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November 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. ER19-323-000  
Proposed Tariff for Transmission Constraint Penalty Factors*

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”) and Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (“Operating Agreement”).<sup>1</sup> Specifically, as explained below, PJM proposes to add new sections in Tariff, Attachment K – Appendix and the parallel provisions of the Operating Agreement, Schedule 1 to (a) specify the circumstances under which the Transmission Constraint Penalty Factor<sup>2</sup> may be used to determine the Marginal Value<sup>3</sup> of a transmission constraint, (b) provide the default Transmission Constraint Penalty Factor values, and (c) explain the procedure for temporarily changing the default Transmission Constraint

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<sup>1</sup> Because Tariff, Attachment K- Appendix and the parallel provisions of Operating Agreement, Schedule 1 are identical, PJM will reference only the Tariff changes throughout this letter for convenience.

<sup>2</sup> Capitalized terms not defined herein shall have the meaning as contained in the Tariff, Operating Agreement or the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region.

<sup>3</sup> In this filing, PJM proposes to define the Marginal Value as shown in blackline below:

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

Penalty Factor values. This filing is the culmination of a year-long stakeholder process designed to amend PJM's existing practice of applying Constraint Relaxation Logic<sup>4</sup> on a transmission constraint and incorporate PJM's procedures governing Transmission Constraint Penalty Factors in the Tariff. This filing also is intended to satisfy PJM's outstanding compliance requirement to include certain rules pertaining to Transmission Constraint Penalty Factors in PJM's governing documents pursuant to Order No. 844.<sup>5</sup>

PJM requests that the Commission issue an order accepting the enclosed revisions by no later than January 8, 2019, sixty (60) days from the date of this filing, with an effective date of February 1, 2019.

## **I. BACKGROUND**

A transmission constraint occurs when a physical limitation may be reached on one or more Transmission Facilities during normal or contingency system operations. Transmission constraints result when the most economic generation cannot be delivered to the load due to physical limitations on Transmission Facilities. When this occurs, more expensive generation that is closer to the load must be dispatched in order to ensure that flows on Transmission Facilities are maintained within their operating limits.

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<sup>4</sup> In this filing, PJM proposes to define the Constraint Relaxation Logic as shown in blackline below:

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

<sup>5</sup> See *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 163 FERC ¶ 61,041, P 121 (April 19, 2018) ("Order No. 844"). The Commission granted PJM's Motion for Extension of Time until November 9, 2018 to incorporate PJM's Transmission Constraint Penalty Factors into the relevant governing documents. See Notice of Extension of Time, Docket No. RM17-2-000 (August 10, 2018). PJM is submitting an informational filing in PJM's Order No. 844 compliance proceeding in Docket No. ER18-2401, which references this filing as intended to satisfy the compliance directive on Transmission Constraint Penalty Factors.

This generation dispatch is accomplished via an optimization algorithm in PJM's market clearing engine, known as security-constrained economic dispatch ("SCED"), which is used by PJM to determine resource commitments and resource dispatch basepoints. This optimization algorithm utilizes Transmission Constraint Penalty Factors<sup>6</sup> to ensure that the market clearing engine reliably arrives at reasonable dispatch solutions. The Transmission Constraint Penalty Factor is one of the parameters used within the SCED application and represents the maximum cost that may be incurred to control a transmission constraint.<sup>7</sup> SCED determines the least cost means of serving load and meeting reserve requirements at different locations within the PJM Region based on actual system conditions, including transmission constraints. To that end, SCED is allowed to exhaust all available controlling actions to economically relieve a transmission constraint up to the relevant Transmission Constraint Penalty Factor.

Occasionally, however, a transmission constraint cannot be controlled within the binding limit of the Transmission Constraint Penalty Factor in the dispatch interval because (1) no resources are available to solve the constraint or (2) the cost of re-dispatch is greater than the Transmission Constraint Penalty Factor. When this occurs, SCED is currently designed to apply Constraint Relaxation Logic, which increases the limit of the constrained Transmission Facility by the amount of excess flow. By increasing the Transmission Facility's limit, SCED produces an alternative solution that results in a reduced Marginal Value equal to the savings from re-dispatching marginal resources. This savings occurs because, by increasing the transmission

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<sup>6</sup> In this filing, PJM proposes to define the Transmission Constraint Penalty Factor as shown in blackline below:

"Transmission Constraint Penalty Factor" shall mean the maximum cost of the re-dispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the Marginal Value."

<sup>7</sup> This is similar in concept with the Reserve Penalty Factor, which is used as a proxy that specifies the maximum willingness to pay for reserves.

limit, the SCED application is able to solve for the transmission constraint which utilizes resources at a cost below the Transmission Constraint Penalty Factor. In turn, this results in a Marginal Value of the constraint that is less than the Transmission Constraint Penalty Factor. Since the resultant Marginal Value is lower than the Transmission Constraint Penalty Factor, the application of Constraint Relaxation Logic effectively prevents the Transmission Constraint Penalty Factor from setting the Marginal Value.

This practice, however, produces Locational Marginal Prices (“LMPs”) that can understate the severity of the localized transmission shortage. An artificially lower Marginal Value as a result of applying Constraint Relaxation Logic does not accurately reflect the local supply and demand conditions caused by transmission constraints. Since the Marginal Value of the transmission constraint is ultimately used as an input for determining LMP,<sup>8</sup> the resulting LMP value does not provide transparent price signals that are important in determining where transmission and generation investments are needed.

To address this issue, PJM Stakeholders approved an Issue Charge on August 9, 2017 to review and potentially revise the current practice related to the use of Constraint Relaxation Logic. In addition, and independent of Order No. 844, the Issue Charge included developing clear rules to specify PJM actions related to the application of Transmission Constraint Penalty Factors and how they affect LMPs.<sup>9</sup>

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<sup>8</sup> See Tariff, Attachment K – Appendix, sections 2.5 through 2.6.

<sup>9</sup> See Transmission Penalty Factors Issue Charge, available at: <https://www.pjm.com/-/media/committees-groups/committees/mic/20180510-special/20180510-item-02a-problem-statement-transmission-penalty-factors.ashx>

## **II. PJM PROPOSES TO INCORPORATE RULES GOVERNING TRANSMISSION CONSTRAINT PENALTY FACTORS INTO THE TARIFF AND OPERATING AGREEMENT**

### ***A. The Transmission Constraint Penalty Factors Will Be Allowed to Set the Marginal Value of a Transmission Constraint.***

To address the fact that the Constraint Relaxation Logic approach results in LMPs that can understate the severity of a transmission constraint, PJM stakeholders initiated a stakeholder process and ultimately agreed to remove the application of Constraint Relaxation Logic. As a result, PJM proposes to allow the relevant Transmission Constraint Penalty Factor to set the Marginal Value for the constraint instead of applying Constraint Relaxation Logic when the SCED's algorithm cannot produce a solution that manages the flow on a transmission constraint within its limits.<sup>10</sup> Since PJM will no longer apply Constraint Relaxation Logic to raise the limit of the transmission capability, the Transmission Constraint Penalty Factor will set the Marginal Value of the transmission constraint. The outcome of this change will no longer result in a lower Marginal Value by increasing the limit of the transmission constraint.<sup>11</sup> Since the Marginal Value of the transmission constraint is used as a component in the calculation of LMP, the result of this amendment will be more transparent pricing and create proper investment signals for the underlying transmission constraint.<sup>12</sup>

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<sup>10</sup> Since the Transmission Constraint Penalty Factor used in the Day-ahead Energy Market is used to ensure a feasible market clearing solution and never intended to set the Marginal Value, only the Transmission Constraint Penalty Factor used in the Real-time Energy Market will set the Marginal Value.

<sup>11</sup> This proposed amendment is similar to PJM's existing practice of allowing the Reserve Penalty Factor to set the price for reserves when the reserve requirement cannot be met. *See* Tariff, Attachment K- Appendix, section 2.5(b).

<sup>12</sup> The ultimate goal of this change is to ensure transparent market pricing such that it creates proper price signals for where investments are needed. Nevertheless, to quantify, the price impact is negligible as can be seen in the PJM Market Monitor's analysis, which indicates this change would have resulted in only a 0.06% increase in total net load payments in 2017. *See* [Impact on Energy Market if Transmission Penalty Factors set prices](http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MIC_TX_Penalty_Factors_Impact_on_EM_if_TX_Penalty_Factors_Set_Prices20180627.pdf), June 27, 2018, available at [http://www.monitoringanalytics.com/reports/Presentations/2018/IMM\\_MIC\\_TX\\_Penalty\\_Factors\\_Impact\\_on\\_EM\\_if\\_TX\\_Penalty\\_Factors\\_Set\\_Prices20180627.pdf](http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MIC_TX_Penalty_Factors_Impact_on_EM_if_TX_Penalty_Factors_Set_Prices20180627.pdf)

To address the Commission's directive in Order No. 844 that PJM include in the Tariff circumstances under which the Transmission Constraint Penalty Factor can set LMP, PJM is clarifying in the proposed Tariff how the Transmission Constraint Penalty Factor is reflected in LMP. That is, the Transmission Constraint Penalty Factor is used to determine the Marginal Value of a transmission constraint. In turn, the Marginal Value is a factor used in determining Congestion Price. Congestion Price is one of the three inputs in to LMP. To clarify this chain, PJM cross referenced Tariff, Attachment K – Appendix, sections 2.5 through 2.6 in the proposed Tariff language, which describe how the Marginal Value ultimately is used as one factor in the determination of LMP. More particularly, the Marginal Value is used in the determination of the Congestion Price, which is one component of LMP. The Congestion Price at any location is equal to the sum of the product of the transmission constraint's Marginal Value and the distribution factor<sup>13</sup> of that location on that constraint for all binding constraints in a given dispatch interval.<sup>14</sup> Since the components of LMP are System Energy Price, Congestion Price, and Loss Price,<sup>15</sup> the Transmission Constraint Penalty Factor affects LMP by impacting the value of the Congestion Price.<sup>16</sup>

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<sup>13</sup> The distribution factor represents the change (or sensitivity) of an active power flow in a reference direction on a transmission line with respect to a change in injection at the generator bus and a corresponding change in withdrawal at the reference bus (calculated with a DC power flow).

<sup>14</sup> See Tariff, Attachment K – Appendix, section 5.1

<sup>15</sup> See Tariff, Attachment K – Appendix, sections 2.5 through 2.6.

<sup>16</sup> To satisfy the Commission's compliance directive from Order No. 844, which requires the inclusion of the circumstances for when Transmission Constraint Penalty Factors can set LMP, PJM proposes to specify in the Tariff that the Marginal Value of the transmission constraint is used in the determination of the Congestion Price component of LMP.

Based on the foregoing, PJM proposes to add the following new language in the Tariff, Attachment K – Appendix, section 5.6.1 to explain when the Transmission Constraint Penalty Factors may be used to set the Marginal Value:

In the Day-ahead Energy Market, the Transmission Constraint Penalty Factors shall be used to ensure a feasible market clearing solution but not used to determine the Marginal Value of a transmission constraint. In the Real-time Energy Market, the Office of the Interconnection shall use Transmission Constraint Penalty Factors to determine the Marginal Value for a transmission constraint when that transmission constraint cannot be managed within the binding transmission limit in a dispatch interval. The Marginal Value of the transmission constraint shall be used in the determination of the Congestion Price component of Locational Marginal Price as referenced in Tariff, Attachment K – Appendix, section 2.5 through Tariff, Attachment K – Appendix, section 2.6, and the parallel provisions of Operating Agreement, Schedule 1, section 2.5 through Operating Agreement, Schedule 1, section 2.6. The Transmission Constraint Penalty Factor may set the Marginal Value of the transmission constraint during any dispatch interval in the Real-time Energy Market depending on the following:

- (a) If the market clearing software that clears the Real-time Energy Market cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval at a cost less than or equal to the Transmission Constraint Penalty Factor, the Transmission Constraint Penalty Factor shall set the Marginal Value of the transmission constraint. In such instances, to manage the flow over the constraint, the Office of the Interconnection may adjust the Transmission Constraint Penalty Factor as set forth in Tariff, Attachment K – Appendix, section 5.6.3 and the parallel provisions of Operating Agreement, Schedule 1, section 5.6.3.

PJM will allow the Transmission Constraint Penalty Factor to set the Marginal Value of a transmission constraint, including for market-to-market congestion management protocols. However, in certain limited instances, PJM will retain the ability to use Constraint Relaxation Logic and allow the resulting shadow price to set the Marginal Value of the transmission constraint for market-to-market congestion management. This operational flexibility would allow PJM to coordinate with and accommodate potential requests from an adjacent Regional Transmission Organizations (“RTO”) that requires a transmission limit to be adjusted and apply

Constraint Relaxation Logic.<sup>17</sup> The application of Constraint Relaxation Logic would only occur upon mutual agreement in accordance with the Joint Operating Agreements by PJM and the relevant adjacent RTO. Absent mutual agreement, PJM intends to allow the Transmission Constraint Penalty Factor set the Marginal Value of the transmission constraints that are subject to market-to-market congestion management protocols. Therefore, PJM expects the use of Constraint Relaxation Logic will be used sparingly and occur on a limited basis.

To retain this ability, PJM proposes to add the following new language in the Tariff, Attachment K – Appendix, section 5.6.1, for market-to-market constraints:

(b) If the Real-time Energy Market constraints are subject to market-to-market congestion management protocols with an adjacent Regional Transmission Organization and the market clearing software cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval, the Office of the Interconnection may coordinate with such Regional Transmission Organization to either allow the Transmission Constraint Penalty Factor to set the Marginal Value of the transmission constraint or to apply the Constraint Relaxation Logic upon mutual agreement in accordance with applicable Joint Operating Agreements.

***B. Default Transmission Constraint Penalty Factor Values***

To provide additional transparency, this filing also incorporates PJM’s existing default Transmission Constraint Penalty Factor values into the Tariff. Specifically, the proposed Tariff specifies that the default Transmission Constraint Penalty Factor used in the Real-time Energy Market is \$2,000/MWh for transmission constraints located within the metered boundaries of the PJM Region (excluding market-to-market coordinated constraints). This value has been applied by PJM for several years and is set appropriately high enough to ensure that the market software

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<sup>17</sup> The Midcontinent Independent System Operator (“MISO”) notified PJM that it does not expect updates to its market clearing engine to allow Transmission Constraint Penalty Factors to set the Marginal Value of the transmission constraint any earlier than the second quarter of 2019. Therefore, until MISO completes the software update, PJM expects to continue applying Constraint Relaxation Logic for transmission constraints that are subject to market-to-market congestion management protocols with MISO.

will automatically use all physically available dispatch options up to this default value to satisfy the transmission network's limits. PJM's historical data demonstrates that at \$2,000/MWh, the percentage of constraints that exceed the transmission limits and require modification to this default value is reasonably low and acceptable.<sup>18</sup>

For market-to-market coordinated transmission constraints that are located within the metered boundaries of the PJM Region, PJM applies a \$1,000/MWh default Transmission Constraint Penalty Factor value in the Real-time Energy Market. This value has been applied for many years and PJM does not see a need to change this historically applied value. No default Transmission Constraint Penalty Factor value exists for transmission constraints that are outside of PJM's metered boundaries because transmission constraints that are located within another RTO's metered boundaries are subject to the relevant RTO's default Transmission Constraint Penalty Factor values. As the non-monitoring RTO, PJM limits its constraint Marginal Values to those resulting from the relevant RTO's dispatch.

For the Day-ahead Energy Market, the default Transmission Constraint Penalty Factor must be set sufficiently high to ensure that the market clearing engine makes commitment decisions using all available units, including those with high start-up and no-load costs to relieve a transmission constraint. Doing so allows the market clearing engine to better manage congestion and relieve constraints in a post-contingency situation. That is why PJM has used a default Transmission Constraint Penalty Factor value of \$30,000/MWh for the Day-ahead Energy Market since the inception of this market more than twenty years ago.<sup>19</sup> This value has

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<sup>18</sup> Affidavit of Timothy Horger on behalf of PJM ("Horger Affidavit") at ¶ 6.

<sup>19</sup> While this value may appear high, the Marginal Value has never reached this default \$30,000/MWh value in the Day-ahead Energy Market and PJM does not expect the Marginal Value in the Day-Ahead Energy Market to ever reach this amount. This is because when the first solution produces a preliminary result that contains a Marginal

been time tested and ensures that the market clearing engines can solve for all transmission constraints, even under the most stressed system conditions, by including resources with higher start-up and no-load costs. If the default Transmission Constraint Penalty Factor for the Day-ahead Energy Market is set too low, the clearing engine may not commit the appropriate available generation to alleviate the constraint. Historical experience demonstrates that the \$30,000/MWh default Transmission Constraint Penalty Factor used in the Day-ahead Energy Market has been sufficient to accomplish these goals without compromising the solution performance.<sup>20</sup>

As Mr. Horger explains, unlike the Real-time Energy Market, which is a short term economic dispatch where the Transmission Constraint Penalty Factors only need to be high enough to cover the energy offer cost, the Transmission Constraint Penalty Factor used in the Day-ahead Energy Market incorporates higher costs associated with offline and longer start-time resources that can be used to reduce power flows at the transmission constraint.<sup>21</sup> This is because the Day-ahead Energy Market is a 24 hour look-ahead unit commitment and can be used to commit offline and longer start-time resources to reduce power flows at the transmission constraint.<sup>22</sup> Thus, PJM uses the \$30,000/MWh value essentially as a check to confirm that transmission constraints are being properly solved with all available generation. Setting the default value in the Day-ahead Energy Market at the \$30,000/MWh level alerts market operators

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Value amounting to the \$30,000/MWh value, PJM reruns the Day-ahead Energy Market solution to ensure that the transmission constraint is being properly evaluated. By rerunning the solution, the final Day-ahead Energy Market solutions have always resulted in a Marginal Values that is below \$30,000/MWh.

<sup>20</sup> Horger Affidavit at ¶ 7.

<sup>21</sup> Horger Affidavit at ¶ 7.

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

when the preliminary solution does not adequately alleviate the transmission constraint and ensures that the preliminary solution is rerun to produce a result that relieves the constraint.<sup>23</sup>

Based on the forgoing, PJM proposes to add the following new language in Tariff, Attachment K – Appendix, section 5.6.2 that specifies the default Transmission Constraint Penalty Factor values as shown below:

Transmission constraints located within the metered boundaries of the PJM Region, including market-to-market coordinated constraints, regardless of voltage level, are defaulted to a \$30,000/MWh Transmission Constraint Penalty Factor in the Day-ahead Energy Market. Constraints located within the metered boundaries of the PJM Region, excluding market-to-market coordinated constraints, regardless of voltage level, are defaulted to a \$2,000/MWh Transmission Constraint Penalty Factor in the Real-time Energy Market. Market-to-market coordinated constraints in the Real-time Energy Market, located within the metered boundaries of the PJM Region, will use a default Transmission Constraint Penalty Factor of \$1,000/MWh or a value agreed upon by PJM and the relevant Regional Transmission Organization in accordance with applicable Joint Operating Agreements.

***C. Procedures for Modifying Default Transmission Constraint Penalty Factor Values.***

While PJM's default Transmission Constraint Penalty Factor values for both the Day-ahead Energy Market and Real-time Energy Market are generally appropriate under most circumstances, PJM historically has retained the ability to modify these values. This is because there are occasions when the default values may need to be adjusted higher or lower to reflect persistent system operational or reliability needs and to accurately reflect the costs of resources available to relieve congestion. In addition, a different value may be appropriate to reflect changes to the operating practices with the neighboring RTO for managing market-to-market

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<sup>23</sup> As reflected in the proposed language in Tariff, Attachment K – Appendix, section 5.6.1, the Transmission Constraint Penalty Factor used in the Day-ahead Energy Market will not set the Marginal Value. Instead, it is merely used to ensure a feasible market clearing solution as described above.

coordinated constraints.<sup>24</sup> Lastly, certain Transmission Facilities may have unique attributes where application of the default value may not be appropriate.<sup>25</sup> More detail around when PJM would modify the values is provided below. Ultimately, the ability to modify the default Transmission Constraint Penalty Factor values is necessary to maintain adequate system control by ensuring a feasible market clearing solution.<sup>26</sup>

1. Circumstances Under Which PJM May Raise the Transmission Constraint Penalty Factor Values

As Mr. Horger explains, PJM may raise the Transmission Constraint Penalty Factor when not enough relief can be provided by resources at a cost below the default Transmission Constraint Penalty Factor, which results in the flow on a constraint above or approaching the binding limit.<sup>27</sup> When such conditions occur, PJM may increase the penalty factor (or willingness to pay for control) if there are available resources with a \$/MW cost above the default Transmission Constraint Penalty Factor that can provide additional relief. Mr. Horger specifies that conditions requiring increasing the default values for a transmission constraint include, but are not limited to, when PJM needs to:

- raise a resource's output to help alleviate the constraint, but the system energy price has decreased such that the resource's \$/MW cost exceeds the default penalty factor.
- lower a resource's output to help alleviate the constraint, but the system energy price has increased such that the resource's \$/MW cost exceeds the default penalty factor.
- raise or lower a resource's output to help alleviate the constraint, but the resource's effective cost is above the default penalty factor based on the resource's offer price and/or  $D_{\text{fax}}$ .<sup>28</sup>

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<sup>24</sup> Market-to-Market constraints will only be adjusted in coordination with neighboring partners. The process for adjusting the penalty factor on a Market to Market constraint is similar to the one discussed herein, but has the additional step of coordination and agreement between the coordinating RTOs.

<sup>25</sup> Horger Affidavit at ¶ 8.

<sup>26</sup> The Commission acknowledged that there may be circumstances under which the Transmission Constraint Penalty Factors may need to be changed and required the inclusion of any procedures for doing so in the Tariff. *See* Order No. 844 at P 122.

<sup>27</sup> Horger Affidavit at ¶ 9.

<sup>28</sup> Horger Affidavit at ¶ 9.

2. Circumstances Under Which PJM May Lower the Transmission Constraint Penalty Factor Values

Conversely, PJM may lower the Transmission Constraint Penalty Factor when sufficient congestion relief on the constraint can be provided by available resources at a cost below the default Transmission Constraint Penalty Factor in order to prevent a high cost resource that cannot provide material congestion relief on the constraint from inappropriately setting price for the constraint. For example, PJM may lower the default Transmission Constraint Penalty Factor for radial constraints where sufficient relief is available but isolated in a localized area. As Mr. Horger explains, this prevents SCED from attempting to over-control the constraint and dispatch resources that cannot provide material relief, which would result in Area Control Error deviations and/or other system controlling issues.<sup>29</sup> Another example where the default Transmission Constraint Penalty Factor may be lowered is when a thermal constraint is being used as a surrogate for a voltage control issue (needed for reactive power rather than real power). The market clearing engines model real power flows, rather than reactive power flows. Therefore, when reactive power issues are identified, PJM dispatchers must make resource commitments outside of the market clearing engines to address these issues.<sup>30</sup> These reactive power needs are then modeled in the market clearing engines via the use of a thermal surrogate constraint so that the cost of these out of market commitments can be captured in pricing. As explained by Mr. Horger, because the intent of these constraints is to capture the cost of out of market commitments, rather than to find relief for real power flows over the constraint, PJM lowers the default Transmission Constraint Penalty Factor to reflect the cost of resources that

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<sup>29</sup> Horger Affidavit at ¶ 10.

<sup>30</sup> Horger Affidavit at ¶ 10.

were committed for reactive control. This prevents the market clearing engine from attempting to dispatch additional resources that cannot provide voltage support to the affected area.<sup>31</sup>

### 3. Calculation of the Modified Value

To calculate the value of the revised Transmission Constraint Penalty Factor, PJM takes into account the System Energy Price, Loss Price, Congestion Price (for all binding constraints), and Incremental Energy Offer (including start up and no load costs as applicable).<sup>32</sup> More particularly, when an adjustment is required, PJM dispatchers and Real-time Energy Market support engineers make real-time evaluations of the appropriate penalty factor adjustments based on the effective cost (expressed in \$/MW) of the resources that are available to provide the necessary congestion relief. The effective cost is approximated using the resource's incremental cost, distribution factor<sup>33</sup> on the constraint, and the system energy cost.<sup>34</sup> Because such inputs may vary as system conditions change throughout the day, PJM uses estimated input values when modifying the default Transmission Constraint Penalty Factor values.<sup>35</sup> This allows PJM to avoid re-modifying the Transmission Constraint Penalty Factor values numerous times within a short period of time.

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<sup>31</sup> Horger Affidavit at ¶ 10.

<sup>32</sup> The term "Incremental Energy Offer" is defined in the Tariff to exclude no load costs. However, to recognize the inclusion of startup and no load costs used in the determination of a modified Transmission Constraint Penalty Factor for the Day-ahead Energy Market, PJM clarifies that for purposes of this calculation only, Incremental Energy Offer includes start up and no load costs.

<sup>33</sup> Distribution Factor represents the change (or sensitivity) of active power flow in a reference direction on a transmission line with respect to a change in injection at the generator bus and a corresponding change in withdrawal at the reference bus.

<sup>34</sup> Horger Affidavit at ¶ 11.

<sup>35</sup> To illustrate how the Transmission Constraint Penalty Factor may be modified, Mr. Horger provides an example in the attached affidavit. *See* Horger Affidavit at ¶ 12.

Consistent with the foregoing, PJM proposes to add the following new language in Tariff, Attachment K – Appendix, section 5.6.3 that specifies the procedures for modifying the default Transmission Constraint Penalty Factor values, as shown below:

5.6.3 Modifications to Transmission Constraint Penalty Factor Values.

(a) The Office of the Interconnection may modify the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market or Day-ahead Energy Market for individual transmission constraints to: (1) ensure the market clearing solution is feasible (2) reflect changes to the operating practices which are mutually agreed upon with the neighboring RTO for managing such constraints for market-to-market coordinated constraints or (3) reflect persistent system operational or reliability needs and the cost of the resources available to effectively relieve congestion on the constraint. When such conditions occur, the Office of the Interconnection may raise the Transmission Constraint Penalty Factor when sufficient congestion relief on the constraint cannot be provided by available resources at a cost below the default Transmission Constraint Penalty Factor. The Office of the Interconnection may lower the Transmission Constraint Penalty Factor when sufficient congestion relief on the constraint can be provided by available resources at a cost below the default Transmission Constraint Penalty Factor in order to prevent a high cost resource that cannot provide material congestion relief on the constraint from inappropriately setting price for the constraint. In either instance, to effectively relieve congestion on the constraint, the revised Transmission Constraint Penalty Factor value may be determined using the following formula, while accounting for the ability for such inputs to vary as system conditions change throughout the operating day:

$$\text{Revised Transmission Constraint Penalty Factor (\$/MW)} = \frac{\text{System Energy Price} + \text{Loss Price} + \text{Congestion Price}}{\text{(all binding constraints)} - \text{Incremental Energy Offer}^*} \cdot D_{\text{fax}}$$

Where  $D_{\text{fax}}$  equals the distribution factor of the resource for the transmission constraint

\* For purposes of this equation only, Incremental Energy Offer includes start up and no load costs where appropriate.<sup>36</sup>

In compliance with Order No. 844, PJM will post adjusted Transmission Constraint Penalty Factor values as soon as practicable when the default values are modified. PJM

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<sup>36</sup> PJM notes that this clarifying sentence was not originally included in the language endorsed by stakeholders. However, this clarification ensures that Members are aware start up and no load costs may be included in Incremental Energy Offer for purposes of calculating a modified Transmission Constraint Penalty Factor used in the Day-ahead Energy Market. Such costs are not included in the Real-time Energy Market since offline and longer start-time resources are not used to solve for constraints in real-time.

anticipates that such posting would occur no later than the business day following the day that the default Transmission Constraint Penalty Factor value is modified. Consistent with other provisions within PJM's Tariff,<sup>37</sup> while PJM intends to post modified Transmission Constraint Penalty Factors no later than the following business day, PJM declines to specify a deadline in the proposed Tariff language. This will provide PJM with sufficient flexibility in the event an unforeseen circumstance arises that prevents modified values from being posted within such a self-imposed deadline. Accordingly, PJM proposes to add the following new language to Tariff, Attachment K – Appendix, section 5.6.3:

(b) The Office of the Interconnection shall post, as soon as practicable, on its website any changes to the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market and/or the Day-ahead Energy Market.

### **III. STAKEHOLDER PROCESS**

This filing is the culmination of a nearly one year stakeholder process. The problem statement and accompanying issue charge for this topic was first reviewed at the August 9, 2017 Markets and Implementation Committee meeting. Thereafter, PJM and its stakeholders developed and endorsed the proposed revisions at the MIC by acclamation with no objections and four abstentions on September 12, 2018. The revisions were subsequently endorsed by acclamation with no objections and three abstentions at the Markets and Reliability Committee meeting and by acclamation with no objections or abstentions at the Members Committee meeting, both held on October 25, 2018.

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<sup>37</sup> See, e.g., Tariff, Attachment K – Appendix, section 2.5(c); Tariff, Attachment K – Appendix, section 1.5A.8(b); Tariff, Attachment K – Appendix, section 3.2.3A.01(m).

#### **IV. PROPOSED EFFECTIVE DATES**

PJM proposes an effective date of February 1, 2019 for the proposed Tariff and Operating Agreement sections referenced herein.<sup>38</sup> This will ensure that the necessary changes to the market clearing engines will be made in time to allow Transmission Constraint Penalty Factors to set the Marginal Value of a transmission constraint, rather than the current practice of applying Constraint Relaxation Logic. PJM requests that the Commission issue an order on this filing by January 8, 2019, sixty (60) days from the date of this filing. An order by January 8, 2019 will provide appropriate time for PJM to update its systems in time to implement on the requested effective date of February 1, 2019.

#### **V. DESCRIPTION OF SUBMITTAL**

This filing consists of the following:

1. This transmittal letter;
2. Attachment A – Revisions to the Operating Agreement and Tariff in redline format;
3. Attachment B – Revisions to the Operating Agreement and Tariff in clean format; and
4. Attachment C – Affidavit of Timothy Horger.

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<sup>38</sup> PJM notes that Order No. 844 requires Tariff changes to become effective no more than 120 days after compliance filings are due. *See* Order No. 844, P 141. Since the Commission granted PJM an extension of time to file compliance pertaining to Transmission Constraint Penalty Factors until November 9, 2018, the latest effective date for this Tariff change should be March 9, 2019.

## V. 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:

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## VI. SERVICE

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,<sup>39</sup> PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: <http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx> with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region<sup>40</sup> alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: <http://www.ferc.gov/docs-filing/elibrary.asp> in accordance with the Commission's regulations and Order No. 714.

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<sup>39</sup> See 18C.F.R §§ 35.2(e) and 385.2010(f)(3).

<sup>40</sup> PJM already maintains updates and regularly uses e-mail lists for all PJM Members and affected state commissions.

## VII. CONCLUSION

Based on the foregoing, PJM respectfully requests that the Commission accept the proposed revisions to PJM's Tariff and Operating Agreement no later than January 8, 2019, effective February 1, 2019.

Respectfully submitted,



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# Attachment A

## Revisions to the PJM Open Access Transmission Tariff and PJM Operating Agreement

(Marked / Redline Format)

Section(s) of the  
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(Marked / Redline Format)

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- 8.8 Market Settlements
- 8.9 Reporting and Compliance
- 8.10 Non-Hourly Metered Customer Pilot
- 8.11 Emergency Load Response and Pre-Emergency Load Response Participant Aggregation

**ATTACHMENT L**

**List of Transmission Owners**

**ATTACHMENT M**

**PJM Market Monitoring Plan**

**ATTACHMENT M – APPENDIX**

**PJM Market Monitor Plan Attachment M Appendix**

- I Confidentiality of Data and Information
- II Development of Inputs for Prospective Mitigation
- III Black Start Service
- IV Deactivation Rates
- V Opportunity Cost Calculation
- VI FTR Forfeiture Rule
- VII Forced Outage Rule
- VIII Data Collection and Verification

**ATTACHMENT M-1 (FirstEnergy)**

**Energy Procedure Manual for Determining Supplier Total Hourly Energy Obligation**

**ATTACHMENT M-2 (First Energy)**

**Energy Procedure Manual for Determining Supplier Peak Load Share Procedures for Load Determination**

**ATTACHMENT M-2 (ComEd)**

**Determination of Capacity Peak Load Contributions and Network Service Peak Load Contributions**

**ATTACHMENT M-2 (PSE&G)**

**Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers**

**ATTACHMENT M-2 (Atlantic City Electric Company)**

**Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers**

**ATTACHMENT M-2 (Delmarva Power & Light Company)**

**Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers**

**ATTACHMENT M-2 (Delmarva Power & Light Company)**

**Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers**

**ATTACHMENT M-2 (Duke Energy Ohio, Inc.)**

**Procedures for Determination of Peak Load Contributions, Network Service Peak Load and Hourly Load Obligations for Retail Customers**

**ATTACHMENT M-3**

**Additional Procedures for Planning of Supplemental Projects**

**ATTACHMENT N**

**Form of Generation Interconnection Feasibility Study Agreement**

**ATTACHMENT N-1**

**Form of System Impact Study Agreement**

**ATTACHMENT N-2**

**Form of Facilities Study Agreement**

**ATTACHMENT N-3**

**Form of Optional Interconnection Study Agreement**

**ATTACHMENT O**

**Form of Interconnection Service Agreement**

- 1.0 Parties
- 2.0 Authority
- 3.0 Customer Facility Specifications
- 4.0 Effective Date
- 5.0 Security
- 6.0 Project Specific Milestones
- 7.0 Provision of Interconnection Service
- 8.0 Assumption of Tariff Obligations
- 9.0 Facilities Study
- 10.0 Construction of Transmission Owner Interconnection Facilities
- 11.0 Interconnection Specifications
- 12.0 Power Factor Requirement
- 12.0A RTU
- 13.0 Charges
- 14.0 Third Party Benefits
- 15.0 Waiver
- 16.0 Amendment
- 17.0 Construction With Other Parts Of The Tariff
- 18.0 Notices
- 19.0 Incorporation Of Other Documents
- 20.0 Addendum of Non-Standard Terms and Conditions for Interconnection Service
- 21.0 Addendum of Interconnection Customer's Agreement  
to Conform with IRS Safe Harbor Provisions for Non-Taxable Status
- 22.0 Addendum of Interconnection Requirements for a Wind Generation Facility
- 23.0 Infrastructure Security of Electric System Equipment and Operations and Control  
Hardware and Software is Essential to Ensure Day-to-Day Reliability and  
Operational Security

**Specifications for Interconnection Service Agreement**

- 1.0 Description of [generating unit(s)] [Merchant Transmission Facilities] (the  
Customer Facility) to be Interconnected with the Transmission System in the PJM  
Region
- 2.0 Rights
- 3.0 Construction Responsibility and Ownership of Interconnection Facilities
- 4.0 Subject to Modification Pursuant to the Negotiated Contract Option
- 4.1 Attachment Facilities Charge
- 4.2 Network Upgrades Charge

- 4.3 Local Upgrades Charge
- 4.4 Other Charges
- 4.5 Cost breakdown
- 4.6 Security Amount Breakdown

**ATTACHMENT O APPENDIX 1: Definitions**

**ATTACHMENT O APPENDIX 2: Standard Terms and Conditions for Interconnections**

- 1 Commencement, Term of and Conditions Precedent to Interconnection Service**
  - 1.1 Commencement Date
  - 1.2 Conditions Precedent
  - 1.3 Term
  - 1.4 Initial Operation
  - 1.4A Limited Operation
  - 1.5 Survival
- 2 Interconnection Service**
  - 2.1 Scope of Service
  - 2.2 Non-Standard Terms
  - 2.3 No Transmission Services
  - 2.4 Use of Distribution Facilities
  - 2.5 Election by Behind The Meter Generation
- 3 Modification Of Facilities**
  - 3.1 General
  - 3.2 Interconnection Request
  - 3.3 Standards
  - 3.4 Modification Costs
- 4 Operations**
  - 4.1 General
  - 4.2 [Reserved]
  - 4.3 Interconnection Customer Obligations
  - 4.4 Transmission Interconnection Customer Obligations
  - 4.5 Permits and Rights-of-Way
  - 4.6 No Ancillary Services
  - 4.7 Reactive Power
  - 4.8 Under- and Over-Frequency and Under- and Over- Voltage Conditions
  - 4.9 System Protection and Power Quality
  - 4.10 Access Rights
  - 4.11 Switching and Tagging Rules
  - 4.12 Communications and Data Protocol
  - 4.13 Nuclear Generating Facilities
- 5 Maintenance**
  - 5.1 General
  - 5.2 [Reserved]
  - 5.3 Outage Authority and Coordination
  - 5.4 Inspections and Testing
  - 5.5 Right to Observe Testing
  - 5.6 Secondary Systems

- 5.7 Access Rights
- 5.8 Observation of Deficiencies
- 6 Emergency Operations**
  - 6.1 Obligations
  - 6.2 Notice
  - 6.3 Immediate Action
  - 6.4 Record-Keeping Obligations
- 7 Safety**
  - 7.1 General
  - 7.2 Environmental Releases
- 8 Metering**
  - 8.1 General
  - 8.2 Standards
  - 8.3 Testing of Metering Equipment
  - 8.4 Metering Data
  - 8.5 Communications
- 9 Force Majeure**
  - 9.1 Notice
  - 9.2 Duration of Force Majeure
  - 9.3 Obligation to Make Payments
  - 9.4 Definition of Force Majeure
- 10 Charges**
  - 10.1 Specified Charges
  - 10.2 FERC Filings
- 11 Security, Billing And Payments**
  - 11.1 Recurring Charges Pursuant to Section 10
  - 11.2 Costs for Transmission Owner Interconnection Facilities
  - 11.3 No Waiver
  - 11.4 Interest
- 12 Assignment**
  - 12.1 Assignment with Prior Consent
  - 12.2 Assignment Without Prior Consent
  - 12.3 Successors and Assigns
- 13 Insurance**
  - 13.1 Required Coverages for Generation Resources Of More Than 20 Megawatts and Merchant Transmission Facilities
  - 13.1A Required Coverages for Generation Resources Of 20 Megawatts Or Less
  - 13.2 Additional Insureds
  - 13.3 Other Required Terms
  - 13.3A No Limitation of Liability
  - 13.4 Self-Insurance
  - 13.5 Notices; Certificates of Insurance
  - 13.6 Subcontractor Insurance
  - 13.7 Reporting Incidents
- 14 Indemnity**

- 14.1 Indemnity
- 14.2 Indemnity Procedures
- 14.3 Indemnified Person
- 14.4 Amount Owing
- 14.5 Limitation on Damages
- 14.6 Limitation of Liability in Event of Breach
- 14.7 Limited Liability in Emergency Conditions
- 15 Breach, Cure And Default**
  - 15.1 Breach
  - 15.2 Continued Operation
  - 15.3 Notice of Breach
  - 15.4 Cure and Default
  - 15.5 Right to Compel Performance
  - 15.6 Remedies Cumulative
- 16 Termination**
  - 16.1 Termination
  - 16.2 Disposition of Facilities Upon Termination
  - 16.3 FERC Approval
  - 16.4 Survival of Rights
- 17 Confidentiality**
  - 17.1 Term
  - 17.2 Scope
  - 17.3 Release of Confidential Information
  - 17.4 Rights
  - 17.5 No Warranties
  - 17.6 Standard of Care
  - 17.7 Order of Disclosure
  - 17.8 Termination of Interconnection Service Agreement
  - 17.9 Remedies
  - 17.10 Disclosure to FERC or its Staff
  - 17.11 No Interconnection Party Shall Disclose Confidential Information
  - 17.12 Information that is Public Domain
  - 17.13 Return or Destruction of Confidential Information
- 18 Subcontractors**
  - 18.1 Use of Subcontractors
  - 18.2 Responsibility of Principal
  - 18.3 Indemnification by Subcontractors
  - 18.4 Subcontractors Not Beneficiaries
- 19 Information Access And Audit Rights**
  - 19.1 Information Access
  - 19.2 Reporting of Non-Force Majeure Events
  - 19.3 Audit Rights
- 20 Disputes**
  - 20.1 Submission
  - 20.2 Rights Under The Federal Power Act
  - 20.3 Equitable Remedies

- 21 Notices**
  - 21.1 General
  - 21.2 Emergency Notices
  - 21.3 Operational Contacts
- 22 Miscellaneous**
  - 22.1 Regulatory Filing
  - 22.2 Waiver
  - 22.3 Amendments and Rights Under the Federal Power Act
  - 22.4 Binding Effect
  - 22.5 Regulatory Requirements
- 23 Representations And Warranties**
  - 23.1 General
- 24 Tax Liability**
  - 24.1 Safe Harbor Provisions
  - 24.2 Tax Indemnity
  - 24.3 Taxes Other Than Income Taxes
  - 24.4 Income Tax Gross-Up
  - 24.5 Tax Status

**ATTACHMENT O - SCHEDULE A**

**Customer Facility Location/Site Plan**

**ATTACHMENT O - SCHEDULE B**

**Single-Line Diagram**

**ATTACHMENT O - SCHEDULE C**

**List of Metering Equipment**

**ATTACHMENT O - SCHEDULE D**

**Applicable Technical Requirements and Standards**

**ATTACHMENT O - SCHEDULE E**

**Schedule of Charges**

**ATTACHMENT O - SCHEDULE F**

**Schedule of Non-Standard Terms & Conditions**

**ATTACHMENT O - SCHEDULE G**

**Interconnection Customer's Agreement to Conform with IRS Safe Harbor Provisions for Non-Taxable Status**

**ATTACHMENT O - SCHEDULE H**

**Interconnection Requirements for a Wind Generation Facility**

**ATTACHMENT O - SCHEDULE I**

**Interconnection Specifications for an Energy Storage Resource**

**ATTACHMENT O-1**

**Form of Interim Interconnection Service Agreement**

**ATTACHMENT P**

**Form of Interconnection Construction Service Agreement**

- 1.0 Parties
- 2.0 Authority
- 3.0 Customer Facility
- 4.0 Effective Date and Term
  - 4.1 Effective Date

- 4.2 Term
- 4.3 Survival
- 5.0 Construction Responsibility
- 6.0 [Reserved.]
- 7.0 Scope of Work
- 8.0 Schedule of Work
- 9.0 [Reserved.]
- 10.0 Notices
- 11.0 Waiver
- 12.0 Amendment
- 13.0 Incorporation Of Other Documents
- 14.0 Addendum of Interconnection Customer's Agreement to Conform with IRS Safe Harbor Provisions for Non-Taxable Status
- 15.0 Addendum of Non-Standard Terms and Conditions for Interconnection Service
- 16.0 Addendum of Interconnection Requirements for a Wind Generation Facility
- 17.0 Infrastructure Security of Electric System Equipment and Operations and Control Hardware and Software is Essential to Ensure Day-to-Day Reliability and Operational Security

**ATTACHMENT P - APPENDIX 1 – DEFINITIONS**

**ATTACHMENT P - APPENDIX 2 – STANDARD CONSTRUCTION TERMS AND CONDITIONS**

**Preamble**

**1 Facilitation by Transmission Provider**

**2 Construction Obligations**

- 2.1 Interconnection Customer Obligations
- 2.2 Transmission Owner Interconnection Facilities and Merchant Network Upgrades
- 2.2A Scope of Applicable Technical Requirements and Standards
- 2.3 Construction By Interconnection Customer
- 2.4 Tax Liability
- 2.5 Safety
- 2.6 Construction-Related Access Rights
- 2.7 Coordination Among Constructing Parties

**3 Schedule of Work**

- 3.1 Construction by Interconnection Customer
- 3.2 Construction by Interconnected Transmission Owner
  - 3.2.1 Standard Option
  - 3.2.2 Negotiated Contract Option
  - 3.2.3 Option to Build
- 3.3 Revisions to Schedule of Work
- 3.4 Suspension
  - 3.4.1 Costs
  - 3.4.2 Duration of Suspension
- 3.5 Right to Complete Transmission Owner Interconnection Facilities
- 3.6 Suspension of Work Upon Default

- 3.7 Construction Reports
- 3.8 Inspection and Testing of Completed Facilities
- 3.9 Energization of Completed Facilities
- 3.10 Interconnected Transmission Owner's Acceptance of Facilities Constructed by Interconnection Customer
- 4 Transmission Outages**
  - 4.1 Outages; Coordination
- 5 Land Rights; Transfer of Title**
  - 5.1 Grant of Easements and Other Land Rights
  - 5.2 Construction of Facilities on Interconnection Customer Property
  - 5.3 Third Parties
  - 5.4 Documentation
  - 5.5 Transfer of Title to Certain Facilities Constructed By Interconnection Customer
  - 5.6 Liens
- 6 Warranties**
  - 6.1 Interconnection Customer Warranty
  - 6.2 Manufacturer Warranties
- 7 [Reserved.]**
- 8 [Reserved.]**
- 9 Security, Billing And Payments**
  - 9.1 Adjustments to Security
  - 9.2 Invoice
  - 9.3 Final Invoice
  - 9.4 Disputes
  - 9.5 Interest
  - 9.6 No Waiver
- 10 Assignment**
  - 10.1 Assignment with Prior Consent
  - 10.2 Assignment Without Prior Consent
  - 10.3 Successors and Assigns
- 11 Insurance**
  - 11.1 Required Coverages For Generation Resources Of More Than 20 Megawatts and Merchant Transmission Facilities
  - 11.1A Required Coverages For Generation Resources of 20 Megawatts Or Less
  - 11.2 Additional Insureds
  - 11.3 Other Required Terms
  - 11.3A No Limitation of Liability
  - 11.4 Self-Insurance
  - 11.5 Notices; Certificates of Insurance
  - 11.6 Subcontractor Insurance
  - 11.7 Reporting Incidents
- 12 Indemnity**
  - 12.1 Indemnity
  - 12.2 Indemnity Procedures

- 12.3 Indemnified Person
- 12.4 Amount Owing
- 12.5 Limitation on Damages
- 12.6 Limitation of Liability in Event of Breach
- 12.7 Limited Liability in Emergency Conditions
- 13 Breach, Cure And Default**
  - 13.1 Breach
  - 13.2 Notice of Breach
  - 13.3 Cure and Default
    - 13.3.1 Cure of Breach
  - 13.4 Right to Compel Performance
  - 13.5 Remedies Cumulative
- 14 Termination**
  - 14.1 Termination
  - 14.2 [Reserved.]
  - 14.3 Cancellation By Interconnection Customer
  - 14.4 Survival of Rights
- 15 Force Majeure**
  - 15.1 Notice
  - 15.2 Duration of Force Majeure
  - 15.3 Obligation to Make Payments
  - 15.4 Definition of Force Majeure
- 16 Subcontractors**
  - 16.1 Use of Subcontractors
  - 16.2 Responsibility of Principal
  - 16.3 Indemnification by Subcontractors
  - 16.4 Subcontractors Not Beneficiaries
- 17 Confidentiality**
  - 17.1 Term
  - 17.2 Scope
  - 17.3 Release of Confidential Information
  - 17.4 Rights
  - 17.5 No Warranties
  - 17.6 Standard of Care
  - 17.7 Order of Disclosure
  - 17.8 Termination of Construction Service Agreement
  - 17.9 Remedies
  - 17.10 Disclosure to FERC or its Staff
  - 17.11 No Construction Party Shall Disclose Confidential Information of Another Construction Party
  - 17.12 Information that is Public Domain
  - 17.13 Return or Destruction of Confidential Information
- 18 Information Access And Audit Rights**
  - 18.1 Information Access
  - 18.2 Reporting of Non-Force Majeure Events
  - 18.3 Audit Rights
- 19 Disputes**

- 19.1 Submission
- 19.2 Rights Under The Federal Power Act
- 19.3 Equitable Remedies
- 20 Notices**
  - 20.1 General
  - 20.2 Operational Contacts
- 21 Miscellaneous**
  - 21.1 Regulatory Filing
  - 21.2 Waiver
  - 21.3 Amendments and Rights under the Federal Power Act
  - 21.4 Binding Effect
  - 21.5 Regulatory Requirements
- 22 Representations and Warranties**
  - 22.1 General

**ATTACHMENT P - SCHEDULE A**

**Site Plan**

**ATTACHMENT P - SCHEDULE B**

**Single-Line Diagram of Interconnection Facilities**

**ATTACHMENT P - SCHEDULE C**

**Transmission Owner Interconnection Facilities to be Built by Interconnected  
Transmission Owner**

**ATTACHMENT P - SCHEDULE D**

**Transmission Owner Interconnection Facilities to be Built by Interconnection  
Customer Pursuant to Option to Build**

**ATTACHMENT P - SCHEDULE E**

**Merchant Network Upgrades to be Built by Interconnected Transmission Owner**

**ATTACHMENT P - SCHEDULE F**

**Merchant Network Upgrades to be Built by Interconnection Customer  
Pursuant to Option to Build**

**ATTACHMENT P - SCHEDULE G**

**Customer Interconnection Facilities**

**ATTACHMENT P - SCHEDULE H**

**Negotiated Contract Option Terms**

**ATTACHMENT P - SCHEDULE I**

**Scope of Work**

**ATTACHMENT P - SCHEDULE J**

**Schedule of Work**

**ATTACHMENT P - SCHEDULE K**

**Applicable Technical Requirements and Standards**

**ATTACHMENT P - SCHEDULE L**

**Interconnection Customer's Agreement to Confirm with IRS Safe Harbor  
Provisions For Non-Taxable Status**

**ATTACHMENT P - SCHEDULE M**

**Schedule of Non-Standard Terms and Conditions**

**ATTACHMENT P - SCHEDULE N**

**Interconnection Requirements for a Wind Generation Facility**

**ATTACHMENT Q**

**PJM Credit Policy**

**ATTACHMENT R**

**Lost Revenues Of PJM Transmission Owners And Distribution of Revenues  
Remitted By MISO, SECA Rates to Collect PJM Transmission Owner Lost  
Revenues Under Attachment X, And Revenues From PJM Existing Transactions**

**ATTACHMENT S**

**Form of Transmission Interconnection Feasibility Study Agreement**

**ATTACHMENT T**

**Identification of Merchant Transmission Facilities**

**ATTACHMENT U**

**Independent Transmission Companies**

**ATTACHMENT V**

**Form of ITC Agreement**

**ATTACHMENT W**

**COMMONWEALTH EDISON COMPANY**

**ATTACHMENT X**

**Seams Elimination Cost Assignment Charges**

**NOTICE OF ADOPTION OF NERC TRANSMISSION LOADING RELIEF  
PROCEDURES**

**NOTICE OF ADOPTION OF LOCAL TRANSMISSION LOADING RELIEF  
PROCEDURES**

**SCHEDULE OF PARTIES ADOPTING LOCAL TRANSMISSION LOADING  
RELIEF PROCEDURES**

**ATTACHMENT Y**

**Forms of Screens Process Interconnection Request (For Generation Facilities of 2  
MW or less)**

**ATTACHMENT Z**

**Certification Codes and Standards**

**ATTACHMENT AA**

**Certification of Small Generator Equipment Packages**

**ATTACHMENT BB**

**Form of Certified Inverter-Based Generating Facility No Larger Than 10 kW  
Interconnection Service Agreement**

**ATTACHMENT CC**

**Form of Certificate of Completion  
(Small Generating Inverter Facility No Larger Than 10 kW)**

**ATTACHMENT DD**

**Reliability Pricing Model**

**ATTACHMENT EE**

**Form of Upgrade Request**

**ATTACHMENT FF**

**[Reserved]**

**ATTACHMENT GG**

**Form of Upgrade Construction Service Agreement  
Article 1 – Definitions And Other Documents**

- 1.0 Defined Terms
- 1.1 Incorporation of Other Documents
- Article 2 – Responsibility for Direct Assignment Facilities or Customer-Funded Upgrades
  - 2.0 New Service Customer Financial Responsibilities
  - 2.1 Obligation to Provide Security
  - 2.2 Failure to Provide Security
  - 2.3 Costs
  - 2.4 Transmission Owner Responsibilities
- Article 3 – Rights To Transmission Service
  - 3.0 No Transmission Service
- Article 4 – Early Termination
  - 4.0 Termination by New Service Customer
- Article 5 – Rights
  - 5.0 Rights
    - 5.1 Amount of Rights Granted
    - 5.2 Availability of Rights Granted
    - 5.3 Credits
- Article 6 – Miscellaneous
  - 6.0 Notices
  - 6.1 Waiver
  - 6.2 Amendment
  - 6.3 No Partnership
  - 6.4 Counterparts

**ATTACHMENT GG - APPENDIX I –**

**SCOPE AND SCHEDULE OF WORK FOR DIRECT ASSIGNMENT FACILITIES OR CUSTOMER-FUNDED UPGRADES TO BE BUILT BY TRANSMISSION OWNER**

**ATTACHMENT GG - APPENDIX II - DEFINITIONS**

- 1 Definitions
  - 1.1 Affiliate
  - 1.2 Applicable Laws and Regulations
  - 1.3 Applicable Regional Reliability Council
  - 1.4 Applicable Standards
  - 1.5 Breach
  - 1.6 Breaching Party
  - 1.7 Cancellation Costs
  - 1.8 Commission
  - 1.9 Confidential Information
  - 1.10 Constructing Entity
  - 1.11 Control Area
  - 1.12 Costs
  - 1.13 Default
  - 1.14 Delivering Party
  - 1.15 Emergency Condition
  - 1.16 Environmental Laws

- 1.17 Facilities Study
- 1.18 Federal Power Act
- 1.19 FERC
- 1.20 Firm Point-To-Point
- 1.21 Force Majeure
- 1.22 Good Utility Practice
- 1.23 Governmental Authority
- 1.24 Hazardous Substances
- 1.25 Incidental Expenses
- 1.26 Local Upgrades
- 1.27 Long-Term Firm Point-To-Point Transmission Service
- 1.28 MAAC
- 1.29 MAAC Control Zone
- 1.30 NERC
- 1.31 Network Upgrades
- 1.32 Office of the Interconnection
- 1.33 Operating Agreement of the PJM Interconnection, L.L.C. or Operating Agreement
- 1.34 Part I
- 1.35 Part II
- 1.36 Part III
- 1.37 Part IV
- 1.38 Part VI
- 1.39 PJM Interchange Energy Market
- 1.40 PJM Manuals
- 1.41 PJM Region
- 1.42 PJM West Region
- 1.43 Point(s) of Delivery
- 1.44 Point(s) of Receipt
- 1.45 Project Financing
- 1.46 Project Finance Entity
- 1.47 Reasonable Efforts
- 1.48 Receiving Party
- 1.49 Regional Transmission Expansion Plan
- 1.50 Schedule and Scope of Work
- 1.51 Security
- 1.52 Service Agreement
- 1.53 State
- 1.54 Transmission System
- 1.55 VACAR

**ATTACHMENT GG - APPENDIX III – GENERAL TERMS AND CONDITIONS**

- 1.0 Effective Date and Term
  - 1.1 Effective Date
  - 1.2 Term
  - 1.3 Survival
- 2.0 Facilitation by Transmission Provider

- 3.0 Construction Obligations
  - 3.1 Direct Assignment Facilities or Customer-Funded Upgrades
  - 3.2 Scope of Applicable Technical Requirements and Standards
- 4.0 Tax Liability
  - 4.1 New Service Customer Payments Taxable
  - 4.2 Income Tax Gross-Up
  - 4.3 Private Letter Ruling
  - 4.4 Refund
  - 4.5 Contests
  - 4.6 Taxes Other Than Income Taxes
  - 4.7 Tax Status
- 5.0 Safety
  - 5.1 General
  - 5.2 Environmental Releases
- 6.0 Schedule Of Work
  - 6.1 Standard Option
  - 6.2 Option to Build
  - 6.3 Revisions to Schedule and Scope of Work
  - 6.4 Suspension
- 7.0 Suspension of Work Upon Default
  - 7.1 Notification and Correction of Defects
- 8.0 Transmission Outages
  - 8.1 Outages; Coordination
- 9.0 Security, Billing and Payments
  - 9.1 Adjustments to Security
  - 9.2 Invoice
  - 9.3 Final Invoice
  - 9.4 Disputes
  - 9.5 Interest
  - 9.6 No Waiver
- 10.0 Assignment
  - 10.1 Assignment with Prior Consent
  - 10.2 Assignment Without Prior Consent
  - 10.3 Successors and Assigns
- 11.0 Insurance
  - 11.1 Required Coverages
  - 11.2 Additional Insureds
  - 11.3 Other Required Terms
  - 11.4 No Limitation of Liability
  - 11.5 Self-Insurance
  - 11.6 Notices: Certificates of Insurance
  - 11.7 Subcontractor Insurance
  - 11.8 Reporting Incidents
- 12.0 Indemnity
  - 12.1 Indemnity
  - 12.2 Indemnity Procedures

- 12.3 Indemnified Person
- 12.4 Amount Owing
- 12.5 Limitation on Damages
- 12.6 Limitation of Liability in Event of Breach
- 12.7 Limited Liability in Emergency Conditions
- 13.0 Breach, Cure And Default
  - 13.1 Breach
  - 13.2 Notice of Breach
  - 13.3 Cure and Default
  - 13.4 Right to Compel Performance
  - 13.5 Remedies Cumulative
- 14.0 Termination
  - 14.1 Termination
  - 14.2 Cancellation By New Service Customer
  - 14.3 Survival of Rights
  - 14.4 Filing at FERC
- 15.0 Force Majeure
  - 15.1 Notice
  - 15.2 Duration of Force Majeure
  - 15.3 Obligation to Make Payments
- 16.0 Confidentiality
  - 16.1 Term
  - 16.2 Scope
  - 16.3 Release of Confidential Information
  - 16.4 Rights
  - 16.5 No Warranties
  - 16.6 Standard of Care
  - 16.7 Order of Disclosure
  - 16.8 Termination of Upgrade Construction Service Agreement
  - 16.9 Remedies
  - 16.10 Disclosure to FERC or its Staff
  - 16.11 No Party Shall Disclose Confidential Information of Party 16.12 Information that is Public Domain
  - 16.13 Return or Destruction of Confidential Information
- 17.0 Information Access And Audit Rights
  - 17.1 Information Access
  - 17.2 Reporting of Non-Force Majeure Events
  - 17.3 Audit Rights
  - 17.4 Waiver
  - 17.5 Amendments and Rights under the Federal Power Act
  - 17.6 Regulatory Requirements
- 18.0 Representation and Warranties
  - 18.1 General
- 19.0 Inspection and Testing of Completed Facilities
  - 19.1 Coordination
  - 19.2 Inspection and Testing

- 19.3 Review of Inspection and Testing by Transmission Owner
- 19.4 Notification and Correction of Defects
- 19.5 Notification of Results
- 20.0 Energization of Completed Facilities
- 21.0 Transmission Owner's Acceptance of Facilities Constructed  
by New Service Customer
- 22.0 Transfer of Title to Certain Facilities Constructed By New Service Customer
- 23.0 Liens

**ATTACHMENT HH – RATES, TERMS, AND CONDITIONS OF SERVICE FOR  
PJMSETTLEMENT, INC.**

**ATTACHMENT II – MTEP PROJECT COST RECOVERY FOR ATSI ZONE**

**ATTACHMENT JJ – MTEP PROJECT COST RECOVERY FOR DEOK ZONE**

**ATTACHMENT KK - FORM OF DESIGNATED ENTITY AGREEMENT**

**ATTACHMENT LL - FORM OF INTERCONNECTION COORDINATION  
AGREEMENT**

**ATTACHMENT MM – FORM OF PSEUDO-TIE AGREEMENT – WITH NATIVE BA  
AS PARTY**

**ATTACHMENT MM-1 – FORM OF SYSTEM MODIFICATION COST  
REIMBURSEMENT AGREEMENT – PSEUDO-TIE INTO PJM**

**ATTACHMENT NN – FORM OF PSEUDO-TIE AGREEMENT WITHOUT NATIVE BA  
AS PARTY**

**ATTACHMENT OO – FORM OF DYNAMIC SCHEDULE AGREEMENT INTO THE  
PJM REGION**

**ATTACHMENT PP – FORM OF FIRM TRANSMISSION FEASIBILITY STUDY  
AGREEMENT**

## **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.

**Committed Offer:**

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

**Completed Application:**

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

**Compliance Aggregation Area (CAA):**

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

**Conditional Incremental Auction:**

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

**CONE Area:**

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

**Confidential Information:**

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

**Congestion Price:**

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

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

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

**Constraint Relaxation Logic:**

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

**Constructing Entity:**

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

**Construction Party:**

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

**Construction Service Agreement:**

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

**Control Area:**

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

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

**Control Zone:**

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

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

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

**Coordinated External Transaction:**

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

**Coordinated Transaction Scheduling:**

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

**Corporate Guaranty:**

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

**Cost of New Entry:**

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

**Costs:**

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

**Counterparty:**

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

supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member's own load .

**Credit Available for Export Transactions:**

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

**Credit Available for Virtual Transactions:**

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

**Credit Breach:**

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

**Credit-Limited Offer:**

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

**Credit Score:**

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

**CTS Enabled Interface:**

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

Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

**CTS Interface Bid:**

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

**Curtailement:**

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

**Curtailement Service Provider:**

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

**Customer Interconnection Facilities:**

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

are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

**Daily Deficiency Rate:**

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

**Daily Unforced Capacity Obligation:**

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

**Day-ahead Congestion Price:**

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

**Day-ahead Energy Market:**

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

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

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

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

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

No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

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

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

**Day-ahead Loss Price:**

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

**Day-ahead Prices:**

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

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

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

**Day-ahead Scheduling Reserves:**

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

**Day-ahead Scheduling Reserves Market:**

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

**Day-ahead Scheduling Reserves Requirement:**

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

**Day-ahead Scheduling Reserves Resources:**

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

**Day-ahead Settlement Interval:**

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

**Day-ahead System Energy Price:**

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

**Deactivation:**

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

**Deactivation Avoidable Cost Credit:**

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

**Deactivation Avoidable Cost Rate:**

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

**Deactivation Date:**

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

**Decrement Bid:**

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

**Default:**

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

**Delivering Party:**

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

**Delivery Year:**

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

**Demand Bid:**

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

**Demand Bid Limit:**

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

**Demand Bid Screening:**

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

**Demand Resource:**

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

**Demand Resource Factor or DR Factor:**

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

**Designated Agent:**

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

**Designated Entity:**

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

**Direct Assignment Facilities:**

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

**Direct 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 – L – M – N**

### **Limited Demand Resource:**

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

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

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

**Limited Resource Constraint:**

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

**Limited Resource Price Decrement:**

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

**List of Approved Contractors:**

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

**Load Management:**

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

**Load Management Event:**

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

**Load Ratio Share:**

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

**Load Reduction Event:**

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

**Load Serving Entity (LSE):**

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

**Load Shedding:**

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

**Local Upgrades:**

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

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

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

**Location:**

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

**LOC Deviation:**

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

mean the deviation of the generating unit's output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource's bus, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

**Locational Deliverability Area (LDA):**

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

**Locational Deliverability Area Reliability Requirement:**

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

**Locational Price Adder:**

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

**Locational Reliability Charge:**

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

**Locational UCAP:**

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

**Locational UCAP Seller:**

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

**Long-lead Project:**

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

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

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

**Loss Price:**

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

**M2M Flowgate:**

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

**Maintenance Adder:**

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

**Manual Load Dump Action:**

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

**Manual Load Dump Warning:**

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

**Marginal Value:**

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

**Market Monitor:**

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

**Market Monitoring Unit or MMU:**

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

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

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

**Market Operations Center:**

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

**Market Participant:**

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

**Market Participant Energy Injection:**

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

**Market Participant Energy Withdrawal:**

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

**Market Seller Offer Cap:**

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

**Market Violation:**

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

**Material Modification:**

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

**Maximum Daily Starts:**

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

**Maximum Emergency:**

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

**Maximum Facility Output:**

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

output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

**Maximum Generation Emergency:**

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

**Maximum Generation Emergency Alert:**

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

**Maximum Run Time:**

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

**Maximum Weekly Starts:**

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

**Member:**

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

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

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

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

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

**Merchant Network Upgrades:**

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

**Merchant Transmission Facilities:**

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

**Merchant Transmission Provider:**

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

**Metering Equipment:**

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

**Minimum Annual Resource Requirement:**

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

Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

**Minimum Down Time:**

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

**Minimum Extended Summer Resource Requirement:**

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

**Minimum Generation Emergency:**

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

**Minimum Participation Requirements:**

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

**Minimum Run Time:**

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

**MISO:**

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

**Multi-Driver Project:**

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

**Native Load Customers:**

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

**NERC:**

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

**NERC Interchange Distribution Calculator:**

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

**Net Benefits Test:**

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

**Net Cost of New Entry:**

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

**Net Obligation:**

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

**Net Sell Position:**

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

**Network Customer:**

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

**Network External Designated Transmission Service:**

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

**Network Integration Transmission Service:**

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

**Network Load:**

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

**Network Operating Agreement:**

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

**Network Operating Committee:**

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

**Network Resource:**

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

**Network Service User:**

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

**Network Transmission Service:**

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

**Network Upgrades:**

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

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

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

**Neutral Party:**

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

**New PJM Zone(s):**

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

**New Service Customers:**

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

**New Service Request:**

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

**New Services Queue:**

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

**New Services Queue Closing Date:**

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

**New York ISO or NYISO:**

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

**Nodal Reference Price:**

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

corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

**No-load Cost:**

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

**Nominal Rated Capability:**

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

**Nominated Demand Resource Value:**

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

**Nominated Energy Efficiency Value:**

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

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

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

**Non-Firm Sale:**

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

**Non-Firm Transmission Withdrawal Rights:**

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

**Non-Performance Charge:**

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

**Nonincumbent Developer:**

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

**Non-Regulatory Opportunity Cost:**

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

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

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

**Non-Synchronized Reserve:**

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

**Non-Synchronized Reserve Event:**

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

**Non-Variable Loads:**

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

**Non-Zone Network Load:**

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

**Normal Maximum Generation:**

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

**Normal Minimum Generation:**

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

## **Definitions – 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.

### **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 Constraint Penalty Factor:**

“Transmission Constraint Penalty Factor” shall mean the maximum cost of the re-dispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the Marginal Value.

**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, Part IV, 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 a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

**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 and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E, and Tariff, Attachment DD, section 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 and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment

DD, section 5.14E and Tariff, Attachment DD, section 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: 30<sup>th</sup> percentile
- For Up-to Congestion Counterflow Transactions when bid: 20<sup>th</sup> percentile
- For Up-to Congestion Counterflow Transactions when cleared: 5<sup>th</sup> 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.

## **5.6 Transmission Constraint Penalty Factors**

### **5.6.1 Application of Transmission Constraint Penalty Factors in the Day-ahead and Real-time Energy Markets**

In the Day-ahead Energy Market, the Transmission Constraint Penalty Factors shall be used to ensure a feasible market clearing solution but not used to determine the Marginal Value of a transmission constraint. In the Real-time Energy Market, the Office of the Interconnection shall use Transmission Constraint Penalty Factors to determine the Marginal Value for a transmission constraint when that transmission constraint cannot be managed within the binding transmission limit in a dispatch interval. The Marginal Value of the transmission constraint shall be used in the determination of the Congestion Price component of Locational Marginal Price as referenced in Tariff, Attachment K-Appendix, section 2.5 through Tariff, Attachment K-Appendix, section 2.6, and the parallel provisions of Operating Agreement, Schedule 1, section 2.5 through Operating Agreement, Schedule 1, section 2.6. The Transmission Constraint Penalty Factor may set the Marginal Value of the transmission constraint during any dispatch interval in the Real-time Energy Market depending on the following:

(a) If the market clearing software that clears the Real-time Energy Market cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval at a cost less than or equal to the Transmission Constraint Penalty Factor, the Transmission Constraint Penalty Factor shall set the Marginal Value of the transmission constraint. In such instances, to manage the flow over the constraint, the Office of the Interconnection may adjust the Transmission Constraint Penalty Factor as set forth in Tariff, Attachment K-Appendix, section 5.6.3 and the parallel provisions of Operating Agreement, Schedule 1, section 5.6.3.

(b) If the Real-time Energy Market constraints are subject to market-to-market congestion management protocols with an adjacent Regional Transmission Organization and the market clearing software cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval, the Office of the Interconnection may coordinate with such Regional Transmission Organization to either allow the Transmission Constraint Penalty Factor to set the Marginal Value of the transmission constraint or to apply the Constraint Relaxation Logic upon mutual agreement in accordance with applicable Joint Operating Agreements.

### **5.6.2 Default Transmission Constraint Penalty Factor Values**

Transmission constraints located within the metered boundaries of the PJM Region, including market-to-market coordinated constraints, regardless of voltage level, are defaulted to a \$30,000/MWh Transmission Constraint Penalty Factor in the Day-ahead Energy Market. Constraints located within the metered boundaries of the PJM Region, excluding market-to-market coordinated constraints, regardless of voltage level, are defaulted to a \$2,000/MWh Transmission Constraint Penalty Factor in the Real-time Energy Market. Market-to-market coordinated constraints in the Real-time Energy Market, located within the metered boundaries of the PJM Region, will use a default Transmission Constraint Penalty Factor of \$1,000/MWh or

a value agreed upon by PJM and the relevant Regional Transmission Organization in accordance with applicable Joint Operating Agreements.

### **5.6.3 Modifications to Transmission Constraint Penalty Factor Values**

(a) The Office of the Interconnection may modify the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market or Day-ahead Energy Market for individual transmission constraints to: (1) ensure the market clearing solution is feasible, (2) reflect changes to the operating practices which are mutually agreed upon with the neighboring RTO for managing such constraints for market-to-market coordinated constraints, or (3) reflect persistent system operational or reliability needs and the cost of the resources available to effectively relieve congestion on the constraint. When such conditions occur, the Office of the Interconnection may raise the Transmission Constraint Penalty Factor when sufficient congestion relief on the constraint cannot be provided by available resources at a cost below the default Transmission Constraint Penalty Factor. The Office of the Interconnection may lower the Transmission Constraint Penalty Factor when sufficient congestion relief on the constraint can be provided by available resources at a cost below the default Transmission Constraint Penalty Factor in order to prevent a high cost resource that cannot provide material congestion relief on the constraint from inappropriately setting price for the constraint. In either instance, to effectively relieve congestion on the constraint, the revised Transmission Constraint Penalty Factor value may be determined using the following formula, while accounting for the ability for such inputs to vary as system conditions change throughout the operating day:

$$\text{Revised Transmission Constraint Penalty Factor (\$/MW)} = \frac{\text{System Energy Price} + \text{Loss Price} + \text{Congestion Price (all binding constraints)} - \text{Incremental Energy Offer}^*}{D_{\text{fax}}}$$

Where  $D_{\text{fax}}$  equals the distribution factor of the resource for the transmission constraint

\*For purposes of this equation only, Incremental Energy Offer includes start up and no load costs where appropriate.

(b) The Office of the Interconnection shall post, as soon as practicable, on its website any changes to the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market and/or the Day-ahead Energy Market.

Section(s) of the  
PJM Operating Agreement  
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## **5.6 Transmission Constraint Penalty Factors**

### **5.6.1 Application of Transmission Constraint Penalty Factors in the Day-ahead and Real-time Energy Markets**

In the Day-ahead Energy Market, the Transmission Constraint Penalty Factors shall be used to ensure a feasible market clearing solution but not used to determine the Marginal Value of a transmission constraint. In the Real-time Energy Market, the Office of the Interconnection shall use Transmission Constraint Penalty Factors to determine the Marginal Value for a transmission constraint when that transmission constraint cannot be managed within the binding transmission limit in a dispatch interval. The Marginal Value of the transmission constraint shall be used in the determination of the Congestion Price component of Locational Marginal Price as referenced in Tariff, Attachment K-Appendix, section 2.5 through Tariff, Attachment K-Appendix, section 2.6, and the parallel provisions of Operating Agreement, Schedule 1, section 2.5 through Operating Agreement, Schedule 1, section 2.6. The Transmission Constraint Penalty Factor may set the Marginal Value of the transmission constraint during any dispatch interval in the Real-time Energy Market depending on the following:

(a) If the market clearing software that clears the Real-time Energy Market cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval at a cost less than or equal to the Transmission Constraint Penalty Factor, the Transmission Constraint Penalty Factor shall set the Marginal Value of the transmission constraint. In such instances, to manage the flow over the constraint, the Office of the Interconnection may adjust the Transmission Constraint Penalty Factor as set forth in Tariff, Attachment K-Appendix, section 5.6.3 and the parallel provisions of Operating Agreement, Schedule 1, section 5.6.3.

(b) If the Real-time Energy Market constraints are subject to market-to-market congestion management protocols with an adjacent Regional Transmission Organization and the market clearing software cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval, the Office of the Interconnection may coordinate with such Regional Transmission Organization to either allow the Transmission Constraint Penalty Factor to set the Marginal Value of the transmission constraint or to apply the Constraint Relaxation Logic upon mutual agreement in accordance with applicable Joint Operating Agreements.

### **5.6.2 Default Transmission Constraint Penalty Factor Values**

Transmission constraints located within the metered boundaries of the PJM Region, including market-to-market coordinated constraints, regardless of voltage level, are defaulted to a \$30,000/MWh Transmission Constraint Penalty Factor in the Day-ahead Energy Market. Constraints located within the metered boundaries of the PJM Region, excluding market-to-market coordinated constraints, regardless of voltage level, are defaulted to a \$2,000/MWh Transmission Constraint Penalty Factor in the Real-time Energy Market. Market-to-market coordinated constraints in the Real-time Energy Market, located within the metered boundaries of the PJM Region, will use a default Transmission Constraint Penalty Factor of \$1,000/MWh or

a value agreed upon by PJM and the relevant Regional Transmission Organization in accordance with applicable Joint Operating Agreements.

### **5.6.3 Modifications to Transmission Constraint Penalty Factor Values**

(a) The Office of the Interconnection may modify the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market or Day-ahead Energy Market for individual transmission constraints to: (1) ensure the market clearing solution is feasible, (2) reflect changes to the operating practices which are mutually agreed upon with the neighboring RTO for managing such constraints for market-to-market coordinated constraints, or (3) reflect persistent system operational or reliability needs and the cost of the resources available to effectively relieve congestion on the constraint. When such conditions occur, the Office of the Interconnection may raise the Transmission Constraint Penalty Factor when sufficient congestion relief on the constraint cannot be provided by available resources at a cost below the default Transmission Constraint Penalty Factor. The Office of the Interconnection may lower the Transmission Constraint Penalty Factor when sufficient congestion relief on the constraint can be provided by available resources at a cost below the default Transmission Constraint Penalty Factor in order to prevent a high cost resource that cannot provide material congestion relief on the constraint from inappropriately setting price for the constraint. In either instance, to effectively relieve congestion on the constraint, the revised Transmission Constraint Penalty Factor value may be determined using the following formula, while accounting for the ability for such inputs to vary as system conditions change throughout the operating day:

$$\text{Revised Transmission Constraint Penalty Factor (\$/MW)} = \frac{\text{System Energy Price} + \text{Loss Price} + \text{Congestion Price (all binding constraints)} - \text{Incremental Energy Offer}^*}{D_{\text{fax}}}$$

Where  $D_{\text{fax}}$  equals the distribution factor of the resource for the transmission constraint

\*For purposes of this equation only, Incremental Energy Offer includes start up and no load costs where appropriate.

(b) The Office of the Interconnection shall post, as soon as practicable, on its website any changes to the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market and/or the Day-ahead Energy Market.

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## PJM Open Access Transmission Tariff and PJM Operating Agreement

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- 2.5 Calculation of Real-time Prices
- 2.6 Calculation of Day-ahead Prices
- 2.6A Interface Prices
- 2.7 Performance Evaluation

**3. ACCOUNTING AND BILLING**

- 3.1 Introduction
- 3.2 Market Buyers
- 3.3 Market Sellers

- 3.3A Economic Load Response Participants
- 3.4 Transmission Customers
- 3.5 Other Control Areas
- 3.6 Metering Reconciliation
- 3.7 Inadvertent Interchange
- 3.8 Market-to-Market Coordination
- 4. [Reserved For Future Use]**
- 5. CALCULATION OF CHARGES AND CREDITS FOR TRANSMISSION CONGESTION AND LOSSES**
  - 5.1 Transmission Congestion Charge Calculation
  - 5.2 Transmission Congestion Credit Calculation
  - 5.3 Unscheduled Transmission Service (Loop Flow)
  - 5.4 Transmission Loss Charge Calculation
  - 5.5 Distribution of Total Transmission Loss Charges
  - 5.6 Transmission Constraint Penalty Factors
- 6. “MUST-RUN” FOR RELIABILITY GENERATION**
  - 6.1 Introduction
  - 6.2 Identification of Facility Outages
  - 6.3 Dispatch for Local Reliability
  - 6.4 Offer Price Caps
  - 6.5 [Reserved]
  - 6.6 Minimum Generator Operating Parameters – Parameter-Limited Schedules
- 6A. [Reserved]**
  - 6A.1 [Reserved]
  - 6A.2 [Reserved]
  - 6A.3 [Reserved]
- 7. FINANCIAL TRANSMISSION RIGHTS AUCTIONS**
  - 7.1 Auctions of Financial Transmission Rights
  - 7.1A Long-Term Financial Transmission Rights Auctions
  - 7.2 Financial Transmission Rights Characteristics
  - 7.3 Auction Procedures
  - 7.4 Allocation of Auction Revenues
  - 7.5 Simultaneous Feasibility
  - 7.6 New Stage 1 Resources
  - 7.7 Alternate Stage 1 Resources
  - 7.8 Elective Upgrade Auction Revenue Rights
  - 7.9 Residual Auction Revenue Rights
  - 7.10 Financial Settlement
  - 7.11 PJM Settlement as Counterparty
- 8. EMERGENCY AND PRE-EMERGENCY LOAD RESPONSE PROGRAM**
  - 8.1 Emergency Load Response and Pre-Emergency Load Response Program Options
  - 8.2 Participant Qualifications
  - 8.3 Metering Requirements
  - 8.4 Registration
  - 8.5 Pre-Emergency Operations
  - 8.6 Emergency Operations

- 8.7 Verification
- 8.8 Market Settlements
- 8.9 Reporting and Compliance
- 8.10 Non-Hourly Metered Customer Pilot
- 8.11 Emergency Load Response and Pre-Emergency Load Response Participant Aggregation

**ATTACHMENT L**

**List of Transmission Owners**

**ATTACHMENT M**

**PJM Market Monitoring Plan**

**ATTACHMENT M – APPENDIX**

**PJM Market Monitor Plan Attachment M Appendix**

- I Confidentiality of Data and Information
- II Development of Inputs for Prospective Mitigation
- III Black Start Service
- IV Deactivation Rates
- V Opportunity Cost Calculation
- VI FTR Forfeiture Rule
- VII Forced Outage Rule
- VIII Data Collection and Verification

**ATTACHMENT M-1 (FirstEnergy)**

**Energy Procedure Manual for Determining Supplier Total Hourly Energy Obligation**

**ATTACHMENT M-2 (First Energy)**

**Energy Procedure Manual for Determining Supplier Peak Load Share Procedures for Load Determination**

**ATTACHMENT M-2 (ComEd)**

**Determination of Capacity Peak Load Contributions and Network Service Peak Load Contributions**

**ATTACHMENT M-2 (PSE&G)**

**Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers**

**ATTACHMENT M-2 (Atlantic City Electric Company)**

**Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers**

**ATTACHMENT M-2 (Delmarva Power & Light Company)**

**Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers**

**ATTACHMENT M-2 (Delmarva Power & Light Company)**

**Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers**

**ATTACHMENT M-2 (Duke Energy Ohio, Inc.)**

**Procedures for Determination of Peak Load Contributions, Network Service Peak Load and Hourly Load Obligations for Retail Customers**

**ATTACHMENT M-3**

**Additional Procedures for Planning of Supplemental Projects**

**ATTACHMENT N**

**Form of Generation Interconnection Feasibility Study Agreement**

**ATTACHMENT N-1**

**Form of System Impact Study Agreement**

**ATTACHMENT N-2**

**Form of Facilities Study Agreement**

**ATTACHMENT N-3**

**Form of Optional Interconnection Study Agreement**

**ATTACHMENT O**

**Form of Interconnection Service Agreement**

- 1.0 Parties
- 2.0 Authority
- 3.0 Customer Facility Specifications
- 4.0 Effective Date
- 5.0 Security
- 6.0 Project Specific Milestones
- 7.0 Provision of Interconnection Service
- 8.0 Assumption of Tariff Obligations
- 9.0 Facilities Study
- 10.0 Construction of Transmission Owner Interconnection Facilities
- 11.0 Interconnection Specifications
- 12.0 Power Factor Requirement
- 12.0A RTU
- 13.0 Charges
- 14.0 Third Party Benefits
- 15.0 Waiver
- 16.0 Amendment
- 17.0 Construction With Other Parts Of The Tariff
- 18.0 Notices
- 19.0 Incorporation Of Other Documents
- 20.0 Addendum of Non-Standard Terms and Conditions for Interconnection Service
- 21.0 Addendum of Interconnection Customer's Agreement  
to Conform with IRS Safe Harbor Provisions for Non-Taxable Status
- 22.0 Addendum of Interconnection Requirements for a Wind Generation Facility
- 23.0 Infrastructure Security of Electric System Equipment and Operations and Control  
Hardware and Software is Essential to Ensure Day-to-Day Reliability and  
Operational Security

**Specifications for Interconnection Service Agreement**

- 1.0 Description of [generating unit(s)] [Merchant Transmission Facilities] (the  
Customer Facility) to be Interconnected with the Transmission System in the PJM  
Region
- 2.0 Rights
- 3.0 Construction Responsibility and Ownership of Interconnection Facilities
- 4.0 Subject to Modification Pursuant to the Negotiated Contract Option
- 4.1 Attachment Facilities Charge
- 4.2 Network Upgrades Charge

- 4.3 Local Upgrades Charge
- 4.4 Other Charges
- 4.5 Cost breakdown
- 4.6 Security Amount Breakdown

**ATTACHMENT O APPENDIX 1: Definitions**

**ATTACHMENT O APPENDIX 2: Standard Terms and Conditions for Interconnections**

- 1 Commencement, Term of and Conditions Precedent to Interconnection Service**
  - 1.1 Commencement Date
  - 1.2 Conditions Precedent
  - 1.3 Term
  - 1.4 Initial Operation
  - 1.4A Limited Operation
  - 1.5 Survival
- 2 Interconnection Service**
  - 2.1 Scope of Service
  - 2.2 Non-Standard Terms
  - 2.3 No Transmission Services
  - 2.4 Use of Distribution Facilities
  - 2.5 Election by Behind The Meter Generation
- 3 Modification Of Facilities**
  - 3.1 General
  - 3.2 Interconnection Request
  - 3.3 Standards
  - 3.4 Modification Costs
- 4 Operations**
  - 4.1 General
  - 4.2 [Reserved]
  - 4.3 Interconnection Customer Obligations
  - 4.4 Transmission Interconnection Customer Obligations
  - 4.5 Permits and Rights-of-Way
  - 4.6 No Ancillary Services
  - 4.7 Reactive Power
  - 4.8 Under- and Over-Frequency and Under- and Over- Voltage Conditions
  - 4.9 System Protection and Power Quality
  - 4.10 Access Rights
  - 4.11 Switching and Tagging Rules
  - 4.12 Communications and Data Protocol
  - 4.13 Nuclear Generating Facilities
- 5 Maintenance**
  - 5.1 General
  - 5.2 [Reserved]
  - 5.3 Outage Authority and Coordination
  - 5.4 Inspections and Testing
  - 5.5 Right to Observe Testing
  - 5.6 Secondary Systems

- 5.7 Access Rights
- 5.8 Observation of Deficiencies
- 6 Emergency Operations**
  - 6.1 Obligations
  - 6.2 Notice
  - 6.3 Immediate Action
  - 6.4 Record-Keeping Obligations
- 7 Safety**
  - 7.1 General
  - 7.2 Environmental Releases
- 8 Metering**
  - 8.1 General
  - 8.2 Standards
  - 8.3 Testing of Metering Equipment
  - 8.4 Metering Data
  - 8.5 Communications
- 9 Force Majeure**
  - 9.1 Notice
  - 9.2 Duration of Force Majeure
  - 9.3 Obligation to Make Payments
  - 9.4 Definition of Force Majeure
- 10 Charges**
  - 10.1 Specified Charges
  - 10.2 FERC Filings
- 11 Security, Billing And Payments**
  - 11.1 Recurring Charges Pursuant to Section 10
  - 11.2 Costs for Transmission Owner Interconnection Facilities
  - 11.3 No Waiver
  - 11.4 Interest
- 12 Assignment**
  - 12.1 Assignment with Prior Consent
  - 12.2 Assignment Without Prior Consent
  - 12.3 Successors and Assigns
- 13 Insurance**
  - 13.1 Required Coverages for Generation Resources Of More Than 20 Megawatts and Merchant Transmission Facilities
  - 13.1A Required Coverages for Generation Resources Of 20 Megawatts Or Less
  - 13.2 Additional Insureds
  - 13.3 Other Required Terms
  - 13.3A No Limitation of Liability
  - 13.4 Self-Insurance
  - 13.5 Notices; Certificates of Insurance
  - 13.6 Subcontractor Insurance
  - 13.7 Reporting Incidents
- 14 Indemnity**

- 14.1 Indemnity
- 14.2 Indemnity Procedures
- 14.3 Indemnified Person
- 14.4 Amount Owing
- 14.5 Limitation on Damages
- 14.6 Limitation of Liability in Event of Breach
- 14.7 Limited Liability in Emergency Conditions
- 15 Breach, Cure And Default**
  - 15.1 Breach
  - 15.2 Continued Operation
  - 15.3 Notice of Breach
  - 15.4 Cure and Default
  - 15.5 Right to Compel Performance
  - 15.6 Remedies Cumulative
- 16 Termination**
  - 16.1 Termination
  - 16.2 Disposition of Facilities Upon Termination
  - 16.3 FERC Approval
  - 16.4 Survival of Rights
- 17 Confidentiality**
  - 17.1 Term
  - 17.2 Scope
  - 17.3 Release of Confidential Information
  - 17.4 Rights
  - 17.5 No Warranties
  - 17.6 Standard of Care
  - 17.7 Order of Disclosure
  - 17.8 Termination of Interconnection Service Agreement
  - 17.9 Remedies
  - 17.10 Disclosure to FERC or its Staff
  - 17.11 No Interconnection Party Shall Disclose Confidential Information
  - 17.12 Information that is Public Domain
  - 17.13 Return or Destruction of Confidential Information
- 18 Subcontractors**
  - 18.1 Use of Subcontractors
  - 18.2 Responsibility of Principal
  - 18.3 Indemnification by Subcontractors
  - 18.4 Subcontractors Not Beneficiaries
- 19 Information Access And Audit Rights**
  - 19.1 Information Access
  - 19.2 Reporting of Non-Force Majeure Events
  - 19.3 Audit Rights
- 20 Disputes**
  - 20.1 Submission
  - 20.2 Rights Under The Federal Power Act
  - 20.3 Equitable Remedies

- 21 Notices**
  - 21.1 General
  - 21.2 Emergency Notices
  - 21.3 Operational Contacts
- 22 Miscellaneous**
  - 22.1 Regulatory Filing
  - 22.2 Waiver
  - 22.3 Amendments and Rights Under the Federal Power Act
  - 22.4 Binding Effect
  - 22.5 Regulatory Requirements
- 23 Representations And Warranties**
  - 23.1 General
- 24 Tax Liability**
  - 24.1 Safe Harbor Provisions
  - 24.2 Tax Indemnity
  - 24.3 Taxes Other Than Income Taxes
  - 24.4 Income Tax Gross-Up
  - 24.5 Tax Status

**ATTACHMENT O - SCHEDULE A**

**Customer Facility Location/Site Plan**

**ATTACHMENT O - SCHEDULE B**

**Single-Line Diagram**

**ATTACHMENT O - SCHEDULE C**

**List of Metering Equipment**

**ATTACHMENT O - SCHEDULE D**

**Applicable Technical Requirements and Standards**

**ATTACHMENT O - SCHEDULE E**

**Schedule of Charges**

**ATTACHMENT O - SCHEDULE F**

**Schedule of Non-Standard Terms & Conditions**

**ATTACHMENT O - SCHEDULE G**

**Interconnection Customer's Agreement to Conform with IRS Safe Harbor Provisions for Non-Taxable Status**

**ATTACHMENT O - SCHEDULE H**

**Interconnection Requirements for a Wind Generation Facility**

**ATTACHMENT O - SCHEDULE I**

**Interconnection Specifications for an Energy Storage Resource**

**ATTACHMENT O-1**

**Form of Interim Interconnection Service Agreement**

**ATTACHMENT P**

**Form of Interconnection Construction Service Agreement**

- 1.0 Parties
- 2.0 Authority
- 3.0 Customer Facility
- 4.0 Effective Date and Term
  - 4.1 Effective Date

- 4.2 Term
- 4.3 Survival
- 5.0 Construction Responsibility
- 6.0 [Reserved.]
- 7.0 Scope of Work
- 8.0 Schedule of Work
- 9.0 [Reserved.]
- 10.0 Notices
- 11.0 Waiver
- 12.0 Amendment
- 13.0 Incorporation Of Other Documents
- 14.0 Addendum of Interconnection Customer's Agreement to Conform with IRS Safe Harbor Provisions for Non-Taxable Status
- 15.0 Addendum of Non-Standard Terms and Conditions for Interconnection Service
- 16.0 Addendum of Interconnection Requirements for a Wind Generation Facility
- 17.0 Infrastructure Security of Electric System Equipment and Operations and Control Hardware and Software is Essential to Ensure Day-to-Day Reliability and Operational Security

**ATTACHMENT P - APPENDIX 1 – DEFINITIONS**

**ATTACHMENT P - APPENDIX 2 – STANDARD CONSTRUCTION TERMS AND CONDITIONS**

**Preamble**

**1 Facilitation by Transmission Provider**

**2 Construction Obligations**

- 2.1 Interconnection Customer Obligations
- 2.2 Transmission Owner Interconnection Facilities and Merchant Network Upgrades
- 2.2A Scope of Applicable Technical Requirements and Standards
- 2.3 Construction By Interconnection Customer
- 2.4 Tax Liability
- 2.5 Safety
- 2.6 Construction-Related Access Rights
- 2.7 Coordination Among Constructing Parties

**3 Schedule of Work**

- 3.1 Construction by Interconnection Customer
- 3.2 Construction by Interconnected Transmission Owner
  - 3.2.1 Standard Option
  - 3.2.2 Negotiated Contract Option
  - 3.2.3 Option to Build
- 3.3 Revisions to Schedule of Work
- 3.4 Suspension
  - 3.4.1 Costs
  - 3.4.2 Duration of Suspension
- 3.5 Right to Complete Transmission Owner Interconnection Facilities
- 3.6 Suspension of Work Upon Default

- 3.7 Construction Reports
- 3.8 Inspection and Testing of Completed Facilities
- 3.9 Energization of Completed Facilities
- 3.10 Interconnected Transmission Owner's Acceptance of Facilities Constructed by Interconnection Customer
- 4 Transmission Outages**
  - 4.1 Outages; Coordination
- 5 Land Rights; Transfer of Title**
  - 5.1 Grant of Easements and Other Land Rights
  - 5.2 Construction of Facilities on Interconnection Customer Property
  - 5.3 Third Parties
  - 5.4 Documentation
  - 5.5 Transfer of Title to Certain Facilities Constructed By Interconnection Customer
  - 5.6 Liens
- 6 Warranties**
  - 6.1 Interconnection Customer Warranty
  - 6.2 Manufacturer Warranties
- 7 [Reserved.]**
- 8 [Reserved.]**
- 9 Security, Billing And Payments**
  - 9.1 Adjustments to Security
  - 9.2 Invoice
  - 9.3 Final Invoice
  - 9.4 Disputes
  - 9.5 Interest
  - 9.6 No Waiver
- 10 Assignment**
  - 10.1 Assignment with Prior Consent
  - 10.2 Assignment Without Prior Consent
  - 10.3 Successors and Assigns
- 11 Insurance**
  - 11.1 Required Coverages For Generation Resources Of More Than 20 Megawatts and Merchant Transmission Facilities
  - 11.1A Required Coverages For Generation Resources of 20 Megawatts Or Less
  - 11.2 Additional Insureds
  - 11.3 Other Required Terms
  - 11.3A No Limitation of Liability
  - 11.4 Self-Insurance
  - 11.5 Notices; Certificates of Insurance
  - 11.6 Subcontractor Insurance
  - 11.7 Reporting Incidents
- 12 Indemnity**
  - 12.1 Indemnity
  - 12.2 Indemnity Procedures

- 12.3 Indemnified Person
- 12.4 Amount Owing
- 12.5 Limitation on Damages
- 12.6 Limitation of Liability in Event of Breach
- 12.7 Limited Liability in Emergency Conditions
- 13 Breach, Cure And Default**
  - 13.1 Breach
  - 13.2 Notice of Breach
  - 13.3 Cure and Default
    - 13.3.1 Cure of Breach
  - 13.4 Right to Compel Performance
  - 13.5 Remedies Cumulative
- 14 Termination**
  - 14.1 Termination
  - 14.2 [Reserved.]
  - 14.3 Cancellation By Interconnection Customer
  - 14.4 Survival of Rights
- 15 Force Majeure**
  - 15.1 Notice
  - 15.2 Duration of Force Majeure
  - 15.3 Obligation to Make Payments
  - 15.4 Definition of Force Majeure
- 16 Subcontractors**
  - 16.1 Use of Subcontractors
  - 16.2 Responsibility of Principal
  - 16.3 Indemnification by Subcontractors
  - 16.4 Subcontractors Not Beneficiaries
- 17 Confidentiality**
  - 17.1 Term
  - 17.2 Scope
  - 17.3 Release of Confidential Information
  - 17.4 Rights
  - 17.5 No Warranties
  - 17.6 Standard of Care
  - 17.7 Order of Disclosure
  - 17.8 Termination of Construction Service Agreement
  - 17.9 Remedies
  - 17.10 Disclosure to FERC or its Staff
  - 17.11 No Construction Party Shall Disclose Confidential Information of Another Construction Party 17.12 Information that is Public Domain
  - 17.13 Return or Destruction of Confidential Information
- 18 Information Access And Audit Rights**
  - 18.1 Information Access
  - 18.2 Reporting of Non-Force Majeure Events
  - 18.3 Audit Rights
- 19 Disputes**

- 19.1 Submission
- 19.2 Rights Under The Federal Power Act
- 19.3 Equitable Remedies
- 20 Notices**
  - 20.1 General
  - 20.2 Operational Contacts
- 21 Miscellaneous**
  - 21.1 Regulatory Filing
  - 21.2 Waiver
  - 21.3 Amendments and Rights under the Federal Power Act
  - 21.4 Binding Effect
  - 21.5 Regulatory Requirements
- 22 Representations and Warranties**
  - 22.1 General

**ATTACHMENT P - SCHEDULE A**

**Site Plan**

**ATTACHMENT P - SCHEDULE B**

**Single-Line Diagram of Interconnection Facilities**

**ATTACHMENT P - SCHEDULE C**

**Transmission Owner Interconnection Facilities to be Built by Interconnected  
Transmission Owner**

**ATTACHMENT P - SCHEDULE D**

**Transmission Owner Interconnection Facilities to be Built by Interconnection  
Customer Pursuant to Option to Build**

**ATTACHMENT P - SCHEDULE E**

**Merchant Network Upgrades to be Built by Interconnected Transmission Owner**

**ATTACHMENT P - SCHEDULE F**

**Merchant Network Upgrades to be Built by Interconnection Customer  
Pursuant to Option to Build**

**ATTACHMENT P - SCHEDULE G**

**Customer Interconnection Facilities**

**ATTACHMENT P - SCHEDULE H**

**Negotiated Contract Option Terms**

**ATTACHMENT P - SCHEDULE I**

**Scope of Work**

**ATTACHMENT P - SCHEDULE J**

**Schedule of Work**

**ATTACHMENT P - SCHEDULE K**

**Applicable Technical Requirements and Standards**

**ATTACHMENT P - SCHEDULE L**

**Interconnection Customer's Agreement to Confirm with IRS Safe Harbor  
Provisions For Non-Taxable Status**

**ATTACHMENT P - SCHEDULE M**

**Schedule of Non-Standard Terms and Conditions**

**ATTACHMENT P - SCHEDULE N**

**Interconnection Requirements for a Wind Generation Facility**

**ATTACHMENT Q**

**PJM Credit Policy**

**ATTACHMENT R**

**Lost Revenues Of PJM Transmission Owners And Distribution of Revenues  
Remitted By MISO, SECA Rates to Collect PJM Transmission Owner Lost  
Revenues Under Attachment X, And Revenues From PJM Existing Transactions**

**ATTACHMENT S**

**Form of Transmission Interconnection Feasibility Study Agreement**

**ATTACHMENT T**

**Identification of Merchant Transmission Facilities**

**ATTACHMENT U**

**Independent Transmission Companies**

**ATTACHMENT V**

**Form of ITC Agreement**

**ATTACHMENT W**

**COMMONWEALTH EDISON COMPANY**

**ATTACHMENT X**

**Seams Elimination Cost Assignment Charges**

**NOTICE OF ADOPTION OF NERC TRANSMISSION LOADING RELIEF  
PROCEDURES**

**NOTICE OF ADOPTION OF LOCAL TRANSMISSION LOADING RELIEF  
PROCEDURES**

**SCHEDULE OF PARTIES ADOPTING LOCAL TRANSMISSION LOADING  
RELIEF PROCEDURES**

**ATTACHMENT Y**

**Forms of Screens Process Interconnection Request (For Generation Facilities of 2  
MW or less)**

**ATTACHMENT Z**

**Certification Codes and Standards**

**ATTACHMENT AA**

**Certification of Small Generator Equipment Packages**

**ATTACHMENT BB**

**Form of Certified Inverter-Based Generating Facility No Larger Than 10 kW  
Interconnection Service Agreement**

**ATTACHMENT CC**

**Form of Certificate of Completion  
(Small Generating Inverter Facility No Larger Than 10 kW)**

**ATTACHMENT DD**

**Reliability Pricing Model**

**ATTACHMENT EE**

**Form of Upgrade Request**

**ATTACHMENT FF**

**[Reserved]**

**ATTACHMENT GG**

**Form of Upgrade Construction Service Agreement  
Article 1 – Definitions And Other Documents**

- 1.0 Defined Terms
- 1.1 Incorporation of Other Documents
- Article 2 – Responsibility for Direct Assignment Facilities or Customer-Funded Upgrades
  - 2.0 New Service Customer Financial Responsibilities
  - 2.1 Obligation to Provide Security
  - 2.2 Failure to Provide Security
  - 2.3 Costs
  - 2.4 Transmission Owner Responsibilities
- Article 3 – Rights To Transmission Service
  - 3.0 No Transmission Service
- Article 4 – Early Termination
  - 4.0 Termination by New Service Customer
- Article 5 – Rights
  - 5.0 Rights
    - 5.1 Amount of Rights Granted
    - 5.2 Availability of Rights Granted
    - 5.3 Credits
- Article 6 – Miscellaneous
  - 6.0 Notices
  - 6.1 Waiver
  - 6.2 Amendment
  - 6.3 No Partnership
  - 6.4 Counterparts

**ATTACHMENT GG - APPENDIX I –**

**SCOPE AND SCHEDULE OF WORK FOR DIRECT ASSIGNMENT FACILITIES OR CUSTOMER-FUNDED UPGRADES TO BE BUILT BY TRANSMISSION OWNER**

**ATTACHMENT GG - APPENDIX II - DEFINITIONS**

- 1 Definitions
  - 1.1 Affiliate
  - 1.2 Applicable Laws and Regulations
  - 1.3 Applicable Regional Reliability Council
  - 1.4 Applicable Standards
  - 1.5 Breach
  - 1.6 Breaching Party
  - 1.7 Cancellation Costs
  - 1.8 Commission
  - 1.9 Confidential Information
  - 1.10 Constructing Entity
  - 1.11 Control Area
  - 1.12 Costs
  - 1.13 Default
  - 1.14 Delivering Party
  - 1.15 Emergency Condition
  - 1.16 Environmental Laws

- 1.17 Facilities Study
- 1.18 Federal Power Act
- 1.19 FERC
- 1.20 Firm Point-To-Point
- 1.21 Force Majeure
- 1.22 Good Utility Practice
- 1.23 Governmental Authority
- 1.24 Hazardous Substances
- 1.25 Incidental Expenses
- 1.26 Local Upgrades
- 1.27 Long-Term Firm Point-To-Point Transmission Service
- 1.28 MAAC
- 1.29 MAAC Control Zone
- 1.30 NERC
- 1.31 Network Upgrades
- 1.32 Office of the Interconnection
- 1.33 Operating Agreement of the PJM Interconnection, L.L.C. or Operating Agreement
- 1.34 Part I
- 1.35 Part II
- 1.36 Part III
- 1.37 Part IV
- 1.38 Part VI
- 1.39 PJM Interchange Energy Market
- 1.40 PJM Manuals
- 1.41 PJM Region
- 1.42 PJM West Region
- 1.43 Point(s) of Delivery
- 1.44 Point(s) of Receipt
- 1.45 Project Financing
- 1.46 Project Finance Entity
- 1.47 Reasonable Efforts
- 1.48 Receiving Party
- 1.49 Regional Transmission Expansion Plan
- 1.50 Schedule and Scope of Work
- 1.51 Security
- 1.52 Service Agreement
- 1.53 State
- 1.54 Transmission System
- 1.55 VACAR

**ATTACHMENT GG - APPENDIX III – GENERAL TERMS AND CONDITIONS**

- 1.0 Effective Date and Term
  - 1.1 Effective Date
  - 1.2 Term
  - 1.3 Survival
- 2.0 Facilitation by Transmission Provider

- 3.0 Construction Obligations
  - 3.1 Direct Assignment Facilities or Customer-Funded Upgrades
  - 3.2 Scope of Applicable Technical Requirements and Standards
- 4.0 Tax Liability
  - 4.1 New Service Customer Payments Taxable
  - 4.2 Income Tax Gross-Up
  - 4.3 Private Letter Ruling
  - 4.4 Refund
  - 4.5 Contests
  - 4.6 Taxes Other Than Income Taxes
  - 4.7 Tax Status
- 5.0 Safety
  - 5.1 General
  - 5.2 Environmental Releases
- 6.0 Schedule Of Work
  - 6.1 Standard Option
  - 6.2 Option to Build
  - 6.3 Revisions to Schedule and Scope of Work
  - 6.4 Suspension
- 7.0 Suspension of Work Upon Default
  - 7.1 Notification and Correction of Defects
- 8.0 Transmission Outages
  - 8.1 Outages; Coordination
- 9.0 Security, Billing and Payments
  - 9.1 Adjustments to Security
  - 9.2 Invoice
  - 9.3 Final Invoice
  - 9.4 Disputes
  - 9.5 Interest
  - 9.6 No Waiver
- 10.0 Assignment
  - 10.1 Assignment with Prior Consent
  - 10.2 Assignment Without Prior Consent
  - 10.3 Successors and Assigns
- 11.0 Insurance
  - 11.1 Required Coverages
  - 11.2 Additional Insureds
  - 11.3 Other Required Terms
  - 11.4 No Limitation of Liability
  - 11.5 Self-Insurance
  - 11.6 Notices: Certificates of Insurance
  - 11.7 Subcontractor Insurance
  - 11.8 Reporting Incidents
- 12.0 Indemnity
  - 12.1 Indemnity
  - 12.2 Indemnity Procedures

- 12.3 Indemnified Person
- 12.4 Amount Owing
- 12.5 Limitation on Damages
- 12.6 Limitation of Liability in Event of Breach
- 12.7 Limited Liability in Emergency Conditions
- 13.0 Breach, Cure And Default
  - 13.1 Breach
  - 13.2 Notice of Breach
  - 13.3 Cure and Default
  - 13.4 Right to Compel Performance
  - 13.5 Remedies Cumulative
- 14.0 Termination
  - 14.1 Termination
  - 14.2 Cancellation By New Service Customer
  - 14.3 Survival of Rights
  - 14.4 Filing at FERC
- 15.0 Force Majeure
  - 15.1 Notice
  - 15.2 Duration of Force Majeure
  - 15.3 Obligation to Make Payments
- 16.0 Confidentiality
  - 16.1 Term
  - 16.2 Scope
  - 16.3 Release of Confidential Information
  - 16.4 Rights
  - 16.5 No Warranties
  - 16.6 Standard of Care
  - 16.7 Order of Disclosure
  - 16.8 Termination of Upgrade Construction Service Agreement
  - 16.9 Remedies
  - 16.10 Disclosure to FERC or its Staff
  - 16.11 No Party Shall Disclose Confidential Information of Party 16.12 Information that is Public Domain
  - 16.13 Return or Destruction of Confidential Information
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**ATTACHMENT II – MTEP PROJECT COST RECOVERY FOR ATSI ZONE**

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**ATTACHMENT KK - FORM OF DESIGNATED ENTITY AGREEMENT**

**ATTACHMENT LL - FORM OF INTERCONNECTION COORDINATION  
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**ATTACHMENT MM – FORM OF PSEUDO-TIE AGREEMENT – WITH NATIVE BA  
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**ATTACHMENT MM-1 – FORM OF SYSTEM MODIFICATION COST  
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PJM REGION**

**ATTACHMENT PP – FORM OF FIRM TRANSMISSION FEASIBILITY STUDY  
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## **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.

**Committed Offer:**

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

**Completed Application:**

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

**Compliance Aggregation Area (CAA):**

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

**Conditional Incremental Auction:**

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

**CONE Area:**

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

**Confidential Information:**

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

**Congestion Price:**

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

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

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

**Constraint Relaxation Logic:**

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

**Constructing Entity:**

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

**Construction Party:**

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

**Construction Service Agreement:**

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

**Control Area:**

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

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

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

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

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

**Control Zone:**

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

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

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

**Coordinated External Transaction:**

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

**Coordinated Transaction Scheduling:**

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

**Corporate Guaranty:**

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

**Cost of New Entry:**

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

**Costs:**

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

**Counterparty:**

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

supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member's own load .

**Credit Available for Export Transactions:**

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

**Credit Available for Virtual Transactions:**

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

**Credit Breach:**

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

**Credit-Limited Offer:**

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

**Credit Score:**

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

**CTS Enabled Interface:**

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

Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

**CTS Interface Bid:**

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

**Curtailement:**

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

**Curtailement Service Provider:**

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

**Customer Interconnection Facilities:**

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

are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

**Daily Deficiency Rate:**

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

**Daily Unforced Capacity Obligation:**

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

**Day-ahead Congestion Price:**

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

**Day-ahead Energy Market:**

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

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

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

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

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

No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

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

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

**Day-ahead Loss Price:**

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

**Day-ahead Prices:**

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

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

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

**Day-ahead Scheduling Reserves:**

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

**Day-ahead Scheduling Reserves Market:**

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

**Day-ahead Scheduling Reserves Requirement:**

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

**Day-ahead Scheduling Reserves Resources:**

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

**Day-ahead Settlement Interval:**

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

**Day-ahead System Energy Price:**

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

**Deactivation:**

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

**Deactivation Avoidable Cost Credit:**

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

**Deactivation Avoidable Cost Rate:**

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

**Deactivation Date:**

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

**Decrement Bid:**

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

**Default:**

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

**Delivering Party:**

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

**Delivery Year:**

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

**Demand Bid:**

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

**Demand Bid Limit:**

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

**Demand Bid Screening:**

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

**Demand Resource:**

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

**Demand Resource Factor or DR Factor:**

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

**Designated Agent:**

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

**Designated Entity:**

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

**Direct Assignment Facilities:**

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

**Direct 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 – L – M – N**

### **Limited Demand Resource:**

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

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

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

**Limited Resource Constraint:**

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

**Limited Resource Price Decrement:**

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

**List of Approved Contractors:**

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

**Load Management:**

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

**Load Management Event:**

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

**Load Ratio Share:**

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

**Load Reduction Event:**

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

**Load Serving Entity (LSE):**

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

**Load Shedding:**

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

**Local Upgrades:**

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

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

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

**Location:**

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

**LOC Deviation:**

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

mean the deviation of the generating unit's output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource's bus, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

**Locational Deliverability Area (LDA):**

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

**Locational Deliverability Area Reliability Requirement:**

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

**Locational Price Adder:**

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

**Locational Reliability Charge:**

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

**Locational UCAP:**

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

**Locational UCAP Seller:**

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

**Long-lead Project:**

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

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

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

**Loss Price:**

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

**M2M Flowgate:**

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

**Maintenance Adder:**

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

**Manual Load Dump Action:**

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

**Manual Load Dump Warning:**

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

**Marginal Value:**

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

**Market Monitor:**

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

**Market Monitoring Unit or MMU:**

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

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

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

**Market Operations Center:**

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

**Market Participant:**

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

**Market Participant Energy Injection:**

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

**Market Participant Energy Withdrawal:**

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

**Market Seller Offer Cap:**

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

**Market Violation:**

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

**Material Modification:**

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

**Maximum Daily Starts:**

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

**Maximum Emergency:**

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

**Maximum Facility Output:**

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

output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

**Maximum Generation Emergency:**

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

**Maximum Generation Emergency Alert:**

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

**Maximum Run Time:**

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

**Maximum Weekly Starts:**

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

**Member:**

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

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

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

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

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

**Merchant Network Upgrades:**

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

**Merchant Transmission Facilities:**

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

**Merchant Transmission Provider:**

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

**Metering Equipment:**

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

**Minimum Annual Resource Requirement:**

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

Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

**Minimum Down Time:**

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

**Minimum Extended Summer Resource Requirement:**

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

**Minimum Generation Emergency:**

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

**Minimum Participation Requirements:**

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

**Minimum Run Time:**

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

**MISO:**

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

**Multi-Driver Project:**

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

**Native Load Customers:**

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

**NERC:**

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

**NERC Interchange Distribution Calculator:**

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

**Net Benefits Test:**

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

**Net Cost of New Entry:**

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

**Net Obligation:**

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

**Net Sell Position:**

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

**Network Customer:**

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

**Network External Designated Transmission Service:**

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

**Network Integration Transmission Service:**

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

**Network Load:**

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

**Network Operating Agreement:**

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

**Network Operating Committee:**

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

**Network Resource:**

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

**Network Service User:**

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

**Network Transmission Service:**

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

**Network Upgrades:**

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

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

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

**Neutral Party:**

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

**New PJM Zone(s):**

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

**New Service Customers:**

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

**New Service Request:**

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

**New Services Queue:**

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

**New Services Queue Closing Date:**

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

**New York ISO or NYISO:**

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

**Nodal Reference Price:**

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

corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

**No-load Cost:**

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

**Nominal Rated Capability:**

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

**Nominated Demand Resource Value:**

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

**Nominated Energy Efficiency Value:**

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

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

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

**Non-Firm Sale:**

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

**Non-Firm Transmission Withdrawal Rights:**

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

**Non-Performance Charge:**

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

**Nonincumbent Developer:**

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

**Non-Regulatory Opportunity Cost:**

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

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

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

**Non-Synchronized Reserve:**

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

**Non-Synchronized Reserve Event:**

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

**Non-Variable Loads:**

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

**Non-Zone Network Load:**

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

**Normal Maximum Generation:**

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

**Normal Minimum Generation:**

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

## **Definitions – 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.

### **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 Constraint Penalty Factor:**

“Transmission Constraint Penalty Factor” shall mean the maximum cost of the re-dispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the Marginal Value.

**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, Part IV, 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 a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

**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 and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E, and Tariff, Attachment DD, section 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 and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment

DD, section 5.14E and Tariff, Attachment DD, section 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: 30<sup>th</sup> percentile
- For Up-to Congestion Counterflow Transactions when bid: 20<sup>th</sup> percentile
- For Up-to Congestion Counterflow Transactions when cleared: 5<sup>th</sup> 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.

## **5.6 Transmission Constraint Penalty Factors**

### **5.6.1 Application of Transmission Constraint Penalty Factors in the Day-ahead and Real-time Energy Markets**

In the Day-ahead Energy Market, the Transmission Constraint Penalty Factors shall be used to ensure a feasible market clearing solution but not used to determine the Marginal Value of a transmission constraint. In the Real-time Energy Market, the Office of the Interconnection shall use Transmission Constraint Penalty Factors to determine the Marginal Value for a transmission constraint when that transmission constraint cannot be managed within the binding transmission limit in a dispatch interval. The Marginal Value of the transmission constraint shall be used in the determination of the Congestion Price component of Locational Marginal Price as referenced in Tariff, Attachment K-Appendix, section 2.5 through Tariff, Attachment K-Appendix, section 2.6, and the parallel provisions of Operating Agreement, Schedule 1, section 2.5 through Operating Agreement, Schedule 1, section 2.6. The Transmission Constraint Penalty Factor may set the Marginal Value of the transmission constraint during any dispatch interval in the Real-time Energy Market depending on the following:

(a) If the market clearing software that clears the Real-time Energy Market cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval at a cost less than or equal to the Transmission Constraint Penalty Factor, the Transmission Constraint Penalty Factor shall set the Marginal Value of the transmission constraint. In such instances, to manage the flow over the constraint, the Office of the Interconnection may adjust the Transmission Constraint Penalty Factor as set forth in Tariff, Attachment K-Appendix, section 5.6.3 and the parallel provisions of Operating Agreement, Schedule 1, section 5.6.3.

(b) If the Real-time Energy Market constraints are subject to market-to-market congestion management protocols with an adjacent Regional Transmission Organization and the market clearing software cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval, the Office of the Interconnection may coordinate with such Regional Transmission Organization to either allow the Transmission Constraint Penalty Factor to set the Marginal Value of the transmission constraint or to apply the Constraint Relaxation Logic upon mutual agreement in accordance with applicable Joint Operating Agreements.

### **5.6.2 Default Transmission Constraint Penalty Factor Values**

Transmission constraints located within the metered boundaries of the PJM Region, including market-to-market coordinated constraints, regardless of voltage level, are defaulted to a \$30,000/MWh Transmission Constraint Penalty Factor in the Day-ahead Energy Market. Constraints located within the metered boundaries of the PJM Region, excluding market-to-market coordinated constraints, regardless of voltage level, are defaulted to a \$2,000/MWh Transmission Constraint Penalty Factor in the Real-time Energy Market. Market-to-market coordinated constraints in the Real-time Energy Market, located within the metered boundaries of the PJM Region, will use a default Transmission Constraint Penalty Factor of \$1,000/MWh or

a value agreed upon by PJM and the relevant Regional Transmission Organization in accordance with applicable Joint Operating Agreements.

### 5.6.3 Modifications to Transmission Constraint Penalty Factor Values

(a) The Office of the Interconnection may modify the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market or Day-ahead Energy Market for individual transmission constraints to: (1) ensure the market clearing solution is feasible, (2) reflect changes to the operating practices which are mutually agreed upon with the neighboring RTO for managing such constraints for market-to-market coordinated constraints, or (3) reflect persistent system operational or reliability needs and the cost of the resources available to effectively relieve congestion on the constraint. When such conditions occur, the Office of the Interconnection may raise the Transmission Constraint Penalty Factor when sufficient congestion relief on the constraint cannot be provided by available resources at a cost below the default Transmission Constraint Penalty Factor. The Office of the Interconnection may lower the Transmission Constraint Penalty Factor when sufficient congestion relief on the constraint can be provided by available resources at a cost below the default Transmission Constraint Penalty Factor in order to prevent a high cost resource that cannot provide material congestion relief on the constraint from inappropriately setting price for the constraint. In either instance, to effectively relieve congestion on the constraint, the revised Transmission Constraint Penalty Factor value may be determined using the following formula, while accounting for the ability for such inputs to vary as system conditions change throughout the operating day:

$$\text{Revised Transmission Constraint Penalty Factor (\$/MW)} = \frac{\text{System Energy Price} + \text{Loss Price} + \text{Congestion Price (all binding constraints)} - \text{Incremental Energy Offer}^*}{D_{\text{fax}}}$$

Where  $D_{\text{fax}}$  equals the distribution factor of the resource for the transmission constraint

\*For purposes of this equation only, Incremental Energy Offer includes start up and no load costs where appropriate.

(b) The Office of the Interconnection shall post, as soon as practicable, on its website any changes to the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market and/or the Day-ahead Energy Market.

Section(s) of the  
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  - 2.1 Common and Uniform Procedures
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- 3. NEGOTIATION AND MEDIATION
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- 4.9 Confidentiality
- 4.10 Timetable
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  - 1.3 Establishment of Committees
  - 1.4 Contents of the Regional Transmission Expansion Plan
  - 1.5 Procedure for Development of the Regional Transmission Expansion Plan
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2. Protection of Confidentiality
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3. Remedies
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1. Definitions
2. Requisite Authority
3. Protection of Confidential Information
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  - Exhibit A - Certification List of Authorized Persons

#### SCHEDULE 11 – ALLOCATION OF COSTS ASSOCIATED WITH NERC PENALTY ASSESSMENTS

- 1.1 Purpose and Objectives

- 1.2 Definitions
- 1.3 Allocation of Costs When PJM is the Registered Entity
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- 1.5

**SCHEDULE 12 – PJM MEMBER LIST**

**RESOLUTION TO AMEND THE PROCEDURES REQUIRING THE RETENTION OF AN INDEPENDENT CONSULTANT TO PROPOSE A LIST OF CANDIDATES FOR THE BOARD OF MANAGERS ELECTION FOR 2001**

## **5.6 Transmission Constraint Penalty Factors**

### **5.6.1 Application of Transmission Constraint Penalty Factors in the Day-ahead and Real-time Energy Markets**

In the Day-ahead Energy Market, the Transmission Constraint Penalty Factors shall be used to ensure a feasible market clearing solution but not used to determine the Marginal Value of a transmission constraint. In the Real-time Energy Market, the Office of the Interconnection shall use Transmission Constraint Penalty Factors to determine the Marginal Value for a transmission constraint when that transmission constraint cannot be managed within the binding transmission limit in a dispatch interval. The Marginal Value of the transmission constraint shall be used in the determination of the Congestion Price component of Locational Marginal Price as referenced in Tariff, Attachment K-Appendix, section 2.5 through Tariff, Attachment K-Appendix, section 2.6, and the parallel provisions of Operating Agreement, Schedule 1, section 2.5 through Operating Agreement, Schedule 1, section 2.6. The Transmission Constraint Penalty Factor may set the Marginal Value of the transmission constraint during any dispatch interval in the Real-time Energy Market depending on the following:

(a) If the market clearing software that clears the Real-time Energy Market cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval at a cost less than or equal to the Transmission Constraint Penalty Factor, the Transmission Constraint Penalty Factor shall set the Marginal Value of the transmission constraint. In such instances, to manage the flow over the constraint, the Office of the Interconnection may adjust the Transmission Constraint Penalty Factor as set forth in Tariff, Attachment K-Appendix, section 5.6.3 and the parallel provisions of Operating Agreement, Schedule 1, section 5.6.3.

(b) If the Real-time Energy Market constraints are subject to market-to-market congestion management protocols with an adjacent Regional Transmission Organization and the market clearing software cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval, the Office of the Interconnection may coordinate with such Regional Transmission Organization to either allow the Transmission Constraint Penalty Factor to set the Marginal Value of the transmission constraint or to apply the Constraint Relaxation Logic upon mutual agreement in accordance with applicable Joint Operating Agreements.

### **5.6.2 Default Transmission Constraint Penalty Factor Values**

Transmission constraints located within the metered boundaries of the PJM Region, including market-to-market coordinated constraints, regardless of voltage level, are defaulted to a \$30,000/MWh Transmission Constraint Penalty Factor in the Day-ahead Energy Market. Constraints located within the metered boundaries of the PJM Region, excluding market-to-market coordinated constraints, regardless of voltage level, are defaulted to a \$2,000/MWh Transmission Constraint Penalty Factor in the Real-time Energy Market. Market-to-market coordinated constraints in the Real-time Energy Market, located within the metered boundaries of the PJM Region, will use a default Transmission Constraint Penalty Factor of \$1,000/MWh or

a value agreed upon by PJM and the relevant Regional Transmission Organization in accordance with applicable Joint Operating Agreements.

### 5.6.3 Modifications to Transmission Constraint Penalty Factor Values

(a) The Office of the Interconnection may modify the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market or Day-ahead Energy Market for individual transmission constraints to: (1) ensure the market clearing solution is feasible, (2) reflect changes to the operating practices which are mutually agreed upon with the neighboring RTO for managing such constraints for market-to-market coordinated constraints, or (3) reflect persistent system operational or reliability needs and the cost of the resources available to effectively relieve congestion on the constraint. When such conditions occur, the Office of the Interconnection may raise the Transmission Constraint Penalty Factor when sufficient congestion relief on the constraint cannot be provided by available resources at a cost below the default Transmission Constraint Penalty Factor. The Office of the Interconnection may lower the Transmission Constraint Penalty Factor when sufficient congestion relief on the constraint can be provided by available resources at a cost below the default Transmission Constraint Penalty Factor in order to prevent a high cost resource that cannot provide material congestion relief on the constraint from inappropriately setting price for the constraint. In either instance, to effectively relieve congestion on the constraint, the revised Transmission Constraint Penalty Factor value may be determined using the following formula, while accounting for the ability for such inputs to vary as system conditions change throughout the operating day:

$$\text{Revised Transmission Constraint Penalty Factor (\$/MW)} = \frac{\text{System Energy Price} + \text{Loss Price} + \text{Congestion Price (all binding constraints)} - \text{Incremental Energy Offer}^*}{D_{\text{fax}}}$$

Where  $D_{\text{fax}}$  equals the distribution factor of the resource for the transmission constraint

\*For purposes of this equation only, Incremental Energy Offer includes start up and no load costs where appropriate.

(b) The Office of the Interconnection shall post, as soon as practicable, on its website any changes to the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market and/or the Day-ahead Energy Market.

## Attachment C

Affidavit of Timothy Horger

**UNITED STATES OF AMERICA  
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.,                    )  
  )           Docket No. ER19-\_\_\_\_-000  
  )

**AFFIDAVIT OF TIMOTHY HORGER  
ON BEHALF OF PJM INTERCONNECTION, L.L.C.**

1. My name is Timothy Horger. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I currently serve as the Director, Energy Market Operations, for PJM Interconnection, L.L.C. (“PJM”). I am submitting this affidavit on behalf of PJM in support of the proposed Tariff revisions being filed today by PJM in the captioned proceeding.

2. I joined PJM in 2002. Prior to my current position, I worked at PJM as Manager, Interregional Market Operations. Prior to my employment at PJM, I worked as a Power Systems and Control Engineer at Laser Technology, Inc.

3. As part of my work at PJM, I am responsible for overseeing the operation of PJM’s Day-ahead Energy Market and Real-time Energy Market. As relevant here, I am intimately aware of how PJM uses Transmission Constraint Penalty Factors to relieve transmission constraints that may exist on the system.

4. The Transmission Constraint Penalty Factor is a parameter used in the Market Clearing Engines and dictates the maximum cost that is willing to be incurred to control the flows on a transmission constraint. This limits the resources that the market clearing software can utilize to control a constraint to those that have a cost less than or equal to the penalty factor.

**Transmission Constraint Penalty Factor Values**

5. PJM applies a default Transmission Constraint Penalty Factor of \$30,000/MWh in the Day-ahead Energy Market. Constraints located within the metered boundaries of the PJM Region, excluding Market-to-Market coordinated constraints, are defaulted to \$2,000/MWh in the Real-time Energy Market, while Market-to-Market coordinated constraints in the Real-time Energy Market, located within the metered boundaries of the PJM Region, use a default Transmission Constraint Penalty Factor of \$1,000/MWh.

6. I have reviewed PJM’s historical data with respect to the use of the default Transmission Constraint Penalty Factor values and believe the current values are appropriate. For instance, in 2017, only 8% of transmission constraints within PJM’s metered boundaries resulted in occasions where the flows on the transmission constraint could not be controlled at a cost below the default Transmission Constraint Penalty Factor used in the Real-time Energy Market. These default values have been used by PJM for several years and are set sufficiently high to ensure that the market clearing engine will automatically use all physically available dispatch options to satisfy the transmission network’s limits. This also ensures that the market clearing engine makes commitment and dispatch decisions using all available units to relieve a

transmission constraint. Doing so minimizes the need for Operator-initiated Commitments to manage congestion or to relieve constraints in a post-contingency situation.

7. The default Transmission Constraint Penalty Factor value is considerably higher in the Day-ahead Energy Market when compared to the Real-time Energy Market because the Day-ahead Energy Market is a 24 hour look-ahead unit commitment, and for it to clear reasonable offers, the Transmission Constraint Penalty Factors need to capture the startup and no load costs associated with offline and longer start-time resources that can be used to reduce power flows at the transmission constraint. In contrast, the Real-time Energy Market is a short term economic dispatch problem, which simply dispatches the already committed resources. Therefore the Transmission Penalty Factors used in the Real-time Energy Market only need to be high enough to cover the incremental energy offer cost. If the default Transmission Constraint Penalty Factor used in the Day-ahead Energy Market is set too low, the clearing engine may not commit the appropriate available generation to alleviate the constraint. Therefore, PJM uses the \$30,000/MWh value to ensure that transmission constraints are being properly solved with all available generation. Historical experience demonstrates that the \$30,000/MWh Transmission Constraint Penalty Factor used in the Day-ahead Energy Market has been sufficient without compromising solution performance.

#### **Circumstances Under Which PJM May Modify the Transmission Constraint Penalty Factor Value**

8. In order to maintain adequate system control, there are occasions when the default values may need to be adjusted higher or lower in order to reflect persistent system operational or reliability needs and to accurately reflect the costs of resources available to relieve congestion. In addition, a different value may be appropriate to reflect changes to the operating practices with the neighboring Regional Transmission Organization (“RTO”) for managing Market-to-Market coordinated constraints. Also, certain Transmission Facilities may have unique attributes where the application of the default value may not be appropriate.

9. That is, when not enough relief can be provided by resources at a cost below the default penalty factor which results in the flow on a constraint above or approaching the binding limit, PJM may increase the penalty factor (or willingness to pay for control) if there are available resources with a \$/MW cost above the default Transmission Constraint Penalty Factor that can provide additional relief. Conditions requiring increasing the penalty factor for a transmission constraint include, but are not limited to, when PJM needs to:

- raise a resource’s output to help alleviate the constraint, but the system energy price has decreased such that the resource’s \$/MW cost exceeds the default penalty factor.
- lower a resource’s output to help alleviate the constraint, but the system energy price has increased such that the resource’s \$/MW cost exceeds the default penalty factor.

- raise or lower a resource’s output to help alleviate the constraint, but the resource’s effective cost is above the default penalty factor based on the resource’s offer price and/or distribution factor (“D<sub>fax</sub>”).<sup>1</sup>

10. When the congestion flow is within the controlled limit, PJM may lower the default Transmission Constraint Penalty Factor for a constraint in order to prevent a high cost resource that cannot provide material relief on the constraint from inappropriately setting price. For example, PJM may lower the default penalty factor for radial constraints where sufficient relief is available but isolated in a localized area. This prevents the market clearing engine from attempting to over-control the constraint and dispatch resources that cannot provide material relief, which would result in Area Control Error deviations and/or other system controlling issues. Another example where the penalty factor may be lowered is when a thermal constraint is being used as a surrogate for a voltage control issue (need for reactive power rather than real power). The market clearing engines model real power flows, rather than reactive power flows. Therefore, when reactive power issues are identified, PJM dispatchers must make resource commitments outside of the market clearing engines to address these issues. These reactive power needs are then modeled in the market clearing engines via the use of a thermal surrogate constraint so that the cost of these out of market commitments can be captured in pricing. Because the intent of these constraints is to capture the cost of out of market commitments, rather than to find relief for real power flows over the constraint, PJM lowers the Transmission Constraint Penalty factor to reflect the cost of resource that was committed for reactive control. This prevents the market clearing engine from attempting to dispatch additional resources that cannot provide voltage support to the affected area.

### **Calculating the Modified Value**

11. When an adjustment to the Transmission Constraint Penalty Factor is appropriate, PJM dispatchers and real-time markets support engineers make real-time evaluations of the appropriate penalty factor adjustments based on the effective cost (expressed in \$/MW) of the resources that are available to provide the necessary congestion relief. The effective cost is approximated using the resources’ incremental cost, D<sub>fax</sub> on the constraint, and the system energy cost. Although the actual effective cost that is considered by the market clearing engines is the result of a complex optimization problem, the effective cost can be approximated using the simplified formula below:

$$\text{Effective Cost (\$/MWh)} = |(\text{System Energy Price} - \text{Incremental Cost}) / \text{Dfax}|$$

12. As an example, when the System Energy Price is \$40, the resource’s Incremental Cost is \$30, and the resources D<sub>fax</sub> is -0.10:

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<sup>1</sup> Distribution Factor represents the change (or sensitivity) of active power flow in a reference direction on a transmission line with respect to a change in injection at the generator bus and a corresponding change in withdrawal at the reference bus.

$$\text{Effective Cost (\$/MWh)} = |(\$40 - \$30)/0.10|$$
$$\text{Effective Cost (\$/MWh)} = 100$$

If the System Energy Price increased to \$100 and the resource's Incremental Cost and  $D_{\text{fax}}$  remained the same, then the effective cost would be:

$$\text{Effective Cost (\$/MWh)} = |(\$100 - \$30)/0.10|$$
$$\text{Effective Cost (\$/MWh)} = 700$$

13. This concludes my Affidavit.

