 | 48.1% |
| 2014/2015 | 14,009 | 26.9% | 9,831.6 | 70.2% | 4,177.2 | 29.8% |
| 2015/2016 | 11,979 | 72.5% | 9,250.3 | 77.2% | 2,729.1 | 22.8% |
| 2016/2017 | 16,637 | 54.3% | 6,368.1 | 38.3% | 10,268.7 | 61.7% |
| 2017/2018 | 12,414 | 43.4% | 3,504.6 | 28.2% | 8,909.7 | 71.8% |
| Average per DY | 13,005.9 | 43.1% | 6,828.7 | 53.9% | 6,177.2 | 46.1% |

²² Available at: <http://www.pjm.com/-/media/committees-groups/task-forces/iastf/postings/historical-ia-results-ia-buy-cost-vs-bra-value.ashx?la=en>

Table 3 shows the total MW quantity of replacement capacity purchased by participants across all three IAs for each of the six Delivery Years for which all three IAs have been conducted. As explained by Mr. Bastian, “[t]he average total MW quantity of cleared Buy Bids for each of the six Delivery Years for which all three IAs have been conducted was 13,005.9 MWs and the weighted average cost to purchase this replacement capacity was 43.1% of the BRA value of the capacity commitment. The 13,005.9 MWs of Buy Bids that were purchased as replacement capacity in the IAs of these Delivery Years cleared against on average 6,828.7 MW of Capacity Market Seller Sell Offers and 6,177.2 MW of PJM IA Sell Offers. The PJM IA Sell Offers therefore satisfied 46.1% of the 13,005.9 MW of replacement capacity that was purchased in the IAs at a price of only 43.1% of the BRA value.”²³ These statistics demonstrate that the existing rules regarding PJM’s release of excess capacity commitments strongly influence the IA clearing prices and significantly contribute to the persistent disparity between BRA and IA clearing prices.²⁴

E. Existing Rules Regarding PJM’s Release of Excess Capacity Commitment do not Properly Recognize the Value of Excess Capacity Commitment to PJM Load or the Cost Avoided by a Capacity Market Seller that Replaces a BRA Commitment.

A Capacity Market Seller that clears a Capacity Resource in a BRA takes on a capacity commitment that carries with it an obligation to meet certain performance requirements. These performance requirements provide reliability and energy market benefits to PJM’s load that pay the Capacity Market Seller for the quantity of MWs of the Capacity Resource cleared in the BRA. These performance requirements can also result in significant cost being levied on the

²³ Bastian Affidavit at ¶ 12.

²⁴ See Bastian Affidavit at ¶ 13.

Capacity Market Seller if its Capacity Resource is unable to meet these requirements. When a Capacity Market Seller replaces a Capacity Resource's BRA commitment, it continues to receive payment for the MWs that it cleared in the BRA, but the resource is excused of all benefit-providing performance requirements associated with the now replaced commitment in addition to avoiding any potential costs associated with Capacity Resource Deficiency Charges and Non-Performance Charges.

This outcome is illustrated by Mr. Bastian's example below:

Assume a Capacity Market Seller clears 100 MWs in a BRA at a BRA clearing price of \$100/MW-Day, it will receive annual revenues over the relevant BRA Delivery Year of \$3.65 million (100 MW x \$100/MW-Day x 365 days). If the Capacity Market Seller is unable to physically deliver on the BRA commitment (e.g., an Existing Generation Capacity Resource that has retired subsequent to the BRA or a Planned Generation Capacity Resource that has cancelled or delayed its in-service date), it is subject to a Capacity Resource Deficiency Charge of \$4.38 million (100 MW x 120% x \$100/MW-Day x 365 days) or the possibility of Non-Performance Charges up to the maximum non-performance charge stop-loss level of \$12.91 million. If the Capacity Resource is able to physically deliver on the BRA commitment, it would not be subject to a Capacity Resource Deficiency Charge. However, the resource would still face the possibility of Non-Performance Charges up to the maximum stop-loss level of \$12.91 million. By replacing the BRA commitment, the Capacity Market Seller is excused of having to physically deliver the Capacity Resource on the BRA commitment and avoids any potential cost associated with Capacity Resource Deficiency Charge. In addition, such Capacity Market Seller would be excused of all performance requirements associated with the replaced commitment. As a result, the Capacity Market Seller would avoid all possibility of being assessed a Non-Performance Charge for non-performance during any Performance Assessment Intervals that may occur during the Delivery Year. In fact, any and all performance from this resource during any Performance Assessment Interval that may occur during the Delivery Year will be eligible for Bonus Payments. Consequently, Capacity Market Sellers should rationally be willing to pay the BRA clearing price for replacement capacity in order to avoid the significantly higher costs associated with a Capacity Resource Deficiency Charge and/or Non-Performance Charge.

Continuing with this example, next assume that the Capacity Market Seller of such Capacity Resource purchased the 100 MWs of replacement capacity through a 100 MW IA Buy Bid that cleared against a 100 MW PJM IA Sell Offer at an IA clearing price of \$40/MW-Day (i.e. the historical IA data of Table 1 showed the average IA clearing price to be 40.7% of the corresponding BRA clearing price).

The Capacity Market Seller will pay a charge over the relevant BRA Delivery Year of \$1.46 million (100 MW x \$40/MW-Day x 365 days) for the replacement capacity it purchased in the IA, while avoiding an annual cost of \$4.38 million associated with a Capacity Resource Deficiency Charge (if the resource is unable to physically deliver on the BRA commitment) and the possibility of an annual cost of up to \$12.91 million associated with the maximum Non-Performance Charge stop-loss level. Meanwhile, the Capacity Market Seller continues to receive revenue over the relevant BRA Delivery Year of \$3.65 million for the 100 MWs that it cleared in the BRA. After netting out the \$1.46 million annual cost of the IA purchase, the Capacity Market Seller will receive revenues over the relevant BRA Delivery Year of \$2.19 million solely through its participation in PJM's capacity market without any obligation to provide the reliability and energy market benefits associated with a capacity commitment. In addition, to the extent the Capacity Resource of this example does physically exist, any performance from the resource during any Performance Assessment Interval that may occur during the Delivery Year will be eligible for Bonus Payments.

Through the Locational Reliability Charge that is assessed to PJM load each day of the Delivery Year, PJM load will pay the Capacity Market Seller of the Capacity Resource of this example \$3.65 million over the course of the annual BRA Delivery Year period for the 100 MWs that the resource cleared in the BRA and it will receive a \$1.46 million credit over the annual BRA Delivery Year period for the 100 MWs of excess capacity commitment that was released in the IA on behalf of PJM load. From the perspective of PJM load, it will pay the Capacity Resource of this example \$2.19 million over the annual BRA Delivery Year period without receiving the reliability and energy market benefits that are provided by a Capacity Resource having a commitment obligation. The economic value to load of these foregone benefits is not zero. In fact, PJM conducted annual energy market simulations during the course of stakeholder discussion that showed energy market benefit to load alone to be in the range of \$86,000/MW-Year to \$124,000/MW-Year. Using this range of estimated energy market benefits, the 100 MW Capacity Resource in the example would have provided load with annual energy market benefits ranging from \$8.6 million to \$12.4 million. Therefore, PJM load is paying the Capacity Resource of this example \$2.19 million over the annual BRA Delivery Year period while at the same time forgoing annual energy market benefits ranging from \$8.6 million to \$12.4 million that the Capacity Resource would have otherwise provided. This outcome suggests that excess capacity commitment should be retained and not released unless it was released at a price equivalent to the \$8.6 million foregone value noted above.²⁵

²⁵ Bastian Affidavit at ¶ 14.

In summary, the existing rules regarding the pricing of PJM's release of excess capacity commitment on behalf of PJM load do not properly recognize a rational price that the Capacity Market Seller of a Capacity Resource should be willing to pay in order to avoid the significant cost it would otherwise incur due to an inability to physically deliver on a BRA commitment or an inability to satisfy the performance requirements of the BRA commitment. Nor do the existing rules recognize the forgone value of the benefit provided to load by a BRA commitment that is subsequently replaced by a PJM release of excess capacity commitment. Thus, as discussed in more detail in section III.A., the proposed revisions of this filing will release excess capacity commitment in an IA at a Sell Offer price equal to the BRA clearing price of the relevant Delivery Year.

III. THE PROPOSED TARIFF REVISIONS TO EXISTING INCREMENTAL AUCTION RULES ARE JUST AND REASONABLE.

PJM proposes four main revisions to the current IA rules. Specifically, as further explained below, PJM proposes to (1) release excess capacity commitments at a Sell Offer price equal to the relevant BRA clearing price, (2) replace the current practice of allocating uncleared PJM IA Sell Offer MWs as ECCs with a process for excusal of capacity commitments up to the uncleared PJM Sell Offer MW quantity that remains after the Final Incremental Auction, (3) reduce the number of IAs from three to two, and (4) revise the triggers that determine the MW quantity of PJM Buy Bids and/or Sell Offers in the IAs. These revisions are just and reasonable as they are designed to rectify the current RPM environment that incentivizes Sell Offers in the BRA that have no reasonable expectation of physical delivery, while at the same time, continue to allow Capacity Market Sellers to buy out their capacity obligations when unforeseen circumstances arise. If accepted, PJM proposes that these revisions be applicable to the BRA and associated IAs starting with the 2021/2022 Delivery Year and beyond.

A. PJM Will Release Excess Capacity Commitments Using a Sell Offer Price Equal to the BRA Clearing Price.

The current RPM Auction rules direct PJM to release capacity when the need for such capacity, as determined at the time of the IA, is lower than the need for capacity as determined at the time of the BRA.²⁶ Specifically, when the updated IA reliability requirement has decreased from the reliability requirement used in the BRA, existing rules direct PJM to release the excess capacity commitment quantity via a PJM IA Sell Offer at a price that is based on the updated VRR Curve Decrement.

As Mr. Bastian explains, PJM's utilization of the VRR Curve Decrement to price the release of capacity has led to a consistent pattern of IA prices that are significantly lower than the corresponding BRA prices. This is because the use of the VRR Curve Decrement has led to PJM's "willingness" to release excess capacity at low prices relative to the BRA clearing price, often times at zero. This persistent outcome creates an environment that may incentivize Capacity Market Sellers to submit BRA Sell Offers that have little or no reasonable expectation of physical delivery.²⁷ Such Sell Offers can distort the price signals on the value of capacity that RPM is designed to disclose, which is detrimental to the long term resource adequacy and reliability objective of RPM. Additionally, the low IA prices have provided little value back to load of otherwise committed resources relative to the cost of the initial BRA procurement. The use of the updated VRR Curve Decrement that results in a low Sell Offer Price for PJM's release of excess capacity commitment does not properly recognize the rational price that the owner of a Capacity Resource would be willing to pay. That is, a rational seller should be willing to pay up to an amount that is just below the cost it would otherwise incur due to an inability to physically

²⁶ See Tariff, Attachment DD § 5.12(b)(iii).

²⁷ Bastian Affidavit at ¶ 8.

deliver on a BRA commitment or an inability to satisfy the performance requirements of the BRA commitment. Nor does this pricing mechanism recognize the forgone value of the benefit provided to load by a BRA commitment that is subsequently replaced by a PJM release of excess capacity commitment.

To address these concerns, this filing proposes to release excess capacity commitment using a PJM IA Sell Offer at a price equal to the relevant Delivery Year's BRA clearing price.²⁸ In other words, excess capacity commitments will only be released at an IA clearing price equal to the relevant BRA clearing price. Releasing excess capacity commitment at the BRA clearing price has the dual benefit of more fairly compensating PJM load while addressing the concern that persistently low IA clearing prices may act to encourage BRA Sell Offers that have little or no reasonable expectation of physical delivery. By releasing excess capacity commitment at the BRA clearing price, PJM (on behalf of PJM load) is permitting a Capacity Market Seller to be relieved of the agreement it made three years prior under the same terms and conditions under which the commitment was initially made (i.e., payment at the BRA clearing price for the entire annual BRA Delivery Year period). The BRA clearing price is reflective of a Capacity Market Seller's need to replace a BRA commitment for physical reasons (i.e. the intended purpose of IAs) rather than for financial gain. Thus, releasing excess capacity commitment at the BRA clearing price will continue to allow Capacity Market Sellers to replace a BRA commitment obligation in the event of an unforeseen physical circumstance.

This proposed change is not intended to nor will it ensure that the IAs clear at the relevant BRA clearing price. That is because other Capacity Market Sellers seeking to sell capacity in the IA may do so at a price that is below the relevant Delivery Year's BRA price.

²⁸ See proposed Tariff, Attachment DD, section 5.12(b)(iii).

Thus, Capacity Market Sellers are not precluded from purchasing replacement capacity in an IA at prices below the BRA clearing price. Nonetheless, the role that the PJM release of capacity plays in the persistent ability to do so will be justly eliminated. As a result, the proposed revision will provide significant mitigation of the historical persistent pattern of IA prices being significantly lower than the corresponding BRA prices and address the concern that BRA Sell Offers that have little or no reasonable expectation of physical delivery have taken advantage of this pattern.

In summary, PJM's release of excess capacity commitments into an IA with an offer price set equal to the relevant BRA clearing price will ensure that PJM's release of capacity mitigates against a low IA clearing price that otherwise supports the replacement of capacity commitments for a financial gain. Further, releasing excess capacity commitment at the BRA clearing price to a Capacity Market Seller with a BRA commitment is analogous to the reasonable outcome of equally excusing both PJM load and the Capacity Market Seller from the terms and conditions of the agreement that was entered into when the Capacity Market Seller cleared in the BRA. More particularly, PJM's load is effectively excused from paying to the Capacity Market Seller the annual revenues that it initially agreed to pay, and the Capacity Resource is excused from providing the beneficial services that it initially agreed to provide. By releasing excess capacity commitment at the BRA clearing price and never at a price below the BRA clearing price, the PJM sell-back MW quantity is preserved for the intended purpose of the IA, which is to provide a means for a resource owner to avoid the charges associated with a BRA commitment that it cannot physically satisfy, while maintaining the same level of adequacy that PJM procured in the BRA.

While the Commission previously declined to accept proposed tariff changes that included a price floor of the BRA clearing price on the excess capacity commitment that PJM sought to release in an IA, the instant revised proposal is distinguishable because the 2014 Filing contained several components as part of the proposed market rule changes. Specifically, the 2014 Filing included a replacement capacity adjustment charge that would equal the difference between the annual BRA clearing price and the IA price and that would be applied to each and every commitment replacement transaction. In denying PJM's initial proposed capacity replacement rules, the Commission reasoned that the BRA Sell Offer price was unnecessary because the proposed replacement capacity adjustment charge would have accomplished the same goal of protecting load.²⁹ Unlike the prior 2014 Filing, however, the proposed revisions in this filing do not contain a replacement capacity adjustment charge. Therefore, the Sell Offer at the BRA clearing price is appropriate in this filing as it is not repetitive of any other revision in this filing. Further, this proposed revision is a just and reasonable as it will lead to IA clearing prices that better reflect the value of the capacity being replaced.

B. PJM Will Allow for Excusal of Excess Capacity After the Final Incremental Auction and Retain Any Remaining Excess Commitments.

Under current rules, any PJM IA Sell Offer MW quantity that does not clear in the Third IA is allocated in the form of ECCs to Load Serving Entity ("LSE"). For the reasons discussed below, this filing proposes to replace the current process of allocating uncleared PJM IA Sell Offer MWs to PJM's load as ECCs, and instead allow for the excusal of capacity commitments up to the uncleared PJM Sell Offer MW quantity that remains after the Final Incremental Auction.

²⁹ 2014 Order at P 72.

Under existing rules, the total uncleared MW quantity of a PJM IA Sell Offer of the Third IA is allocated as excess capacity commitment MWs to PJM's LSEs.³⁰ ECCs are allocated in the form of MWs that may be used as replacement capacity in the same way that a cleared IA Buy Bid is used. Once allocated, the LSE may use excess capacity commitment MWs to replace the commitment of a Capacity Resource owned or contracted by the LSE or the LSE may bilaterally transact excess capacity commitment MWs to another party to be used as replacement capacity. The rationale behind the allocation of ECCs to PJM LSEs is that PJM's load pays for all Capacity Resource commitments made by clearing in a BRA through the daily Locational Reliability Charge that is assessed to all PJM load, and PJM load should therefore be the recipient of any excess capacity commitment that may remain after first attempting to release this quantity through a PJM IA Sell Offer. While this rationale appears reasonable, this practice has several negative features. Specifically, as described in more detail below, the current ECC allocation process (1) creates unequal access to excess capacity commitments for Capacity Market Sellers seeking to replace a BRA commitment, (2) disproportionately credits to PJM load when excess capacity commitment MWs are used as replacement capacity, and (3) undermines the intent of other revisions proposed in this filing by providing an alternative means to access excess capacity commitment at a price below the BRA clearing price.

The existing ECC mechanism provides unequal access for all Capacity Market Sellers to excess capacity commitments for replacement purposes. Specifically, Capacity Resources that are owned or contracted by an LSE or affiliated with an LSE can access excess capacity commitment through the ECC allocation. Once allocated, an LSE may use excess capacity commitment MWs to replace the commitment of a Capacity Resource that it owns or contracts

³⁰ Tariff, Attachment DD, section 5.12(b)(viii)(B).

for or the LSE may bilaterally transact excess capacity commitment MWs to another party to be used as replacement capacity. Certainly, an LSE that owns one or more other Capacity Resources with a BRA commitment will benefit from any excess capacity commitment MWs it was allocated because it can use the excess capacity commitment MW to replace the BRA commitment of its own Capacity Resources, thereby avoiding the need to physically deliver on the BRA commitment and the need to meet the performance requirements of the BRA commitment. However, while all PJM LSEs are allocated a share of the total excess capacity commitment MWs, it is only those LSEs that own a Capacity Resource or that can find a buyer for the excess capacity commitment MW that can benefit from the allocation. Because PJM procures commitments from eligible Capacity Market Sellers in a BRA without regard to ownership or affiliations of the resources, all Capacity Resources that clear in a BRA should be treated equally when it comes to purchasing any excess capacity commitment MWs that might exist.

This effectively results in disproportionately distributing the value of the allocated excess capacity commitment MWs to PJM's load. As explained, ECCs are allocated in the form of MWs, not dollars, that may be used as replacement capacity in the same way that a cleared IA Buy Bid is used. Therefore, only LSEs that are able to monetize the ECCs will benefit. As a result, not all of PJM's LSEs realize the same benefit when the uncleared MW portions of a PJM IA Sell Offer are allocated to PJM's LSEs in the form of ECCs. The remaining PJM load would not be equally compensated for the ECCs, while forgoing any incremental reliability and energy market benefits that the replaced commitment would otherwise have provided.

In addition, retaining the existing ECC mechanism would undermine the proposal for PJM to release excess capacity commitments in an IA only at the BRA clearing price or higher

by providing an end run means of access to excess capacity commitments either through direct allocation of excess capacity commitment MWs or through bilateral purchase of excess capacity commitment MWs. Providing a Capacity Market Seller with direct or bilateral access to excess capacity commitment MWs will discourage the seller from meaningful participation in the IA to purchase PJM's release of excess capacity commitment MWs. A Capacity Market Seller that expects to have access to any uncleared MWs remaining after the IA is incented to keep as many of these MWs uncleared as possible and will either not participate in the IA to purchase replacement capacity or will participate with a Buy Bid price below the BRA clearing price.

Under the proposed revisions in this filing, if PJM releases excess capacity commitment MWs into the Final Incremental Auction conducted prior to the start of the Delivery Year, it will do so using a PJM capacity release price equal to the BRA clearing price. Under this approach, all Capacity Market Sellers of Capacity Resources with a BRA commitment will have equal opportunity to purchase replacement capacity by submitting a Buy Bid into the IA and all such Capacity Market Sellers will be aware that they will not be able to replace capacity against PJM's release of capacity commitments in the IA unless they are willing to pay a price equal to the BRA clearing price or higher. All Capacity Market Sellers of Capacity Resources that cannot physically deliver on a BRA commitment or that have concerns with the costs of not meeting the performance requirements of a BRA commitment should have the same financial incentives to replace the commitment and should have access to the same replacement options regardless of whether or not the Capacity Resource is affiliated with or owned or contracted by an LSE.

When PJM's released capacity clears in an IA, all PJM load realizes a reduced Locational Reliability Charge as a result of the release. The total dollar amount that needs to be collected each day of the Delivery Year from PJM's load in order to pay Capacity Resources that were

procured in RPM Auctions on behalf of PJM load is reduced by the dollar value of the released MW quantity (i.e., released MW quantity times the IA clearing price), and all of the LSEs in PJM will see a reduced overall cost regardless of whether the LSE serves wholesale or retail customers and regardless of whether the LSE has ownership in a Capacity Resource(s) with a capacity commitment.

For all of the reasons discussed above, the filed revisions eliminate the existing ECC mechanism that allocates the uncleared MW quantity of a PJM IA Sell Offer to LSEs.³¹ Instead, the filed revisions include a proposed mechanism that will allow Capacity Market Sellers to be excused of their BRA commitments up to the level of any remaining excess capacity commitment MWs that are not sold in the Final Incremental Auction.³² Specifically, during an open request window that closes fifteen Business Days prior to the start of the relevant Delivery Year, Capacity Market Sellers may request to be excused of all or a portion of a Capacity Resource's BRA commitment up to the total MW quantity of uncleared excess capacity commitment that remains after the Final Incremental Auction.³³ When a Capacity Market Seller's BRA commitment is voluntarily excused, the Capacity Market Seller relinquishes the BRA auction credit that it would otherwise receive for the excused BRA MW quantity and is no longer responsible for satisfying the commitment and performance obligation of the commitment associated with the excused BRA MW quantity. The total relinquished dollar value of all accepted BRA commitment excusals will be allocated as a separate RPM-related billing line item to PJM load each day of the Delivery Year based on each LSE's pro-rata share of the total RTO

³¹ See proposed Tariff, Attachment DD, section 5.12(b)(viii)(B).

³² See proposed Tariff, Attachment DD, section 5.12(b)(ix).

³³ *Id.*

UCAP obligation. All Capacity Market Sellers with a BRA commitment will have access to this mechanism and all PJM LSEs will receive a pro-rata share on a daily basis of the total dollar value of relinquished BRA commitments.

Under this proposal, the maximum total MW quantity of BRA commitment excusal requests that may be accepted across the entire RTO equals the total of uncleared MW commitments that PJM seeks to release in the Final Incremental Auction. The maximum total MW quantity of BRA commitment that may be excused within each modeled Locational Delivery Area (“LDA”) is equal to the updated final LDA Reliability Requirement minus the total committed capacity located within the LDA minus the LDA Capacity Emergency Transfer Limit, not to exceed the maximum total MW quantity that may be excused across the entire RTO. All requests will be accepted if the total MW quantity of all BRA excusal requests received during the open request window is less than the maximum permissible levels for the RTO and each modeled LDA. However, in the event the total MW quantity of all BRA excusal requests exceeds the maximum permissible level for the entire RTO, all requests will be accepted but at reduced levels based on each requestor’s pro-rata share of the maximum permissible MW quantity of the RTO. If after this proration, the total MW quantity of BRA excusal requests exceeds the maximum permissible level for a modeled LDA, all requests within that LDA will be reallocated based on each requestor’s pro-rata share of the maximum permissible level for that LDA. Any residual quantity will be allocated to requests located outside of that LDA while again ensuring that the maximum permissible level of any given modeled LDA is not exceeded.

This excusal proposal is just and reasonable as it allows for the release of excess capacity commitments in a manner that is entirely consistent with the proposed revision of releasing excess capacity commitment in the Final Incremental Auction at the BRA clearing

price. PJM's load is excused from paying a Capacity Resource that has been excused of all benefit-providing services that it initially agreed to deliver by clearing in a BRA, and, it preserves excess capacity commitment MWs for replacement of a BRA commitment for physical reason rather than for financial gain at the expense of PJM's load. Further, unlike the existing excess capacity commitment MW allocation to PJM LSE, this proposed mechanism provides equal access for all Capacity Resources to excess capacity commitments for purposes of replacing a BRA commitment and provides value to all PJM LSEs, rather than only a subset of PJM LSEs.

C. PJM Will Reduce the Number of IAs to Two Per Delivery Year.

The current market rules allow Capacity Market Sellers to buy out of BRA commitments in any of the three IAs that are conducted for each Delivery Year. This construct effectively provides Capacity Market Sellers that clear in a BRA with three separate chances to successfully "shop" for BRA replacement capacity at a low price that is not consistent with what a rational seller should be willing to release, as detailed above. On the supply side, by contrast, all available capacity of each Existing Generation Capacity Resources must be offered into each IA and PJM must offer excess capacity commitment into each IA under existing rules that have resulted in substantial supplies into the IAs at a fairly low price relative to the BRA, often times at zero. These rules tend to reduce IA clearing prices, as compulsory Sell Offers are matched against Buy Bids that have a choice to participant in any or all of the three IAs.

To address this issue, this filing proposes to revise the number of IAs conducted for each Delivery Year from three to two. More particularly, PJM proposes to eliminate the Second Incremental Auction and replace the Third Incremental Auction with a Final Incremental Auction. The First Incremental Auction will be conducted twenty months prior to the start of the

associated Delivery Year, consistent with the current timing of the First Incremental Auction.³⁴

The Final Incremental Auction will be conducted three months prior to the start of the Delivery Year, consistent with the current timing of the Third Incremental Auction.³⁵ Also consistent with the current rules, Capacity Market Sellers may submit Buy Bids in both the First and Final Incremental Auctions. Existing Generation Capacity Resources are required to offer any available capacity into both the First and Final Incremental Auctions while Planned Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources may elect to voluntarily offer capacity in both the First and Final Incremental Auctions. However, unlike current rules, proposed revisions limit PJM participation to either procure additional MWs or release excess MWs to only the Final Incremental Auction. Under the proposed revisions, the First Incremental Auction will provide a means for the buying of replacement capacity and the selling of available capacity amongst Capacity Market Sellers. The Third Incremental Auction will serve this same purpose while also providing a means for PJM to either procure additional capacity commitment or release excess capacity commitment as needed. This proposed revision is just and reasonable as it will mitigate against the ability for Capacity Market Sellers to sell at an unjustifiably low price, while still allowing the ability for PJM and Capacity Market Sellers to buy and sell capacity as needed due to changing needs.

³⁴ Tariff, Attachment DD, section 5.4(b).

³⁵ *Id.* PJM proposes to rename the Third Incremental Auction as the Final Incremental Auction in the revised rules for purposes of clarity in the tariff language. Specifically, it is necessary to retain the distinction between Third Incremental Auctions and Final Incremental Auctions while the new rules are phased in since these proposed revisions will only apply starting with the 2021/2022 Delivery Year and associated Incremental Auctions.

D. PJM Proposes to Revise the Triggers for Determining the Quantity of PJM Buy Bid/Sell Offer.

In conjunction with the aforementioned changes, this filing proposes to amend the triggers that determine whether to buy additional commitments in the IAs and whether to release excess capacity commitment in the IAs. Under current rules, PJM is required to submit Buy Bids in any IA to procure capacity if the updated reliability requirement exceeds total committed capacity level by more than the lesser of 500 MW or 1% in any IA.³⁶ In addition, PJM is required to submit Buy Bids in any IA to procure capacity when the updated reliability requirement exceeds the prior utilized reliability requirement. However, in the First and Second Incremental Auctions, the requirement to procure additional capacity due to an increase in reliability requirement is triggered only if the increase is more than the lesser of 500 MW or 1%.³⁷ Conversely, under current rules, PJM is required to submit a PJM IA Sell Offer in any IA to release excess capacity commitment when the updated reliability requirement decreases from the prior utilized Reliability Requirement. In the First and Second Incremental Auctions, this requirement to release excess capacity commitment due to a decrease in reliability requirement is triggered only if the decrease is more than the lesser of 500 MW or 1%.³⁸

In this filing, PJM proposes to eliminate the existing requirement to procure capacity in the IAs due to an increase in the reliability requirement, but retain the existing requirement to procure capacity in the Final Incremental Auction if the updated final reliability requirement exceeds the current level of committed capacity by more than the more than the lesser of

³⁶ Tariff, Attachment DD, section 5.4(c)(1).

³⁷ Tariff, Attachment DD, section 5.4(c)(2)(i)

³⁸ Tariff, Attachment DD, section 5.4(c)(3)(i)

500 MW or 1%.³⁹ Further, PJM will retain the existing requirement to release excess capacity commitment when the updated reliability requirement falls below the prior utilized reliability requirement, but only in the Final Incremental Auction.

This proposal is just and reasonable as it will eliminate the possibility that PJM buy additional capacity in one IA only to release excess capacity commitment in the next IA for the same Delivery Year, or vice versa. This inefficient outcome is clearly possible under the current rules that require PJM to participate to procure or release capacity in each IA for relatively small changes in reliability requirement either up or down. This will also limit PJM's participation to the point in time where the final requirements are known and not subject to further change, as well as the point in time when the owners of Capacity Resources that cleared in the BRA should be more certain of their ability to physically deliver the commitment. Further, the proposed revision takes advantage of any reserve level procured in the BRA above the target reserve level. That is, the reserve level will offset any subsequent increases in the reliability requirement up to the point where a reliability concern is presented by the procured reserve level falling short of the updated reliability requirement.

E. PJM Proposes to Include Non-substantive Revisions Contained Within These Sections as Part of this Filing.

In addition to the proposed substantive revisions described above, PJM also submits minor and non-substantive revisions to correct certain formatting issues and modify incorrect references located within the relevant Energy Efficiency sections. For example, rather than the reference "section 5.10(a) of this Attachment DD" as currently used in Tariff, Attachment DD, section 5.11(a)(vi), PJM proposes to change the reference to "Tariff, Attachment DD, section

³⁹ See proposed Tariff, Attachment DD, section 5.4(c).

5.10(a)” in order to provide consistent references to PJM’s Tariff. These technical revisions are part of PJM’s ongoing efforts to continually review and make non-controversial and non-substantive revisions to the Governing Documents in order to ensure consistency and accuracy of the relevant definitions and provisions.

IV. STAKEHOLDER PROCESS

This filing is the result of a vigorous stakeholder process that lasted nearly one year. These proposed revisions are designed to ensure that Capacity Market Sellers submit BRA Sell Offers with reasonable expectations of physical delivery. The problem statement and accompanying issue charge for this topic was endorsed on November 17, 2016 by the MRC. Thereafter, PJM and its stakeholders developed these proposed market rules in the Incremental Auction Senior Task Force between February, 2017 and January, 2018. The revisions filed herein were endorsed at the December 21, 2017 MRC by sector-weighted vote of 3.55 out of 5.0 in favor of endorsement. After endorsement at the MRC, the Members Committee endorsed the proposal with a 3.38 out of 5.0 sector-weighted vote at its January 25, 2018 meeting. Finally, as required by RAA, section 16.4, the PJM Board of Managers approved the revisions contained within the RAA at its February 14, 2018 meeting.

V. PROPOSED EFFECTIVE DATES

PJM proposes an effective date of May 8, 2018 for the proposed Tariff, Operating Agreement and RAA revisions referenced herein. PJM requests that the Commission issue an order on this filing by May 8, 2018. PJM proposes that these revisions be applicable to the BRA and associated IAs starting with the 2021/2022 Delivery Year and beyond.

VI. DESCRIPTION OF SUBMITTAL

This filing consists of the following:

1. This transmittal letter;
2. Attachment A – Revisions to the Tariff and RAA in redline format;
3. Attachment B – Revisions to the Tariff and RAA in clean format; and
4. Attachment C – Affidavit of Jeffery D. Bastian

VII. CORRESPONDENCE

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

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

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

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,⁴⁰ PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: <http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx> with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region⁴¹ alerting them that this filing has been made by PJM and is

⁴⁰ See 18C.F.R §§ 35.2(e) and 385.2010(f)(3).

⁴¹ PJM already maintains updates and regularly uses e-mail lists for all PJM Members and affected state commissions.

available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: <http://www.ferc.gov/docs-filing/elibrary.asp> in accordance with the Commission's regulations and Order No. 714.

IX. CONCLUSION

Based on the foregoing, PJM respectfully requests that the Commission accept the proposed revisions to PJM's Tariff and RAA by no later than May 8, 2018, effective May 8, 2018.

Respectfully submitted,



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

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

Jennifer Tribulski
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
(610) 666-4363 (phone)
(610) 666-8211 (fax)
Jennifer.Tribulski@pjm.com

CERTIFICATE OF SERVICE

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

Dated at Audubon, PA, 9th day of March, 2018.

/s/ Chen Lu
Chenchao Lu
Counsel
PJM Interconnection, LLC
2750 Monroe Boulevard
Audubon, PA 19403
Ph: (610) 666-2255
Chenchao.Lu@pjm.com

Attachment A

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

(Marked / Redline Format)

Section(s) of the
PJM Open Access Transmission Tariff
(Marked / Redline Format)

Definitions – C-D

Canadian Guaranty:

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

Cancellation Costs:

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

Capacity:

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

Capacity Emergency Transfer Limit:

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

Capacity Emergency Transfer Objective:

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

Capacity Export Transmission Customer:

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

Capacity Import Limit:

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

Capacity Interconnection Rights:

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

Capacity Market Buyer:

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

Capacity Market Seller:

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

Capacity Performance Resource:

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

Capacity Performance Transition Incremental Auction:

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

Capacity Resource:

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

Capacity Resource 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 hydroelectric power plant, flywheel, battery storage, or other such facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets and which participates in the Reliability Pricing Model.

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.

Cold/Warm/Hot Notification Time:

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

Cold/Warm/Hot Start-up Time:

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

Cold Weather Alert:

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

Collateral:

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

Collateral Call:

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

Commencement Date:

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

Commission:

“Commission” shall mean the Federal Energy Regulatory Commission or FERC.

Committed Offer:

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

Completed Application:

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

Compliance Aggregation Area (CAA):

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

separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, ~~or~~ the same locational price separation in the Third Incremental Auction, or the same locational price separation in the Final Incremental Auction.

Conditional Incremental Auction:

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

CONE Area:

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

Confidential Information:

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

Congestion Price:

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

Consolidated Transmission Owners Agreement:

“Consolidated 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.

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.

Control Area:

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

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

Control Zone:

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

Controllable A.C. Merchant Transmission Facilities:

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

facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and [Tariff](#), Part VI.

Coordinated External Transaction:

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

Coordinated Transaction Scheduling:

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

Corporate Guaranty:

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

Cost of New Entry:

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

Costs:

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

Counterparty:

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

Credit Available for Export Transactions:

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

Credit Available for Virtual Transactions:

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

Credit Breach:

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

Credit-Limited Offer:

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

Credit Score:

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

CTS Enabled Interface:

“CTS Enabled Interface” shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling (“CTS”). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in ~~Schedule A to~~ 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).

CTS Interface Bid:

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

Curtailment:

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

Curtailment Service Provider:

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

Customer Facility:

“Customer Facility” shall mean generation facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under ~~Subparts A of~~ Tariff, Part IV, subparts A.

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, 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, sections 7, 8, 9, or 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 and import 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 and Export 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 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, section 114.

Deactivation Avoidable Cost Rate:

“Deactivation Avoidable Cost Rate” shall mean the formula rate established pursuant to Tariff, section 115 ~~of this Tariff~~.

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 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.

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.

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 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.

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 Schedule 2 of the Operating Agreement.

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 flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets as a Market Seller.

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.

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.

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.

Federal Power Act:

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

FERC:

“FERC” 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 Incremental Auction:

“Final Incremental Auction” shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates for the 2021/2022 Delivery Year and all subsequent Delivery Years.

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 Schedule 8 of the Reliability Assurance Agreement.

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 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 sections 19.3 and 32.3 of the Tariff.

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.

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 V.G.

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 auctions.

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 – I – J - K

IDR Transfer Agreement:

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

Immediate-need Reliability Project:

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

Inadvertent Interchange:

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

Incidental Expenses:

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

Incremental Auction:

“Incremental Auction” shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction, Final Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction for which (i) below does not apply, and the First Incremental Auction for the 2021/2022 Delivery year and all subsequent Delivery Year for which (ii) below does not apply), shall be held for the purposes of:

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

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

Incremental Auction Revenue Rights:

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

Incremental Available Transfer Capability Revenue Rights:

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

Incremental Capacity Transfer Right:

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

Incremental Deliverability Rights (IDRs):

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

Incremental Energy Offer:

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

Incremental Multi-Driver Project:

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

Incremental Rights-Eligible Required Transmission Enhancements:

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

Increment Offer:

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

Initial Operation:

“Initial Operation” shall mean the commencement of operation of the Customer Facility and Customer Interconnection Facilities after satisfaction of the conditions of Section 1.4 of Appendix 2 of an Interconnection Service Agreement.

Interconnected Entity:

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

Interconnected Transmission Owner:

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

Interconnection Construction Service Agreement:

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

Transmission Owner that is responsible for construction of any Attachment Facilities, Network Upgrades, or Local Upgrades associated with interconnection of a Customer Facility.

Interconnection Customer:

“Interconnection Customer” shall mean a Generation Interconnection Customer and/or a Transmission Interconnection Customer.

Interconnection Facilities:

“Interconnection Facilities” shall mean the Transmission Owner Interconnection Facilities and the Customer Interconnection Facilities.

Interconnection Feasibility Study:

“Interconnection Feasibility Study” shall mean either a Generation Interconnection Feasibility Study or Transmission Interconnection Feasibility Study.

Interconnection Party:

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

Interconnection Request:

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

Interconnection Service:

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

Interconnection Service Agreement:

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

Interconnection Studies:

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

Interface Pricing Point:

“Interface Pricing Point” shall have the meaning specified in Operating Agreement, Schedule 1, section 2.6A, and the parallel provisions of Tariff, Attachment K-Appendix, [section 2.6A](#).

Intermittent Resource:

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

Internal Market Buyer:

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

Interregional Transmission Project:

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

Interruption:

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

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 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 two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 10.096 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 Schedule 6 of the Operating Agreement 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 Effective Megawatts:

“Regulation Effective Megawatts” shall equal the product of 1) the amount of Regulation that a resource is providing in a given hour, 2) the resource’s historic performance score, and 3) the resource’s Regulation Rate of Technical Substitution.

Regulation Marginal Rate of Technical Substitution:

“Regulation Marginal Rate of Technical Substitution” shall mean the Regulation Rate of Technical Substitution assigned to the last dynamic Regulation resource committed to provide Regulation service in a given hour.

Regulation Rate of Technical Substitution:

“Regulation Rate of Technical Substitution” shall mean a value along the Regulation Rate of Technical Substitution Curve that translates a dynamic Regulation resource into a traditional Regulation resource. Regulation Rate of Technical Substitution is calculated in accordance with the PJM Manuals.

Regulation Rate of Technical Substitution Curve:

“Regulation Rate of Technical Substitution Curve” shall mean a function that defines the operational relationship between traditional and dynamic Regulation resources utilized to meet the Regulation Requirement. Regulation Rate of Technical Substitution Curve is calculated in accordance with the PJM Manuals.

Regulation Requirement:

“Regulation Requirement” shall mean the calculated Regulation Effective Megawatts required to be maintained in a Regulation Zone, absent any increase to account for additional Regulation scheduled to address operational uncertainty. Regulation Requirement is defined in accordance with 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:

“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 Schedule 6 of the Operating Agreement 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 for Delivery Years prior to the 2021/2022 Delivery Year; and the First or Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years.

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. A Second Incremental Auction is conducted for Delivery Years prior to the 2021/2022 Delivery Year but is not conducted for the 2021/2022 Delivery Year and all subsequent Delivery Years.

Security:

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

Segment:

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

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.

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, Ssection 15.3 or Ssection 29.1 ~~under the Tariff~~.

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](#).

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 for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource or a Capacity Storage Resource; or (v) used in association with restoration or black start service.

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) ~~of Tariff Attachment DD~~ 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.

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.

Definitions – T – U - V

Tangible Net Worth:

“Tangible Net Worth” shall mean all assets (not including any intangible assets such as goodwill) less all liabilities. Any such calculation may be reduced by PJM Settlement upon review of the available financial information.

Target Allocation:

“Target Allocation” shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, *section 5.2.3* or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, *section 7.4.3*.

Third Incremental Auction:

“Third Incremental Auction” shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates for Delivery Years prior to the 2021/2022 Delivery Year.

Third-Party Sale:

“Third-Party Sale” shall mean any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service but not including a sale of energy through the PJM Interchange Energy Market established under the PJM Operating Agreement.

Tie Line:

“Tie Line” shall mean a circuit connecting two balancing authority areas, Control Areas or fully metered electric system regions. Tie Lines may be classified as external or internal as set forth in the PJM Manuals.

Total Lost Opportunity Cost Offer:

“Total Lost Opportunity Cost Offer” shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1), *and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1)*, the Total Lost Opportunity Cost Offer shall equal the *Real-time Settlement Interval* offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the *Real-time Settlement Interval* offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer

or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost Opportunity Cost Offer shall equal the *Real-time Settlement Interval* offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated costbased Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Net Obligation:

“Total Net Obligation” shall mean all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position:

“Total Net Sell Position” shall mean all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

Total Operating Reserve Offer:

“Total Operating Reserve Offer” shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual *Real-time Settlement Interval* energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every *Real-time Settlement Interval* in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Transmission Congestion Charge:

“Transmission Congestion Charge” shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1 and the parallel provisions of Tariff, Attachment K-Appendix, *section 5.1*.

Transmission Congestion Credit:

“Transmission Congestion Credit” shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2, and the parallel provisions of Tariff, Attachment K-Appendix, *section 5.2*.

Transmission Customer:

“Transmission Customer” shall mean any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission a proposed unexecuted Service Agreement, to receive transmission service under Tariff, Part II. This term is used in Tariff, Part I and Part VI to include customers receiving transmission service under Tariff, Part II and Part III.

Where used in Tariff, Attachment K-Appendix and the parallel provisions of Operating Agreement, Schedule 1, Transmission Customer shall mean an entity using Point-to-Point Transmission Service.

Transmission Facilities:

“Transmission Facilities” shall have the meaning set forth in the Operating Agreement.

Transmission Forced Outage:

“Transmission Forced Outage” shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Injection Rights:

“Transmission Injection Rights” shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Customer:

“Transmission Interconnection Customer” shall mean an entity that submits an Interconnection Request to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region or an entity that submits an Upgrade Request for Merchant Network Upgrades (including accelerating the construction of any transmission enhancement or expansion, other than Merchant Transmission Facilities, that is included in the Regional Transmission Expansion Plan prepared pursuant to *Operating Agreement*, Schedule 6).

Transmission Interconnection Facilities Study:

“Transmission Interconnection Facilities Study” shall mean a Facilities Study related to a Transmission Interconnection Request.

Transmission Interconnection Feasibility Study:

“Transmission Interconnection Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with *Tariff*, section 36.2.

Transmission Interconnection Request:

“Transmission Interconnection Request” shall mean a request by a Transmission Interconnection Customer pursuant to *Tariff*, Part IV to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of existing Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

Transmission Loading Relief:

“Transmission Loading Relief” shall mean NERC’s procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loading Relief Customer:

“Transmission Loading Relief Customer” shall mean an entity that, in accordance with Operating Agreement, Schedule 1, section 1.10.6A and the parallel provisions of *Tariff*, Attachment K-Appendix, *section 1.10.6A* has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

Transmission Loss Charge:

“Transmission Loss Charge” shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of *Tariff*, Attachment K-Appendix, *section 5*.

Transmission Owner:

“Transmission Owner” shall mean each entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the *Tariff*. The Transmission Owners are listed in *Tariff*, Attachment L.

Transmission Owner Attachment Facilities:

“Transmission Owner Attachment Facilities” shall mean that portion of the Transmission Owner Interconnection Facilities comprised of all Attachment Facilities on the Interconnected Transmission Owner’s side of the Point of Interconnection.

Transmission Owner Interconnection Facilities:

“Transmission Owner Interconnection Facilities” shall mean all Interconnection Facilities that are not Customer Interconnection Facilities and that, after the transfer under *Tariff, Attachment P, Appendix 2*, section 5.5 to the Interconnected Transmission Owner of title to any Transmission Owner Interconnection Facilities that the Interconnection Customer constructed, are owned, controlled, operated and maintained by the Interconnected Transmission Owner on the Interconnected Transmission Owner’s side of the Point of Interconnection identified in 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 or interconnected distribution facilities.

Transmission Owner Upgrade:

“Transmission Owner Upgrade” shall have the same meaning provided in the Operating Agreement.

Transmission Planned Outage:

“Transmission Planned Outage” shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of *Tariff, Attachment K-Appendix* or the PJM Manuals.

Transmission Provider:

The “Transmission Provider” shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

- (a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;
- (b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and
- (c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the *Tariff, Operating Agreement*

and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Provider's Monthly Transmission System Peak:

"Transmission Provider's Monthly Transmission System Peak" shall mean the maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

Transmission Service:

"Transmission Service" shall mean Point-To-Point Transmission Service provided under Tariff, Part II on a firm and non-firm basis.

Transmission Service Request:

"Transmission Service Request" shall mean a request for Firm Point-To-Point Transmission Service or a request for Network Integration Transmission Service.

Transmission System:

"Transmission System" shall mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III.

Transmission Withdrawal Rights:

"Transmission Withdrawal Rights" shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Turn Down Ratio:

"Turn Down Ratio" shall mean the ratio of a generating unit's economic maximum megawatts to its economic minimum megawatts.

Unconstrained LDA Group:

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10 shall be combined with all other such LDAs that form an electrically contiguous area.

Unforced Capacity:

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

Unsecured Credit:

“Unsecured Credit” shall mean any credit granted by PJMSettlement to a Participant that is not secured by Collateral.

Unsecured Credit Allowance:

“Unsecured Credit Allowance” shall mean Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement’s evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Collateral. See also: “Working Credit Limit.”

Updated VRR Curve:

“Updated VRR Curve” shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction, and for Delivery Years through May 31, 2018, the Short-term Resource Procurement Target applicable to the relevant Incremental Auction.

Updated VRR Curve Decrement:

“Updated VRR Curve Decrement” shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year (excluding net Unforced Capacity committed to the PJM Region associated with the transition provisions of Tariff, Attachment DD, section 5.14D as related to the 2017/2018 Delivery Year) and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, sections 5.14C, 5.14D (as related to the 2016/2017 Delivery Year), 5.14E, and 5.5A(c)(i)(B), *and RAA, Schedule 6, section L.9.*

Updated VRR Curve Increment:

“Updated VRR Curve Increment” shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year (excluding net Unforced Capacity committed to the PJM Region associated with the transition provision of Tariff, Attachment DD, section 5.14D as related to the 2017/2018 Delivery Year) and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, sections 5.14C, 5.14D (as related to the 2016/2017 Delivery Year), 5.14E and 5.5A(c)(i)(B) *and RAA, Schedule 6, section L.9.*

Upgrade Construction Service Agreement:

“Upgrade Construction Service Agreement” shall mean that agreement entered into by an Eligible Customer, Upgrade Customer or Interconnection Customer proposing Merchant Network Upgrades, a Transmission Owner, and the Transmission Provider, pursuant to Tariff, Part VI, Subpart B, and in the form set forth in *Tariff*, Attachment GG.

Upgrade Customer:

“Upgrade Customer” shall mean a customer that submits an Upgrade Request pursuant to *Operating Agreement, Schedule 1, section 7.8*.

Upgrade Feasibility Study:

“Upgrade Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, section 36.3.

Upgrade-Related Rights:

“Upgrade-Related Rights” shall mean Incremental Auction Revenue Rights, Incremental Available Transfer Capability Revenue Rights, Incremental Deliverability Rights, and Incremental Capacity Transfer Rights.

Upgrade Request:

“Upgrade Request” shall mean a request submitted in the form prescribed in *Tariff*, Attachment EE, for evaluation by the Transmission Provider of the feasibility and estimated costs of (a) a Merchant Network Upgrade or (b) the Customer-Funded Upgrades that would be needed to provide Incremental Auction Revenue Rights specified in a request pursuant to *Operating Agreement, Schedule 1, section 7.8*.

Up-to Congestion Counterflow Transaction:

“Up-to Congestion Counterflow Transaction” shall mean an Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month’s average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month:

“Up-to Congestion Historical Month” shall mean a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction:

An Up-to Congestion Transaction shall mean an “Up-to Congestion Prevailing Flow Transaction” if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price:

“Up-to Congestion Reference Price” for an Up-to Congestion Transaction, shall be the specified percentile price differential between source and sink (defined as sink price minus source price) for real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30th percentile

For Up-to Congestion Counterflow Transactions when bid: 20th percentile

For Up-to Congestion Counterflow Transactions when cleared: 5th percentile

Up-to Congestion Transaction:

“Up-to Congestion Transaction” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.10.1A, and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.10.1A*.

Variable Loads:

“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*.

Variable Resource Requirement Curve:

“Variable Resource Requirement Curve” shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Tariff, Attachment DD, section 5.

Virtual Credit Exposure:

“Virtual Credit Exposure” shall mean the amount of potential credit exposure created by a market participant’s bid submitted into the Day-ahead market, as defined in Tariff, Attachment Q.

Virtual Transaction:

“Virtual Transaction” shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

Virtual Transaction Screening:

“Virtual Transaction Screening” shall be the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity:

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

Voltage Reduction Action:

“Voltage Reduction Action” shall mean a notification during capacity deficient conditions in which PJM notifies Members to reduce voltage on the distribution system in order to reduce demand and therefore provide a sufficient amount of reserves, maintain tie flow schedules and preserve limited energy sources.

Voltage Reduction Alert:

“Voltage Reduction Alert” shall mean a notification from PJM to alert Members that a voltage reduction may be required during a future critical period.

Voltage Reduction Warning:

“Voltage Reduction Warning” shall mean a notification from PJM to warn Members that PJM’s available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

3. RESPONSIBILITIES OF THE OFFICE OF THE INTERCONNECTION

3.1 Support for Self-Supply and Bilateral Transactions

The Office of the Interconnection shall:

(a) support electronic tools to facilitate communication by Market Sellers and Market Buyers of information to the Office of the Interconnection concerning Self-Supply arrangements;

(b) support an electronic bulletin board providing a forum for prospective buyers and sellers to transact Capacity Resources outside the Reliability Pricing Model Auctions, including Locational UCAP transactions (including mechanisms to allow prospective Sellers with partial-year resources to explore voluntary opportunities to combine their resources such that they can be offered together for a full Delivery Year) and support electronic tools to report bilateral capacity transactions between Market Participants to the Office of the Interconnection, in accordance with procedures set forth in the PJM Manuals; and

(c) define one or more capacity trading hubs and determine and publicize values for such hubs based on the capacity prices determined for one or more Locational Deliverability Areas, in accordance with the PJM Manuals.

3.2 Administration of the Base Residual Auction and Incremental Auctions

The Office of the Interconnection shall conduct and administer the Base Residual Auction and Incremental Auctions in accordance with this Attachment, the Operating Agreement, and the Reliability Assurance Agreement. Administration of the Base Residual Auction and Incremental Auctions shall include, but not be limited to, the following:

a) Determining the qualification of entities to become Capacity Market Sellers and Capacity Market Buyers;

b) Determining PJM Region Peak Load Forecasts and Locational Deliverability Area Reliability Requirements;

c) Determining the Minimum Annual Resource Requirements and the Minimum Extended Summer Resource Requirements for the PJM Region and applicable LDAs for Delivery Years starting June 1, 2014 and ending May 31, 2017;

d) Determining Limited Resource Constraints and Sub-Annual Resource Constraints for the 2017/2018 Delivery Year;

e) Determining Base Capacity Demand Resource Constraints and Base Capacity Resource Constraints for the 2018/2019 and 2019/2020 Delivery Years;

f) Determining the need, if any, for a Conditional Incremental Auction and providing appropriate prior notice of any such auction

g) Calculating the EFORD for each Generation Capacity Resource in the PJM Region to be used in the Third Incremental Auction or Final Incremental Auction, as applicable;

h) Receiving Buy Bids and Sell Offers, determining Locational Deliverability Requirements and Variable Resource Requirement Curves, and determining the clearing price that reflects all such inputs;

i) Conducting settlements for auction transactions, including but not limited to rendering bills to, receiving payments from, and disbursing payments to, participants in Base Residual Auctions and Incremental Auctions.

j) Maintaining such records of Sell Offers and Buy Bids, clearing price determinations, and other aspects of auction transactions, as may be appropriate to the administration of Base Residual Auctions and Incremental Auctions; and

k) Posting of selected non-confidential data used in Reliability Pricing Model Auctions to calculate clearing prices and other auction results, as appropriate to inform market participants of auction conditions.

3.3 Records and Reports

The Office of the Interconnection shall prepare and maintain such records as are required for the administration of the Base Residual Auction and Incremental Auctions. For each auction conducted, the Office of the Interconnection shall, consistent with Operating Agreement, section 18.17 ~~of the Operating Agreement~~, publish the following: (i) Zonal Capacity Prices for each LDA; (ii) Capacity Resource Clearing Prices for each LDA; (iii) Locational Price Adders; (iv) the total megawatts of Unforced Capacity that cleared; and (v) such other auction data as may be appropriate to the efficient and competitive conduct of the Base Residual Auction and Incremental Auctions. Such information shall be available on the PJM internet site through the end of the Delivery Year to which such auctions apply.

3.4 Counterparty

(a) PJMSettlement shall be the Counterparty to the transactions arising from the cleared Base Residual Auctions and Incremental Auctions; provided, however, PJMSettlement shall not be a contracting party to (i) any bilateral transactions between Market Participants, or (ii) with respect to Self-Supply for which designation of Self-Supply has been reported to the Office of the Interconnection.

(b) Charges. PJMSettlement shall be the Counterparty with respect to the obligations to pay, and the payment of, charges pursuant to this Attachment DD.

5.3A Locational UCAP Bilateral Transactions

A Member that has committed capacity through an RPM Auction for a Delivery Year may purchase Locational UCAP as replacement capacity from a Member with available uncommitted capacity for such Delivery Year in accordance with the terms of this section and the PJM Manuals. Locational UCAP may not be sold or purchased prior to the date that the final EFORD is established for such Delivery Year, and if designated to PJM by the Locational UCAP Seller as sold prior to the Third Incremental Auction or Final Incremental Auction, as applicable for a Delivery Year must be confirmed by the buyer prior to such Third Incremental Auction or Final Incremental Auction as purchased for replacement capacity, or such transaction shall be rejected. In accordance with procedures specified in the PJM Manuals, the parties to a Locational UCAP transaction must notify PJM of such transaction, which notification must specify: i) the buyer, ii) the Locational UCAP Seller, iii) the start and end dates of the transaction (which may not be retroactive), iv) the Locational UCAP amount (no less than 0.1 megawatts), v) the demand or generation resource with available uncommitted capacity that is the basis for the sale, and vi) the Locational Delivery Area in which the resource is located. The Locational UCAP Seller shall be responsible for any charges imposed under Tariff, Attachment DD, sections 7, 8, 9, 10, 10A, 11, or 13, as applicable, for such Delivery Year, with respect to the increment of capacity sold as Locational UCAP; any other settlement of charges under the Locational UCAP transaction shall be between the parties. A purchaser of Locational UCAP may not offer such capacity into an RPM Auction.

5.4 Reliability Pricing Model Auctions

The Office of the Interconnection shall conduct the following Reliability Pricing Model Auctions:

a) Base Residual Auction.

PJM shall conduct for each Delivery Year a Base Residual Auction to secure commitments of Capacity Resources as needed to satisfy the portion of the RTO Unforced Capacity Obligation not satisfied through Self-Supply of Capacity Resources for such Delivery Year. All Self-Supply Capacity Resources must be offered in the Base Residual Auction. As set forth in Tariff, Attachment DD, section 6.6, all other Capacity Resources, and certain other existing generation resources, must be offered in the Base Residual Auction. The Base Residual Auction shall be conducted in the month of May that is three years prior to the start of such Delivery Year. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Load Serving Entities through the Locational Reliability Charge during such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and the payments, by Load Serving Entities; provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

b) Scheduled Incremental Auctions.

For Delivery Years prior to the 2021/2022 Delivery Year, PJM shall conduct for each Delivery Year a First, a Second, and a Third Incremental Auction ~~for the purposes set forth in section 2.34~~. The First Incremental Auction shall be conducted in the month of September that is twenty months prior to the start of the Delivery Year; the Second Incremental Auction shall be conducted in the month of July that is ten months prior to the start of the Delivery Year; and the Third Incremental Auction shall be conducted in the month of February that is three months prior to the start of the Delivery Year. For the 2021/2022 Delivery Year and all subsequent Delivery Years, PJM shall conduct a First Incremental Auction and a Final Incremental Auction. The First Incremental Auction shall be conducted in the month of September that is twenty months prior to the start of the Delivery Year; and the Final Incremental Auction shall be conducted in the month of February that is three months prior to the start of the Delivery Year.

c) Adjustment through Scheduled Incremental Auctions of Capacity Previously Committed.

For Delivery Years prior to the 2021/2022 Delivery Year, ~~t~~The Office of the Interconnection shall recalculate the PJM Region Reliability Requirement and each LDA Reliability Requirement prior to each Scheduled Incremental Auction, based on an updated peak load forecast, updated Installed Reserve Margin and an updated Capacity Emergency Transfer Objective; shall update such reliability requirements for the Third Incremental Auction to reflect any change from such recalculation; and shall update such reliability requirements for the First Incremental Auction or Second Incremental Auction only if the change is greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement. For

the 2021/2022 Delivery Year and all subsequent Delivery Years, the Office of the Interconnection shall recalculate the PJM Region Reliability Requirement and each LDA Reliability Requirement prior to the Final Incremental Auction, based on an updated peak load forecast, updated Installed Reserve Margin and an updated Capacity Emergency Transfer Objective. Based on such updates, the Office of the Interconnection shall, under certain conditions, seek through the Scheduled Incremental Auctions for Delivery Years prior to the 2021/2022 Delivery Year and the Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years to secure additional commitments of capacity or release sellers from prior capacity commitments. Specifically, the Office of the Interconnection shall:

1) for Delivery Years prior to the 2021/2022 Delivery Year, seek additional capacity commitments to serve the PJM Region or an LDA if the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) is less than, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such additional capacity commitments only if such shortfall is in an amount greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement;

2) seek additional capacity commitments to serve the PJM Region or an LDA in Scheduled Incremental Auctions for Delivery Years prior to the 2021/2022 Delivery Year and the Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years if:

i) the updated PJM Region Reliability Requirement less, for Delivery Years through May 31, 2018, the PJM Region Short-Term Resource Procurement Target utilized in the most recent auction conducted for the Delivery Year, or if the LDA Reliability Requirement less, for Delivery Years through May 31, 2018, the LDA Short Term Resource Procurement Target applicable to such auction, exceeds the total capacity committed in all prior auctions in such region or area, respectively, for such Delivery Year by an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM conducts a Conditional Incremental Auction for such Delivery Year and does not obtain all additional commitments of Capacity Resources sought in such Conditional Incremental Auction, in which case, PJM shall seek in the Incremental Auction the commitments that were sought in the Conditional Incremental Auction but not obtained.

3) seek agreements to release prior capacity commitments to the PJM Region or to an LDA in Scheduled Incremental Auctions for Delivery Years prior to the 2021/2022

Delivery Year and the Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years if:

i) the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) exceeds, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction for Delivery Years prior to the 2021/2022 Delivery Year and in the Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years the Office of the Interconnection shall seek such agreements only if such excess is in an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM obtains additional commitments of Capacity Resources in a Conditional Incremental Auction, in which case PJM shall seek release of an equal number of megawatts (comparing the total purchase amount for all LDAs and the PJM Region related to the delay in Backbone Transmission with the total sell amount for all LDAs and the PJM Region related to the delay in Backbone Transmission) of prior committed capacity that would not have been committed had the delayed Backbone Transmission upgrade that prompted the Conditional Incremental Auction not been assumed, at the time of the Base Residual Auction, to be in service for the relevant Delivery Year; and if PJM obtains additional commitments of capacity in an ~~i~~Incremental ~~a~~Auction pursuant to subsection c.2.ii above, PJM shall seek in such Incremental Auction to release an equal amount of capacity (in total for all LDAs and the PJM Region related to the delay in Backbone Transmission) previously committed that would not have been committed absent the Backbone Transmission upgrade.

4) The cost of payments to Market Sellers for additional Capacity Resources cleared in such auctions, and the credits from payments from Market Sellers for the release of previously committed Capacity Resources, shall be apportioned to Load Serving Entities in the PJM Region or LDA, as applicable, through adjustments to the Locational Reliability Charge for such Delivery Year.

5) PJMSettlement shall be the Counterparty to the sales (including releases) of Capacity Resources that clear in such auctions and to the obligations to pay, and the payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

d) Commitment of Replacement Capacity through Scheduled Incremental Auctions.

Each Scheduled Incremental Auction for each Delivery Year shall allow Capacity Market Sellers that committed Capacity Resources in any prior Reliability Pricing Model Auction for such Delivery Year to submit Buy Bids for replacement Capacity Resources. Capacity Market Sellers that submit Buy Bids into an Incremental Auction must specify the type of Unforced Capacity desired, i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource. The need to purchase replacement Capacity Resources may arise for any reason, including but not limited to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Capacity Market Buyers that purchase replacement Capacity Resources in such auction. PJMSettlement shall be the Counterparty to the sales and purchases that clear in such auction, provided, however, PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

e) Conditional Incremental Auction.

PJM shall conduct for any Delivery Year a Conditional Incremental Auction if the in service date of a Backbone Transmission Upgrade that was modeled in the Base Residual Auction is announced as delayed by the Office of the Interconnection beyond July 1 of the Delivery Year for which it was modeled and if such delay causes a reliability criteria violation. If conducted, the Conditional Incremental Auction shall be for the purpose of securing commitments of additional capacity for the PJM Region or for any LDA to address the identified reliability criteria violation. If PJM determines to conduct a Conditional Incremental Auction, PJM shall post on its website the date and parameters for such auction (including whether such auction is for the PJM Region or for an LDA, and the type of Capacity Resources required) at least one month prior to the start of such auction. The cost of payments to Market Sellers for Capacity Resources cleared in such auction shall be collected by PJMSettlement from Load Serving Entities in the PJM Region or LDA, as applicable, through an adjustment to the Locational Reliability Charge for such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

5.6 Sell Offers

Sell Offers shall be submitted or withdrawn via the internet site designated by the Office of the Interconnection, under the procedures and time schedule set forth in the PJM Manuals.

5.6.1 Specifications

A Sell Offer shall state quantities in increments of 0.1 megawatts and shall specify, as appropriate:

a) Identification of the Generation Capacity Resource, Demand Resource, Capacity Storage Resource or Energy Efficiency Resource on which such Sell Offer is based;

b) Minimum and maximum megawatt quantity of installed capacity that the Capacity Market Seller is willing to offer (notwithstanding such specification, the product offered shall be Unforced Capacity), or designate as Self-Supply, from a Generation Capacity Resource;

i) Price, in dollars and cents per megawatt-day, that will be accepted by the Capacity Market Seller for the megawatt quantity of Unforced Capacity offered from such Generation Capacity Resource.

ii) The Sell Offer may take the form of offer segments with varying price-quantity pairs for varying output levels from the underlying resource, but may not take the form of an offer curve with nonzero slope.

c) EFORd of each Generation Capacity Resource offered.

i) If a Capacity Market Seller is offering such resource in a Base Residual Auction, First Incremental Auction, Second Incremental Auction, or Conditional Incremental Auction occurring before the Third Incremental Auction or Final Incremental Auction, the Capacity Market Seller shall specify the EFORd to apply to the offer.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Capacity Market Seller shall specify the EFORd to apply to the commitment.

iii) The EFORd applied to the Third Incremental Auction or Final Incremental Auction will be the final EFORd established by the Office of the Interconnection six (6) months prior to the Delivery Year, based on the actual EFORd in the PJM Region during the 12-month period ending September 30 that last precedes such Delivery Year.

d) The Nominated Demand Resource Value for each Demand Resource offered and the Nominated Energy Efficiency Value for each Energy Efficiency Resource offered. The Office of the Interconnection shall, in both cases, convert such value to an Unforced Capacity basis by multiplying such value by the DR Factor (for Delivery Years through May 31, 2018) times the Forecast Pool Requirement. Demand Resources shall specify the LDA in which the Demand Resource is located, including the location of such resource within any Zone that includes more than one LDA as identified on RAA, Schedule 10.1 ~~of the RAA~~.

e) For Delivery Years through May 31, 2018, a Demand Resource with the potential to qualify as two or more of a Limited Demand Resource, Extended Summer Demand Resource or Annual Demand Resource may submit separate but coupled Sell Offers for each Demand Resource type for which it qualifies at different prices and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. For such coupled Demand Resource offers, the offer price of an Annual Demand Resource offer must be at least \$.01 per MW-day greater than the offer price of a coupled Extended Summer Demand Resource offer and the offer price of a Extended Summer Demand Resource offer must be at least \$.01 per MW-day greater than the offer price of a coupled Limited Demand Resource offer.

f) For a Qualifying Transmission Upgrade, the Sell Offer shall identify such upgrade, and the Office of the Interconnection shall determine and certify the increase in CETL provided by such upgrade. The Capacity Market Seller may offer the upgrade with an associated increase in CETL to an LDA in accordance with such certification, including an offer price that will be accepted by the Capacity Market Seller, stated in dollars and cents per megawatt-day as a price difference between a Capacity Resource located outside such an LDA and a Capacity Resource located inside such LDA; and the increase in CETL into such LDA to be provided by such Qualifying Transmission Upgrade, as certified by the Office of the Interconnection.

g) For the 2018/2019 and 2019/2020 Delivery Years, each Capacity Market Seller owning or controlling a resource that qualifies as both a Base Capacity Resource and a Capacity Performance Resource may submit separate but coupled Sell Offers for such resource as a Base Capacity Resource and as a Capacity Performance Resource, at different prices, and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. Submission of a coupled Base Capacity Resource Sell Offer shall be mandatory for any Capacity Performance Resource Sell Offer that exceeds a Sell Offer Price equal to the applicable Net Cost of New Entry times the Balancing Ratio as provided for in [Tariff, Attachment DD](#), section 6.4. For such coupled Sell Offers, the offer price of a Capacity Performance Resource offer must be at least \$.01 per MW-day greater than the offer price of a coupled Base Capacity Resource offer.

(h) For the 2018/2019 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, or Energy Efficiency Resources may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with their average expected output during peak-hour periods. Alternatively, for the 2018/2019 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, Energy Efficiency Resources, or Environmentally-Limited Resources may submit a Sell Offer which represents the aggregated Unforced Capacity value of such resources, where such Sell Offer shall be considered to be located in the smallest modeled LDA common to the aggregated resources. Such aggregated resources shall be owned by or under contract to the Capacity Market Seller, including all such resources obtained through bilateral contract and reported to the Office of the Interconnection in accordance with the Office of the Interconnection's rules related to its eRPM tools. For the 2018/2019 and 2019/2020 Delivery Years, any such offer may be submitted as Capacity Performance Resource, Base Capacity Resource, or as a coupled offer for Capacity Performance Resource and Base Capacity Resource, provided that, for any such coupled Sell Offers, the offer

price of a Capacity Performance Resource offer must be at least \$.01 per MW-day greater than the offer price of a coupled Base Capacity Resource offer. For the 2020/2021 Delivery Year and subsequent Delivery Years, any such offer must be submitted as a Capacity Performance Resource.

(i) For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Summer-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Summer-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during summer peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Summer-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Winter-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Winter-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during winter peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Winter-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. Each segment of a Seasonal Capacity Performance Resource Sell Offer must be submitted as a flexible Sell Offer segment with the minimum MW quantity offered set to zero.

5.6.2 Compliance with PJM Credit Policy

Capacity Market Sellers shall comply with the provisions of the PJM Credit Policy as set forth in Tariff, Attachment Q ~~to this Tariff~~, including the provisions specific to the Reliability Pricing Model, prior to submission of Sell Offers in any Reliability Pricing Model Auction. A Capacity Market Seller desiring to submit a Credit-Limited Offer shall specify in its Sell Offer the maximum auction credit requirement, in dollars, and the maximum amount of Unforced Capacity, in megawatts, applicable to its Sell Offer.

5.6.3 [reserved]

5.6.4 Qualifying Transmission Upgrades

A Qualifying Transmission Upgrade may not be the subject of any Sell Offer in a Base Residual Auction unless it has been approved by the Office of the Interconnection, including certification of the increase in Import Capability to be provided by such Qualifying Transmission Upgrade, no later than 45 days prior to such Base Residual Auction. No such approval shall be granted unless, at a minimum, a Facilities Study Agreement has been executed with respect to such upgrade, and such upgrade conforms to all applicable standards of the Regional Transmission Expansion Plan process.

5.6.5 Market-based Sell Offers

Subject to [Tariff, Attachment DD](#), section 6, a Market Seller authorized by FERC to sell electric generating capacity at market-based prices, or that is not required to have such authorization, may submit Sell Offers that specify market-based prices in any Base Residual Auction or Incremental Auction.

5.6.6 Availability of Capacity Resources for Sale

(a) The Office of the Interconnection shall determine the quantity of megawatts of available installed capacity that each Capacity Market Seller must offer in any RPM Auction pursuant to [Tariff, Attachment DD](#), ~~Section 6.6-of Attachment DD~~, through verification of the availability of megawatts of installed capacity from: (i) all Generation Capacity Resources owned by or under contract to the Capacity Market Seller, including all Generation Capacity Resources obtained through bilateral contract; (ii) the results of prior Reliability Pricing Model Auctions, if any, for such Delivery Year (including consideration of any restriction imposed as a consequence of a prior failure to offer); and (iii) such other information as may be available to the Office of the Interconnection. The Office of the Interconnection shall reject Sell Offers or portions of Sell Offers for Capacity Resources in excess of the quantity of installed capacity from such Capacity Market Seller's Capacity Resource that it determines to be available for sale.

(b) The Office of the Interconnection shall determine the quantity of installed capacity available for sale in a Base Residual Auction or Incremental Auction as of the beginning of the period during which Buy Bids and Sell Offers are accepted for such auction, as applicable, in accordance with the time schedule set forth in the PJM Manuals. Removal of a resource from Capacity Resource status shall not be reflected in the determination of available installed capacity unless the associated unit-specific bilateral transaction is approved, the designation of such resource (or portion thereof) as a network resource for the external load is demonstrated to the Office of the Interconnection, or equivalent evidence of a firm external sale is provided prior to the deadline established therefor. The determination of available installed capacity shall also take into account, as they apply in proportion to the share of each resource owned or controlled by a Capacity Market Seller, any approved capacity modifications, and existing capacity commitments established in a prior RPM Auction, an FRR Capacity Plan, Locational UCAP transactions and/or replacement capacity transactions under this Attachment DD. To enable the Office of the Interconnection to make this determination, no bilateral transactions for Capacity Resources applicable to the period covered by an auction will be processed from the beginning of the period for submission of Sell Offers and Buy Bids, as appropriate, for that auction until completion of the clearing determination for such auction. Processing of such bilateral transactions will reconvene once clearing for that auction is completed. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

(c) In order for a bilateral transaction for the purchase and sale of a Capacity Resource to be processed by the Office of the Interconnection, both parties to the transaction must notify the Office of the Interconnection of the transfer of the Capacity Resource from the seller to the buyer in accordance with procedures established by the Office of the Interconnection and set forth in the PJM Manuals. If a material change with respect to any of the prerequisites

| for the application of Tariff, Attachment DD, sSection 5.6.6 to the Generation Capacity Resource occurs, the Capacity Resource Owner shall immediately notify the Market Monitoring Unit and the Office of the Interconnection.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (for Delivery Years through May 31, 2018, less the Short-Term Resource Procurement Target) or Locational Deliverability Area Reliability Requirement (for Delivery Year through May 31, 2018, less the Short-Term Resource Procurement Target for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;
- For the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:
 - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORD) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin (“IRM”)% minus 3%) divided by (100% plus IRM%)], and for Delivery Years

through May 31, 2018, minus the Short-Term Resource Procurement Target;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORD) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)], and for Delivery Years through May 31, 2018, minus the Short-Term Resource Procurement Target; and
- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORD) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)], and for Delivery Years through May 31, 2018, minus the Short-Term Resource Procurement Target;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORD) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin (“IRM”)% minus 0.2%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;
 - For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORD) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 2.9%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target; and
 - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 8.8%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target.

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

- A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or
- B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or
- C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the Eastern Mid-Atlantic Region (“EMAR”), Southwest Mid-Atlantic Region (“SWMAR”), and Mid-Atlantic Region (“MAR”) LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and, for Delivery Years through May 31, 2018, the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

For each such LDA, for the 2018/2019 Delivery Year and subsequent Delivery Years, the Office of the Interconnection shall (a) determine the Net Cost of New Entry for each Zone in such LDA, with such Net Cost of New Entry equal to the applicable Cost of New Entry value for such Zone minus the Net Energy and Ancillary Services Revenue Offset value for such Zone, and (b) compute the average of the Net Cost of New Entry values of all such Zones to determine the Net Cost of New Entry for such LDA; provided however, that the Net Cost of New Entry for an LDA may

be greater than, but shall be no less than, the Net Cost of New Entry determined for any other LDA in which the first LDA resides (immediately or successively) including the Net Cost of New Entry for the RTO. The Net Cost of New Entry for use in an LDA in any Incremental Auction for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years shall be the Net Cost of New Entry used for such LDA in the Base Residual Auction for such Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

- A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
- B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.
- C) The PJM Members shall either vote to (i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
- D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape 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.

iv) Cost of New Entry

- A) For the Incremental Auctions for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, the Cost of New Entry for the PJM Region and for each LDA shall be the respective value used in the Base Residual Auction for such Delivery Year and LDA. For the Delivery Year commencing on June 1, 2018, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(B).

| Geographic Location Within the PJM Region Encompassing These Zones | Cost of New Entry in \$/MW-Year |
|--|--|
| PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”) | 132,200 |
| BGE, PEPCO (“CONE Area 2”) | 130,300 |
| AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”) | 128,900 |
| PPL, MetEd, Penelec (“CONE Area 4”) | 130,300 |

- B) Beginning with the 2019/2020 Delivery Year, the CONE for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics (“BLS”) Composite Index, in accordance with the following:

(1) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Price Index for Construction Materials and Components (weighted 50%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 30%), as each such index is further specified for each CONE Area in the PJM Manuals.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable BLS Composite Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark

CONE values for the 2018/2019 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years).

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

- A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of \$6.47 per MWh, and actual PJM *hourly* average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of \$2,199 per MW-year.
- B) For the Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the Office of the Interconnection will employ for purposes of the Variable Resource Requirement Curves for such Delivery Years the same calculations of the sub-regional Net Energy and Ancillary Services Revenue Offsets that were used in the Base Residual Auctions for such Delivery year and sub-region. For the 2018/2019 Delivery Year and subsequent Delivery Years, the Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for such Zone shall be used in place of the PJM Region average hourly LMPs; (2) if such Zone was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the Zone was integrated; and (3) a posted fuel pricing point in such Zone, if available, and (if such pricing point is not available in such Zone) a fuel transmission adder appropriate

to such Zone from an appropriate PJM Region pricing point shall be used for each such Zone.

Curve

vi) Process for Establishing Parameters of Variable Resource Requirement

- A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.
- B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.
- C) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.
 - 1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - 2) The PJM Members shall review the proposed values.
 - 3) The PJM Members shall either vote to (i) endorse the proposed values, (ii) propose alternate values or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - 4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values 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.

- D) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.
- 1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.
 - 2) The PJM Members shall review the proposed methodology.
 - 3) The PJM Members shall either vote to (i) endorse the proposed methodology, (ii) propose an alternate methodology or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.
 - 4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Resource Requirements and Constraints

Prior to the Base Residual Auction and each Incremental Auction for the Delivery Years starting on June 1, 2014 and ending May 31, 2017, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and

Incremental Auctions for the 2017/2018 Delivery Year, the Office of the Interconnection shall establish the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and Incremental Auctions for 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for ~~such~~ Delivery Years prior to the 2021/2022 Delivery Year and the Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years.

5.11 Posting of Information Relevant to the RPM Auctions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5.11A Backbone Transmission Upgrade Project Development Milestones

A Transmission Upgrade including transmission facilities at voltages of 500 kV or higher that is in an approved Regional Transmission Expansion Plan (“Backbone Transmission”) shall be included in the system model for an RPM Auction only if it satisfies the project development milestones set forth in this section.

a) Base Residual Auction

Backbone Transmission shall be included in the system model used for a Base Residual Auction only if:

i) No later than 60 days before posting of the planning parameters for the Base Residual Auction, a corporate officer of the project sponsor submits a current critical path project development schedule containing intermediate milestones and showing the project in full commercial operation no later than the start of the Delivery Year corresponding to such Base Residual Auction, and must certify that such schedule is reasonably achievable based on information then known to and reasonably anticipated by the project sponsor. Such notice must identify all states in which such project is subject to the requirement to obtain a certificate of public convenience and necessity, or functional equivalent approval or licensure requirement, and must describe the nature and current status of such approval requirement;

ii) such development schedule additionally must show the scope, schedule, and current status of all other key milestones, including, at a minimum, right-of-way acquisition, engineering design, equipment procurement, construction permitting, and construction activities;

iii) applications for certificates of public convenience and necessity (or for equivalent approval) have been filed in all states applicable to such project that have such requirement.

b) Incremental Auctions

A Backbone Transmission project shall be included in the system models for Incremental Auctions only if the following requirements are satisfied no later than 60 days before each Incremental Auction, as indicated below:

i) a corporate officer submits, and certifies to, an updated project development schedule for the First Incremental Auction that shows, among other things, that 50% of the right-of-way by linear distance has been secured;

ii) a corporate officer submits, and certifies to, an updated project development schedule for the Second Incremental Auction that shows, among other things, that 75% of the right-of-way by linear distance has been secured, and that all certificates of public convenience and necessity (or equivalent approvals) have been issued by the responsible regulatory bodies;

iii) a corporate officer submits, and certifies to, an updated project development schedule for the Third Incremental Auction or Final Incremental Auction, as applicable, that shows, among other things, that 100% of the right-of-way by linear distance has been secured.

c) Audit, Removal from System Model, and Reinstatement in System Model

i) for the Backbone Transmission project to remain in the applicable system model, the Office of the Interconnection or independent third party with established expertise in such area must audit the project development schedule and affirm, no later than 30 days before each applicable auction, that the schedule is reasonable and remains on progress to full commercial operation prior to the commencement of the relevant Delivery Year. Audits may include site visits as deemed necessary by the auditor to verify progress.

ii) a Backbone Transmission project that fails to satisfy any of the requirements indicated for the Base Residual Auction shall not be included in the system model for such Base Residual Auction or any Incremental Auction for the relevant Delivery Year. A Backbone Transmission project that fails to satisfy any of the requirements indicated for an Incremental Auction shall not be included in the system model for such Incremental Auction or any subsequent Incremental Auction for the relevant Delivery Year.

iii) a Backbone Transmission project that is excluded from the system model for any RPM Auction for a Delivery Year may be included in the system model for RPM Auctions for a subsequent Delivery Year only if it demonstrates that all deficiencies have been cured and the project is on schedule for full commercial operation prior to such subsequent Delivery Year.

5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;
- the Variable Resource Requirement Curves for the PJM Region and each LDA;
- any constraints resulting from the Locational Deliverability Requirement and any applicable Capacity Import Limit;
- for Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a) ~~of this Attachment DD~~; for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a) ~~of this Attachment DD~~; and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a) ~~of this Attachment DD~~;
- For the Delivery Years through May 31, 2018, the PJM Region Reliability Requirement minus the Short-Term Resource Procurement Target;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement; and
- For the 2020/2021 Delivery Year and subsequent Delivery Years, the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region.

The optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, while respecting all applicable requirements and constraints, including any restrictions specified in any Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. For the 2020/2021 Delivery Year and subsequent Delivery Years, the supply curve formed by the Sell Offers submitted within an LDA for which a separate VRR Curve is established, shall only consider the quantity of MW from Summer-Period Capacity Performance Resources that are equally matched with Winter-Period Capacity Performance Resources within the LDA, such that only the equally matched quantity of opposite-season Sell Offers are considered in satisfying the LDA's reliability requirement.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year. The Capacity Resource clearing results and Capacity Resource Clearing Prices determined for Summer-Period Capacity Performance Resources shall be applicable for the calendar months of June through October and the following May of such Delivery Year; and shall be applicable for Winter-Period Capacity Performance Resources for the calendar months of November through April of such Delivery Year.

b) Scheduled Incremental Auctions.

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- For the Delivery years through May 31, 2018, the PJM Region Reliability Requirement, less the Short-term Resource Procurement Target;

- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;
- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;
- The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- For the Delivery Years through May 31, 2018, for each LDA, such LDA's updated Reliability Requirement, less such LDA's Short-Term Resource Procurement Target;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, for each LDA, such LDA's updated Reliability Requirement
- ~~For Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each LDA for which PJM is required to establish a separate VRR Curve for the Base Residual Auction for the relevant Delivery Year; for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a)~~~~of this Attachment DD~~; and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a)~~of this Attachment DD~~;
- For the 2020/2021 Delivery Year and subsequent Delivery Years, the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region;
- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;
- The Sell Offers submitted in such auction; and
- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction for Delivery Years prior to the 2021/2022 Delivery Year and the Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years is triggered by Tariff, Attachment DD, section 5.4(c)(2) ~~of this Attachment~~, the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction for Delivery Years prior to the 2021/2022 Delivery Year and the Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years is triggered by Tariff, Attachment DD, section 5.4(c)(1) ~~of this Attachment~~, and the conditions stated in Tariff, Attachment DD, section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, sections 5.14B, 5.14C, 5.14E, and 5.5A(c)(i)(B) ~~of this Attachment DD~~ and RAA, Schedule 6, section L.9, minus (E) the quantity of new Unforced Capacity commitments for the 2016/2017 and 2017/2018 Delivery Years associated with the transition provisions in Tariff, Attachment DD, section 5.14D ~~of this Attachment DD~~ where this quantity is assumed to have been procured in the form of non-Capacity Performance Resources for purposes of this paragraph E. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, with exception for the Third Incremental Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. In seeking to sell back such quantity for the Third Incremental Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall employ in the clearing of the auction a curve represented by a straight line connecting two points with the first point located at 0 megawatts and at a price set to the lowest price point of the Updated VRR Curve Decrement and the second point located at a megawatt amount corresponding to the negative quantity defined above and at a price set to the Resource Clearing Price of the 2017/2018 Base Residual Auction.

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction for Delivery Years prior to the 2021/2022 Delivery Year is indicated for the PJM Region or any LDA by Tariff, Attachment DD, section

5.4(c)(3)(i) ~~of this Attachment~~, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by Tariff, Attachment DD, section 5.4(c)(3)(ii) ~~of this Attachment~~, plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, sections 5.14B, 5.14C, 5.14E, and 5.5A(c)(i)(B) ~~of this Attachment DD~~ and RAA, Schedule 6, section L.9, minus (E) the quantity of new Unforced Capacity commitments for the 2016/2017 and 2017/2018 Delivery Years associated with the transition provisions in Tariff, Attachment DD, section 5.14D ~~of this Attachment DD~~ where this quantity is assumed to have been procured in the form of non-Capacity Performance Resources for purposes of this paragraph E; provided, however, that the amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, with exception for the Third Incremental Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. In seeking to sell back such quantity for the Third Incremental Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall employ in the clearing of the auction a curve represented by a straight line connecting two points with the first point located at 0 megawatts and at a price set to the lowest price point of the Updated VRR Curve Decrement and the second point located at a megawatt amount corresponding to the negative quantity defined above and at a price set to the Resource Clearing Price of the 2017/2018 Base Residual Auction.

When the possible need to seek agreements to release capacity commitments in any Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years is indicated for the PJM Region or any LDA by Tariff, Attachment DD, section 5.4(c)(3)(i), the Office of the Interconnection shall seek to sell back such quantity at a sell offer price equal to the Resource Clearing Price of the Base Residual Auction applicable to the relevant Delivery Year.

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction for Delivery Years prior to the 2021/2022 Delivery Year, the Office of the Interconnection first shall

determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. For the Delivery Years through May 31, 2018, if more than one of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection shall not seek to procure the Short-Term Resource Procurement Target Applicable Share more than once for such region or area for such auction

(v) If PJM seeks to procure additional capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years due to a triggering of the tests in subsections (i), (ii), (iii) or (iv) then the Minimum Annual Resource Requirement for such Auction will be equal to the updated Minimum Annual Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity from Annual Resources, and the Minimum Extended Summer Resource Requirement for such Auction will be equal to the updated Minimum Extended Summer Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years from Annual Resources and Extended Summer Demand Resources. If PJM seeks to release prior committed capacity due to a triggering of the test in subsection (iii) then PJM may not release prior committed capacity from Annual Resources or Extended Summer Demand Resources below the updated Minimum Annual Resource Requirement and updated Minimum Extended Summer Resource Requirement, respectively.

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits (“Excess Commitment Credits”) under certain circumstances as follows:

- (A) For either or both of the Delivery Years commencing on June 1, 2010 or June 1, 2011, if the PJM Region Reliability Requirement used for purposes of the Base Residual Auction for such Delivery Year exceeds the PJM Region Reliability Requirement that is based on the last updated load forecast prior to such Delivery Year, then such excess will be allocated to Load Serving Entities as set forth below;
- (B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, through and including the Delivery Year ending on May 31, 2021, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;
- (C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;
- (D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

(ix) For the 2021/2022 Delivery Year and all subsequent Delivery Years, the total megawatt amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Final Incremental Auction for such Delivery Year that does not clear such auction will be made available for purposes of accepting requests from Capacity Market Sellers to be excused of all or a portion of a Capacity Resource’s Base Residual Auction commitment. Such requests must be provided to PJM during an open request window that closes 15 business days prior to the start of the relevant Delivery Year and such requests must identify the Capacity Resource and the unforced capacity megawatt quantity of the Capacity Resource’s

Base Residual Auction commitment for which the Capacity Market Seller seeks to be excused. Only Capacity Resource commitments made by clearing in the Base Residual Auction are eligible to be excused through this process. The maximum total megawatt quantity of Base Residual Auction commitment excusal requests that may be accepted across the entire RTO is equal to the total uncleared megawatt quantity that PJM sought to release in the Final Incremental Auction, and, the maximum total megawatt quantity of Base Residual Auction commitment that may be excused within each modeled LDA is equal to the updated final LDA Reliability Requirement minus the total committed capacity located within the LDA minus the LDA CETL, not to exceed the maximum total megawatt quantity that may be excused across the entire RTO. If the total megawatt quantity of all Base Residual Auction excusal requests received during the open request window is less than the maximum permissible levels for the RTO and each modeled LDA, then all requests will be accepted. If the total megawatt quantity of all Base Residual Auction excusal requests exceeds the maximum permissible level for the entire RTO then all requests will be accepted at reduced levels based on each request's pro-rata share of the maximum permissible megawatt quantity of the RTO. If after this proration, the total megawatt quantity of Base Residual Auction excusal requests exceeds the maximum permissible level for a modeled LDA, then all requests within that LDA will be reallocated based on each request's pro-rata share of the maximum permissible level for that LDA and the residual quantity will be allocated to requests located outside of that LDA while again ensuring that the maximum permissible level of any given modeled LDA is not exceeded. PJM will notify Capacity Market Sellers that submitted requests to be excused of a Base Residual Auction commitment during the open request window of the accepted megawatt values within 2 business days of the close of the request window.

When a Capacity Resource's Base Residual Auction commitment is excused through this process, the Capacity Market Seller relinquishes the Base Residual Auction Credit that it would otherwise receive for the excused unforced capacity megawatt quantity and is no longer responsible for satisfying any obligation associated with the excused quantity. The total dollar value of relinquished auction credits associated with all accepted Base Residual Auction commitment excusals shall be distributed throughout the relevant Delivery Year on a daily basis to all LSEs that were charged a Locational Reliability Charge for the day. Such distribution shall be based on each LSE's pro-rata share of the total Daily Unforced Capacity Obligation.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;
- All applicable Capacity Import Limits;

- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

6. MARKET POWER MITIGATION

6.1 Applicability

The provisions of the Market Monitoring Plan (in [Tariff](#), Attachment M and Attachment - M Appendix ~~to this Tariff~~ and this section 6) shall apply to the Reliability Pricing Model Auctions.

6.2 Process

(a) [Reserved for Future Use]

(b) In accordance with the schedule specified in the PJM Manuals, following PJM's conduct of a Base Residual Auction or Incremental Auction pursuant to [Tariff, Attachment DD](#), section 5.12, but prior to the Office of the Interconnection's final determination of clearing prices and charges pursuant to [Tariff, Attachment DD](#), section 5.14, the Office of the Interconnection shall: (i) apply the Market Structure Test to any LDA having a Locational Price Adder greater than zero and to the entire PJM region; (ii) apply Market Seller Offer Caps, if required under this section 6; and (iii) recompute the optimization algorithm to clear the auction with the Market Seller Offer Caps in place.

(c) Within seven days after the deadline for submission of Sell Offers in a Base Residual Auction or Incremental Auction, the Office of the Interconnection shall file with FERC a report of any determination made pursuant to [Tariff, Attachment DD](#), sections 5.14(h), 6.5(a)(ii), or 6.7(c) identified in such sections as subject to the procedures of this section. Such report shall list each such determination, the information considered in making each such determination, and an explanation of each such determination. Any entity that objects to any such determination may file a written objection with FERC no later than seven days after the filing of the report. Any such objection must not merely allege that the determination was in error, and must provide support for the objection, demonstrating that the determination overlooked or failed to consider relevant evidence. In the event that no objection is filed, the determination shall be final. In the event that an objection is filed, FERC shall issue any decision modifying the determination no later than 60 days after the filing of such report; otherwise, the determination shall be final. Final auction results shall reflect any decision made by FERC regarding the report.

6.3 Market Structure Test

(a) [Reserved for Future Use]

(b) Market Structure Test.

A constrained LDA or the PJM Region shall fail the Market Structure Test, and mitigation shall be applied to all jointly pivotal suppliers (including all Affiliates of such suppliers, and all third-party supply in the relevant LDA controlled by such suppliers by contract), if, as to the Sell Offers that comprise the incremental supply determined pursuant to section 6.3(c) that are based on Generation Capacity Resources, there are not more than three jointly pivotal suppliers. The Office of the Interconnection shall apply the Market Structure Test. The Office of the

Interconnection shall confirm the results of the Market Structure Test with the Market Monitoring Unit.

(c) Determination of Incremental Supply

In applying the Market Structure Test, the Office of the Interconnection shall consider all (i) incremental supply (provided, however, that the Office of the Interconnection shall consider only such supply available from Generation Capacity Resources) available to solve the constraint applicable to a constrained LDA offered at less than or equal to 150% of the cost-based clearing price; or (ii) supply for the PJM Region, offered at less than or equal to 150% of the cost-based clearing price, provided that supply in this section includes only the lower of cost-based or market-based offers from Generation Capacity Resources. Cost-based clearing prices are the prices resulting from the RPM auction algorithm using the lower of cost-based or price-based offers for all Capacity Resources.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW/day of unforced capacity, applicable to price-quantity offers within the Base Offer Segment for an Existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW/day of unforced capacity, provided, however, that the default Market Seller Offer Cap for any Capacity Performance Resource shall be the product of (the Net Cost of New Entry applicable for the Delivery Year and Locational Deliverability Area for which such Capacity Performance Resource is offered times the average of the Balancing Ratios in the three consecutive calendar years (during the Performance Assessment *Intervals* in such calendar years) that precede the Base Residual Auction for such Delivery Year), however, for the Base Residual Auction for the 2021/2022 Delivery Year, the Balancing Ratio used in the determination of the default Market Seller Offer Cap shall be 78.5 percent, and provided further that the submission of a Sell Offer with an Offer Price at or below the revised Market Seller Offer Cap permitted under this proviso shall not, in and of itself, be deemed an exercise of market power in the RPM market. Notwithstanding the previous sentence, a Capacity Market Seller may seek and obtain a Market Seller Offer Cap for a Capacity Performance Resource that exceeds the revised Market Seller Offer Cap permitted under the prior sentence, if it supports and obtains approval of such alternative offer cap pursuant to the procedures and standards of subsection (b) of this section 6.4. A Capacity Market Seller may not use the Capacity Performance default Market Seller Offer Cap, and also seek to include any one or more categories of the Avoidable Cost Rate defined in Tariff, Attachment DD, section 6.8. The Market Seller Offer Cap for an Existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with Tariff, Attachment DD, section 6.7. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in Tariff, Attachment M-Appendix, section II.E.3 ~~of Attachment M-Appendix~~.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection data and

documentation required under [Tariff, Attachment DD](#), section 6.7 to establish the level of the Market Seller Offer Cap applicable to each resource by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the Market Seller Offer Cap proposed by the Market Monitoring Unit, and attempt to reach agreement with the Market Monitoring Unit on the level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller shall notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, whether an agreement with the Market Monitoring Unit has been reached or, if no agreement has been reached, specifying the level of Market Seller Offer Cap to which it commits by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. The Office of the Interconnection shall review the data submitted by the Capacity Market Seller, make a determination whether to accept or reject the requested unit-specific Market Seller Offer Cap, and notify the Capacity Market Seller and the Market Monitoring Unit of its determination in writing, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction. If the Market Monitoring Unit does not provide its determination to the Capacity Market Seller and the Office of the Interconnection by the specified deadline, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction the Office of the Interconnection will make the determination of the level of the Market Seller Offer Cap, which shall be deemed to be final. If the Capacity Market Seller does not notify the Market Monitoring Unit and the Office of the Interconnection of the Market Seller Offer Cap it desires to utilize by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction, it shall be required to utilize a Market Seller Offer Cap determined using the applicable default Avoidable Cost Rate specified in [Tariff, Attachment DD](#), section 6.7(c).

(c) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the Sell Offer complies with the requirements of the Tariff.

(d) For any Third Incremental Auction for Delivery Years through the 2017/2018 Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction for the 2018/2019 or 2019/2020 Delivery Years, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Base Capacity resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction [or Final Incremental Auction, as applicable](#), for the 2018/2019 Delivery Year or any subsequent Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Capacity Performance Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to the greater of the Net Cost of New Entry for the

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

6.5 Mitigation

The Office of the Interconnection shall apply market power mitigation measures in any Base Residual Auction or Incremental Auction for any LDA, Unconstrained LDA Group, or the PJM Region that fails the Market Structure Test.

(a) Mitigation for Generation Capacity Resources.

i) Existing Generation Capacity Resource

Mitigation will be applied on a unit-specific basis and only if the Sell Offer of Unforced Capacity from an Existing Generation Capacity Resource: (1) is greater than the Market Seller Offer Cap applicable to such resource; and (2) would, absent mitigation, increase the Capacity Resource Clearing Price in the relevant auction. If such conditions are met, such Sell Offer shall be set equal to the Market Seller Offer Cap.

ii) Planned Generation Capacity Resources

(A) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) shall be presumed to be competitive and shall not be subject to market power mitigation in any Base Residual Auction or Incremental Auction for which such resource qualifies as a Planned Generation Capacity Resource, but any such Sell Offer shall be rejected if it meets the criteria set forth in subsection (C) below, unless the Capacity Market Seller obtains approval from FERC for use of such offer prior to the close of the offer period for the applicable RPM Auction.

(B) Sell Offers based on Planned Generation Capacity Resources (including Planned External Generation Capacity Resources) shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that modeled LDA are pivotal, shall be subject to mitigation.

(C) Where the two conditions stated in subsection (B) are not met, or the Sell Offer is pivotal, the Sell Offer shall be rejected if it exceeds 140 percent of: 1) the average of location-adjusted Sell Offers for Planned Generation Capacity Resources from the same asset class as such Sell

Offer, submitted (and not rejected) (Asset-Class New Plant Offers) for such Delivery Year; or 2) if there are no Asset-Class New Plant Offers for such Delivery Year, the average of Asset-Class New Plant Offers for all prior Delivery Years; or 3) if there are no Asset-Class New Plant Offers for any prior Delivery Year, the Net CONE applicable for such Delivery Year in the LDA for which such Sell Offer was submitted. For purposes of this section, asset classes shall be as stated in [Tariff, Attachment DD](#), section 6.7(c) as effective for such Delivery Year, and Asset-Class New Plant Offers shall be location-adjusted by the ratio between the Net CONE effective for such Delivery Year for the LDA in which the Sell Offer subject to this section was submitted and the average, weighted by installed capacity, of the Net CONEs for all LDAs in which the units underlying such Asset Class New Plant Offers are located. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with Section 6.2(b) above, each Capacity Market Seller whose Sell Offer is so rejected shall be notified in writing by the Office of the Interconnection by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction and allowed an opportunity to submit a revised Sell Offer that does not exceed such threshold within one (1) Business Day of the Office of the Interconnection's rejection of such Sell Offer. If such revised Sell Offer is accepted by the Office of the Interconnection, the Office of the Interconnection then shall clear the auction with such revised Sell Offer in place. Pursuant to [Tariff, Attachment M-Appendix](#), Section II.F-~~of Attachment M-Appendix~~, the Market Monitoring Unit shall notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

(b) Mitigation for Demand Resources

The Market Seller Offer Cap shall not be applied to Sell Offers of Demand Resources or Energy Efficiency Resources.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h), all of the installed capacity of all Existing Generation Capacity Resources located in the PJM Region shall be offered by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to this RPM must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to [Tariff, Attachment DD](#), ~~s~~Section 5.6.6-~~of Attachment DD of the Tariff~~. The Unforced Capacity of such resources is determined using the EFORD value that is submitted by the Capacity Market Seller in its Sell Offer, which shall not exceed the maximum EFORD for

that resource as defined in Section 6.6(b). If a resource should be included on the list of Existing Generation Capacity Resources subject to the RPM must-offer requirement that is maintained by the Market Monitoring Unit pursuant to Tariff, Attachment M-Appendix, sSection II.C.1 of Attachment M – Appendix of the Tariff, but is omitted therefrom whether by mistake of the Market Monitoring Unit or failure of the Capacity Market Seller that owns or controls all or part of such resource to provide information about the resource to the Market Monitoring Unit, this shall not excuse such resource from the RPM must-offer requirement.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit and the Office of the Interconnection all data and documentation required under section 6.6 to establish the maximum EFORD applicable to each resource in accordance with standards and procedures specified in the PJM Manuals. The maximum EFORD that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORDs used for a Delivery Year are posted, is the greater of (i) the average EFORD for the five consecutive years ending on the September 30 that last precedes the Base Residual Auction, or (ii) the EFORD for the 12 months ending on the September 30 that last precedes the Base Residual Auction.

Notwithstanding the foregoing, a Capacity Market Seller may request an alternate maximum EFORD for Sell Offers submitted in such auctions if it has a documented, known reason that would result in an increase in its EFORD, by submitting a written request to the Market Monitoring Unit and Office of the Interconnection, along with data and documentation required to support the request for an alternate maximum EFORD, by no later one hundred twenty (120) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. The Capacity Market Seller must address any concerns identified by the Market Monitoring Unit and/or the Office of the Interconnection regarding the data and documentation provided and attempt to reach agreement with the Market Monitoring Unit on the level of the alternate maximum EFORD by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. As further described in Tariff, Attachment M-Appendix, Section II.C ~~of Attachment M-Appendix~~, the Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination of the requested alternate maximum EFORD by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than eighty (80) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Capacity Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing whether it agrees with the Market Monitoring Unit on the alternate maximum EFORD or, if no agreement has been reached, specifying the level of alternate maximum EFORD to which it commits. If a Capacity Market Seller fails to request an alternate maximum EFORD prior to the specified deadlines, the maximum EFORD for the applicable RPM Auction shall be deemed to be the default EFORD calculated pursuant to this section.

The maximum EFORD that may be used in a Sell Offer for a Third or Final Incremental Auctions, and for Conditional Incremental Auctions held after the date on which the final EFORD used for a Delivery Year is posted, is the EFORD for the 12 months ending on the September 30 that last precedes the submission of such offers.

(c) [Reserved for Future Use]

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the maximum level of the alternate EFORD that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORDs used for a Delivery Year are posted, the Office of the Interconnection shall make its own determination of the maximum level of the alternate EFORD based on the requirements of the Tariff and the PJM Manuals, per Section 5.8 of Attachment DD, by no later than sixty-five (65) days prior to the commencement of the offer period for the Base Residual for the applicable Delivery Year, and shall notify the Capacity Market Seller and the Market Monitoring Unit in writing of such determination.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORD complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit an EFORD that it chooses for an RPM Auction held prior to the date on which the final EFORD used for a Delivery Year is posted, provided that (i) it has participated in good faith with the process described in this section 6.6 and in Tariff, attachment M-Appendix, section II.C ~~of Attachment M-Appendix~~, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) A Capacity Market Seller that owns or controls an existing generation resource in the PJM Region that is capable of qualifying as an Existing Generation Capacity Resource as of the date on which bidding commences for an RPM Auction may not avoid the rule in subsection (a) or be removed from Capacity Resource status by failing to qualify as a Generation Capacity Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource for that RPM Auction. However, generation resource may qualify for an exception to the RPM must-offer requirement, as shown by appropriate documentation, if the Capacity Market Seller that owns or controls such resource demonstrates that it: (i) is reasonably expected to be physically unable to participate in the relevant Delivery Year; (ii) has a financially and physically firm commitment to an external sale of its capacity, or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

- A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Tariff, sSection 113.1 ~~of the PJM Tariff~~, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Tariff.

~~Section 113.2 of the PJM Tariff~~ for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

- B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff;
- C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or
- D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity as set forth in (ii) above, the Capacity Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export.

A Capacity Market Seller that seeks to remove a Generation Capacity Resource from PJM Capacity Resource status and/or seeks approval for an exception to the RPM must-offer requirement, for any reason other than the reason specified in Paragraph A above, shall first submit such request in writing, along with all supporting data and documentation, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to obtain an exception to the RPM must-offer requirement for the reason specified in Paragraph A above, a Capacity Market Seller shall first submit a preliminary exception request in writing, along with supporting data and documentation indicating the reasons and conditions upon which the Capacity Market Seller is relying in its analysis of whether to retire such resource, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than (a) November 1, 2013 for the Base Residual Auction for the 2017/2018 Delivery Year, (b) the September 1 that last precedes the Base Residual Auction for the 2018/2019 and subsequent Delivery Years, and (c) two hundred forty (240) days prior to the commencement of the offer period for the applicable

Incremental Auction. By no later than five (5) Business Days after receipt of any such preliminary exception requests, the Office of the Interconnection will post on its website a summary of the number of megawatts of Generation Capacity Resources for which it has received notification of preliminary exception requests, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

Thereafter, as applicable, such Capacity Market Seller shall by no later than (a) the December 1 that last precedes the Base Residual Auction for the applicable Delivery Year, or (b) one hundred twenty (120) days prior to the commencement of the offer period for the applicable Incremental Auction, either (a) notify the Office of the Interconnection and the Market Monitoring Unit in writing that it is withdrawing its preliminary exception request and explaining the changes to its analysis of whether to retire such resource that support its decision to withdraw, or (b) demonstrate that it has met the requirements specified under Paragraph A above. By no later than five (5) Business Days after receipt of such notification, the Office of the Interconnection will post on its website a revised summary of the number of megawatts of Generation Capacity Resources for which it has received requests for exceptions to the RPM must-offer requirement for the reason specified in Paragraph A above, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

A Capacity Market Seller may only remove the Generation Capacity Resource from PJM Capacity Resource status if (i) the Market Monitoring Unit has determined that the Generation Capacity Resource meets the applicable criteria set forth in [Tariff, Attachment DD, sSections 5.6.6 and 6.6 of Attachment DD](#) and the Office of the Interconnection agrees with this determination, or (ii) the Commission has issued an order terminating the Capacity Resource status of the resource. Nothing herein shall require a Market Seller to offer its resource into an RPM Auction prior to seeking to remove a resource from Capacity Resource status, subject to satisfaction of Section 6.6.

If the Capacity Market Seller disagrees with the Market Monitoring Unit's determination of its request to remove a resource from Capacity Resource status or its request for an exception to the RPM must-offer requirement, it must notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, of the same by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. After the Market Monitoring Unit has made its determination of whether a resource has satisfied the RPM must-offer requirement or meets one of the exceptions thereto and has notified the Capacity Market Seller and the Office of the Interconnection of the same pursuant to [Tariff, Attachment M-Appendix, sSection II.C.4 of Attachment M – Appendix](#), the Office of the Interconnection shall approve or deny the exception request. The exception request shall be deemed to be approved by the Office of the Interconnection, consistent with the determination of the Market Monitoring Unit, unless the Office of the Interconnection notifies the Capacity Market Seller and Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences, that the exception request is denied.

If the Market Monitoring Unit does not timely notify the Capacity Market Seller and the Office of the Interconnection of its determination of the request to remove a Generation Capacity

Resource from Capacity Resource status or for an exception to the RPM must-offer requirement, the Office of the Interconnection shall make the determination whether the request shall be approved or denied, and will notify the Capacity Market Seller of its determination in writing, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences.

After the Market Monitoring Unit and the Office of the Interconnection have made their determinations of whether a resource meets the criteria to qualify for an exception to the RPM must-offer requirement, the Capacity Market Seller must notify the Market Monitoring Unit and the Office of the Interconnection whether it intends to exclude from its Sell Offer some or all of the subject capacity on the basis of an identified exception by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences. PJM does not make determinations of whether withholding of capacity constitutes market power. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation Capacity Resource during a Delivery Year pursuant to a sale or transfer agreement entered into after March 26, 2009 shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

If a Capacity Market Seller doesn't timely seek to remove a Generation Capacity Resource from Capacity Resource status or timely submit a request for an exception to the RPM must-offer requirement, the Generation Capacity Resource shall only be removed from Capacity Resource status, and may only be approved for an exception to the RPM must-offer requirement, upon the Capacity Market Seller requesting and receiving an order from FERC, prior to the close of the offer period for the applicable RPM Auction, directing the Office of the Interconnection to remove the resource from Capacity Resource status and/or granting an exception to the RPM must-offer requirement or a waiver of the RPM must-offer requirement as to such resource.

(h) Any existing generation resource located in the PJM Region that satisfies the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for the Base Residual Auction for a Delivery Year, that is not offered into such Base Residual Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under [Tariff, Attachment DD](#), section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All generation resources located in the PJM Region that satisfy the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for an Incremental Auction for a particular Delivery Year, but that did not satisfy such criteria as of the date that on which bidding commenced in the Base Residual Auction for that Delivery Year, that is not offered into that Incremental Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent

Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All Existing Generation Capacity Resources that are offered into a Base Residual Auction or Incremental Auction for a particular Delivery Year but do not clear in such auction, that are not offered into each subsequent Incremental Auction, and that do not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any Incremental Auctions conducted for such Delivery Year subsequent to such failure to offer; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any such Existing Generation Capacity Resources may also be subject to further action by the Market Monitoring Unit under the terms of Attachment M and Attachment M – Appendix.

(i) In addition to the remedies set forth in subsections (g) and (h) above, if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources, for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement, into an RPM Auction as required by this Section 6.6 would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, and the Office of the Interconnection agrees with that determination, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the relevant RPM Auction, or for other appropriate relief, and PJM will postpone clearing the auction pending FERC's decision on the matter. If the Office of the Interconnection disagrees with the Market Monitoring Unit's determination and does not apply to FERC for an order directing the Capacity Market Seller to participate in the auction or for other appropriate relief, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and to seek appropriate relief.

6.6A Offer Requirement for Capacity Performance Resources

(a) For the 2018/2019 Delivery Year and subsequent Delivery Years, the installed capacity of every Generation Capacity Resource located in the PJM Region that is capable (or that reasonably can become capable) of qualifying as a Capacity Performance Resource shall be offered as a Capacity Performance Resource by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each such Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to the Capacity Performance Resource must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, ~~Section 5.6.6 of Attachment DD of the Tariff.~~

(b) Determinations of EFORD and Unforced Capacity made under section 6.6 hereof as to a Generation Capacity Resource shall govern the offers required under this section as to the same Generation Capacity Resource.

(c) Exceptions to the requirement in subsection (a) shall be permitted only for a resource which the Capacity Market Seller demonstrates is reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource. Intermittent Resources, Capacity Storage Resources, Demand Resources, and Energy Efficiency Resources shall not be required to offer as a Capacity Performance Resource, but shall not be precluded from being offered as a Capacity Performance Resource at a level that demonstrably satisfies such requirements. Exceptions shall be determined using the same timeline and procedures as specified in section 6.6.

(d) A resource not exempted or excepted under subsection (c) hereof that is capable of qualifying as a Capacity Performance Resource and does not offer into an RPM Auction as a Capacity Performance Resource shall be subject to the same restrictions on subsequent offers, and other possible remedies, as specified in section 6.6.

6.7 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit and the Office of the Interconnection no later than one hundred twenty (120) days prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORD and the net (unforced) capacity. A potential participant intending to offer any Capacity Performance Resource at or below the default Market Seller Offer Cap described in [Tariff, Attachment DD](#), section 6.4(a) must provide the associated offer cap and the MW to which the offer cap applies.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that request a unit specific Avoidable Cost Rate shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above: (1) the applicable default level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

Nothing herein precludes the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource as outlined in [Tariff, Attachment M-Appendix](#), section II.G ~~of Attachment M-Appendix~~. Any Sell Offer submitted in any auction that is inconsistent with any agreement or commitment made pursuant to this subsection shall be rejected, and the Capacity Market Seller shall be required to resubmit a Sell Offer that complies with such agreement or commitment within one (1) Business Day of the Office of the Interconnection's rejection of such Sell Offer. If the Capacity Market Seller does not timely resubmit its Sell Offer, fails to request a unit-specific Avoidable Cost Rate by the specified deadline, or if the Office of the Interconnection determines that the information provided by the Capacity Market Seller in support of the requested unit-specific Avoidable Cost Rate or Sell Offer is incomplete, the Capacity Market Seller shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default offer for the applicable class of resource or nearest comparable class of resource determined under this subsection (c)(ii). The obligation imposed under [Tariff, Attachment DD](#), section 6.6(a) shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection or subject to the procedures set forth in [Tariff, Attachment DD](#), section 6.4 and [Tariff, Attachment M-Appendix](#), section II.H ~~of Attachment M-Appendix~~.

The default retirement and mothball Avoidable Cost Rates ("ACR") referenced in this subsection (c)(ii) are as set forth in the tables below for the 2013/2014 Delivery Year through the 2016/2017 Delivery Year. Capacity Market Sellers shall use the one-year mothball Avoidable Cost Rate shown below, unless such Capacity Market Seller satisfies the criteria set forth in [Tariff, Attachment DD](#), section 6.7(e), in which case the Capacity Market Seller may use the retirement Avoidable Cost Rate. PJM shall also publish on its Web site the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates. A Capacity Market Seller may not use the default Market Seller Offer Cap contained in the ACR tables in this subsection, and also seek to include any one or more categories of the Avoidable Cost Rate defined [Tariff, Attachment DD](#), section 6.8.

| |
|---|
| Maximum Avoidable Cost Rates by Technology Class |
|---|

| Technology | 2013/14 Mothball ACR (\$/MW- Day) | 2013/14 Retirement ACR (\$/MW- Day) | 2014/15 Mothball ACR (\$/MW- Day) | 2014/15 Retirement ACR (\$/MW- Day) | 2015/16 Mothball ACR (\$/MW- Day) | 2015/16 Retirement ACR (\$/MW- Day) | 2016/2017 Mothball ACR (\$/MW- Day) | 2016/2017 Retirement ACR (\$/MW- Day) |
|--|--|--|--|--|--|--|--|--|
| Nuclear | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Pumped Storage | \$23.64 | \$33.19 | \$24.56 | \$34.48 | \$25.56 | \$35.89 | \$24.05 | \$33.78 |
| Hydro | \$80.80 | \$105.67 | \$83.93 | \$109.76 | \$87.35 | \$114.24 | \$82.23 | \$107.55 |
| Sub-Critical Coal | \$193.98 | \$215.02 | \$201.49 | \$223.35 | \$209.71 | \$232.46 | \$197.43 | \$218.84 |
| Super Critical Coal | \$200.41 | \$219.21 | \$208.17 | \$227.70 | \$216.66 | \$236.99 | \$203.96 | \$223.10 |
| Waste Coal - Small | \$255.81 | \$309.83 | \$265.72 | \$321.83 | \$276.56 | \$334.96 | \$260.35 | \$315.34 |
| Waste Coal – Large | \$94.61 | \$114.29 | \$98.27 | \$118.72 | \$102.28 | \$123.56 | \$96.29 | \$116.32 |
| Wind | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| CC-2 on 1 Frame F | \$35.18 | \$49.90 | \$36.54 | \$51.83 | \$38.03 | \$53.94 | \$35.81 | \$50.79 |
| CC-3 on 1 Frame E/Siemens | \$39.06 | \$52.89 | \$40.57 | \$54.94 | \$42.23 | \$57.18 | \$39.75 | \$53.83 |
| CC–3 or More on 1 or More Frame F | \$30.46 | \$42.28 | \$31.64 | \$43.92 | \$32.93 | \$45.71 | \$30.99 | \$43.03 |
| CC-NUG Cogen. Frame B or E Technology | \$130.76 | \$175.71 | \$135.82 | \$182.52 | \$141.36 | \$189.97 | \$133.09 | \$178.83 |
| CT - 1st & 2nd Gen. Aero (P&W FT 4) | \$27.96 | \$37.19 | \$29.04 | \$38.63 | \$30.22 | \$40.21 | \$28.45 | \$37.85 |
| CT - 1st & Gen. Frame B | \$27.63 | \$36.87 | \$28.70 | \$38.30 | \$29.87 | \$39.86 | \$28.11 | \$37.52 |
| CT - 2nd Gen. Frame E | \$26.26 | \$35.14 | \$27.28 | \$36.50 | \$28.39 | \$37.99 | \$26.73 | \$35.77 |
| CT - 3rd Gen. Aero (GE LM 6000) | \$63.57 | \$93.70 | \$66.03 | \$97.33 | \$68.72 | \$101.30 | \$64.70 | \$95.37 |
| CT - 3rd Gen. Aero (P&W FT - 8 TwinPak) | \$33.34 | \$49.16 | \$34.63 | \$51.06 | \$36.04 | \$53.14 | \$33.93 | \$50.03 |
| CT - 3rd Gen. Frame F | \$26.96 | \$38.83 | \$28.00 | \$40.33 | \$29.14 | \$41.98 | \$27.43 | \$39.52 |
| Diesel | \$29.92 | \$37.98 | \$31.08 | \$39.45 | \$32.35 | \$41.06 | \$30.44 | \$38.66 |
| Oil and Gas Steam | \$74.20 | \$90.33 | \$77.07 | \$93.83 | \$80.21 | \$97.66 | \$75.51 | \$91.94 |

Commencing with the Base Residual Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall determine the default retirement and mothball Avoidable Cost Rates referenced in section (c)(ii) above, and post them on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the applicable ACR rates, the Office of the Interconnection shall use the actual rate of change in the historical values from the Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission (“Handy-Whitman Index”) to the extent they are available to update the base values for the Delivery Year, and for future Delivery Years for which the updated Handy-Whitman Index values are not yet available the Office of the Interconnection shall update the base values for the Delivery Year using the most recent ten-calendar-year annual average rate of change. The ACR rates shall be expressed in dollar values for the applicable Delivery Year.

| Maximum Avoidable Cost Rates by Technology Class (Expressed in 2011 Dollars for the 2011/2012 Delivery Year) | | |
|---|-------------------------------------|---------------------------------------|
| Technology | Mothball ACR (\$/MW-Day) | Retirement ACR (\$/MW-Day) |
| Combustion Turbine - Industrial Frame | \$24.13 | \$33.04 |
| Coal Fired | \$136.91 | \$157.83 |
| Combined Cycle | \$29.58 | \$40.69 |
| Combustion Turbine - Aero Derivative | \$26.13 | \$37.18 |
| Diesel | \$25.46 | \$32.33 |
| Hydro | \$68.78 | \$89.96 |
| Oil and Gas Steam | \$63.16 | \$76.90 |
| Pumped Storage | \$20.12 | \$28.26 |

To determine the default retirement and mothball ACR values for the 2017/2018 Delivery Year, the Office of the Interconnection shall multiply the base default retirement and mothball ACR values in the table above by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Indices for the 2011 to 2013 calendar years to determine updated base default retirement and mothball ACR values. The updated base default retirement and mothball ACR values shall then be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

To determine the default retirement and mothball ACR values for the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, the Office of the Interconnection shall multiply the updated base default retirement and mothball ACR values from the immediately preceding Delivery Year by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Index. These values become the new adjusted base default retirement and mothball ACR values, as calculated by the Office of the Interconnection and posted to its website. These resulting adjusted base values for the Delivery Year shall be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the

applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

PJM shall also publish on its website the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

After the Market Monitoring Unit conducts its annual review of the table of default Avoidable Cost Rates included in section 6.7(c) above in accordance with the procedure specified in [Tariff, Attachment M-Appendix](#), section II.H ~~of Attachment M—Appendix~~, it will provide updated values or notice of its determination that updated values are not needed to Office of the Interconnection. In the event that the Office of the Interconnection determines that the values should be updated, the Office of the Interconnection shall file its proposed values with the Commission by no later than October 30th prior to the commencement of the offer period for the first RPM Auction for which it proposes to apply the updated values.

(d) In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection relevant unit-specific cost data concerning each data item specified as set forth in section 6 by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. If cost data is not available at the time of submission for the time periods specified in [Tariff, Attachment DD](#), section 6.8, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used, as may be further specified in the PJM Manuals. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination pursuant to [Tariff, Attachment M-Appendix](#), section II.E ~~of Attachment M-Appendix~~.

i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment.

ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate less the Projected Market Revenues for such resource (as defined in [Tariff, Attachment DD](#), Section 6.4). The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost

Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(e) below.

iii. **Projected PJM Market Revenues:** Projected PJM Market Revenues are defined by [Tariff, Attachment DD](#), section 6.8(d), for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

(e) In order for the retirement Avoidable Cost Rate set forth in the table in section 6.7(c) to apply, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction, a Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer representing that the Capacity Market Seller will retire the Generation Capacity Resource if it does not receive during the relevant Delivery Year at least the applicable retirement Avoidable Cost Rate because it would be uneconomic to continue to operate the Generation Capacity Resource in the Delivery Year without the retirement Avoidable Cost Rate, and specifying the date the Generation Capacity Resource would otherwise be retired.

6.8 Avoidable Cost Definition

(a) Avoidable Cost Rate:

The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer shall be determined using the following formula, expressed in dollars per MW-year:

$$\text{Avoidable Cost Rate} = [\text{Adjustment Factor} * (\text{AOML} + \text{AAE} + \text{AFAE} + \text{AME} + \text{AVE} + \text{ATFI} + \text{ACC} + \text{ACLE}) + \text{ARPIR} + \text{APIR} + \text{CPQR}]$$

Where:

- **Adjustment Factor** equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.
- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.
- **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit for twelve months preceding the month in which the data must be

provided. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

- **AFAE (Avoidable Fuel Availability Expenses)** consists of avoidable operating expenses related directly to fuel availability and delivery for the generating unit that can be demonstrated by the Capacity Market Seller based on data for the twelve months preceding the month in which the data must be provided , or on reasonable projections for the Delivery Year supported by executed contracts, published tariffs, or other data sufficient to demonstrate with reasonable certainty the level of costs that have been or shall be incurred for such purpose. The categories of expenses included in AFAE are those incurred for: (a) firm gas pipeline transportation; (b) natural gas storage costs; (c) costs of gas balancing agreements; and (d) costs of gas park and loan services. AFAE expenses are for firm fuel supply and apply solely for offers for a Capacity Performance Resource
- **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.
- **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.
- **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AFTI are those incurred for: (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site; and (d) property taxes.
- **ACC (Avoidable Carrying Charges)** consists of avoidable short-term carrying charges related directly to the generating unit in the twelve months preceding the month in which the data must be provided. Avoidable short-term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC,

short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services, (b) environmental reporting; and (c) procurement expenses.
- **CPQR (Capacity Performance Quantifiable Risk)** consists of the quantifiable and reasonably-supported costs of mitigating the risks of non-performance associated with submission of a Capacity Performance Resource offer (or of a Base Capacity Resource offer for the 2018/19 or 2019/20 Delivery Years), such as insurance expenses associated with resource non-performance risks. CPQR shall be considered reasonably supported if it is based on actuarial practices generally used by the industry to model or value risk and if it is based on actuarial practices used by the Capacity Market Seller to model or value risk in other aspects of the Capacity Market Seller's business. Such reasonable support shall also include an officer certification that the modeling and valuation of the CPQR was developed in accord with such practices. Provision of such reasonable support shall be sufficient to establish the CPQR. A Capacity Market Seller may use other methods or forms of support for its proposed CPQR that shows the CPQR is limited to risks the seller faces from committing a Capacity Resource hereunder, that quantifies the costs of mitigating such risks, and that includes supporting documentation (which may include an officer certification) for the identification of such risks and quantification of such costs. Such showing shall establish the proposed CPQR upon acceptance by the Office of the Interconnection.
- **APIR (Avoidable Project Investment Recovery Rate) = $PI * CRF$**

Where:

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

- **CRF** is the annual capital recovery factor from the following table, applied in accordance with the terms specified below.

| Age of Existing Units (Years) | Remaining Life of Plant (Years) | Levelized CRF |
|-------------------------------|---------------------------------|---------------|
| 1 to 5 | 30 | 0.107 |
| 6 to 10 | 25 | 0.114 |
| 11 to 15 | 20 | 0.125 |
| 16 to 20 | 15 | 0.146 |
| 21 to 25 | 10 | 0.198 |
| 25 Plus | 5 | 0.363 |
| Mandatory CapEx | 4 | 0.450 |
| 40 Plus Alternative | 1 | 1.100 |

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the 25 Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment.

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the

APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource (“rebate payment”); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other Existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of \$10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third [BRABase Residual Auction](#) (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds \$200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant [BRABase Residual Auction](#).

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the Mandatory CapEx option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third [BRABase Residual Auction](#) (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant [BRABase Residual Auction](#) (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Part V of the PJM Tariff. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 Plus Alternative option will be modeled in the RTEP process as “at-risk” at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the 40 Plus Alternative option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Multi-Year Pricing Option

A Seller submitting a Sell Offer with an APIR component that is based on a Project Investment of at least \$450/kW may elect this Multi-Year Pricing Option by providing written notice to such effect the first time it submits a Sell Offer that includes an APIR component for such Project Investment. Such option shall be available on the same terms, and under the same conditions, as are available to Planned Generation Capacity Resources under Tariff, Attachment DD, section 5.14(c) ~~of this Attachment~~.

- **ARPIR (Avoidable Refunds of Project Investment Reimbursements)** consists of avoidable refund amounts of Project Investment Reimbursements payable by a Generation Owner to PJM under Tariff, Part V, ~~sSection 118 of this Tariff~~ or avoidable refund amounts of project investment reimbursements payable by a Generation Owner to PJM under a Cost of Service Recovery Rate filed under Tariff, Part V, ~~sSection 119 of the Tariff~~ and approved by the Commission.

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

(c) For the purpose of determining an Avoidable Cost Rate, avoidable expenses shall exclude variable costs recoverable under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market under the Operating Agreement.

(d) Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of energy and ancillary services market offers for such resource. Net energy market revenues shall be based on the non-zero market-based offers of the Capacity Market Seller of such Generation Capacity Resource unless one of the following conditions is met, in which case the cost-based offer shall be used: (x) the market-based offer for the resource is zero, (y) the market-based offer for the resource is higher than its cost-based offer and such offer has been mitigated, or (z) the market-based offer for the resource is less than such Capacity Market Seller's fuel and environmental costs for the resource which shall be determined either

by directly summing the fuel and environmental costs if they are available, or by subtracting from the cost-based offer for the resource all costs developed pursuant to the Operating Agreement and PJM Manuals that are not fuel or environmental costs.

The calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the Base Residual Auction~~BRA~~ is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, or if data is not available to the Capacity Market Seller for the entire period, despite the good faith efforts of such seller to obtain such data, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

8. CAPACITY RESOURCE DEFICIENCY CHARGE

8.1

A Capacity Resource Deficiency Charge shall be assessed on any Capacity Market Seller that commits a Capacity Resource, and on any Locational UCAP Seller that sells Locational UCAP for a Delivery Year based on a Generation Capacity Resource, for a Delivery Year that is unable or unavailable to deliver Unforced Capacity for all or any part of such Delivery Year for any reason, including but not limited to the following, and that does not obtain replacement Unforced Capacity meeting the same locational requirements and same or better temporal availability characteristics (i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource) in the megawatt quantity required to satisfy the capacity committed from such resource by such seller as a result of all cleared Sell Offers from such seller based on such resource in any RPM Auctions for such Delivery Year, the reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and the increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource:

a) Unit Derating – Such Capacity Resource is a Generation Capacity Resource and its capacity value is derated prior to or during the Delivery Year;

b) EFORD Increase – Such Capacity Resource is a Generation Capacity Resource and the EFORD value determined for such resource at least two (2) months prior to the Third or Final Incremental Auction is higher than the EFORD value submitted in the Capacity Market Seller's cleared Sell Offer;

c) External Generation Resource – Such Capacity Resource is an Existing Generation Capacity Resource that is located outside of the PJM Control Area and arrangements for the firm delivery of the output of such resource to the interface with the PJM Region are not in place for such resource prior to the start of the Delivery Year;

d) Planned Generation Resource – Such Capacity Resource is a Planned Generation Capacity Resource and Interconnection Service has not commenced as to such resource prior to the start of the Delivery Year;

e) Planned Demand Resource - Such Capacity Resource is a Planned Demand Resource or an Energy Efficiency Resource and the associated demand response program or energy efficiency measure is not installed prior to the start of the Delivery Year; or

f) Existing Demand Resource – Such Capacity Resource is an existing Demand Resource or Energy Efficiency Resource and, subject to Tariff, Attachment DD, section 8.4, is not capable of providing the megawatt quantity of load response specified in the cleared Sell Offer for the time periods of availability associated with the product type.

8.2. Capacity Resource Deficiency Charge

The Capacity Resource Deficiency Charge shall equal the Daily Deficiency Rate (as defined in section 7) multiplied by the megawatt quantity of deficiency below the level of capacity committed in such Capacity Market Seller's Sell Offer(s) or bilateral capacity commitments, or Locational UCAP Seller's Locational UCAP sale for each day such seller is deficient, provided, however, that a resource that is subject to a charge under this section that is also subject to a charge under [Tariff, Attachment DD, sSection 10A](#) hereof for a Performance Shortfall during one or more Performance Assessment *Intervals* occurring during the period of resource deficiency addressed by this section shall be assessed a charge equal to the greater of the charge determined under this section and the charge determined under [Tariff, Attachment DD, sSection 10A](#), but shall not be assessed a charge under both this section and [Tariff, Attachment DD, sSection 10A](#) for such simultaneous occurrence of a resource deficiency and Performance Shortfall.

8.3. Allocation of Revenue Collected from Capacity Resource Deficiency Charges

The revenue collected from the assessment of a Capacity Resource Deficiency Charge shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which such Capacity Resource Deficiency Charge was assessed. Such revenues shall be distributed on a pro-rata basis to such LSEs based on their Daily Unforced Capacity Obligations.

8.4 Relief from Charges

A Capacity Market Seller or Locational UCAP Seller that is otherwise subject to the Capacity Resource Deficiency Charge solely as a result of [Tariff, Attachment DD, section 8.1\(f\)](#) may receive relief from such Charge if it demonstrates that the inability to provide the level of demand response specified in its Sell Offer is due to the permanent departure (due to plant closure, efficiency gains, or similar reasons) from the Transmission System of load that was relied upon for load response in such Sell Offer; provided, however, that such seller 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. Such seller shall receive no RPM Auction Credit for the amount of reduction in the committed Existing Demand Resources.

Section(s) of the
PJM Reliability Assurance Agreement
(Marked / Redline Format)

ARTICLE 1 – DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto, or in the PJM Tariff or PJM Operating Agreement if not otherwise defined in this Agreement, for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

Agreement:

“Agreement” shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

Annual Demand Resource:

“Annual Demand Resource” shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Annual Energy Efficiency Resource:

“Annual Energy Efficiency Resource” shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer and winter periods described in such Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Applicable Regional Entity:

“Applicable Regional Entity” shall have the same meaning as in the PJM Tariff.

Base Capacity Demand Resource:

“Base Capacity Demand Resource” shall mean, for the 2018/2019 and 2019/2020 Delivery

Years, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through September of a Delivery Year, and will be available to the Office of the Interconnection for an unlimited number of interruptions during such months, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Base Capacity Demand Resource must be available June through September in the corresponding Delivery Year to be offered for sale or self-supplied in an RPM Auction, or included as a Base Capacity Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Base Capacity Energy Efficiency Resource:

“Base Capacity Energy Efficiency Resource” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of the Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Base Capacity Resource:

“Base Capacity Resource” shall have the same meaning as in Tariff, Attachment DD.

Base Residual Auction:

“Base Residual Auction” shall have the same meaning as in Tariff, Attachment DD.

Behind The Meter Generation:

“Behind The Meter Generation” shall mean a generating 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 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 Capacity Resource or (ii) in any 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 Capability:

“Black Start Capability” shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

Capacity Emergency Transfer Objective (CETO):

“Capacity Emergency Transfer Objective” or “CETO” shall mean the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be calculated based in part on EFORD determined in accordance with Reliability Assurance Agreement, Schedule 5, Paragraph C.

Capacity Emergency Transfer Limit (CETL):

Capacity Emergency Transfer Limit” or “CETL” shall mean the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity Import Limit:

For any Delivery Year up to and including the 2019/2020 Delivery Year, “Capacity Import Limit” shall mean, (a) for the PJM Region, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines for each Delivery Year, through appropriate modeling and the application of engineering judgment, the transmission system can receive, in aggregate at the interface of the PJM Region with all external balancing authority areas and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus (2) the then-applicable Capacity Benefit Margin; and (b) for certain source zones identified in the PJM manuals as groupings of one or more balancing authority areas, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines the transmission system can receive at the interface of the PJM Region with each such source zone and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus the then-applicable Capacity Benefit Margin times (2) the ratio of the maximum import quantity from each such source zone divided by the PJM total maximum import quantity. As more fully set forth in the PJM Manuals, PJM shall make such determination based on the latest peak load forecast for the studied period, the same computer simulation model of loads, generation and transmission topography employed in the determination of Capacity Emergency Transfer Limit for such Delivery Year, including external facilities from an industry standard model of the loads, generation, and transmission topography of the Eastern Interconnection under peak conditions. PJM shall specify in the PJM Manuals the areas and minimum distribution factors for identifying monitored bulk electric system facilities that have an electrically significant response to such transfers on the PJM interface. Employing such tools, PJM shall model increased power transfers from external areas into PJM to determine the transfer level at which one or more reliability criteria is violated on any monitored bulk electric system facilities that have an electrically significant response to such transfers. For the

PJM Region Capacity Import Limit, PJM shall optimize transfers from other source areas not experiencing any reliability criteria violations as appropriate to increase the Capacity Import Limit. The aggregate megawatt quantity of transfers into PJM at the point where any increase in transfers on the interface would violate reliability criteria will establish the Capacity Import Limit. Notwithstanding the foregoing, a Capacity Resource located outside the PJM Region shall not be subject to the Capacity Import Limit if the Capacity Market Seller seeks an exception thereto by demonstrating to PJM, by no later than five (5) business days prior to the commencement of the offer period for the relevant RPM Auction, that such resource meets all of the following requirements:

(i) it has, at the time such exception is requested, met all applicable requirements to be pseudo-tied into the PJM Region, or the Capacity Market Seller has committed in writing that it will meet such requirements, unless prevented from doing so by circumstances beyond the control of the Capacity Market Seller, prior to the relevant Delivery Year;

(ii) at the time such exception is requested, it has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and

(iii) it 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; provided, however, that (a) the total megawatt quantity of all exceptions granted hereunder for a Delivery Year, plus the Capacity Import Limit for the applicable interface determined for such Delivery Year, may not exceed the total megawatt quantity of Network External Designated Transmission Service on such interface that PJM has confirmed for such Delivery Year; and (b) if granting a qualified exception would result in a violation of the rule in clause (a), PJM shall grant the requested exception but reduce the Capacity Import Limit by the quantity necessary to ensure that the total quantity of Network External Designated Transmission Service is not exceeded.

Capacity Performance Resource:

“Capacity Performance Resource” shall have the same meaning as in Tariff, Attachment DD.

Capacity Resources:

“Capacity Resources” shall mean megawatts of (i) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources meeting the requirements of the Reliability Assurance Agreement, Schedules 9 and 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under the Reliability Assurance Agreement, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in such Schedules 9 and 10; and (iii) load reduction capability provided by Demand Resources or Energy Efficiency Resources that are accredited to the PJM Region pursuant to the procedures set forth in the Reliability Assurance Agreement, Schedule 6.

Capacity Transfer Right:

“Capacity Transfer Right” shall have the meaning specified in Tariff, Attachment DD.

Compliance Aggregation Area (CAA):

“Compliance Aggregation Area” or “CAA” shall have the same meaning as in the Tariff.

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 generation control scheme is applied in order to:

- (a) 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);
- (b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;
- (d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and
- (e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

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 the Reliability Assurance Agreement, Schedule 8 or, as to an FRR Entity, in the Reliability Assurance Agreement, Schedule 8.1.

Delivery Year:

“Delivery Year” shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, section 5 or pursuant to an FRR Capacity Plan.

Demand Resource (DR):

“Demand Resource” or “DR” shall mean a Limited Demand Resource, Extended Summer Demand Resource, Annual Demand Resource, Base Capacity Demand Resource or Summer-Period Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of the Reliability Assurance Agreement, Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan.

Demand Resource Officer Certification Form:

“Demand Resource Officer Certification Form” shall mean a certification as to an intended Demand Resource Sell Offer, in accordance with the Reliability Assurance Agreement, Schedules 6 and 8.1 and the PJM Manuals.

Demand Resource Sell Offer Plan:

“Demand Resource Sell Offer Plan” shall mean the plan required by the Reliability Assurance Agreement, Schedules 6 and 8.1 in support of an intended offer of Demand Resources in an RPM Auction, or an intended inclusion of Demand Resources in an FRR Capacity Plan.

Demand Resource Factor or DR Factor:

“Demand Resource Factor” or “DR Factor” shall mean, for Delivery Years through May 31, 2018, that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource in accordance with the Reliability Assurance Agreement, Schedule 6.

Electric Cooperative:

“Electric Cooperative” shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

Electric Distributor:

“Electric Distributor” shall mean a Member that 1) owns or leases with rights equivalent to ownership of electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to the electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Emergency:

“Emergency” shall mean (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of

system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

End-Use Customer:

“End-Use Customer” shall mean a Member that is a retail end-user of electricity within the PJM Region.

Energy Efficiency Resource:

“Energy Efficiency Resource” shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of the Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the periods described in the Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention. Annual Energy Efficiency Resources, Base Capacity Energy Efficiency Resources and Summer-Period Energy Efficiency Resources are types of Energy Efficiency Resources.

Existing Demand Resource:

“Existing Demand Resource” shall mean a Demand Resource for which the Demand Resource Provider has identified existing end-use customer sites that are registered for the current Delivery Year with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such resource is offered.

Existing Generation Capacity Resource:

“Existing Generation Capacity Resource” shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as

those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

Extended Summer Demand Resource:

“Extended Summer Demand Resource” shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Facilities Study Agreement:

“Facilities Study Agreement” shall have the same meaning as in the PJM Tariff

FERC:

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

Firm Point-To-Point Transmission Service:

“Firm Point-To-Point Transmission Service” shall mean Firm Transmission Service provided pursuant to the rates, terms and conditions set forth in Tariff, Part II.

Firm Transmission Service:

“Firm Transmission Service” shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

Fixed Resource Requirement Alternative or FRR Alternative:

“Fixed Resource Requirement Alternative” or “FRR Alternative” shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in the Reliability Assurance Agreement, Schedule 8.1.

Forecast Pool Requirement:

“Forecast Pool Requirement” or “FPR” shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Reliability Assurance Agreement, as approved by the PJM Board pursuant to Reliability Assurance Agreement, Schedule 4.1.

FRR Capacity Plan or FRR Plan:

“FRR Capacity Plan” or “FRR Plan” shall mean a long-term plan for the commitment of Capacity Resources to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in the Reliability Assurance Agreement, Schedule 8.1.

FRR Entity:

“FRR Entity” shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

FRR Service Area:

“FRR Service Area” shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

Full Requirements Service:

“Full Requirements Service” shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Generation Capacity Resource:

“Generation Capacity Resource” shall mean a generation unit, or the contractual right to capacity from a specified generation unit, that meets the requirements of Schedules 9 and 10 of this Agreement, and, for generation units that are committed to an FRR Capacity Plan, that meets the

requirements of Schedule 8.1 of this Agreement. A Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity Resource.

Generation Owner:

“Generation Owner” shall mean a Member that owns or leases with rights equivalent to ownership, facilities for the generation of electric energy that are located within the PJM Region. Purchasing all or a portion of the output of a generation facility shall not be sufficient to qualify a Member as a Generation Owner.

Generator Forced Outage:

“Generator Forced Outage” shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

Generator Maintenance Outage:

“Generator Maintenance Outage” shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

Generator Planned Outage:

“Generator Planned Outage” shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

Good Utility Practice:

“Good Utility Practice” shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region; including those practices required by Federal Power Act Section 215(a)(4).

Incremental Auction:

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

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

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

IOU:

“IOU” shall mean an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

Limited Demand Resource:

“Limited Demand Resource” shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 Load Management Events during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Load Serving Entity or LSE:

“Load Serving Entity” or “LSE” shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a

utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

Locational Reliability Charge:

“Locational Reliability Charge” shall mean the charge determined pursuant to Operating Agreement, Schedule 8.

Markets and Reliability Committee:

“Markets and Reliability Committee” shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

Maximum Emergency Service Level:

“Maximum Emergency Service Level” or “MESL” of Price Responsive Demand shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when a Maximum Generation Emergency is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan.

Member:

“Member” shall mean an entity that satisfies the requirements of Operating Agreement, sSections 1.24 and 11.6~~of the PJM Operating Agreement~~. In accordance with the Reliability Assurance Agreement, Article 4, each Party to this Agreement also is a Member.

Members Committee:

“Members Committee” shall mean the committee specified in Operating Agreement, sSection 8~~of the PJM Operating Agreement~~ composed of the representatives of all the Members.

NERC:

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

Network External Designated Transmission Service:

“Network External Designated Transmission Service” shall mean the quantity of network transmission service confirmed by PJM for use by a market participant to import power and energy from an identified Generation Capacity Resource located outside the PJM Region, upon demonstration by such market participant that it owns such Generation Capacity Resource, has an executed contract to purchase power and energy from such Generation Capacity Resource, or has a contract to purchase power and energy from such Generation Capacity Resource contingent upon securing firm transmission service from such resource.

Network Resources:

“Network Resources” shall have the meaning set forth in the PJM Tariff.

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 (as that term is defined in the PJM Tariff).

Nominal PRD Value:

“Nominal PRD Value” shall mean, as to any PRD Provider, an adjustment, determined in accordance with Operating Agreement, Schedule 6.1, to the peak-load forecast used to determine the quantity of capacity sought through an RPM Auction, reflecting the aggregate effect of Price Responsive Demand on peak load resulting from the Price Responsive Demand to be provided by such PRD Provider.

Nominated Demand Resource Value:

“Nominated Demand Resource Value” shall have the meaning specified in Tariff, Attachment DD.

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, and electric distribution companies to serve load.

Obligation Peak Load:

“Obligation Peak Load” shall have the meaning specified in Operating Agreement, Schedule 8.

Office of the Interconnection:

“Office of the Interconnection” shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Operating Agreement of the PJM Interconnection, L.L.C. or Operating Agreement:

“Operating Agreement of the PJM Interconnection, L.L.C.” or “Operating Agreement” shall mean that Agreement, dated as of April 1, 1997 and as amended and restated as of June 2, 1997,

including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C.

Operating Day:

“Operating Day” shall have the same meaning as provided in the Operating Agreement.

Operating Reserve:

“Operating Reserve” shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Other Supplier:

“Other Supplier” shall mean a Member that is (i) a seller, buyer or transmitter of electric capacity or energy in, from or through the PJM Region, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

Partial Requirements Service:

“Partial Requirements Service” shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Performance Assessment *Interval*:

“Performance Assessment *Interval*” shall have the meaning specified in Attachment DD of the PJM Tariff.

Percentage Internal Resources Required:

“Percentage Internal Resources Required” shall mean, for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in such LDA.

Party:

“Party” shall mean an entity bound by the terms of the Operating Agreement.

PJM:

“PJM” shall mean the PJM Board and the Office of the Interconnection.

PJM Board:

“PJM Board” shall mean the Board of Managers of the PJM Interconnection, L.L.C., acting pursuant to the Operating Agreement.

PJM Manuals:

“PJM Manuals” shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

PJM Tariff (Tariff):

“PJM Tariff” or “Tariff” shall mean that certain “PJM Open Access Transmission Tariff, including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

PJM Region:

“PJM Region” shall have the same meaning as provided in the Operating Agreement.

PJM Region Installed Reserve Margin:

“PJM Region Installed Reserve Margin” shall mean the percent installed reserve margin for the PJM Region required pursuant to the Operating Agreement, as approved by the PJM Board pursuant to Operating Agreement, Schedule 4.1.

Planned Demand Resource:

“Planned Demand Resource” shall mean any Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Operating Agreement, Schedule 6. As set forth in Operating Agreement, Schedules 6 and 8.1, a Demand Resource Provider submitting a DR Sell Offer Plan shall identify as Planned Demand Resources in such plan all Demand Resources in excess of those that qualify as Existing Demand Resources.

Planned External Generation Capacity Resource:

“Planned External Generation Capacity Resource” shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery

Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Base Residual Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has a fully executed system impact study agreement (or other documentation which is functionally equivalent to a System Impact Study Agreement under the PJM Tariff) or, for resources which are greater than 20MWs participating in a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, an agreement or other documentation which is functionally equivalent to a Facilities Study Agreement under the PJM Tariff), with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. Prior to participating in any Incremental Auction for such Delivery Year, the Capacity Market Seller must demonstrate it has entered into an interconnection agreement, or such other documentation that is functionally equivalent to an Interconnection Service Agreement under the PJM Tariff, with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to be delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. Any such resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

Planned Generation Capacity Resource:

“Planned Generation Capacity Resource” shall mean a Generation Capacity Resource, or additional megawatts to increase the size of a Generation Capacity Resource that is being or has been modified to increase the number of megawatts of available installed capacity thereof, participating in the generation interconnection process under Tariff, Part IV, Subpart A, as applicable, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Capacity Plan; (ii) for any such resource seeking to offer into a Base Residual Auction, or for any such resource of 20 MWs or less seeking to offer into a Base Residual Auction, a System Impact Study Agreement (or, for resources for which a System Impact Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a System Impact Study Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; (iii) for any such resource of more than 20 MWs seeking to offer into a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, a Facilities Study Agreement (or, for resources for which a Facilities Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a Facility Studies Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; (iv) an Interconnection Service Agreement has been executed prior to any Incremental Auction for

such Delivery Year in which such resource plans to participate; and (iv) no megawatts of capacity have cleared an RPM Auction for any prior Delivery Year. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years.

Planning Period:

“Planning Period” shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

PRD Curve:

“PRD Curve” shall mean a price-consumption curve at a PRD Substation level, if available, and otherwise at a Zonal (or sub-Zonal LDA, if applicable) level, that details the base consumption level of Price Responsive Demand and the decreasing consumption levels at increasing prices.

PRD Provider:

“PRD Provider” shall mean (i) a Load Serving Entity that provides PRD; or (ii) an entity without direct load serving responsibilities that has entered contractual arrangements with end-use customers served by a Load Serving Entity that satisfy the eligibility criteria for Price Responsive Demand.

PRD Provider’s Zonal Expected Peak Load Value of PRD:

“PRD Provider’s Zonal Expected Peak Load Value of PRD” shall mean the expected contribution to Delivery Year peak load of a PRD Provider’s Price Responsive Demand, were such demand not to be reduced in response to price, based on the contribution of the end-use customers comprising such Price Responsive Demand to the most recent prior Delivery Year’s peak demand, escalated to the Delivery Year in question, as determined in a manner consistent with the Office of the Interconnection’s load forecasts used for purposes of the RPM Auctions.

PRD Reservation Price:

“PRD Reservation Price” shall mean an RPM Auction clearing price identified in a PRD Plan for Price Responsive Demand load below which the PRD Provider desires not to commit the identified load as Price Responsive Demand.

PRD Substation:

“PRD Substation” shall mean an electrical substation that is located in the same Zone or in the same sub-Zonal LDA as the end-use customers identified in a PRD Plan or PRD registration and

that, in terms of the electrical topography of the Transmission Facilities comprising the PJM Region, is as close as practicable to such loads.

Price Responsive Demand:

“Price Responsive Demand” or “PRD” shall mean end-use customer load registered by a PRD Provider pursuant to Schedule 6.1 of the PJM Reliability Assurance Agreement that have, as set forth in more detail in the PJM Manuals, the metering capability to record electricity consumption at an interval of one hour or less, Supervisory Control capable of curtailing such load (consistent with applicable RERRA requirements) at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection, and a retail rate structure, or equivalent contractual arrangement, capable of changing retail rates as frequently as an hourly basis, that is linked to or based upon changes in real-time Locational Marginal Prices at a PRD Substation level and that results in a predictable automated response to varying wholesale electricity prices.

Price Responsive Demand Credit:

“Price Responsive Demand Credit” shall mean a credit, based on committed Price Responsive Demand, as determined under Operating Agreement, Schedule 6.1.

Price Responsive Demand Plan or PRD Plan:

“Price Responsive Demand Plan” or “PRD Plan” shall mean a plan, submitted by a PRD Provider and received by the Office of the Interconnection in accordance with Operating Agreement, Schedule 6.1 and procedures specified in the PJM Manuals, claiming a peak demand limitation due to Price Responsive Demand to support the determination of such PRD Provider’s Nominal PRD Value.

Public Power Entity:

“Public Power Entity” shall mean any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

Qualifying Transmission Upgrades:

“Qualifying Transmission Upgrades” shall have the meaning specified in Attachment DD to the PJM Tariff.

Relevant Electric Retail Regulatory Authority:

“Relevant Electric Retail Regulatory Authority” or “RERRA” shall have the meaning specified in the PJM Operating Agreement.

Reliability Principles and Standards:

“Reliability Principles and Standards” shall mean the principles and standards established by NERC or an Applicable Regional Entity to define, among other things, an acceptable probability of loss of load due to inadequate generation or transmission capability, as amended from time to time.

Required Approvals:

“Required Approvals” shall mean all of the approvals required for the Operating Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of the Operating Agreement.

Self-Supply:

“Self-Supply” shall have the meaning provided in Tariff, Attachment DD.

Small Commercial Customer:

“Small Commercial Customer” shall have the same meaning as in the PJM Tariff.

State Consumer Advocate:

“State Consumer Advocate” shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Regulatory Structural Change:

“State Regulatory Structural Change” shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party’s default service rules that materially affect whether retail choice is economically viable.

Summer-Period Demand Resource:

Summer-Period Demand Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a resource that is placed under the direction of the Office of the Interconnection, and will be available June through October and the following May of the Delivery Year, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Summer-Period Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale in an RPM Auction, or included as a Summer-Period Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Summer-Period Energy Efficiency Resource:

Summer-Period Energy Efficiency Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Schedule 6 of this Agreement and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Summer-Period Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Supervisory Control:

“Supervisory Control” shall mean the capability to curtail, in accordance with applicable RERRA requirements, load registered as Price Responsive Demand at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection. Except to the extent automation is not required by the provisions of the Operating Agreement, the curtailment shall be automated, meaning that load shall be reduced automatically in response to control signals sent by the PRD Provider or its designated agent directly to the control equipment where the load is located without the requirement for any action by the end-use customer.

Threshold Quantity:

“Threshold Quantity” shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity’s Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base FRR Scaling Factor (as determined in accordance with Operating Agreement, Schedule 8.1).

Transmission Facilities:

“Transmission Facilities” shall mean facilities that: (i) are within the PJM Region; (ii) 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; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Owner:

“Transmission Owner” shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owners Agreement:

“Transmission Owners Agreement” shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005 and as amended from time to time, among transmission owners within the PJM Region.

Unforced Capacity:

“Unforced Capacity” shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

Winter Peak Load (or WPL):

“Winter Peak Load” or “WPL” shall mean the Demand Resource customer specific peak load between hour ending 7:00 EPT through 21:00 EPT on the PJM defined 5 coincident peak days from December through February two Delivery Years prior the Delivery Year for which the registration is submitted and as outlined in the PJM Manuals.

Zonal Capacity Price:

“Zonal Capacity Price” shall mean the price of Unforced Capacity in a Zone that an LSE that has not elected the FRR Alternative is obligated to pay for a Delivery Year as determined pursuant to Attachment DD to the PJM Tariff.

Zone or Zonal:

“Zone” or “Zonal” shall refer to an area within the PJM Region, as set forth in Operating Agreement, Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A

Zone shall include any Non-Zone Network Load (as defined in the PJM Tariff) located outside the PJM Region that is served from such Zone under Schedule H-A of the PJM Tariff.

Zonal Winter Weather Adjustment Factor (ZWWAF):

“Zonal Winter Weather Adjustment Factor” or “ZWWAF” shall mean the PJM zonal winter weather normalized coincident peak divided by PJM zonal average of 5 coincident peak loads in December through February.

SCHEDULE 5

FORCED OUTAGE RATE CALCULATION

- A. The equivalent demand forced outage rate ("EFOR_D") shall be calculated as follows:

$$\text{EFOR}_D (\%) = \{(f_f * \text{FOH} + f_p * \text{EFPOH}) / (\text{SH} + f_f * \text{FOH})\} * 100$$

where

f_f = full outage factor

f_p = partial outage factor

FOH = full forced outage hours

EFPOH = equivalent forced partial outage hours

SH = service hours

- B. Calculation of EFOR_D for individual Generation Capacity Resources.

For each Delivery Year, EFOR_D shall be calculated at least one month prior to the start of the Third or Final Incremental Auction, as applicable for: (i) each Generation Capacity Resource for which a sell offer will be submitted in such Third or Final Incremental Auction, as applicable; and (ii) each Generation Capacity Resource previously committed to serve load in such Delivery Year pursuant to an FRR Capacity Plan or prior auctions for such Delivery Year. Such calculation shall be based upon such resource's service history in the twelve (12) consecutive months ending September 30 last preceding such auction. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments approved by the Members Committee to adjust the parameters of a designated unit. For purposes of the calculations under this Paragraph B, for Delivery Years through May 31, 2018, outages deemed to be outside plant management control in accordance with NERC guidelines shall not be considered, and for the 2018/2019 Delivery Year and all subsequent Delivery Years, outages deemed to be outside plant management control in accordance with NERC guidelines shall be considered.

1. The EFOR_D of a unit in service twelve or more full calendar months prior to the calculation month shall be the average rate experienced by such unit during the twelve-month period specified above. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.
2. The EFOR_D of a unit in service at least one full calendar month but less than the twelve-month period specified above shall be the average of the EFOR_D experienced by the unit weighted by full months of service, and the class average rate for units with that capability and of that type weighted by a factor of [(twelve) minus (the number of months the unit was in service)]. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

C. Calculation of average EFOR_D for the PJM Region

The forecast average EFOR_D for the PJM Region in a Delivery Year shall be the average of the forced outage rates, weighted for unit capability and expected time in service, attributable to all of the Generation Capacity Resources within the PJM Region, that are planned to be in service during the Delivery Year, including Generation Capacity Resources purchased from specified units and excluding Generation Capacity Resources sold outside the PJM Region from specified units. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments developed by the Office of Interconnection and maintained in the PJM Manuals to adjust the parameters of a designated unit when such parameters are or will be used to determine a future PJM Region reserve requirement and such adjustment is required to more accurately predict the future performance of such unit in light of extraordinary circumstances. For the purposes of this Schedule, the average EFOR_D shall be the average of the capacity-weighted EFOR_Ds of all units committed to serve load in the PJM Region; and for purposes of the EFOR_D calculations under this Paragraph C for any Delivery Year beginning after May 31, 2010, outages deemed to be outside plant management control in accordance with NERC guidelines shall not be considered, and for the 2018/2019 Delivery Year and all subsequent Delivery Years, outages deemed to be outside plant management control in accordance with NERC guidelines shall be considered. All rates shall be in percent.

1. The EFOR_D of a unit not yet in service or which has been in service less than one full calendar year at the time of forecast shall be the class average rate for units with that capability and of that type, as estimated and used in the calculation of the Forecast Pool Requirement.
2. The EFOR_D of a unit in service five or more full calendar years at the time of forecast shall be the average rate experienced by such unit during the five most recent calendar years. Historical data shall be based on official reports of the Parties under rules and practices developed by the Office of Interconnection and maintained in the PJM Manuals.
3. The EFOR_D of a unit in service at least one full calendar year but less than five full calendar years at the time of the forecast shall be determined as follows:

Full Calendar
Years of Service

- | | |
|---|--|
| 1 | One-fifth the rate experienced during the calendar year, plus four-fifths the class average rate. |
| 2 | Two-fifths the average rate experienced during the two calendar years, plus three-fifths the class average rate. |

- 3 Three-fifths the average rate experienced during the three calendar years, plus two-fifths the class average rate.
- 4 Four-fifths the average rate experienced during the four calendar years, plus one-fifth the class average rate.

SCHEDULE 6.1

PRICE RESPONSIVE DEMAND

A. As more fully set forth in this Schedule 6.1 and the PJM Manuals, for any Delivery Year beginning on or after June 1, 2015 (subject to a transition plan, as set forth below), any PRD Provider, including any FRR Entity, may commit that certain loads identified by such PRD Provider shall not exceed a specified demand level at specified prices during Maximum Generation Emergencies, as a consequence of the implementation of Price Responsive Demand. Based on information provided by the PRD Provider in a PRD Plan (and, to the extent such plan identifies a PRD Reservation Price, based on the clearing price in the Base Residual Auction or Third Incremental Auction, or Final Incremental Auction, as applicable), the Office of the Interconnection shall determine the Nominal PRD Value for the specified loads identified by such PRD Provider by Zone (or sub-Zonal LDA, if applicable). The Office of the Interconnection shall adjust the PJM Region Reliability Requirement and LDA Reliability Requirements, as applicable, to reflect committed PRD. Actual PRD reductions in response to price shall be added back in determining peak load contributions. Any PRD Provider that fails fully to honor its PRD commitments for a Delivery Year shall be assessed compliance charges.

B. End-use customer loads identified in a PRD Plan or PRD registration for a Delivery Year as Price Responsive Demand may not, for such Delivery Year, (i) be registered as Economic Load Response, Pre-Emergency Load Response or Emergency Load Response; (ii) be used as the basis of any Demand Resource Sell Offer or Energy Efficiency Resource Sell Offer in any RPM Auction; or (iii) be identified in a PRD Plan or PRD registration of any other PRD Provider.

C. Any PRD Provider seeking to commit PRD hereunder for a Delivery Year must submit to the Office of the Interconnection a PRD Plan identifying and supporting the Nominal PRD Value (calculated as the difference between the PRD Provider's Zonal Expected Peak Load Value of PRD and the Maximum Emergency Service Level of Price Responsive Demand) for each Zone (or sub-Zonal LDA, if applicable) for which such PRD is committed; such information shall be provided on a PRD Substation level to the extent available at the time the PRD Plan is submitted. Such plan must be submitted no later than the January 15 last preceding the Base Residual Auction for the Delivery Year for which such PRD is committed; any submitted plan that does not contain, by such January 15, all information required hereunder shall be rejected. A PRD Provider may submit a PRD Plan, or a modified PRD Plan, by the January 15 last preceding the Third or Final Incremental Auction, as applicable for such Delivery Year requesting approval of additional Price Responsive Demand but only in the event, and to the extent, that the final peak load forecast for the relevant LDA for such Delivery Year exceeds the preliminary peak load forecast for such LDA and Delivery Year. The Office of the Interconnection shall revise such requests (as adjusted, to the extent a PRD Reservation Price is specified, for the results of the Third or Final Incremental Auction, as applicable) for additional Price Responsive Demand downward, in accordance with rules in the PJM Manuals, if the submitted requests (as adjusted) in the aggregate exceed the increase in the load forecast in the LDA modeled. The Office of the Interconnection shall advise the PRD Provider, following the Third or Final Incremental

Auction, of its acceptance of, or any downward adjustment to, the Nominal PRD Value based on its review of the PRD Plan and the results of the auction. Approval of the PRD Plan by the Office of the Interconnection shall establish a firm commitment by the PRD Provider to the specified Nominal PRD Value of Price Responsive Demand at each Zone (or sub-Zonal LDA, if applicable) during the relevant Delivery Year (subject to any PRD Reservation Price), and may not be uncommitted or replaced by any Capacity Resource. Although the PRD Plan may include reasonably supported forecasts and expectations concerning the development of Price Responsive Demand for a Delivery Year, the PRD Provider's commitment to a Nominal PRD Value for such Delivery Year shall not depend or be conditioned upon realization of such forecasts or expectations.

D. All submitted PRD Plans must comply with the requirements and criteria in the PJM Manuals for such plans, including assumptions and standards specified in the PJM Manuals for estimates of expected load levels. The PRD Plan shall explain and justify the methods used to determine the Nominal PRD Value. All assumptions and relevant variables affecting the Nominal PRD Value must be clearly stated. The PRD Plan must include sufficient data to allow a third party to audit the procedures and verify the Nominal PRD Value. Any non-compliance with a Nominal PRD Value for a prior Delivery Year shall be identified and taken into account. In addition, each submitted PRD Plan must include:

(i) documentation, in the form specified in the PJM Manuals, that: (1) where the PRD Provider is a Load Serving Entity, the Relevant Electric Retail Regulatory Authority has provided any required approval (including conditional approval, but only if the Load Serving Entity asserts that all such conditions have been satisfied) of such Load Serving Entity's time-varying retail rate structure and, regardless of whether RERRA approval is required, that such rate structure adheres to PRD implementation standards specified in the PJM Manuals; and (2) where the PRD Provider is not a Load Serving Entity, such PRD Provider has in place contractual arrangements with the relevant end-use customers establishing a time-varying retail rate structure that conforms to any RERRA requirements, and adheres to PRD implementation standards specified in the PJM Manuals; in such cases, the PRD Provider shall provide the Office of the Interconnection copies of its applicable contracts with end-use customers (including any proposed contracts) within ten Business Days after a request for such contracts, or its PRD Plan shall be rejected;

(ii) the expected peak load value that would apply, absent load reductions in response to price, to the end-use customer loads at a PRD Substation level, including applicable peak-load contribution data for such customers, to the extent available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level;

(iii) the Maximum Emergency Service Level of the identified load given the load's price-responsive characteristics, at a PRD Substation level if available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level;

(iv) Price-consumption curves ("PRD Curves") at a PRD Substation level if available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level that detail the base consumption

level of the identified loads; and the decreasing consumption levels at increasing prices, provided that all identified load reductions must be capable of full implementation within 15 minutes of declaration of a Maximum Generation Emergency by the Office of the Interconnection, and provided further that the specified prices may not exceed the maximum energy offer price cap under the PJM Tariff and Operating Agreement;

(v) the estimated Nominal PRD Value of the Price Responsive Demand at a PRD Substation level if available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level;

(vi) specifications of equipment used to satisfy the advanced metering and Supervisory Control criteria for eligible Price Responsive Demand, including a timeline and milestones demonstrating that such equipment shall be available and operational for the start of the relevant Delivery Year. Such equipment shall comply with applicable RERRA requirements and shall be designed to meet all PRD requirements, including, without limitation, meter reading requirements and Supervisory Control requirements, specified in the PJM Manuals. The PRD Provider shall demonstrate in the PRD Plan that the Supervisory Control equipment enables an automated load response by Price Responsive Demand to the price trigger; provided, however, that the PRD Provider may request in the PRD Plan an exception to the automation requirement for any individual registered end-use customer that is located at a single site and that has Supervisory Control over processes by which load reduction would be accomplished; and provided further that nothing herein relieves such end-use customer of the obligation to respond within 15 minutes to declaration of a Maximum Generation Emergency in accordance with applicable PRD Curves. In addition to the above requirements and those in the PJM Manuals for metering equipment and associated data, metering equipment shall provide integrated hourly kWh values on an electric distribution company account basis and shall either meet the electric distribution company requirements for accuracy or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers). The installed metering equipment must be that used for retail electric service; or metering equipment owned by the end-use customer or PRD Provider that is approved by PJM and either read electronically by PJM or read by the customer or PRD Provider and forwarded to PJM, in either case in accordance with requirements set forth in the PJM Manuals; and

(vii) any RPM Auction clearing price below which the PRD Provider does not choose to commit PRD ("PRD Reservation Price"), specifying the relevant auction, Zone (or sub-Zonal LDA if applicable), and, if applicable, a range of up to ten pairs of PRD commitment levels and associated minimum RPM Auction clearing prices; provided however that the Office of the Interconnection may interpolate PRD commitment levels based on clearing prices between prices specified by the PRD Provider.

E. Each PRD Provider that commits Price Responsive Demand through an accepted PRD Plan must, no later than one day before the tenth Business Day prior to the start of the Delivery Year for which such PRD is committed, register with PJM, in the form and manner specified in the PJM Manuals, sufficient PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment. All information required in the PRD Plan to be at a PRD Substation level if available at the time of submission of the PRD Plan that was not provided at the time of submission of such plan must be provided with the registration. The PRD Provider shall also identify in the registration each individual end-use customer with a peak demand of 10 kW or

greater included in such Price Responsive Demand, the peak demand of such customers, the Load Serving Entity responsible for serving such customers, and the Load Serving Entities responsible for serving the end-use customers not identified on an individual basis. PJM shall provide notification of such PRD registrations to the applicable electric distribution company(ies) and load serving entity(ies). The PRD Provider shall maintain, and provide to the Office of the Interconnection upon request, an identification of all individual end-use customers with a peak load contribution of less than 10kW included in such Price Responsive Demand, and the peak load contribution of such customers. The PRD Provider must maintain its PRD Substation-level registration of PRD-eligible load at the level of its Zonal (or sub-zonal LDA, if applicable) Nominal PRD Value commitment during each day of the Delivery Year for which such commitment was made. The PRD Provider may change the end-use customer registered to meet the PRD Provider's commitment during the Delivery Year, but such PRD Provider must always in the aggregate register sufficient Price Responsive Demand to meet or exceed the Zonal (or sub-Zonal LDA, if applicable) committed Nominal PRD Value level. A PRD Provider must timely notify the Office of the Interconnection, in accordance with the PJM Manuals, of all changes in PRD registrations. Such notification must remove from the PRD Provider's registration(s) any end-use customer load that no longer meets the eligibility criteria for PRD, effective as of the first day that such end-use customer load is no longer PRD-eligible.

F. Each PRD Provider that is a Load Serving Entity shall be required to identify its committed Price Responsive Demand as price-sensitive demand at a PRD Substation level in the Day-Ahead and Real-Time Energy Markets. Each PRD Provider that is not a Load Serving Entity shall be required to identify its committed Price Responsive Demand as price-sensitive demand at a PRD Substation level in the Real-Time Energy Market. The most recent PRD Curve submitted by the PRD Provider in its PRD Plan or PRD registration shall be used for such purpose unless and until changed by the PRD Provider in accordance with the market rules of the Office of the Interconnection, provided that any changes to PRD Curves must be consistent with the PRD Provider's commitment of Price Responsive Demand hereunder.

G. The Obligation Peak Load of a Load Serving Entity that serves end-users registered as Price Responsive Demand in any Zone shall be as determined in Schedule 8 to this Agreement; provided, however, that such Load Serving Entity shall receive, for each day that an approved Price Response Demand registration is effective and applicable to such LSE's load, a Price Responsive Demand Credit for such registration during the Delivery Year, against the Locational Reliability Charge otherwise assessed upon such Load Serving Entity in such Zone for such day, determined as follows:

$$\text{LSE PRD Credit} = [(\text{Share of Zonal Nominal PRD Value committed in Base Residual Auction} * (\text{FZWNSP/FZPLDY}) * \text{Final Zonal RPM Scaling Factor} * \text{FPR} * \text{Final Zonal Capacity Price}) + (\text{Share of Zonal Nominal PRD Value committed in Third or Final Incremental Auction, as applicable} * (\text{FZWNSP/FZPLDY}) * \text{Final Zonal RPM Scaling Factor} * \text{FPR} * \text{Final Zonal Capacity Price} * \text{Third or Final Incremental Auction, as applicable, Component of Final Zonal Capacity Price stated as a Percentage})]$$

Where:

Share of Zonal Nominal PRD Value Committed in Base Residual Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration *Zonal Nominal PRD Value committed in the Base Residual Auction by the PRD Provider of such registration .

Share of Zonal Nominal PRD Value Committed in Third or Final Incremental Auction, as applicable = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration *Zonal Nominal PRD Value committed in the Third or Final Incremental Auction, as applicable by the PRD Provider of such registration.

FZPLDY = Final Zonal Peak Load Forecast for such Delivery Year; and

FZWNSP = Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of such Delivery Year;

And where the PRD registration is associated with a sub-Zone, the Share of the Nominal PRD Value Committed in Base Residual Auction ~~or~~ Third Incremental Auction, or Final Incremental Auction, as applicable will be based on the Nominal PRD Values committed and registered in a sub-Zone. A Load Serving Entity will receive a LSE PRD Credit for each approved Price Responsive Demand registration that is effective and applicable to load served by such Load Serving Entity on a given day. The total daily credit to an LSE in a Zone shall be the sum of the credits received as a result of all approved registrations in the Zone for load served by such LSE on a given day.

H. A PRD Provider may transfer all or part of its PRD commitment for a Delivery Year in a Zone (or sub-Zonal LDA) to another PRD Provider for its use in the same Zone or sub-Zonal LDA, through notice of such transfer provided by both the transferor and transferee PRD Providers to the Office of the Interconnection in the form and manner specified in the PJM Manuals. From and after the effective date of such transfer, and to the extent of such transfer, the transferor PRD Provider shall be relieved of its PRD commitment and credit requirements, shall not be liable for PRD compliance charges, and shall not be entitled to a Price Responsive Demand Credit; and the transferee PRD Provider, to the extent of such transfer, shall assume such PRD commitment, credit requirements, and obligation for compliance charges and, if it is a Load Serving Entity, shall be entitled to a Price Responsive Demand Credit.

I. Any PRD Provider that commits Price Responsive Demand and does not register and maintain registration of sufficient PRD-eligible load, (including, without limitation, failing to install or maintain the required advanced metering or Supervisory Control facilities) in a Zone (or sub-Zonal LDA, if applicable) to satisfy in full its Nominal PRD Value commitment in such Zone (or sub-Zonal LDA) on each day of the Delivery Year for which such commitment is made shall be assessed a compliance charge for each day that the registered Price Responsive Demand is less than the committed Nominal PRD Value. Such daily penalty shall equal:

[MW Shortfall] * [Forecast Pool Requirement] * [(Weighted Final Zonal Capacity Price in \$/MW-day)

+ higher of (0.2 * Weighted Final Zonal Capacity Price) or (\$20/MW-day)]

Where: MW Shortfall = Daily Nominal PRD Value committed in such PRD Provider's PRD Plan (including any permitted amendment to such plan) for the relevant Zone or sub-Zonal LDA – Daily Nominal PRD Value as a result of PRD registration for such Zone or sub-Zonal LDA; and

Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price attributable to the Third or Final Incremental Auction, as applicable, weighted by the Nominal PRD Values committed by such PRD Provider in connection with the Base Residual Auction and those committed by such PRD Provider in connection with the Third or Final Incremental Auction, as applicable.

The MW Shortfall shall not be reduced through replacement of the Price Responsive Demand by any Capacity Resource or Excess Commitment Credits, provided, however, that the PRD Provider may register additional PRD-eligible end-use customer load to satisfy its PRD commitment.

J. PRD Providers shall be responsible for verifying the performance of their PRD loads during each maximum emergency event declared by the Office of the Interconnection. PRD Providers shall demonstrate that the identified PRD loads performed in accordance with the PRD Curves submitted at a PRD Substation level in the PRD Plan or PRD registration; provided, however, that the previously submitted MESL value shall be adjusted by a ratio equal to the amount by which the actual Zonal load during the declared event exceeded the PJM load forecast underlying the previously submitted MESL value. In accordance with procedures and deadlines specified in the PJM Manuals, the PRD Providers must submit actual customer load levels for all hours during the declared event and all other information reasonably required by the Office of the Interconnection to verify performance of the committed PRD loads.

K. If the identified loads submitted for a Zone (or sub-Zonal LDA) by a PRD Provider exceed during any Emergency the aggregate Maximum Emergency Service Level ("MESL") specified in all PRD registrations of such PRD Provider that have a PRD Curve specifying a price at or below the highest Real-time LMP recorded during such Emergency, the PRD Provider that committed such loads as Price Responsive Demand shall be assessed a compliance charge hereunder. The charge shall be based on the net performance during an Emergency of the loads that were identified as Price Responsive Demand for such Delivery Year in the PRD registrations submitted by such PRD Provider in each Zone (or sub-Zonal LDA, if applicable) and that specified a price at the MESL that is at or below the highest Real-Time LMP recorded during such Emergency. The compliance charge hereunder shall equal:

[MW Shortfall] * [Forecast Pool Requirement] * [(Weighted Final Zonal Capacity Price in \$/MW-day)

+ higher of (0.2 * Final Zonal Capacity Price) or (\$20/MW-day)] * 365 days

Where: MW Shortfall = [highest hourly integrated aggregate metered load for such PRD Provider's PRD load in the Zone or sub-Zonal LDA meeting the price condition specified above] – {(aggregate MESL for the Zone or sub-Zonal LDA) * the higher of [1.0] or [(actual Zonal load – actual total PRD load in Zone) / (Final Zonal Peak Load Forecast – final Zonal Expected Peak Load Value of PRD in total for all PRD load in Zone meeting the price condition specified above)]}.

For purposes of the above provision, the MW Shortfall for any portion of the Emergency event that is less than a full clock hour shall be treated as a shortfall for a full clock hour unless either: (i) the load was reduced to the adjusted MESL level within 15 minutes of the emergency procedures notification, regardless of the response rate submitted, or (ii) the hourly integrated value of the load was at or below the adjusted MESL. Such MW shortfall shall not be reduced through replacement of the Price Responsive Demand by any Capacity Resource or Excess Commitment Credits; provided, however, that the performance and MW Shortfalls of all PRD-eligible load registered by the PRD Provider, including any additional or replacement load registered by such PRD Provider, provided that it meets the price condition specified above, shall be reflected in the calculation of the overall MW Shortfall. Any greater MW Shortfall during a subsequent Emergency for such Zone or sub-Zonal LDA during the same Delivery Year shall result in a further charge hereunder, limited to the additional increment of MW Shortfall. As appropriate, the MW Shortfall for non-compliance during an Emergency shall be adjusted downward to the extent such PRD Provider also was assessed a compliance penalty for failure to register sufficient PRD to satisfy its PRD commitment.

L. PRD Providers that register Price Responsive Demand shall be subject to test at least once per year to demonstrate the ability of the registered Price Responsive Demand to reduce to the specified Maximum Emergency Service Level, and such PRD Providers shall be assessed a compliance charge to the extent of failure by the registered Price Responsive Demand during such test to reduce to the Maximum Emergency Service Level, in accordance with the following:

(i) If the Office of the Interconnection does not declare during the relevant Delivery Year a Maximum Generation Emergency that requires the registered PRD to reduce to the Maximum Emergency Service Level then such registered PRD must demonstrate that it was tested for a one-hour period during any hour when a Maximum Generation Emergency may be called during June through October or the following May of the relevant Delivery Year. If a Maximum Generation Emergency that requires the registered PRD to reduce to the Maximum Emergency Service Level is called during the relevant Delivery Year, then no compliance charges will be assessed hereunder.

(ii) All PRD registered in a zone must be tested simultaneously except that, when less than 25 percent (by megawatts) of a PRD Provider's total PRD registered in a Zone fails a test, the PRD Provider may conduct a re-test limited to all registered PRD that failed the prior test, provided that such re-test must be at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registered PRD must test simultaneously, where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. If less than 25 percent of a PRD Provider's total PRD registered in a Zone fails the test and the PRD Provider chooses to conduct a retest, the PRD Provider may elect to maintain the performance compliance result for registered PRD achieved during the test if the PRD Provider: (1) notifies the Office of the Interconnection 48 hours prior to the re-test under this election; and (2) the PRD Provider retests affiliated registered PRD under this election as set forth in the PJM Manuals.

(iii) A PRD Provider that registered PRD shall be assessed a PRD Test Failure Charge equal to the net PRD capability testing shortfall in a Zone during such test in the aggregate of all of

such PRD Provider's registered PRD in such Zone times the PRD Test Failure Charge Rate. The net capability testing shortfall in such Zone shall be the following megawatt quantity, converted to an Unforced Capacity basis using the applicable Forecast Pool Requirement:

MW Shortfall = [highest hourly integrated aggregate metered load for such PRD Provider's PRD load in the Zone or sub-Zonal LDA] – {(aggregate MESL for the Zone or sub-Zonal LDA) * the higher of [1.0] or [(actual Zonal load – actual total PRD load in Zone) / (Final Zonal Peak Load Forecast – final Zonal Expected Peak Load Value of PRD in total for all PRD load in Zone)]}.

The net PRD capability testing shortfall in such Zone shall be reduced by the PRD Provider's summer daily average of the MW shortfalls determined for compliance charge purposes under section I of this Schedule 6.1 in such Zone for such PRD Provider's registered PRD.

(iv) The PRD Test Failure Charge Rate shall equal such PRD Provider's Weighted Final Zonal Capacity Price in such Zone plus the greater of (0.20 times the Weighted Final Zonal Capacity Price in such Zone or \$20/MW-day) times the number of days in the Delivery Year, where the Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price attributable to the Third or Final Incremental Auction, as applicable, weighted by the Nominal PRD Values committed by such PRD Provider in connection with the Base Residual Auction and those committed by such PRD Provider in connection with the Third or Final Incremental Auction, as applicable. Such charge shall be assessed daily and charged monthly (or otherwise in accordance with customary PJM billing practices in effect at the time); provided, however, that a lump sum payment may be required to reflect amounts due, as a result of a test failure, from the start of the Delivery Year to the day that charges are reflected in regular billing.

M. The revenue collected from assessment of the charges assessed under subsections I, K, and L of this Schedule 6.1 shall be distributed on a pro-rata basis to all entities that committed Capacity Resources in the RPM Auctions for the Delivery Year for which the compliance charge is assessed, pro rata based on each such entity's revenues from Capacity Market Clearing Prices in such auctions, net of any compliance charges incurred by such entity.

N. Aggregate Price Responsive Demand that may be registered shall be limited for the first three Delivery Years that peak load adjustments for Price Responsive Demand are allowed under this Agreement. The maximum quantity of Price Responsive Demand that may be registered by all PRD Providers for the PJM Region as a whole shall be:

1. 2500 MW for the Delivery Year that begins on June 1, 2016;
2. 3500 MW for the Delivery Year that begins on June 1, 2017; and
3. 4000 MW for the Delivery Year that begins on June 1, 2018.

For Delivery Years in which the region-wide limit is not met, no limit as to the amount of Price Responsive Demand that may register in a Zone (or sub-Zone) shall apply. However, in the event the region-wide limit is met for a Delivery Year, then a portion of such limit shall be assigned to each Zone (or sub-Zonal LDA, if applicable) pro rata based on each such Zone's (or sub-Zone's) Preliminary Zonal Peak Load Forecast for the Delivery Year compared to the PJM Region's Preliminary RTO Peak Load Forecast for such Delivery Year (less, in each case, load

expected to be served in such area under the Fixed Resource Requirement). Within each Zone (or sub-Zonal LDA, if applicable) the permitted registrations shall be those quantities within the Zonal (or sub-Zonal LDA) limit with the lowest identified PRD Reservation Prices for their identified loads; and, as between PRD Providers submitting PRD registrations at the same PRD Reservation Price, pro rata based on each such LSE's share of the Preliminary Zonal Peak Load Forecast for such Zone (or sub-Zonal LDA) less load expected to be served under the Fixed Resource Requirement. For Delivery Years in which the region-wide limit is met, any PRD registrations that are not permitted by operation of this section will, to the extent not permitted, not be required to perform in accordance with its registration, not be considered in determining an LSE's PRD Credit or Nominal PRD Value, and not be accounted for in the applicable PRD Provider's PRD Curves. Nothing in this section precludes price-responsive load from exercising any opportunity it may otherwise have to participate in the day-ahead or real-time energy markets in the PJM Region. For Delivery Years beginning on or after June 1, 2019, there is no limit on the quantity of Price Responsive Demand that may register.

SCHEDULE 7

PLANS TO MEET OBLIGATIONS

- A. Each Party that elects to meet its estimated obligations for a Delivery Year by Self-Supply of Capacity Resources shall notify the Office of the Interconnection via the Internet site designated by the Office of the Interconnection, prior to the start of the Base Residual Auction for such Delivery Year.
- B. A Party that Self-Supplies Capacity Resources to satisfy its obligations for a Delivery Year must submit a Sell Offer as to such resource in the Base Residual Auction for such Delivery Year, in accordance with Attachment DD to the PJM Tariff.
- | C. If, at any time after the close of the Third or Final Incremental Auction, as applicable, for a Delivery Year, including at any time during such Delivery Year, a Capacity Resource that a Party has committed as a Self-Supplied Capacity Resource becomes physically incapable of delivering capacity or reducing load, the Party may submit a replacement Capacity Resource to the Office of the Interconnection. Such replacement Capacity Resource (1) may not be previously committed for such Delivery Year, (2) shall be capable of providing the same quantity of megawatts of capacity or load reduction as the originally committed Capacity Resource, and (3) shall meet the same locational requirements, if applicable, as the originally committed resource. In accordance with Attachment DD to the PJM Tariff, the Office of the Interconnection shall determine the acceptability of the replacement Capacity Resource.

Attachment B

PJM Open Access Transmission Tariff and PJM Reliability Assurance Agreement

(Clean Format)

Section(s) of the
PJM Open Access Transmission Tariff
(Clean Format)

Definitions – C-D

Canadian Guaranty:

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

Cancellation Costs:

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

Capacity:

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

Capacity Emergency Transfer Limit:

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

Capacity Emergency Transfer Objective:

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

Capacity Export Transmission Customer:

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

Capacity Import Limit:

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

Capacity Interconnection Rights:

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

Capacity Market Buyer:

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

Capacity Market Seller:

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

Capacity Performance Resource:

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

Capacity Performance Transition Incremental Auction:

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

Capacity Resource:

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

Capacity Resource 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 hydroelectric power plant, flywheel, battery storage, or other such facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets and which participates in the Reliability Pricing Model.

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.

Cold/Warm/Hot Notification Time:

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

Cold/Warm/Hot Start-up Time:

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

Cold Weather Alert:

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

Collateral:

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

Collateral Call:

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

Commencement Date:

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

Commission:

“Commission” shall mean the Federal Energy Regulatory Commission or FERC.

Committed Offer:

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

Completed Application:

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

Compliance Aggregation Area (CAA):

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

separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, the same locational price separation in the Third Incremental Auction, or the same locational price separation in the Final Incremental Auction.

Conditional Incremental Auction:

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

CONE Area:

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

Confidential Information:

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

Congestion Price:

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

Consolidated Transmission Owners Agreement:

“Consolidated 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.

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.

Control Area:

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

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

Control Zone:

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

Controllable A.C. Merchant Transmission Facilities:

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

facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and Tariff, Part VI.

Coordinated External Transaction:

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

Coordinated Transaction Scheduling:

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

Corporate Guaranty:

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

Cost of New Entry:

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

Costs:

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

Counterparty:

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

Credit Available for Export Transactions:

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

Credit Available for Virtual Transactions:

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

Credit Breach:

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

Credit-Limited Offer:

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

Credit Score:

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

CTS Enabled Interface:

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

CTS Interface Bid:

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

Curtailment:

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

Curtailment Service Provider:

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

Customer Facility:

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

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, 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, sections 7, 8, 9, or 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 and import 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 and Export 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 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, section 114.

Deactivation Avoidable Cost Rate:

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

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.

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 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.

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 Schedule 2 of the Operating Agreement.

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 flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets as a Market Seller.

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.

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.

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.

Federal Power Act:

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

FERC:

“FERC” 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 Incremental Auction:

“Final Incremental Auction” shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates for the 2021/2022 Delivery Year and all subsequent Delivery Years.

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 Schedule 8 of the Reliability Assurance Agreement.

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 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 sections 19.3 and 32.3 of the Tariff.

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.

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 V.G.

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 auctions.

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 – I – J - K

IDR Transfer Agreement:

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

Immediate-need Reliability Project:

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

Inadvertent Interchange:

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

Incidental Expenses:

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

Incremental Auction:

“Incremental Auction” shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction, Final Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction for which (i) below does not apply, and the First Incremental Auction for the 2021/2022 Delivery year and all subsequent Delivery Year for which (ii) below does not apply), shall be held for the purposes of:

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

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

Incremental Auction Revenue Rights:

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

Incremental Available Transfer Capability Revenue Rights:

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

Incremental Capacity Transfer Right:

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

Incremental Deliverability Rights (IDRs):

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

Incremental Energy Offer:

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

Incremental Multi-Driver Project:

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

Incremental Rights-Eligible Required Transmission Enhancements:

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

Increment Offer:

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

Initial Operation:

“Initial Operation” shall mean the commencement of operation of the Customer Facility and Customer Interconnection Facilities after satisfaction of the conditions of Section 1.4 of Appendix 2 of an Interconnection Service Agreement.

Interconnected Entity:

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

Interconnected Transmission Owner:

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

Interconnection Construction Service Agreement:

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

Transmission Owner that is responsible for construction of any Attachment Facilities, Network Upgrades, or Local Upgrades associated with interconnection of a Customer Facility.

Interconnection Customer:

“Interconnection Customer” shall mean a Generation Interconnection Customer and/or a Transmission Interconnection Customer.

Interconnection Facilities:

“Interconnection Facilities” shall mean the Transmission Owner Interconnection Facilities and the Customer Interconnection Facilities.

Interconnection Feasibility Study:

“Interconnection Feasibility Study” shall mean either a Generation Interconnection Feasibility Study or Transmission Interconnection Feasibility Study.

Interconnection Party:

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

Interconnection Request:

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

Interconnection Service:

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

Interconnection Service Agreement:

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

Interconnection Studies:

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

Interface Pricing Point:

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

Intermittent Resource:

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

Internal Market Buyer:

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

Interregional Transmission Project:

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

Interruption:

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

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 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 two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 10.096 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 Schedule 6 of the Operating Agreement 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 Effective Megawatts:

“Regulation Effective Megawatts” shall equal the product of 1) the amount of Regulation that a resource is providing in a given hour, 2) the resource’s historic performance score, and 3) the resource’s Regulation Rate of Technical Substitution.

Regulation Marginal Rate of Technical Substitution:

“Regulation Marginal Rate of Technical Substitution” shall mean the Regulation Rate of Technical Substitution assigned to the last dynamic Regulation resource committed to provide Regulation service in a given hour.

Regulation Rate of Technical Substitution:

“Regulation Rate of Technical Substitution” shall mean a value along the Regulation Rate of Technical Substitution Curve that translates a dynamic Regulation resource into a traditional Regulation resource. Regulation Rate of Technical Substitution is calculated in accordance with the PJM Manuals.

Regulation Rate of Technical Substitution Curve:

“Regulation Rate of Technical Substitution Curve” shall mean a function that defines the operational relationship between traditional and dynamic Regulation resources utilized to meet the Regulation Requirement. Regulation Rate of Technical Substitution Curve is calculated in accordance with the PJM Manuals.

Regulation Requirement:

“Regulation Requirement” shall mean the calculated Regulation Effective Megawatts required to be maintained in a Regulation Zone, absent any increase to account for additional Regulation scheduled to address operational uncertainty. Regulation Requirement is defined in accordance with 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:

“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 Schedule 6 of the Operating Agreement 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 for Delivery Years prior to the 2021/2022 Delivery Year; and the First or Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years.

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. A Second Incremental Auction is conducted for Delivery Years prior to the 2021/2022 Delivery Year but is not conducted for the 2021/2022 Delivery Year and all subsequent Delivery Years.

Security:

“Security” shall mean the security provided by the New Service Customer pursuant to Tariff, section 212.4 or 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, 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.

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, section 15.3 or 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.

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 for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource or a Capacity Storage Resource; or (v) used in association with restoration or black start service.

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.

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.

Definitions – T – U - V

Tangible Net Worth:

“Tangible Net Worth” shall mean all assets (not including any intangible assets such as goodwill) less all liabilities. Any such calculation may be reduced by PJM Settlement upon review of the available financial information.

Target Allocation:

“Target Allocation” shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, *section 5.2.3* or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, *section 7.4.3*.

Third Incremental Auction:

“Third Incremental Auction” shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates for Delivery Years prior to the 2021/2022 Delivery Year.

Third-Party Sale:

“Third-Party Sale” shall mean any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service but not including a sale of energy through the PJM Interchange Energy Market established under the PJM Operating Agreement.

Tie Line:

“Tie Line” shall mean a circuit connecting two balancing authority areas, Control Areas or fully metered electric system regions. Tie Lines may be classified as external or internal as set forth in the PJM Manuals.

Total Lost Opportunity Cost Offer:

“Total Lost Opportunity Cost Offer” shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1), *and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1)*, the Total Lost Opportunity Cost Offer shall equal the *Real-time Settlement Interval* offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the *Real-time Settlement Interval* offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer

or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost Opportunity Cost Offer shall equal the *Real-time Settlement Interval* offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated costbased Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Net Obligation:

“Total Net Obligation” shall mean all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position:

“Total Net Sell Position” shall mean all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

Total Operating Reserve Offer:

“Total Operating Reserve Offer” shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual *Real-time Settlement Interval* energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every *Real-time Settlement Interval* in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Transmission Congestion Charge:

“Transmission Congestion Charge” shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1 and the parallel provisions of Tariff, Attachment K-Appendix, *section 5.1*.

Transmission Congestion Credit:

“Transmission Congestion Credit” shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2, and the parallel provisions of Tariff, Attachment K-Appendix, *section 5.2*.

Transmission Customer:

“Transmission Customer” shall mean any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission a proposed unexecuted Service Agreement, to receive transmission service under Tariff, Part II. This term is used in Tariff, Part I and Part VI to include customers receiving transmission service under Tariff, Part II and Part III.

Where used in Tariff, Attachment K-Appendix and the parallel provisions of Operating Agreement, Schedule 1, Transmission Customer shall mean an entity using Point-to-Point Transmission Service.

Transmission Facilities:

“Transmission Facilities” shall have the meaning set forth in the Operating Agreement.

Transmission Forced Outage:

“Transmission Forced Outage” shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Injection Rights:

“Transmission Injection Rights” shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Customer:

“Transmission Interconnection Customer” shall mean an entity that submits an Interconnection Request to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region or an entity that submits an Upgrade Request for Merchant Network Upgrades (including accelerating the construction of any transmission enhancement or expansion, other than Merchant Transmission Facilities, that is included in the Regional Transmission Expansion Plan prepared pursuant to *Operating Agreement*, Schedule 6).

Transmission Interconnection Facilities Study:

“Transmission Interconnection Facilities Study” shall mean a Facilities Study related to a Transmission Interconnection Request.

Transmission Interconnection Feasibility Study:

“Transmission Interconnection Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with *Tariff*, section 36.2.

Transmission Interconnection Request:

“Transmission Interconnection Request” shall mean a request by a Transmission Interconnection Customer pursuant to *Tariff*, Part IV to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of existing Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

Transmission Loading Relief:

“Transmission Loading Relief” shall mean NERC’s procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loading Relief Customer:

“Transmission Loading Relief Customer” shall mean an entity that, in accordance with Operating Agreement, Schedule 1, section 1.10.6A and the parallel provisions of *Tariff*, Attachment K-Appendix, *section 1.10.6A* has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

Transmission Loss Charge:

“Transmission Loss Charge” shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of *Tariff*, Attachment K-Appendix, *section 5*.

Transmission Owner:

“Transmission Owner” shall mean each entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the *Tariff*. The Transmission Owners are listed in *Tariff*, Attachment L.

Transmission Owner Attachment Facilities:

“Transmission Owner Attachment Facilities” shall mean that portion of the Transmission Owner Interconnection Facilities comprised of all Attachment Facilities on the Interconnected Transmission Owner’s side of the Point of Interconnection.

Transmission Owner Interconnection Facilities:

“Transmission Owner Interconnection Facilities” shall mean all Interconnection Facilities that are not Customer Interconnection Facilities and that, after the transfer under *Tariff, Attachment P, Appendix 2*, section 5.5 to the Interconnected Transmission Owner of title to any Transmission Owner Interconnection Facilities that the Interconnection Customer constructed, are owned, controlled, operated and maintained by the Interconnected Transmission Owner on the Interconnected Transmission Owner’s side of the Point of Interconnection identified in 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 or interconnected distribution facilities.

Transmission Owner Upgrade:

“Transmission Owner Upgrade” shall have the same meaning provided in the Operating Agreement.

Transmission Planned Outage:

“Transmission Planned Outage” shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of *Tariff, Attachment K-Appendix* or the PJM Manuals.

Transmission Provider:

The “Transmission Provider” shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

- (a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;
- (b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and
- (c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the *Tariff, Operating Agreement*

and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Provider's Monthly Transmission System Peak:

"Transmission Provider's Monthly Transmission System Peak" shall mean the maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

Transmission Service:

"Transmission Service" shall mean Point-To-Point Transmission Service provided under Tariff, Part II on a firm and non-firm basis.

Transmission Service Request:

"Transmission Service Request" shall mean a request for Firm Point-To-Point Transmission Service or a request for Network Integration Transmission Service.

Transmission System:

"Transmission System" shall mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III.

Transmission Withdrawal Rights:

"Transmission Withdrawal Rights" shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Turn Down Ratio:

"Turn Down Ratio" shall mean the ratio of a generating unit's economic maximum megawatts to its economic minimum megawatts.

Unconstrained LDA Group:

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10 shall be combined with all other such LDAs that form an electrically contiguous area.

Unforced Capacity:

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

Unsecured Credit:

“Unsecured Credit” shall mean any credit granted by PJMSettlement to a Participant that is not secured by Collateral.

Unsecured Credit Allowance:

“Unsecured Credit Allowance” shall mean Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement’s evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Collateral. See also: “Working Credit Limit.”

Updated VRR Curve:

“Updated VRR Curve” shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction, and for Delivery Years through May 31, 2018, the Short-term Resource Procurement Target applicable to the relevant Incremental Auction.

Updated VRR Curve Decrement:

“Updated VRR Curve Decrement” shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year (excluding net Unforced Capacity committed to the PJM Region associated with the transition provisions of Tariff, Attachment DD, section 5.14D as related to the 2017/2018 Delivery Year) and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, sections 5.14C, 5.14D (as related to the 2016/2017 Delivery Year), 5.14E, and 5.5A(c)(i)(B), *and RAA, Schedule 6, section L.9.*

Updated VRR Curve Increment:

“Updated VRR Curve Increment” shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year (excluding net Unforced Capacity committed to the PJM Region associated with the transition provision of Tariff, Attachment DD, section 5.14D as related to the 2017/2018 Delivery Year) and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, sections 5.14C, 5.14D (as related to the 2016/2017 Delivery Year), 5.14E and 5.5A(c)(i)(B) *and RAA, Schedule 6, section L.9.*

Upgrade Construction Service Agreement:

“Upgrade Construction Service Agreement” shall mean that agreement entered into by an Eligible Customer, Upgrade Customer or Interconnection Customer proposing Merchant Network Upgrades, a Transmission Owner, and the Transmission Provider, pursuant to Tariff, Part VI, Subpart B, and in the form set forth in *Tariff*, Attachment GG.

Upgrade Customer:

“Upgrade Customer” shall mean a customer that submits an Upgrade Request pursuant to *Operating Agreement, Schedule 1, section 7.8*.

Upgrade Feasibility Study:

“Upgrade Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, section 36.3.

Upgrade-Related Rights:

“Upgrade-Related Rights” shall mean Incremental Auction Revenue Rights, Incremental Available Transfer Capability Revenue Rights, Incremental Deliverability Rights, and Incremental Capacity Transfer Rights.

Upgrade Request:

“Upgrade Request” shall mean a request submitted in the form prescribed in *Tariff*, Attachment EE, for evaluation by the Transmission Provider of the feasibility and estimated costs of (a) a Merchant Network Upgrade or (b) the Customer-Funded Upgrades that would be needed to provide Incremental Auction Revenue Rights specified in a request pursuant to *Operating Agreement, Schedule 1, section 7.8*.

Up-to Congestion Counterflow Transaction:

“Up-to Congestion Counterflow Transaction” shall mean an Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month’s average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month:

“Up-to Congestion Historical Month” shall mean a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction:

An Up-to Congestion Transaction shall mean an “Up-to Congestion Prevailing Flow Transaction” if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price:

“Up-to Congestion Reference Price” for an Up-to Congestion Transaction, shall be the specified percentile price differential between source and sink (defined as sink price minus source price) for real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30th percentile

For Up-to Congestion Counterflow Transactions when bid: 20th percentile

For Up-to Congestion Counterflow Transactions when cleared: 5th percentile

Up-to Congestion Transaction:

“Up-to Congestion Transaction” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.10.1A, and the parallel provisions of Tariff, Attachment K-Appendix, *section 1.10.1A*.

Variable Loads:

“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*.

Variable Resource Requirement Curve:

“Variable Resource Requirement Curve” shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Tariff, Attachment DD, section 5.

Virtual Credit Exposure:

“Virtual Credit Exposure” shall mean the amount of potential credit exposure created by a market participant’s bid submitted into the Day-ahead market, as defined in Tariff, Attachment Q.

Virtual Transaction:

“Virtual Transaction” shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

Virtual Transaction Screening:

“Virtual Transaction Screening” shall be the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity:

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

Voltage Reduction Action:

“Voltage Reduction Action” shall mean a notification during capacity deficient conditions in which PJM notifies Members to reduce voltage on the distribution system in order to reduce demand and therefore provide a sufficient amount of reserves, maintain tie flow schedules and preserve limited energy sources.

Voltage Reduction Alert:

“Voltage Reduction Alert” shall mean a notification from PJM to alert Members that a voltage reduction may be required during a future critical period.

Voltage Reduction Warning:

“Voltage Reduction Warning” shall mean a notification from PJM to warn Members that PJM’s available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

3. RESPONSIBILITIES OF THE OFFICE OF THE INTERCONNECTION

3.1 Support for Self-Supply and Bilateral Transactions

The Office of the Interconnection shall:

(a) support electronic tools to facilitate communication by Market Sellers and Market Buyers of information to the Office of the Interconnection concerning Self-Supply arrangements;

(b) support an electronic bulletin board providing a forum for prospective buyers and sellers to transact Capacity Resources outside the Reliability Pricing Model Auctions, including Locational UCAP transactions (including mechanisms to allow prospective Sellers with partial-year resources to explore voluntary opportunities to combine their resources such that they can be offered together for a full Delivery Year) and support electronic tools to report bilateral capacity transactions between Market Participants to the Office of the Interconnection, in accordance with procedures set forth in the PJM Manuals; and

(c) define one or more capacity trading hubs and determine and publicize values for such hubs based on the capacity prices determined for one or more Locational Deliverability Areas, in accordance with the PJM Manuals.

3.2 Administration of the Base Residual Auction and Incremental Auctions

The Office of the Interconnection shall conduct and administer the Base Residual Auction and Incremental Auctions in accordance with this Attachment, the Operating Agreement, and the Reliability Assurance Agreement. Administration of the Base Residual Auction and Incremental Auctions shall include, but not be limited to, the following:

a) Determining the qualification of entities to become Capacity Market Sellers and Capacity Market Buyers;

b) Determining PJM Region Peak Load Forecasts and Locational Deliverability Area Reliability Requirements;

c) Determining the Minimum Annual Resource Requirements and the Minimum Extended Summer Resource Requirements for the PJM Region and applicable LDAs for Delivery Years starting June 1, 2014 and ending May 31, 2017;

d) Determining Limited Resource Constraints and Sub-Annual Resource Constraints for the 2017/2018 Delivery Year;

e) Determining Base Capacity Demand Resource Constraints and Base Capacity Resource Constraints for the 2018/2019 and 2019/2020 Delivery Years;

f) Determining the need, if any, for a Conditional Incremental Auction and providing appropriate prior notice of any such auction

g) Calculating the EFORD for each Generation Capacity Resource in the PJM Region to be used in the Third Incremental Auction or Final Incremental Auction, as applicable;

h) Receiving Buy Bids and Sell Offers, determining Locational Deliverability Requirements and Variable Resource Requirement Curves, and determining the clearing price that reflects all such inputs;

i) Conducting settlements for auction transactions, including but not limited to rendering bills to, receiving payments from, and disbursing payments to, participants in Base Residual Auctions and Incremental Auctions.

j) Maintaining such records of Sell Offers and Buy Bids, clearing price determinations, and other aspects of auction transactions, as may be appropriate to the administration of Base Residual Auctions and Incremental Auctions; and

k) Posting of selected non-confidential data used in Reliability Pricing Model Auctions to calculate clearing prices and other auction results, as appropriate to inform market participants of auction conditions.

3.3 Records and Reports

The Office of the Interconnection shall prepare and maintain such records as are required for the administration of the Base Residual Auction and Incremental Auctions. For each auction conducted, the Office of the Interconnection shall, consistent with Operating Agreement, section 18.17, publish the following: (i) Zonal Capacity Prices for each LDA; (ii) Capacity Resource Clearing Prices for each LDA; (iii) Locational Price Adders; (iv) the total megawatts of Unforced Capacity that cleared; and (v) such other auction data as may be appropriate to the efficient and competitive conduct of the Base Residual Auction and Incremental Auctions. Such information shall be available on the PJM internet site through the end of the Delivery Year to which such auctions apply.

3.4 Counterparty

(a) PJMSettlement shall be the Counterparty to the transactions arising from the cleared Base Residual Auctions and Incremental Auctions; provided, however, PJMSettlement shall not be a contracting party to (i) any bilateral transactions between Market Participants, or (ii) with respect to Self-Supply for which designation of Self-Supply has been reported to the Office of the Interconnection.

(b) Charges. PJMSettlement shall be the Counterparty with respect to the obligations to pay, and the payment of, charges pursuant to this Attachment DD.

5.3A Locational UCAP Bilateral Transactions

A Member that has committed capacity through an RPM Auction for a Delivery Year may purchase Locational UCAP as replacement capacity from a Member with available uncommitted capacity for such Delivery Year in accordance with the terms of this section and the PJM Manuals. Locational UCAP may not be sold or purchased prior to the date that the final EFORD is established for such Delivery Year, and if designated to PJM by the Locational UCAP Seller as sold prior to the Third Incremental Auction or Final Incremental Auction, as applicable for a Delivery Year must be confirmed by the buyer prior to such Third Incremental Auction or Final Incremental Auction as purchased for replacement capacity, or such transaction shall be rejected. In accordance with procedures specified in the PJM Manuals, the parties to a Locational UCAP transaction must notify PJM of such transaction, which notification must specify: i) the buyer, ii) the Locational UCAP Seller, iii) the start and end dates of the transaction (which may not be retroactive), iv) the Locational UCAP amount (no less than 0.1 megawatts), v) the demand or generation resource with available uncommitted capacity that is the basis for the sale, and vi) the Locational Delivery Area in which the resource is located. The Locational UCAP Seller shall be responsible for any charges imposed under Tariff, Attachment DD, sections 7, 8, 9, 10, 10A, 11, or 13, as applicable, for such Delivery Year, with respect to the increment of capacity sold as Locational UCAP; any other settlement of charges under the Locational UCAP transaction shall be between the parties. A purchaser of Locational UCAP may not offer such capacity into an RPM Auction.

5.4 Reliability Pricing Model Auctions

The Office of the Interconnection shall conduct the following Reliability Pricing Model Auctions:

a) Base Residual Auction.

PJM shall conduct for each Delivery Year a Base Residual Auction to secure commitments of Capacity Resources as needed to satisfy the portion of the RTO Unforced Capacity Obligation not satisfied through Self-Supply of Capacity Resources for such Delivery Year. All Self-Supply Capacity Resources must be offered in the Base Residual Auction. As set forth in Tariff, Attachment DD, section 6.6, all other Capacity Resources, and certain other existing generation resources, must be offered in the Base Residual Auction. The Base Residual Auction shall be conducted in the month of May that is three years prior to the start of such Delivery Year. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Load Serving Entities through the Locational Reliability Charge during such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and the payments, by Load Serving Entities; provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

b) Scheduled Incremental Auctions.

For Delivery Years prior to the 2021/2022 Delivery Year, PJM shall conduct for each Delivery Year a First, a Second, and a Third Incremental Auction. The First Incremental Auction shall be conducted in the month of September that is twenty months prior to the start of the Delivery Year; the Second Incremental Auction shall be conducted in the month of July that is ten months prior to the start of the Delivery Year; and the Third Incremental Auction shall be conducted in the month of February that is three months prior to the start of the Delivery Year. For the 2021/2022 Delivery Year and all subsequent Delivery Years, PJM shall conduct a First Incremental Auction and a Final Incremental Auction. The First Incremental Auction shall be conducted in the month of September that is twenty months prior to the start of the Delivery Year; and the Final Incremental Auction shall be conducted in the month of February that is three months prior to the start of the Delivery Year.

c) Adjustment through Scheduled Incremental Auctions of Capacity Previously Committed.

For Delivery Years prior to the 2021/2022 Delivery Year, the Office of the Interconnection shall recalculate the PJM Region Reliability Requirement and each LDA Reliability Requirement prior to each Scheduled Incremental Auction, based on an updated peak load forecast, updated Installed Reserve Margin and an updated Capacity Emergency Transfer Objective; shall update such reliability requirements for the Third Incremental Auction to reflect any change from such recalculation; and shall update such reliability requirements for the First Incremental Auction or Second Incremental Auction only if the change is greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement. For the 2021/2022

Delivery Year and all subsequent Delivery Years, the Office of the Interconnection shall recalculate the PJM Region Reliability Requirement and each LDA Reliability Requirement prior to the Final Incremental Auction, based on an updated peak load forecast, updated Installed Reserve Margin and an updated Capacity Emergency Transfer Objective. Based on such updates, the Office of the Interconnection shall, under certain conditions, seek through the Scheduled Incremental Auctions for Delivery Years prior to the 2021/2022 Delivery Year and the Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years to secure additional commitments of capacity or release sellers from prior capacity commitments. Specifically, the Office of the Interconnection shall:

1) for Delivery Years prior to the 2021/2022 Delivery Year, seek additional capacity commitments to serve the PJM Region or an LDA if the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) is less than, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such additional capacity commitments only if such shortfall is in an amount greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement;

2) seek additional capacity commitments to serve the PJM Region or an LDA in Scheduled Incremental Auctions for Delivery Years prior to the 2021/2022 Delivery Year and the Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years if:

i) the updated PJM Region Reliability Requirement less, for Delivery Years through May 31, 2018, the PJM Region Short-Term Resource Procurement Target utilized in the most recent auction conducted for the Delivery Year, or if the LDA Reliability Requirement less, for Delivery Years through May 31, 2018, the LDA Short Term Resource Procurement Target applicable to such auction, exceeds the total capacity committed in all prior auctions in such region or area, respectively, for such Delivery Year by an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM conducts a Conditional Incremental Auction for such Delivery Year and does not obtain all additional commitments of Capacity Resources sought in such Conditional Incremental Auction, in which case, PJM shall seek in the Incremental Auction the commitments that were sought in the Conditional Incremental Auction but not obtained.

3) seek agreements to release prior capacity commitments to the PJM Region or to an LDA in Scheduled Incremental Auctions for Delivery Years prior to the 2021/2022

Delivery Year and the Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years if:

- i) the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) exceeds, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction for Delivery Years prior to the 2021/2022 Delivery Year and in the Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years the Office of the Interconnection shall seek such agreements only if such excess is in an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or
 - ii) PJM obtains additional commitments of Capacity Resources in a Conditional Incremental Auction, in which case PJM shall seek release of an equal number of megawatts (comparing the total purchase amount for all LDAs and the PJM Region related to the delay in Backbone Transmission with the total sell amount for all LDAs and the PJM Region related to the delay in Backbone Transmission) of prior committed capacity that would not have been committed had the delayed Backbone Transmission upgrade that prompted the Conditional Incremental Auction not been assumed, at the time of the Base Residual Auction, to be in service for the relevant Delivery Year; and if PJM obtains additional commitments of capacity in an Incremental Auction pursuant to subsection c.2.ii above, PJM shall seek in such Incremental Auction to release an equal amount of capacity (in total for all LDAs and the PJM Region related to the delay in Backbone Transmission) previously committed that would not have been committed absent the Backbone Transmission upgrade.
- 4) The cost of payments to Market Sellers for additional Capacity Resources cleared in such auctions, and the credits from payments from Market Sellers for the release of previously committed Capacity Resources, shall be apportioned to Load Serving Entities in the PJM Region or LDA, as applicable, through adjustments to the Locational Reliability Charge for such Delivery Year.
- 5) PJMSettlement shall be the Counterparty to the sales (including releases) of Capacity Resources that clear in such auctions and to the obligations to pay, and the payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.
- d) Commitment of Replacement Capacity through Scheduled Incremental Auctions.

Each Scheduled Incremental Auction for each Delivery Year shall allow Capacity Market Sellers that committed Capacity Resources in any prior Reliability Pricing Model Auction for such Delivery Year to submit Buy Bids for replacement Capacity Resources. Capacity Market Sellers that submit Buy Bids into an Incremental Auction must specify the type of Unforced Capacity desired, i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource. The need to purchase replacement Capacity Resources may arise for any reason, including but not limited to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Capacity Market Buyers that purchase replacement Capacity Resources in such auction. PJMSettlement shall be the Counterparty to the sales and purchases that clear in such auction, provided, however, PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

e) Conditional Incremental Auction.

PJM shall conduct for any Delivery Year a Conditional Incremental Auction if the in service date of a Backbone Transmission Upgrade that was modeled in the Base Residual Auction is announced as delayed by the Office of the Interconnection beyond July 1 of the Delivery Year for which it was modeled and if such delay causes a reliability criteria violation. If conducted, the Conditional Incremental Auction shall be for the purpose of securing commitments of additional capacity for the PJM Region or for any LDA to address the identified reliability criteria violation. If PJM determines to conduct a Conditional Incremental Auction, PJM shall post on its website the date and parameters for such auction (including whether such auction is for the PJM Region or for an LDA, and the type of Capacity Resources required) at least one month prior to the start of such auction. The cost of payments to Market Sellers for Capacity Resources cleared in such auction shall be collected by PJMSettlement from Load Serving Entities in the PJM Region or LDA, as applicable, through an adjustment to the Locational Reliability Charge for such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

5.6 Sell Offers

Sell Offers shall be submitted or withdrawn via the internet site designated by the Office of the Interconnection, under the procedures and time schedule set forth in the PJM Manuals.

5.6.1 Specifications

A Sell Offer shall state quantities in increments of 0.1 megawatts and shall specify, as appropriate:

a) Identification of the Generation Capacity Resource, Demand Resource, Capacity Storage Resource or Energy Efficiency Resource on which such Sell Offer is based;

b) Minimum and maximum megawatt quantity of installed capacity that the Capacity Market Seller is willing to offer (notwithstanding such specification, the product offered shall be Unforced Capacity), or designate as Self-Supply, from a Generation Capacity Resource;

i) Price, in dollars and cents per megawatt-day, that will be accepted by the Capacity Market Seller for the megawatt quantity of Unforced Capacity offered from such Generation Capacity Resource.

ii) The Sell Offer may take the form of offer segments with varying price-quantity pairs for varying output levels from the underlying resource, but may not take the form of an offer curve with nonzero slope.

c) EFORD of each Generation Capacity Resource offered.

i) If a Capacity Market Seller is offering such resource in a Base Residual Auction, First Incremental Auction, Second Incremental Auction, or Conditional Incremental Auction occurring before the Third Incremental Auction or Final Incremental Auction, the Capacity Market Seller shall specify the EFORD to apply to the offer.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Capacity Market Seller shall specify the EFORD to apply to the commitment.

iii) The EFORD applied to the Third Incremental Auction or Final Incremental Auction will be the final EFORD established by the Office of the Interconnection six (6) months prior to the Delivery Year, based on the actual EFORD in the PJM Region during the 12-month period ending September 30 that last precedes such Delivery Year.

d) The Nominated Demand Resource Value for each Demand Resource offered and the Nominated Energy Efficiency Value for each Energy Efficiency Resource offered. The Office of the Interconnection shall, in both cases, convert such value to an Unforced Capacity basis by multiplying such value by the DR Factor (for Delivery Years through May 31, 2018) times the Forecast Pool Requirement. Demand Resources shall specify the LDA in which the Demand Resource is located, including the location of such resource within any Zone that includes more than one LDA as identified on RAA, Schedule 10.1.

e) For Delivery Years through May 31, 2018, a Demand Resource with the potential to qualify as two or more of a Limited Demand Resource, Extended Summer Demand Resource or Annual Demand Resource may submit separate but coupled Sell Offers for each Demand Resource type for which it qualifies at different prices and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. For such coupled Demand Resource offers, the offer price of an Annual Demand Resource offer must be at least \$.01 per MW-day greater than the offer price of a coupled Extended Summer Demand Resource offer and the offer price of a Extended Summer Demand Resource offer must be at least \$.01 per MW-day greater than the offer price of a coupled Limited Demand Resource offer.

f) For a Qualifying Transmission Upgrade, the Sell Offer shall identify such upgrade, and the Office of the Interconnection shall determine and certify the increase in CETL provided by such upgrade. The Capacity Market Seller may offer the upgrade with an associated increase in CETL to an LDA in accordance with such certification, including an offer price that will be accepted by the Capacity Market Seller, stated in dollars and cents per megawatt-day as a price difference between a Capacity Resource located outside such an LDA and a Capacity Resource located inside such LDA; and the increase in CETL into such LDA to be provided by such Qualifying Transmission Upgrade, as certified by the Office of the Interconnection.

g) For the 2018/2019 and 2019/2020 Delivery Years, each Capacity Market Seller owning or controlling a resource that qualifies as both a Base Capacity Resource and a Capacity Performance Resource may submit separate but coupled Sell Offers for such resource as a Base Capacity Resource and as a Capacity Performance Resource, at different prices, and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. Submission of a coupled Base Capacity Resource Sell Offer shall be mandatory for any Capacity Performance Resource Sell Offer that exceeds a Sell Offer Price equal to the applicable Net Cost of New Entry times the Balancing Ratio as provided for in Tariff, Attachment DD, section 6.4. For such coupled Sell Offers, the offer price of a Capacity Performance Resource offer must be at least \$.01 per MW-day greater than the offer price of a coupled Base Capacity Resource offer.

(h) For the 2018/2019 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, or Energy Efficiency Resources may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with their average expected output during peak-hour periods. Alternatively, for the 2018/2019 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, Energy Efficiency Resources, or Environmentally-Limited Resources may submit a Sell Offer which represents the aggregated Unforced Capacity value of such resources, where such Sell Offer shall be considered to be located in the smallest modeled LDA common to the aggregated resources. Such aggregated resources shall be owned by or under contract to the Capacity Market Seller, including all such resources obtained through bilateral contract and reported to the Office of the Interconnection in accordance with the Office of the Interconnection's rules related to its eRPM tools. For the 2018/2019 and 2019/2020 Delivery Years, any such offer may be submitted as Capacity Performance Resource, Base Capacity Resource, or as a coupled offer for Capacity Performance Resource and Base Capacity Resource, provided that, for any such coupled Sell Offers, the offer

price of a Capacity Performance Resource offer must be at least \$.01 per MW-day greater than the offer price of a coupled Base Capacity Resource offer. For the 2020/2021 Delivery Year and subsequent Delivery Years, any such offer must be submitted as a Capacity Performance Resource.

(i) For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Summer-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Summer-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during summer peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Summer-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Winter-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Winter-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during winter peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Winter-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. Each segment of a Seasonal Capacity Performance Resource Sell Offer must be submitted as a flexible Sell Offer segment with the minimum MW quantity offered set to zero.

5.6.2 Compliance with PJM Credit Policy

Capacity Market Sellers shall comply with the provisions of the PJM Credit Policy as set forth in Tariff, Attachment Q, including the provisions specific to the Reliability Pricing Model, prior to submission of Sell Offers in any Reliability Pricing Model Auction. A Capacity Market Seller desiring to submit a Credit-Limited Offer shall specify in its Sell Offer the maximum auction credit requirement, in dollars, and the maximum amount of Unforced Capacity, in megawatts, applicable to its Sell Offer.

5.6.3 [reserved]

5.6.4 Qualifying Transmission Upgrades

A Qualifying Transmission Upgrade may not be the subject of any Sell Offer in a Base Residual Auction unless it has been approved by the Office of the Interconnection, including certification of the increase in Import Capability to be provided by such Qualifying Transmission Upgrade, no later than 45 days prior to such Base Residual Auction. No such approval shall be granted unless, at a minimum, a Facilities Study Agreement has been executed with respect to such upgrade, and such upgrade conforms to all applicable standards of the Regional Transmission Expansion Plan process.

5.6.5 Market-based Sell Offers

Subject to Tariff, Attachment DD, section 6, a Market Seller authorized by FERC to sell electric generating capacity at market-based prices, or that is not required to have such authorization, may submit Sell Offers that specify market-based prices in any Base Residual Auction or Incremental Auction.

5.6.6 Availability of Capacity Resources for Sale

(a) The Office of the Interconnection shall determine the quantity of megawatts of available installed capacity that each Capacity Market Seller must offer in any RPM Auction pursuant to Tariff, Attachment DD, Section 6.6, through verification of the availability of megawatts of installed capacity from: (i) all Generation Capacity Resources owned by or under contract to the Capacity Market Seller, including all Generation Capacity Resources obtained through bilateral contract; (ii) the results of prior Reliability Pricing Model Auctions, if any, for such Delivery Year (including consideration of any restriction imposed as a consequence of a prior failure to offer); and (iii) such other information as may be available to the Office of the Interconnection. The Office of the Interconnection shall reject Sell Offers or portions of Sell Offers for Capacity Resources in excess of the quantity of installed capacity from such Capacity Market Seller's Capacity Resource that it determines to be available for sale.

(b) The Office of the Interconnection shall determine the quantity of installed capacity available for sale in a Base Residual Auction or Incremental Auction as of the beginning of the period during which Buy Bids and Sell Offers are accepted for such auction, as applicable, in accordance with the time schedule set forth in the PJM Manuals. Removal of a resource from Capacity Resource status shall not be reflected in the determination of available installed capacity unless the associated unit-specific bilateral transaction is approved, the designation of such resource (or portion thereof) as a network resource for the external load is demonstrated to the Office of the Interconnection, or equivalent evidence of a firm external sale is provided prior to the deadline established therefor. The determination of available installed capacity shall also take into account, as they apply in proportion to the share of each resource owned or controlled by a Capacity Market Seller, any approved capacity modifications, and existing capacity commitments established in a prior RPM Auction, an FRR Capacity Plan, Locational UCAP transactions and/or replacement capacity transactions under this Attachment DD. To enable the Office of the Interconnection to make this determination, no bilateral transactions for Capacity Resources applicable to the period covered by an auction will be processed from the beginning of the period for submission of Sell Offers and Buy Bids, as appropriate, for that auction until completion of the clearing determination for such auction. Processing of such bilateral transactions will reconvene once clearing for that auction is completed. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

(c) In order for a bilateral transaction for the purchase and sale of a Capacity Resource to be processed by the Office of the Interconnection, both parties to the transaction must notify the Office of the Interconnection of the transfer of the Capacity Resource from the seller to the buyer in accordance with procedures established by the Office of the Interconnection and set forth in the PJM Manuals. If a material change with respect to any of the prerequisites

for the application of Tariff, Attachment DD, section 5.6.6 to the Generation Capacity Resource occurs, the Capacity Resource Owner shall immediately notify the Market Monitoring Unit and the Office of the Interconnection.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (for Delivery Years through May 31, 2018, less the Short-Term Resource Procurement Target) or Locational Deliverability Area Reliability Requirement (for Delivery Year through May 31, 2018, less the Short-Term Resource Procurement Target for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;
- For the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:
 - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORD) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin (“IRM”)% minus 3%) divided by (100% plus IRM%)], and for Delivery Years

through May 31, 2018, minus the Short-Term Resource Procurement Target;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORD) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)], and for Delivery Years through May 31, 2018, minus the Short-Term Resource Procurement Target; and
- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORD) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)], and for Delivery Years through May 31, 2018, minus the Short-Term Resource Procurement Target;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORD) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin (“IRM”)% minus 0.2%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;
 - For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORD) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 2.9%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target; and
 - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 8.8%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target.

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

- A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or
- B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or
- C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the Eastern Mid-Atlantic Region (“EMAR”), Southwest Mid-Atlantic Region (“SWMAR”), and Mid-Atlantic Region (“MAR”) LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and, for Delivery Years through May 31, 2018, the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

For each such LDA, for the 2018/2019 Delivery Year and subsequent Delivery Years, the Office of the Interconnection shall (a) determine the Net Cost of New Entry for each Zone in such LDA, with such Net Cost of New Entry equal to the applicable Cost of New Entry value for such Zone minus the Net Energy and Ancillary Services Revenue Offset value for such Zone, and (b) compute the average of the Net Cost of New Entry values of all such Zones to determine the Net Cost of New Entry for such LDA; provided however, that the Net Cost of New Entry for an LDA may

be greater than, but shall be no less than, the Net Cost of New Entry determined for any other LDA in which the first LDA resides (immediately or successively) including the Net Cost of New Entry for the RTO. The Net Cost of New Entry for use in an LDA in any Incremental Auction for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years shall be the Net Cost of New Entry used for such LDA in the Base Residual Auction for such Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

- A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
- B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.
- C) The PJM Members shall either vote to (i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
- D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape 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.

iv) Cost of New Entry

- A) For the Incremental Auctions for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, the Cost of New Entry for the PJM Region and for each LDA shall be the respective value used in the Base Residual Auction for such Delivery Year and LDA. For the Delivery Year commencing on June 1, 2018, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(B).

| Geographic Location Within the PJM Region Encompassing These Zones | Cost of New Entry in \$/MW-Year |
|--|--|
| PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”) | 132,200 |
| BGE, PEPCO (“CONE Area 2”) | 130,300 |
| AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”) | 128,900 |
| PPL, MetEd, Penelec (“CONE Area 4”) | 130,300 |

- B) Beginning with the 2019/2020 Delivery Year, the CONE for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics (“BLS”) Composite Index, in accordance with the following:

(1) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Price Index for Construction Materials and Components (weighted 50%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 30%), as each such index is further specified for each CONE Area in the PJM Manuals.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable BLS Composite Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark

CONE values for the 2018/2019 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years).

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

- A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of \$6.47 per MWh, and actual PJM *hourly* average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of \$2,199 per MW-year.
- B) For the Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the Office of the Interconnection will employ for purposes of the Variable Resource Requirement Curves for such Delivery Years the same calculations of the sub-regional Net Energy and Ancillary Services Revenue Offsets that were used in the Base Residual Auctions for such Delivery year and sub-region. For the 2018/2019 Delivery Year and subsequent Delivery Years, the Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for such Zone shall be used in place of the PJM Region average hourly LMPs; (2) if such Zone was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the Zone was integrated; and (3) a posted fuel pricing point in such Zone, if available, and (if such pricing point is not available in such Zone) a fuel transmission adder appropriate

to such Zone from an appropriate PJM Region pricing point shall be used for each such Zone.

Curve

vi) Process for Establishing Parameters of Variable Resource Requirement

- A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.
- B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.
- C) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.
 - 1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - 2) The PJM Members shall review the proposed values.
 - 3) The PJM Members shall either vote to (i) endorse the proposed values, (ii) propose alternate values or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - 4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values 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.

- D) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.
- 1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.
 - 2) The PJM Members shall review the proposed methodology.
 - 3) The PJM Members shall either vote to (i) endorse the proposed methodology, (ii) propose an alternate methodology or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.
 - 4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Resource Requirements and Constraints

Prior to the Base Residual Auction and each Incremental Auction for the Delivery Years starting on June 1, 2014 and ending May 31, 2017, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and

Incremental Auctions for the 2017/2018 Delivery Year, the Office of the Interconnection shall establish the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and Incremental Auctions for 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for Delivery Years prior to the 2021/2022 Delivery Year and the Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years.

5.11 Posting of Information Relevant to the RPM Auctions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5.11A Backbone Transmission Upgrade Project Development Milestones

A Transmission Upgrade including transmission facilities at voltages of 500 kV or higher that is in an approved Regional Transmission Expansion Plan (“Backbone Transmission”) shall be included in the system model for an RPM Auction only if it satisfies the project development milestones set forth in this section.

a) Base Residual Auction

Backbone Transmission shall be included in the system model used for a Base Residual Auction only if:

i) No later than 60 days before posting of the planning parameters for the Base Residual Auction, a corporate officer of the project sponsor submits a current critical path project development schedule containing intermediate milestones and showing the project in full commercial operation no later than the start of the Delivery Year corresponding to such Base Residual Auction, and must certify that such schedule is reasonably achievable based on information then known to and reasonably anticipated by the project sponsor. Such notice must identify all states in which such project is subject to the requirement to obtain a certificate of public convenience and necessity, or functional equivalent approval or licensure requirement, and must describe the nature and current status of such approval requirement;

ii) such development schedule additionally must show the scope, schedule, and current status of all other key milestones, including, at a minimum, right-of-way acquisition, engineering design, equipment procurement, construction permitting, and construction activities;

iii) applications for certificates of public convenience and necessity (or for equivalent approval) have been filed in all states applicable to such project that have such requirement.

b) Incremental Auctions

A Backbone Transmission project shall be included in the system models for Incremental Auctions only if the following requirements are satisfied no later than 60 days before each Incremental Auction, as indicated below:

i) a corporate officer submits, and certifies to, an updated project development schedule for the First Incremental Auction that shows, among other things, that 50% of the right-of-way by linear distance has been secured;

ii) a corporate officer submits, and certifies to, an updated project development schedule for the Second Incremental Auction that shows, among other things, that 75% of the right-of-way by linear distance has been secured, and that all certificates of public convenience and necessity (or equivalent approvals) have been issued by the responsible regulatory bodies;

iii) a corporate officer submits, and certifies to, an updated project development schedule for the Third Incremental Auction or Final Incremental Auction, as applicable, that shows, among other things, that 100% of the right-of-way by linear distance has been secured.

c) Audit, Removal from System Model, and Reinstatement in System Model

i) for the Backbone Transmission project to remain in the applicable system model, the Office of the Interconnection or independent third party with established expertise in such area must audit the project development schedule and affirm, no later than 30 days before each applicable auction, that the schedule is reasonable and remains on progress to full commercial operation prior to the commencement of the relevant Delivery Year. Audits may include site visits as deemed necessary by the auditor to verify progress.

ii) a Backbone Transmission project that fails to satisfy any of the requirements indicated for the Base Residual Auction shall not be included in the system model for such Base Residual Auction or any Incremental Auction for the relevant Delivery Year. A Backbone Transmission project that fails to satisfy any of the requirements indicated for an Incremental Auction shall not be included in the system model for such Incremental Auction or any subsequent Incremental Auction for the relevant Delivery Year.

iii) a Backbone Transmission project that is excluded from the system model for any RPM Auction for a Delivery Year may be included in the system model for RPM Auctions for a subsequent Delivery Year only if it demonstrates that all deficiencies have been cured and the project is on schedule for full commercial operation prior to such subsequent Delivery Year.

5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;
- the Variable Resource Requirement Curves for the PJM Region and each LDA;
- any constraints resulting from the Locational Deliverability Requirement and any applicable Capacity Import Limit;
- for Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a); for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a); and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a);
- For the Delivery Years through May 31, 2018, the PJM Region Reliability Requirement minus the Short-Term Resource Procurement Target;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement; and
- For the 2020/2021 Delivery Year and subsequent Delivery Years, the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region.

The optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity,

while respecting all applicable requirements and constraints, including any restrictions specified in any Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. For the 2020/2021 Delivery Year and subsequent Delivery Years, the supply curve formed by the Sell Offers submitted within an LDA for which a separate VRR Curve is established, shall only consider the quantity of MW from Summer-Period Capacity Performance Resources that are equally matched with Winter-Period Capacity Performance Resources within the LDA, such that only the equally matched quantity of opposite-season Sell Offers are considered in satisfying the LDA's reliability requirement.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year. The Capacity Resource clearing results and Capacity Resource Clearing Prices determined for Summer-Period Capacity Performance Resources shall be applicable for the calendar months of June through October and the following May of such Delivery Year; and shall be applicable for Winter-Period Capacity Performance Resources for the calendar months of November through April of such Delivery Year.

b) Scheduled Incremental Auctions.

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- For the Delivery years through May 31, 2018, the PJM Region Reliability Requirement, less the Short-term Resource Procurement Target;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;

- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;
- The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- For the Delivery Years through May 31, 2018, for each LDA, such LDA's updated Reliability Requirement, less such LDA's Short-Term Resource Procurement Target;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, for each LDA, such LDA's updated Reliability Requirement
- For Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each LDA for which PJM is required to establish a separate VRR Curve for the Base Residual Auction for the relevant Delivery Year; for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a); and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a);
- For the 2020/2021 Delivery Year and subsequent Delivery Years, the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region;
- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;
- The Sell Offers submitted in such auction; and
- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction for Delivery Years prior to the 2021/2022 Delivery Year and the Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years is triggered by Tariff, Attachment DD, section 5.4(c)(2), the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction for Delivery Years prior to the 2021/2022 Delivery Year and the Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years is triggered by Tariff, Attachment DD, section 5.4(c)(1), and the conditions stated in Tariff, Attachment DD, section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, sections 5.14B, 5.14C, 5.14E, *and 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9*, minus (E) the quantity of new Unforced Capacity commitments for the 2016/2017 and 2017/2018 Delivery Years associated with the transition provisions in Tariff, Attachment DD, section 5.14D where this quantity is assumed to have been procured in the form of non-Capacity Performance Resources for purposes of this paragraph E. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, with exception for the Third Incremental Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. In seeking to sell back such quantity for the Third Incremental Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall employ in the clearing of the auction a curve represented by a straight line connecting two points with the first point located at 0 megawatts and at a price set to the lowest price point of the Updated VRR Curve Decrement and the second point located at a megawatt amount corresponding to the negative quantity defined above and at a price set to the Resource Clearing Price of the 2017/2018 Base Residual Auction.

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction for Delivery Years prior to the 2021/2022 Delivery Year is indicated for the PJM Region or any LDA by Tariff, Attachment DD, section 5.4(c)(3)(i), the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior

Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by Tariff, Attachment DD, section 5.4(c)(3)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, sections 5.14B, 5.14C, 5.14E, and 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9, minus (E) the quantity of new Unforced Capacity commitments for the 2016/2017 and 2017/2018 Delivery Years associated with the transition provisions in Tariff, Attachment DD, section 5.14D where this quantity is assumed to have been procured in the form of non-Capacity Performance Resources for purposes of this paragraph E; provided, however, that the amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, with exception for the Third Incremental Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. In seeking to sell back such quantity for the Third Incremental Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall employ in the clearing of the auction a curve represented by a straight line connecting two points with the first point located at 0 megawatts and at a price set to the lowest price point of the Updated VRR Curve Decrement and the second point located at a megawatt amount corresponding to the negative quantity defined above and at a price set to the Resource Clearing Price of the 2017/2018 Base Residual Auction.

When the possible need to seek agreements to release capacity commitments in any Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years is indicated for the PJM Region or any LDA by Tariff, Attachment DD, section 5.4(c)(3)(i), the Office of the Interconnection shall seek to sell back such quantity at a sell offer price equal to the Resource Clearing Price of the Base Residual Auction applicable to the relevant Delivery Year.

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction for Delivery Years prior to the 2021/2022 Delivery Year, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion

of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. For the Delivery Years through May 31, 2018, if more than one of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection shall not seek to procure the Short-Term Resource Procurement Target Applicable Share more than once for such region or area for such auction

(v) If PJM seeks to procure additional capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years due to a triggering of the tests in subsections (i), (ii), (iii) or (iv) then the Minimum Annual Resource Requirement for such Auction will be equal to the updated Minimum Annual Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity from Annual Resources, and the Minimum Extended Summer Resource Requirement for such Auction will be equal to the updated Minimum Extended Summer Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years from Annual Resources and Extended Summer Demand Resources. If PJM seeks to release prior committed capacity due to a triggering of the test in subsection (iii) then PJM may not release prior committed capacity from Annual Resources or Extended Summer Demand Resources below the updated Minimum Annual Resource Requirement and updated Minimum Extended Summer Resource Requirement, respectively.

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits ("Excess Commitment Credits") under certain circumstances as follows:

- (A) For either or both of the Delivery Years commencing on June 1, 2010 or June 1, 2011, if the PJM Region Reliability Requirement used for purposes of the Base Residual Auction for such Delivery Year exceeds the PJM Region Reliability Requirement that is based on the last updated load

forecast prior to such Delivery Year, then such excess will be allocated to Load Serving Entities as set forth below;

- (B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, through and including the Delivery Year ending on May 31, 2021, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;
- (C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;
- (D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

(ix) For the 2021/2022 Delivery Year and all subsequent Delivery Years, the total megawatt amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Final Incremental Auction for such Delivery Year that does not clear such auction will be made available for purposes of accepting requests from Capacity Market Sellers to be excused of all or a portion of a Capacity Resource's Base Residual Auction commitment. Such requests must be provided to PJM during an open request window that closes 15 business days prior to the start of the relevant Delivery Year and such requests must identify the Capacity Resource and the unforced capacity megawatt quantity of the Capacity Resource's Base Residual Auction commitment for which the Capacity Market Seller seeks to be excused. Only Capacity Resource commitments made by clearing in the Base Residual Auction are eligible to be excused through this process. The maximum total megawatt quantity of Base Residual Auction commitment excusal requests that may be accepted across the entire RTO is equal to the total uncleared megawatt quantity that PJM sought to release in the Final Incremental Auction, and, the maximum total megawatt quantity of Base Residual Auction commitment that may be excused within each modeled LDA is equal to the updated final LDA Reliability Requirement

minus the total committed capacity located within the LDA minus the LDA CETL, not to exceed the maximum total megawatt quantity that may be excused across the entire RTO. If the total megawatt quantity of all Base Residual Auction excusal requests received during the open request window is less than the maximum permissible levels for the RTO and each modeled LDA, then all requests will be accepted. If the total megawatt quantity of all Base Residual Auction excusal requests exceeds the maximum permissible level for the entire RTO then all requests will be accepted at reduced levels based on each request's pro-rata share of the maximum permissible megawatt quantity of the RTO. If after this proration, the total megawatt quantity of Base Residual Auction excusal requests exceeds the maximum permissible level for a modeled LDA, then all requests within that LDA will be reallocated based on each request's pro-rata share of the maximum permissible level for that LDA and the residual quantity will be allocated to requests located outside of that LDA while again ensuring that the maximum permissible level of any given modeled LDA is not exceeded. PJM will notify Capacity Market Sellers that submitted requests to be excused of a Base Residual Auction commitment during the open request window of the accepted megawatt values within 2 business days of the close of the request window.

When a Capacity Resource's Base Residual Auction commitment is excused through this process, the Capacity Market Seller relinquishes the Base Residual Auction Credit that it would otherwise receive for the excused unforced capacity megawatt quantity and is no longer responsible for satisfying any obligation associated with the excused quantity. The total dollar value of relinquished auction credits associated with all accepted Base Residual Auction commitment excusals shall be distributed throughout the relevant Delivery Year on a daily basis to all LSEs that were charged a Locational Reliability Charge for the day. Such distribution shall be based on each LSE's pro-rata share of the total Daily Unforced Capacity Obligation.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

6. MARKET POWER MITIGATION

6.1 Applicability

The provisions of the Market Monitoring Plan (in Tariff, Attachment M and Attachment - M Appendix and this section 6) shall apply to the Reliability Pricing Model Auctions.

6.2 Process

(a) [Reserved for Future Use]

(b) In accordance with the schedule specified in the PJM Manuals, following PJM's conduct of a Base Residual Auction or Incremental Auction pursuant to Tariff, Attachment DD, section 5.12, but prior to the Office of the Interconnection's final determination of clearing prices and charges pursuant to Tariff, Attachment DD, section 5.14, the Office of the Interconnection shall: (i) apply the Market Structure Test to any LDA having a Locational Price Adder greater than zero and to the entire PJM region; (ii) apply Market Seller Offer Caps, if required under this section 6; and (iii) recompute the optimization algorithm to clear the auction with the Market Seller Offer Caps in place.

(c) Within seven days after the deadline for submission of Sell Offers in a Base Residual Auction or Incremental Auction, the Office of the Interconnection shall file with FERC a report of any determination made pursuant to Tariff, Attachment DD, sections 5.14(h), 6.5(a)(ii), or 6.7(c) identified in such sections as subject to the procedures of this section. Such report shall list each such determination, the information considered in making each such determination, and an explanation of each such determination. Any entity that objects to any such determination may file a written objection with FERC no later than seven days after the filing of the report. Any such objection must not merely allege that the determination was in error, and must provide support for the objection, demonstrating that the determination overlooked or failed to consider relevant evidence. In the event that no objection is filed, the determination shall be final. In the event that an objection is filed, FERC shall issue any decision modifying the determination no later than 60 days after the filing of such report; otherwise, the determination shall be final. Final auction results shall reflect any decision made by FERC regarding the report.

6.3 Market Structure Test

(a) [Reserved for Future Use]

(b) Market Structure Test.

A constrained LDA or the PJM Region shall fail the Market Structure Test, and mitigation shall be applied to all jointly pivotal suppliers (including all Affiliates of such suppliers, and all third-party supply in the relevant LDA controlled by such suppliers by contract), if, as to the Sell Offers that comprise the incremental supply determined pursuant to section 6.3(c) that are based on Generation Capacity Resources, there are not more than three jointly pivotal suppliers. The Office of the Interconnection shall apply the Market Structure Test. The Office of the

Interconnection shall confirm the results of the Market Structure Test with the Market Monitoring Unit.

(c) Determination of Incremental Supply

In applying the Market Structure Test, the Office of the Interconnection shall consider all (i) incremental supply (provided, however, that the Office of the Interconnection shall consider only such supply available from Generation Capacity Resources) available to solve the constraint applicable to a constrained LDA offered at less than or equal to 150% of the cost-based clearing price; or (ii) supply for the PJM Region, offered at less than or equal to 150% of the cost-based clearing price, provided that supply in this section includes only the lower of cost-based or market-based offers from Generation Capacity Resources. Cost-based clearing prices are the prices resulting from the RPM auction algorithm using the lower of cost-based or price-based offers for all Capacity Resources.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW/day of unforced capacity, applicable to price-quantity offers within the Base Offer Segment for an Existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW/day of unforced capacity, provided, however, that the default Market Seller Offer Cap for any Capacity Performance Resource shall be the product of (the Net Cost of New Entry applicable for the Delivery Year and Locational Deliverability Area for which such Capacity Performance Resource is offered times the average of the Balancing Ratios in the three consecutive calendar years (during the Performance Assessment *Intervals* in such calendar years) that precede the Base Residual Auction for such Delivery Year), however, for the Base Residual Auction for the 2021/2022 Delivery Year, the Balancing Ratio used in the determination of the default Market Seller Offer Cap shall be 78.5 percent, and provided further that the submission of a Sell Offer with an Offer Price at or below the revised Market Seller Offer Cap permitted under this proviso shall not, in and of itself, be deemed an exercise of market power in the RPM market. Notwithstanding the previous sentence, a Capacity Market Seller may seek and obtain a Market Seller Offer Cap for a Capacity Performance Resource that exceeds the revised Market Seller Offer Cap permitted under the prior sentence, if it supports and obtains approval of such alternative offer cap pursuant to the procedures and standards of subsection (b) of this section 6.4. A Capacity Market Seller may not use the Capacity Performance default Market Seller Offer Cap, and also seek to include any one or more categories of the Avoidable Cost Rate defined in Tariff, Attachment DD, section 6.8. The Market Seller Offer Cap for an Existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with Tariff, Attachment DD, section 6.7. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in Tariff, Attachment M-Appendix, section II.E.3.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection data and

documentation required under Tariff, Attachment DD, section 6.7 to establish the level of the Market Seller Offer Cap applicable to each resource by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the Market Seller Offer Cap proposed by the Market Monitoring Unit, and attempt to reach agreement with the Market Monitoring Unit on the level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller shall notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, whether an agreement with the Market Monitoring Unit has been reached or, if no agreement has been reached, specifying the level of Market Seller Offer Cap to which it commits by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. The Office of the Interconnection shall review the data submitted by the Capacity Market Seller, make a determination whether to accept or reject the requested unit-specific Market Seller Offer Cap, and notify the Capacity Market Seller and the Market Monitoring Unit of its determination in writing, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction. If the Market Monitoring Unit does not provide its determination to the Capacity Market Seller and the Office of the Interconnection by the specified deadline, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction the Office of the Interconnection will make the determination of the level of the Market Seller Offer Cap, which shall be deemed to be final. If the Capacity Market Seller does not notify the Market Monitoring Unit and the Office of the Interconnection of the Market Seller Offer Cap it desires to utilize by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction, it shall be required to utilize a Market Seller Offer Cap determined using the applicable default Avoidable Cost Rate specified in Tariff, Attachment DD, section 6.7(c).

(c) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the Sell Offer complies with the requirements of the Tariff.

(d) For any Third Incremental Auction for Delivery Years through the 2017/2018 Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction for the 2018/2019 or 2019/2020 Delivery Years, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Base Capacity resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction or Final Incremental Auction, as applicable, for the 2018/2019 Delivery Year or any subsequent Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Capacity Performance Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to the greater of the Net Cost of New Entry for the

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

6.5 Mitigation

The Office of the Interconnection shall apply market power mitigation measures in any Base Residual Auction or Incremental Auction for any LDA, Unconstrained LDA Group, or the PJM Region that fails the Market Structure Test.

(a) Mitigation for Generation Capacity Resources.

i) Existing Generation Capacity Resource

Mitigation will be applied on a unit-specific basis and only if the Sell Offer of Unforced Capacity from an Existing Generation Capacity Resource: (1) is greater than the Market Seller Offer Cap applicable to such resource; and (2) would, absent mitigation, increase the Capacity Resource Clearing Price in the relevant auction. If such conditions are met, such Sell Offer shall be set equal to the Market Seller Offer Cap.

ii) Planned Generation Capacity Resources

(A) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) shall be presumed to be competitive and shall not be subject to market power mitigation in any Base Residual Auction or Incremental Auction for which such resource qualifies as a Planned Generation Capacity Resource, but any such Sell Offer shall be rejected if it meets the criteria set forth in subsection (C) below, unless the Capacity Market Seller obtains approval from FERC for use of such offer prior to the close of the offer period for the applicable RPM Auction.

(B) Sell Offers based on Planned Generation Capacity Resources (including Planned External Generation Capacity Resources) shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that modeled LDA are pivotal, shall be subject to mitigation.

(C) Where the two conditions stated in subsection (B) are not met, or the Sell Offer is pivotal, the Sell Offer shall be rejected if it exceeds 140 percent of: 1) the average of location-adjusted Sell Offers for Planned Generation Capacity Resources from the same asset class as such Sell

Offer, submitted (and not rejected) (Asset-Class New Plant Offers) for such Delivery Year; or 2) if there are no Asset-Class New Plant Offers for such Delivery Year, the average of Asset-Class New Plant Offers for all prior Delivery Years; or 3) if there are no Asset-Class New Plant Offers for any prior Delivery Year, the Net CONE applicable for such Delivery Year in the LDA for which such Sell Offer was submitted. For purposes of this section, asset classes shall be as stated in Tariff, Attachment DD, section 6.7(c) as effective for such Delivery Year, and Asset-Class New Plant Offers shall be location-adjusted by the ratio between the Net CONE effective for such Delivery Year for the LDA in which the Sell Offer subject to this section was submitted and the average, weighted by installed capacity, of the Net CONEs for all LDAs in which the units underlying such Asset Class New Plant Offers are located. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with Section 6.2(b) above, each Capacity Market Seller whose Sell Offer is so rejected shall be notified in writing by the Office of the Interconnection by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction and allowed an opportunity to submit a revised Sell Offer that does not exceed such threshold within one (1) Business Day of the Office of the Interconnection's rejection of such Sell Offer. If such revised Sell Offer is accepted by the Office of the Interconnection, the Office of the Interconnection then shall clear the auction with such revised Sell Offer in place. Pursuant to Tariff, Attachment M-Appendix, Section II.F, the Market Monitoring Unit shall notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

(b) Mitigation for Demand Resources

The Market Seller Offer Cap shall not be applied to Sell Offers of Demand Resources or Energy Efficiency Resources.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h), all of the installed capacity of all Existing Generation Capacity Resources located in the PJM Region shall be offered by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to this RPM must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6. The Unforced Capacity of such resources is determined using the EFORD value that is submitted by the Capacity Market Seller in its Sell Offer, which shall not exceed the maximum EFORD for that resource as defined in

Section 6.6(b). If a resource should be included on the list of Existing Generation Capacity Resources subject to the RPM must-offer requirement that is maintained by the Market Monitoring Unit pursuant to Tariff, Attachment M-Appendix, section II.C.1 of Attachment M – Appendix of the Tariff, but is omitted therefrom whether by mistake of the Market Monitoring Unit or failure of the Capacity Market Seller that owns or controls all or part of such resource to provide information about the resource to the Market Monitoring Unit, this shall not excuse such resource from the RPM must-offer requirement.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit and the Office of the Interconnection all data and documentation required under section 6.6 to establish the maximum EFORD applicable to each resource in accordance with standards and procedures specified in the PJM Manuals. The maximum EFORD that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORDs used for a Delivery Year are posted, is the greater of (i) the average EFORD for the five consecutive years ending on the September 30 that last precedes the Base Residual Auction, or (ii) the EFORD for the 12 months ending on the September 30 that last precedes the Base Residual Auction.

Notwithstanding the foregoing, a Capacity Market Seller may request an alternate maximum EFORD for Sell Offers submitted in such auctions if it has a documented, known reason that would result in an increase in its EFORD, by submitting a written request to the Market Monitoring Unit and Office of the Interconnection, along with data and documentation required to support the request for an alternate maximum EFORD, by no later one hundred twenty (120) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. The Capacity Market Seller must address any concerns identified by the Market Monitoring Unit and/or the Office of the Interconnection regarding the data and documentation provided and attempt to reach agreement with the Market Monitoring Unit on the level of the alternate maximum EFORD by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. As further described in Tariff, Attachment M-Appendix, Section II.C, the Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination of the requested alternate maximum EFORD by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than eighty (80) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Capacity Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing whether it agrees with the Market Monitoring Unit on the alternate maximum EFORD or, if no agreement has been reached, specifying the level of alternate maximum EFORD to which it commits. If a Capacity Market Seller fails to request an alternate maximum EFORD prior to the specified deadlines, the maximum EFORD for the applicable RPM Auction shall be deemed to be the default EFORD calculated pursuant to this section.

The maximum EFORD that may be used in a Sell Offer for a Third or Final Incremental Auction, and for Conditional Incremental Auctions held after the date on which the final EFORD used for a Delivery Year is posted, is the EFORD for the 12 months ending on the September 30 that last precedes the submission of such offers.

(c) [Reserved for Future Use]

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the maximum level of the alternate EFORD that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORDs used for a Delivery Year are posted, the Office of the Interconnection shall make its own determination of the maximum level of the alternate EFORD based on the requirements of the Tariff and the PJM Manuals, per Section 5.8 of Attachment DD, by no later than sixty-five (65) days prior to the commencement of the offer period for the Base Residual for the applicable Delivery Year, and shall notify the Capacity Market Seller and the Market Monitoring Unit in writing of such determination.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORD complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit an EFORD that it chooses for an RPM Auction held prior to the date on which the final EFORD used for a Delivery Year is posted, provided that (i) it has participated in good faith with the process described in this section 6.6 and in Tariff, attachment M-Appendix, section II.C, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) A Capacity Market Seller that owns or controls an existing generation resource in the PJM Region that is capable of qualifying as an Existing Generation Capacity Resource as of the date on which bidding commences for an RPM Auction may not avoid the rule in subsection (a) or be removed from Capacity Resource status by failing to qualify as a Generation Capacity Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource for that RPM Auction. However, generation resource may qualify for an exception to the RPM must-offer requirement, as shown by appropriate documentation, if the Capacity Market Seller that owns or controls such resource demonstrates that it: (i) is reasonably expected to be physically unable to participate in the relevant Delivery Year; (ii) has a financially and physically firm commitment to an external sale of its capacity, or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

- A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Tariff, section 113.1, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Tariff, section 113.2 for

the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

- B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff;
- C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or
- D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity as set forth in (ii) above, the Capacity Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export.

A Capacity Market Seller that seeks to remove a Generation Capacity Resource from PJM Capacity Resource status and/or seeks approval for an exception to the RPM must-offer requirement, for any reason other than the reason specified in Paragraph A above, shall first submit such request in writing, along with all supporting data and documentation, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to obtain an exception to the RPM must-offer requirement for the reason specified in Paragraph A above, a Capacity Market Seller shall first submit a preliminary exception request in writing, along with supporting data and documentation indicating the reasons and conditions upon which the Capacity Market Seller is relying in its analysis of whether to retire such resource, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than (a) November 1, 2013 for the Base Residual Auction for the 2017/2018 Delivery Year, (b) the September 1 that last precedes the Base Residual Auction for the 2018/2019 and subsequent Delivery Years, and (c) two hundred forty (240) days prior to the commencement of the offer period for the applicable

Incremental Auction. By no later than five (5) Business Days after receipt of any such preliminary exception requests, the Office of the Interconnection will post on its website a summary of the number of megawatts of Generation Capacity Resources for which it has received notification of preliminary exception requests, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

Thereafter, as applicable, such Capacity Market Seller shall by no later than (a) the December 1 that last precedes the Base Residual Auction for the applicable Delivery Year, or (b) one hundred twenty (120) days prior to the commencement of the offer period for the applicable Incremental Auction, either (a) notify the Office of the Interconnection and the Market Monitoring Unit in writing that it is withdrawing its preliminary exception request and explaining the changes to its analysis of whether to retire such resource that support its decision to withdraw, or (b) demonstrate that it has met the requirements specified under Paragraph A above. By no later than five (5) Business Days after receipt of such notification, the Office of the Interconnection will post on its website a revised summary of the number of megawatts of Generation Capacity Resources for which it has received requests for exceptions to the RPM must-offer requirement for the reason specified in Paragraph A above, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

A Capacity Market Seller may only remove the Generation Capacity Resource from PJM Capacity Resource status if (i) the Market Monitoring Unit has determined that the Generation Capacity Resource meets the applicable criteria set forth in Tariff, Attachment DD, sections 5.6.6 and 6.6 of Attachment DD and the Office of the Interconnection agrees with this determination, or (ii) the Commission has issued an order terminating the Capacity Resource status of the resource. Nothing herein shall require a Market Seller to offer its resource into an RPM Auction prior to seeking to remove a resource from Capacity Resource status, subject to satisfaction of Section 6.6.

If the Capacity Market Seller disagrees with the Market Monitoring Unit's determination of its request to remove a resource from Capacity Resource status or its request for an exception to the RPM must-offer requirement, it must notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, of the same by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. After the Market Monitoring Unit has made its determination of whether a resource has satisfied the RPM must-offer requirement or meets one of the exceptions thereto and has notified the Capacity Market Seller and the Office of the Interconnection of the same pursuant to Tariff, Attachment M-Appendix, section II.C.4 of Attachment M – Appendix, the Office of the Interconnection shall approve or deny the exception request. The exception request shall be deemed to be approved by the Office of the Interconnection, consistent with the determination of the Market Monitoring Unit, unless the Office of the Interconnection notifies the Capacity Market Seller and Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences, that the exception request is denied.

If the Market Monitoring Unit does not timely notify the Capacity Market Seller and the Office of the Interconnection of its determination of the request to remove a Generation Capacity

Resource from Capacity Resource status or for an exception to the RPM must-offer requirement, the Office of the Interconnection shall make the determination whether the request shall be approved or denied, and will notify the Capacity Market Seller of its determination in writing, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences.

After the Market Monitoring Unit and the Office of the Interconnection have made their determinations of whether a resource meets the criteria to qualify for an exception to the RPM must-offer requirement, the Capacity Market Seller must notify the Market Monitoring Unit and the Office of the Interconnection whether it intends to exclude from its Sell Offer some or all of the subject capacity on the basis of an identified exception by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences. PJM does not make determinations of whether withholding of capacity constitutes market power. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation Capacity Resource during a Delivery Year pursuant to a sale or transfer agreement entered into after March 26, 2009 shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

If a Capacity Market Seller doesn't timely seek to remove a Generation Capacity Resource from Capacity Resource status or timely submit a request for an exception to the RPM must-offer requirement, the Generation Capacity Resource shall only be removed from Capacity Resource status, and may only be approved for an exception to the RPM must-offer requirement, upon the Capacity Market Seller requesting and receiving an order from FERC, prior to the close of the offer period for the applicable RPM Auction, directing the Office of the Interconnection to remove the resource from Capacity Resource status and/or granting an exception to the RPM must-offer requirement or a waiver of the RPM must-offer requirement as to such resource.

(h) Any existing generation resource located in the PJM Region that satisfies the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for the Base Residual Auction for a Delivery Year, that is not offered into such Base Residual Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All generation resources located in the PJM Region that satisfy the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for an Incremental Auction for a particular Delivery Year, but that did not satisfy such criteria as of the date that on which bidding commenced in the Base Residual Auction for that Delivery Year, that is not offered into that Incremental Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent

Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All Existing Generation Capacity Resources that are offered into a Base Residual Auction or Incremental Auction for a particular Delivery Year but do not clear in such auction, that are not offered into each subsequent Incremental Auction, and that do not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any Incremental Auctions conducted for such Delivery Year subsequent to such failure to offer; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any such Existing Generation Capacity Resources may also be subject to further action by the Market Monitoring Unit under the terms of Attachment M and Attachment M – Appendix.

(i) In addition to the remedies set forth in subsections (g) and (h) above, if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources, for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement, into an RPM Auction as required by this Section 6.6 would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, and the Office of the Interconnection agrees with that determination, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the relevant RPM Auction, or for other appropriate relief, and PJM will postpone clearing the auction pending FERC's decision on the matter. If the Office of the Interconnection disagrees with the Market Monitoring Unit's determination and does not apply to FERC for an order directing the Capacity Market Seller to participate in the auction or for other appropriate relief, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and to seek appropriate relief.

6.6A Offer Requirement for Capacity Performance Resources

(a) For the 2018/2019 Delivery Year and subsequent Delivery Years, the installed capacity of every Generation Capacity Resource located in the PJM Region that is capable (or that reasonably can become capable) of qualifying as a Capacity Performance Resource shall be offered as a Capacity Performance Resource by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each such Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to the Capacity Performance Resource must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6.

(b) Determinations of EFORD and Unforced Capacity made under section 6.6 hereof as to a Generation Capacity Resource shall govern the offers required under this section as to the same Generation Capacity Resource.

(c) Exceptions to the requirement in subsection (a) shall be permitted only for a resource which the Capacity Market Seller demonstrates is reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource. Intermittent Resources, Capacity Storage Resources, Demand Resources, and Energy Efficiency Resources shall not be required to offer as a Capacity Performance Resource, but shall not be precluded from being offered as a Capacity Performance Resource at a level that demonstrably satisfies such requirements. Exceptions shall be determined using the same timeline and procedures as specified in section 6.6.

(d) A resource not exempted or excepted under subsection (c) hereof that is capable of qualifying as a Capacity Performance Resource and does not offer into an RPM Auction as a Capacity Performance Resource shall be subject to the same restrictions on subsequent offers, and other possible remedies, as specified in section 6.6.

6.7 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit and the Office of the Interconnection no later than one hundred twenty (120) days prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORD and the net (unforced) capacity. A potential participant intending to offer any Capacity Performance Resource at or below the default Market Seller Offer Cap described in Tariff, Attachment DD, section 6.4(a) must provide the associated offer cap and the MW to which the offer cap applies.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that request a unit specific Avoidable Cost Rate shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above: (1) the applicable default level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

Nothing herein precludes the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource as outlined in Tariff, Attachment M-Appendix, section II.G. Any Sell Offer submitted in any auction that is inconsistent with any agreement or commitment made pursuant to this subsection shall be rejected, and the Capacity Market Seller shall be required to resubmit a Sell Offer that complies with such agreement or commitment within one (1) Business Day of the Office of the Interconnection's rejection of such Sell Offer. If the Capacity Market Seller does not timely resubmit its Sell Offer, fails to request a unit-specific Avoidable Cost Rate by the specified deadline, or if the Office of the Interconnection determines that the information provided by the Capacity Market Seller in support of the requested unit-specific Avoidable Cost Rate or Sell Offer is incomplete, the Capacity Market Seller shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default offer for the applicable class of resource or nearest comparable class of resource determined under this subsection (c)(ii). The obligation imposed under Tariff, Attachment DD, section 6.6(a) shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection or subject to the procedures set forth in Tariff, Attachment DD, section 6.4 and Tariff, Attachment M-Appendix, section II.H.

The default retirement and mothball Avoidable Cost Rates ("ACR") referenced in this subsection (c)(ii) are as set forth in the tables below for the 2013/2014 Delivery Year through the 2016/2017 Delivery Year. Capacity Market Sellers shall use the one-year mothball Avoidable Cost Rate shown below, unless such Capacity Market Seller satisfies the criteria set forth in Tariff, Attachment DD, section 6.7(e), in which case the Capacity Market Seller may use the retirement Avoidable Cost Rate. PJM shall also publish on its Web site the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates. A Capacity Market Seller may not use the default Market Seller Offer Cap contained in the ACR tables in this subsection, and also seek to include any one or more categories of the Avoidable Cost Rate defined Tariff, Attachment DD, section 6.8.

| Maximum Avoidable Cost Rates by Technology Class | | | | | | | | |
|---|--|--|--|--|--|--|--|--|
| Technology | 2013/14 Mothball ACR (\$/MW- Day) | 2013/14 Retirement ACR (\$/MW- Day) | 2014/15 Mothball ACR (\$/MW- Day) | 2014/15 Retirement ACR (\$/MW- Day) | 2015/16 Mothball ACR (\$/MW- Day) | 2015/16 Retirement ACR (\$/MW- Day) | 2016/2017 Mothball ACR (\$/MW- Day) | 2016/2017 Retirement ACR (\$/MW- Day) |

| | | | | | | | | |
|---|----------|----------|----------|----------|----------|----------|----------|----------|
| Nuclear | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Pumped Storage | \$23.64 | \$33.19 | \$24.56 | \$34.48 | \$25.56 | \$35.89 | \$24.05 | \$33.78 |
| Hydro | \$80.80 | \$105.67 | \$83.93 | \$109.76 | \$87.35 | \$114.24 | \$82.23 | \$107.55 |
| Sub-Critical Coal | \$193.98 | \$215.02 | \$201.49 | \$223.35 | \$209.71 | \$232.46 | \$197.43 | \$218.84 |
| Super Critical Coal | \$200.41 | \$219.21 | \$208.17 | \$227.70 | \$216.66 | \$236.99 | \$203.96 | \$223.10 |
| Waste Coal - Small | \$255.81 | \$309.83 | \$265.72 | \$321.83 | \$276.56 | \$334.96 | \$260.35 | \$315.34 |
| Waste Coal – Large | \$94.61 | \$114.29 | \$98.27 | \$118.72 | \$102.28 | \$123.56 | \$96.29 | \$116.32 |
| Wind | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| CC-2 on 1 Frame F | \$35.18 | \$49.90 | \$36.54 | \$51.83 | \$38.03 | \$53.94 | \$35.81 | \$50.79 |
| CC-3 on 1 Frame E/Siemens | \$39.06 | \$52.89 | \$40.57 | \$54.94 | \$42.23 | \$57.18 | \$39.75 | \$53.83 |
| CC–3 or More on 1 or More Frame F | \$30.46 | \$42.28 | \$31.64 | \$43.92 | \$32.93 | \$45.71 | \$30.99 | \$43.03 |
| CC-NUG Cogen. Frame B or E Technology | \$130.76 | \$175.71 | \$135.82 | \$182.52 | \$141.36 | \$189.97 | \$133.09 | \$178.83 |
| CT - 1st & 2nd Gen. Aero (P&W FT 4) | \$27.96 | \$37.19 | \$29.04 | \$38.63 | \$30.22 | \$40.21 | \$28.45 | \$37.85 |
| CT - 1st & Gen. Frame B | \$27.63 | \$36.87 | \$28.70 | \$38.30 | \$29.87 | \$39.86 | \$28.11 | \$37.52 |
| CT - 2nd Gen. Frame E | \$26.26 | \$35.14 | \$27.28 | \$36.50 | \$28.39 | \$37.99 | \$26.73 | \$35.77 |
| CT - 3rd Gen. Aero (GE LM 6000) | \$63.57 | \$93.70 | \$66.03 | \$97.33 | \$68.72 | \$101.30 | \$64.70 | \$95.37 |
| CT - 3rd Gen. Aero (P&W FT - 8 TwinPak) | \$33.34 | \$49.16 | \$34.63 | \$51.06 | \$36.04 | \$53.14 | \$33.93 | \$50.03 |
| CT - 3rd Gen. Frame F | \$26.96 | \$38.83 | \$28.00 | \$40.33 | \$29.14 | \$41.98 | \$27.43 | \$39.52 |
| Diesel | \$29.92 | \$37.98 | \$31.08 | \$39.45 | \$32.35 | \$41.06 | \$30.44 | \$38.66 |
| Oil and Gas Steam | \$74.20 | \$90.33 | \$77.07 | \$93.83 | \$80.21 | \$97.66 | \$75.51 | \$91.94 |

Commencing with the Base Residual Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall determine the default retirement and mothball Avoidable Cost Rates referenced in section (c)(ii) above, and post them on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the applicable ACR rates, the Office of the Interconnection shall use the actual rate of change in the historical values from the Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission (“Handy-Whitman Index”) to the extent they are available to update the base values for the Delivery Year, and for future Delivery Years for which the updated Handy-Whitman Index values are not yet available the Office of the Interconnection shall update the base values for the Delivery Year using the most recent ten-calendar-year annual average rate of change. The ACR rates shall be expressed in dollar values for the applicable Delivery Year.

| Maximum Avoidable Cost Rates by Technology Class (Expressed in 2011 Dollars for the 2011/2012 Delivery Year) | | |
|---|-------------------------------------|---------------------------------------|
| Technology | Mothball ACR (\$/MW-Day) | Retirement ACR (\$/MW-Day) |
| Combustion Turbine - Industrial Frame | \$24.13 | \$33.04 |
| Coal Fired | \$136.91 | \$157.83 |
| Combined Cycle | \$29.58 | \$40.69 |
| Combustion Turbine - Aero Derivative | \$26.13 | \$37.18 |
| Diesel | \$25.46 | \$32.33 |
| Hydro | \$68.78 | \$89.96 |
| Oil and Gas Steam | \$63.16 | \$76.90 |
| Pumped Storage | \$20.12 | \$28.26 |

To determine the default retirement and mothball ACR values for the 2017/2018 Delivery Year, the Office of the Interconnection shall multiply the base default retirement and mothball ACR values in the table above by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Indices for the 2011 to 2013 calendar years to determine updated base default retirement and mothball ACR values. The updated base default retirement and mothball ACR values shall then be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

To determine the default retirement and mothball ACR values for the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, the Office of the Interconnection shall multiply the updated base default retirement and mothball ACR values from the immediately preceding Delivery Year by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Index. These values become the new adjusted base default retirement and mothball ACR values, as calculated by the Office of the Interconnection and posted to its website. These resulting adjusted base values for the Delivery Year shall be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the

applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

PJM shall also publish on its website the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

After the Market Monitoring Unit conducts its annual review of the table of default Avoidable Cost Rates included in section 6.7(c) above in accordance with the procedure specified in Tariff, Attachment M-Appendix, section II.H, it will provide updated values or notice of its determination that updated values are not needed to Office of the Interconnection. In the event that the Office of the Interconnection determines that the values should be updated, the Office of the Interconnection shall file its proposed values with the Commission by no later than October 30th prior to the commencement of the offer period for the first RPM Auction for which it proposes to apply the updated values.

(d) In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection relevant unit-specific cost data concerning each data item specified as set forth in section 6 by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. If cost data is not available at the time of submission for the time periods specified in Tariff, Attachment DD, section 6.8, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used, as may be further specified in the PJM Manuals. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination pursuant to Tariff, Attachment M-Appendix, section II.E.

i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment.

ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate less the Projected Market Revenues for such resource (as defined in Tariff, Attachment DD, Section 6.4). The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost

Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(e) below.

iii. **Projected PJM Market Revenues:** Projected PJM Market Revenues are defined by Tariff, Attachment DD, section 6.8(d), for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

(e) In order for the retirement Avoidable Cost Rate set forth in the table in section 6.7(c) to apply, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction, a Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer representing that the Capacity Market Seller will retire the Generation Capacity Resource if it does not receive during the relevant Delivery Year at least the applicable retirement Avoidable Cost Rate because it would be uneconomic to continue to operate the Generation Capacity Resource in the Delivery Year without the retirement Avoidable Cost Rate, and specifying the date the Generation Capacity Resource would otherwise be retired.

6.8 Avoidable Cost Definition

(a) Avoidable Cost Rate:

The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer shall be determined using the following formula, expressed in dollars per MW-year:

$$\text{Avoidable Cost Rate} = [\text{Adjustment Factor} * (\text{AOML} + \text{AAE} + \text{AFAE} + \text{AME} + \text{AVE} + \text{ATFI} + \text{ACC} + \text{ACLE}) + \text{ARPIR} + \text{APIR} + \text{CPQR}]$$

Where:

- **Adjustment Factor** equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.
- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.
- **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit for twelve months preceding the month in which the data must be

provided. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

- **AFAE (Avoidable Fuel Availability Expenses)** consists of avoidable operating expenses related directly to fuel availability and delivery for the generating unit that can be demonstrated by the Capacity Market Seller based on data for the twelve months preceding the month in which the data must be provided , or on reasonable projections for the Delivery Year supported by executed contracts, published tariffs, or other data sufficient to demonstrate with reasonable certainty the level of costs that have been or shall be incurred for such purpose. The categories of expenses included in AFAE are those incurred for: (a) firm gas pipeline transportation; (b) natural gas storage costs; (c) costs of gas balancing agreements; and (d) costs of gas park and loan services. AFAE expenses are for firm fuel supply and apply solely for offers for a Capacity Performance Resource
- **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.
- **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.
- **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AFTI are those incurred for: (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site; and (d) property taxes.
- **ACC (Avoidable Carrying Charges)** consists of avoidable short-term carrying charges related directly to the generating unit in the twelve months preceding the month in which the data must be provided. Avoidable short-term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC,

short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services, (b) environmental reporting; and (c) procurement expenses.
- **CPQR (Capacity Performance Quantifiable Risk)** consists of the quantifiable and reasonably-supported costs of mitigating the risks of non-performance associated with submission of a Capacity Performance Resource offer (or of a Base Capacity Resource offer for the 2018/19 or 2019/20 Delivery Years), such as insurance expenses associated with resource non-performance risks. CPQR shall be considered reasonably supported if it is based on actuarial practices generally used by the industry to model or value risk and if it is based on actuarial practices used by the Capacity Market Seller to model or value risk in other aspects of the Capacity Market Seller's business. Such reasonable support shall also include an officer certification that the modeling and valuation of the CPQR was developed in accord with such practices. Provision of such reasonable support shall be sufficient to establish the CPQR. A Capacity Market Seller may use other methods or forms of support for its proposed CPQR that shows the CPQR is limited to risks the seller faces from committing a Capacity Resource hereunder, that quantifies the costs of mitigating such risks, and that includes supporting documentation (which may include an officer certification) for the identification of such risks and quantification of such costs. Such showing shall establish the proposed CPQR upon acceptance by the Office of the Interconnection.
- **APIR (Avoidable Project Investment Recovery Rate) = $PI * CRF$**

Where:

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

- **CRF** is the annual capital recovery factor from the following table, applied in accordance with the terms specified below.

| Age of Existing Units (Years) | Remaining Life of Plant (Years) | Levelized CRF |
|-------------------------------|---------------------------------|---------------|
| 1 to 5 | 30 | 0.107 |
| 6 to 10 | 25 | 0.114 |
| 11 to 15 | 20 | 0.125 |
| 16 to 20 | 15 | 0.146 |
| 21 to 25 | 10 | 0.198 |
| 25 Plus | 5 | 0.363 |
| Mandatory CapEx | 4 | 0.450 |
| 40 Plus Alternative | 1 | 1.100 |

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the 25 Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment.

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the

APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource (“rebate payment”); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other Existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of \$10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third Base Residual Auction (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds \$200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant Base Residual Auction.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the Mandatory CapEx option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third Base Residual Auction (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant Base Residual Auction (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Part V of the PJM Tariff. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 Plus Alternative option will be modeled in the RTEP process as “at-risk” at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the 40 Plus Alternative option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Multi-Year Pricing Option

A Seller submitting a Sell Offer with an APIR component that is based on a Project Investment of at least \$450/kW may elect this Multi-Year Pricing Option by providing written notice to such effect the first time it submits a Sell Offer that includes an APIR component for such Project Investment. Such option shall be available on the same terms, and under the same conditions, as are available to Planned Generation Capacity Resources under Tariff, Attachment DD, section 5.14(c).

- **ARPIR (Avoidable Refunds of Project Investment Reimbursements)** consists of avoidable refund amounts of Project Investment Reimbursements payable by a Generation Owner to PJM under Tariff, Part V, section 118 or avoidable refund amounts of project investment reimbursements payable by a Generation Owner to PJM under a Cost of Service Recovery Rate filed under Tariff, Part V, section 119 and approved by the Commission.

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

(c) For the purpose of determining an Avoidable Cost Rate, avoidable expenses shall exclude variable costs recoverable under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market under the Operating Agreement.

(d) Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of energy and ancillary services market offers for such resource. Net energy market revenues shall be based on the non-zero market-based offers of the Capacity Market Seller of such Generation Capacity Resource unless one of the following conditions is met, in which case the cost-based offer shall be used: (x) the market-based offer for the resource is zero, (y) the market-based offer for the resource is higher than its cost-based offer and such offer has been mitigated, or (z) the market-based offer for the resource is less than such Capacity Market Seller's fuel and environmental costs for the resource which shall be determined either

by directly summing the fuel and environmental costs if they are available, or by subtracting from the cost-based offer for the resource all costs developed pursuant to the Operating Agreement and PJM Manuals that are not fuel or environmental costs.

The calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the Base Residual Auction is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, or if data is not available to the Capacity Market Seller for the entire period, despite the good faith efforts of such seller to obtain such data, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

8. CAPACITY RESOURCE DEFICIENCY CHARGE

8.1

A Capacity Resource Deficiency Charge shall be assessed on any Capacity Market Seller that commits a Capacity Resource, and on any Locational UCAP Seller that sells Locational UCAP for a Delivery Year based on a Generation Capacity Resource, for a Delivery Year that is unable or unavailable to deliver Unforced Capacity for all or any part of such Delivery Year for any reason, including but not limited to the following, and that does not obtain replacement Unforced Capacity meeting the same locational requirements and same or better temporal availability characteristics (i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource) in the megawatt quantity required to satisfy the capacity committed from such resource by such seller as a result of all cleared Sell Offers from such seller based on such resource in any RPM Auctions for such Delivery Year, the reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and the increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource:

a) Unit Derating – Such Capacity Resource is a Generation Capacity Resource and its capacity value is derated prior to or during the Delivery Year;

b) EFORD Increase – Such Capacity Resource is a Generation Capacity Resource and the EFORD value determined for such resource at least two (2) months prior to the Third or Final Incremental Auction is higher than the EFORD value submitted in the Capacity Market Seller's cleared Sell Offer;

c) External Generation Resource – Such Capacity Resource is an Existing Generation Capacity Resource that is located outside of the PJM Control Area and arrangements for the firm delivery of the output of such resource to the interface with the PJM Region are not in place for such resource prior to the start of the Delivery Year;

d) Planned Generation Resource – Such Capacity Resource is a Planned Generation Capacity Resource and Interconnection Service has not commenced as to such resource prior to the start of the Delivery Year;

e) Planned Demand Resource - Such Capacity Resource is a Planned Demand Resource or an Energy Efficiency Resource and the associated demand response program or energy efficiency measure is not installed prior to the start of the Delivery Year; or

f) Existing Demand Resource – Such Capacity Resource is an existing Demand Resource or Energy Efficiency Resource and, subject to Tariff, Attachment DD, section 8.4, is not capable of providing the megawatt quantity of load response specified in the cleared Sell Offer for the time periods of availability associated with the product type.

8.2. Capacity Resource Deficiency Charge

The Capacity Resource Deficiency Charge shall equal the Daily Deficiency Rate (as defined in section 7) multiplied by the megawatt quantity of deficiency below the level of capacity committed in such Capacity Market Seller's Sell Offer(s) or bilateral capacity commitments, or Locational UCAP Seller's Locational UCAP sale for each day such seller is deficient, provided, however, that a resource that is subject to a charge under this section that is also subject to a charge under Tariff, Attachment DD, section 10A hereof for a Performance Shortfall during one or more Performance Assessment *Intervals* occurring during the period of resource deficiency addressed by this section shall be assessed a charge equal to the greater of the charge determined under this section and the charge determined under Tariff, Attachment DD, section 10A, but shall not be assessed a charge under both this section and Tariff, Attachment DD, section 10A for such simultaneous occurrence of a resource deficiency and Performance Shortfall.

8.3. Allocation of Revenue Collected from Capacity Resource Deficiency Charges

The revenue collected from the assessment of a Capacity Resource Deficiency Charge shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which such Capacity Resource Deficiency Charge was assessed. Such revenues shall be distributed on a pro-rata basis to such LSEs based on their Daily Unforced Capacity Obligations.

8.4 Relief from Charges

A Capacity Market Seller or Locational UCAP Seller that is otherwise subject to the Capacity Resource Deficiency Charge solely as a result of Tariff, Attachment DD, section 8.1(f) may receive relief from such Charge if it demonstrates that the inability to provide the level of demand response specified in its Sell Offer is due to the permanent departure (due to plant closure, efficiency gains, or similar reasons) from the Transmission System of load that was relied upon for load response in such Sell Offer; provided, however, that such seller 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. Such seller shall receive no RPM Auction Credit for the amount of reduction in the committed Existing Demand Resources.

Section(s) of the
PJM Reliability Assurance Agreement
(Clean Format)

ARTICLE 1 – DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto, or in the PJM Tariff or PJM Operating Agreement if not otherwise defined in this Agreement, for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

Agreement:

“Agreement” shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

Annual Demand Resource:

“Annual Demand Resource” shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Annual Energy Efficiency Resource:

“Annual Energy Efficiency Resource” shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer and winter periods described in such Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Applicable Regional Entity:

“Applicable Regional Entity” shall have the same meaning as in the PJM Tariff.

Base Capacity Demand Resource:

“Base Capacity Demand Resource” shall mean, for the 2018/2019 and 2019/2020 Delivery

Years, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through September of a Delivery Year, and will be available to the Office of the Interconnection for an unlimited number of interruptions during such months, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Base Capacity Demand Resource must be available June through September in the corresponding Delivery Year to be offered for sale or self-supplied in an RPM Auction, or included as a Base Capacity Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Base Capacity Energy Efficiency Resource:

“Base Capacity Energy Efficiency Resource” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of the Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Base Capacity Resource:

“Base Capacity Resource” shall have the same meaning as in Tariff, Attachment DD.

Base Residual Auction:

“Base Residual Auction” shall have the same meaning as in Tariff, Attachment DD.

Behind The Meter Generation:

“Behind The Meter Generation” shall mean a generating 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 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 Capacity Resource or (ii) in any 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 Capability:

“Black Start Capability” shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

Capacity Emergency Transfer Objective (CETO):

“Capacity Emergency Transfer Objective” or “CETO” shall mean the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be calculated based in part on EFORD determined in accordance with Reliability Assurance Agreement, Schedule 5, Paragraph C.

Capacity Emergency Transfer Limit (CETL):

Capacity Emergency Transfer Limit” or “CETL” shall mean the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity Import Limit:

For any Delivery Year up to and including the 2019/2020 Delivery Year, “Capacity Import Limit” shall mean, (a) for the PJM Region, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines for each Delivery Year, through appropriate modeling and the application of engineering judgment, the transmission system can receive, in aggregate at the interface of the PJM Region with all external balancing authority areas and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus (2) the then-applicable Capacity Benefit Margin; and (b) for certain source zones identified in the PJM manuals as groupings of one or more balancing authority areas, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines the transmission system can receive at the interface of the PJM Region with each such source zone and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus the then-applicable Capacity Benefit Margin times (2) the ratio of the maximum import quantity from each such source zone divided by the PJM total maximum import quantity. As more fully set forth in the PJM Manuals, PJM shall make such determination based on the latest peak load forecast for the studied period, the same computer simulation model of loads, generation and transmission topography employed in the determination of Capacity Emergency Transfer Limit for such Delivery Year, including external facilities from an industry standard model of the loads, generation, and transmission topography of the Eastern Interconnection under peak conditions. PJM shall specify in the PJM Manuals the areas and minimum distribution factors for identifying monitored bulk electric system facilities that have an electrically significant response to such transfers on the PJM interface. Employing such tools, PJM shall model increased power transfers from external areas into PJM to determine the transfer level at which one or more reliability criteria is violated on any monitored bulk electric system facilities that have an electrically significant response to such transfers. For the

PJM Region Capacity Import Limit, PJM shall optimize transfers from other source areas not experiencing any reliability criteria violations as appropriate to increase the Capacity Import Limit. The aggregate megawatt quantity of transfers into PJM at the point where any increase in transfers on the interface would violate reliability criteria will establish the Capacity Import Limit. Notwithstanding the foregoing, a Capacity Resource located outside the PJM Region shall not be subject to the Capacity Import Limit if the Capacity Market Seller seeks an exception thereto by demonstrating to PJM, by no later than five (5) business days prior to the commencement of the offer period for the relevant RPM Auction, that such resource meets all of the following requirements:

(i) it has, at the time such exception is requested, met all applicable requirements to be pseudo-tied into the PJM Region, or the Capacity Market Seller has committed in writing that it will meet such requirements, unless prevented from doing so by circumstances beyond the control of the Capacity Market Seller, prior to the relevant Delivery Year;

(ii) at the time such exception is requested, it has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and

(iii) it 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; provided, however, that (a) the total megawatt quantity of all exceptions granted hereunder for a Delivery Year, plus the Capacity Import Limit for the applicable interface determined for such Delivery Year, may not exceed the total megawatt quantity of Network External Designated Transmission Service on such interface that PJM has confirmed for such Delivery Year; and (b) if granting a qualified exception would result in a violation of the rule in clause (a), PJM shall grant the requested exception but reduce the Capacity Import Limit by the quantity necessary to ensure that the total quantity of Network External Designated Transmission Service is not exceeded.

Capacity Performance Resource:

“Capacity Performance Resource” shall have the same meaning as in Tariff, Attachment DD.

Capacity Resources:

“Capacity Resources” shall mean megawatts of (i) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources meeting the requirements of the Reliability Assurance Agreement, Schedules 9 and 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under the Reliability Assurance Agreement, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in such Schedules 9 and 10; and (iii) load reduction capability provided by Demand Resources or Energy Efficiency Resources that are accredited to the PJM Region pursuant to the procedures set forth in the Reliability Assurance Agreement, Schedule 6.

Capacity Transfer Right:

“Capacity Transfer Right” shall have the meaning specified in Tariff, Attachment DD.

Compliance Aggregation Area (CAA):

“Compliance Aggregation Area” or “CAA” shall have the same meaning as in the Tariff.

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 generation control scheme is applied in order to:

(a) 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);

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

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

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

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 the Reliability Assurance Agreement, Schedule 8 or, as to an FRR Entity, in the Reliability Assurance Agreement, Schedule 8.1.

Delivery Year:

“Delivery Year” shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, section 5 or pursuant to an FRR Capacity Plan.

Demand Resource (DR):

“Demand Resource” or “DR” shall mean a Limited Demand Resource, Extended Summer Demand Resource, Annual Demand Resource, Base Capacity Demand Resource or Summer-Period Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of the Reliability Assurance Agreement, Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan.

Demand Resource Officer Certification Form:

“Demand Resource Officer Certification Form” shall mean a certification as to an intended Demand Resource Sell Offer, in accordance with the Reliability Assurance Agreement, Schedules 6 and 8.1 and the PJM Manuals.

Demand Resource Sell Offer Plan:

“Demand Resource Sell Offer Plan” shall mean the plan required by the Reliability Assurance Agreement, Schedules 6 and 8.1 in support of an intended offer of Demand Resources in an RPM Auction, or an intended inclusion of Demand Resources in an FRR Capacity Plan.

Demand Resource Factor or DR Factor:

“Demand Resource Factor” or “DR Factor” shall mean, for Delivery Years through May 31, 2018, that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource in accordance with the Reliability Assurance Agreement, Schedule 6.

Electric Cooperative:

“Electric Cooperative” shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

Electric Distributor:

“Electric Distributor” shall mean a Member that 1) owns or leases with rights equivalent to ownership of electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to the electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Emergency:

“Emergency” shall mean (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of

system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

End-Use Customer:

“End-Use Customer” shall mean a Member that is a retail end-user of electricity within the PJM Region.

Energy Efficiency Resource:

“Energy Efficiency Resource” shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of the Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the periods described in the Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention. Annual Energy Efficiency Resources, Base Capacity Energy Efficiency Resources and Summer-Period Energy Efficiency Resources are types of Energy Efficiency Resources.

Existing Demand Resource:

“Existing Demand Resource” shall mean a Demand Resource for which the Demand Resource Provider has identified existing end-use customer sites that are registered for the current Delivery Year with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such resource is offered.

Existing Generation Capacity Resource:

“Existing Generation Capacity Resource” shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as

those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

Extended Summer Demand Resource:

“Extended Summer Demand Resource” shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Facilities Study Agreement:

“Facilities Study Agreement” shall have the same meaning as in the PJM Tariff

FERC:

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

Firm Point-To-Point Transmission Service:

“Firm Point-To-Point Transmission Service” shall mean Firm Transmission Service provided pursuant to the rates, terms and conditions set forth in Tariff, Part II.

Firm Transmission Service:

“Firm Transmission Service” shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

Fixed Resource Requirement Alternative or FRR Alternative:

“Fixed Resource Requirement Alternative” or “FRR Alternative” shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in the Reliability Assurance Agreement, Schedule 8.1.

Forecast Pool Requirement:

“Forecast Pool Requirement” or “FPR” shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Reliability Assurance Agreement, as approved by the PJM Board pursuant to Reliability Assurance Agreement, Schedule 4.1.

FRR Capacity Plan or FRR Plan:

“FRR Capacity Plan” or “FRR Plan” shall mean a long-term plan for the commitment of Capacity Resources to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in the Reliability Assurance Agreement, Schedule 8.1.

FRR Entity:

“FRR Entity” shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

FRR Service Area:

“FRR Service Area” shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

Full Requirements Service:

“Full Requirements Service” shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Generation Capacity Resource:

“Generation Capacity Resource” shall mean a generation unit, or the contractual right to capacity from a specified generation unit, that meets the requirements of Schedules 9 and 10 of this Agreement, and, for generation units that are committed to an FRR Capacity Plan, that meets the

requirements of Schedule 8.1 of this Agreement. A Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity Resource.

Generation Owner:

“Generation Owner” shall mean a Member that owns or leases with rights equivalent to ownership, facilities for the generation of electric energy that are located within the PJM Region. Purchasing all or a portion of the output of a generation facility shall not be sufficient to qualify a Member as a Generation Owner.

Generator Forced Outage:

“Generator Forced Outage” shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

Generator Maintenance Outage:

“Generator Maintenance Outage” shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

Generator Planned Outage:

“Generator Planned Outage” shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

Good Utility Practice:

“Good Utility Practice” shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region; including those practices required by Federal Power Act Section 215(a)(4).

Incremental Auction:

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

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

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

IOU:

“IOU” shall mean an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

Limited Demand Resource:

“Limited Demand Resource” shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 Load Management Events during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Load Serving Entity or LSE:

“Load Serving Entity” or “LSE” shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a

utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

Locational Reliability Charge:

“Locational Reliability Charge” shall mean the charge determined pursuant to Operating Agreement, Schedule 8.

Markets and Reliability Committee:

“Markets and Reliability Committee” shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

Maximum Emergency Service Level:

“Maximum Emergency Service Level” or “MESL” of Price Responsive Demand shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when a Maximum Generation Emergency is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan.

Member:

“Member” shall mean an entity that satisfies the requirements of Operating Agreement, sections 1.24 and 11.6. In accordance with the Reliability Assurance Agreement, Article 4, each Party to this Agreement also is a Member.

Members Committee:

“Members Committee” shall mean the committee specified in Operating Agreement, section 8 composed of the representatives of all the Members.

NERC:

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

Network External Designated Transmission Service:

“Network External Designated Transmission Service” shall mean the quantity of network transmission service confirmed by PJM for use by a market participant to import power and energy from an identified Generation Capacity Resource located outside the PJM Region, upon demonstration by such market participant that it owns such Generation Capacity Resource, has an executed contract to purchase power and energy from such Generation Capacity Resource, or has a contract to purchase power and energy from such Generation Capacity Resource contingent upon securing firm transmission service from such resource.

Network Resources:

“Network Resources” shall have the meaning set forth in the PJM Tariff.

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 (as that term is defined in the PJM Tariff).

Nominal PRD Value:

“Nominal PRD Value” shall mean, as to any PRD Provider, an adjustment, determined in accordance with Operating Agreement, Schedule 6.1, to the peak-load forecast used to determine the quantity of capacity sought through an RPM Auction, reflecting the aggregate effect of Price Responsive Demand on peak load resulting from the Price Responsive Demand to be provided by such PRD Provider.

Nominated Demand Resource Value:

“Nominated Demand Resource Value” shall have the meaning specified in Tariff, Attachment DD.

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, and electric distribution companies to serve load.

Obligation Peak Load:

“Obligation Peak Load” shall have the meaning specified in Operating Agreement, Schedule 8.

Office of the Interconnection:

“Office of the Interconnection” shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Operating Agreement of the PJM Interconnection, L.L.C. or Operating Agreement:

“Operating Agreement of the PJM Interconnection, L.L.C.” or “Operating Agreement” shall mean that Agreement, dated as of April 1, 1997 and as amended and restated as of June 2, 1997,

including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C.

Operating Day:

“Operating Day” shall have the same meaning as provided in the Operating Agreement.

Operating Reserve:

“Operating Reserve” shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Other Supplier:

“Other Supplier” shall mean a Member that is (i) a seller, buyer or transmitter of electric capacity or energy in, from or through the PJM Region, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

Partial Requirements Service:

“Partial Requirements Service” shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Performance Assessment *Interval*:

“Performance Assessment *Interval*” shall have the meaning specified in Attachment DD of the PJM Tariff.

Percentage Internal Resources Required:

“Percentage Internal Resources Required” shall mean, for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in such LDA.

Party:

“Party” shall mean an entity bound by the terms of the Operating Agreement.

PJM:

“PJM” shall mean the PJM Board and the Office of the Interconnection.

PJM Board:

“PJM Board” shall mean the Board of Managers of the PJM Interconnection, L.L.C., acting pursuant to the Operating Agreement.

PJM Manuals:

“PJM Manuals” shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

PJM Tariff (Tariff):

“PJM Tariff” or “Tariff” shall mean that certain “PJM Open Access Transmission Tariff, including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

PJM Region:

“PJM Region” shall have the same meaning as provided in the Operating Agreement.

PJM Region Installed Reserve Margin:

“PJM Region Installed Reserve Margin” shall mean the percent installed reserve margin for the PJM Region required pursuant to the Operating Agreement, as approved by the PJM Board pursuant to Operating Agreement, Schedule 4.1.

Planned Demand Resource:

“Planned Demand Resource” shall mean any Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Operating Agreement, Schedule 6. As set forth in Operating Agreement, Schedules 6 and 8.1, a Demand Resource Provider submitting a DR Sell Offer Plan shall identify as Planned Demand Resources in such plan all Demand Resources in excess of those that qualify as Existing Demand Resources.

Planned External Generation Capacity Resource:

“Planned External Generation Capacity Resource” shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery

Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Base Residual Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has a fully executed system impact study agreement (or other documentation which is functionally equivalent to a System Impact Study Agreement under the PJM Tariff) or, for resources which are greater than 20MWs participating in a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, an agreement or other documentation which is functionally equivalent to a Facilities Study Agreement under the PJM Tariff), with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. Prior to participating in any Incremental Auction for such Delivery Year, the Capacity Market Seller must demonstrate it has entered into an interconnection agreement, or such other documentation that is functionally equivalent to an Interconnection Service Agreement under the PJM Tariff, with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to be delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. Any such resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

Planned Generation Capacity Resource:

“Planned Generation Capacity Resource” shall mean a Generation Capacity Resource, or additional megawatts to increase the size of a Generation Capacity Resource that is being or has been modified to increase the number of megawatts of available installed capacity thereof, participating in the generation interconnection process under Tariff, Part IV, Subpart A, as applicable, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Capacity Plan; (ii) for any such resource seeking to offer into a Base Residual Auction, or for any such resource of 20 MWs or less seeking to offer into a Base Residual Auction, a System Impact Study Agreement (or, for resources for which a System Impact Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a System Impact Study Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; (iii) for any such resource of more than 20 MWs seeking to offer into a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, a Facilities Study Agreement (or, for resources for which a Facilities Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a Facility Studies Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; (iv) an Interconnection Service Agreement has been executed prior to any Incremental Auction for

such Delivery Year in which such resource plans to participate; and (iv) no megawatts of capacity have cleared an RPM Auction for any prior Delivery Year. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years.

Planning Period:

“Planning Period” shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

PRD Curve:

“PRD Curve” shall mean a price-consumption curve at a PRD Substation level, if available, and otherwise at a Zonal (or sub-Zonal LDA, if applicable) level, that details the base consumption level of Price Responsive Demand and the decreasing consumption levels at increasing prices.

PRD Provider:

“PRD Provider” shall mean (i) a Load Serving Entity that provides PRD; or (ii) an entity without direct load serving responsibilities that has entered contractual arrangements with end-use customers served by a Load Serving Entity that satisfy the eligibility criteria for Price Responsive Demand.

PRD Provider’s Zonal Expected Peak Load Value of PRD:

“PRD Provider’s Zonal Expected Peak Load Value of PRD” shall mean the expected contribution to Delivery Year peak load of a PRD Provider’s Price Responsive Demand, were such demand not to be reduced in response to price, based on the contribution of the end-use customers comprising such Price Responsive Demand to the most recent prior Delivery Year’s peak demand, escalated to the Delivery Year in question, as determined in a manner consistent with the Office of the Interconnection’s load forecasts used for purposes of the RPM Auctions.

PRD Reservation Price:

“PRD Reservation Price” shall mean an RPM Auction clearing price identified in a PRD Plan for Price Responsive Demand load below which the PRD Provider desires not to commit the identified load as Price Responsive Demand.

PRD Substation:

“PRD Substation” shall mean an electrical substation that is located in the same Zone or in the same sub-Zonal LDA as the end-use customers identified in a PRD Plan or PRD registration and

that, in terms of the electrical topography of the Transmission Facilities comprising the PJM Region, is as close as practicable to such loads.

Price Responsive Demand:

“Price Responsive Demand” or “PRD” shall mean end-use customer load registered by a PRD Provider pursuant to Schedule 6.1 of the PJM Reliability Assurance Agreement that have, as set forth in more detail in the PJM Manuals, the metering capability to record electricity consumption at an interval of one hour or less, Supervisory Control capable of curtailing such load (consistent with applicable RERRA requirements) at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection, and a retail rate structure, or equivalent contractual arrangement, capable of changing retail rates as frequently as an hourly basis, that is linked to or based upon changes in real-time Locational Marginal Prices at a PRD Substation level and that results in a predictable automated response to varying wholesale electricity prices.

Price Responsive Demand Credit:

“Price Responsive Demand Credit” shall mean a credit, based on committed Price Responsive Demand, as determined under Operating Agreement, Schedule 6.1.

Price Responsive Demand Plan or PRD Plan:

“Price Responsive Demand Plan” or “PRD Plan” shall mean a plan, submitted by a PRD Provider and received by the Office of the Interconnection in accordance with Operating Agreement, Schedule 6.1 and procedures specified in the PJM Manuals, claiming a peak demand limitation due to Price Responsive Demand to support the determination of such PRD Provider’s Nominal PRD Value.

Public Power Entity:

“Public Power Entity” shall mean any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

Qualifying Transmission Upgrades:

“Qualifying Transmission Upgrades” shall have the meaning specified in Attachment DD to the PJM Tariff.

Relevant Electric Retail Regulatory Authority:

“Relevant Electric Retail Regulatory Authority” or “RERRA” shall have the meaning specified in the PJM Operating Agreement.

Reliability Principles and Standards:

“Reliability Principles and Standards” shall mean the principles and standards established by NERC or an Applicable Regional Entity to define, among other things, an acceptable probability of loss of load due to inadequate generation or transmission capability, as amended from time to time.

Required Approvals:

“Required Approvals” shall mean all of the approvals required for the Operating Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of the Operating Agreement.

Self-Supply:

“Self-Supply” shall have the meaning provided in Tariff, Attachment DD.

Small Commercial Customer:

“Small Commercial Customer” shall have the same meaning as in the PJM Tariff.

State Consumer Advocate:

“State Consumer Advocate” shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Regulatory Structural Change:

“State Regulatory Structural Change” shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party’s default service rules that materially affect whether retail choice is economically viable.

Summer-Period Demand Resource:

Summer-Period Demand Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a resource that is placed under the direction of the Office of the Interconnection, and will be available June through October and the following May of the Delivery Year, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Summer-Period Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale in an RPM Auction, or included as a Summer-Period Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Summer-Period Energy Efficiency Resource:

Summer-Period Energy Efficiency Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Schedule 6 of this Agreement and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Summer-Period Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Supervisory Control:

“Supervisory Control” shall mean the capability to curtail, in accordance with applicable RERRA requirements, load registered as Price Responsive Demand at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection. Except to the extent automation is not required by the provisions of the Operating Agreement, the curtailment shall be automated, meaning that load shall be reduced automatically in response to control signals sent by the PRD Provider or its designated agent directly to the control equipment where the load is located without the requirement for any action by the end-use customer.

Threshold Quantity:

“Threshold Quantity” shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity’s Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base FRR Scaling Factor (as determined in accordance with Operating Agreement, Schedule 8.1).

Transmission Facilities:

“Transmission Facilities” shall mean facilities that: (i) are within the PJM Region; (ii) 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; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Owner:

“Transmission Owner” shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owners Agreement:

“Transmission Owners Agreement” shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005 and as amended from time to time, among transmission owners within the PJM Region.

Unforced Capacity:

“Unforced Capacity” shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

Winter Peak Load (or WPL):

“Winter Peak Load” or “WPL” shall mean the Demand Resource customer specific peak load between hour ending 7:00 EPT through 21:00 EPT on the PJM defined 5 coincident peak days from December through February two Delivery Years prior the Delivery Year for which the registration is submitted and as outlined in the PJM Manuals.

Zonal Capacity Price:

“Zonal Capacity Price” shall mean the price of Unforced Capacity in a Zone that an LSE that has not elected the FRR Alternative is obligated to pay for a Delivery Year as determined pursuant to Attachment DD to the PJM Tariff.

Zone or Zonal:

“Zone” or “Zonal” shall refer to an area within the PJM Region, as set forth in Operating Agreement, Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A

Zone shall include any Non-Zone Network Load (as defined in the PJM Tariff) located outside the PJM Region that is served from such Zone under Schedule H-A of the PJM Tariff.

Zonal Winter Weather Adjustment Factor (ZWWAF):

“Zonal Winter Weather Adjustment Factor” or “ZWWAF” shall mean the PJM zonal winter weather normalized coincident peak divided by PJM zonal average of 5 coincident peak loads in December through February.

SCHEDULE 5

FORCED OUTAGE RATE CALCULATION

- A. The equivalent demand forced outage rate ("EFOR_D") shall be calculated as follows:

$$\text{EFOR}_D (\%) = \{(f_f * \text{FOH} + f_p * \text{EFPOH}) / (\text{SH} + f_f * \text{FOH})\} * 100$$

where

f_f = full outage factor

f_p = partial outage factor

FOH = full forced outage hours

EFPOH = equivalent forced partial outage hours

SH = service hours

- B. Calculation of EFOR_D for individual Generation Capacity Resources.

For each Delivery Year, EFOR_D shall be calculated at least one month prior to the start of the Third or Final Incremental Auction, as applicable for: (i) each Generation Capacity Resource for which a sell offer will be submitted in such Third or Final Incremental Auction, as applicable; and (ii) each Generation Capacity Resource previously committed to serve load in such Delivery Year pursuant to an FRR Capacity Plan or prior auctions for such Delivery Year. Such calculation shall be based upon such resource's service history in the twelve (12) consecutive months ending September 30 last preceding such auction. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments approved by the Members Committee to adjust the parameters of a designated unit. For purposes of the calculations under this Paragraph B, for Delivery Years through May 31, 2018, outages deemed to be outside plant management control in accordance with NERC guidelines shall not be considered, and for the 2018/2019 Delivery Year and all subsequent Delivery Years, outages deemed to be outside plant management control in accordance with NERC guidelines shall be considered.

1. The EFOR_D of a unit in service twelve or more full calendar months prior to the calculation month shall be the average rate experienced by such unit during the twelve-month period specified above. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.
2. The EFOR_D of a unit in service at least one full calendar month but less than the twelve-month period specified above shall be the average of the EFOR_D experienced by the unit weighted by full months of service, and the class average rate for units with that capability and of that type weighted by a factor of [(twelve) minus (the number of months the unit was in service)]. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

C. Calculation of average EFOR_D for the PJM Region

The forecast average EFOR_D for the PJM Region in a Delivery Year shall be the average of the forced outage rates, weighted for unit capability and expected time in service, attributable to all of the Generation Capacity Resources within the PJM Region, that are planned to be in service during the Delivery Year, including Generation Capacity Resources purchased from specified units and excluding Generation Capacity Resources sold outside the PJM Region from specified units. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments developed by the Office of Interconnection and maintained in the PJM Manuals to adjust the parameters of a designated unit when such parameters are or will be used to determine a future PJM Region reserve requirement and such adjustment is required to more accurately predict the future performance of such unit in light of extraordinary circumstances. For the purposes of this Schedule, the average EFOR_D shall be the average of the capacity-weighted EFOR_Ds of all units committed to serve load in the PJM Region; and for purposes of the EFOR_D calculations under this Paragraph C for any Delivery Year beginning after May 31, 2010, outages deemed to be outside plant management control in accordance with NERC guidelines shall not be considered, and for the 2018/2019 Delivery Year and all subsequent Delivery Years, outages deemed to be outside plant management control in accordance with NERC guidelines shall be considered. All rates shall be in percent.

1. The EFOR_D of a unit not yet in service or which has been in service less than one full calendar year at the time of forecast shall be the class average rate for units with that capability and of that type, as estimated and used in the calculation of the Forecast Pool Requirement.
2. The EFOR_D of a unit in service five or more full calendar years at the time of forecast shall be the average rate experienced by such unit during the five most recent calendar years. Historical data shall be based on official reports of the Parties under rules and practices developed by the Office of Interconnection and maintained in the PJM Manuals.
3. The EFOR_D of a unit in service at least one full calendar year but less than five full calendar years at the time of the forecast shall be determined as follows:

Full Calendar
Years of Service

- | | |
|---|--|
| 1 | One-fifth the rate experienced during the calendar year, plus four-fifths the class average rate. |
| 2 | Two-fifths the average rate experienced during the two calendar years, plus three-fifths the class average rate. |

- 3 Three-fifths the average rate experienced during the three calendar years, plus two-fifths the class average rate.
- 4 Four-fifths the average rate experienced during the four calendar years, plus one-fifth the class average rate.

SCHEDULE 6.1

PRICE RESPONSIVE DEMAND

A. As more fully set forth in this Schedule 6.1 and the PJM Manuals, for any Delivery Year beginning on or after June 1, 2015 (subject to a transition plan, as set forth below), any PRD Provider, including any FRR Entity, may commit that certain loads identified by such PRD Provider shall not exceed a specified demand level at specified prices during Maximum Generation Emergencies, as a consequence of the implementation of Price Responsive Demand. Based on information provided by the PRD Provider in a PRD Plan (and, to the extent such plan identifies a PRD Reservation Price, based on the clearing price in the Base Residual Auction or Third Incremental Auction, or Final Incremental Auction, as applicable), the Office of the Interconnection shall determine the Nominal PRD Value for the specified loads identified by such PRD Provider by Zone (or sub-Zonal LDA, if applicable). The Office of the Interconnection shall adjust the PJM Region Reliability Requirement and LDA Reliability Requirements, as applicable, to reflect committed PRD. Actual PRD reductions in response to price shall be added back in determining peak load contributions. Any PRD Provider that fails fully to honor its PRD commitments for a Delivery Year shall be assessed compliance charges.

B. End-use customer loads identified in a PRD Plan or PRD registration for a Delivery Year as Price Responsive Demand may not, for such Delivery Year, (i) be registered as Economic Load Response, Pre-Emergency Load Response or Emergency Load Response; (ii) be used as the basis of any Demand Resource Sell Offer or Energy Efficiency Resource Sell Offer in any RPM Auction; or (iii) be identified in a PRD Plan or PRD registration of any other PRD Provider.

C. Any PRD Provider seeking to commit PRD hereunder for a Delivery Year must submit to the Office of the Interconnection a PRD Plan identifying and supporting the Nominal PRD Value (calculated as the difference between the PRD Provider's Zonal Expected Peak Load Value of PRD and the Maximum Emergency Service Level of Price Responsive Demand) for each Zone (or sub-Zonal LDA, if applicable) for which such PRD is committed; such information shall be provided on a PRD Substation level to the extent available at the time the PRD Plan is submitted. Such plan must be submitted no later than the January 15 last preceding the Base Residual Auction for the Delivery Year for which such PRD is committed; any submitted plan that does not contain, by such January 15, all information required hereunder shall be rejected. A PRD Provider may submit a PRD Plan, or a modified PRD Plan, by the January 15 last preceding the Third or Final Incremental Auction, as applicable for such Delivery Year requesting approval of additional Price Responsive Demand but only in the event, and to the extent, that the final peak load forecast for the relevant LDA for such Delivery Year exceeds the preliminary peak load forecast for such LDA and Delivery Year. The Office of the Interconnection shall revise such requests (as adjusted, to the extent a PRD Reservation Price is specified, for the results of the Third or Final Incremental Auction, as applicable) for additional Price Responsive Demand downward, in accordance with rules in the PJM Manuals, if the submitted requests (as adjusted) in the aggregate exceed the increase in the load forecast in the LDA modeled. The Office of the Interconnection shall advise the PRD Provider, following the Third or Final Incremental

Auction, of its acceptance of, or any downward adjustment to, the Nominal PRD Value based on its review of the PRD Plan and the results of the auction. Approval of the PRD Plan by the Office of the Interconnection shall establish a firm commitment by the PRD Provider to the specified Nominal PRD Value of Price Responsive Demand at each Zone (or sub-Zonal LDA, if applicable) during the relevant Delivery Year (subject to any PRD Reservation Price), and may not be uncommitted or replaced by any Capacity Resource. Although the PRD Plan may include reasonably supported forecasts and expectations concerning the development of Price Responsive Demand for a Delivery Year, the PRD Provider's commitment to a Nominal PRD Value for such Delivery Year shall not depend or be conditioned upon realization of such forecasts or expectations.

D. All submitted PRD Plans must comply with the requirements and criteria in the PJM Manuals for such plans, including assumptions and standards specified in the PJM Manuals for estimates of expected load levels. The PRD Plan shall explain and justify the methods used to determine the Nominal PRD Value. All assumptions and relevant variables affecting the Nominal PRD Value must be clearly stated. The PRD Plan must include sufficient data to allow a third party to audit the procedures and verify the Nominal PRD Value. Any non-compliance with a Nominal PRD Value for a prior Delivery Year shall be identified and taken into account. In addition, each submitted PRD Plan must include:

(i) documentation, in the form specified in the PJM Manuals, that: (1) where the PRD Provider is a Load Serving Entity, the Relevant Electric Retail Regulatory Authority has provided any required approval (including conditional approval, but only if the Load Serving Entity asserts that all such conditions have been satisfied) of such Load Serving Entity's time-varying retail rate structure and, regardless of whether RERRA approval is required, that such rate structure adheres to PRD implementation standards specified in the PJM Manuals; and (2) where the PRD Provider is not a Load Serving Entity, such PRD Provider has in place contractual arrangements with the relevant end-use customers establishing a time-varying retail rate structure that conforms to any RERRA requirements, and adheres to PRD implementation standards specified in the PJM Manuals; in such cases, the PRD Provider shall provide the Office of the Interconnection copies of its applicable contracts with end-use customers (including any proposed contracts) within ten Business Days after a request for such contracts, or its PRD Plan shall be rejected;

(ii) the expected peak load value that would apply, absent load reductions in response to price, to the end-use customer loads at a PRD Substation level, including applicable peak-load contribution data for such customers, to the extent available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level;

(iii) the Maximum Emergency Service Level of the identified load given the load's price-responsive characteristics, at a PRD Substation level if available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level;

(iv) Price-consumption curves ("PRD Curves") at a PRD Substation level if available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level that detail the base consumption

level of the identified loads; and the decreasing consumption levels at increasing prices, provided that all identified load reductions must be capable of full implementation within 15 minutes of declaration of a Maximum Generation Emergency by the Office of the Interconnection, and provided further that the specified prices may not exceed the maximum energy offer price cap under the PJM Tariff and Operating Agreement;

(v) the estimated Nominal PRD Value of the Price Responsive Demand at a PRD Substation level if available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level;

(vi) specifications of equipment used to satisfy the advanced metering and Supervisory Control criteria for eligible Price Responsive Demand, including a timeline and milestones demonstrating that such equipment shall be available and operational for the start of the relevant Delivery Year. Such equipment shall comply with applicable RERRA requirements and shall be designed to meet all PRD requirements, including, without limitation, meter reading requirements and Supervisory Control requirements, specified in the PJM Manuals. The PRD Provider shall demonstrate in the PRD Plan that the Supervisory Control equipment enables an automated load response by Price Responsive Demand to the price trigger; provided, however, that the PRD Provider may request in the PRD Plan an exception to the automation requirement for any individual registered end-use customer that is located at a single site and that has Supervisory Control over processes by which load reduction would be accomplished; and provided further that nothing herein relieves such end-use customer of the obligation to respond within 15 minutes to declaration of a Maximum Generation Emergency in accordance with applicable PRD Curves. In addition to the above requirements and those in the PJM Manuals for metering equipment and associated data, metering equipment shall provide integrated hourly kWh values on an electric distribution company account basis and shall either meet the electric distribution company requirements for accuracy or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers). The installed metering equipment must be that used for retail electric service; or metering equipment owned by the end-use customer or PRD Provider that is approved by PJM and either read electronically by PJM or read by the customer or PRD Provider and forwarded to PJM, in either case in accordance with requirements set forth in the PJM Manuals; and

(vii) any RPM Auction clearing price below which the PRD Provider does not choose to commit PRD (“PRD Reservation Price”), specifying the relevant auction, Zone (or sub-Zonal LDA if applicable), and, if applicable, a range of up to ten pairs of PRD commitment levels and associated minimum RPM Auction clearing prices; provided however that the Office of the Interconnection may interpolate PRD commitment levels based on clearing prices between prices specified by the PRD Provider.

E. Each PRD Provider that commits Price Responsive Demand through an accepted PRD Plan must, no later than one day before the tenth Business Day prior to the start of the Delivery Year for which such PRD is committed, register with PJM, in the form and manner specified in the PJM Manuals, sufficient PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment. All information required in the PRD Plan to be at a PRD Substation level if available at the time of submission of the PRD Plan that was not provided at the time of submission of such plan must be provided with the registration. The PRD Provider shall also identify in the registration each individual end-use customer with a peak demand of 10 kW or

greater included in such Price Responsive Demand, the peak demand of such customers, the Load Serving Entity responsible for serving such customers, and the Load Serving Entities responsible for serving the end-use customers not identified on an individual basis. PJM shall provide notification of such PRD registrations to the applicable electric distribution company(ies) and load serving entity(ies). The PRD Provider shall maintain, and provide to the Office of the Interconnection upon request, an identification of all individual end-use customers with a peak load contribution of less than 10kW included in such Price Responsive Demand, and the peak load contribution of such customers. The PRD Provider must maintain its PRD Substation-level registration of PRD-eligible load at the level of its Zonal (or sub-zonal LDA, if applicable) Nominal PRD Value commitment during each day of the Delivery Year for which such commitment was made. The PRD Provider may change the end-use customer registered to meet the PRD Provider's commitment during the Delivery Year, but such PRD Provider must always in the aggregate register sufficient Price Responsive Demand to meet or exceed the Zonal (or sub-Zonal LDA, if applicable) committed Nominal PRD Value level. A PRD Provider must timely notify the Office of the Interconnection, in accordance with the PJM Manuals, of all changes in PRD registrations. Such notification must remove from the PRD Provider's registration(s) any end-use customer load that no longer meets the eligibility criteria for PRD, effective as of the first day that such end-use customer load is no longer PRD-eligible.

F. Each PRD Provider that is a Load Serving Entity shall be required to identify its committed Price Responsive Demand as price-sensitive demand at a PRD Substation level in the Day-Ahead and Real-Time Energy Markets. Each PRD Provider that is not a Load Serving Entity shall be required to identify its committed Price Responsive Demand as price-sensitive demand at a PRD Substation level in the Real-Time Energy Market. The most recent PRD Curve submitted by the PRD Provider in its PRD Plan or PRD registration shall be used for such purpose unless and until changed by the PRD Provider in accordance with the market rules of the Office of the Interconnection, provided that any changes to PRD Curves must be consistent with the PRD Provider's commitment of Price Responsive Demand hereunder.

G. The Obligation Peak Load of a Load Serving Entity that serves end-users registered as Price Responsive Demand in any Zone shall be as determined in Schedule 8 to this Agreement; provided, however, that such Load Serving Entity shall receive, for each day that an approved Price Response Demand registration is effective and applicable to such LSE's load, a Price Responsive Demand Credit for such registration during the Delivery Year, against the Locational Reliability Charge otherwise assessed upon such Load Serving Entity in such Zone for such day, determined as follows:

$$\text{LSE PRD Credit} = [(\text{Share of Zonal Nominal PRD Value committed in Base Residual Auction} * (\text{FZWNSP/FZPLDY}) * \text{Final Zonal RPM Scaling Factor} * \text{FPR} * \text{Final Zonal Capacity Price}) + (\text{Share of Zonal Nominal PRD Value committed in Third or Final Incremental Auction, as applicable} * (\text{FZWNSP/FZPLDY}) * \text{Final Zonal RPM Scaling Factor} * \text{FPR} * \text{Final Zonal Capacity Price} * \text{Third or Final Incremental Auction, as applicable, Component of Final Zonal Capacity Price stated as a Percentage})]$$

Where:

Share of Zonal Nominal PRD Value Committed in Base Residual Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration *Zonal Nominal PRD Value committed in the Base Residual Auction by the PRD Provider of such registration .

Share of Zonal Nominal PRD Value Committed in Third or Final Incremental Auction, as applicable = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration *Zonal Nominal PRD Value committed in the Third or Final Incremental Auction, as applicable by the PRD Provider of such registration.

FZPLDY = Final Zonal Peak Load Forecast for such Delivery Year; and

FZWNSP = Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of such Delivery Year;

And where the PRD registration is associated with a sub-Zone, the Share of the Nominal PRD Value Committed in Base Residual Auction Third Incremental Auction, or Final Incremental Auction, as applicable will be based on the Nominal PRD Values committed and registered in a sub-Zone. A Load Serving Entity will receive a LSE PRD Credit for each approved Price Responsive Demand registration that is effective and applicable to load served by such Load Serving Entity on a given day. The total daily credit to an LSE in a Zone shall be the sum of the credits received as a result of all approved registrations in the Zone for load served by such LSE on a given day.

H. A PRD Provider may transfer all or part of its PRD commitment for a Delivery Year in a Zone (or sub-Zonal LDA) to another PRD Provider for its use in the same Zone or sub-Zonal LDA, through notice of such transfer provided by both the transferor and transferee PRD Providers to the Office of the Interconnection in the form and manner specified in the PJM Manuals. From and after the effective date of such transfer, and to the extent of such transfer, the transferor PRD Provider shall be relieved of its PRD commitment and credit requirements, shall not be liable for PRD compliance charges, and shall not be entitled to a Price Responsive Demand Credit; and the transferee PRD Provider, to the extent of such transfer, shall assume such PRD commitment, credit requirements, and obligation for compliance charges and, if it is a Load Serving Entity, shall be entitled to a Price Responsive Demand Credit.

I. Any PRD Provider that commits Price Responsive Demand and does not register and maintain registration of sufficient PRD-eligible load, (including, without limitation, failing to install or maintain the required advanced metering or Supervisory Control facilities) in a Zone (or sub-Zonal LDA, if applicable) to satisfy in full its Nominal PRD Value commitment in such Zone (or sub-Zonal LDA) on each day of the Delivery Year for which such commitment is made shall be assessed a compliance charge for each day that the registered Price Responsive Demand is less than the committed Nominal PRD Value. Such daily penalty shall equal:

[MW Shortfall] * [Forecast Pool Requirement] * [(Weighted Final Zonal Capacity Price in \$/MW-day)

+ higher of (0.2 * Weighted Final Zonal Capacity Price) or (\$20/MW-day)]

Where: MW Shortfall = Daily Nominal PRD Value committed in such PRD Provider's PRD Plan (including any permitted amendment to such plan) for the relevant Zone or sub-Zonal LDA – Daily Nominal PRD Value as a result of PRD registration for such Zone or sub-Zonal LDA; and

Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price attributable to the Third or Final Incremental Auction, as applicable, weighted by the Nominal PRD Values committed by such PRD Provider in connection with the Base Residual Auction and those committed by such PRD Provider in connection with the Third or Final Incremental Auction, as applicable.

The MW Shortfall shall not be reduced through replacement of the Price Responsive Demand by any Capacity Resource or Excess Commitment Credits, provided, however, that the PRD Provider may register additional PRD-eligible end-use customer load to satisfy its PRD commitment.

J. PRD Providers shall be responsible for verifying the performance of their PRD loads during each maximum emergency event declared by the Office of the Interconnection. PRD Providers shall demonstrate that the identified PRD loads performed in accordance with the PRD Curves submitted at a PRD Substation level in the PRD Plan or PRD registration; provided, however, that the previously submitted MESL value shall be adjusted by a ratio equal to the amount by which the actual Zonal load during the declared event exceeded the PJM load forecast underlying the previously submitted MESL value. In accordance with procedures and deadlines specified in the PJM Manuals, the PRD Providers must submit actual customer load levels for all hours during the declared event and all other information reasonably required by the Office of the Interconnection to verify performance of the committed PRD loads.

K. If the identified loads submitted for a Zone (or sub-Zonal LDA) by a PRD Provider exceed during any Emergency the aggregate Maximum Emergency Service Level ("MESL") specified in all PRD registrations of such PRD Provider that have a PRD Curve specifying a price at or below the highest Real-time LMP recorded during such Emergency, the PRD Provider that committed such loads as Price Responsive Demand shall be assessed a compliance charge hereunder. The charge shall be based on the net performance during an Emergency of the loads that were identified as Price Responsive Demand for such Delivery Year in the PRD registrations submitted by such PRD Provider in each Zone (or sub-Zonal LDA, if applicable) and that specified a price at the MESL that is at or below the highest Real-Time LMP recorded during such Emergency. The compliance charge hereunder shall equal:

$$[\text{MW Shortfall}] * [\text{Forecast Pool Requirement}] * [(\text{Weighted Final Zonal Capacity Price in } \$/\text{MW-day})$$

$$+ \text{higher of } (0.2 * \text{Final Zonal Capacity Price}) \text{ or } (\$20/\text{MW-day})] * 365 \text{ days}$$

Where: MW Shortfall = [highest hourly integrated aggregate metered load for such PRD Provider's PRD load in the Zone or sub-Zonal LDA meeting the price condition specified above] – {(aggregate MESL for the Zone or sub-Zonal LDA) * the higher of [1.0] or [(actual Zonal load – actual total PRD load in Zone) / (Final Zonal Peak Load Forecast – final Zonal Expected Peak Load Value of PRD in total for all PRD load in Zone meeting the price condition specified above)]}.

For purposes of the above provision, the MW Shortfall for any portion of the Emergency event that is less than a full clock hour shall be treated as a shortfall for a full clock hour unless either: (i) the load was reduced to the adjusted MESL level within 15 minutes of the emergency procedures notification, regardless of the response rate submitted, or (ii) the hourly integrated value of the load was at or below the adjusted MESL. Such MW shortfall shall not be reduced through replacement of the Price Responsive Demand by any Capacity Resource or Excess Commitment Credits; provided, however, that the performance and MW Shortfalls of all PRD-eligible load registered by the PRD Provider, including any additional or replacement load registered by such PRD Provider, provided that it meets the price condition specified above, shall be reflected in the calculation of the overall MW Shortfall. Any greater MW Shortfall during a subsequent Emergency for such Zone or sub-Zonal LDA during the same Delivery Year shall result in a further charge hereunder, limited to the additional increment of MW Shortfall. As appropriate, the MW Shortfall for non-compliance during an Emergency shall be adjusted downward to the extent such PRD Provider also was assessed a compliance penalty for failure to register sufficient PRD to satisfy its PRD commitment.

L. PRD Providers that register Price Responsive Demand shall be subject to test at least once per year to demonstrate the ability of the registered Price Responsive Demand to reduce to the specified Maximum Emergency Service Level, and such PRD Providers shall be assessed a compliance charge to the extent of failure by the registered Price Responsive Demand during such test to reduce to the Maximum Emergency Service Level, in accordance with the following:

(i) If the Office of the Interconnection does not declare during the relevant Delivery Year a Maximum Generation Emergency that requires the registered PRD to reduce to the Maximum Emergency Service Level then such registered PRD must demonstrate that it was tested for a one-hour period during any hour when a Maximum Generation Emergency may be called during June through October or the following May of the relevant Delivery Year. If a Maximum Generation Emergency that requires the registered PRD to reduce to the Maximum Emergency Service Level is called during the relevant Delivery Year, then no compliance charges will be assessed hereunder.

(ii) All PRD registered in a zone must be tested simultaneously except that, when less than 25 percent (by megawatts) of a PRD Provider's total PRD registered in a Zone fails a test, the PRD Provider may conduct a re-test limited to all registered PRD that failed the prior test, provided that such re-test must be at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registered PRD must test simultaneously, where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. If less than 25 percent of a PRD Provider's total PRD registered in a Zone fails the test and the PRD Provider chooses to conduct a retest, the PRD Provider may elect to maintain the performance compliance result for registered PRD achieved during the test if the PRD Provider: (1) notifies the Office of the Interconnection 48 hours prior to the re-test under this election; and (2) the PRD Provider retests affiliated registered PRD under this election as set forth in the PJM Manuals.

(iii) A PRD Provider that registered PRD shall be assessed a PRD Test Failure Charge equal to the net PRD capability testing shortfall in a Zone during such test in the aggregate of all of

such PRD Provider's registered PRD in such Zone times the PRD Test Failure Charge Rate. The net capability testing shortfall in such Zone shall be the following megawatt quantity, converted to an Unforced Capacity basis using the applicable Forecast Pool Requirement:

$$\text{MW Shortfall} = [\text{highest hourly integrated aggregate metered load for such PRD Provider's PRD load in the Zone or sub-Zonal LDA}] - \{(\text{aggregate MESL for the Zone or sub-Zonal LDA}) * \text{the higher of } [1.0] \text{ or } [(\text{actual Zonal load} - \text{actual total PRD load in Zone}) / (\text{Final Zonal Peak Load Forecast} - \text{final Zonal Expected Peak Load Value of PRD in total for all PRD load in Zone})]\}.$$

The net PRD capability testing shortfall in such Zone shall be reduced by the PRD Provider's summer daily average of the MW shortfalls determined for compliance charge purposes under section I of this Schedule 6.1 in such Zone for such PRD Provider's registered PRD.

(iv) The PRD Test Failure Charge Rate shall equal such PRD Provider's Weighted Final Zonal Capacity Price in such Zone plus the greater of (0.20 times the Weighted Final Zonal Capacity Price in such Zone or \$20/MW-day) times the number of days in the Delivery Year, where the Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price attributable to the Third or Final Incremental Auction, as applicable, weighted by the Nominal PRD Values committed by such PRD Provider in connection with the Base Residual Auction and those committed by such PRD Provider in connection with the Third or Final Incremental Auction, as applicable. Such charge shall be assessed daily and charged monthly (or otherwise in accordance with customary PJM billing practices in effect at the time); provided, however, that a lump sum payment may be required to reflect amounts due, as a result of a test failure, from the start of the Delivery Year to the day that charges are reflected in regular billing.

M. The revenue collected from assessment of the charges assessed under subsections I, K, and L of this Schedule 6.1 shall be distributed on a pro-rata basis to all entities that committed Capacity Resources in the RPM Auctions for the Delivery Year for which the compliance charge is assessed, pro rata based on each such entity's revenues from Capacity Market Clearing Prices in such auctions, net of any compliance charges incurred by such entity.

N. Aggregate Price Responsive Demand that may be registered shall be limited for the first three Delivery Years that peak load adjustments for Price Responsive Demand are allowed under this Agreement. The maximum quantity of Price Responsive Demand that may be registered by all PRD Providers for the PJM Region as a whole shall be:

1. 2500 MW for the Delivery Year that begins on June 1, 2016;
2. 3500 MW for the Delivery Year that begins on June 1, 2017; and
3. 4000 MW for the Delivery Year that begins on June 1, 2018.

For Delivery Years in which the region-wide limit is not met, no limit as to the amount of Price Responsive Demand that may register in a Zone (or sub-Zone) shall apply. However, in the event the region-wide limit is met for a Delivery Year, then a portion of such limit shall be assigned to each Zone (or sub-Zonal LDA, if applicable) pro rata based on each such Zone's (or sub-Zone's) Preliminary Zonal Peak Load Forecast for the Delivery Year compared to the PJM Region's Preliminary RTO Peak Load Forecast for such Delivery Year (less, in each case, load

expected to be served in such area under the Fixed Resource Requirement). Within each Zone (or sub-Zonal LDA, if applicable) the permitted registrations shall be those quantities within the Zonal (or sub-Zonal LDA) limit with the lowest identified PRD Reservation Prices for their identified loads; and, as between PRD Providers submitting PRD registrations at the same PRD Reservation Price, pro rata based on each such LSE's share of the Preliminary Zonal Peak Load Forecast for such Zone (or sub-Zonal LDA) less load expected to be served under the Fixed Resource Requirement. For Delivery Years in which the region-wide limit is met, any PRD registrations that are not permitted by operation of this section will, to the extent not permitted, not be required to perform in accordance with its registration, not be considered in determining an LSE's PRD Credit or Nominal PRD Value, and not be accounted for in the applicable PRD Provider's PRD Curves. Nothing in this section precludes price-responsive load from exercising any opportunity it may otherwise have to participate in the day-ahead or real-time energy markets in the PJM Region. For Delivery Years beginning on or after June 1, 2019, there is no limit on the quantity of Price Responsive Demand that may register.

SCHEDULE 7

PLANS TO MEET OBLIGATIONS

- A. Each Party that elects to meet its estimated obligations for a Delivery Year by Self-Supply of Capacity Resources shall notify the Office of the Interconnection via the Internet site designated by the Office of the Interconnection, prior to the start of the Base Residual Auction for such Delivery Year.
- B. A Party that Self-Supplies Capacity Resources to satisfy its obligations for a Delivery Year must submit a Sell Offer as to such resource in the Base Residual Auction for such Delivery Year, in accordance with Attachment DD to the PJM Tariff.
- C. If, at any time after the close of the Third or Final Incremental Auction, as applicable, for a Delivery Year, including at any time during such Delivery Year, a Capacity Resource that a Party has committed as a Self-Supplied Capacity Resource becomes physically incapable of delivering capacity or reducing load, the Party may submit a replacement Capacity Resource to the Office of the Interconnection. Such replacement Capacity Resource (1) may not be previously committed for such Delivery Year, (2) shall be capable of providing the same quantity of megawatts of capacity or load reduction as the originally committed Capacity Resource, and (3) shall meet the same locational requirements, if applicable, as the originally committed resource. In accordance with Attachment DD to the PJM Tariff, the Office of the Interconnection shall determine the acceptability of the replacement Capacity Resource.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.

)
)
)

Docket No. ER18-988-000

**AFFIDAVIT OF JEFFERY D. BASTIAN
ON BEHALF OF PJM INTERCONNECTION, L.L.C.**

1. My name is Jeffrey D. Bastian. I am employed by PJM Interconnection, L.L.C. (“PJM”) as Manager, Capacity Market Operations. My business address is PJM Interconnection, L.L.C., 2750 Monroe Blvd., Audubon, PA 19403. My Affidavit is offered in support of PJM’s proposed revisions to Incremental Auction (“IA”) rules concurrently filed in this proceeding.
2. PJM’s Capacity Market Operations Department is responsible for all operational aspects of the Capacity Market, including administering PJM’s three-year forward capacity market – known as the Reliability Pricing Model (“RPM”). The Capacity Market Operations Department develops the systems, documentation, and participant training material necessary to conduct all RPM Auctions and support the daily operational activities of the RPM. Among other duties, the Capacity Market Operations Department receives, reviews, and assesses pre-auction information provided by market sellers and is responsible for clearing each RPM Auction.
3. Prior to becoming Manager of the Capacity Market Operations Department, I managed the PJM Day-Ahead Energy Market Operations Department and the PJM Market Simulation Department. The Market Simulation Department is responsible for all operational aspects of PJM’s Financial Transmission Rights market, and performs analysis to determine the economic impact of proposed transmission projects in support of the Regional Transmission Expansion Plan. Prior to joining to PJM in 1996, I was an engineer for twelve years in the Transmission Planning and Analysis Department of General Public Utilities.
4. I earned a Bachelor’s Degree in Electrical Engineering from Pennsylvania State University in 1984.
5. The purpose of my Affidavit is to show historical IA results and the influence on these results of existing rules regarding PJM’s release of excess capacity commitment in each IA.

6. As background, under the RPM construct, PJM conducts a BRA three years in advance of a Delivery Year to secure commitments of identifiable physical resources sufficient to satisfy projected load. Thereafter, PJM conducts First, Second and Third Incremental Auctions which are held twenty, ten, and three months prior to the start of the relevant Delivery Year, respectively. Each IA provides an opportunity for Capacity Market Sellers to sell available capacity and purchase replacement capacity, as well as a means for PJM to secure additional commitments of capacity or release sellers from prior capacity commitments based on updated reliability requirements.
7. PJM's responsibility to procure or release capacity in an IA is based on review of the updated demand leading up the relevant Delivery Year. PJM utilizes an updated demand curve – Variable Resource Requirement ("VRR") Curve Decrement – to price the PJM release of excess capacity commitment MWs. By excess capacity commitment, I am referring to the megawatt ("MW") quantity reduction in the PJM Region Reliability Requirement due to an updated PJM Region forecasted peak load that is lower than the forecasted peak load value used in the BRA.
8. PJM's utilization of the VRR Curve Decrement to price the release of capacity has led to a consistent pattern of IA prices that are significantly lower than the corresponding BRA prices. This is because the use of the VRR Curve Decrement has led to PJM's "willingness" to release excess capacity at low prices relative to the BRA clearing price, often times at zero. This persistent outcome creates an environment that may incentivize Capacity Market Sellers to submit BRA Sell Offers that have little or no reasonable expectation of physical delivery.
9. Table 1 compares the clearing prices in the BRA and corresponding IAs on a MW-weighted basis for all cleared IA buy bids in all areas. This table shows that the weighted average replacement cost has ranged from 16.2% to 72.5% of the BRA value of those capacity commitments. In addition, the average cost to purchase replacement capacity across the twenty-one IAs conducted since the three-IA format was first implemented for the 2012/2013 Delivery Year has been only 40.7% of the value assigned to those capacity commitments by the BRA. Notably, the 72.5% value occurred in the 2015/2016 Delivery Year for which PJM had sought and received approval of a waiver to not release excess capacity commitment in the 3rd IA. We observed that in the 3rd IA for the 2015/2016 Delivery Year, the cost to procure replacement capacity was 98.5% of the corresponding BRA value. This observation is evidence of the significant impact of PJM's release of capacity on the IA clearing price that I describe in further detail with respect to Table 3 below.

Table 1: Weighted-Average IA Replacement Cost relative to BRA Capacity Values

| | | Cleared Buy Bids | | | |
|----------------------|-----------------|------------------|---------------------------|-------------------------|-----------------------------|
| Delivery Year | # of IAs | MW | BRA Value (\$/Day) | IA Cost (\$/Day) | IA Cost vs BRA Value |
| 2012/2013 | 3 | 9,346.4 | \$611,014 | \$99,200 | 16.2% |
| 2013/2014 | 3 | 13,649.2 | \$1,461,507 | \$412,800 | 28.2% |
| 2014/2015 | 3 | 14,008.5 | \$1,819,935 | \$488,731 | 26.9% |
| 2015/2016 | 3 | 11,979.4 | \$2,058,554 | \$1,492,561 | 72.5% |
| 2016/2017 | 3 | 16,636.8 | \$1,526,192 | \$828,800 | 54.3% |
| 2017/2018 | 3 | 12,414.3 | \$1,538,809 | \$667,501 | 43.4% |
| 2018/2019 | 2 | 7,254.1 | \$1,263,498 | \$214,309 | 17.0% |
| 2019/2020 | 1 | 3,992.0 | \$398,425 | \$139,101 | 34.9% |
| Total | 21 | 89,280.7 | \$10,677,934 | \$4,343,004 | 40.7% |

10. Table 2 shows the MW quantity of replaced commitment and the replacement rate (shown as a percent of replaced MW quantity versus total MW quantity cleared in all auctions) by Delivery Year¹ and by category of resource type.

Table 2: Replacement Rate by Capacity Resource Type

| | Internal In-Service Generation | | | Internal Planned Generation | | | External Generation | | | Demand Resource | | |
|----------------|---------------------------------------|--------------|--------------|------------------------------------|--------------|--------------|----------------------------|-------------|--------------|------------------------|--------------|--------------|
| Delivery Year | Cleared MW | Replaced MW | Replace Rate | Cleared MW | Replaced MW | Replace Rate | Cleared MW | Replaced MW | Replace Rate | Cleared MW | Replaced MW | Replace Rate |
| 2012/13 | 127,361 | 7,056 | 5.5% | 2,999 | -67 | -2.2% | 1,517 | 123 | 8.1% | 8,753 | 2,265 | 25.9% |
| 2013/14 | 141,713 | 8,083 | 5.7% | 4,020 | 480 | 11.9% | 2,429 | 479 | 19.7% | 10,780 | 3,314 | 30.7% |
| 2014/15 | 138,240 | 6,314 | 4.6% | 3,275 | -27 | -0.8% | 3,678 | 812 | 22.1% | 14,943 | 6,732 | 45.0% |
| 2015/16 | 146,096 | 6,662 | 4.6% | 5,432 | 859 | 15.8% | 5,353 | -160 | -3.0% | 15,775 | 5,151 | 32.7% |
| 2016/17 | 147,893 | 6,143 | 4.2% | 9,112 | 2,342 | 25.7% | 7,761 | 2,938 | 37.9% | 13,285 | 4,820 | 36.3% |
| 2017/18 | 148,243 | 5,881 | 4.0% | 13,574 | 4,162 | 30.7% | 4,981 | 264 | 5.3% | 11,871 | 3,871 | 32.6% |
| Average | 141,591 | 6,690 | 4.7% | 6,402 | 1,291 | 20.2% | 4,286 | 743 | 17.3% | 12,568 | 4,359 | 34.7% |

11. As can be seen in Table 2, Demand Resources, External Resources, and Planned Generation Capacity Resources show the highest replacement rate on average among the different resource categories. This is indicative of Capacity Market Sellers submitting Sell Offers that have a heightened degree of uncertainty in the BRA. This is because at the time of the BRA, Planned Generation Capacity Resources will still be in development and Demand Resources likely will not have all of their end-users identified and under contract.

¹ The data shows the replacement quantities on the June 1 start date of the relevant Delivery Year.

12. Table 3 shows the total MW quantity of replacement capacity purchased by participants across all three IAs for each of the six Delivery Years for which all three IAs have been conducted. The average total MW quantity of cleared Buy Bids for each of the six Delivery Years for which all three IAs have been conducted was 13,005.9 MWs and the weighted average cost to purchase this replacement capacity was 43.1% of the BRA value of the capacity commitment. The 13,005.9 MWs of Buy Bids that were purchased as replacement capacity in the IAs of these Delivery Years cleared against on average 6,828.7 MW of Capacity Market Seller Sell Offers and 6,177.2 MW of PJM IA Sell Offers. The PJM IA Sell Offers therefore satisfied 46.1% of the 13,005.9 MW of replacement capacity that was purchased in the IAs at a price of only 43.1% of the BRA value.

Table 3: Source of Supply and Cost of Cleared IA Buy Bids

| | | | Cleared Participant Sell Offer MW | | Cleared Net PJM Sell Offer MW | |
|---------------------------|-----------------------------------|---|--|------------------------------------|--|------------------------------------|
| Delivery Year | Cleared Buy Bid MW | IA Cost vs BRA Value | MW | % of Cleared Supply | MW | % of Cleared Supply |
| 2012/2013 | 9,346 | 16.2% | 4,930.0 | 52.7% | 4,416.4 | 47.3% |
| 2013/2014 | 13,649 | 28.2% | 7,087.6 | 51.9% | 6,562.0 | 48.1% |
| 2014/2015 | 14,009 | 26.9% | 9,831.6 | 70.2% | 4,177.2 | 29.8% |
| 2015/2016 | 11,979 | 72.5% | 9,250.3 | 77.2% | 2,729.1 | 22.8% |
| 2016/2017 | 16,637 | 54.3% | 6,368.1 | 38.3% | 10,268.7 | 61.7% |
| 2017/2018 | 12,414 | 43.4% | 3,504.6 | 28.2% | 8,909.7 | 71.8% |
| Average per DY | 13,005.9 | 43.1% | 6,828.7 | 53.9% | 6,177.2 | 46.1% |

13. The historical IA results of Table 3 provide clear evidence that PJM's release excess capacity commitment is a significant contributor to the persistent pattern of IA clearing prices that are consistently significantly lower than the corresponding BRA clearing price. PJM's "willingness" to release excess capacity commitment at low prices contributed to 46.1% of the total cleared IA Buy Bids that paid on average only 43.1% of BRA value.

14. I am providing the following example to explain why the existing rules regarding excess capacity commitment do not recognize the value to load or the cost avoided by a Capacity Market Seller that replaces a BRA commitment:

Assume a Capacity Market Seller clears 100 MWs in a BRA at a BRA clearing price of \$100/MW-Day, it will receive annual revenues over the relevant BRA Delivery Year of \$3.65 million (100 MW x \$100/MW-Day x 365 days). If the Capacity Market Seller is unable to physically deliver on the BRA commitment (e.g., an Existing Generation Capacity Resource that has retired subsequent to the BRA or a Planned Generation Capacity Resource that has cancelled or delayed its in-service date), it is subject to a Capacity Resource Deficiency Charge of \$4.38 million (100 MW x 120% x \$100/MW-Day x 365 days) or the possibility of Non-Performance Charges up to the maximum non-performance charge stop-loss level of \$12.91 million. If the Capacity Resource is able to physically deliver on the BRA commitment, it would not be subject to a Capacity Resource Deficiency Charge. However, the resource would still face the possibility of Non-Performance Charges up to the maximum stop-loss level of \$12.91 million. By replacing the BRA commitment, the Capacity Market Seller is excused of having to physically deliver the Capacity Resource on the BRA commitment and avoids any potential cost associated with Capacity Resource Deficiency Charge. In addition, such Capacity Market Seller would be excused of all performance requirements associated with the replaced commitment. As a result, the Capacity Market Seller would avoid all possibility of being assessed a Non-Performance Charge for non-performance during any Performance Assessment Intervals that may occur during the Delivery Year. In fact, any and all performance from this resource during any Performance Assessment Interval that may occur during the Delivery Year will be eligible for Bonus Payments. Consequently, Capacity Market Sellers should rationally be willing to pay the BRA clearing price for replacement capacity in order to avoid the significantly higher costs associated with a Capacity Resource Deficiency Charge and/or Non-Performance Charge.

Continuing with this example, next assume that the Capacity Market Seller of such Capacity Resource purchased the 100 MWs of replacement capacity through a 100 MW IA Buy Bid that cleared against a 100 MW PJM IA Sell Offer at an IA clearing price of \$40/MW-Day (i.e. the historical IA data of Table 1 showed the average IA clearing price to be 40.7% of the corresponding BRA clearing price). The Capacity Market Seller will pay a charge over the relevant BRA Delivery Year of \$1.46 million (100 MW x \$40/MW-Day x 365 days) for the replacement capacity it purchased in the IA, while avoiding an annual cost of \$4.38 million associated with a Capacity Resource Deficiency Charge (if the resource is unable to physically deliver on the BRA commitment) and the possibility of an annual cost of up to \$12.91 million associated with the maximum Non-Performance Charge stop-loss level. Meanwhile, the Capacity Market Seller continues to receive revenue over the relevant BRA

Delivery Year of \$3.65 million for the 100 MWs that it cleared in the BRA. After netting out the \$1.46 million annual cost of the IA purchase, the Capacity Market Seller will receive revenues over the relevant BRA Delivery Year of \$2.19 million solely through its participation in PJM's capacity market without any obligation to provide the reliability and energy market benefits associated with a capacity commitment. In addition, to the extent the Capacity Resource of this example does physically exist, any performance from the resource during any Performance Assessment Interval that may occur during the Delivery Year will be eligible for Bonus Payments.

Through the Locational Reliability Charge that is assessed to PJM load each day of the Delivery Year, PJM load will pay the Capacity Market Seller of the Capacity Resource of this example \$3.65 million over the course of the annual BRA Delivery Year period for the 100 MWs that the resource cleared in the BRA and it will receive a \$1.46 million credit over the annual BRA Delivery Year period for the 100 MWs of excess capacity commitment that was released in the IA on behalf of PJM load. From the perspective of PJM load, it will pay the Capacity Resource of this example \$2.19 million over the annual BRA Delivery Year period without receiving the reliability and energy market benefits that are provided by a Capacity Resource having a commitment obligation. The economic value to load of these foregone benefits is not zero. In fact, PJM conducted annual energy market simulations during the course of stakeholder discussion that showed energy market benefit to load alone to be in the range of \$86,000/MW-Year to \$124,000/MW-Year. Using this range of estimated energy market benefits, the 100 MW Capacity Resource in the example would have provided load with annual energy market benefits ranging from \$8.6 million to \$12.4 million. Therefore, PJM load is paying the Capacity Resource of this example \$2.19 million over the annual BRA Delivery Year period while at the same time forgoing annual energy market benefits ranging from \$8.6 million to \$12.4 million that the Capacity Resource would have otherwise provided. This outcome suggests that excess capacity commitment should be retained and not released unless it was released at a price equivalent to the \$8.6 million foregone value noted above.

This concludes my affidavit.

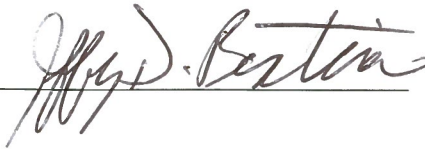
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.

)

Docket No. ER-__-000

I, Jeffery D. Bastian, being first duly sworn, deposes and states that I am the Jeffery D. Bastian referred to in the foregoing document entitled "Affidavit of Jeffery D. Bastian on Behalf of PJM Interconnection, L.L.C." that I has read the same and am familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.



Subscribed and sworn to before me, the undersigned notary public, this 9th day of March,

2018.

COMMONWEALTH OF PENNSYLVANIA

NOTARIAL SEAL

Linda Spreeman, Notary Public

Lower Providence Twp., Montgomery County

My Commission Expires Nov. 17, 2019

MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES



Notary Public

My Commission expires: Nov 17, 2019

