Manual 18 clarifying and conforming changes
October 2023

Reason [Conforming] - Conforming changes for interconnection process changes (ER22-2110).

Redline Change:

4.2.3 Planned Generation Capacity Resources - Internal

A Planned Generation Capacity Resource that is participating in PJM's Regional Transmission Expansion Planning Process (RTEPP) is eligible to be offered into PJM's RPM Auctions if it meets the following requirements:

- The planned unit's start date of Interconnection Service is on or before the start of Delivery Year.
- At a minimum, ~~a Facilities Study Agreement has been executed for planned generation resources greater than 20 MWs and an Impact Study Agreement has been executed for planned generation resources less than or equal to 20 MWs, for the unit to participate in the Base Residual Auction~~ planned generation resources greater than 20 MW must be in the Phase III System Impact Study and planned generation resources less than or equal to 20 MW must be in Phase II System Impact Study, for the unit to participate in the Base Residual Auction.
- A~~n Interconnection Service~~ Generation Interconnection Agreement (~~ISA~~GIA) or Wholesale Market Participant Agreement (WMPA) has been executed for the unit to participate in an Incremental Auction.
- ~~A planned unit with an Interim ISA can offer only into the BRA or Incremental Auction for which the Interim ISA is valid.~~A Capacity Modification for the planned unit has been submitted and "Provisionally Approved" in Capacity Exchange.
- Planned Generation Capacity Resources must establish an RPM Credit Limit prior to an RPM Auction
- Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.
- If the Planned Generation Capacity Resource was committed through the Base Residual Auction and the ~~ISA~~ GIA is not received prior to opening of the bid window for the First Incremental Auction, the status of the Capacity Modification will be changed from "Provisionally Approved" to "Denied" so that the planned generation will no longer be included in a resource provider's Capacity Exchange Generation Resource portfolio.
- If an ~~ISA~~ GIA is eventually executed with a start date of Interconnection Service that is on or before the start of the Delivery Year, a new Capacity Modification will need to be submitted and "Provisionally Approved" in order to be re-included in a resource provider's Capacity Exchange Generation Resource portfolio
- If the Planned Generation Capacity Resource is delayed and has not commenced Interconnection Service by the start date of the Capacity Modification, the status of the Capacity Modification will be changed from "Provisionally Approved" to "Denied". A new Capacity Modification will need to be submitted and approved with a start date that corresponds to the start date of Interconnection Service.

- Planned Generation Capacity Resources are required to submit an acceptance test to PJM Planning prior to the start date of the submitted CAPMOD in accordance with Manual 21 Section 1.3.
- If PJM Planning determines a portion of a Planned Generation Capacity Resource has commenced Interconnection Service, or considered Partially In-Service, the status of the Capacity Modification may be changed from "Provisionally Approved" to "Approved" up to the amount of MWs deemed in-service by PJM Planning. A Capacity Modification for the remaining Planned MWs should be submitted and remain "Provisionally Approved" until PJM Planning confirms the MWs are in-service.

Reason [Conforming] - RAA updated definition based on Hybrid filing (ER22-1420). Remove definition in the manual and refer to RAA for definition.

Redline Change:

5.4.1 Resource-Specific Sell Offer Requirements

− Capacity Storage Resources shall mean any Energy Storage Resource~~20~~ as defined in the OATT that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM's markets such as through a Fixed Resource Requirement Capacity Plan. An acceptable method for determining the quantity of unforced capacity MWs that may offer as Capacity Performance for a Capacity Storage Resource is based on calculating the average of the hourly output (MWh) of the intermittent resource during the expected performance hours in the summer and winter. The expected performance hours in the summer are hours ending 15:00 through 20:00 EPT in the months of June, July, and August. The expected performance hours in the winter are hours ending 6:00 through 9:00 EPT and 18:00 through 21:00 EPT in the months of January and February.

20 ~~Energy Storage Resource shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity, and Ancillary Services markets as a Market Participant~~ ~~See OATT for definition~~.

Reason [Conforming] - RAA updated for Transitional MW (Docket No. ER23-1067-000). Accredited UCAP cannot exceed CIR plus transitional MW based on tariff changes.

Redline Change:

4.7.1 Resource Position for Generation Capacity Resources

A party's Daily Generation Capacity Resource Position in unforced capacity terms is calculated dynamically by the Capacity Exchange system for each unit and is equal to the party's Daily ICAP Owned on a unit multiplied by one minus the unit's Effective EFORd.
A party's Daily ICAP Owned on a unit is calculated by adding the ICAP Value of a unit as determined by a party's approved Capacity Modifications to ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases. The Installed Capacity (ICAP) Value of a unit is determined in accordance with ***PJM Manual for the Rules and Procedures for the Determination of Generating Capability (M-21).*** For an ELCC Resource, the term "ICAP" in this manual refers to the lesser of the Accredited UCAP or the resource's CIRs ~~or~~plus any awarded transitional resource MWs in accordance with Manual 21 Section 1.2.

4.2.6 Capacity Modifications (CAP Mods)

Capacity Modifications (CAP MODs) are a type of Capacity Exchange transaction used by generation owners to request the addition of a new unit or the removal of an existing unit from their resource portfolio in Capacity Exchange, or to request a MW increase or decrease in the summer or winter installed capacity rating of an existing unit.

The purpose of a CAP MOD is to establish the installed capacity value of a generation resource in the Capacity Exchange system. CAP MOD transactions represent permanent changes to the installed capacity value of a generation unit.

CAP MODs are also used by a generation owner to establish the capacity value of an ELCC Resource to be offered into the PJM Capacity Market and by PJM to establish the Delivery Year capacity value of an ELCC Resource.

A CAP MOD may also be submitted by PJM to establish the capacity value of a Winter-Period Capacity Performance Resource for November through April of the Delivery Year.

The following are business rules that apply to Capacity Modifications (CAP Mods):

- CAP MODs with a start date that occurs on or before the start of the Delivery Year must be submitted and "Provisionally Approved" or "Approved" by PJM in the Capacity Exchange system prior to the opening of the Base Residual Auction's or Incremental Auction's bidding window in order for the CAP MODs to be considered in a party's Generation Resource Position and the calculation of Available ICAP to offer for a Base Residual Auction, Incremental Auction or bilateral unit-specific transaction.

- All other CAP MODs must be submitted a minimum of 2 business days prior to the start date of the CAP MOD. The CAP MOD must be "Approved" by PJM in the Capacity Exchange system prior to the start date of the CAP MOD in order to be considered in a party's final Daily Generation Resource Position.

- If the status of a "Provisionally Approved" CAP MOD changes to "Denied" or "PJM Withdrawn", there will be no change to any party's RPM Resource Commitments[11].

- CAP MODs cannot be created during an RPM Auction's bidding window and clearing week.

- CAP MODs that are not in the "Approved" status by the start date of the CAP MOD will have their status changed to "PJM Withdrawn".

- CAP MODs that would cause the summer rating of a generation resource or the capacity value of an ELCC Resource to exceed such unit's Capacity Interconnection Rights plus transitional resource MWs will be "Denied" by PJM.

4.2.7 Accredited UCAP for ELCC Resources

Effective Load Carrying Capability (ELCC) establishes the Accredited UCAP value for ELCC Resources such as renewables and storage. For the sole purpose of Manual 18 and the Capacity Exchange tool, the "ICAP" and "UCAP" for an ELCC Resource are set equal to

the lesser of its Accredited UCAP or its Capacity Interconnection Rights plus transitional resource MW, and the EFORd of
an ELCC Resource is shown as zero because the actual EFORd of an ELCC Resource, if applicable, has already been used in the determination of its Accredited UCAP.
The ELCC method is described in Manual 20 (**PJM Resource Adequacy Analysis**), and the calculation of Accredited UCAP for an ELCC Resource is described in Manual 21A (**Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis**).

Reason [Conforming] – Conforming language for Order 841 and Hybrid Order (ER22-1420). Change is also consistent with M-27

Redline Change:

7.4 Obligation Peak Load

Obligation Peak Load is the peak load value on which LSEs' Unforced Capacity Obligations are based. Each PJM Electric Distribution Company (EDC) is responsible for allocating its normalized previous summer's peak to each customer in the zone (both retail and wholesale). LSE Obligation Peak Load represents the summation of Peak Load Contributions for each of an LSE's customers.

The following business rules apply to Delivery Year Obligation Peak Load data for a zone/area:

- The Obligation Peak Load allocation for a zone/area is constant and effective for the entire Delivery Year.
- The EDC is also responsible for allocating the Obligation Peak Load for a zone/area among end-use customers by calculating Peak Load Contributions (i.e., "capacity tickets") for each end-use customer by December 31 prior to the start of the Delivery Year.
- The EDC must make Peak Load Contribution information available to LSEs by December 31 prior to the start of the Delivery Year.
- Non-dispatched charging energy for Energy Storage Model Participants and Open—Loop Hybrid Resources shall not be allocated a Peak Load Contribution value in accordance with Manual 27~~Energy Storage Resources shall not be allocated a Peak Load Contribution for purchases of energy for later resale to PJM~~.

Reason [Conforming] - Remove reference to DR Factor. This was eliminated with implementation of CP.

Redline Change:

8.2.2 Demand Resources

A demand resource provider may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Load management program cancellation or delay– The load management program(s) associated with the planned demand resource is cancelled or delayed and is not installed prior to the start of the Delivery Year.

- Decrease in nominated value of demand resource – The final nominated value of the demand resource during the Delivery Year is less than the nominated value of the demand resource used in cleared offers in RPM Auctions for the Delivery Year due to a decrease in the peak load contributions (i.e., capacity tickets) of end-use customers providing the actual load response.
- Failure to have enough sites registered and approved in the DR Hub system prior to the start of the Delivery Year to support the nominated value of the demand resource committed for such Delivery Year. The sites registered and approved in the DR Hub system must be of the Capacity Performance product-type and sufficient to support the summer and non-summer commitments on the Demand Resource.
- Decrease in the ~~DR Factor or~~ Forecast Pool Requirement - The final UCAP value of the demand resource during the Delivery Year is less than the UCAP value committed in the auction due to the final FPR for the Delivery Year being less than the ~~DR Factor or~~ FPR that was used in RPM Auction for which the demand resource cleared. During the Delivery Year, failure to meet demand resource commitments will be determined by comparing a party's Daily RPM Demand Resource Position to their Daily RPM Resource Commitments for such resource. If a party's Daily RPM Demand Resource Position is less than their Daily RPM Resource Commitments for such resource on a delivery day, a Daily Capacity Resource Deficiency Charge will be assessed on the RPM Commitment Shortage.

Reason [Conforming]: Updates to Sections 3.3 and 3.4 to conform to the approved quad review filing (Docket ER22-2984-000)

Redline Changes:

3.3.1 Cost of New Entry

The value for Cost of New Entry (CONE) (in ICAP terms) is determined in accordance with Attachment DD of the Open Access Transmission Tariff (OATT), Section 5.10 (a) (iv). For Delivery Years up to and including the 2025/2026 Delivery Year, the~~The~~ Reference Resource is a combustion turbine (CT) generating station, configured with a single General Electric Frame 7HA turbine as defined in the OATT. For the 2026/2027 Delivery Year and subsequent Delivery Years, the Reference Resource is a combined cycle (CC) generating station, configured with a double train 1 x 1 single shaft General Electric Frame 7HA.02 turbine with an F-A650 steam turbine as defined in the OATT.

The gross Cost of New Entry values for the following four CONE Areas for the 2022/2023 Delivery Year are specified in the OATT, Attachment DD, Section 5.10 (a) (iv)(A) :

1. AE, DPL, JCPL, PECO, PSEG, RECO ("CONE Area 1");
2. BGE, PEPCO ("CONE Area 2");
3. AEP, APS, COMED, DAYTON, DLCo, ATSI, DEOK, EKPC, Dominion, OVEC ("CONE Area 3"); and
4. METED, PENELEC, PPL ("CONE Area 4").

The gross Cost of New Entry value for the PJM Region shall be the average of the gross CONE values for the four CONE Areas.

For the 2023/2024 Delivery Year, the gross CONE values specified in the OATT for the 2022/2023 Delivery Year shall be adjusted to reflect changes in generating plant construction costs based on changes in the applicable United States Bureau of Labor Statistics (BLS) Composite Index, and then adjusted further by a factor of 1.022 to reflect the annual decline in bonus appreciation scheduled under federal tax law, to establish the CONE values used in the development of the Variable Resource Requirement Curves for the PJM Region and the modeled LDAs for all RPM Auctions for the 2023/2024 Delivery Year.

The applicable BLS Composite Index for a Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Index for Construction Materials and Components (weighted 55%), and the BLS Producer Price Index for Turbines and Turbine Generator Sets (weighted 25%). The Quarterly Census of Employment and Wages for Utility System Construction will be based on the state of New Jersey for CONE Area 1, Maryland for CONE Area 2, Ohio for CONE Area 3, and Pennsylvania for CONE Area 4.

For subsequent Delivery Years up to and including the 2025/2026 Delivery Year, the Benchmark CONE values will be the CONE values used in the development of the Variable Resource Requirement Curves for the prior Delivery Year. The applicable BLS Composite Index for the Delivery Year will be applied to the Benchmark CONE values, and then multiplying the result by 1.022, to establish the CONE values used in the development of the Variable Resource Requirement Curves for the PJM Region and the modeled LDAs for all RPM Auctions for such Delivery Year.

The gross Cost of New Entry values for the following four CONE Areas for the 2026/2027 Delivery Year are specified in the OATT, Attachment DD, Section 5.10 (a) (iv)(C):

1. AE, DPL, JCPL, PECO, PSEG, RECO (“CONE Area 1”);
2. BGE, PEPCO (“CONE Area 2”);
3. AEP, APS, COMED, DAYTON, DLCo, ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”); and
4. METED, PENELEC, PPL (“CONE Area 4”).

The gross Cost of New Entry value for the PJM Region shall be the average of the gross CONE values for the four CONE Areas. For the 2027/2028 Delivery Year, the gross CONE values specified in the OATT for the 2026/2027 Delivery Year shall be adjusted to reflect changes in generating plant construction costs based on changes in the applicable United States Bureau of Labor Statistics (BLS) Composite Index to establish the CONE values used in the development of the Variable Resource Requirement Curves for the PJM Region and the modeled LDAs for all RPM Auctions for the 2027/2028 Delivery Year.

The applicable BLS Composite Index for a Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 40%), the BLS Producer Index for Construction Materials and Components (weighted 45%), and the BLS Producer Price Index for Turbines and Turbine Generator Sets (weighted 15%). The Quarterly Census of Employment and Wages for Utility System Construction will be based on the state of New Jersey for CONE Area 1, Maryland for CONE Area 2, Ohio for CONE Area 3, and Pennsylvania for CONE Area 4.

For subsequent Delivery Years, the Benchmark CONE values will be the CONE values used in the development of the Variable Resource Requirement Curves for the prior Delivery Year. The applicable BLS Composite Index for the Delivery Year will be applied to the Benchmark CONE values to establish the CONE values used in the development of the Variable Resource Requirement Curves for the PJM Region and the modeled LDAs for all RPM Auctions for such Delivery Year.

3.3.2 Net Energy and Ancillary Services Offset

Pursuant to Attachment DD, Section 5.10(a)(v and v-1) of the PJM Tariff, PJM determines a Net Energy and Ancillary Services (E&AS) Revenue Offset for the PJM Region and for each Zone.

For Delivery Years 2023/2024 through and Including 2025/2026

The Net E&AS Revenue Offset for the PJM Region for a Delivery Year is (a) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the Base Residual Auction for such Delivery Year plus (b) an assumed value for ancillary services revenues ($/MW-year) as set forth in Attachment DD, Section 5.10(a)(v) of the PJM Tariff.

The annual average of energy revenues for the PJM Region is based on (1) heat rate and other characteristics of such Reference Resource; (2) daily natural gas prices averaged across the fuel pricing points specified in the table below with a fuel transmission adder appropriate for the PJM region; (3) assumed variable operation and maintenance expenses for such Reference Resource as set forth in Attachment DD, Section 5.10(a)(v) of the PJM Tariff; (4) actual PJM hourly average LMP prices recorded in the PJM Region during such period; and (5) an assumption that the Reference Resource would be dispatched for both Day-Ahead and Real-Time Energy Markets on Peak-Hour Dispatch basis.

The Net E&AS Revenue Offset for each Zone for a Delivery Year is determined using the same procedures and methods used to determine the Net E&AS Revenue Offset for the PJM Region; provided, however, that (1) actual hourly average LMPs for such Zone shall be used in place of the PJM Region hourly average LMPs; and (2) daily natural gas prices at the fuel pricing points specified in the table below in this section 3.3.2 with a fuel transmission adder appropriate to the zone.

Peak-Hour Dispatch means, for purposes of calculating the energy revenues in the Energy and

Ancillary Services Revenue Offset, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

For the 2026/2027 Delivery Year and subsequent Delivery Years

The Net E&AS Revenue Offset for the PJM Region for a Delivery Year is the annual average of the revenues that the Reference Resource is projected to receive from the PJM energy and ancillary service markets from three separate simulations, with each simulation using forward prices shaped using historical data from one of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such shapes. The projected Net E&AS Revenue Offset will be determined for the PJM Region and each Zone as specified in Attachment DD, Section 5.10(a)(v-1) of the PJM Tariff.

The annual average of energy revenues for the PJM Region is based on (1) heat rate and other characteristics of such Reference Resource; (2) forward daily natural gas prices averaged across the fuel pricing points specified in the table above with a fuel transmission adder appropriate for the PJM region; (3) assumed variable operation and maintenance expenses for such Reference Resource; (4) Forward Hourly LMPs for the PJM Region; (4) Forward Hourly Ancillary Services Prices; and (5) an assumption that the Reference Resource would be dispatched on a Projected EAS Dispatch basis.

Projected EAS Dispatch means, for purposes of calculating the Net Energy and Ancillary Services Revenue Offset, a simulated dispatch with the objective of committing and dispatching a resource for the purpose of maximizing its net revenues. The calculation shall take inputs including Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and Forward Daily Natural Gas Prices or forecasted fuel prices, as applicable, in addition to the operating parameters and costs of the specific resource, including the cost emission allowances. Using operating parameters, forward or forecasted fuel prices, as applicable and other cost pricing inputs, a composite, cost-based energy offer is created for the resource such that its commitment and dispatch is co-optimized between energy and ancillary services in the Day-Ahead Energy Market and then the Real-Time Energy Market considering the electricity and ancillary service price inputs. In the Real-Time Energy Market co-optimization, the resource is assumed to be operating in the hours it was scheduled in the Day-Ahead Energy Market but is dispatched according to the real-time price inputs. In the hours where the resource was not committed in the Day-Ahead Market, the resource may be committed and dispatched in real-time only subject to the real-time electricity and ancillary service price inputs and the resource’s offer and operating parameters.

The Net E&AS Revenue Offset for each Zone is determined using the same procedures and methods used to determine the Net E&AS Revenue Offset for the PJM Region; provided, however, that (1) Forward Hourly LMPs of each such Zone are used in place of the Forward Hourly LMPs of the PJM Region; and (2) forward daily natural gas prices are used for each such Zone based on the fuel price point to Zone mapping shown in the table below.

The Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and Forward Daily Natural Gas Prices used in the calculation of the Net E&AS Revenue Offset are determined as defined in Attachment DD, Section 5.10(a)(v-1) of the PJM Tariff.

In the determination of Forward Hourly LMPs, the ComEd Zone is mapped to the N. Illinois Hub, the AEP, ATSI, DAY, DEOK, DUQ, EKPC and OVEC Zones are mapped to the AEP-Dayton Hub, and all other Zones are mapped to the Western Hub. In addition, several of the fuel pricing points of the table below lack sufficient liquidity and are therefore mapped to more liquid hubs for the purposes of calculating Forward Daily Natural Gas Prices. For the purpose of calculating Forward Daily Natural Gas Prices, Transco-Z6 (non-NY) is used in place of Transco-Z5 Dlv and Transco-Z6 (NY).

Zone to Fuel Pricing Point Mapping

The fuel pricing point used for the purpose of establishing the Net E&AS Offset for each Zone is provided in the table below.

Zone	Fuel Pricing Point
AE, BGE, DPL, & JCPL	Transco-Z6 (non-NY)
COMED	Chicago Citygates
DUQ, METED, PECO, & PPL	TETCO M3
PEPCO & DOM	Transco Z5 Dlv
AEP, OVEC	Columbia-Appalachia TCO
DAY, DEOK, ATSI, EKPC	Mich Con
APS & PENELEC	Dominion South
PSEG & RECO	Transco Z6 (NY)
~~EKPC~~	~~Tenn LA 500 Leg~~

3.3.3 Net Cost of New Entry

The Net Cost of New Entry (Net CONE) for the PJM Region is the gross Cost of New Entry for the PJM Region minus the Net E&AS Revenue Offset for the PJM Region.

PJM shall determine the Net Cost of New Entry for each Zone that comprises the modeled LDA. The Net Cost of New Entry for a Zone is the applicable gross Cost of Net Entry value for such Zone minus the Net E&AS Revenue Offset for such Zone. The Net Cost of New Entry for the Zone is used for a sub-zonal LDA. The Net Cost of New Entry for a modeled LDA shall be the average of the Net CONE values of all zones within the modeled LDA.

3.4 Plotting the Variable Resource Requirement Curve

For the 2022/2023 Delivery Year through and including the 2025/2026 Delivery Year, the ~~The~~ Variable Resource Requirement Curve is plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis using the following three points a, b, and c:

a. The price is equal to the greater of [the Cost of New Entry or 1.5 times (the Cost of New Entry minus the Net E&AS Revenue Offset, referred to as "Net CONE")] divided by (one minus Pool-Wide Average EFORd) and Unforced Capacity is equal to [PJM Region Reliability Requirement10 multiplied by (100% plus the approved IRM% minus 1.2%) divided by (100% plus approved IRM %)].
Basis for Price at Point a:
Greaterof CONEor1.5 (CONE − E & AS)
1 − Pool Wide EFORd
Basis for Quantity at Point a:
RelReq (100% + IRM − 1 . 2%)
(100% + IRM)

b. The price is equal to 0.75 times Net CONE divided by (one minus Pool-Wide Average EFORd) and Unforced Capacity equals [PJM Region Reliability Requirement multiplied by (100% plus the approved IRM% plus 1.9%) divided by (100% plus approved IRM%)]..
Basis for Price at Point b:
0.75 (CONE − E & AS)
1 − Pool Wide EFORd
Basis for Quantity at Point b:
RelReq (100% + IRM + 1.9%)
(100% + IRM)

c. The price is equal to zero and Unforced Capacity equals [PJM Region Reliability Requirement multiplied by (100% plus the approved IRM% plus 7.8%) divided by (100% plus approved IRM %)].
Basis for Price at Point c:
$0/MW − day
Basis for Quantity at Point c:
RelReq (100% + IRM + 7.8%)
(100% + IRM)

For the 2026/2027 Delivery Year and subsequent Delivery Years, the Variable Resource Requirement Curve is plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis using the following three points a, b, and c:

a. The price is equal to the greater of [the Cost of New Entry or 1.75 times (the Cost of New Entry minus the Net E&AS Revenue Offset, referred to as "Net CONE")] divided by (one minus Pool-Wide Average EFORd) and Unforced Capacity is equal to (PJM Region Reliability Requirement10 multiplied by 99%).

b. The price is equal to 0.75 times Net CONE divided by (one minus Pool-Wide Average EFORd) and Unforced Capacity equals (PJM Region Reliability Requirement multiplied by 101.5%).

c. The price is equal to zero and Unforced Capacity equals (PJM Region Reliability Requirement multiplied by 104.5%).

3.4.1 Plotting the Variable Resource Requirement Curves

The graph below illustrates the process for plotting the Variable Resource Requirement curve. The VRR Curve is plotted by combining a horizontal line from the y-axis to point (a), a straight line connecting points (a) and (b), a straight line connecting points (b) and (c).

Exhibit 1: Illustrative Example of a Variable Resource Requirement Curve

The same process shall be used to establish the Variable Resource Requirement Curve for each LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement, and the FRR adjustments will be for the FRR Entities in the LDA.

Beginning with the 2018/2019 Delivery Year and continuing no later than for every fourth Delivery Year thereafter, PJM will perform a review of the shape of the Variable Resource Requirement Curve, CONE values, and Energy & Ancillary Services methodology, and any FERC approved changes resulting from this review will be incorporated into the appropriate BRA Auctions.

The Variable Resource Requirement Curve will be further adjusted to reflect the impact of any PRD that is proposed in a PRD Plan and that is reviewed and accepted by PJM. To reflect accepted PRD Plans, the Variable Resource Requirement Curve will be shifted leftward along the horizontal axis by a quantity equal to the Nominal PRD Value multiplied by the FPR. This quantity represents the quantity of Unforced Capacity that would have been procured in the RTO on behalf of the PRD load but that is now not needed due to the PRD loads' commitment to reduce consumption. The curve will be shifted leftward in this manner only for those portions of the curve that are at or above the PRD Reservation Price, since the PRD load can be excluded only if the auction clears at or above that price. The Variable Resource Requirement Curve for each LDA in which the PRD resides (including the RTO curve) will be shifted in the exact same manner.

The Variable Resource Requirement Curve will be further adjusted to reflect the impact of any EE addback. The Variable Resource Requirement Curve will be shifted rightward along the horizontal axis by a quantity equal to the EE addback MW quantity as explained in Section 2.4.5. The Variable Resource Requirement Curve for each LDA in which EE resides (including the RTO curve) will be shifted in the exact same manner.

Reason [Conforming]: Change to PAI Trigger (Docket ER23-1996-000)

Redline Changes:

8.4A Non-Performance Assessment

A Non-Performance Assessment will assess performance of resources during emergency conditions. Non-Performance Assessment applies to Capacity Performance Resource commitments and Price Responsive Demand commitments. Capacity Performance Resource commitments and PRD commitments are exposed to Non-Performance Charges for underperformance during Emergency Actions throughout the entire Delivery Year. Resources that fail to perform are subject to Non-Performance Charge and resources that over-perform may be eligible for Bonus Performance Credit.

Implementation of the Non-Performance Assessment eliminated Peak Season Maintenance Compliance and Peak-Hour Period Availability Assessment for generation resources and Load Management Event Compliance for Demand Resources.

The Non-Performance Assessment will compare each Capacity Resource's Expected Performance against its Actual Performance for each Performance Assessment Interval. Performance Assessment Interval shall mean each Real-time Settlement Interval for which an Emergency Action as defined in the OATT has been declared by PJM. A Performance Assessment Interval~~s are delineated by PJM's declaration of Emergency Actions~~ is triggered based on either of the two conditions defined below and such condition must be in effect for the entire Real-time Settlement Interval. . ~~Emergency Actions shall mean any emergency action for locational or system-wide capacity shortages that either utilizes preemergency mandatory load management reductions or other emergency capacity, or initiates a more severe action, including but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning, or Manual Load Dump Actions. Performance is assessed for each interval that PJM declares the following actions:~~

- ~~Pre-Emergency Load Management Reduction Action~~
- ~~Emergency Load Management Reduction Action~~
- ~~Primary Reserve Warning~~
- ~~Maximum Generation Emergency Action~~
- ~~Emergency Voluntary Energy Only Demand Response Reductions~~
- ~~Voltage Reduction Warning and Reduction of Non-Critical Plant Load~~
- ~~Curtailment of Non-Essential Business Load~~
- ~~Deploy All Resources Action~~
- ~~Manual Load Dump Warning~~
- ~~Voltage Reduction Action~~
- ~~Manual Load Dump Action~~

25 OATT, Attachment DD, Section 10A

- ~~Load Shed Directive~~
- Condition 1 - A Primary Reserve Shortage is determined for the Reserve Zone or active Reserve Sub-zone and one of the following emergency procedures is issued that encompasses such Reserve Zone or active Reserve Sub-zone:
  - Voltage Reduction Warning and Reduction of Non-Critical Plant Load
  - Manual Load Dump Warning
  - Maximum Emergency Generation Action
  - Voltage Reduction Warning and Curtailment of Non-Essential Building Load

The following table illustrates which resources will be assessed for a PAI based on the location of the resource and the location of the above Emergency Procedure and location of the Primary Reserve Shortage.

		Primary Reserve Shortage			
Condition 1 Emergency Procedures		Reserve Zone (RTO)	Reserve Subzone (MAD)	Reserve Zone and Reserve Subzone (RTO & MAD)	None
	Reserve Zone (RTO)	RTO	MAD	RTO	None
	Reserve Subzone (MAD)	None	MAD	MAD	None
	None	None	None	None	None

- Condition 2 - One of the following emergency procedures is issued for the entire Reserve Zone or Sub-Zone:
  - Deploy All Resources Action
  - Voltage Reduction Action
  - Manual Load Dump Action
  - Load Shed Directive

See Manual 13 for details on the issuance of emergency procedures and Manual 11 for detail on Primary Reserve Shortage which is determined when the reserve MW assigned in the dispatch run is less than the Primary Reserve requirement for either the Reserve Zone or active Reserve Sub-zone.

When assessment is for the Reserve Sub-zone, the list of resources subject to assessment is determined based on the active subzone bus and resource list effective at the time of the PAI. The posting is found on the Ancillary Service page of PJM.com. DR/PRD dispatched and located in the Reserve Sub-zone will be included in the Reserve Sub-zone assessment.

~~The Non-Performance Assessment will encompass all resources located in the area defined by the Emergency Action.~~ If the Emergency Action area is for the Reserve Zone~~PJM-wide~~, Net Energy Imports are included in this assessment. External Generation Capacity Resources are included in the assessment if such external resource would have helped resolve the declared Emergency Action that was the subject of the assessment. At the start of the Delivery Year, PJM will inform the Capacity Market Seller of an external resource as to which Locational Deliverability Area it has been assigned for Non-Performance Assessment purposes. QTUs will be deemed to be located in the LDA into which such upgrade increased the CETL and the QTU will be included in the Non-Performance Assessment only if, and to the extent that, the declared Emergency Action encompasses only the LDA into which the upgrade increased the CETL.

Reason [Conforming]: Updated Default Gross CONE and Gross ACR for Minimum Offer Price rule (Docket ER23-1700)

Redline Changes:

5.4.8.4 Default MOPR Floor Offer Prices

A. Default New Entry MOPR Floor Offer Price

The Default New Entry MOPR Floor Offer Price for a Generation Capacity Resource that is subject to the MOPR and for which a Sell Offer based on that resource, or any uprate of the Generation Capacity Resource, has not previously cleared an RPM Auction for any Delivery Year is based on the net cost of new entry ("CONE") of the applicable resource type. The net CONE values are determined by subtracting the estimated net energy and ancillary service revenues from the gross cost of new entry ("CONE") values shown in the table below. The gross CONE values of the table below ~~are applicable to the 2022/2023 Delivery Year and~~ are adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, as described below. The net energy and ancillary services revenue estimate is determined for each resource type and for each Zone as described in sections 5.14(h-2)(3)(A)(i) through (viii) of Attachment DD of the PJM OATT.

For the capacity resource types listed in the table below, the Default New Entry MOPR Floor Offer Price is set equal to the net CONE of each resource type expressed in terms of Unforced Capacity ("UCAP") MW where the net CONE values are initially calculated for each resource type in terms of nameplate MW and then converted to UCAP MW terms based on the applicable class average EFORd for thermal generation resource types and battery energy storage resource types and the applicable ELCC Class Rating for battery storage, wind and solar generation resource types. The resultant net CONE in nameplate MW terms of the battery energy storage resource type is multiplied by 2.5 prior to applying the class average EFORd of the battery energy storage resource type.

~~Tracking Solar PV~~	~~$290~~
~~Onshore Wind~~	~~$420~~
~~Offshore Wind~~	~~$1,155~~
~~Battery Energy Storage~~	~~$532~~

Gross CONE Values used to determine default New Entry MOPR floor offer prices

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

Beginning with the 2023/2024 Delivery Year, the gross CONE values of the table above will be adjusted annually based on changes in the Applicable United States Bureau of Labor Statistics ("BLS") Composite Index~~, and then adjusted further by a factor of 1.022 to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law~~. The Applicable BLS Composite Index for the combustion turbine and combined cycle resource types shall be the same Applicable BLS Composite Index as that applied to adjust the gross CONE used to determine the VRR Curve for that Delivery Year (see Section 3.3.1 of this manual) ~~most recently published twelve-month change, at the time CONE values are required to be posted for the BRA for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Price Index for Construction Materials and Components (weighted 55%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 25%).~~ For all other resource types, the "BLS Producer Price Index Turbines and Turbine Generator Sets" component shall be replaced with the "BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment". For the 2023/2024 through 2025/2026 Delivery Years, inclusive, ~~and~~ the resultant value shall then be then adjusted further by a factor of 1.022 for nuclear and coal resource types or 1.01 for solar, wind, and storage resource types to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law. No such further adjustment shall be made to the resultant values for the 2027/2028 Delivery Year and subsequent Delivery Years.

B. Default Gross Avoidable Cost Rate for Determination of Cleared MOPR Floor Offer Prices

For a Generation Capacity Resource that is subject to the MOPR and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year, the applicable Cleared MOPR Floor Offer Price is based on the net Avoidable Cost Rate determined by subtracting the estimated net energy and ancillary service revenues of the resource from the gross ACR of the resource. The Cleared MOPR Floor Offer Price of a Generation Capacity Resource shall be, at the election of the Capacity Market Seller, either (i) based on the unitspecific net Avoidable Cost Rate ("ACR"), or (ii) if available, the default gross ACR of the applicable resource type shown in the table below net of energy and ancillary services revenue determined for the resource as described in section 5.4.8.5 of this manual. The gross ACR values of the table below ~~are applicable to the 2022/2023 Delivery Year and~~ are adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, using the 10-year average Handy-Whitman Index to account for expected inflation.

For purposes of submitting a Sell Offer, the net ACR values are expressed in terms of Unforced Capacity ("UCAP") MW where the net ACR values are initially calculated for each resource in terms of nameplate MW and then converted to UCAP MW terms based on the unit-specific EFORd for thermal generation resource types and battery energy storage resource types and the unit-specific Accredited UCAP value for battery energy storage, solar and wind generation resource types (appropriately time-weighted for any winter Capacity Interconnection Rights). The resultant net ACR in nameplate MW terms of the battery energy storage resource type is multiplied by 2.5 prior to applying the unit-specific of the battery energy storage resource type.

Default Gross ACR Values (in 2022/2023 $/MW-Day) used to determine MOPR Floor Offer Price of Cleared Capacity Resources with State Subsidy

Resource Type	Gross ACR (2022/2023 $/MW-Day) (Nameplate)
Nuclear – Single Unit	$697
Nuclear – Multi Unit	$445
Coal	$80
Combined Cycle	$56
Combustion Turbine	$50
Solar PV (Fixed and Tracking)	$40
Onshore Wind	$83

Default Gross ACR values used to determine MOPR Floor Offer Price of Existing Capacity Resources

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