

6.4 Offer Price Caps.

6.4.1 Applicability.

(a) If, at any time, it is determined by the Office of the Interconnection in accordance with Sections 1.10.8 or 6.1 of this Schedule that any generation resource may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, the offer prices for energy from such resource shall be capped as specified below. For such generation resources committed in the Day-ahead Energy Market, if the Office of the Interconnection is able to do so, such offer prices shall be capped for the entire commitment period, and such offer prices will be capped at a cost-based offer in accordance with section 6.4.2 and committed at the market-based offer or cost-based offer which results in the lowest overall system production cost. For such generation resources committed in the Real-time Energy Market such offer prices shall be capped at a cost-based offer in accordance with section 6.4.2 and dispatched on the market-based offer or cost-based offer which results in the lowest dispatch cost in accordance with 6.4.1(g) until the earlier of: (i) the resource is released from its commitment by the Office of the Interconnection; (ii) the end of the Operating Day; or (iii) the start of the generation resource's next pre-existing commitment.

The offer on which a resource is committed shall initially be determined at the time of the commitment. If any of the resource's Incremental Energy Offer, No-load Cost or Start-Up Cost are updated for any portion of the offer capped hours subsequent to commitment, the Office of the Interconnection will redetermine the level of the offer cap using the updated offer values. The Office of the Interconnection will dispatch the resource on the market-based offer or cost-based offer which results in the lowest dispatch cost as determined in accordance with section 6.4.1(g).

Resources that are self-scheduled to run in either the Day-ahead Energy Market or in the Real-time Energy Market are subject to the provisions of this section 6.4. The offer on which a resource is dispatched shall be used to determine any Locational Marginal Price affected by the offer price of such resource and as further limited as described in Operating Agreement, Schedule 1, section 2.4 and Operating Agreement, Schedule 1, section 2.4A.

In accordance with section 6.4.1(h), a generation resource that is offer capped in the Real-time Energy Market but released from its commitment by the Office of the Interconnection will be subject to the three pivotal supplier test and further offer capping, as applicable, if the resource is committed for a period later in the same Operating Day.

(b) The energy offer price by any generation resource requested to be dispatched in accordance with Section 6.3 of this Schedule shall be capped at the levels specified in Section 6.4.2 of this Schedule. If the Office of the Interconnection is able to do so, such offer prices shall be capped only during each hour when the affected resource is so scheduled, and otherwise shall be capped for the entire Operating Day. Energy offer prices as capped shall be used to determine any Locational Marginal Price affected by the price of such resource.

(c) Generation resources subject to an offer price cap shall be paid for energy at the applicable Locational Marginal Price.

(d) [Reserved for Future Use]

(e) Offer price caps under section 6.4 of this Schedule shall be suspended for a generation resource with respect to transmission limit(s) for any period in which a generation resource is committed by the Office of the Interconnection for the Operating Day or any period for which the generation resource has been self-scheduled where (1) there are not three or fewer generation suppliers available for redispatch under subsection (a) that are jointly pivotal with respect to such transmission limit(s), and (2) the Market Seller of the generation resource, when combined with the two largest other generation suppliers, is not pivotal (“three pivotal supplier test”). In the event the Office of the Interconnection system is unable to perform the three pivotal supplier test for a Market Seller, generation resources of that Market Seller that are dispatched to control transmission constraints will be dispatched on the resource’s market-based offer or cost-based offer which results in the lowest dispatch cost as determined in accordance with section 6.4.1(g).

(f) For the purposes of conducting the three pivotal supplier test in subsection (e), the following applies:

- (i) All megawatts of available incremental supply, including available self-scheduled supply for which the power distribution factor (“dfax”) has an absolute value equal to or greater than the dfax used by the Office of the Interconnection’s system operators when evaluating the impact of generation with respect to the constraint (“effective megawatts”) will be included in the available supply analysis at costs equal to the cost-based offers of the available incremental supply adjusted for dfax (“effective costs”). The Office of the Interconnection will post on the PJM website the dfax value used by operators with respect to a constraint when it varies from three percent.
- (ii) The three pivotal supplier test will include in the definition of the relevant market incremental supply up to and including all such supply available at an effective cost equal to 150% of the cost-based clearing price calculated using effective costs and effective megawatts and the need for megawatts to solve the constraint.
- (iii) Offer price caps will apply on a generation supplier basis (i.e. not a generating unit by generating unit basis) and only the generation suppliers that fail the three pivotal supplier test with respect to any hour in the relevant period will have their units that are dispatched with respect to the constraint offer capped. A generation supplier for the purposes of this section includes corporate affiliates. Supply controlled by a generation supplier or its affiliates by contract with unaffiliated third parties or otherwise will be included as supply of that generation supplier; supply owned by a generation supplier but controlled by an unaffiliated third party by contract or otherwise will be included as supply of that third party.

A generation supplier's units, including self-scheduled units, are offer capped if, when combined with the two largest other generation suppliers, the generation supplier is pivotal.

- (iv) In the Day-ahead Energy Market, the Office of the Interconnection shall include price sensitive demand, Increment Offers and Decrement Bids as demand or supply, as applicable, in the relevant market.

(g) In the Real-time Energy Market, the schedule on which offer capped resources will be placed shall be determined using dispatch cost, where dispatch cost is calculated pursuant to the following formulas:

Dispatch cost for the applicable hour = ((Incremental Energy Offer @ Economic Minimum for the hour [\$/MWh] * Economic Minimum for the hour [MW]) + No-load Cost for the hour [\$/H])

- (i) For resources committed in the Real-time Energy Market, the resource is committed on the offer with the lowest Total Dispatch cost at the time of commitment,

where:

Total Dispatch cost = Sum of hourly dispatch cost over a resource's minimum run time [\$] + Start-Up Cost [\$]

- (ii) For resources operating in real-time pursuant to a day-ahead or real-time commitment, and whose offers are updated after commitment, the resource is dispatched on the offer with the lowest dispatch cost for the each of the updated hours.
- (iii) However, once the resource is dispatched on a cost-based offer, it will remain on a cost-based offer regardless of the determination of the cheapest schedule.

(h) A generation resource that was committed in the Day-ahead Energy Market or Real-time Energy Market, is operating in real time, and may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, will be offer price capped, subject to the outcome of a three pivotal supplier test, for each hour the resource operates beyond its committed hours or Minimum Run Time, whichever is greater, or in the case of resources self-scheduled in the Real-time Energy Market, for each hour the resource operates beyond its first hour of operation, in accordance with the following provisions.

- (i) If the resource is operating on a cost-based offer, it will remain on a cost-based offer regardless of the results of the three pivotal supplier test.

- (ii) If the resource is operating on a market-based offer and the Market Seller fails the three pivotal supplier test then the resource will be dispatched on the cheaper of its market-based offer or the cost-based offer representing the offer cap as determined by section 6.4.2, whichever results in the lowest dispatch cost as determined under section 6.4.1(g).
- (iii) If the Market Seller passes the three pivotal supplier test and the resource is currently operating on a market-based offer then the resource will remain on that offer, unless the Market Seller elects to not have its market-based offer considered for dispatch and to have only the cost-based offer that represents the offer cap level as determined under section 6.4.2 considered for dispatch in which case the resource will be dispatched on its cost-based offer for the remainder of the Operating Day.

6.4.2 Level.

- (a) The offer price cap shall be one of the amounts specified below, as specified in advance by the Market Seller for the affected unit:
 - (i) The weighted average Locational Marginal Price at the generation bus at which energy from the capped resource was delivered during a specified number of hours during which the resource was dispatched for energy in economic merit order, the specified number of hours to be determined by the Office of the Interconnection and to be a number of hours sufficient to result in an offer price cap that reflects reasonably contemporaneous competitive market conditions for that unit;
 - (ii) For offers of \$2,000/MWh or less, the incremental operating cost of the generation resource as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals (“incremental cost”), plus up to the lesser of 10% of such costs or \$100 MWh, the sum of which shall not exceed \$2,000/MWh; and, for offers greater than \$2,000/MWh, the incremental cost of the generation resource;
 - (iii) For units that are frequently offer capped (“Frequently Mitigated Unit” or “FMU”), and for which the unit’s market-based offer was greater than its cost based offer, the following shall apply:
 - (a) For units that are offer capped for 60% or more of their run hours, but less than 70% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10% or (ii) incremental cost plus \$20 per megawatt-hour;
 - (b) For units that are offer capped for 70% or more of their run hours, but less than 80% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10%, or (ii) incremental cost plus \$30

per megawatt-hour;

(c) For units that are offer capped for 80% or more of their run hours, the offer price cap will be the greater of either (i) incremental costs plus 10%; or (ii) incremental cost plus \$40 per megawatt-hour.

(b) For purposes of section 6.4.2(a)(iii), a generating unit shall qualify for the specified offer cap upon issuance of written notice from the Market Monitoring Unit, pursuant to Section II.A of the Attachment M-Appendix, that it is a “Frequently Mitigated Unit” because it meets all of the following criteria:

- (i) The unit was offer capped for the applicable percentage of its run hours, determined on a rolling 12-month basis, effective with a one month lag.
- (ii) The unit’s Projected PJM Market Revenues plus the unit’s PJM capacity market revenues on a rolling 12-month basis, divided by the unit’s MW of installed capacity (in \$/MW-year) are less than its accepted unit specific Avoidable Cost Rate (in \$/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in \$/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the Delivery Years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.)
- (iii) No portion of the unit is included in a FRR Capacity Plan or receiving compensation under Part V of the Tariff.
- (iv) The unit is internal to the PJM Region and subject only to PJM dispatch.

(c) Any generating unit, without regard to ownership, located at the same site as a Frequently Mitigated Unit qualifying under Sections 6.4.2(a)(iii) shall become an “Associated Unit” upon issuance of written notice from the Market Monitoring Unit pursuant to Section II.A of Attachment M-Appendix, that it meets all of the following criteria:

1. The unit has the identical electric impact on the transmission system as the FMU;
2. The unit (i) belongs to the same design class (where a design class includes generation that is the same size and utilizes the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder;
3. The unit (i) has an average daily cost-based offer, as measured over the preceding 12-month period, that is less than or equal to the FMU’s

average daily cost-based offer adjusted to include the currently applicable FMU adder or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder.

The offer cap for an associated unit shall be equal to the incremental operating cost of such unit, as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals, plus the applicable percentage adder or dollar per megawatt-hour adder as specified in Section 6.4.2(a)(iii)(a), (b), or (c) for the unit with which it is associated.

(d) Market Participants shall have exclusive responsibility for preparing and submitting their offers on the basis of accurate information and in compliance with the FERC Market Rules, inclusive of the level of any applicable offer cap, and in no event shall PJM be held liable for the consequences of or make any retroactive adjustment to any clearing price on the basis of any offer submitted on the basis of inaccurate or non-compliant information.

6.4.3 Verification of Cost-Based Offers Over \$1,000/Megawatt-hour

(a) If a Market Seller submits a cost-based energy offer for a generation resource that includes an Incremental Energy Offer greater than \$1,000/megawatt-hour, then, in order for that offer to be eligible to set the applicable Locational Marginal Price as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement Schedule 1, section 2.6 (for determining Day-ahead Prices), the Office of the Interconnection shall apply a formulaic screen to verify the reasonableness of the Incremental Energy Offer component of such cost-based offer. For each Incremental Energy Offer segment greater than \$1,000/megawatt-hour, the Office of the Interconnection shall evaluate whether such offer segment exceeds the reasonably expected costs for that generation resource by determining the Maximum Allowable Incremental Cost for each segment in accordance with the following formula:

Maximum Allowable Incremental Cost (\$/MWh segment in accordance with the following formula: @ MW) =

$$[(\text{Maximum Allowable Operating Rate}_i) - (\text{Bid Production Cost}_{i-1})] / (\text{MW}_i - \text{MW}_{i-1})$$

where

i = an offer segment within the Incremental Energy Offer, which is comprised of a pairing of price (\$/MWh) and a megawatt quantity

Maximum Allowable Operating Rate (\$/hour @ MW) =

$$[(\text{Heat Input}_i \text{ @ MW}_i) \times (\text{Performance Factor}) \times (\text{Fuel Cost})] \times (1 + A)$$

where

Heat Input = a point on the heat input curve (in MMBtu/hr), determined in accordance with PJM Manual 15, describing the resource's operational

characteristics for converting the applicable fuel input (MMBtu) into energy (MWh) specified in the Incremental Energy Offer;

Performance Factor = a scaling factor that is a calculated ratio of actual fuel burn to either theoretical fuel burn (i.e., design Heat Input) or other current tested Heat Input, which is determined annually in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, reflecting the resource's actual ability to convert fuel into energy (normal operation is 1.0);

Fuel Cost = applicable fuel cost as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent; and

A = Cost adder, in accordance with section 6.4.2(a)(ii) of this Schedule.

$$\text{Bid Production Cost (\$/hour @ MW)} = \left[\sum_{i=1}^n (MW_i - MW_{i-1}) \times (P_i) - \frac{1}{2} \times \text{UBS} \times (MW_i - MW_{i-1}) \times (P_i - P_{i-1}) \right] + \text{No-Load Cost}$$

where

MW = the MW quantity per offer segment within the Incremental Energy Offer;

P = the price (in dollars per megawatt-hour) per offer segment within the Incremental Energy Offer;

UBS = Uses Bid-Slope = 0 for block-offer resources (i.e., a resource with an Incremental Energy Offer that uses a step function curve); and 1 for all other resources (i.e., resources with an Incremental Energy Offer that uses a sloped offer curve); and

If the price submitted for the offer segment is less than or equal to the Maximum Allowable Incremental Cost then that offer segment shall be deemed verified and is eligible to set the applicable Locational Marginal Price. If the price submitted for the offer segment is greater than the Maximum Allowable Incremental Cost, then the Market Seller's cost-based offer for that segment and all segments at an equal or greater price are deemed not verified and are not eligible to set the applicable Locational Marginal Price and such offer shall be price capped at the greater of \$1,000/megawatt-hour or the offer price of the most expensive verified segment on the Incremental Energy Offer for the purpose of setting Locational Marginal Prices; provided however, such Market Seller shall be allowed to submit a challenge to a non-verification determination, including supporting documentation, to the Office of the Interconnection in accordance with the procedures set forth in the PJM Manuals. Upon review of such documentation, the Office of the Interconnection may determine that the Market Seller's cost-based offer is verified and eligible to set the applicable Locational Marginal Price as described above.

- (i) For the first incremental segment ($i=1$), when the MW in the segment is greater than zero, the first segment shall be screened as a block-loaded segment ($UBS=0$) as if there was a preceding MW_{i-1} of zero. The Maximum Allowable Incremental Cost calculation for the first incremental would use a preceding Bid Production Cost $i-1$ (at zero MW) equal to the energy No-Load Cost.
- (ii) For the first incremental segment ($i=1$), when the MW in the segment is equal to zero, and is the only bid-in segment to be verified, then the segment shall be deemed not verified and subject to the rules as described above.
- (iii) For the first incremental segment ($i=1$), when the MW in the segment is equal to zero, and there are additional segments to be verified, then the first segment shall be deemed verified only if the second segment is deemed verified. If the second segment is deemed not verified, then the first segment shall also be deemed not verified and subject to the rules as described above.

(b) If an Economic Load Response Participant a cost-based demand reduction offer that includes incremental costs greater than or equal to \$1,000/megawatt-hour, in order for that offer to be eligible to determine the applicable Locational Marginal Price as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Economic Load Response Participant must validate the incremental costs with the end use customer(s) and, upon request, submit to the Office of the Interconnection supporting documentation demonstrating that the end-use customer's costs in providing such demand reduction are greater than \$1,000/megawatt-hour in accordance with the following provisions:

- (i) The supporting documentation must explain and support the quantification of the end-use customer's incremental costs; and
- (ii) The end use customer's incremental costs shall include quantifiable cost incurred for not consuming electricity when dispatched by the Office of the Interconnection, such as wages paid without production, lost sales, damaged products that cannot be sold, or other incremental costs as defined in the PJM Manuals or as approved by the Office of the Interconnection, and may not include shutdown costs.

If upon review of the supporting documentation for the Economic Load Response Participant's, cost-based offer by the Office of the Interconnection and the Market Monitoring Unit, the Office of the Interconnection and/or the Market Monitoring Unit determines that the offer was not reasonably supported by incremental costs greater than or equal to \$1,000/megawatt-hour, the Office of the Interconnection and/or the Market Monitoring Unit may refer the matter to the FERC Office of Enforcement for investigation.

6.4.3A Verification of Fast-Start Resource Composite Energy Offers Over \$1,000/Megawatt-hour

(a) If a Market Seller submits a cost-based offer for a generation resource that is a Fast-Start Resource that results in a Composite Energy Offer that is greater than \$1,000/megawatt-hour, then, in order for that Composite Energy Offer to be eligible to set the applicable Locational Marginal Price under Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Office of the Interconnection shall apply a formulaic screen to verify the reasonableness of the offer components:

Incremental Energy Offer and No-load Cost components of each offer segment shall be evaluated for whether it exceeds the reasonably expected costs for that resource by applying the test described in Operating Agreement, Schedule 1, section 6.4.3.

Start-Up Cost component shall be evaluated for whether it exceeds the reasonably expected costs for that resource by applying the following formula:

$$\text{Start-Up Cost (\$)} = [[(\text{Performance Factor}) \times (\text{Start Fuel}) \times (\text{Fuel Cost})] + \text{Start Maintenance Adder} + \text{Additional Start Labor} + \text{Station Service Cost}] \times (1 + A)$$

Where:

Start Fuel =

For units without a soak process, "Start Fuel" is fuel consumed from first fire of the start process to first breaker closing plus fuel expended from last breaker opening to shutdown.

For units with soak process, "Start Fuel" is fuel consumed from first fire of start process (initial reactor criticality for nuclear units) to the level at which the unit can follow PJM's dispatch (including auxiliary boiler fuel) plus fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements; fuel consumed from first fire of start process to breaker closing plus fuel expended from breaker opening of the previous shutdown to initialization of the (hot) unit start up, excluding normal plant heating/auxiliary equipment fuel requirements;

Fuel Cost = applicable fuel cost as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent;

Performance Factor = a scaling factor that is a calculated ratio of actual fuel burn to either theoretical fuel burn (i.e., design Heat Input) or other current tested Heat Input, which is determined annually in accordance

with the Market Seller's PJM-approved Fuel Cost Policy under Operating Agreement, Schedule 2 and PJM Manual 15, reflecting the resource's actual ability to convert fuel into energy (normal operation is 1.0);

Start Maintenance Adder = an adder based on all available maintenance expense history for the defined Maintenance Period regardless of unit ownership. Only expenses incurred as a result of electric production qualify for inclusion. Only Maintenance Adders specified as \$/Start, \$/MMBtu, or \$/equivalent operating hour can be included in the Start Maintenance Adder;

~~Start Additional Labor = additional labor costs for startup required above normal station manning levels; and~~

Station Service Cost = station service usage (MWh) during start-up multiplied by the 12-month rolling average off-peak energy prices as updated quarterly by the Office of the Interconnection.

A = cost adder, in accordance with Operating Agreement, Schedule 1, section 6.4.2(a)(ii).

(b) Should the submitted Incremental Energy Offer and No-load Cost exceed the reasonably expected costs for that resource as calculated pursuant to subsection (a) above for any segment, then for the determination of Locational Marginal Prices as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices):

- (i) the Incremental Energy Offer for each segment shall be capped at the lesser of the cap described above in Operating Agreement, Schedule 1, section 6.4.3 or the submitted Incremental Energy Offer; and
- (ii) the amortized No-load cost shall be adjusted as described in Operating Agreement, Schedule 1, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Operating Agreement, Schedule 1, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

(c) Should the submitted Start-Up Cost exceed the reasonably expected costs for that resource as calculated pursuant to subsection (a) above, then for the determination of Locational Marginal Prices as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Start-Up Costs shall be adjusted as described in Operating Agreement, Schedule 1, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Operating Agreement, Schedule 1, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

(d) If an Economic Load Response Participant submits an offer to reduce demand for a Fast-Start Resource where the maximum segment of the resulting Composite Energy Offer exceeds

\$1,000/megawatt-hour, then, in order for that Composite Energy Offer to be eligible to set the applicable Locational Marginal Price under Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Economic Load Response Participant must validate such costs with the end use customer(s) and, upon request, submit to the Office of the Interconnection supporting documentation demonstrating that the end-use customer's costs in providing such demand reduction are greater than \$1,000/megawatt-hour in accordance with the following provisions:

(i) The supporting documentation must explain and support the quantification of the end-use customer's incremental costs and shutdown costs; and

(ii) The end use customer's incremental and shutdown costs shall include quantifiable cost incurred for not consuming electricity when dispatched by the Office of the Interconnection, such as wages paid without production, lost sales, damaged products that cannot be sold, or other incremental costs as defined in the PJM Manuals or as approved by the Office of the Interconnection.

If upon review of the supporting documentation for the Economic Load Response Participant's, cost-based offer by the Office of the Interconnection and the Market Monitoring Unit, the Office of the Interconnection and/or the Market Monitoring Unit determines that the offer was not reasonably supported by incremental and shutdown costs greater than or equal to \$1,000/megawatt-hour, the Office of the Interconnection and/or the Market Monitoring Unit may refer the matter to the FERC Office of Enforcement for investigation.

Should the submitted shutdown cost exceed the reasonably supported costs for that resource, then for the determination of Locational Marginal Prices as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the shutdown costs shall be adjusted as described in Operating Agreement, Schedule 1, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Operating Agreement, Schedule 1, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

SCHEDULE 2 - COMPONENTS OF COST

1. GENERAL COST PROVISIONS

1.1 Permissible Components of Cost-based Offers of Energy.

Each Market Participant obligated to sell energy on the PJM Interchange Energy Market at cost-based rates may include the following components or their equivalent in the determination of costs for energy supplied to or from the PJM Region:

(a) For generating units powered by boilers

~~Start-Up Cost Firing-up cost (including Start Fuel)~~

Peak-prepared-for maintenance cost

(b) For generating units powered by machines

~~Start-up cost from cold to synchronized operation-Up Cost (including Start Fuel)~~

(c) For all generating units

Incremental maintenance cost

No-load cost during period of operation

Labor cost

Operating Costs

Opportunity Costs

Emission allowances/adders

Maintenance Adders

Ten percent adder

Charging costs for Energy Storage Resources

Fuel Cost

1.2 Method of Determining Cost Components.

The PJM Board, upon consideration of the advice and recommendations of the Members Committee, shall from time to time define in detail the method of determining the costs entering into the said components, and the Members shall adhere to such definitions in the preparation of incremental costs used on the Interconnection.

1.3 Application of Cost Components to Three-Part Cost-based Offers.

A cost-based offer, as defined in Operating Agreement, Schedule 1, section 1.2, is a three-part offer consisting of Start-up Costs, No-load Costs, and the Incremental Energy Offer. These terms are as defined in Operating Agreement, section 1.

The following lists the categories of cost that may be applicable to a Market Participant's three-part cost-based offer:

(a) For Start-up Costs

Fuel cost
Emission allowances/adders
Maintenance Adders
Operating Costs
Station service
~~Labor costs~~

(b) For No-load Costs

Fuel cost
Emission allowances/adders
Maintenance Adders
Operating Costs

(c) Incremental Costs in Incremental Energy Offers

Fuel cost
Emission allowances/adders
Maintenance Adders
Operating Costs
Opportunity Costs

(d) All fuel costs shall employ the marginal fuel price experienced by the Member.

2. FUEL COST POLICY

2.1 Approved Fuel Cost Policy Requirement for Non-Zero Cost-based Offer.

A Market Seller may only submit a non-zero cost-based offer into the PJM Interchange Energy Market for a generation resource if it has a PJM-approved Fuel Cost Policy, or follows the temporary cost offer methodology set forth in Operating Agreement, Schedule 2, section 6.3, consistent with each fuel type for such generation resource.

2.2 Fuel Cost Policy Approval Process.

(a) A Market Seller shall provide a Fuel Cost Policy to PJM and the Market Monitoring Unit for each generation resource that it intends to submit with a non-zero cost-based offer into the PJM Interchange Energy Market, for each fuel type utilized by the resource. The Market Seller shall submit its initial Fuel Cost Policy for a generation resource to PJM and the Market Monitoring Unit for review and shall update existing Fuel Cost Policies consistent with the requirements set forth below in Operating Agreement, Schedule 2, section 2.6.

(i) For each new generation resource for which the Market Seller intends to submit a non-zero cost-based offer, the Market Seller may also:

- A. Submit a provisional Fuel Cost Policy to PJM and the Market Monitoring Unit for review and approval when it does not have commercial operating data. The provisional Fuel Cost Policy shall describe the Market Seller's methodology to procure and price fuel and include all available operating data. Within 90 calendar days of the commercial operation date of such generation resource, the Market Seller shall submit to PJM and the Market Monitoring Unit for review an updated Fuel Cost Policy reflecting actual commercial operating data of the resource; or
 - B. Follow the temporary cost offer methodology set forth in Operating Agreement, Schedule 2, section 6.3, until PJM approves a new Fuel Cost Policy.
- (ii) A Market Seller of a generation resource that is transferred from another Market Seller that intends to submit a non-zero cost-based offer must:
- A. Affirm the currently approved Fuel Cost Policy on file for such generation resource prior to the submission of a cost-based offer; or
 - B. Submit an updated Fuel Cost Policy for review, which must be approved prior to the submission of a cost-based offer developed in accordance with such policy; or
 - C. Follow the temporary cost offer methodology set forth in Operating Agreement, Schedule 2, section 6.3, until PJM approved a new Fuel Cost Policy.
- (b) PJM and the Market Monitoring Unit will have an initial thirty (30) Business Days for review of a submitted policy.
- (c) The basis for the Market Monitoring Unit's review is described in Tariff, Attachment M-Appendix. PJM shall consult with the Market Monitoring Unit, and consider any input and advice timely received from the Market Monitoring Unit, in its determination of whether to approve a Market Seller's Fuel Cost Policy.
- (d) After it has completed its evaluation of the submitted Fuel Cost Policy, PJM shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the Fuel Cost Policy is approved or rejected. If PJM rejects a Market Seller's Fuel Cost Policy, PJM shall include an explanation for why the Fuel Cost Policy was rejected in its written notification.
- (e) PJM shall establish an expiration date for each Fuel Cost Policy, with timely input and advice from the Market Monitoring Unit and Market Seller, and notify the Market Seller of such date at the time of the Fuel Cost Policy approval. Upon such expiration, the Fuel Cost Policy will no longer be deemed approved by PJM and the provisions of Operating Agreement, Schedule 2, section 2.4(b) shall apply.

2.3 Standard of Review.

(a) PJM shall review and approve a Fuel Cost Policy if it meets the requirements set forth in subsections (a)(i) through (v) of this section. PJM shall reject Fuel Cost Policies that fail to meet such requirements and that do not accurately reflect the applicable costs, such as the fuel source, transportation cost, procurement process used, applicable adders, commodity cost, or provide sufficient information for PJM to verify the Market Seller's fuel cost at the time of the Market Seller's cost-based offer. If PJM rejects a Market Seller's Fuel Cost Policy, PJM shall include an explanation for why the Fuel Cost Policy was rejected in its written notification. A Fuel Cost Policy must:

(i) Provide information sufficient for the verification of the Market Seller's fuel pricing and/or cost estimation method, as further described below and in PJM Manual 15, and how those practices are utilized to determine cost-based offers the Market Seller submits into the PJM Interchange Energy Market;

(ii) Reflect the Market Seller's applicable commodity and/or transportation contracts (to the extent it holds such contracts) and the Market Seller's method of calculating delivered fossil fuel cost, limited to inventoried cost, replacement cost or a combination thereof, that reflect the way fuel is purchased or scheduled for purchase, and set forth all applicable indices as a measure that PJM can use to verify how anticipated spot market purchases are utilized in determining fuel costs;

(iii) Provide a detailed explanation of the basis for and reasonableness of any applicable adders included in determining fuel costs in accordance with PJM Manual 15;

(iv) Account for situations where applicable indices or other objective market measures are not sufficiently liquid by documenting the alternative means actually utilized by the Market Seller to price the applicable fuel used in the determination of its cost-based offers, such as documented quotes for the procurement of natural gas; and

(v) Adhere to all requirements of PJM Manual 15 applicable to the generation resource.

(b) To the extent a Market Seller proposes alternative measures to document its fuel costs in its Fuel Cost Policy for a generation resource, the Market Seller shall explain how such alternative measures are consistent with or superior to the standard specified in subsection (a) of this section, accounting for the unique circumstances associated with procurement of fuel to supply the generation resource.

(c) If PJM determines that a Fuel Cost Policy submitted for review does not contain adequate support for PJM to make a determination as to the acceptability of any portion of the proposed policy consistent with the standards set forth above, PJM shall reject the Fuel Cost Policy. If PJM rejects the Fuel Cost Policy, the Market Seller may use:

(i) The existing approved Fuel Cost Policy, if the policy is not expired and is still reflective of the Market Sellers current fuel pricing and/or cost estimation method; or

(ii) The temporary cost offer methodology provided in Operating Agreement, Schedule 2, section 6.3 to develop its cost-based offers until such time as PJM approves a new Fuel Cost Policy for the Market Seller.

2.4 Expiration of Approved Fuel Cost Policies.

(a) PJM, in consultation with the Market Seller and with timely input and advice from the Market Monitoring Unit, may:

(i) Update the Market Seller's Fuel Cost Policy expiration date, with at least 90 days notification to the Market Seller, due to a business rule change in the PJM Governing Documents.

(ii) Immediately expire the Market Seller's Fuel Cost Policy with written notification to the Market Seller when a change in circumstance causes the Market Seller's fuel pricing and/or cost estimation method to be no longer consistent with the approved Fuel Cost Policy, this Operating Agreement, Schedule 2 or PJM Manual 15.

(b) If the Market Seller of a generation resource that has been transferred from another Market Seller does not affirm the current approved Fuel Cost Policy on file for that generation resource, then such Fuel Cost Policy shall terminate as of the date on which the generation resource was transferred to the new Market Seller.

(c) PJM shall notify the Market Seller and the Market Monitoring Unit in writing when it has approved or denied a requested update to a Fuel Cost Policy expiration date and the rationale for its determination.

(d) On the next Business Day following the expiration of a Fuel Cost Policy, the Market Seller may only submit a cost-based offer of zero or a cost-based offer that is consistent with the temporary cost offer methodology in Operating Agreement, Schedule 2, section 6.3 until a new Fuel Cost Policy is approved by PJM for the relevant resource. If PJM expires a Market Seller's previously approved Fuel Cost Policy under Operating Agreement, Schedule 2, section 2.4(a)(i) or (ii), PJM shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, and include an explanation for the expiration, along with relevant documentation to support the expiration of a Fuel Cost Policy. Upon expiration, the Market Seller may rebut the expiration pursuant to Operating Agreement, Schedule 2, section 6.2

2.5 Information Required To Be Included In Fuel Cost Policies.

(a) Each Market Seller shall include in its Fuel Cost Policy the following information, as further described in the applicable provisions of PJM Manual 15:

(i) For all Fuel Cost Policies, regardless of fuel type, the Market Seller shall provide a detailed explanation of the Market Seller's established method of calculating or estimating fuel costs, indicating whether fuel purchases are subject to a contract price and/or spot pricing, and

specifying how it is determined which of the contract prices and/or spot market prices to use. The Market Seller shall include its method for determining commodity, handling and transportation costs.

(ii) For Fuel Cost Policies applicable to generation resources using a fuel source other than natural gas, the Market Seller shall adhere to the following guidelines:

1. Fuel costs for solar and run-of-river hydro resources shall be zero.
2. Fuel costs for nuclear resources shall not include in-service interest charges whether related to fuel that is leased or capitalized.
3. For Pumped Storage Hydro resources, fuel cost shall be determined based on the amount of energy necessary to pump from the lower reservoir to the upper reservoir.
4. For wind resources, the Market Seller shall identify how it accounts for renewable energy credits and production tax credits.
5. For solid waste, bio-mass and landfill gas resources, the Market Seller shall include the costs of such fuels even when the cost is negative.
6. For Energy Storage Resources, fuel cost shall include costs to charge for later injection to the grid.

(iii) Market Sellers shall report, for all of the generation resource's operating modes, fuels, and at various operating temperatures, the incremental, no load and start heat requirements, the method of developing heat inputs, and the frequency of updating heat inputs when requested by the Office of the Interconnection.

(iv) Market Sellers shall include any applicable unit specific performance factors, and the method used to determine them, which may be modified seasonally to reflect ambient conditions when requested by the Office of the Interconnection.

(v) Market Sellers shall include the cost-based Start-Up Cost calculation for the generation resource, and identify for each temperature state the starting fuel (MMBtu), station service (MWh), and start Maintenance Adder, ~~and any Start Additional Labor Cost~~ when requested by the Office of the Interconnection.

(vi) A Fuel Cost Policy shall also include any other incremental operating costs included in a Market Seller's cost-based offer for a resource, including but not limited to the consumables used for operation and the marginal value of costs in terms of dollars per MWh or dollars per unit of fuel, along with all applicable descriptions, calculation methodologies associated with such costs, and frequency of updating such costs.

2.6 Periodic Update and Review of Fuel Cost Policies.

Prior to expiration of a Fuel Cost Policy, all Market Sellers will be required to either submit to PJM and the Market Monitoring Unit an updated Fuel Cost Policy that complies with this Operating Agreement, Schedule 2 and PJM Manual 15, or confirm that their expiring Fuel Cost Policy remains compliant, pursuant to the procedures and deadlines specified in PJM Manual 15. PJM shall consult with the Market Monitoring Unit, and consider any input timely received from the Market Monitoring Unit, in its determination of whether to approve a Market Seller's updated Fuel Cost Policy. After it has completed its evaluation of the request, PJM shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, of its determination whether the updated Fuel Cost Policy is approved or rejected. If PJM rejects a Market Seller's updated Fuel Cost Policy, in its written notification, PJM shall provide an explanation for why the Fuel Cost Policy was rejected.

The Market Seller shall follow the applicable processes and deadlines specified in this Operating Agreement, Schedule 2 and the PJM Manual 15 to submit an updated Fuel Cost Policy:

- (a) If the Market Seller's fuel pricing or cost estimation method is no longer consistent with the approved Fuel Cost Policy, or
- (b) If a Market Seller desires to update its Fuel Cost Policy.

2.7 Market Monitoring Unit Review For Market Power Concerns.

Nothing in this Operating Agreement, Schedule 2 is intended to abrogate or in any way alter the responsibility of the Market Monitoring Unit to make determinations about market power pursuant to Tariff, Attachment M and Attachment M-Appendix.

3. EMISSION ALLOWANCES/ADDERS

3.1 Review of Emissions Allowances/Adders.

- (a) For emissions costs, Market Sellers shall report the emissions rate of each generation resource, the method for determining the emissions allowance cost, and the frequency of updating emission rates. Such adders must be submitted and reviewed at least annually by PJM and be changed if they are no longer accurate.
- (b) Market Sellers may submit emissions cost information to PJM and the Market Monitoring Unit as part of the information it submits during the annual Fuel Cost Policy review process, described in Operating Agreement, Schedule 2, section 2.6. The basis for the Market Monitoring Unit's review is described in Tariff, Attachment M-Appendix, section II.A.2. PJM shall consult with the Market Monitoring Unit, and consider any input and advice timely received from the Market Monitoring Unit, in its determination of whether to approve emissions costs.

4. MAINTENANCE ADDERS & OPERATING COSTS

4.1 Maintenance Adders

Maintenance Adders are expenses directly related to electric production and can be a function of starts and/or run hours. Allowable expenses may include repair, replacement, and major inspection, and overhaul expenses including variable long term service agreement expenses. Maintenance Adders are calculated as the 10 or 20 year average cost of a unit's maintenance history, or all available actual maintenance history if a unit has less than 20 years of maintenance history. The major inspection and overhaul costs listed below in sections (a)-(c) are not exhaustive. A Market Seller may include costs in cost-based offers if those costs are similar to the costs outlined in this provision, so long as they are variable costs that are directly attributable to the production of electricity.

(a) Major inspections and overhauls of gas turbine and steam turbine generators include, but are not limited to, the following costs:

- turbine blade repair/replacement;
- turbine diaphragm repair;
- casing repair/replacement;
- bearing repair/refurbishment;
- seal repair/replacement and generator refurbishment;
- heat transfer replacement and cleaning;
- cooling tower fan motor and gearbox inspection;
- cooling tower fill and drift eliminators replacement;
- Selective Catalytic Reduction and CO Reduction Catalyst replacement;
- Reverse Osmosis Cartridges replacement;
- air filter replacement;
- fuel and water pump inspection/replacement;

(b) Major maintenance of gas turbine generators directly related to electric production include, but are not limited to:

- compressor blade repair/replacement;
- hot gas path inspections, repairs, or replacements.

(c) Major maintenance of steam turbine generators directly related to electric production include, but are not limited to:

- stop valve repairs;
- throttle valve repairs;
- nozzle block repairs;
- intercept valve repairs.

(d) Maintenance Costs that cannot be included in a Market Seller's cost-based offer are preventative maintenance and routine maintenance on auxiliary equipment like buildings, HVAC, compressed air, closed cooling water, heat tracing/freeze protection, and water treatment.

4.2 Operating Costs

- (a) Operating Costs are expenses related to consumable materials used during unit operation and include, but are not limited to, lubricants, chemicals, limestone, trona, ammonia, acids, caustics, water injection, activated carbon for mercury control, and demineralizers usage. These operating costs not exhaustive. A Market Seller may include other operating costs in cost-based offers so long as they are operating costs that are directly attributable to the production of energy.
- (b) Operating Costs may be calculated based on a fixed or rolling average of values from one to five years in length, reviewed (and updated if changed) annually, or a rolling average from twelve to sixty months in length, reviewed (and updated if changed) monthly.

4.3 Labor Costs

Labor costs included in cost-based offers do not include straight-time labor costs and are limited to ~~:(1) start-up costs for additional staffing requirements and (2)~~ contractor labor or plant personnel overtime labor included in the Maintenance Adder associated with maintenance activities directly related to electric production. Straight time labor expenses may be included under an Avoidable Cost Rate in the RPM auction.

4.4 Review of Maintenance Adders & Operating Costs.

- (a) Maintenance Adders and Operating Costs must be submitted and reviewed at least annually by PJM and be changed if they are no longer accurate. Maintenance Adders and Operating Costs cannot include any costs that are included in the generation resource's Avoidable Cost Rate pursuant to Tariff, Attachment DD, section 6.8(c).
- (b) Market Sellers must specify the maintenance history years utilized in calculating Maintenance Adders during the annual review.
- (c) Market Sellers must specify the years used to calculate Operating Costs during the annual review. Market Sellers that elect to use a six month to twelve month rolling average must submit these costs for a monthly review.
- (d) Market Sellers may submit Maintenance Adder and Operating Costs information to PJM and the Market Monitoring Unit as part of the information it submits during the annual Fuel Cost Policy review process, described in Operating Agreement, Schedule 2, section 2.6. The basis for the Market Monitoring Unit's review is described in Tariff, Attachment M-Appendix, section II.A.2. PJM shall consult with the Market Monitoring Unit, and consider any input and advice timely received from the Market Monitoring Unit, in its determination of whether to approve Maintenance Adders and Operating Costs.

5. OPPORTUNITY COSTS

(a) For a generating unit that is subject to operational limitations due to energy or environmental limitations imposed on the generating unit by Applicable Laws and Regulations, the Market Participant may include a calculation of its “Opportunity Costs” which is an amount reflecting the unit-specific Energy Market Opportunity Costs expected to be incurred. Such unit-specific Energy Market Opportunity Costs are calculated by forecasting Locational Marginal Prices based on future contract prices for electricity using PJM Western Hub forward prices, taking into account historical variability and basis differentials for the bus at which the generating unit is located for the prior three year period immediately preceding the relevant compliance period, and subtract therefrom the forecasted costs to generate energy at the bus at which the generating unit is located, as specified in more detail in PJM Manual 15. If the difference between the forecasted Locational Marginal Prices and forecasted costs to generate energy is negative, the resulting Energy Market Opportunity Cost shall be zero. Notwithstanding the foregoing, a Market Participant may submit a request to PJM for consideration and approval of an alternative method of calculating its Energy Market Opportunity Cost if the standard methodology described herein does not accurately represent the Market Participant’s Energy Market Opportunity Cost.

(b) For a generating unit that is subject to operational limitations because it 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, or (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure, the Market Participant may include a calculation of its “Opportunity Costs” which is an amount reflecting the unit-specific Non-Regulatory Opportunity Costs expected to be incurred. Such unit-specific Non-Regulatory Opportunity Costs are calculated by forecasting Locational Marginal Prices based on future contract prices for electricity using PJM Western Hub forward prices, taking into account historical variability and basis differentials for the bus at which the generating unit is located for the prior three year period immediately preceding the period of time in which the unit is bound by the referenced restrictions, and subtract therefrom the forecasted costs to generate energy at the bus at which the generating unit is located, as specified in more detail in PJM Manual 15. If the difference between the forecasted Locational Marginal Prices and forecasted costs to generate energy is negative, the resulting Non-Regulatory Opportunity Cost shall be zero.

6. PENALTY PROVISIONS

6.1 Penalties.

(a) If upon review of a Market Seller’s cost-based offer, PJM determines that the offer is not in compliance with the Market Seller’s PJM-approved Fuel Cost Policy or this Operating Agreement, Schedule 2 and the Market Monitoring Unit agrees with that determination, or the Market Monitoring Unit determines that the offer is not in compliance with the Market Seller’s PJM-approved Fuel Cost Policy and PJM agrees with the Market Monitoring Unit’s determination, or PJM determines that any portion of the cost-based offer is not in compliance with this Operating Agreement, Schedule 2, the Market Seller shall be subject to a penalty. If:

1. The Market Seller ceased submitting the non-compliant offer either prior to, or upon notification from PJM, or the Market Seller reports such error to PJM after ceasing submission of the non-compliant cost-based offer then the penalty calculation will use the average hourly MWh and LMP for each hour of the day across the non-compliant period, as shown in the equation below. For the purposes of this equation, the non-compliant period is defined as the first hour for which the non-compliant offer was first submitted through the earlier of: a) the last hour for which the non-compliant offer was submitted; or b) notification of the non-compliant offer from PJM.

$$\text{Non-Escalating Penalty} = \sum_{h=1}^{24} \left(\left(\frac{1}{20} \right) \times \text{LMP}_h \times \text{MW}_h \times E \times I \right)$$

where:

h is the applicable hour of the Operating Day.

LMP_h is the average hourly real-time LMP at the applicable location of the resource for the given hour across the non-compliant period.

MW_h is the average hourly available capacity of the resource for the given hour across the non-compliant period, where available capacity is defined as the greater of the real-time megawatt output and emergency maximum of the generation resource.

E is the Market Seller error identification factor. The Market Seller error identification factor shall be equal 0.25 when the non-compliant offer is identified by the Market Seller without inquiry from or being prompted by PJM or the Market Monitoring Unit, and PJM, with timely input and advice from the Market Monitoring Unit, agrees that the Market Seller first identified the error. The Market Seller error identification shall equal 1 in the absence of a valid self-identified error.

I is the market impact factor over the duration of the non-compliant cost-based offer. The market impact factor shall be equal to 1 if the Market Seller continued submitting non-compliant offers after receiving notice from PJM of its non-compliant offer, or if the Market Seller continued submitting non-compliant offers after notifying PJM of the non-compliant cost-based offer, or when any of the following conditions exist for any hour throughout the duration of the non-compliant cost-based offer:

A. The generation resource clears in the Day-ahead Energy Market on the non-compliant cost-based offer, or runs in Real-time Energy Market on the non-compliant cost-based offer and is either:

- (i) paid day-ahead or balancing operating reserves as described in Operating Agreement, Schedule 1, section 3.2.3; or
- (ii) The marginal resource for energy, transmission constraint control, regulation or reserves.

B. The Market Seller does not pass the three pivotal supplier test as described in Operating Agreement, Schedule 1, section 6.4.1(e) and any of the following conditions apply:

- (i) The generation resource is not committed
- (ii) The generation resource runs on its cost-based offer
- (iii) The generation resource is running on its market-based offer and it did not pass the three pivotal supplier test at the time of commitment

C. The non-compliant incremental cost-based offer is greater than \$1,000.MWh

If none of the above conditions apply, then the market impact factor shall be equal to 0.1

2. In addition to being issued the penalty described in 6.1(a)(1), a Market Seller will be subject to a daily escalating penalty for each day beyond which the Market Seller continues submitting the non-compliant cost-based offer after notification from PJM, or after the Market Seller reports such error to PJM. Escalating daily penalty will be calculated as shown in the equation below:

$$\text{Escalating Daily Penalty} = \sum_{h=1}^{24} \left(\left(\frac{d}{20} \right) \times \text{LMP}_h \times \text{MW}_h \right)$$

where:

d is the the number of days, starting at 2 and increasing by 1 for each additional day of non-compliance following notification, and capped at a value of 15.

h is the applicable hour of the Operating Day.

LMP_h is the hourly real-time LMP at the applicable pricing location for the resource for the applicable hour of the Operating Day.

MW_h is the hourly available capacity of the resource for the applicable hour of the Operating Day, where available capacity is defined as the greater of the real-time megawatt output and emergency maximum of the generation resource.

(b) All charges collected pursuant to this provision shall be allocated to Market Participants based on each Market Participant's real-time load ratio share for each applicable hour, as determined based on the Market Participant's total hourly load (net of operating Behind The Meter Generation, but not to be less than zero) to the total hourly load of all Market Participants in the PJM Region.

(c) Market Sellers that are assessed a penalty for a cost-based offer not in compliance with the Market Seller's PJM-approved Fuel Cost Policy, the temporary cost offer methodology, or this Schedule 2 shall be assessed penalties until the day after PJM determines that the Market Seller's cost-based offers are in compliance with the Market Seller's approved Fuel Cost Policy or in compliance with this Schedule 2. Such penalties will be assessed for no less than one (1) Operating Day.

6.2 Rebuttal Period To Challenge Expiration of Fuel Cost Policy.

Market Sellers who have a Fuel Cost Policy that has been immediately expired by PJM will be provided a three (3) Business Day rebuttal period, starting from the date of expiration, to submit supporting documentation to PJM demonstrating that the expired Fuel Cost Policy accurately reflects the fuel pricing and/or cost estimation method documented in the previously approved Fuel Cost Policy that was expired. However, if, upon review of the Market Seller's supporting documentation, PJM determines that the expired policy accurately reflects the Market Seller's actual methodology used to develop the cost-based offer that was submitted at the time of expiration and that the Market Seller has not violated its Fuel Cost Policy, then PJM will make whole the Market Seller via uplift payments for the time period for which the applicable Fuel Cost Policy had been expired and the generation resource was mitigated to its cost-based offer.

6.3 Exemption From Penalty

(a) A Market Seller will not be subject to a penalty under Operating Agreement, Schedule 2, section 6.1 for utilizing a fuel pricing and/or cost estimation method inconsistent with the methodology in the Market Seller's PJM-approved Fuel Cost Policy or this Operating Agreement, Schedule 2 if the reason for fuel pricing and/or cost estimation deviation is due to an unforeseen event outside of the control of the Market Seller, its agents, and its affiliated fuel suppliers which, by exercise of due diligence the Market Seller could not reasonably have contemplated at the time the Fuel Cost Policy was developed, such as:

(i) physical events such as acts of God, landslides, lightning, earthquakes, fires, storms or storm warnings, such as hurricanes, which result in evacuation of the affected area, floods, washouts, explosions, breakage or accident or necessity of repairs to machinery or equipment or lines of pipe;

(ii) weather related events affecting an entire geographic region, such as low temperatures which cause freezing or failure of wells or lines of pipe or other fuel delivery infrastructure;

(iii) interruption and/or curtailment of firm transportation and/or storage by transporters;

(iv) acts of unaffiliated third parties including but not limited to strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections or wars, or acts of terror; and

(v) governmental actions such as necessity for compliance with any court order, law, statute, ordinance, regulation, or policy having the effect of law promulgated by a governmental authority having jurisdiction.

(b) Market Seller shall provide evidence of the event and direct impact on the Market Seller's ability to utilize a fuel pricing and/or cost estimation method consistent with the methodology in the Market Seller's PJM-approved Fuel Cost Policy or this Operating Agreement, Schedule 2. Such evidence shall be provided to PJM and the Market Monitoring Unit. Upon providing such evidence to PJM and the Market Monitoring Unit, and after receiving timely comments from the Market Monitoring Unit, PJM shall determine and notify the Market Seller as to whether the evidence sufficiently demonstrates that the force majeure event directly impacted the Market Seller's ability to conform to the methodology described in the applicable PJM-approved Fuel Cost Policy. The applicability of this provision shall not apply for economic hardship nor obviate the requirement for a Market Seller to submit cost-based offers that are just and reasonable, and utilize best available information to develop fuel costs during a force majeure event.

6.4 Temporary Cost Offer Methodology

(a) As an option, Market Sellers may utilize the temporary cost offer methodology to calculate a generation resource's cost-based offer while developing a new Fuel Cost Policy in good faith for the following:

- (i) Generation resources that initiate participation in the PJM Energy Market
- (ii) Generation resources transferring from one Market Seller to another Market Seller
- (iii) Generation resources that have an expired Fuel Cost Policy

(b) The temporary cost offer methodology shall be comprised of the index settle price, described below, at the PJM-assigned commodity pricing point multiplied by heat input curves submitted by the Market Seller, as described in Manual 15.

For generation resources that opt-out of intraday offers, the last published closing index settle price shall be used for all hours of the Operating Day.

For generation resources that opt-in to intraday offers, index settle prices shall be based on the last published closing settle price for all hours of the Operating Day, and updated to reflect the:

1. last published closing settle price, if decreased, for hours ending 11 through 24 for natural gas

2. last published closing settle price, if decreased, for all hours of the Operating Day for all other fuel types

(c) The commodity pricing point and index publication source shall be assigned by PJM in consultation with the Market Seller and with timely input and advice from the Market Monitoring Unit.

(d) A Market Seller may not include any of the other permissible components for cost-based offers that listed in this Operating Agreement, section 1.1.

(e) If a Market Seller without a PJM-approved Fuel Cost Policy does not utilize this temporary cost offer methodology to calculate its cost-based offer, the Market Seller shall only submit a zero cost-based offer.

Definitions S – T

Sector Votes:

“Sector Votes” shall mean the affirmative and negative votes of each sector of a Senior Standing Committee, as specified in Operating Agreement, section 8.4.

Securities:

“Securities” shall mean negotiable or non-negotiable investment or financing instruments that can be sold and bought. Securities include bonds, stocks, debentures, notes and options.

Segment:

“Segment” shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(e).

Senior Standing Committees:

“Senior Standing Committees” shall mean the Members Committee, and the Markets, and Reliability Committee, as established in Operating Agreement, section 8.1 and Operating Agreement, section 8.6.

SERC:

“SERC” or “Southeastern Electric Reliability Council” shall mean the reliability council under section 202 of the Federal Power Act established pursuant to the SERC Agreement dated January 14, 1970, or any successor thereto.

Short-term Project:

“Short-term Project” shall mean a transmission enhancement or expansion with an in-service date of more than three years but no more than five years from the year in which, pursuant to Operating Agreement, Schedule 6, section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Special Member:

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

Spot Market Backup:

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

Spot Market Energy:

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

Standing Committees:

“Standing Committees” shall mean the Members Committee, the committees established and maintained under Operating Agreement, section 8.6, and such other committees as the Members Committee may establish and maintain from time to time.

Start Fuel:

For units without a soak process, “Start Fuel” shall consist of fuel consumed from first fire of the start process to first breaker closing, plus any fuel expended from last breaker opening to shutdown.

For units with a soak process, “Start Fuel” is fuel consumed from first fire of the start process (initial reactor criticality for nuclear units) to the level at which the unit can follow PJM’s dispatch (including auxiliary boiler fuel), plus any fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements. Start Fuel included for each temperature state from breaker closure to the level at which the unit can follow PJM’s dispatch shall not exceed the unit specific soak time period reviewed and approved as part of the unit-specific parameter process detailed in Tariff, Attachment K-Appendix, section 6.6(c) or the defaults below:

- Cold Soak Time = $0.73 * \text{unit specific Minimum Run Time (in hours)}$
- Intermediate Soak Time = $0.61 * \text{unit specific Minimum Run Time (in hours)}$
- Hot Soak Time = $0.43 * \text{unit specific Minimum Run Time (in hours)}$

Start-Up Costs:

“Start-Up Costs” shall consist primarily of the cost of fuel, as determined by the unit’s start heat input (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances/adders, and station service cost. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

For units with soak process: Start-Up Cost shall mean the net unit costs from PJM’s notification to the level at which the unit can follow PJM’s dispatch and from last breaker open to shutdown.

~~For units without soak process: Start-Up Cost shall mean the unit costs from PJM's notification to first breaker close and from last breaker open to shutdown. mean the unit costs to bring the boiler, turbine and generator from shutdown conditions to the point after breaker closure which is typically indicated by telemetered or aggregated state estimator megawatts greater than zero and is determined based on the cost of start fuel, total fuel-related cost, performance factor, electrical costs (station service), start maintenance adder, and additional labor cost if required above normal station manning. Start Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.~~

State:

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

State Certification:

“State Certification” shall mean the Certification of an Authorized Commission, pursuant to Operating Agreement, section 18, the form of which is appended to the Operating Agreement as Operating Agreement, Schedule 10A, wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

State Consumer Advocate:

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

State Estimator:

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

State of Charge:

“State of Charge” shall mean the operating parameter that represents the quantity of physical energy stored (measured in units of megawatt-hours) in an Energy Storage Resource Model Participant in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

“State of Charge Management” shall mean the control of State of Charge of an Energy Storage Resource Market Participant using Charge and Discharge Economic Minimum and Maximum Megawatts limits, changes in operating mode, charging and discharging offer curves, and self-

scheduling of non-dispatchable purchases and sales of energy in the PJM markets. State of Charge Management shall not interfere with an Energy Storage Resource Model Participant's obligation to follow PJM dispatch, consistent with all other resources.

Station Power:

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

Sub-meter:

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

Subregional RTEP Project:

“Subregional RTEP Project” shall mean a transmission expansion or enhancement rated below 230 kV which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

Supplemental Project:

“Supplemental Project” shall mean a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii). Any system upgrades required to maintain the reliability of the system that are driven by a Supplemental Project are considered part of that Supplemental Project and are the responsibility of the entity sponsoring that Supplemental Project.

Synchronized Reserve:

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

Synchronized Reserve Event:

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

Synchronized Reserve Requirement:

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

System:

“System” shall mean the interconnected electric supply system of a Member and its interconnected subsidiaries exclusive of facilities which it may own or control outside of the PJM Region. Each Member may include in its system the electric supply systems of any party or parties other than Members which are within the PJM Region, provided its interconnection agreements with such other party or parties do not conflict with such inclusion.

System Energy Price:

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

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 Party Request:

“Third Party Request” shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of confidential information provided to the Authorized Person or Authorized Commission by the Office of the Interconnection or the Market Monitoring Unit. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for confidential information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

Tie Line:

“Tie Line” shall have the same meaning provided in the Open Access Transmission Tariff.

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 Operating Reserve Offer:

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

Transmission Congestion Charge:

“Transmission Congestion Charge” shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is

operating under constrained conditions, or as necessary to provide energy for third-party transmission losses, which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

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

Transmission Customer:

“Transmission Customer” shall have the meaning set forth in the PJM Tariff.

Transmission Facilities:

“Transmission Facilities” shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission 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 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 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 Operator:

“Transmission Operator” shall have the same meaning set forth in the NERC Glossary of Terms used in NERC Reliability Standards.

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 Upgrade:

“Transmission Owner Upgrade” shall mean an upgrade to a Transmission Owner’s own transmission facilities, which is an improvement to, addition to, or replacement of a part of, an existing facility and is not an entirely new transmission facility.

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.

Turn Down Ratio:

“Turn Down Ratio” shall mean the ratio of a generating unit’s economic maximum megawatts to its economic minimum megawatts.