



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

Daniel Vinnik
Counsel
T: (267) 858-9451
daniel.vinnik@pjm.com

September 30, 2026

The Honorable Debbie-Anne A. Reese
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426-0001

*Re: PJM Interconnection L.L.C., Docket No. ER26-3898-000,
Proposed Updates to the Default Gross Cost of New Entry and Default Gross Avoidable
Cost Rate for the Minimum Offer Price Rule*

Dear Secretary Reese:

Pursuant to Section 205 of the Federal Power Act,¹ and the Federal Energy Regulatory Commission's ("Commission") Regulations,² PJM Interconnection, L.L.C. ("PJM") hereby submits proposed revisions to the Open Access Transmission Tariff ("Tariff"). Specifically, as further explained below, the proposed revisions in this filing serve to update the default gross Cost of New Entry ("Gross CONE") and default gross Avoidable Cost Rate ("Gross ACR") used for purposes of the Minimum Offer Price Rule ("MOPR") and Market Seller Offer Cap ("MSOC") rule³ effective with the Reliability Pricing Model ("RPM") Auctions associated with the 2030/2031 Delivery Year. The primary components of this filing are: (1) updating the default Gross CONE values for nine resource types used for MOPR purposes, and (2) updating the default

¹ 16 U.S.C. § 824d.

² 18 C.F.R. Part 35.

³ For the purpose of this filing, capitalized terms not defined herein shall have the meaning as contained in the Open Access Transmission Tariff ("Tariff"), the Amended and Restated Operating Agreement of PJM ("Operating Agreement"), and the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA").

Gross ACR values for nine resource types used for MOPR and MSOC purposes starting with the 2030/2031 Delivery Year.⁴

This filing is submitted in accordance with a Tariff requirement for PJM to review default Gross CONE and Gross ACR values every fourth Delivery Year beginning with the 2022/2023 Delivery Year.⁵ To that end, PJM is proposing updated default Gross CONE and Gross ACR values in advance of the Base Residual Auction (“BRA”) associated with the 2030/2031 Delivery Year, which is currently scheduled to commence in May 2027. This filing represents the culmination of a successful stakeholder process that began on June 16, 2026.⁶ During this process, PJM incorporated all of the feedback received at the various stakeholder meetings. The proposed revisions were endorsed by PJM stakeholders at the August 19, 2026 Markets and Reliability Committee (“MRC”) meeting, by acclamation with no objections and one abstention,⁷ and Members Committee (“MC”) meeting by acclamation with two objections and four abstentions.⁸ PJM requests that the Commission issue its order accepting the enclosed revisions by November 29, 2026, sixty (60) days from the date of this filing, with an effective date of November 30, 2026, for all revisions.

⁴ Offshore wind has a default Gross CONE value but not a default Gross ACR value. There are not enough active offshore wind projects to calculate the avoidable ongoing costs for this resource type. Steam oil and gas have a default Gross ACR value, but not a default Gross CONE value. There are not enough new steam oil and gas units entering PJM to require a default Gross CONE value for this resource type.

⁵ See Tariff, Attachment DD, section 5.14(h-2)(3).

⁶ The agenda from PJM’s June 16, 2026 special Market Implementation Committee meeting is available at <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2026/20260616-special/agenda.pdf>.

⁷ The agenda for PJM’s August 19, 2026 MRC is available at <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2026/20260819/20260819-agenda.pdf>.

⁸ The agenda for PJM’s August 19, 2026 MC is available at <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2026/20260819/20260819-agenda.pdf>.

I. BACKGROUND

Under PJM's existing capacity market rules, Capacity Market Sellers may have Sell Offers mitigated when certain market power conditions are deemed to exist. More particularly, the MOPR and MSOC rules are two main instances where capacity offers may be mitigated. The MOPR applies to resources offered by Capacity Market Sellers that may exercise buyer-side market power and acts as a price floor. Conversely, the MSOC acts as a price ceiling and applies to resources offered by Capacity Market Sellers that have the potential to exercise seller-side market power. The applicable default MOPR and default MSOC prices are dependent upon whether the resource is a Planned Generation Capacity Resource (CONE) or an Existing Generation Capacity Resource (ACR) and the relevant technology type.

The default gross MOPR and MSOC values are specified in the Tariff and are escalated for each subsequent Delivery Year. In advance of each auction, PJM posts the default net values for the various resource types. For Planned Generation Capacity Resources that are subject to the MOPR, these values will be based the default Gross CONE values from which PJM will subtract the estimated net energy and ancillary services ("E&AS") revenues for each resource type and Zone to determine the Net CONE. Likewise, for Existing Generation Capacity Resources that are subject to the MOPR or MSOC, the default values will be based on the default Gross ACR value from which PJM will subtract the unit-specific historical net E&AS revenues for each resource to determine the net ACR.

The Tariff requires PJM to review and "propose either to modify or retain" the default Gross CONE and default Gross ACR values no later than every four delivery years.⁹ As a result,

⁹ Tariff, Attachment DD, section 5.14(h-2)(3).

PJM is required to review and update these values effective with the 2030/2031 Delivery Year. In complying with this Tariff requirement, PJM engaged with an independent consultant, The Brattle Group (“Brattle”), in independently reviewing and proposing updated default ACR values, while PJM separately reviewed publicly available sources and leveraged the analysis that was recently completed during the periodic review of the Variable Resource Requirement (“VRR”) Curve and Reference Resource¹⁰ in updating the default CONE values for the combined cycle, combustion turbine, and battery energy storage system resources (“BESS”). After the review of the updated Gross CONE and Gross ACR values, PJM stakeholders overwhelmingly supported PJM’s proposal to update both the default Gross CONE and default Gross ACR values beginning with the 2030/2031 Delivery Year. This filing serves to meet the requirement to file such updates with the Commission.

To be clear, while the Tariff requirements to review and update the default Gross CONE and Gross ACR values are specified under the MOPR provisions,¹¹ given that the same default ACR values apply to resources that are subject to the MSOC, PJM is also proposing to update the default Gross ACR values for MSOC purposes. In other words, just as it exists under the current rules, the updated default Gross ACR values will be the same values used in both MOPR calculations and MSOC calculations.

II. PJM PROPOSES UPDATED DEFAULT GROSS CONE AND DEFAULT ACR VALUES FOR MOPR AND MSOC PURPOSES.

The applicable default MOPR and default MSOC prices are dependent upon whether the

¹⁰ The analysis from the last periodic review considered combustion turbine, combined cycle, and BESS resources. See *PJM Interconnection, L.L.C.*, 2025 Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, Docket No. ER26-455-000, at 17-22 (Nov. 7, 2025) (“2025 Periodic Review”).

¹¹ *Id.*

resource is a new or existing resource and the technology type. Specifically, for a Planned Generation Capacity Resource that is subject to the MOPR, the default applicable Offer Floor Price is calculated using the default Gross CONE value minus the default net energy and ancillary revenues for the applicable Delivery Year. For Existing Generation Capacity Resources that are subject to the MOPR or MSOC, the default applicable MOPR Floor Offer Price is calculated using the Gross ACR value minus the unit specific net revenues for the applicable Delivery Year. Currently, there are default Gross ACR values for eight resource types for the 2026/2027 Delivery Year. This proposal retains those existing resource types and adds one additional default value for a BESS¹² for a total of nine resource types with default Gross ACR values starting with the 2030/2031 Delivery Year.

A. Updated default Gross CONE values.

For a previously uncleared Capacity Resource that is subject to the MOPR, the default applicable Offer Floor Price is calculated using the Gross CONE value for the applicable Delivery Year. The updated Gross CONE values reflect an estimate of the levelized annual cost to construct and develop new construction for the resource type.¹³ The table below shows the selected reference resources, with their technology descriptions, that were selected for this update. The selected specific technology types used as the reference resource are reasonable because they best

¹² Although this filing only proposes one additional default value representing a four-hour standalone BESS, this proposal also incorporates plant cost adjustment factors for alternative durations, as determined by the Brattle Report. *See* The Brattle Group and Sargent & Lundy, 2026 Avoidable Fixed Costs for Existing Resources, at 50, Table 11 (Sept. 15, 2026), <https://www.pjm.com/-/media/DotCom/library/reports-notice/reliability-pricing-model/brattle-acr-report-30-31-msoc.pdf> (“Brattle Report”). The Brattle Report is included as Attachment D. Those values are .574 for a 2-hour standalone BESS resource, 1.436 for a 6-hour standalone BESS resource, 1.866 for an 8-hour standalone BESS resource, and 2.297 for a 10-hour standalone BESS resource. *Id.*; *see also* The Affidavit of Peter Langbein at Table 5 (“Langbein Aff.”), which is included as Attachment C.

¹³ Langbein Aff. ¶ 5.

align with the expected new entry resources within PJM based on market trends and/or what has already entered PJM's queue.¹⁴

Table 1: Reference Resources with Technology Description, Source of Information, and Costs

Resource Type	Technology Description	Source of Information	Fixed O&M (\$/kW ICAP-Year)	Overnight Capital Costs (\$/kW ICAP)
Nuclear	2x Westinghouse AP 1000 pressurized water reactor (2,156 MW)	EIA	163	7,862
Coal	Ultra-Supercritical Coal (650 MW)	EIA	50	5,360
Combined cycle	1,401 MW (GE Frame 7HA.03 CT, SCR, an evaporative cooler, wet compression, and dual-fuel capability)	2025 Periodic Review	47	1,432
Combustion Turbine	440 MW (GE 7HA.03 turbines in two trains of a single shaft CC plant, each with a single CT, HRSG, and steam turbine)	2025 Periodic Review	25	1,280
Solar PV - Tracking	Single-axis tracking (150 MW AC)	EIA	24	1,484
Solar PV - Fixed	Fixed Tilt (100 MW AC)	EIA, LBNL	28	1,751
Onshore Wind	200 MW 2.8-MW Wind Turbine Generator (WTG)	EIA	35	1,712
Offshore Wind	900 MW 15 MW WTG	EIA	161	3,711
Battery Energy Storage	200 MW (800 MWh for 4-hour duration)	2025 Periodic Review	73	1,820

As explained by PJM's Senior Manager of Capacity Market Operations, Peter Langbein,

¹⁴ The combustion turbine resource type was updated to reflect the updated reference technology from the 2025 Periodic Review. All other resource types aligned with the initial reference resources used in the existing default values.

PJM developed the updated default Gross CONE values based on review of cost data from publicly available sources such as the U.S. Energy Information Administration (“EIA”).¹⁵ Ultimately, PJM used the EIA data for all of the technologies, except for solar PV (fixed),¹⁶ combustion turbine, combined cycle, and battery energy storage resource types,¹⁷ as the EIA data “represents the most recent (published in April 2026) publicly available source, is well-documented, and is the same source used to develop the currently approved values in the tariff.”¹⁸ Further, the EIA data includes overnight capital costs and fixed operating and maintenance (“FOM”) values for all other technology types, which provides transparency into the Gross CONE determination. The CT, CC, and BESS Gross CONE values were calculated using the FOM based on the latest values that Brattle developed as part of the 2025 Periodic Review.¹⁹

The general use of information from the EIA and PJM’s 2025 Periodic Review for calculating the default Gross CONE values is consistent with PJM’s previous approach approved by the Commission.²⁰ Likewise, as shown in the table below, PJM adopted the same financial assumptions from the recent 2025 Periodic Review proceeding in calculating the default Gross CONE values.²¹ These values have already been reviewed by the Commission with the 2025

¹⁵ See U.S. Energy Information Administration (“EIA”), Annual Energy Outlook 2026: Electricity Market Module from the U.S. Energy Information Administration, Table 3 - Cost and performance characteristics of new central station electricity generating technologies (Apr. 2026), https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf.

¹⁶ For solar PV (fixed) data, PJM utilized the solar PV (tracking) data publicly available through EIA in conjunction with the fixed-to-tracking cost ratio determined by the Lawrence Berkeley National Laboratory’s Utility Scale Solar Data Update to calculate a Gross CONE value for that resource type. See Langbein Aff. ¶ 8.

¹⁷ *Id.*

¹⁸ *Id.*

¹⁹ *Id.* ¶ 10; see 2025 Periodic Review.

²⁰ *Id.*; see *PJM Interconnection, L.L.C.*, Delegated Letter Order, Docket No. ER23-1700-000 (June 5, 2023).

²¹ Langbein Aff. ¶ 15 & Table 3.

Periodic Review.²² Mr. Langbein also provides additional explanation and supporting documentation for these Gross CONE values.²³

Table 2: Financial Assumptions

Expected Life	20 Years
Debt Ratio	55%
Debt Rate	5.8%
Equity Rate	16.0%
Total Tax Rate	27.7%
After-Tax Weighted Average Cost of Capital (“ATWACC”)	9.506%
Inflation Rate	2.2%

The proposed default Gross CONE calculations are based on publicly available data, which have the added benefit of providing transparency and a clear independent source for the values presented. Indeed, PJM used the publicly available CONE template, developed by PJM’s Independent Market Monitor (“IMM”), Monitoring Analytics.²⁴ With access to a pro forma analysis tool, any member of the public can use the publicly available FOM data with the financial assumptions provided by PJM to produce the CONE values PJM calculated.²⁵

²² See 2025 Periodic Review.

²³ See *generally* Langbein Aff. Mr. Langbein also separately provides the overnight capital cost and fixed operating and maintenance cost (“FOM”) reviewed from different sources of data, which are the actual values used for each resource in developing CONE.

²⁴ See Independent Market Monitor of PJM, CONE Template Version 2, Monitoring Analytics, https://www.monitoringanalytics.com/tools/docs/IMM_MOPR_Gross_CONE_Template_v2.xlsx.

²⁵ Langbein Aff. ¶ 18.

One difference from the 2023 periodic review of default Gross CONE and ACR values from this filing is the assumed bonus depreciation schedule.²⁶ Recent tax law changes allow 100% of bonus depreciation, which has resulted in the Tariff escalation factors no longer aligning with the impact of bonus depreciation on resources.²⁷ As a result, PJM is proposing to amend Tariff, Attachment DD, section 5.14(h-2)(3)(A) to remove obsolete bonus depreciation factors that are no longer applicable and to substitute them with “the bonus depreciation, if any, that is applicable under federal corporate tax law associated with the relevant Delivery Year.”²⁸ This allows PJM to reflect any changes in the federal tax laws related to bonus depreciation without having to specify depreciation factors that could change each time the tax law changes.

Based on the foregoing and as further supported in Mr. Langbein’s affidavit, the resulting updated default Gross CONE values being proposed in this filing, along with illustrative net CONE values based on estimated net E&AS revenues, are shown in the table below. The updated Gross CONE values are reflected in the proposed updates to Tariff, Attachment DD, section 5.14(h-2)(3)(A).

²⁶ *Id.* ¶ 9.

²⁷ See Internal Revenue Service, Notice 2026-11 (announcing intent to issue proposed regulations to implement the additional first year depreciation deduction under § 168(k) of the Internal Revenue Code, as amended by §§ 70301 and 70434(g) of Public Law 119-21, 139 Stat. 72 (July 4, 2025), so that the applicable percentage would be for “100 percent”), <https://www.irs.gov/pub/irs-drop/n-26-11.pdf>.

²⁸ See Attachment A, Proposed Tariff, Attachment DD, section 5.14(h-2)(3)(A).

Table 3: Proposed Gross CONE values used for the determination of the MOPR default prices

Planned Resource Type	Gross CONE (2030/2031 Delivery Year \$/MW-Day) (Nameplate ICAP)
Nuclear	\$4,403
Coal	\$2,896
Combined Cycle	\$814
Combustion Turbine	\$642
Solar PV (Tracking)	\$659
Solar PV (Fixed)	\$780
Onshore Wind	\$786
Offshore Wind	\$2,243
Battery Energy Storage	\$696

B. Updated default Gross ACR values.

For an Existing Generation Capacity Resource that is subject to MOPR or the MSOC, the default offer floor or offer cap price, is calculated using the gross ACR value for the applicable resource type. The Gross ACR values are based on the resource’s going-forward costs that are avoidable by not participating in PJM’s capacity market.

In updating the Gross ACRs, PJM contracted Brattle, along with Sargent & Lundy (“S&L”). The results of the updated Gross ACR values are detailed in the Brattle Report which is included as Attachment D of this filing. Brattle’s report provides a comprehensive description of the analysis and methodology employed.²⁹

Brattle used a bottom-up analysis to determine the various costs associated with each resource type. For each resource type, Brattle determined the characteristics of a “representative

²⁹ See Brattle Report.

plant” that is widely representative of the cost of most of the fleet.³⁰ Brattle also provided a representative low-cost plant and representative high-cost plant for comparison for each unit type. Brattle used four primary cost drivers when analyzing each resource technology type; (1) unit size, (2) plant age and technology vintage, (3) location in PJM, and (4) configuration of the unit, including pollution controls.³¹ With these guiding principles, Brattle was able to select a median plant as a “representative plant.” When selecting each representative plant, Brattle was careful to balance the risks of under-mitigation and over-mitigation which could amount to a burdensome amount of unit-specific reviews.³² Using publicly available data, Brattle developed ACRs for these resources and then benchmarked and adjusted using confidential cost estimates from S&L’s project database.³³ Thermal plants are based on S&L’s regression analyses of FERC Form 1 filings with characteristics similar to the representative plant by technology type, benchmarked and adjusted using confidential cost estimates from S&L’s project database. Nuclear plants are based on NEI’s latest “Nuclear Costs in Context” study, with adjustments to reflect the representative plant.³⁴ Intermittent plants used FERC Form 1 data and S&L’s project database where FERC Form 1 data was insufficient.³⁵

Brattle’s updated default Gross ACR values include all avoidable costs necessary to operate the resource for another year and align with the Tariff-based approach for determining

³⁰ Langbein Aff. ¶ 16.

³¹ Brattle Report at 8. For BESS resources Brattle used a fifth criterion assessing the duration and the augmentation approach.

³² *Id.* at iv, 7.

³³ *Id.* at 9.

³⁴ *Id.*

³⁵ *Id.*

ACR. Specifically, following prescriptions in Operating Agreement, Schedule 2 and the Tariff, Attachment DD, section 6.8, Brattle included in its gross ACR analysis only those costs that may not be included in a resource's cost-based offers into the energy and ancillary services markets.³⁶ Consistent with the Tariff, default Gross ACRs include fixed capital costs and FOM costs, but not major maintenance costs for systems directly related to electricity production.³⁷

As part of this periodic review of Gross ACR, PJM is proposing to add BESS as a new default resource type. Brattle was able to add this resource type to their report, as there were enough resources in PJM to select a representative plant.³⁸ As there are currently 4 GW of BESS in PJM's expedited interconnection track and over 60 GW of storage projects that have been selected as part of PJM's first cycle of the reformed interconnection process, Brattle determined it would be prudent to establish an ACR for standalone BESS.³⁹ As Brattle explains, "[u]tility-scale BESS uses standardized, modular equipment for which fixed costs are less influenced by geography than other technologies."⁴⁰ Given extensive recent deployment in other Regional Transmission Organization and Independent System Operator regions, ample information has accumulated on the fixed costs associated with utility-scale BESS across configurations which can be leveraged to provide a credible basis for bottom-up fixed-cost estimates for BESS in PJM despite the relatively small existing fleet.⁴¹ The resulting Brattle-determined default gross ACR values are based on the current 2026 values. These 2026 values are then escalated based on the

³⁶ *Id.* at 8; *see id.* at iv-v

³⁷ *Id.*

³⁸ *Id.* at v, 10.

³⁹ *Id.* at 45.

⁴⁰ *Id.*

⁴¹ *Id.* at 45 (internal citations omitted); *see* Langbein Aff. ¶ 21.

tariff defined escalation process⁴² to represent mid-year 2030 costs so that these values are applicable with RPM Auctions beginning with the 2030/2031 Delivery Year. In short, the proposed Gross ACR values effective with RPM Auctions associated with the 2030/2031 are shown in the table below,⁴³ which is also stated in the Tariff.

Table 4: Proposed Gross ACR values used for MOPR and MSOC default prices (2026 and 2030 values)

Resource Type	Updated Gross ACR (2026 \$/MW-day, ICAP)	Proposed Escalated Gross ACR Value for the 2030/2031 Delivery Year (2030 \$/MW-day, ICAP)
Nuclear – single	\$654	\$776
Nuclear – dual	\$580	\$688
Coal	\$135	\$160
Combined Cycle	\$133	\$158
Combustion Turbine	\$64	\$76
Steam Oil & Gas	\$72	\$85
Solar PV (Fixed and Tracking)	\$35	\$42
Wind Onshore	\$190	\$225
Battery Energy Storage	\$187	\$222

⁴² See Tariff, Attachment DD, section 6.4(a).

In addition to the Gross ACR value for 4-hour BESS used in Table 4, PJM also proposes to utilize plant cost adjustment factors for BESS with alternative durations, as determined by the Brattle Report.⁴⁴ As the Brattle Report found that most BESS resources are 4-hour duration, the adjustment factor for such resources shall be 1.000.⁴⁵ The Brattle Report also derived the BESS adjustment factors based on S&L-developed bottom-up cost estimates for a 200 MW plant at each system duration (2, 6, 8, and 10 hours).⁴⁶ S&L calculated the avoidable fixed costs for each duration using their internal O&M model based on recent BESS projects, which were then used to establish an adjustment factor relative to the reference 4-hour BESS case.⁴⁷ To adjust the 4-hour BESS avoidable fixed cost to other durations, the adjustment factors shown in Table 5 below can be applied directly to the baseline 4-hour avoidable fixed cost estimate.

Table 5: Alternative Duration BESS Adjustment Factors

4-hour duration	2-hour duration	6-hour duration	8-hour duration	10-hour duration
1.000	0.574	1.436	1.866	2.297

⁴⁴ See Brattle Report at 50, Table 11; *see also* Langbein Aff., Table 5.

⁴⁵ Brattle Report at 46.

⁴⁶ *Id.* at 50.

⁴⁷ *Id.*

III. STAKEHOLDER PROCESS

This filing is the culmination of a Tariff requirement to review MOPR prices every fourth Delivery Year and the stakeholder process that began on June 16, 2026.⁴⁸ The proposed revisions were endorsed by PJM stakeholders at the August 19, 2026 Markets and Reliability Committee (“MRC”) meeting, by acclamation with no objections and one abstention,⁴⁹ and Members Committee (“MC”) meeting by acclamation with two objections and four abstentions.⁵⁰

V. PROPOSED EFFECTIVE DATE

PJM proposes an effective date of November 30, 2026, for the proposed Tariff revisions referenced herein. PJM requests that the Commission issue an order on this filing by November 29, 2026.

VI. DESCRIPTION OF SUBMITTAL

This filing consists of the following:

1. This transmittal letter;
2. Attachment A – Revisions to the Operating Agreement, in redline format;
3. Attachment B – Revisions to the Operating Agreement, in clean format;
4. Attachment C – Affidavit of Peter Langbein; and
5. Attachment D – Brattle Gross Avoidable Costs for Existing Generation report.

⁴⁸ The agenda from PJM’s June 16, 2026 special Market Implementation Committee meeting is available at <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2026/20260616-special/agenda.pdf>.

⁴⁹ PJM, Markets & Reliability Committees, Consent Agenda of Minutes (Sept. 24, 2026), <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2026/20260924/20260924-consent-agenda-a---draft-mrc-minutes---8192026.pdf>.

⁵⁰ PJM, Members Committee, Consent Agenda of Minutes (Sept. 24, 2026), <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2026/20260924/20260924-consent-agenda-a---draft-mc-minutes---8192026.pdf>.

VII. CORRESPONDENCE

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

Daniel Vinnik
Counsel
PJM Interconnection, L.L.C.
2750 Monroe Boulevard
Audubon, Pennsylvania 19403
(267) 858-9451
daniel.vinnik@pjm.com

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

VIII. SERVICE

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,⁵¹ PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: <https://www.pjm.com/library/filing-order> with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region⁵² alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: <http://www.ferc.gov/docsfiling/elibrary.asp> in accordance with the Commission's regulations and Order No. 714.

⁵¹ See 18 C.F.R. §§ 35.2(e) and 385.2010(f)(3).

⁵² PJM already maintains, updates and regularly uses e-mail lists for all PJM Members and affected state commissions.

IX. CONCLUSION

Based on the foregoing, PJM respectfully requests that the Commission accept proposed revisions to PJM's Tariff.

Respectfully submitted,

/s/ Daniel Vinnik

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

Daniel Vinnik
Counsel
PJM Interconnection, L.L.C.
2750 Monroe Boulevard
Audubon, PA* 19403
(*Licensed in the District of
Columbia and Illinois)
(267) 858-9451
daniel.vinnik@pjm.com

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

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

Attachment A

Revisions to the
PJM Open Access Transmission Tariff

(Marked Format)

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying an LDA's reliability requirement. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDAs and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest Sell Offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher level constrained LDA, where they are considered in a similar manner for compensation.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. If the Sell Offer price of a cleared Seasonal Capacity Performance Resource exceeds the applicable Capacity Resource Clearing Price, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the difference between the Sell Offer price and Capacity Resource Clearing Price in such RPM Auction. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole

Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORD) through the 2024/2025 Delivery Year, and beginning with the 2025/2026 Delivery Year, divided by the applicable ELCC Class Rating for the Reference Resource.

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

- (i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal

offer, in accordance with Tariff, Attachment DD, section 5.12(a) and section 5.14(a) above.

- (ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b) above; or
- (iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in Tariff, Attachment DD, section 5.12(a), and
- (iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) above that is entitled to compensation pursuant to section 5.14(b) above; and
- (v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) above shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with section 5.14(b) above. Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in section 5.14(a) above.

6. The failure to submit a Sell Offer consistent with section 5.14(c)(i)-(iii) above in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) above in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Tariff, Attachment DD, section 5.10(a)(ii).

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to

establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under Tariff, Attachment DD, section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in Tariff, Attachment DD, section 5.14B, Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D, Tariff, Attachment DD, section 5.14E and Tariff, Attachment DD, section 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

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

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

g) Resource Substitution Charge

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

h) [Reserved for future use]

h-1) [Reserved for future use]

h-2) Minimum Offer Price Rule Effective with the 2023/2024 Delivery Year

(1) **Certification Requirement.**

(A) By no later than one hundred and fifty (150) days prior to the commencement of the offer period of any RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year, each Capacity Market Seller must certify to the Office of Interconnection for each Generation Capacity Resource and each applicable DER Capacity Aggregation Resource the Capacity Market Seller intends to offer into the RPM Auction, in accordance with the PJM Manuals:

(i) whether or not the Generation Capacity Resource is receiving or expected to receive Conditioned State Support under any legislative or other governmental policy or program that has been enacted or effective at the time of the certification; and

(ii) whether or not the Capacity Market Seller acknowledges and understands that the Exercise of Buyer-Side Market Power is not permitted in RPM Auctions, and does not intend to submit a Sell Offer for their Generation Capacity Resource as an Exercise of Buyer-Side Market Power.

(B) All Capacity Market Sellers shall be responsible for the accuracy of each certification and its conformance with the Tariff irrespective of any guidance developed by the Office of the Interconnection and the Market Monitoring Unit.

(C) Once a Capacity Market Seller has certified whether or not a Generation Capacity Resource is receiving or expected to receive Conditioned State Support, the certification requirements in subsection (A)(i) above do not apply and the status of such Generation Capacity Resource will remain unchanged unless and until the Capacity Market Seller (or a subsequent Capacity Market Seller of the underlying resource) that owns or controls such Generation Capacity Resource provides a certification of a change in such status, the Office of the Interconnection removes such status, or by FERC order. All Capacity Market Sellers shall have an ongoing obligation to certify to the Office of Interconnection and the Market Monitoring Unit a Generation Capacity Resource's material change in status regarding whether such resource is receiving or expected to receive Conditioned State Support within 30 days of such material change. Nothing in this provision shall supersede the requirement for all Capacity Market Sellers to certify to the Office of Interconnection pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii).

(2) Determining Generation Capacity Resources Subject to the Minimum Offer Price Rule.

(A) Conditioned State Support.

(i) If the Office of the Interconnection reasonably believes a government policy or program would provide Conditioned State Support or a Capacity Market Seller certifies that it is receiving or is expected to receive Conditioned State Support associated with a given Generation Capacity Resource, the Office of Interconnection shall submit, pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d, a filing at FERC indicating the Office of the Interconnection's intent to classify the government policy or program from which that support is derived as Conditioned State Support (and adding such policy or program to the list in Tariff, Attachment DD-3) and apply the Minimum Offer Price Rule to each Generation Capacity Resource reasonably expected to receive such Conditioned State Support. If FERC has already ruled on whether a specific government program or policy constitutes Conditioned State Support and such policy or program is listed in Tariff, Attachment DD-3, the Office of the Interconnection shall not be required to submit the filing described in the preceding sentence.

(ii) Government policies or programs that do not provide payments or other financial benefit outside of PJM markets and do not provide payment or other financial benefit in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction do not constitute Conditioned State Support. Examples of such government policies that do not constitute Conditioned State Support may include, but are not limited to:

policies designed to procure, incent, or require environmental attributes, whether bundled or unbundled (e.g., Renewable Energy Credits, Zero Emission Credits; Regional Greenhouse Gas Initiative); economic development programs and policies; tax incentives; state retail default service auctions; policies or programs that provide incentives related to fuel supplies; any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., Cross-State Air Pollution Rule). In addition, Conditioned State Support shall not be determined solely based on the business model of the Capacity Market Seller, such that the fact that a Self-Supply Entity is the Capacity Market Seller, for example, is not a basis for determining Conditioned State Support.

(iii) Upon FERC acceptance (whether by order or operation of law) that a government policy or program or contract with a state entity constitutes Conditioned State Support, a Generation Capacity Resource for which a Capacity Market Seller certifies pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i) that it is receiving Conditioned State Support or is reasonably expected to receive such Conditioned State Support, as identified by the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, will be subject to the provisions of the Minimum Offer Price Rule.

(B) Exercise of Buyer-Side Market Power

(i) If a Capacity Market Seller does not certify that it acknowledges the prohibition of the Exercise of Buyer Side Market Power and the Capacity Market Seller intends to exercise Buyer-Side Market Power for this Generation Capacity Resource, then the underlying Capacity Resource shall be subject to the MOPR pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i). If the Office of the Interconnection and/or the Market Monitoring Unit reasonably suspects that a certification submitted under Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii) contains fraudulent or material misrepresentations such that the Capacity Market Seller's Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or otherwise reasonably suspects that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall initiate a fact-specific review into the facts and circumstances regarding the Generation Capacity Resource and whether the Capacity Market Seller has the ability and incentive to exercise Buyer-Side Market Power with respect to such Generation Capacity Resource. During such fact-specific review, the Capacity Market Seller will have the opportunity to explain and justify why a Sell Offer for the Generation Capacity Resource would not be an Exercise of Buyer-Side Market Power. The Office of the Interconnection and/or the Market Monitoring Unit shall notify the Capacity Market Seller of the bases for inquiry and initiation of review at least 135 days in advance of the RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year.

In initiating a review, the Office of the Interconnection and/or the Market Monitoring Unit shall provide the affected Capacity Market Seller, in writing, the basis for its inquiry, including, but not limited to, the Generation Capacity Resource(s), and the purported beneficiary of any price suppression. The Office of the Interconnection and/or the Market Monitoring Unit may request from the Capacity Market Seller additional information and

documentation that is reasonably related to the basis for its inquiry, provided that, the Office of the Interconnection and the Market Monitoring Unit shall confer with the Capacity Market Seller in advance of any such requests. The Capacity Market Seller shall provide any additional supporting information and documentation requested by the Office of the Interconnection and/or the Market Monitoring Unit, and any other information and documentation the Capacity Market Seller believes may justify the conduct or action in question as not representing an Exercise of Buyer-Side Market Power, within 15 days or other such timeline as agreed to in writing by the Office of the Interconnection, Market Monitoring Unit and Capacity Market Seller.

The fact-specific review will determine, as necessary, whether a Capacity Market Seller has the ability and incentive to submit a Sell Offer for the Generation Capacity Resource that could be an Exercise of Buyer-Side Market Power, as follows:

(a) To determine whether a Capacity Market Seller may have Buyer Side Market Power associated with the Generation Capacity Resource for the applicable RPM Auction, the Office of the Interconnection and/or the Market Monitoring Unit will perform ex-ante testing to determine the extent to which a shift in the supply curve by a number of megawatts equal to the size of the Generation Capacity Resource would affect RPM Auction clearing prices, where such analysis would reflect expected supply and demand conditions in the region of the market clearing prices and quantities in recent RPM Auctions, would reflect whether the relevant LDAs have been constrained in recent RPM Auctions, and would reflect reasonably expected material changes in an LDA including the modeling of the LDA and expected changes in supply and demand for the applicable Delivery Year. To the extent the foregoing analyses show that the Generation Capacity Resource would have a material effect on RPM Auction clearing prices, the Capacity Market Seller shall be deemed to have the ability to exercise Buyer Side Market Power.

(b) To determine whether the Capacity Market Seller's submission of a Sell Offer at any given price level for such Generation Capacity Resource may constitute an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall perform ex-ante testing to determine whether, given the ability to suppress prices identified in the relevant LDAs and the PJM Region, such price suppression would be economically beneficial to the Capacity Market Seller by comparing its expected cost with its economic benefit, and where the expected cost shall reflect the excess economic costs of the resource above expected market revenues, and the expected benefit shall reflect the expected cost savings to the expected net short position (based on estimated capacity obligations and owned and contracted capacity measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction in which the Generation Capacity Resource is being offered) in the relevant LDAs and RTO multiplied by the price change resulting from offering the resource uneconomically. In this analysis, the Office of Interconnection and/or the Market Monitoring Unit shall consider whether any capacity obligations in which the capacity costs based on RPM Auction clearing prices are directly passed through to load and consider whether the price of any contracted capacity passes through RPM Auction clearing prices. If the expected benefit outweighs the expected cost, the Capacity Market Seller shall be deemed to have the incentive to exercise Buyer Side Market Power. If a resource offer can be justified, economically or otherwise, without consideration of the benefit to the Capacity Market Seller of the suppressed prices, the Capacity Market Seller shall be deemed not

to have the incentive to exercise Buyer Side Market Power with respect to that resource. Out-of-market compensation (such as from renewable energy credits and zero emission credits) that are not tied to either Conditioned State Support or a bilateral contract that directs the submission of an offer to lower market clearing prices may be used to support the economics of the resource under review.

(ii) The following nonexhaustive list of circumstances would preclude an inquiry into or determination regarding an Exercise of Buyer-Side Market Power in the course of a review initiated pursuant to subsection (i) above: (a) the Generation Capacity Resource is a merchant generation supply resources that is not contracted to an entity with a Load Interest; (b) the Generation Capacity Resource is acquired by or under the contractual control of the Capacity Market Seller through a competitive and non-discriminatory procurement process open to new and existing resources; or (c) the Generation Capacity Resource is owned by or bilaterally contracted to a Self-Supply Seller and such resource is demonstrated as consistent with or included in the Self-Supply Seller's long-range resource plan (e.g., a long-range hedging plan) that is approved or otherwise reviewed and accepted by the RERRA, provided that any such plan approval or contracts do not direct the submission of an uneconomic offer to deliberately lower market clearing prices or for the Capacity Market Seller to otherwise perform an Exercise of Buyer-Side Market Power. In addition, to the extent a Generation Capacity Resource may receive compensation in support of characteristics aligned with well-demonstrated customer preferences, such compensation shall not, in and of itself, be a basis for the determination of Buyer-Side Market Power.

(iii) Based on the foregoing tests and fact-specific review, including the facts and circumstances of the Generation Capacity Resource, the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, shall determine whether a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power. If the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, determines that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or the Capacity Market Seller certifies that it intends to exercise Buyer-Side Market Power, then such resource will be subject to the provisions of the Minimum Offer Price Rule. If the resource will be subject to the provisions of the Minimum Offer Price Rule, the Office of the Interconnection shall include in the notice a written explanation for such determination. A Capacity Market Seller that is dissatisfied with the Office of the Interconnection's determination of whether a given Generation Capacity Resource is subject to the Minimum Offer Price Rule may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules based on its determination hereunder unless FERC by order directs otherwise.

(C) Failure to timely submit a certification. Any Generation Capacity Resource for which a Capacity Market Seller has not timely submitted the certifications required under Tariff, Attachment DD, section 5.14(h-2)(1) shall be subject to the provisions of the Minimum Offer Price Rule. Notwithstanding the foregoing, if a Capacity Market Seller submits a timely unit-specific exception pursuant to Tariff, Attachment DD, section 5.14(h-2)(4) for the relevant Delivery Year, and PJM approves the unit-specific MOPR Floor Offer Price, then the

Capacity Market Seller may use such floor price regardless of whether it timely submitted the foregoing certifications.

(3) **Minimum Offer Price Rule.** Any Sell Offer for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the applicable MOPR Floor Offer Price is higher than the applicable Market Seller Offer Cap, in which circumstance the Capacity Market Seller, to participate in an RPM Auction, must request a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process, and the unit-specific MOPR Floor Offer Price shall establish the offer level for such resource.

(A) **New Entry MOPR Floor Offer Price.** For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and for which a Sell Offer based on that resource, or any uprate of such Generation Capacity Resource participating in the generation interconnection process under Tariff, Part IV, Subpart A, that has not cleared an RPM Auction for any Delivery Year, the applicable MOPR Floor Offer Price, based on the net cost of new entry for the resource type, shall be, at the election of the Capacity Market Seller, (i) the unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-2)(4) below or (ii) if applicable, the default New Entry MOPR Floor Offer Price for the applicable resource based on the gross cost of new entry values shown in the table below, as adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

Resource Type	Through the 2025 <u>2029</u> / 2026 <u>30</u> Delivery Years: Gross Cost of New Entry (2022 <u>6</u> / 2023 <u>7</u> \$/ MW-day) (Nameplate)	For the 2026 <u>30</u> / 2027 <u>31</u> Delivery Year and Subsequent Delivery Years: Gross Cost of New Entry (2026 <u>30</u> / 2027 <u>31</u> \$/ MW-day) (Nameplate)
Nuclear	\$2,000 <u>2,568</u>	\$2,568 <u>4,403</u>
Coal	\$1,068 <u>1,480</u>	\$1,480 <u>2,896</u>
Combined Cycle	\$320 <u>540</u>	\$540 <u>814</u>
Combustion Turbine	\$294 <u>394</u>	\$427 <u>642</u>
Fixed Solar PV	\$271 <u>298</u>	\$298 <u>780</u>
Tracking Solar PV	\$290 <u>321</u>	\$321 <u>659</u>
Onshore Wind	\$420 <u>438</u>	\$438 <u>786</u>
Offshore Wind	\$1,155 <u>1,351</u>	\$1,351 <u>2,243</u>
Battery Energy Storage	\$532 <u>502</u>	\$502 <u>696</u>

The gross cost of new entry values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the gross cost of new entry values must be converted to a net cost of new entry by subtracting the estimated net energy and ancillary service revenues, as determined below, from the gross cost of new entry. However,

the resultant net cost of new entry of the battery energy storage resource type in the table above must be multiplied by 2.5. The net cost of new entry based on nameplate capacity is then converted to Unforced Capacity (“UCAP”) MW-day. For the 2023/2024 and 2024/2025 Delivery Years, the net cost of new entry is adjusted using: for battery storage, wind, and solar resource types, the applicable ELCC Class Rating; or for all other generation resource types, the applicable class average EFORD. For the 2025/2026 Delivery Year and subsequent Delivery Years, the net cost of new entry is adjusted by the applicable class average Accredited UCAP Factor. The resulting default New Entry MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default gross costs of new entry in the table above and post the preliminary estimates of the adjusted applicable default New Entry MOPR Floor Offer Prices on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the adjusted applicable default New Entry MOPR Floor Offer Prices for all resource types, the Office of the Interconnection shall adjust the gross costs of new entry utilizing, for combustion turbine and combined cycle resource types, the same Applicable BLS Composite Index applied for such Delivery Year to adjust the CONE value used to determine the Variable Resource Requirement Curve, in accordance with Tariff, Attachment DD, section 5.10(a)(iv), and for all other resource types, the “BLS Producer Price Index Turbines and Turbine Generator Sets” component of the Applicable BLS Composite Index used to determine the Variable Resource Requirement Curve shall be replaced with the “BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment” when adjusting the gross costs of new entry. The resultant value shall then be then adjusted further ~~by a factor of 1.022 for nuclear, coal, combustion turbine, and combine cycle resource types or 1.01 for solar, wind, and storage resource types to reflect the annual decline in based on the~~ bonus depreciation, if any, that is applicable-scheduled under federal corporate tax law associated with the relevant Delivery Year. Updated estimates of the net energy and ancillary service revenues for each default resource type and applicable Zone, which shall include, but are not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2 shall then be subtracted from the adjusted gross costs of new entry to determine the adjusted New Entry MOPR Floor Offer Price. The net energy and ancillary services revenue is equal to the average of the annual net revenues of the three most recent calendar years preceding the Base Residual Auction, where such annual net revenues shall be determined in accordance with the following and the PJM Manuals:

(i) for nuclear resource type, the net energy and ancillary services revenue estimate shall be determined by the gross energy market revenue determined by the product of [average annual zonal day-ahead LMP, times 8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times \$9.02/MWh for a single unit plant or \$7.66/MWh for a multi-unit plant] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of Maintenance Adder costs, plus an ancillary services revenue of \$3,350/MW-year;

(ii) for coal resource type, the net energy and ancillary services revenue estimate shall be determined by a simulated dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh and variable operations and maintenance variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of \$9.50/MWh) using applicable coal prices, as set forth in the PJM Manuals, plus reactive services revenue of \$3,350/MW-year. The unit is committed day-ahead in profitable blocks of at least eight hours, and then committed in real-time for profitable hours if not already committed day ahead;

(iii) for combustion turbine resource type, the net energy and ancillary services revenue estimate shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v)(B) for the Reference Resource combustion turbine.

(iv) for combined cycle resource type, the net energy and ancillary services revenue estimate shall be determined in the same manner as that prescribed for a combustion turbine resource type, except that the heat rate assumed for the combined cycle resource shall be 6,553 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be \$2.11/MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the CC resource continuously during the full peak-hour period, as described in Peak-Hour Dispatch, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary services revenue shall be \$3,350/MW-year.

(v) for solar PV resource type, the net energy and ancillary services revenue estimate shall be determined using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of \$3,350/MW-year. Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource;

(vi) for onshore wind resource type, the net energy and ancillary services revenue estimate shall be determined using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of \$3,350/MW-year;

(vii) for offshore wind resource type, the net energy and ancillary services revenue estimate shall be the product of [the average annual zonal real-time LMP times 8,760 hours times an assumed annual capacity factor of 45%], plus an ancillary services revenue of \$3,350/MW-year; and

(viii) for Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by a simulated dispatch against historical real-time zonal LMPs where the resource is assumed to be dispatched for the four hours of highest LMP of a daily twenty-four hour period if the average LMP of these four hours exceeds 120% of the average LMP of the four lowest LMP hours of the same twenty-four hour period. The net energy market revenues will be determined by the product of [hourly output of 1 MW times the hourly LMP for each hour of assumed discharging] minus the product of [hourly consumption of 1.2 MW times the hourly LMP for each hour of assumed charging] with this net value summed across all of the hours of an annual period, plus an ancillary services revenue of \$3,350/MW-year. An 83.3% efficiency of the battery energy storage resource is reflected by assuming each 1.0 MW of discharge requires 1.2 MW of charge.

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default gross cost of new entry values. Such review may include, without limitation, analyses of the fixed development, construction, operation, and maintenance costs for such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default gross cost of new entry values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default gross cost of new entry values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has not previously cleared an RPM Auction for that or any prior Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource for the relevant RPM Auction.

(B) Cleared MOPR Floor Offer Prices.

For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year, the applicable Cleared MOPR Floor Offer Price shall be, at the election of the Capacity Market Seller, (a) based on the unit-specific MOPR Floor Offer Price, as determined in accordance with Tariff, Attachment DD, section 5.14(h-2)(4) below, or (b) if available, the default Avoidable Cost Rate for the applicable resource type shown in the table below, as adjusted for Delivery Years subsequent for the 2022/2023 or 2026/2027 Delivery Year, as applicable, to reflect changes in avoidable costs, net of projected PJM market revenues equal to the resource's historical net energy and ancillary service revenues consistent with Tariff, Attachment DD, section 6.8(d).

Existing Resource Type	Through the 202529/202630 Delivery Years: Default Gross ACR (20226/20237) (\$/MW-day) (Nameplate)	For the 202630/202731 Delivery Year and Subsequent Delivery Years: Default Gross ACR (202630/202731) (\$/ MW-day) (Nameplate)
Nuclear - single	\$697591	\$591776
Nuclear - dual	\$445537	\$537688
Coal	\$8094	\$94160
Combined Cycle	\$56113	\$113158
Combustion Turbine	\$5052	\$5276
Steam Oil & Gas	NA64	\$6485
Solar PV (fixed and tracking)	\$4070	\$7042
Wind Onshore	\$83147	\$147225
Battery Energy Storage*	N/A	\$222

*Default Gross ACR for Battery Energy Storage will be further adjusted based on their duration in alignment with the table below:

<u>4-hour duration</u>	<u>2-hour duration</u>	<u>6-hour duration</u>	<u>8-hour duration</u>	<u>10-hour duration</u>
<u>1.000</u>	<u>0.574</u>	<u>1.436</u>	<u>1.866</u>	<u>2.297</u>

The default gross Avoidable Cost Rate values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. Through the 2024/2025 Delivery Year, for purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity (“UCAP”) MW-day, where the UCAP MW-day value will be determined based on the resource-specific Accredited UCAP value for solar and wind resource types (with appropriate time-weighting for any winter Capacity Interconnection Rights) or the resource-specific EFORd for all other generation resource types. Effective for the 2025/2026 Delivery Year and subsequent Delivery Years, for purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity (“UCAP”) MW-day, based on the resource’s Accredited UCAP Factor. The resulting default Cleared MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default Avoidable Cost Rates in the table above, and post the adjusted values on its website, by no later than one hundred fifty (150) days prior to the

commencement of the offer period for each Base Residual Auction. To determine the adjusted Avoidable Cost Rates, the Office of the Interconnection shall utilize the 10-year average Handy-Whitman Index in order to adjust the Gross ACR values to account for expected inflation. Updated estimates of the net energy and ancillary service revenues shall be determined on a resource-specific basis in accordance with Tariff, Attachment DD, section 6.8(d) and the PJM Manuals.

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default Avoidable Cost Rates for Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) that have cleared in an RPM Auction for any Delivery Year. Such review may include, without limitation, analyses of the avoidable costs of such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default Avoidable Cost Rate values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default Avoidable Cost Rate values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction for any Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource.

(4) **Unit-Specific Exception.** A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Capacity Resource. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is under a fact-specific review for Buyer-Side Market Power pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B)(ii), and where the offer is below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Generation Capacity Resource. A Sell Offer below the default MOPR Floor Offer Price, but no lower than the unit-specific MOPR Floor Offer Price, shall be permitted if the Capacity Market Seller obtains approval from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer. The unit-specific MOPR Floor Offer Price determined under this provision shall be based on the unit-specific Accredited UCAP value for battery energy storage resource types and for solar and wind generation resource types (appropriately time-weighted for any winter Capacity Interconnection Rights) or on the unit-specific EFORd for all other generation resource types, and shall be applied to each MW offered by the resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource. Such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of

the resource. All supporting data must be provided for all requests. The following requirements shall apply to requests for such determinations:

(A) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, the Capacity Market Seller shall submit the unit-specific exception request to the Office of the Interconnection and the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer. For such purpose, the Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of the default Minimum Floor Offer Prices, determined pursuant to Tariff, Attachment DD, sections 5.14(h-2)(3)(A) and (B). If the final applicable default Minimum Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

(B) For a unit-specific exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has never cleared an RPM Auction, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the Capacity Resource, as well as estimates of offsetting net revenues.

The financial modeling assumptions for calculating Cost of New Entry for Generation Capacity Resources shall be: (i) nominal levelization of gross costs, (ii) asset life of twenty years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues (which may include revenues from the sale of renewable energy credits or any other revenues outside of PJM markets that do not constitute Conditioned State Support), and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. Notwithstanding the foregoing, a Capacity Market Seller that seeks to utilize an asset life other than twenty years (but no greater than 35 years) shall provide evidence to support the use of a different asset life, including but not limited to, the asset life term for such resource as utilized in the Capacity Market Seller's financial accounting (e.g., independently audited financial statements), or project financing documents for the resource or evidence of actual costs or financing assumptions of recent comparable projects to the extent the seller has not executed project financing for the resource (e.g., independent project engineer opinion or manufacturer's performance guarantee), or opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects. Capacity Market Sellers may also rely on evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an asset life other than 20 years of similar asset projects.

Supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general

costs; financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. In addition to the certification, signed by an officer of the Capacity Market Seller, the request must include a certification that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a unit-specific exception hereunder. The request also shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, evidence of compensation outside the PJM market not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, which may include Maintenance Adders, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. Any evaluation of net revenues should be consistent with Operating Agreement, Schedule 2, including, but not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable.

(C) For a Unit-Specific Exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction, the Capacity Market Seller shall submit a Sell Offer consistent with the unit-specific Market Seller Offer Cap process pursuant to Tariff, Attachment DD, section 6.8; except that the 10% uncertainty adder may not be included in the "Adjustment Factor." In addition and notwithstanding the requirements of Tariff, Attachment DD, section 6.8, the Capacity Market Seller may, at its election, include in its request for an exception under this subsection documentation to support projected energy and ancillary services markets revenues. Such a request shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, evidence of compensation outside of PJM markets not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance

expenses, energy demand, which may include Maintenance Adders, and emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. Any evaluation of revenues should include, but would not be not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2.

(D) A Sell Offer evaluated at the unit-specific exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, fixed, cost-based offer level is below the default MOPR Floor Offer Price, based on competitive cost advantages relative to the costs estimated by the default MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those estimated by the default MOPR Floor Offer Price. Capacity Market Sellers shall demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection, and that out-of-market compensation is not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices. Failure to adequately support such claimed cost advantages or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in the elimination of consideration of the unsupported element(s) of a unit-specific exception by the Office of the Interconnection.

(E) The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of the unit-specific exception request and that to the best of his/her knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception; and (3) the request satisfies the criteria for the exception.

(F) The Market Monitoring Unit shall review, in an open and transparent manner with the Capacity Market Seller and the Office of the Interconnection, the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review, in an open and transparent manner, all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it

shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. After the Office of the Interconnection determines with the advice and input of Market Monitor, the acceptable minimum Sell Offer, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction, and in making such determination, the Capacity Market Seller may consider the applicable default MOPR Floor Offer Price and may select such default value if it is lower than the unit-specific determination. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules based on the lower of the applicable default MOPR Floor Offer Price and the unit-specific determination unless and until ordered to do otherwise by FERC.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export (“Export Reserved Capacity”) multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) above also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under Tariff, Attachment DD, section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) above times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

$(\text{Export Path Import} * \text{Export Reserved Capacity}) /$

$(\text{Export Reserved Capacity} + \text{Daily Unforced Capacity Obligations of all LSEs in such Zone}).$

Where:

“Export Path Import” means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW/day of unforced capacity, applicable to price-quantity offers within the Base Offer Segment for an Existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW/day of unforced capacity. Notwithstanding, beginning with the 2026/2027 Delivery Year, the Market Seller Offer Cap shall be the greater of (a) Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, or (b) if applicable, the Capacity Performance Quantifiable Risk for such resource, as defined in Tariff, Attachment DD, section 6.8(a), to the extent such value has been supported and obtained approval pursuant to the requirements set forth in this Tariff, Attachment DD, section 6.4(b), stated in dollars per MW-day of unforced capacity. A Capacity Market Seller offering above \$0/MW-day must support and obtain approval of a unit-specific Market Seller Offer Cap pursuant to the procedures and standards of subsection (b) of this section 6.4 or may, at its election, if available, utilize a Market Seller Offer Cap determined using the applicable default gross Avoidable Cost Rate for the applicable resource type shown in the table below, as adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, to reflect changes in avoidable costs, net of Projected PJM Market Revenues equal to the resource's net energy and ancillary service revenues for the resource type, as determined in accordance with Tariff, Attachment DD, section 6.8(d).

Existing Resource Type	Through the 2025 <u>2026</u> Delivery Years: Default Gross ACR (202 26 <u>27</u>) (\$/MW-day) (Nameplate)	For the 2026 <u>2027</u> Delivery Year and Subsequent Delivery Years: Default Gross ACR (20 26 <u>27</u>) (\$/MW-day) (Nameplate)
Nuclear – single	\$697 <u>\$591</u>	\$594 <u>\$776</u>
Nuclear – dual	\$445 <u>\$537</u>	\$537 <u>\$688</u>
Coal	\$80 <u>\$94</u>	\$94 <u>\$160</u>
Combined Cycle	\$56 <u>\$113</u>	\$113 <u>\$158</u>
Combustion Turbine	\$50 <u>\$52</u>	\$52 <u>\$76</u>
Steam Oil & Gas	NA <u>\$64</u>	\$64 <u>\$85</u>
Solar PV (fixed and tracking)	\$40 <u>\$70</u>	\$70 <u>\$42</u>
Wind Onshore	\$83 <u>\$147</u>	\$147 <u>\$225</u>
<u>Battery Energy Storage</u>	<u>N/A</u>	<u>\$222</u>

*Default Gross ACR for Battery Energy Storage will be further adjusted based on their duration in alignment with the table below:

<u>4-hour duration</u>	<u>2-hour duration</u>	<u>6-hour duration</u>	<u>8-hour duration</u>	<u>10-hour duration</u>
<u>1.000</u>	<u>0.574</u>	<u>1.436</u>	<u>1.866</u>	<u>2.297</u>

The Market Seller Offer Cap for an Existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with Tariff, Attachment DD, section 6.7.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection data and documentation required under section 6.7 below to establish the level of the Market Seller Offer Cap applicable to each resource by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the Market Seller Offer Cap proposed by the Market Monitoring Unit, and attempt to reach agreement with the Market Monitoring Unit on the level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller shall notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, whether an agreement with the Market Monitoring Unit has been reached or, if no agreement has been reached, specifying the level of Market Seller Offer Cap to which it commits by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. The Office of the Interconnection shall review the data submitted by the Capacity Market Seller, make a determination whether to accept or reject the requested unit-specific Market Seller Offer Cap, and notify the Capacity Market Seller and the Market Monitoring Unit of its determination in writing, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction. In the event the Office of the Interconnection rejects the Capacity Market Seller's requested unit-specific Market Seller Offer Cap for a particular Capacity Resource, the Capacity Market Seller of such Capacity Resource may submit an offer up to (1) should one exist, the default gross Avoidable Cost Rate for the applicable resource type net of Projected PJM Market Revenues equal to the resource's net energy and ancillary service revenues for the resource type, or (2) the unit-specific Market Seller Offer Cap proposed by the Market Monitoring Unit upon PJM approval of such value. If the Market Monitoring Unit does not provide its determination to the Capacity Market Seller and the Office of the Interconnection by the specified deadline, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction the Office of the Interconnection will make the determination of the level of the Market Seller Offer Cap, which shall be deemed to be final. If the Capacity Market Seller does not notify the Market Monitoring Unit and the Office of the Interconnection of the Market Seller Offer Cap it desires to utilize by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction, it shall be required to utilize a Market Seller Offer Cap determined using the applicable default Avoidable Cost Rate specified in section 6.4(a) above.

Notwithstanding the provisions of Tariff, Attachment M-Appendix, section II.E.2 and this Tariff, Attachment DD, section 6.4(b), no later than eighty (80) days prior to the commencement of the offer period for the auction, the Market Monitoring Unit and the relevant Capacity Market Seller may mutually agree on the value of such Market Seller Offer Cap.

Nothing herein shall preclude the Market Monitoring Unit from modifying the Market Seller Offer Cap for a Generation Capacity Resource beyond the eighty-day (80-day) deadline prior to the commencement of the offer period for the auction, through the commencement of the offer period for the auction, so long as the Market Monitoring Unit and the relevant Capacity Market Seller mutually agree with the value of such Market Seller Offer Cap. The Capacity Market Seller shall notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, if such an agreement with the Market Monitoring Unit has been reached. The Office of the Interconnection shall review the Market Seller Offer Cap submitted by the Capacity Market Seller and make a determination whether the Market Seller Offer Cap complies with the tariff, and notify the Capacity Market Seller and the Market Monitoring Unit of its determination.

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

(d) For any Third Incremental Auction for the 2018/2019 Delivery Year or any subsequent Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Capacity Performance Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

(e) Effective with the 2026/2027 Delivery Year, Capacity Market Sellers that request a resource-specific Market Seller Offer Cap by the deadline may request to use and provide support for a segmented offer cap to reflect incremental costs of having a capacity obligation across different segments of their resource. Such request shall be submitted and reviewed in accordance with the timelines set forth in this Tariff, Attachment DD, section 6.4(b) and provide adequate justification for the use of a segmented offer cap with supporting documentation and calculations for the Market Seller Offer Cap of each segment. Segmented Market Seller Offer Caps shall be comprised of multiple Market Seller Offer Caps, each calculated in accordance with Tariff, Attachment DD, sections 6.4(a) and 6.8. If elected by the Capacity Market Seller, the first segment shall have a Market Seller Offer Cap reflective of the resource-specific Avoidable Cost Rate, less the Projected PJM Market Revenues for such resource. All subsequent offer segments (and in the first segment if solely requesting a Capacity Performance Quantifiable Risk for the Market Seller Offer Cap) shall include only incremental Capacity Performance Quantifiable Risk associated with the incremental capacity commitment in that offer segment to the extent such value has been supported and obtained approval pursuant to the requirements set forth in this Tariff, Attachment DD, section 6.8(b), and each subsequent segmented offer cap shall be greater than the prior segments.

Attachment B

Revisions to the
PJM Open Access Transmission Tariff

(Clean Format)

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying an LDA's reliability requirement. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDAs and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest Sell Offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher level constrained LDA, where they are considered in a similar manner for compensation.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. If the Sell Offer price of a cleared Seasonal Capacity Performance Resource exceeds the applicable Capacity Resource Clearing Price, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the difference between the Sell Offer price and Capacity Resource Clearing Price in such RPM Auction. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole

Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORD) through the 2024/2025 Delivery Year, and beginning with the 2025/2026 Delivery Year, divided by the applicable ELCC Class Rating for the Reference Resource.

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

- (i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal

offer, in accordance with Tariff, Attachment DD, section 5.12(a) and section 5.14(a) above.

- (ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b) above; or
- (iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in Tariff, Attachment DD, section 5.12(a), and
- (iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) above that is entitled to compensation pursuant to section 5.14(b) above; and
- (v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) above shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with section 5.14(b) above. Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in section 5.14(a) above.

6. The failure to submit a Sell Offer consistent with section 5.14(c)(i)-(iii) above in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) above in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Tariff, Attachment DD, section 5.10(a)(ii).

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to

establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under Tariff, Attachment DD, section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in Tariff, Attachment DD, section 5.14B, Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D, Tariff, Attachment DD, section 5.14E and Tariff, Attachment DD, section 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

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

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

g) Resource Substitution Charge

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

h) [Reserved for future use]

h-1) [Reserved for future use]

h-2) Minimum Offer Price Rule Effective with the 2023/2024 Delivery Year

(1) **Certification Requirement.**

(A) By no later than one hundred and fifty (150) days prior to the commencement of the offer period of any RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year, each Capacity Market Seller must certify to the Office of Interconnection for each Generation Capacity Resource and each applicable DER Capacity Aggregation Resource the Capacity Market Seller intends to offer into the RPM Auction, in accordance with the PJM Manuals:

(i) whether or not the Generation Capacity Resource is receiving or expected to receive Conditioned State Support under any legislative or other governmental policy or program that has been enacted or effective at the time of the certification; and

(ii) whether or not the Capacity Market Seller acknowledges and understands that the Exercise of Buyer-Side Market Power is not permitted in RPM Auctions, and does not intend to submit a Sell Offer for their Generation Capacity Resource as an Exercise of Buyer-Side Market Power.

(B) All Capacity Market Sellers shall be responsible for the accuracy of each certification and its conformance with the Tariff irrespective of any guidance developed by the Office of the Interconnection and the Market Monitoring Unit.

(C) Once a Capacity Market Seller has certified whether or not a Generation Capacity Resource is receiving or expected to receive Conditioned State Support, the certification requirements in subsection (A)(i) above do not apply and the status of such Generation Capacity Resource will remain unchanged unless and until the Capacity Market Seller (or a subsequent Capacity Market Seller of the underlying resource) that owns or controls such Generation Capacity Resource provides a certification of a change in such status, the Office of the Interconnection removes such status, or by FERC order. All Capacity Market Sellers shall have an ongoing obligation to certify to the Office of Interconnection and the Market Monitoring Unit a Generation Capacity Resource's material change in status regarding whether such resource is receiving or expected to receive Conditioned State Support within 30 days of such material change. Nothing in this provision shall supersede the requirement for all Capacity Market Sellers to certify to the Office of Interconnection pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii).

(2) Determining Generation Capacity Resources Subject to the Minimum Offer Price Rule.

(A) Conditioned State Support.

(i) If the Office of the Interconnection reasonably believes a government policy or program would provide Conditioned State Support or a Capacity Market Seller certifies that it is receiving or is expected to receive Conditioned State Support associated with a given Generation Capacity Resource, the Office of Interconnection shall submit, pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d, a filing at FERC indicating the Office of the Interconnection's intent to classify the government policy or program from which that support is derived as Conditioned State Support (and adding such policy or program to the list in Tariff, Attachment DD-3) and apply the Minimum Offer Price Rule to each Generation Capacity Resource reasonably expected to receive such Conditioned State Support. If FERC has already ruled on whether a specific government program or policy constitutes Conditioned State Support and such policy or program is listed in Tariff, Attachment DD-3, the Office of the Interconnection shall not be required to submit the filing described in the preceding sentence.

(ii) Government policies or programs that do not provide payments or other financial benefit outside of PJM markets and do not provide payment or other financial benefit in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction do not constitute Conditioned State Support. Examples of such government policies that do not constitute Conditioned State Support may include, but are not limited to:

policies designed to procure, incent, or require environmental attributes, whether bundled or unbundled (e.g., Renewable Energy Credits, Zero Emission Credits; Regional Greenhouse Gas Initiative); economic development programs and policies; tax incentives; state retail default service auctions; policies or programs that provide incentives related to fuel supplies; any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., Cross-State Air Pollution Rule). In addition, Conditioned State Support shall not be determined solely based on the business model of the Capacity Market Seller, such that the fact that a Self-Supply Entity is the Capacity Market Seller, for example, is not a basis for determining Conditioned State Support.

(iii) Upon FERC acceptance (whether by order or operation of law) that a government policy or program or contract with a state entity constitutes Conditioned State Support, a Generation Capacity Resource for which a Capacity Market Seller certifies pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i) that it is receiving Conditioned State Support or is reasonably expected to receive such Conditioned State Support, as identified by the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, will be subject to the provisions of the Minimum Offer Price Rule.

(B) Exercise of Buyer-Side Market Power

(i) If a Capacity Market Seller does not certify that it acknowledges the prohibition of the Exercise of Buyer Side Market Power and the Capacity Market Seller intends to exercise Buyer-Side Market Power for this Generation Capacity Resource, then the underlying Capacity Resource shall be subject to the MOPR pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i). If the Office of the Interconnection and/or the Market Monitoring Unit reasonably suspects that a certification submitted under Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii) contains fraudulent or material misrepresentations such that the Capacity Market Seller's Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or otherwise reasonably suspects that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall initiate a fact-specific review into the facts and circumstances regarding the Generation Capacity Resource and whether the Capacity Market Seller has the ability and incentive to exercise Buyer-Side Market Power with respect to such Generation Capacity Resource. During such fact-specific review, the Capacity Market Seller will have the opportunity to explain and justify why a Sell Offer for the Generation Capacity Resource would not be an Exercise of Buyer-Side Market Power. The Office of the Interconnection and/or the Market Monitoring Unit shall notify the Capacity Market Seller of the bases for inquiry and initiation of review at least 135 days in advance of the RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year.

In initiating a review, the Office of the Interconnection and/or the Market Monitoring Unit shall provide the affected Capacity Market Seller, in writing, the basis for its inquiry, including, but not limited to, the Generation Capacity Resource(s), and the purported beneficiary of any price suppression. The Office of the Interconnection and/or the Market Monitoring Unit may request from the Capacity Market Seller additional information and

documentation that is reasonably related to the basis for its inquiry, provided that, the Office of the Interconnection and the Market Monitoring Unit shall confer with the Capacity Market Seller in advance of any such requests. The Capacity Market Seller shall provide any additional supporting information and documentation requested by the Office of the Interconnection and/or the Market Monitoring Unit, and any other information and documentation the Capacity Market Seller believes may justify the conduct or action in question as not representing an Exercise of Buyer-Side Market Power, within 15 days or other such timeline as agreed to in writing by the Office of the Interconnection, Market Monitoring Unit and Capacity Market Seller.

The fact-specific review will determine, as necessary, whether a Capacity Market Seller has the ability and incentive to submit a Sell Offer for the Generation Capacity Resource that could be an Exercise of Buyer-Side Market Power, as follows:

(a) To determine whether a Capacity Market Seller may have Buyer Side Market Power associated with the Generation Capacity Resource for the applicable RPM Auction, the Office of the Interconnection and/or the Market Monitoring Unit will perform ex-ante testing to determine the extent to which a shift in the supply curve by a number of megawatts equal to the size of the Generation Capacity Resource would affect RPM Auction clearing prices, where such analysis would reflect expected supply and demand conditions in the region of the market clearing prices and quantities in recent RPM Auctions, would reflect whether the relevant LDAs have been constrained in recent RPM Auctions, and would reflect reasonably expected material changes in an LDA including the modeling of the LDA and expected changes in supply and demand for the applicable Delivery Year. To the extent the foregoing analyses show that the Generation Capacity Resource would have a material effect on RPM Auction clearing prices, the Capacity Market Seller shall be deemed to have the ability to exercise Buyer Side Market Power.

(b) To determine whether the Capacity Market Seller's submission of a Sell Offer at any given price level for such Generation Capacity Resource may constitute an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall perform ex-ante testing to determine whether, given the ability to suppress prices identified in the relevant LDAs and the PJM Region, such price suppression would be economically beneficial to the Capacity Market Seller by comparing its expected cost with its economic benefit, and where the expected cost shall reflect the excess economic costs of the resource above expected market revenues, and the expected benefit shall reflect the expected cost savings to the expected net short position (based on estimated capacity obligations and owned and contracted capacity measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction in which the Generation Capacity Resource is being offered) in the relevant LDAs and RTO multiplied by the price change resulting from offering the resource uneconomically. In this analysis, the Office of Interconnection and/or the Market Monitoring Unit shall consider whether any capacity obligations in which the capacity costs based on RPM Auction clearing prices are directly passed through to load and consider whether the price of any contracted capacity passes through RPM Auction clearing prices. If the expected benefit outweighs the expected cost, the Capacity Market Seller shall be deemed to have the incentive to exercise Buyer Side Market Power. If a resource offer can be justified, economically or otherwise, without consideration of the benefit to the Capacity Market Seller of the suppressed prices, the Capacity Market Seller shall be deemed not

to have the incentive to exercise Buyer Side Market Power with respect to that resource. Out-of-market compensation (such as from renewable energy credits and zero emission credits) that are not tied to either Conditioned State Support or a bilateral contract that directs the submission of an offer to lower market clearing prices may be used to support the economics of the resource under review.

(ii) The following nonexhaustive list of circumstances would preclude an inquiry into or determination regarding an Exercise of Buyer-Side Market Power in the course of a review initiated pursuant to subsection (i) above: (a) the Generation Capacity Resource is a merchant generation supply resources that is not contracted to an entity with a Load Interest; (b) the Generation Capacity Resource is acquired by or under the contractual control of the Capacity Market Seller through a competitive and non-discriminatory procurement process open to new and existing resources; or (c) the Generation Capacity Resource is owned by or bilaterally contracted to a Self-Supply Seller and such resource is demonstrated as consistent with or included in the Self-Supply Seller's long-range resource plan (e.g., a long-range hedging plan) that is approved or otherwise reviewed and accepted by the RERRA, provided that any such plan approval or contracts do not direct the submission of an uneconomic offer to deliberately lower market clearing prices or for the Capacity Market Seller to otherwise perform an Exercise of Buyer-Side Market Power. In addition, to the extent a Generation Capacity Resource may receive compensation in support of characteristics aligned with well-demonstrated customer preferences, such compensation shall not, in and of itself, be a basis for the determination of Buyer-Side Market Power.

(iii) Based on the foregoing tests and fact-specific review, including the facts and circumstances of the Generation Capacity Resource, the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, shall determine whether a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power. If the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, determines that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or the Capacity Market Seller certifies that it intends to exercise Buyer-Side Market Power, then such resource will be subject to the provisions of the Minimum Offer Price Rule. If the resource will be subject to the provisions of the Minimum Offer Price Rule, the Office of the Interconnection shall include in the notice a written explanation for such determination. A Capacity Market Seller that is dissatisfied with the Office of the Interconnection's determination of whether a given Generation Capacity Resource is subject to the Minimum Offer Price Rule may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules based on its determination hereunder unless FERC by order directs otherwise.

(C) Failure to timely submit a certification. Any Generation Capacity Resource for which a Capacity Market Seller has not timely submitted the certifications required under Tariff, Attachment DD, section 5.14(h-2)(1) shall be subject to the provisions of the Minimum Offer Price Rule. Notwithstanding the foregoing, if a Capacity Market Seller submits a timely unit-specific exception pursuant to Tariff, Attachment DD, section 5.14(h-2)(4) for the relevant Delivery Year, and PJM approves the unit-specific MOPR Floor Offer Price, then the

Capacity Market Seller may use such floor price regardless of whether it timely submitted the foregoing certifications.

(3) **Minimum Offer Price Rule.** Any Sell Offer for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the applicable MOPR Floor Offer Price is higher than the applicable Market Seller Offer Cap, in which circumstance the Capacity Market Seller, to participate in an RPM Auction, must request a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process, and the unit-specific MOPR Floor Offer Price shall establish the offer level for such resource.

(A) **New Entry MOPR Floor Offer Price.** For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and for which a Sell Offer based on that resource, or any uprate of such Generation Capacity Resource participating in the generation interconnection process under Tariff, Part IV, Subpart A, that has not cleared an RPM Auction for any Delivery Year, the applicable MOPR Floor Offer Price, based on the net cost of new entry for the resource type, shall be, at the election of the Capacity Market Seller, (i) the unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-2)(4) below or (ii) if applicable, the default New Entry MOPR Floor Offer Price for the applicable resource based on the gross cost of new entry values shown in the table below, as adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

Resource Type	Through the 2029/2030 Delivery Years: Gross Cost of New Entry (2026/2027 \$/ MW-day) (Nameplate)	For the 2030/2031 Delivery Year and Subsequent Delivery Years: Gross Cost of New Entry (2030/2031 \$/ MW-day) (Nameplate)
Nuclear	\$2,568	\$4,403
Coal	\$1,480	\$2,896
Combined Cycle	\$540	\$814
Combustion Turbine	\$394	\$642
Fixed Solar PV	\$298	\$780
Tracking Solar PV	\$321	\$659
Onshore Wind	\$438	\$786
Offshore Wind	\$1,351	\$2,243
Battery Energy Storage	\$502	\$696

The gross cost of new entry values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the gross cost of new entry values must be converted to a net cost of new entry by subtracting the estimated net energy and ancillary service revenues, as determined below, from the gross cost of new entry. However,

the resultant net cost of new entry of the battery energy storage resource type in the table above must be multiplied by 2.5. The net cost of new entry based on nameplate capacity is then converted to Unforced Capacity (“UCAP”) MW-day. For the 2023/2024 and 2024/2025 Delivery Years, the net cost of new entry is adjusted using: for battery storage, wind, and solar resource types, the applicable ELCC Class Rating; or for all other generation resource types, the applicable class average EFORD. For the 2025/2026 Delivery Year and subsequent Delivery Years, the net cost of new entry is adjusted by the applicable class average Accredited UCAP Factor. The resulting default New Entry MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default gross costs of new entry in the table above and post the preliminary estimates of the adjusted applicable default New Entry MOPR Floor Offer Prices on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the adjusted applicable default New Entry MOPR Floor Offer Prices for all resource types, the Office of the Interconnection shall adjust the gross costs of new entry utilizing, for combustion turbine and combined cycle resource types, the same Applicable BLS Composite Index applied for such Delivery Year to adjust the CONE value used to determine the Variable Resource Requirement Curve, in accordance with Tariff, Attachment DD, section 5.10(a)(iv), and for all other resource types, the “BLS Producer Price Index Turbines and Turbine Generator Sets” component of the Applicable BLS Composite Index used to determine the Variable Resource Requirement Curve shall be replaced with the “BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment” when adjusting the gross costs of new entry. The resultant value shall then be then adjusted further based on the bonus depreciation, if any, that is applicable under federal corporate tax law associated with the relevant Delivery Year. Updated estimates of the net energy and ancillary service revenues for each default resource type and applicable Zone, which shall include, but are not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2 shall then be subtracted from the adjusted gross costs of new entry to determine the adjusted New Entry MOPR Floor Offer Price. The net energy and ancillary services revenue is equal to the average of the annual net revenues of the three most recent calendar years preceding the Base Residual Auction, where such annual net revenues shall be determined in accordance with the following and the PJM Manuals:

(i) for nuclear resource type, the net energy and ancillary services revenue estimate shall be determined by the gross energy market revenue determined by the product of [average annual zonal day-ahead LMP, times 8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times \$9.02/MWh for a single unit plant or \$7.66/MWh for a multi-unit plant] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of Maintenance Adder costs, plus an ancillary services revenue of \$3,350/MW-year;

(ii) for coal resource type, the net energy and ancillary services revenue estimate shall be determined by a simulated dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh and variable operations and maintenance variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of \$9.50/MWh) using applicable coal prices, as set forth in the PJM Manuals, plus reactive services revenue of \$3,350/MW-year. The unit is committed day-ahead in profitable blocks of at least eight hours, and then committed in real-time for profitable hours if not already committed day ahead;

(iii) for combustion turbine resource type, the net energy and ancillary services revenue estimate shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v)(B) for the Reference Resource combustion turbine.

(iv) for combined cycle resource type, the net energy and ancillary services revenue estimate shall be determined in the same manner as that prescribed for a combustion turbine resource type, except that the heat rate assumed for the combined cycle resource shall be 6,553 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be \$2.11/MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the CC resource continuously during the full peak-hour period, as described in Peak-Hour Dispatch, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary services revenue shall be \$3,350/MW-year.

(v) for solar PV resource type, the net energy and ancillary services revenue estimate shall be determined using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of \$3,350/MW-year. Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource;

(vi) for onshore wind resource type, the net energy and ancillary services revenue estimate shall be determined using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of \$3,350/MW-year;

(vii) for offshore wind resource type, the net energy and ancillary services revenue estimate shall be the product of [the average annual zonal real-time LMP times 8,760 hours times an assumed annual capacity factor of 45%], plus an ancillary services revenue of \$3,350/MW-year; and

(viii) for Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by a simulated dispatch against historical real-time zonal LMPs where the resource is assumed to be dispatched for the four hours of highest LMP of a daily twenty-four hour period if the average LMP of these four hours exceeds 120% of the average LMP of the four lowest LMP hours of the same twenty-four hour period. The net energy market revenues will be determined by the product of [hourly output of 1 MW times the hourly LMP for each hour of assumed discharging] minus the product of [hourly consumption of 1.2 MW times the hourly LMP for each hour of assumed charging] with this net value summed across all of the hours of an annual period, plus an ancillary services revenue of \$3,350/MW-year. An 83.3% efficiency of the battery energy storage resource is reflected by assuming each 1.0 MW of discharge requires 1.2 MW of charge.

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default gross cost of new entry values. Such review may include, without limitation, analyses of the fixed development, construction, operation, and maintenance costs for such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default gross cost of new entry values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default gross cost of new entry values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has not previously cleared an RPM Auction for that or any prior Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource for the relevant RPM Auction.

(B) Cleared MOPR Floor Offer Prices.

For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year, the applicable Cleared MOPR Floor Offer Price shall be, at the election of the Capacity Market Seller, (a) based on the unit-specific MOPR Floor Offer Price, as determined in accordance with Tariff, Attachment DD, section 5.14(h-2)(4) below, or (b) if available, the default Avoidable Cost Rate for the applicable resource type shown in the table below, as adjusted for Delivery Years subsequent for the 2022/2023 or 2026/2027 Delivery Year, as applicable, to reflect changes in avoidable costs, net of projected PJM market revenues equal to the resource's historical net energy and ancillary service revenues consistent with Tariff, Attachment DD, section 6.8(d).

Existing Resource Type	Through the 2029/2030 Delivery Years: Default Gross ACR (2026/2027) (\$/MW-day) (Nameplate)	For the 2030/2031 Delivery Year and Subsequent Delivery Years: Default Gross ACR (2030/2031) (\$/ MW-day) (Nameplate)
Nuclear - single	\$591	\$776
Nuclear - dual	\$537	\$688
Coal	\$94	\$160
Combined Cycle	\$113	\$158
Combustion Turbine	\$52	\$76
Steam Oil & Gas	64	\$85
Solar PV (fixed and tracking)	\$70	\$42
Wind Onshore	\$147	\$225
Battery Energy Storage*	N/A	\$222

*Default Gross ACR for Battery Energy Storage will be further adjusted based on their duration in alignment with the table below:

4-hour duration	2-hour duration	6-hour duration	8-hour duration	10-hour duration
1.000	0.574	1.436	1.866	2.297

The default gross Avoidable Cost Rate values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. Through the 2024/2025 Delivery Year, for purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity (“UCAP”) MW-day, where the UCAP MW-day value will be determined based on the resource-specific Accredited UCAP value for solar and wind resource types (with appropriate time-weighting for any winter Capacity Interconnection Rights) or the resource-specific EFORd for all other generation resource types. Effective for the 2025/2026 Delivery Year and subsequent Delivery Years, for purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity (“UCAP”) MW-day, based on the resource’s Accredited UCAP Factor. The resulting default Cleared MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default Avoidable Cost Rates in the table above, and post the adjusted values on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the adjusted

Avoidable Cost Rates, the Office of the Interconnection shall utilize the 10-year average Handy-Whitman Index in order to adjust the Gross ACR values to account for expected inflation. Updated estimates of the net energy and ancillary service revenues shall be determined on a resource-specific basis in accordance with Tariff, Attachment DD, section 6.8(d) and the PJM Manuals.

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default Avoidable Cost Rates for Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) that have cleared in an RPM Auction for any Delivery Year. Such review may include, without limitation, analyses of the avoidable costs of such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default Avoidable Cost Rate values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default Avoidable Cost Rate values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction for any Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource.

(4) **Unit-Specific Exception.** A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Capacity Resource. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is under a fact-specific review for Buyer-Side Market Power pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B)(ii), and where the offer is below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Generation Capacity Resource. A Sell Offer below the default MOPR Floor Offer Price, but no lower than the unit-specific MOPR Floor Offer Price, shall be permitted if the Capacity Market Seller obtains approval from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer. The unit-specific MOPR Floor Offer Price determined under this provision shall be based on the unit-specific Accredited UCAP value for battery energy storage resource types and for solar and wind generation resource types (appropriately time-weighted for any winter Capacity Interconnection Rights) or on the unit-specific EFORd for all other generation resource types, and shall be applied to each MW offered by the resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource. Such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of

the resource. All supporting data must be provided for all requests. The following requirements shall apply to requests for such determinations:

(A) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, the Capacity Market Seller shall submit the unit-specific exception request to the Office of the Interconnection and the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer. For such purpose, the Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of the default Minimum Floor Offer Prices, determined pursuant to Tariff, Attachment DD, sections 5.14(h-2)(3)(A) and (B). If the final applicable default Minimum Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

(B) For a unit-specific exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has never cleared an RPM Auction, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the Capacity Resource, as well as estimates of offsetting net revenues.

The financial modeling assumptions for calculating Cost of New Entry for Generation Capacity Resources shall be: (i) nominal levelization of gross costs, (ii) asset life of twenty years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues (which may include revenues from the sale of renewable energy credits or any other revenues outside of PJM markets that do not constitute Conditioned State Support), and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. Notwithstanding the foregoing, a Capacity Market Seller that seeks to utilize an asset life other than twenty years (but no greater than 35 years) shall provide evidence to support the use of a different asset life, including but not limited to, the asset life term for such resource as utilized in the Capacity Market Seller's financial accounting (e.g., independently audited financial statements), or project financing documents for the resource or evidence of actual costs or financing assumptions of recent comparable projects to the extent the seller has not executed project financing for the resource (e.g., independent project engineer opinion or manufacturer's performance guarantee), or opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects. Capacity Market Sellers may also rely on evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an asset life other than 20 years of similar asset projects.

Supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general

costs; financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. In addition to the certification, signed by an officer of the Capacity Market Seller, the request must include a certification that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a unit-specific exception hereunder. The request also shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, evidence of compensation outside the PJM market not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, which may include Maintenance Adders, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. Any evaluation of net revenues should be consistent with Operating Agreement, Schedule 2, including, but not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable.

(C) For a Unit-Specific Exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction, the Capacity Market Seller shall submit a Sell Offer consistent with the unit-specific Market Seller Offer Cap process pursuant to Tariff, Attachment DD, section 6.8; except that the 10% uncertainty adder may not be included in the "Adjustment Factor." In addition and notwithstanding the requirements of Tariff, Attachment DD, section 6.8, the Capacity Market Seller may, at its election, include in its request for an exception under this subsection documentation to support projected energy and ancillary services markets revenues. Such a request shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, evidence of compensation outside of PJM markets not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance

expenses, energy demand, which may include Maintenance Adders, and emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. Any evaluation of revenues should include, but would not be not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2.

(D) A Sell Offer evaluated at the unit-specific exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, fixed, cost-based offer level is below the default MOPR Floor Offer Price, based on competitive cost advantages relative to the costs estimated by the default MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those estimated by the default MOPR Floor Offer Price. Capacity Market Sellers shall demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection, and that out-of-market compensation is not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices. Failure to adequately support such claimed cost advantages or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in the elimination of consideration of the unsupported element(s) of a unit-specific exception by the Office of the Interconnection.

(E) The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of the unit-specific exception request and that to the best of his/her knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception; and (3) the request satisfies the criteria for the exception.

(F) The Market Monitoring Unit shall review, in an open and transparent manner with the Capacity Market Seller and the Office of the Interconnection, the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review, in an open and transparent manner, all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it

shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. After the Office of the Interconnection determines with the advice and input of Market Monitor, the acceptable minimum Sell Offer, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction, and in making such determination, the Capacity Market Seller may consider the applicable default MOPR Floor Offer Price and may select such default value if it is lower than the unit-specific determination. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules based on the lower of the applicable default MOPR Floor Offer Price and the unit-specific determination unless and until ordered to do otherwise by FERC.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export (“Export Reserved Capacity”) multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) above also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under Tariff, Attachment DD, section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) above times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

$(\text{Export Path Import} * \text{Export Reserved Capacity}) /$

$(\text{Export Reserved Capacity} + \text{Daily Unforced Capacity Obligations of all LSEs in such Zone}).$

Where:

“Export Path Import” means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW/day of unforced capacity, applicable to price-quantity offers within the Base Offer Segment for an Existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW/day of unforced capacity. Notwithstanding, beginning with the 2026/2027 Delivery Year, the Market Seller Offer Cap shall be the greater of (a) Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, or (b) if applicable, the Capacity Performance Quantifiable Risk for such resource, as defined in Tariff, Attachment DD, section 6.8(a), to the extent such value has been supported and obtained approval pursuant to the requirements set forth in this Tariff, Attachment DD, section 6.4(b), stated in dollars per MW-day of unforced capacity. A Capacity Market Seller offering above \$0/MW-day must support and obtain approval of a unit-specific Market Seller Offer Cap pursuant to the procedures and standards of subsection (b) of this section 6.4 or may, at its election, if available, utilize a Market Seller Offer Cap determined using the applicable default gross Avoidable Cost Rate for the applicable resource type shown in the table below, as adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, to reflect changes in avoidable costs, net of Projected PJM Market Revenues equal to the resource's net energy and ancillary service revenues for the resource type, as determined in accordance with Tariff, Attachment DD, section 6.8(d).

Existing Resource Type	Through the 2029/2030 Delivery Years: Default Gross ACR (2026/2027) (\$/MW-day) (Nameplate)	For the 2030/2031 Delivery Year and Subsequent Delivery Years: Default Gross ACR (2030/2031) (\$/MW-day) (Nameplate)
Nuclear – single	\$591	\$776
Nuclear – dual	\$537	\$688
Coal	\$94	\$160
Combined Cycle	\$113	\$158
Combustion Turbine	\$52	\$76
Steam Oil & Gas	\$64	\$85
Solar PV (fixed and tracking)	\$70	\$42
Wind Onshore	\$147	\$225
Battery Energy Storage	N/A	\$222

*Default Gross ACR for Battery Energy Storage will be further adjusted based on their duration in alignment with the table below:

4-hour duration	2-hour duration	6-hour duration	8-hour duration	10-hour duration
1.000	0.574	1.436	1.866	2.297

The Market Seller Offer Cap for an Existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with Tariff, Attachment DD, section 6.7.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection data and documentation required under section 6.7 below to establish the level of the Market Seller Offer Cap applicable to each resource by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the Market Seller Offer Cap proposed by the Market Monitoring Unit, and attempt to reach agreement with the Market Monitoring Unit on the level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller shall notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, whether an agreement with the Market Monitoring Unit has been reached or, if no agreement has been reached, specifying the level of Market Seller Offer Cap to which it commits by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. The Office of the Interconnection shall review the data submitted by the Capacity Market Seller, make a determination whether to accept or reject the requested unit-specific Market Seller Offer Cap, and notify the Capacity Market Seller and the Market Monitoring Unit of its determination in writing, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction. In the event the Office of the Interconnection rejects the Capacity Market Seller's requested unit-specific Market Seller Offer Cap for a particular Capacity Resource, the Capacity Market Seller of such Capacity Resource may submit an offer up to (1) should one exist, the default gross Avoidable Cost Rate for the applicable resource type net of Projected PJM Market Revenues equal to the resource's net energy and ancillary service revenues for the resource type, or (2) the unit-specific Market Seller Offer Cap proposed by the Market Monitoring Unit upon PJM approval of such value. If the Market Monitoring Unit does not provide its determination to the Capacity Market Seller and the Office of the Interconnection by the specified deadline, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction the Office of the Interconnection will make the determination of the level of the Market Seller Offer Cap, which shall be deemed to be final. If the Capacity Market Seller does not notify the Market Monitoring Unit and the Office of the Interconnection of the Market Seller Offer Cap it desires to utilize by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction, it shall be required to utilize a Market Seller Offer Cap determined using the applicable default Avoidable Cost Rate specified in section 6.4(a) above.

Notwithstanding the provisions of Tariff, Attachment M-Appendix, section II.E.2 and this Tariff, Attachment DD, section 6.4(b), no later than eighty (80) days prior to the commencement of the offer period for the auction, the Market Monitoring Unit and the relevant Capacity Market Seller may mutually agree on the value of such Market Seller Offer Cap.

Nothing herein shall preclude the Market Monitoring Unit from modifying the Market Seller Offer Cap for a Generation Capacity Resource beyond the eighty-day (80-day) deadline prior to the commencement of the offer period for the auction, through the commencement of the offer period for the auction, so long as the Market Monitoring Unit and the relevant Capacity Market Seller mutually agree with the value of such Market Seller Offer Cap. The Capacity Market Seller shall notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, if such an agreement with the Market Monitoring Unit has been reached. The Office of the Interconnection shall review the Market Seller Offer Cap submitted by the Capacity Market Seller and make a determination whether the Market Seller Offer Cap complies with the tariff, and notify the Capacity Market Seller and the Market Monitoring Unit of its determination.

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

(d) For any Third Incremental Auction for the 2018/2019 Delivery Year or any subsequent Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Capacity Performance Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

(e) Effective with the 2026/2027 Delivery Year, Capacity Market Sellers that request a resource-specific Market Seller Offer Cap by the deadline may request to use and provide support for a segmented offer cap to reflect incremental costs of having a capacity obligation across different segments of their resource. Such request shall be submitted and reviewed in accordance with the timelines set forth in this Tariff, Attachment DD, section 6.4(b) and provide adequate justification for the use of a segmented offer cap with supporting documentation and calculations for the Market Seller Offer Cap of each segment. Segmented Market Seller Offer Caps shall be comprised of multiple Market Seller Offer Caps, each calculated in accordance with Tariff, Attachment DD, sections 6.4(a) and 6.8. If elected by the Capacity Market Seller, the first segment shall have a Market Seller Offer Cap reflective of the resource-specific Avoidable Cost Rate, less the Projected PJM Market Revenues for such resource. All subsequent offer segments (and in the first segment if solely requesting a Capacity Performance Quantifiable Risk for the Market Seller Offer Cap) shall include only incremental Capacity Performance Quantifiable Risk associated with the incremental capacity commitment in that offer segment to the extent such value has been supported and obtained approval pursuant to the requirements set forth in this Tariff, Attachment DD, section 6.8(b), and each subsequent segmented offer cap shall be greater than the prior segments.

Attachment C

Affidavit of Peter Langbein

PJM Interconnection, LLC) **Docket No. ER26-3898-000**
)

5. The purpose of my Affidavit is to provide justification for the proposed updates to the default gross Cost of New Entry (“Gross CONE”) and gross Avoidable Cost Rate (“Gross ACR”) resulting from this latest periodic review that are proposed to be effective with RPM Auctions associated with the 2030/2031 Delivery Year.

III. DISCUSSION

A. Updated Cost of New Entry Values Used as Default Offer Floor Prices for Planned Generation Capacity Resources Subject to the MOPR

6. PJM currently posts the default Cost of New Entry (“CONE”) values for nine distinct resource types. As required by the Tariff, PJM is proposing updated default Gross CONE values for Planned Generation Capacity Resources which are used to determine the default Minimum Offer Price Rule (“MOPR”) Floor Offer Prices effective with the 2030/2031 Delivery Year.¹ For Planned Generation Capacity Resources, these values are based on an estimate of the “nominal-levelized” annual cost to construct and develop each resource type, referred to as gross Cost of New Entry (“Gross CONE”), from which PJM will subtract the estimated net energy and ancillary services (“E&AS”) revenues for each resource type and zone to determine the Net Cost of New Entry (“Net CONE”).

7. In this filing, PJM proposes to update the default Gross CONE value for each resource type,² based on the values shown in Table 3 below. The updated default values are proposed to be effective starting with the 2030/2031 Delivery Year. The values will be converted from \$/MW-day (Nameplate ICAP) to \$/MW-day (Accredited UCAP) based on the posted class average effective load carrying capability (“ELCC”) factors³ for such Delivery Year.

8. In developing the updated Gross CONE values, PJM leveraged the same methodology and transparent process used in the previous periodic review for these values.⁴ Specifically, PJM used the 2025 Brattle CONE Report,⁵ which is based on a “bottom-up” cost analysis, to update the combustion turbine (“CT”), combined cycle (“CC”) and battery energy storage system (“BESS”) values. For all other technologies,

¹ “Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default gross cost of new entry values. Such review may include, without limitation, analyses of the fixed development, construction, operation, and maintenance costs for such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default gross cost of new entry values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default gross cost of new entry values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.” See Tariff, Attachment DD, section 5.14(h-2)(3)(A), <https://agreements.pjm.com/oatt/5156>.

² The BESS value represents a 4-hour duration battery. See Tariff, Attachment DD, section 5.14(h-2)(3)(A)(viii).

³ See PJM, Effective Load Carrying Capability (ELCC) Homepage, <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

⁴ *PJM Interconnection, L.L.C.*, 2025 Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, Docket No. ER26-455-000, at 34-36 (Nov. 7, 2025) (“2025 Periodic Review”).

⁵ See Brattle, 2025 CONE Report for PJM (Apr. 9, 2025) (“2025 Brattle CONE Report”), <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250411-special/item-1-02-revised-cone-report-final.pdf>.

PJM utilized cost data sources from U.S. Energy Information Agency (“EIA”) to calculate updated Gross CONE values.⁶ The use of EIA data is appropriate because this data represents the most recent (published in April 2026) publicly available source, is well-documented, and is the same source used to develop the currently approved values in the tariff. PJM used EIA’s 2025 costs, which were developed based on major categories such as equipment, installation, transmission interconnection, fees, and contingencies. Because the EIA data does not include solar PV (fixed) data, PJM calculated a Gross CONE value for that resource type by applying a 1.18 fixed-to-tracking cost ratio to the overnight capital cost and fixed operating and maintenance (FOM) values used for solar PV (tracking). This ratio was determined by reviewing publicly available fixed-to-tracking cost ratios from the Lawrence Berkeley National Laboratory’s Utility Scale Solar.⁷

9. The overnight capital costs were escalated to installed costs based on information and analysis contained in the 2025 Brattle CONE Report.⁸ Bonus depreciation realization timing is based on the ratio of overnight capital costs to installed costs from the Brattle study for CC, CT, and BESS, and applied to the other technologies based on similarly situated construction schedules. The 3-year schedule used for a BESS was applied to Solar Tracking, Solar Fixed, Onshore and Offshore Wind technologies, and the 10-year schedule used for a CC was applied to the Coal and Nuclear technologies.⁹

10. Table 1 shows the reference resources with their technology description, source of information, overnight capital costs, and FOM costs for each resource type. The selected specific technology types used are consistent with the list currently in the Tariff. The source of the resource type is based on the identification of the case number from the EIA report, or other applicable source citation, are provided. The reference resources for combined cycle, combustion turbine, and battery energy storage are those used that were recently studied as part of PJM’s 2025 periodic review and based on the 2025 Brattle CONE report.

⁶ See U.S. Energy Information Administration (“EIA”), Annual Energy Outlook 2026: Electricity Market Module, Table 3 - Cost and performance characteristics of new central station electricity generating technologies (Apr. 2026), https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf.

⁷ See Lawrence Berkeley National Laboratory, Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, PPA Pricing, and Value in the United States – 2025 Edition (Oct. 2025), <https://emp.lbl.gov/utility-scale-solar>.

⁸ See 2025 Brattle CONE Report.

⁹ See PJM, MC Presentation on Periodic Review of Default Cone and ACR Values, at Slide 9 (Aug. 24, 2026), <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2026/20260819/20260819-item-03a---1-periodic-review-of-default-cone-and-acr-values---presentation.pdf>.

Table 1: Reference Resources with Technology Description, Source of Information, and Costs¹⁰

Resource Type	Technology Description	Source of Information	Fixed O&M (\$/kW ICAP-Year)	Overnight Capital Costs (\$/kW ICAP)
Nuclear	2x Westinghouse AP 1000 pressurized water reactor (2,156 MW)	EIA	163	7,862
Coal	Ultra-Supercritical coal (650 MW)	EIA	50	5,360
Combined Cycle	1,401 MW (GE Frame 7HA.03 CT, SCR, an evaporative cooler, wet compression, and dual-fuel capability)	2025 Periodic Review	47	1,432
Combustion Turbine	440 MW (GE 7HA.03 turbines in two trains of a single-shaft CC plant, each with a single CT, HRSG, and steam turbine)	2025 Periodic Review	25	1,280
Solar PV - Tracking	Single-axis tracking (150 MW AC)	EIA	24	1,484
Solar PV - Fixed	Fixed Tilt (100 MW AC)	EIA, LBNL	28	1,751
Onshore Wind	200 MW 2.8-MW Wind Turbine Generator (WTG)	EIA	35	1,712
Offshore Wind	900 MW 15 MW WTG	EIA	161	3,711
Battery Energy Storage	200 MW (800 MWh for 4-hour duration)	2025 Periodic Review	73	1,820

11. PJM used the Gross CONE data for the combustion turbine resource type determined by PJM, and approved by the Commission, in the last periodic review of capacity market inputs in Docket No. ER26-455-000.¹¹ Similarly, overnight capital cost and FOM costs for combined cycle and battery energy storage resource types utilize those developed through the most recent periodic review process. Overnight capital costs were converted to installed costs for CC, CT and BESS as part of that analysis. As indicated above, PJM converted the other resource types' overnight capital costs to installed costs.¹²

¹⁰ For purposes of Table 1, CT, CC and BESS values are provided in 2028 dollars, while all other technology type values are provided in 2025 dollars, with the Tariff defined escalation process used to determine values for the 2030/2031 Delivery Year.

¹¹ *PJM Interconnection, L.L.C.*, 194 FERC ¶ 61,049 (2026).

¹² See 2025 Periodic Review. The 2025 Periodic Review updated the Gross CONE value for the combustion turbine resource type and the combined cycle and battery energy storage resource types.

12. After having identified the reference technologies for each resource class and developing the respective installed cost and FOM levels, the next step in developing the updated default MOPR Floor Offer Prices is to determine the Gross CONE. To calculate this, PJM used the pro forma analysis developed by Monitoring Analytics, the Independent Market Monitor (“IMM”) to PJM,¹³ to determine the nominal-levelized annual revenue requirements for a resource to recover the installed cost and FOM expenses and earn a market-based return for the investor. The expected life and the financial assumptions used by PJM are the same as those used in the as-filed 2025 periodic review and shown in Table 2 below. These assumptions, including cost of capital, return on equity, cost of debt, capital structure, and projected annual inflation rate, were found to be just and reasonable by the Commission in its recent January 2026 order accepting PJM’s periodic review filing.¹⁴

Table 2: Financial Assumptions

Expected Life	20 Years
Debt Ratio	55%
Debt Rate	5.8%
Equity Rate	16.0%
Total Tax Rate	27.7%
After-Tax Weighted Average Cost of Capital (“ATWACC”)	9.506%
Inflation Rate	2.2%

13. The final step was to escalate the nominal levelized Gross CONE value from the 2025 costs for the 2030/2031 Delivery Year cost based on the Tariff defined process that utilizes the Bureau of Labor Statistics (BLS) composite index.¹⁵ Based on the foregoing, PJM is proposing Gross CONE values for the relevant reference resources as shown in Table 3 below.

¹³ See Independent Market Monitor of PJM, CONE Template, https://www.monitoringanalytics.com/tools/docs/IMM_MOPR_Gross_CONE_Template_v2.xlsx.

¹⁴ *PJM Interconnection, L.L.C.*, 194 FERC ¶ 61,049, at P 67 (2026).

¹⁵ See Tariff, Attachment DD, section 5.10(a)(iv)(D)(1).

Table 3: Proposed Gross CONE values used for the determination of the MOPR default prices

Planned Resource Type	Gross CONE (2030/2031 Delivery Year \$/MW-Day) (Nameplate ICAP)
Nuclear	\$4,403
Coal	\$2,896
Combined Cycle	\$814
Combustion Turbine	\$642
Solar PV (Tracking)	\$659
Solar PV (Fixed)	\$780
Onshore Wind	\$786
Offshore Wind	\$2,243
Battery Energy Storage	\$696

B. Updated Default Offer Floor Prices for Existing Generation Capacity Resources subject to MOPR and Default Offer Cap for Existing Generation Capacity Resources subject to MSOC Based on the Avoidable Cost Rate of that Resource Type

14. As with the default floor price for Planned Generation Capacity Resources, PJM is also required to review the default MOPR and Market Seller Offer Cap (“MSOC”) that is applicable to Existing Generation Capacity Resources. Based on this review, PJM is proposing updates to the default Offer Floor Offer Prices for Existing Generation Capacity Resources subject to the MOPR and the default offer cap for resources subject to the MSOC effective with the 2030/2031 Delivery Year.¹⁶ For Existing Generation Capacity Resources that are subject to the MOPR or Capacity Resources that are subject to the MSOC, these values reflect each resource type’s estimated annual cost that could be avoided absent receiving a capacity obligation as a PJM Capacity Resource. This economic avoidable cost is referred to as gross Avoidable Cost Rate (“Gross ACR”) from

¹⁶ “Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default Avoidable Cost Rates for Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) that have cleared in an RPM Auction for any Delivery Year. Such review may include, without limitation, analyses of the avoidable costs of such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default Avoidable Cost Rate values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default Avoidable Cost Rate values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.” See Tariff, Attachment DD, section 5.14 (h-2)(3)(B).

which PJM will subtract the unit-specific historical net energy and ancillary services (“E&AS”)¹⁷ revenues for each resource to determine the Net Avoidable Cost Rate (“Net ACR”).

15. In developing updated gross ACR values, PJM enlisted the Brattle Group (“Brattle”), which prepared the Brattle Report, included with this filing as Attachment D, detailing how the updated values were developed.¹⁸ Brattle, along with Sargent & Lundy (“S&L”), determined updated Gross ACRs for the following resource types: nuclear, coal, combined cycle, combustion turbine, steam oil & gas, solar PV, onshore wind, and battery energy storage resources (“BESS”).¹⁹ The BESS resource type was added since we now expect a significant increase in the amount of BESS that will be in service beginning with the 2030/2031 Delivery Year. Further, these resources tend to be more standardized where the avoidable costs are not as variable as other technologies, and such information exists for projects across the country. As has been done in the past, Brattle used a bottom-up analysis to determine the various fixed costs associated with a “reference plant” of each resource type. Brattle also provided costs associated with “representative low-cost” and “representative high-cost” plants as a reference point. These costs were then used to estimate the Gross ACRs and variable operations and maintenance costs. Importantly, Brattle’s “classification of cost categories as “fixed” versus “variable” align with PJM’s current market rules concerning the costs that can be included in the ACRs (fixed costs) versus those that can be included in cost-based energy offers.”²⁰

16. For each defined resource type, Brattle identified the characteristics of a “representative plant” that is broadly representative of the individual plants within that type. The “representative plant” standard is a median for the population of PJM plants in each type, with the median being defined on a capacity (MW) basis. Since it would have been impractical to develop cost estimates for every plant in the fleet, Brattle instead identified the median plant as one with median or representative values of the main cost drivers: (1) the unit size; (2) the plant age and technology vintage; (3) the plant location in PJM; and (4) the configuration of the units, including pollution controls. Brattle then estimated the costs for such a plant as described below.

17. In updating the default gross ACR for each resource type, Brattle reviewed the range of characteristics of resources in the PJM market and identified the primary cost drivers among those characteristics for each resource type. Specifically, Brattle identified for each resource type the characteristics of a “representative plant” that is widely representative of most of the fleet and reflects the median MW in terms of cost structure. Brattle also identified the characteristics for “representative low-cost” and “representative high-cost” plants to inform the range of costs PJM may see for each type of existing generation resource. Given the assumed characteristics, Brattle then estimated the

¹⁷ See *id.*

¹⁸ See The Brattle Group and Sargent & Lundy, 2026 PJM Gross Avoidable Cost Rates for Existing Generation (July 28, 2026) (“Brattle Report”). The Brattle Report is included as Exhibit No. D.

¹⁹ *Id.* at 10.

²⁰ *Id.* at v.

avoidable gross costs of the representative plants to inform PJM’s filing of Default Gross ACRs. The cost estimates are based on S&L analysis of FERC Form 1 data and the Nuclear Energy Institute’s (NEI’s) “Nuclear Costs in Context” study and its own proprietary database, and Brattle analysis.

18. Only avoidable economic fixed costs are accounted for to determine resources’ default Gross ACRs, while variable costs would be accounted for in resources’ cost-based energy offer and therefore part of the unit specific energy and ancillary service offset which is subtracted from the Gross ACR to determine the unit specific Net ACRs. To avoid double counting any such costs, the estimated gross costs include only Fixed Capital Costs and FOM costs but not major maintenance costs for systems directly related to electric production (i.e., such costs which either vary with energy production and/or which are incurred on a schedule which depends on energy production).

19. I have reviewed the extensive analysis provided by the Brattle Report, containing a range of values for each Gross ACR for each asset class, and believe the updated Gross ACR values contained in the report for the “Representative Plant” are reasonable as the basis for PJM’s default Gross ACR values. The mid-year 2026 Gross ACR values developed and supported by the detailed Brattle analysis and endorsed by PJM stakeholders were escalated by PJM based on the tariff defined escalation process to represent mid-year 2030 costs and will therefore be applicable starting in the 2030/2031 Delivery Year as represented in Table 4. Each year thereafter such value will be escalated through the same tariff defined escalation process.

Table 4: Proposed Gross ACR values used for MOPR and MSOC default prices (2026 and 2030 values)

Resource Type	Updated Gross ACR (2026 \$/MW-day, ICAP)	Proposed Escalated Gross ACR Value for the 2030/2031 Delivery Year (2030 \$/MW-day, ICAP)
Nuclear – single	\$654	\$776
Nuclear – dual	\$580	\$688
Coal	\$135	\$160
Combined Cycle	\$133	\$158
Combustion Turbine	\$64	\$76
Steam Oil & Gas	\$72	\$85
Solar PV (Fixed and Tracking)	\$35	\$42
Wind Onshore	\$190	\$225
Battery Energy Storage	\$187	\$222

20. Brattle’s full analysis will not be repeated here, but the report detailing how the gross ACR was developed for each resource type is included as Attachment D of this filing.²¹ From these ranges PJM selected and stakeholder endorsed the “Representative Plant” values for use as the Gross ACR value (2026 cost) as they are intended to be the most widely representative of each class. Additionally, PJM chose the representative plant value because choosing the low end of the range provided by Brattle would result in setting artificially low Net ACRs that would not be representative of the actual costs for most resources (resulting in potential over-mitigation and/or additional administrative burden associated with pursuing a unit-specific MSOC review), and, similarly, choosing the high end would likely not be representative of the actual costs for most resources in each class (resulting in potential under-mitigation of market power).

21. The standalone BESS was added based on the current and future expected quantity of BESS in PJM by the 2030/2031 Delivery Year.²² Further, utility scale BESS are more standardized and therefore the associated fixed costs are less variable than other technologies. The Brattle report notes “[a]s of June 2026, PJM has approximately 800 MW of BESS. Of this total, 40% are standalone BESS and the remainder are hybrid BESS resources. Over 4 GW of BESS, however, are currently in PJM’s Expedited Process (a ‘fast track’ interconnection process) with the majority expected to come online between 2027 and 2029. Additionally, over 60 GW of storage projects have been selected as part of PJM’s first cycle of the reformed interconnection process, with a substantial portion expected to be online before 2030.” Further, the report goes on to note “Utility-scale BESS uses standardized, modular equipment for which fixed costs are less influenced by geography than other technologies. Given that CAISO and ERCOT have extensive recent deployment, ample information has accumulated on the fixed costs associated with utility-scale BESS across configurations. Leveraging this information provides a credible basis for bottom-up fixed-cost estimates for BESS in PJM despite the relatively small existing fleet.”

22. The Proposed standalone BESS Gross ACR values for the 2030/2031 Delivery Year and subsequent Delivery Years may be converted to different BESS durations based on the values in Table 5 as provided in the Brattle analysis. This provides a reasonably accurate approach to allow a default value for the variety of durations that may be implemented instead of requiring the resources to go through the unit specific process or developing individual values for each duration.

²¹ The proposed Gross ACR for the 2030/2031 Delivery Year for a gas CC resource includes firm gas transportation. This is consistent with the calculation of the currently effective Gross ACR values and is also based on recent PJM survey data where market participants responded that they have firm gas transportation

²² The Gross ACR values are expected to be effective from the 2030/2031 Delivery Year through the 2033/2034 Delivery Year where PJM is expected to have significant penetration of BESS as a capacity resource.

Table 5: Alternative Duration BESS Adjustment Factors

4-hour duration	2-hour duration	6-hour duration	8-hour duration	10-hour duration
1.000	0.574	1.436	1.866	2.297

23. While the Gross CONE and Gross ACR values determined by PJM are supported by the calculations laid out within the Tariff, publicly available data, and expert analysis from the Brattle Group and Sargent and Lundy, they are based on industry average data used in a manner that is intended to yield a reasonable offer price for a resource of a specific class in a specific location. As such, installed cost, FOM and the relevant financing assumptions may differ across new projects as may the actual fixed costs of an existing resource used to determine the Gross ACR. Specifically, parameters such as the Capacity Performance Quantifiable Risk (“CPQR”) adder are set to \$0/MW-day in the calculation of the Default ACR values since it is expected there is a wide variation of these values based on unit specific and owner specific attributes.

IV. SUMMARY AND CONCLUSION

24. This quadrennial review process for the update of these values followed the same general process with the same data sources and the same expert consultant as the last quadrennial review. There was more emphasis put on the Gross ACR value update since the application of these values for MSOC is much wider than the very limited application of Gross CONE values specifically used for MOPR. This is the primary reason why Brattle and Sargent and Lundy were again brought in as experts, with access to extensive actual project cost information to develop the bottom-up Gross ACR values compared to the Gross CONE update which leverages public information as done in the last quadrennial review.

25. This concludes my affidavit.

PJM Interconnection, L.L.C.) **Docket Nos. ER26-3898-000**
)

Dated: September 30, 2026

Attachment D

The Brattle Group and Sargent & Lundy
2026 Avoidable Fixed Costs for Existing Resources
(Sept. 15, 2026)

2026 Avoidable Fixed Costs for Existing Resources

TO INFORM PJM'S AVOIDABLE COST RATES FOR CAPACITY
DELIVERY YEARS BEGINNING 2030/31

PREPARED BY

The Brattle Group

Samuel A. Newell

Andrew W. Thompson

James Herrigel

Sargent & Lundy

Joshua Junge

Kelley McGough

Neil Kern

PREPARED FOR

PJM Interconnection, L.L.C.

September 15, 2026



NOTICE

- This report was prepared for PJM Interconnection, L.L.C., in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts.
- The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.
- There are no third-party beneficiaries with respect to this report, and The Brattle Group does not accept any liability to any third party in respect of the contents of this report or any actions taken or decisions made as a consequence of the information set forth herein.

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TABLE OF CONTENTS

Executive Summary.....	iii
I. Introduction.....	6
A. Purpose of ACRs and this Analysis.....	6
B. Analytical Approach.....	7
II. Selection of Plant Types within PJM Fleet.....	9
III. Avoidable Fixed Costs for Existing Resources.....	11
A. Multi-Unit Nuclear Plants.....	11
B. Single-Unit Nuclear Plants.....	14
C. Coal Plants.....	17
D. Natural Gas-Fired Combined-Cycle Plants.....	22
E. Simple-Cycle Combustion Turbines.....	28
F. Oil- and Gas-Fired Steam Turbines.....	32
G. Onshore Wind Plants.....	37
H. Large-Scale Solar Photovoltaic Plants.....	40
I. Standalone BESS.....	44

Executive Summary

Since the 2022/23 Delivery Year, PJM Interconnection, L.L.C. (PJM) has been required under its Open Access Transmission Tariff (“OATT” or “Tariff”) to update Avoidable Cost Rates (ACRs) every four years.¹ The last time ACRs were updated was in 2022,² so this study supports PJM’s filing requirement by developing updated avoidable fixed cost estimates for existing generation in PJM. These ACRs will be in place for PJM’s Base Residual Auctions for 2030/31 and the following three delivery years.³

ACRs are used primarily in setting existing resources’ Market Seller Offer Caps (MSOCs) to mitigate supplier market power for suppliers that have failed the structural Three Pivotal Supplier Test going into each capacity auction, as follows: ACRs express avoidable going-forward fixed costs for each type of existing resource. ACRs minus unit-specific net energy and ancillary services (E&AS) revenues result in Net ACRs. Unit-specific Net ACRs in turn set resources’ default MSOCs, although resources can offer at higher prices if they demonstrate higher actual costs through unit-specific reviews or requesting an opportunity cost-based price.⁴

In a separate, more limited application of ACRs to buyer-side market power mitigation, resources that were subject to the Minimum Offer Price Rule (MOPR) when first entering as new resources must, in subsequent auctions, not offer their now-existing capacity *below* their Net ACR unless demonstrating higher actual costs through a unit-specific review.⁵

¹ PJM, Open Access Transmission Tariff (“PJM OATT”), [Attachment DD, Section 5 Capacity Resource Commitment, Section 5.14\(h-2\)\(3\)\(B\)](#).

² Newell et al., [Gross Avoidable Costs for Existing Generation](#), (“2022 PJM ACR Study”), January 9, 2023.

³ PJM will escalate these values based on the Tariff-defined process for each of the four Delivery Years.

⁴ This framework was adopted in Federal Energy Regulatory Commission, Order Establishing Just and Reasonable Rates, 176 FERC ¶ 61,137, Docket Nos. EL19-47-000, EL19-63-000, and ER21-2444-000, September 2, 2021, and implemented in PJM, Open Access Transmission Tariff, Attachment DD, Section 6 Market Power Mitigation, Sections 6.4 & 6.8.

⁵ See Federal Energy Regulatory Commission, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582-000, Accession No. 20210929-3009, September 29, 2021; and PJM Open Access Transmission Tariff, Attachment DD, Section 5 Capacity Resource Commitment, [Section 5.14\(h-2\)](#).

To conduct this update of the ACRs, PJM retained The Brattle Group (Brattle) and Sargent & Lundy (S&L) to analyze the avoidable fixed costs for several types of existing generation. We have done so based on bottom-up analysis of costs for representative plants, drawing on data and the combined experience of Brattle and S&L. We also solicited stakeholder input through four rounds of presentations before the Markets Implementation Committee (MIC), Markets and Reliability Committee (MRC), and Members Committee (MC) between June and August 2026.⁶

Our approach recognizes that existing generation resources vary considerably in their characteristics and costs both across and within resource types. This variability must be considered in developing coherent resource “types” and in developing ACR thresholds for each, trading off the risks of under-mitigation against the risks of over-mitigation and/or a burdensome number of unit-specific reviews.

To inform PJM’s determination of a single ACR for each resource type, we reviewed the characteristics of existing resources in the PJM market, identified representative plants, and assessed the primary cost drivers for each resource type. Our default “representative plant” selections capture the median characteristics of the existing fleet for each resource type as a reasonable basis for determining ACRs. Separately, and purely for informational purposes, as an indicator of the range of costs for each type of existing resource, we describe representative “low-cost” and “high-cost” plants. These plants, as well as the median representative, are defined such that their packages of characteristics align with plants that actually exist in PJM and are not based on a hybridization of characteristics to result in a plant design that may not exist.

Given the assumed characteristics, we then estimated the avoidable fixed costs of the representative plants to inform PJM’s filing of ACRs. Cost estimates are based primarily on S&L’s analysis of FERC Form 1 data, the Nuclear Energy Institute’s (NEI’s) “Nuclear Costs in Context” study, and S&L’s own proprietary database of projects, and are supplemented by Brattle analysis for some inputs.

We also provide estimates for Variable Operation and Maintenance (VOM) costs purely for informational purposes to distinguish between costs that are fixed (and therefore relevant to ACRs) and those that are variable (and not included in ACRs). The classification of cost categories as “fixed” versus “variable” aligns with PJM’s market rules concerning the costs that

⁶ We presented on June 16, July 8, and July 28, 2026, at the MIC, and on August 19, 2026, at the joint MRC/MC Meeting.

can be included in the ACRs (fixed costs) versus those that can be included in cost-based energy offers (variable costs which are accounted for in the net E&AS revenue component of Net ACRs). Accordingly, the costs of major maintenance and overhauls directly related to the production of electricity are included in variable costs as a “maintenance adder” in line with PJM’s Tariff.

Table ES-1 below shows the resulting avoidable fixed costs for each existing generation resource type, expressed in 2026 dollars per megawatt (MW) of nameplate capacity, as well as the nominal change from the avoidable fixed costs reported in the 2022 PJM ACR Study. For most resource types, the increases in avoidable fixed cost estimates are attributable to inflation, with the increase roughly aligned with applicable producer price indexes (PPIs). Costs for the representative coal plant increased more than that because many plants that deferred maintenance in the recent past are now conducting extra maintenance to keep their plants operable. Costs for solar PV plants decreased on a per-kW basis due to economies of scale on plants of increasing size. Note that some resource types with high avoidable fixed costs will tend to have high offsetting E&AS revenues due to lower variable costs.

TABLE ES-1: COMPARISON OF AVOIDABLE FIXED COSTS IN 2022 AND 2026 STUDIES

Resource Type	2022 Value (2022 \$/MW-day)	Updated 2026 Value (2026 \$/MW-day)	Nominal % Change
Multi-unit nuclear	\$537	\$580	+8%
Single-unit nuclear	\$591	\$654	+11%
Coal	\$94	\$135	+44%
Natural gas CC	\$113	\$133	+18%
Simple-cycle CT	\$52	\$64	+24%
Steam oil & gas	\$64	\$72	+12%
Onshore wind	\$147	\$190	+29%
Large-scale solar PV	\$70	\$35	-50%
Standalone BESS	N/A	\$187	N/A

Throughout this report, our results are presented as “avoidable fixed costs” rather than “ACRs” because the formal term refers to a rate set forth in PJM’s Tariff and approved by FERC. Our study only informs those rates.

I. Introduction

A. Purpose of ACRs and this Analysis

In the presence of structural market power in capacity markets, PJM as market operator needs to be able to mitigate offers outside of reasonable competitive bounds. Concerns surround both supplier market power and buyer market power. Supplier market power, in the form of resources offering prices above competitive levels, is a concern where jointly-pivotal market sellers fail the Three Pivotal Supplier test, which all typically do.⁷ Under such circumstances, resource offers would be subject to Market Seller Offer Caps (MSOCs). Buyer market power, in the form of resources offering at artificially low prices, is deemed a concern under special circumstances and applicable resources would be subject to the Minimum Offer Price Rule (MOPR), though the application of MOPR is much less frequent.⁸

PJM approaches both instances by setting default offer thresholds for various resource types. Resources may only offer higher than their default MSOC price if they are approved for a higher price through unit-specific reviews of their costs. Similarly, resources subject to MOPR may only offer lower than their default MOPR price if they are approved for a lower price through a unit-specific review. Default thresholds are determined by a generic resource-type-specific Avoidable Cost Rate, minus resource-specific net revenues from energy and ancillary services markets. This updated ACR study will be used for both MSOC and MOPR purposes, in fulfillment of PJM's requirement to periodically update its ACRs every four years.⁹ The last such study was conducted by us in 2022.¹⁰ These ACRs will be in place for PJM's Base Residual Auctions for 2030/31 and the following three delivery years.

PJM requested that this study be an update to the avoidable fixed costs estimated in the 2022 PJM ACR Study, maintaining the same analytical approach. Resource types would be defined to span most of the PJM fleet, where each type includes similar resources with analogous cost

⁷ PJM, [Market Seller Offer Cap \(MSOC\) Reform, February 28, 2022](#).

⁸ MOPR applicability was narrowed as a result of litigation concluding in 2021. See [Federal Energy Regulatory Commission, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582-000](#), Accession No. 20210929-3009, [September 29, 2021](#).

⁹ PJM, [Open Access Transmission Tariff, Attachment DD, Section 5 Capacity Resource Commitment, Section 5.14\(h-2\)\(3\)\(B\)](#).

¹⁰ 2022 PJM ACR Study.

structures; for each type, we would identify representative plant characteristics, then conduct a bottom-up analysis of avoidable going-forward fixed costs. Additionally, PJM requested that we estimate the Variable Operation and Maintenance costs for each resource type, purely for informational purposes, clarifying distinctions from costs that are fixed and therefore included in ACRs.

A key concept in setting offer thresholds is the need to mitigate the exercise of market power and the risks of under-mitigation against the administrative burden and risks of over-mitigation, all in the context of cost diversity among resources and information asymmetry between sellers and PJM. Cost diversity and information asymmetries could result, for example, in a resource's MSOC being set below its true costs; capping offers below costs could discourage participation in the market. Such over-mitigation risk can be avoided in part by setting default MSOCs reasonably high so that many resources would not need a unit-specific review to justify higher offers.¹¹ Conversely, under-mitigation can arise if MSOCs are set substantially above actual costs, which could enable the exercise of market power.¹² How to balance over- and under-mitigation risks is a design decision that PJM and stakeholders make in setting ACRs. In consultation with PJM and stakeholders, and consistent with the last ACR Study, we have developed a reasonable balance by aiming for accurate estimates of the cost of typical plants of each resource type, by targeting median cost characteristics.

B. Analytical Approach

To estimate avoidable fixed costs, we began with the types and representative resources from the 2022 PJM ACR Study. These representative resources were chosen to span a large portion of the overall PJM fleet and so that each type was coherent and had common cost characteristics. We then analyzed the current fleet and identified which characteristics, if any, of the representative plant should be changed and whether new resource types should be defined. We iterated on the defined types with PJM and market stakeholders and included one new resource type for standalone battery energy storage systems (BESS). We did not determine a default type for a small remaining portion of the PJM resource fleet because these resources had more idiosyncratic cost characteristics among individual plants (e.g., due to older and/or non-standard technology) and did not lend themselves well to defining a standardized estimate

¹¹ Similarly, by setting default MOPRs reasonably low.

¹² The converse applies for MOPRs.

of costs. Absent an ACR, these plants will have to rely on unit-specific reviews for non-zero capacity offers.

For each defined resource type, the “representative plant” standard that we agreed on with PJM staff and reviewed with stakeholders was a plant based on the median characteristics for the primary cost drivers for each resource type, which included: (1) the size in MW; (2) the plant age and technology vintage; (3) the location in PJM; (4) the configuration of the units, including pollution controls where relevant; as well as (5) the duration and the augmentation approach (for BESS resources only). The representative plant is defined such that the package of characteristics aligns with plants that actually exist in PJM and is not based on a hybridization of characteristics to result in a plant design that may not exist.

While only the median representative plant costs are used to determine ACRs, in keeping with our approach in the 2022 PJM ACR Study, we also inform the range of costs PJM might see for each type by evaluating a “representative high-cost” and a “representative low-cost” plant for each type. These representatives were identified by considering the range of characteristics of existing plants and especially clusters thereof.

Given the assumed representative characteristics of each resource type, we then estimated the fixed costs of operating such a resource for an additional year that could be avoided if the plant retires.¹³ Our cost analysis is consistent with PJM’s Tariff for the scope of costs allowable in ACRs.¹⁴ Consistent with the Tariff, our estimated costs include fixed capital costs and fixed operation & maintenance (FOM) costs, but not major maintenance costs for systems directly related to electricity production.¹⁵ PJM’s Tariff specifies that such major maintenance costs can

¹³ Given the very limited prevalence of “mothballing,” meaning a unit that does not operate for the Delivery Year but is maintained in a state such that it may be brought back into service in a future year, we only consider the costs that are avoidable if a unit retires.

¹⁴ Variable O&M (VOM) estimates are provided in addition to avoided fixed costs strictly for informational purposes as a means to distinguish between what costs are fixed (and therefore considered by PJM in determining ACRs) and those that are variable (thus part of VOM and excluded from consideration for ACRs).

¹⁵ PJM staff reviewed the specifications in their Tariff and Operating Agreements and provided guidelines to follow based on their interpretation. The PJM Open Access Transmission Tariff (OATT) Attachment DD section 6.8(c) specifies that “[v]ariable costs that are directly attributable to the production of energy shall be excluded from a Market Seller’s generation resource Avoidable Cost Rate.” Section 6.8 also lists eleven components of Avoidable Cost Rates. The PJM Operating Agreement Schedule 2 further specifies the expenses allowed to be included in the maintenance adder as a variable cost as part of energy offers, rather than in the ACR: “Allowable expenses may include repair, replacement, and major inspection, and overhaul expenses including variable long term service agreement expenses.” Schedule 2 states that “preventative maintenance and routine maintenance on auxiliary equipment like buildings, HVAC, compressed air, closed cooling water, heat tracing/freeze protection, and water treatment” cannot be included in cost-based energy offers and thus are

Continued on next page

be included in variable costs in cost-based energy offers, under a maintenance adder that includes activities such as repair, replacement, and major inspection.¹⁶ When sellers include these costs in their variable cost-based offers for energy, PJM would account for them in Net ACRs, through the resource-specific net E&AS.

Our quantitative cost estimates for most types of thermal plants are based on S&L's regression analyses of FERC Form 1 filings, EIA Form 860 data, and S&L internal data for plants with characteristics similar to the representative plants for each resource type, benchmarked and adjusted using confidential cost estimates from S&L's project database. For nuclear plants, we derived avoidable fixed costs for the representative plant from NEI's "Nuclear Costs in Context" study and cost sensitivities it provided, escalated from 2024 dollars to 2026 dollars.¹⁷ For wind, solar, and BESS plants, for which FERC Form 1 data is sparse, we relied on S&L's extensive project database. For most resource types, property taxes and insurance constitute a relatively small fraction of total costs but are less straightforward to quantify uniformly. Our approach to estimating these costs varies by resource type given data availability and is described under each type presented below.

II. Selection of Plant Types within PJM Fleet

Based on the approach described above, PJM input, and stakeholder feedback, we defined the following resource types for estimating avoidable fixed costs:

- Multi-unit nuclear plants
- Single-unit nuclear plants
- Coal-fired steam turbines (Coal plants)
- Natural gas-fired combined-cycle plants (CC)
- Simple-cycle combustion turbines (CT)

included in the ACR. We understand that PJM interprets this to mean that all maintenance costs for systems directly related to electricity production can be included in the operating costs maintenance adder for cost-based energy offers and thus are excluded from the Avoidable Cost Rates. See [PJM Open Access Transmission Tariff, Attachment DD, Section 6 Market Power Mitigation, Section 6.8\(c\)](#); and PJM, [Operating Agreement of PJM Interconnection, L.L.C., Schedule 2, Section 4](#).

¹⁶ PJM, [Operating Agreement of PJM Interconnection, L.L.C., Schedule 2, Section 4](#).

¹⁷ "Nuclear Costs in Context," Nuclear Energy Institute ("NEI"), March 2026 ("2026 NEI Report"). Since this analysis was conducted, an updated version of this report was released in August 2026, available at: <https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>. In our analysis, we used the March 2026 version.

- Oil- and gas-fired steam turbines (ST O&G)
- Onshore wind plants
- Large-scale solar photovoltaic plants (Solar PV)
- Standalone battery energy storage systems (Standalone BESS)

This list maintains the types used in the 2022 PJM ACR Study, expanded to include standalone BESS.¹⁸ Table 1 shows the composition of the PJM fleet by total capacity of these types and others. The chosen resource types combined cover about 95% of the existing PJM resource fleet on a summer ICAP basis.

TABLE 1: 2026 PJM FLEET CAPACITY BY PLANT TYPE

Technology Type	Total MW (Summer ICAP)	Percent of PJM Fleet Capacity	Recommendation
Natural gas CC	59,829	29%	Include
Coal	34,986	17%	Include
Single-unit nuclear	32,556	16%	Include
Multi-unit nuclear			
Simple-cycle CT	27,702	13%	Include
Large-scale solar PV	19,672	10%	Include
Onshore wind	11,395	6%	Include
Steam oil & gas	8,100	4%	Include
Standalone BESS*	316	0.2%	Include
Pumped storage	5,232	3%	Unit Specific
Hydro	3,275	2%	Unit Specific
Other	2,162	1%	Unit Specific

Notes and Sources: ABB, Energy Velocity Suite. Note that percentages are rounded to the nearest integer but actually sum to 100%. *While little standalone BESS exists in PJM today, over 4 GW from the expedited process are expected to come online before the 2030/31 delivery year and more within the subsequent three years these ACRs will be applicable. Therefore, we include avoidable fixed costs for this resource class. See Section III.I for more information.

The remaining resource types, for which avoidable fixed costs were not estimated, represent a small percentage of PJM's capacity. These resource types either have very few plants in their population and/or highly idiosyncratic costs, making them better candidates for unit-specific reviews than an ACR.

¹⁸ 2022 PJM ACR Study.

III. Avoidable Fixed Costs for Existing Resources

A. Multi-Unit Nuclear Plants

Most nuclear plants in PJM have multiple units installed at the same site. In total, there are currently 15 multi-unit nuclear plants operating in the PJM footprint. The capacity of multi-unit nuclear plants in PJM is mostly in the range of 1,750–2,500 MW, and in most cases these plants are 40–60 years old. There are six states in PJM with nuclear plants, with the most located in Illinois and Pennsylvania.¹⁹ Figure 1 below summarizes the age, size, and locations of the multi-unit nuclear fleet.

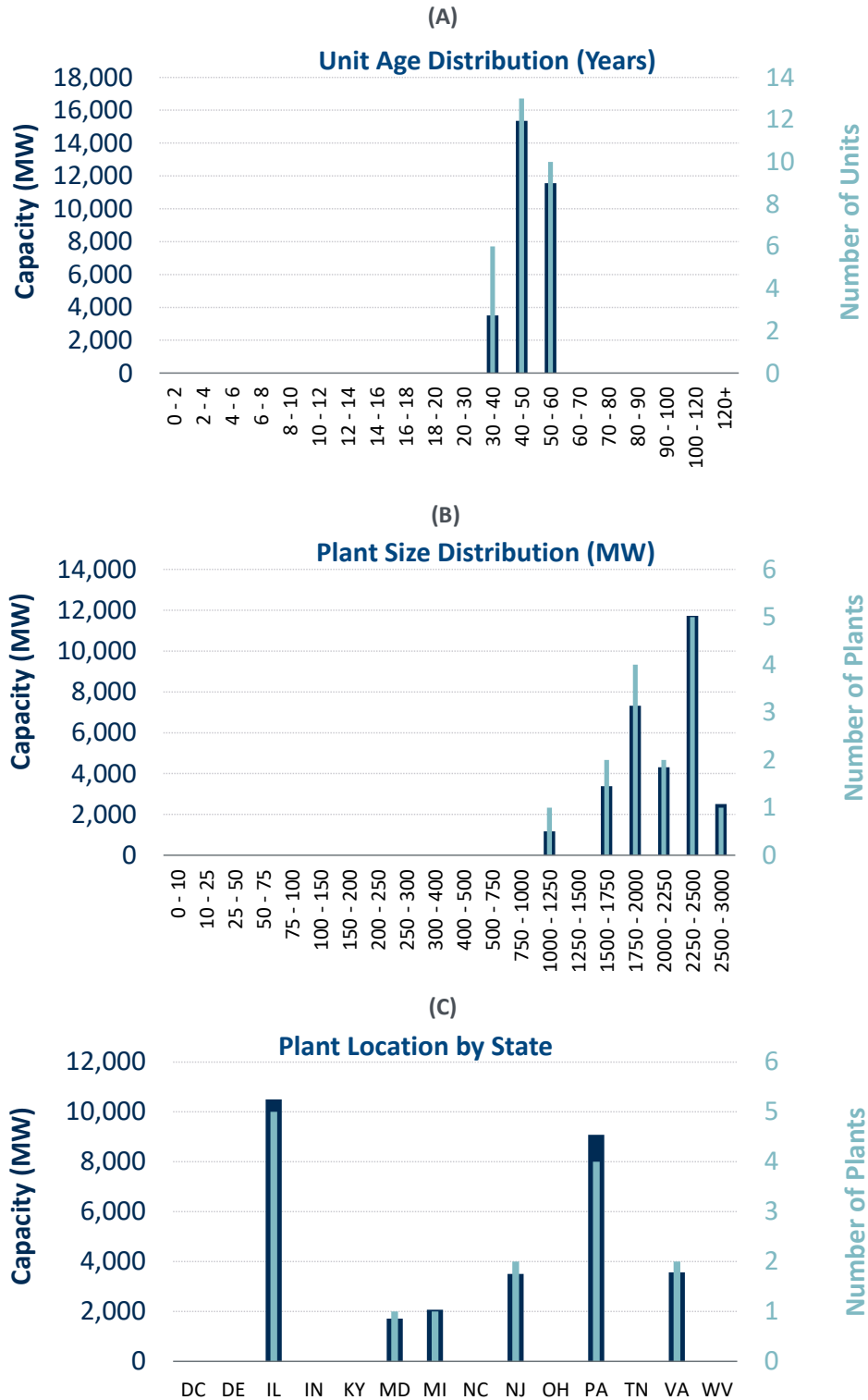
Based on our combined experience, the most significant cost drivers for nuclear plants are the plant size and number of units, reactor type such as the boiling water reactor (BWR) versus the pressurized water reactor (PWR), the location (which affects property taxes and operating costs), the business model (merchant generation vs. regulated cost-of-service generation), the operator's fleet size, and the plant's age.

Representative Multi-Unit Nuclear Plant Characteristics

PJM's multi-unit nuclear fleet has not changed since the 2022 PJM ACR Study. Therefore, we maintained the same assumptions for selecting the representative, low-cost, and high-cost plants, adding four years to the age of each. Based on this approach, the representative multi-unit nuclear plant is a 48-year-old 2,400 MW (comprised of two 1,200 MW units) BWR merchant plant in Illinois with an owner that operates multiple plants. Similarly, the representative low-cost plant is a 51-year-old 2,400 MW (comprised of two 1,200 MW units) PWR plant in Virginia, since PWRs have lower operating costs and Virginia has lower labor costs. For the representative high-cost plant, we assumed a plant identical to the representative plant but with the plant owner only operating a single plant, which would have higher costs due to reduced economies of scale.

¹⁹ The Hope Creek plant in New Jersey is classified as a multi-unit plant because it is co-located with the Salem nuclear plant. Figure 1 shows them as if they were a single 3-unit plant.

FIGURE 1: MULTI-UNIT NUCLEAR FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Multi-Unit Nuclear Plant

Our cost estimates for multi-unit nuclear plants follow the methodology described in our 2022 PJM ACR Study, updated to rely on the 2026 NEI Report. We present nuclear cost components as capital and fixed operating costs, then add property taxes, which the NEI did not estimate.

Capital Costs: Consistent with our 2022 PJM ACR study, we began with published average capital costs for all U.S. nuclear plants from the 2026 NEI Report, including cost sensitivities that helped account for our representative plant characteristics,²⁰ all escalated to 2026 dollars using the Handy Whitman index for nuclear plant equipment.²¹ From this intermediate result, we disaggregated the capital costs to follow PJM's definitions of fixed versus variable costs. We included in fixed costs those capital costs that are part of continuing the life of the plant, and that are incurred consistently by the fleet over time, whereas costs related to incremental electricity production were separated out as variable costs. The resulting contribution of capital costs to the representative multi-unit nuclear plant's avoidable fixed cost is \$75/MW-day.

Fixed Operating Costs: We started with NEI's 2024 average operating costs for all nuclear plants in the U.S., escalated to 2026 dollars using the Handy Whitman index for nuclear plant equipment. We then adjusted this value to account for the representative plant characteristics including its location, boiling water reactor, multiple units, and merchant status within a multiple-plant portfolio of the operator. The components of fixed operating costs reported by NEI primarily reflect labor costs that are not directly attributable to the incremental production of electricity, which are therefore included in avoidable fixed costs. The resulting fixed operating costs total for the multi-unit nuclear representative plant is \$480/MW-day.

Property Taxes: Property taxes were determined using S&L's project database and expertise. We determined the median annual property tax cost for multi-unit nuclear plants on a per MWh basis and scaled this value based on the characteristics of each representative plant. For the representative multi-unit nuclear plant, this is approximately \$25/MW-day.

Capital, operating, and property tax fixed cost components are combined to estimate the total avoidable fixed cost shown in Table 2. The result for the representative multi-unit nuclear plant in PJM is \$580/MW-day (in 2026 dollars). For the representative low-cost plant, estimated avoidable fixed cost is \$514/MW-day, and that for the high-cost plant is \$596/MW-day.

²⁰ NEI tabulated values include cost sensitivities for reactor type, plant size, operator fleet size, and revenue source, each expressed as a deviation from the national average.

²¹ Handy Whitman E1 Electric Utility Construction North Atlantic, Total Nuclear Production Plant.

For context, Table 2 also shows non-fuel variable costs. These include the consumables portion of operating costs and the electricity production-related maintenance portion of ongoing capital expenditures. For the representative multi-unit plant, variable operating costs are \$0.34/MWh, based on the variable component of the adjusted NEI operating-cost data, and the major maintenance adder is \$2.19/MWh, based on the portion of capital expenditure classified under PJM’s variable cost treatment, for a total of \$2.53/MWh.

**TABLE 2: MULTI-UNIT NUCLEAR PLANT AVOIDABLE FIXED AND NON-FUEL VARIABLE COSTS
(2026 DOLLARS)**

		Multi-Unit Nuclear Plant		
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	<i>Nameplate MW</i>	2,400	2,400	2,400
Avoidable Fixed Costs	<i>\$/MW-day</i>	\$514	\$580	\$596
Capital Costs	<i>\$/MW-day</i>	\$77	\$75	\$75
Fixed Operating Costs	<i>\$/MW-day</i>	\$412	\$480	\$496
Property Taxes	<i>\$/MW-day</i>	\$25	\$25	\$25
Non-Fuel Variable Costs	<i>\$/MWh</i>	\$2.49	\$2.53	\$2.54
Operating Costs	<i>\$/MWh</i>	\$0.29	\$0.34	\$0.35
Major Maintenance	<i>\$/MWh</i>	\$2.19	\$2.19	\$2.19

Notes and Sources: avoidable fixed costs are expressed in 2026 dollars per nameplate MW. The major maintenance costs per MWh depend on the capacity factor, which we assumed to be 92% corresponding to the average nuclear capacity factor in 2025.²²

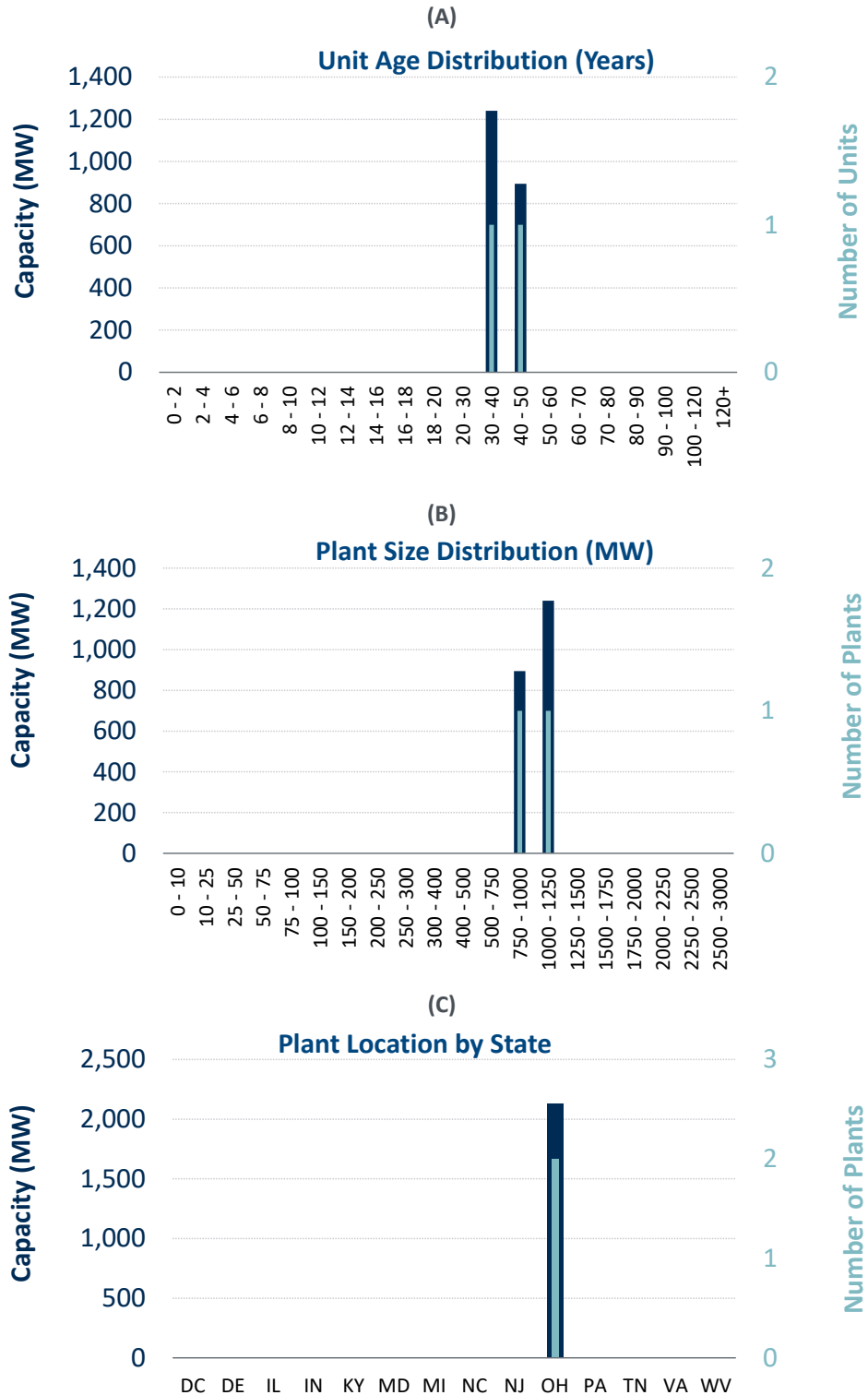
B. Single-Unit Nuclear Plants

There are currently only two single-unit nuclear plants in the PJM market: the 894 MW Davis-Besse plant and the 1,240 MW Perry plant in Ohio.²³ Due to the small number of plants and the limited variation among them, we maintained the representative plant selection from the 2022 PJM ACR Study, adding four years to the age. The representative plant is therefore a 42-year-old, 1,200 MW BWR plant located in Ohio. As in the 2022 PJM ACR Study, due to the small population, we did not designate a representative high or representative low-cost plant. Figure 2 below summarizes the age, size, and locations of the single-unit nuclear fleet.

²² 2026 NEI Report.

²³ See footnote 19, on the treatment of the Hope Creek plant in New Jersey.

FIGURE 2: SINGLE-UNIT NUCLEAR FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Single-Unit Nuclear Plant

Capital Costs: To estimate capital costs for the single-unit nuclear plants, S&L followed the same approach outlined for multi-unit nuclear plants. S&L started with the 2024 average capital costs for all U.S. nuclear plants, escalated to 2026 dollars using the Handy Whitman index for nuclear plant equipment.²⁴ S&L then adjusted this value using NEI's provided sensitivities to account for the characteristics of the representative plant, including its location, boiling water reactor, single-unit, and merchant status within a multiple-plant portfolio of the operator. As with multi-unit nuclear plants, certain components classified by NEI as capital costs are shifted to variable costs using the same approach as for multi-unit nuclear plants. The resulting capital costs for the representative single-unit nuclear plant are \$85/MW-day.

Fixed Operating Costs: To estimate fixed operating costs, S&L used the same method as for multi-unit nuclear, taking the NEI average operating cost for U.S. nuclear plants, escalating it to 2026 dollars, and adjusting it for the representative plant's characteristics. As with the multi-unit nuclear plant, labor and other non-production-related operating costs were included in avoidable fixed costs, while the consumables component was classified as variable. The resulting fixed operating cost for the representative single-unit plant is \$543/MW-day.

Property Taxes: Property tax costs were determined using S&L's project database and expertise and following the same approach as for the multi-unit nuclear plants. S&L determined the median annual property tax cost for single-unit nuclear plants on a per MWh basis and scaled this value based on the characteristics of each representative plant. For the representative single-unit nuclear plant this is approximately \$26/MW-day.

Table 3 below shows the total avoidable fixed cost for a representative single-unit nuclear plant in PJM to be \$654/MW-day (in 2026 dollars). For context, the table also shows non-fuel variable costs. Non-fuel variable costs include the consumables portion of operating costs and the production-related maintenance portion of ongoing capital expenditures. For the representative single-unit plant, variable operating costs are \$0.36/MWh, based on the variable component of the adjusted NEI operating-cost data. The major maintenance adder is \$2.32/MWh, based on the portion of capital expenditures classified under PJM's variable cost treatment. Total non-fuel variable costs for the representative single-unit nuclear plant are therefore \$2.68/MWh.

²⁴ Handy Whitman E1 Electric Utility Construction North Atlantic, Total Nuclear Production Plant.

TABLE 3: SINGLE-UNIT NUCLEAR PLANT AVOIDABLE FIXED AND NON-FUEL VARIABLE COSTS
(2026 DOLLARS)

	Units	Single-Unit Nuclear Plant
Capacity	<i>Nameplate MW</i>	1,200
Avoidable Fixed Costs	<i>\$/MW-day</i>	\$654
Capital Costs	<i>\$/MW-day</i>	\$85
Fixed Operating Costs	<i>\$/MW-day</i>	\$543
Property Taxes	<i>\$/MW-day</i>	\$26
Non-Fuel Variable Costs	<i>\$/MWh</i>	\$2.68
Operating Costs	<i>\$/MWh</i>	\$0.36
Major Maintenance	<i>\$/MWh</i>	\$2.32

Notes and Sources: avoidable fixed costs are expressed in 2026 dollars per nameplate MW. The major maintenance costs per MWh depend on the capacity factor, which we assumed to be 92% corresponding to the average nuclear capacity factor in 2025.²⁵

C. Coal Plants

The fleet of existing coal plants in PJM comprises a wide range of sizes, ages, and locations. There are currently over 110 coal units in the PJM market across 50 different plant sites. Plant capacities range from less than 100 MW to nearly 3,000 MW with an average plant size of 700 MW across all plants and approximately 1,200 MW for plants that are at least 100 MW. Over 65% of the coal capacity is at least 50 years old, with a few plants having come online in the last 15 years. West Virginia has the most installed capacity, followed by Pennsylvania and Ohio. The majority of coal plants have a dry lime or wet limestone flue-gas desulfurization (FGD) unit installed. Figure 3 below summarizes the age, size, locations, and pollution controls of the coal fleet.

Coal plants of similar age tend to have similar plant size, configuration, and technology. The primary drivers of cost variability among plants are age (which typically dictates the capacity, configuration, and technology), followed by the location and the types of post-combustion controls installed at the plant.

²⁵ 2026 NEI Report.

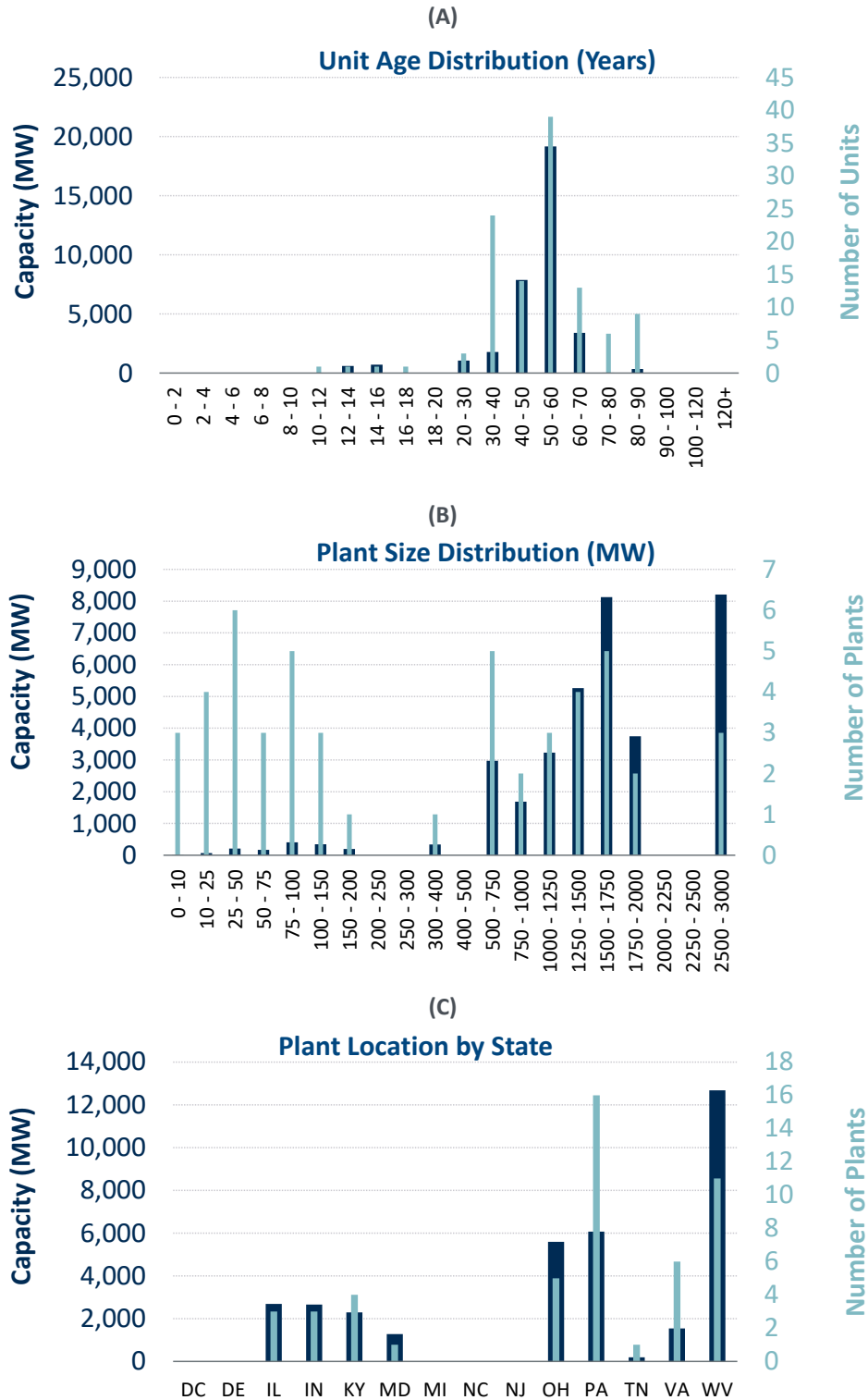
Representative Coal Plant Characteristics

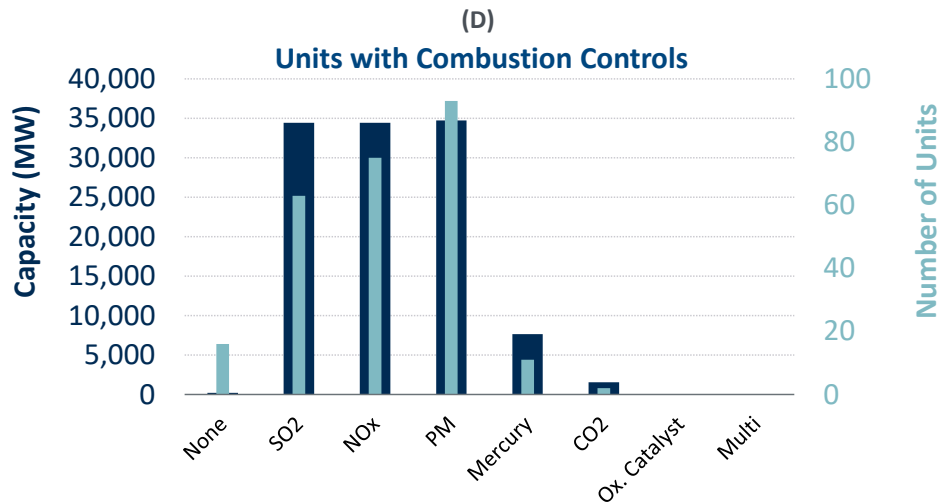
Since the coal fleet has changed substantially since the 2022 PJM ACR Study, we reassessed the representative coal plant as follows. We first filtered for plants in the 1,000-2,000 MW range, where most capacity is concentrated. Then, we assessed the median age of plants in this filtered capacity range, which was approximately 56 years old. Next, we determined the median capacity in the same filtered capacity range, which was approximately 1,500 MW. Finally, we determined that West Virginia was the most common location for coal plants in the 1,000-2,000 MW bucket. Based on this approach, the representative coal plant is a 56-year-old, 1,500 MW plant (with two 750-MW units) in West Virginia. We maintained additional characteristics from the 2022 PJM ACR Report, which assumed the representative plant used Appalachian coal and had a wet limestone flue gas desulfurization (“FGD”) unit for sulfur dioxide control technology.

To identify the representative low-cost plant, we considered larger facilities which would have greater economies of scale and lower per MW costs. We first filtered for plants in the 2,500 to 3,000 MW range, where a significant amount of fleet capacity is concentrated. Next, we determined that the median age of plants in this filtered range was 51 years old. Then, we determined the median capacity of plants in this range to be 2,700 MW. We then observed that the plant that most closely reflected the median characteristics of plants in the filtered range was in Ohio, where the third-most capacity is concentrated across the coal fleet. Based on this approach, the representative low-cost plant is a 51-year-old, 2,700 MW plant (with three 900-MW units) in Ohio, which we assume to have the same fuel and pollution controls as the representative plant.

For the representative high-cost plant, we considered smaller facilities which would have higher per MW costs. We filtered for plants in the 50-150 MW range, where most smaller-scale plant capacity is concentrated. Then, we identified the median age in this filtered group, which was 35 years old. Next, we calculated the median capacity in this range to be 80 MW. We then observed that Pennsylvania was the most common location of coal plants at or near this age and capacity. We assume the representative high-cost plant to have the same fuel and pollution controls as the representative plant. Based on this approach, the representative high-cost plant is a 35-year-old, 80 MW plant (with one 80-MW unit) with FGD in Pennsylvania.

FIGURE 3: COAL FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Coal Plant

Cost estimates for the representative coal plants were developed from recent EIA and FERC Form 1 data by reviewing O&M costs, ongoing capital spending, and cost relationships across coal plant configurations.²⁶ S&L adjusted the reported costs for differences in unit size, number of units, plant age, staffing requirements, FGD reagent and other consumables, and ash and FGD sludge disposal, then validated the results against S&L's proprietary data for similar operating coal plants and escalated values to 2026 dollars using the Handy Whitman index for coal-fired generation.²⁷ The representative high- and low-cost configuration estimates were developed by adjusting the cohort of data in line with the representative plants based on the capacity, location, and age. Variable costs include VOM costs and major maintenance associated with electricity production, which would be accounted for in the maintenance adder based on PJM's Tariff.²⁸

Labor: S&L estimated labor costs using S&L's internal cost database and BLS wage data.²⁹ S&L first estimated the baseline staffing requirements for the representative plant and associated labor economies of scale. Then S&L adjusted for the plant configuration and age based on plant-scale relationships derived from S&L's internal cost database and used BLS data to adjust

²⁶ U.S. Energy Information Administration. 2026. *Form EIA-860: Annual Electric Generator Report (Early Release 2025)*. Washington, DC: U.S. Department of Energy. [Annual Electric Power Industry Report, Form EIA-860 detailed data](#); Federal Energy Regulatory Commission, FERC Form 1, Plant Cost Data, 2010 through 2025.

²⁷ Handy Whitman E1 Electric Utility Construction North Atlantic, Boiler Plant Equipment – Coal Fired.

²⁸ PJM, [Operating Agreement of PJM Interconnection, L.L.C., Schedule 2, Section 4.](#)

²⁹ [Occupational Employment and Wage Statistics \(OEWS\) Tables: U.S. Bureau of Labor Statistics.](#)

wage rates to the representative location. The resulting annual levelized labor cost estimate for the representative coal plant is \$54/MW-day.

Fixed Expenses: Fixed expenses include recurring non-labor operating costs that are not directly attributable to incremental electricity production, including administrative and support services and routine or preventive maintenance for auxiliary equipment. S&L derived the representative value by adjusting observed EIA and FERC Form 1 cost relationships for unit size, number of units, plant age, staffing, and economies of scale, then validated the result against comparable operating coal plants. Normalizing the resulting annual estimate yields \$75/MW-day in fixed expenses for the representative coal plant.

Property Taxes: Property tax rates vary at the municipal and property level and plant economic values are not assessed in a uniform manner. Property taxes, however, comprise a small portion of avoidable fixed costs because coal plants tend to be older facilities that have been fully depreciated. To estimate property taxes for the representative coal plant, S&L surveyed actual property taxes paid by plants that were similar to the representative plant size and applied the median value. This resulted in \$0.02/MW-day of property taxes for the representative coal plant accounting for plant characteristics and depreciation of the taxable value.

Insurance: Insurance costs were estimated using S&L's survey of comparable coal plants and internal project experience, with consideration of plant value, size, location, and technology. The resulting annual insurance estimate for the representative coal plant was \$7/MW-day.

Table 4 below shows that the estimated avoidable fixed cost for the representative coal plant is \$135/MW-day (in 2026 dollars). For the representative low-cost coal plant, estimated avoidable fixed cost is \$101/MW-day, and that for the high-cost coal plant is \$217/MW-day.

For context, Table 4 also shows non-fuel variable costs, including production-related operating costs and maintenance. Production-related operating costs include consumables and production-linked handling or disposal costs, including FGD reagent and ash and FGD sludge disposal. These costs were converted to a \$/MWh basis using the representative plant's assumed capacity factor. The maintenance adder was derived from S&L's analysis of FERC Form 1 data for similar coal plants, including only capital expenditures for systems directly attributable to incremental electricity production. The resulting annual estimates were normalized using a 52% capacity factor for the representative plant, a 49% capacity factor for the low-cost plant, and a 55% capacity factor for the high-cost plant. For the representative

plant, operating costs are \$6.16/MWh, and the maintenance adder is \$6.19/MWh, for total non-fuel variable costs of \$12.35/MWh.

TABLE 4: COAL PLANT AVOIDABLE FIXED AND NON-FUEL VARIABLE COSTS (2026 DOLLARS)

		Coal Plant		
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	<i>Nameplate MW</i>	2700	1500	80
Avoidable Fixed Costs	<i>\$/MW-day</i>	\$101	\$135	\$217
Labor	<i>\$/MW-day</i>	\$41	\$54	\$101
Fixed Expenses	<i>\$/MW-day</i>	\$54	\$75	\$94
Property Taxes	<i>\$/MW-day</i>	\$0	\$0	\$15
Insurance	<i>\$/MW-day</i>	\$6	\$7	\$7
Non-Fuel Variable Costs	<i>\$/MWh</i>	\$10.91	\$12.35	\$13.58
Operating Costs	<i>\$/MWh</i>	\$5.21	\$6.16	\$6.64
Maintenance Adder	<i>\$/MWh</i>	\$5.70	\$6.19	\$6.94

Notes and Sources: avoidable fixed costs are expressed in 2026 dollars per nameplate MW. Fixed Expenses include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, administrative and general, and insurance. Property taxes for the representative plant are non-zero at \$0.02/MW-day. The maintenance adders assume a 52% capacity factor for the representative plant, a 49% capacity factor for the low-cost plant, and 55% for the high-cost plant.

D. Natural Gas-Fired Combined-Cycle Plants

Over 90% of the natural gas-fired combined-cycle (CC) plants in PJM have been built over the past 30 years, with almost 27,000 MW installed in the past 10 years, and most of the rest built in the early 2000s. Plants built in the early 2000s are generally in the 500 MW range; later designs reached the 700-900 MW range. The most recent projects, however, can exceed 1,200 MW, particularly where multiple power blocks are developed at one site. Many of the CCs have been built in regions with access to low-cost gas via pipelines or within gas supply basins, predominantly in Pennsylvania, followed by Ohio, Virginia, and New Jersey. Most CCs are equipped with Selective Catalytic Reduction (SCR) to reduce nitrogen oxide emissions (NO_x). Figure 4 below summarizes the age, size, locations, and pollution controls of the CC fleet.

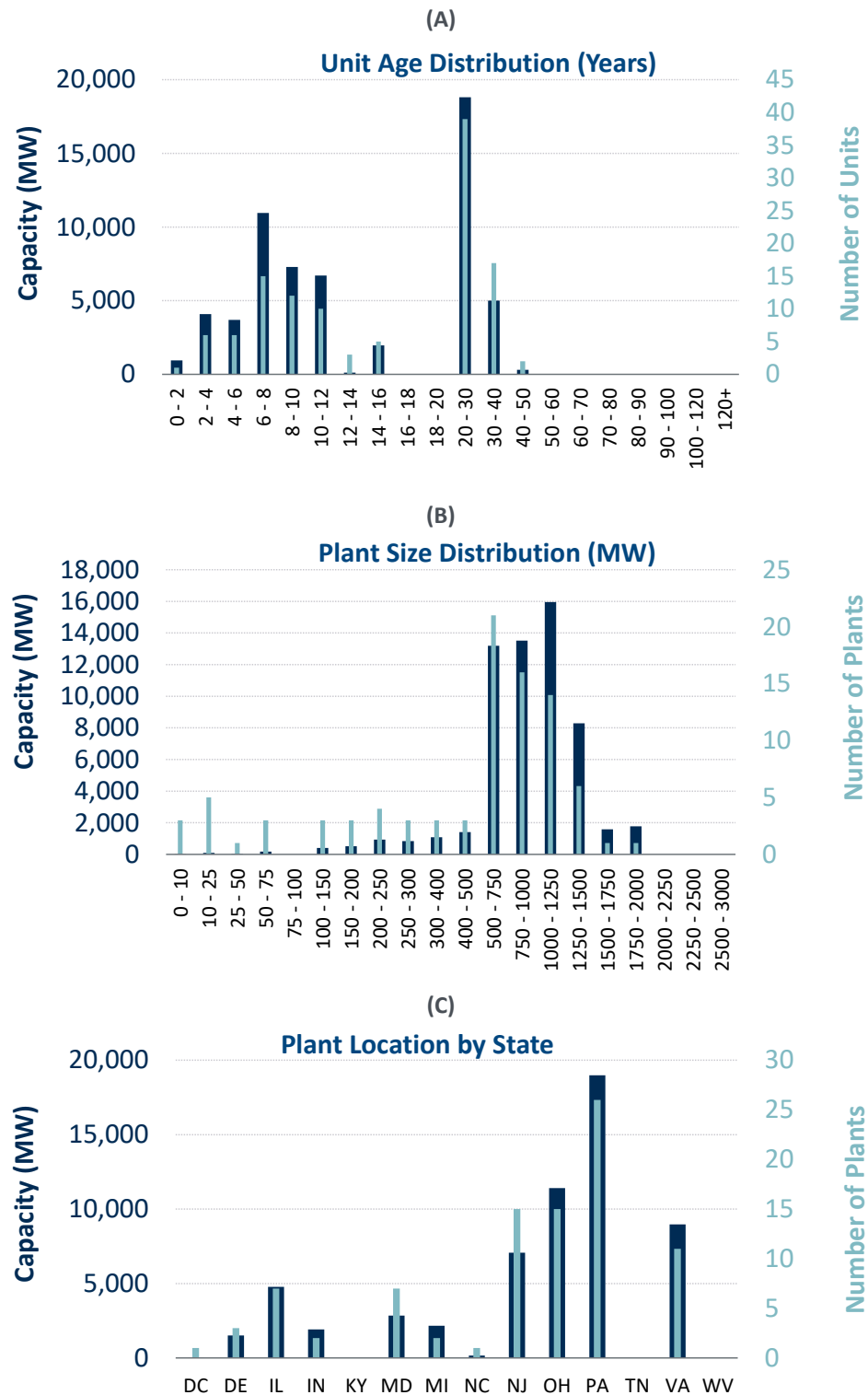
The main cost drivers among CCs are the capacity, age, turbine type, plant configuration, and whether a plant has firm gas transportation service. Location is a secondary driver through its effects on the costs of labor, property taxes, and firm fuel.

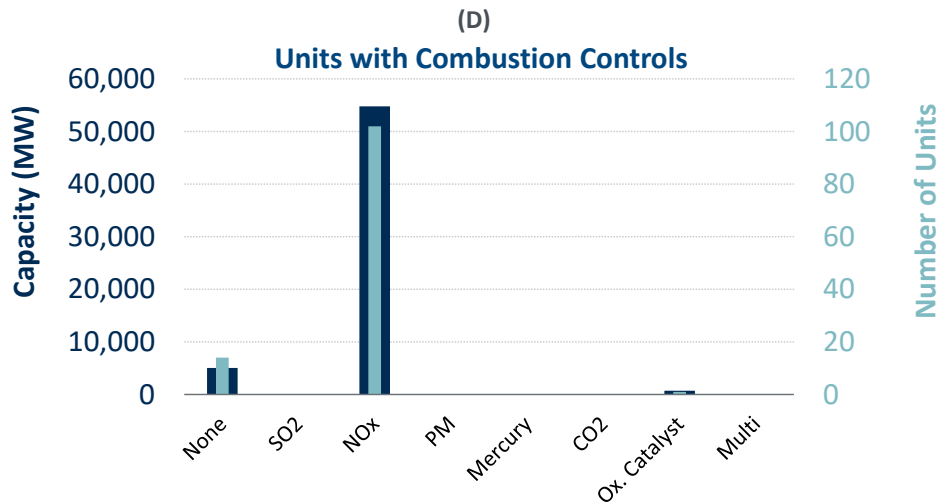
Determination of Representative Natural Gas-Fired Combined-Cycle Plant Characteristics

Because significant new capacity has been added to the natural gas CC fleet in the past four years, we reassessed the representative plant as follows. First, we determined the median plant size of the CC fleet, which was 669 MW, consistent with the 2022 PJM ACR Study. We then filtered the CC fleet data for plants between 600-750 MW and compared the median age of the filtered population to that of the total fleet. Finding that both figures were well aligned, we concluded the representative plant age to be 11 years old. We then compared the plant configuration, location and the installed pollution controls in the filtered population to determine that most plants are in a 2×1 configuration, nearly all plants have SCR installed, and most are in Pennsylvania. 11 years ago, F-class turbines were the predominant turbine technology, which had standardized sizes when employed in a 2×1 configuration. We adjusted the reference plant capacity from the median of 669 MW to 750 MW to account for this standardization. We relied on data from PJM indicating that most existing CC plants have firm gas transportation contracts up to their economic maximum (EcoMax), and therefore the representative plant would be subject to this cost. Based on this approach, the representative gas CC plant is an 11-year-old 750 MW plant (with two F-class gas turbines and one steam turbine in a 2×1 configuration) in Pennsylvania that has SCR technology installed and has firm gas transportation service. This is the same representative plant used in the 2022 PJM ACR Study, which indicates that while the fleet has changed, the median characteristics have not changed much in the CC fleet in the past four years.

Since the representative plant did not change from the 2022 PJM ACR Study, we maintained the same assumptions for the representative low- and high-cost plants, adding four years to the age of each. Therefore, the representative low-cost plant is a 9-year-old, 1,100 MW plant (with two 550 MW H-class turbines in a 2×1 configuration) in Pennsylvania. The representative high-cost plant is a 34-year-old, 400 MW plant (with one 400 MW F-class turbine in a 1×1 configuration) in New Jersey. Both the low- and high-cost plants are also assumed to have SCR technology installed and firm gas transportation service.

FIGURE 4: NATURAL GAS-FIRED COMBINED-CYCLE FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Natural Gas-Fired Combined-Cycle Plant

Avoidable fixed costs represent the avoidable costs of maintaining and operating an existing natural gas combined-cycle plant that are not directly attributable to incremental electricity production. For the representative plants, these costs include labor, fixed operating expenses, firm gas transportation service, property taxes, and insurance. Fixed operating expenses include recurring support and administrative activities and preventive maintenance for auxiliary equipment such as buildings, HVAC, water treatment, and freeze protection. The estimates were developed using the methodology applied in the 2025 PJM CONE Study, supplemented with bottom-up estimates from S&L's internal database of recent Long-Term Service Agreement (LTSA) and consumables pricing, public sources, FERC Form 1 data, and regression analyses of technically similar plants.³⁰ Costs directly attributable to incremental electricity production, including chemicals and consumables and major maintenance under LTSAs, are classified as non-fuel variable costs.

Labor: S&L estimated labor costs using S&L's internal cost database and BLS wage data.³¹ S&L first estimated the baseline staffing requirements for the representative plant and associated labor economies of scale. Then S&L adjusted for the plant configuration and age based on plant-scale relationships derived from S&L's internal cost database and used BLS data to adjust wage rates to the representative location. The resulting annual labor estimate for the representative combined-cycle plant is \$26/MW-day.

³⁰ Newell et al., "Brattle 2025 CONE Report for PJM," The Brattle Group, April 9, 2025 ("2025 PJM CONE Study").

³¹ See FN 29; [Occupational Employment and Wage Statistics \(OEWS\) Tables: U.S. Bureau of Labor Statistics](#).

Fixed Expenses: Fixed expenses include recurring operating costs such as preventive maintenance on auxiliary equipment, information technology, miscellaneous supplies, support services, and administrative and general expenses. S&L derived the representative value using cost information from the 2025 PJM CONE Study, other public sources, and S&L's project database, then adjusted for turbine size, configuration, location, age, staffing requirements, and economies of scale, and validated against comparable operating plants. The resulting annual estimate of fixed expenses for the representative CC plant is \$37/MW-day.

In addition to these fixed expenses, firm gas transportation costs were estimated by Brattle using an updated average tariff rate of \$7.50/Dth per month based on the FT-1 rate schedules for major pipelines servicing Pennsylvania.³² Brattle calculated the average heat rate for all natural gas-fired combined-cycle plants in the PJM fleet to be 7,215 Btu/kWh.³³ We then multiplied the plant capacity for the representative plant by the heat rate to estimate the maximum daily gas requirement and multiplied this by the monthly average tariff rate with unit conversions to result in an annual firm gas transportation cost. This resulted in an annual firm gas cost of \$43/MW-day. Combined, we estimate \$79/MW-day in fixed expenses for the representative combined-cycle plant.

Property Taxes: Property taxes were estimated using the values from the 2025 PJM CONE Study with downward adjustments made for the older, less valuable plant. This resulted in \$7/MW-day for property taxes.

Insurance: Insurance costs were estimated using representative plant costs from S&L's internal database. These costs were scaled to the representative plant configurations on a per-MW basis as insurance costs typically vary with capital costs and plant capacity. The annual estimates reflect the value and characteristics of each representative plant and were normalized by nameplate capacity. For the representative plant, the resulting insurance cost is \$21/MW-day.

³² The tariff rate used in calculation of firm gas costs was the average of TETCO M3 rate and Transco Zone 6 rate. See Texas Eastern Transmission FERC Gas Tariff, M3-M3 effective February 1, 2026, and Transcontinental Gas Pipeline Company FERC Gas Tariff, Delivery Zone 6 and Receipt Zone 6 effective April 1, 2026.

³³ Based on average full load heat rates with data from ABB, Energy Velocity Suite. Many combined-cycle plants employ duct firing to produce higher-pressure steam to increase plant capacity when operating in high ambient temperatures. However, the use of duct firing in CCs causes the efficiency to drop significantly and plants are not designed to be operated constantly with duct firing throughout a year; therefore, we calculate the annual gas requirement using the average full load heat rate without duct-firing.

Table 5 below shows that the estimated avoidable fixed cost for the representative plant is \$133/MW-day (in 2026 dollars). The estimated avoidable fixed cost for the representative low-cost plant is \$120/MW-day, and that for the representative high-cost plant is \$150/MW-day.

For context, Table 5 also shows non-fuel variable costs, including production-related operating costs and a maintenance adder. Operating costs were estimated on a bottom-up basis using recent pricing for chemicals and consumables for similar combined-cycle units, including water supply, ammonia and SCR-related costs, catalyst replacement and disposal, water discharge, water treatment, and other operating consumables from S&L's project database. For the representative plant, the variable operating costs were estimated at \$0.88/MWh. The maintenance adder reflects hours-based major maintenance costs specified in LTSAs for servicing the gas turbines, steam turbine, generators, and heat-recovery steam generators, based on S&L's internal database of recent quotes. For the representative plant, the maintenance adder is \$2.68/MWh. Total non-fuel variable costs are therefore \$3.56/MWh for the representative plant.

**TABLE 5: NATURAL GAS-FIRED CC PLANT AVOIDABLE FIXED AND NON-FUEL VARIABLE COSTS
(2026 DOLLARS)**

Natural Gas-Fired Combined-Cycle Plant				
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	<i>Nameplate MW</i>	1100	750	400
Avoidable Fixed Costs	<i>\$/MW-day</i>	\$120	\$133	\$150
Labor	<i>\$/MW-day</i>	\$21	\$26	\$38
Fixed Expenses	<i>\$/MW-day</i>	\$70	\$79	\$89
Property Taxes	<i>\$/MW-day</i>	\$8	\$7	\$3
Insurance	<i>\$/MW-day</i>	\$21	\$21	\$21
Non-Fuel Variable Costs	<i>\$/MWh</i>	\$3.39	\$3.56	\$4.92
Operating Costs	<i>\$/MWh</i>	\$0.77	\$0.88	\$1.03
Maintenance Adder	<i>\$/MWh</i>	\$2.61	\$2.68	\$3.89

Notes and Sources: avoidable fixed costs are expressed in 2026 dollars per nameplate MW. Fixed Expenses include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, administrative and general, and firm gas transportation service. The estimated maintenance adder costs per MWh are variable based on the capacity factor. The maintenance adders assume a 55% capacity factor for all three representative plants.

E. Simple-Cycle Combustion Turbines

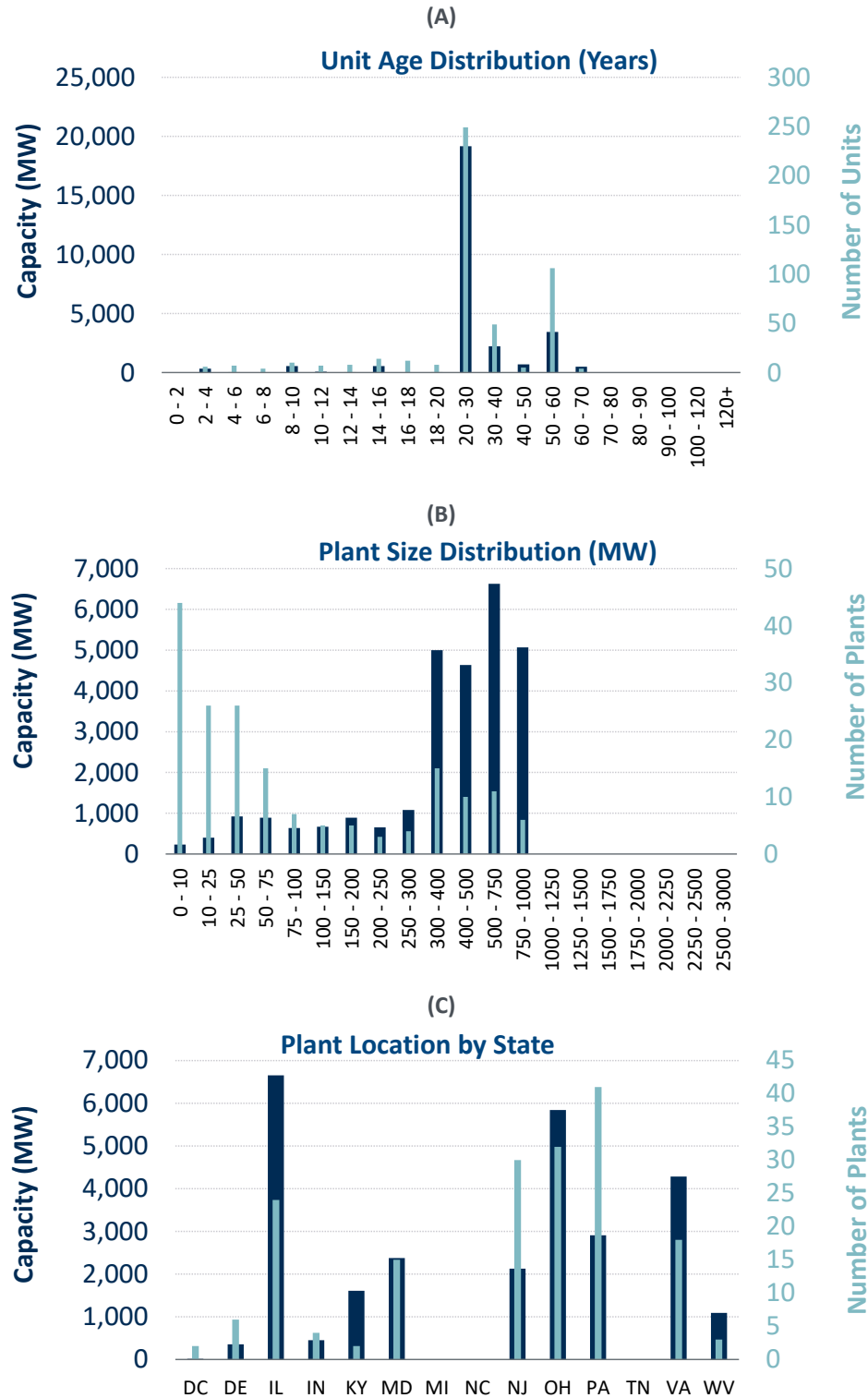
Simple-cycle combustion turbine (CT) plants include oil- and gas-fired CTs. Nearly all CTs were built around the early 2000s, but there is a wide capacity range due to differences in turbine technology and configurations. There are many CT plants in the PJM fleet under 100 MW, but these plants cumulatively do not have a lot of capacity compared to plants 300 MW and above. The states with the most capacity include Illinois, Ohio, and Virginia. Unlike CCs, most CTs are not built with an SCR unit, nor do they have firm gas transportation contracts according to PJM. Figure 5 below summarizes the age, size, locations, and pollution controls of the simple-cycle combustion turbine fleet. The primary cost drivers for CTs are capacity, age, turbine type and configuration, and location.

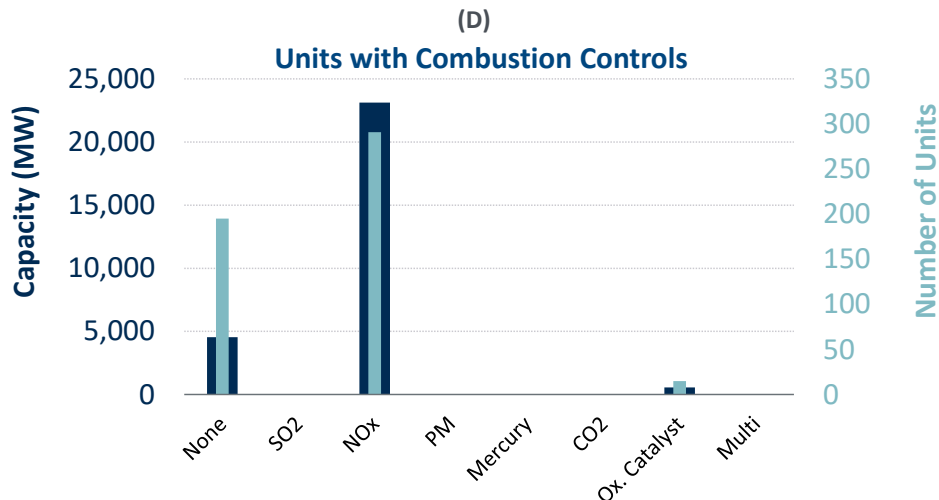
Determination of Representative Simple-Cycle Combustion Turbine Plant Characteristics

To determine the representative plant, we filtered for plants 100 MW and above, then took the median capacity of this filtered population, and found that the median capacity fell in the 300-450 MW range. We then found the median age and location of plants in this range. Based on this approach, the representative CT plant is a 24-year-old, 320 MW plant (with two 160-MW F-class turbines) in Illinois with no firm gas service. This is the same representative plant as in the 2022 PJM ACR Study, with the age increased by four years, indicating that the median characteristics of the fleet have not changed significantly since 2022.

Since the representative plant did not change from the 2022 PJM ACR Study, we maintained the same assumptions for the representative low- and high-cost plants, adding four years to the age of each. Therefore, the representative low-cost plant is a 24-year-old, 640 MW plant (with eight 80 MW E-class turbines) in Illinois with no SCR controls, and the high-cost plant is a 24-year-old, 100 MW plant (with two 50 MW LM6000 units) in Pennsylvania with no SCR controls. Neither the low- nor high-cost plants are assumed to have firm gas transportation contracts.

FIGURE 5: SIMPLE-CYCLE COMBUSTION TURBINE FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for Representative Simple-Cycle Combustion Turbine Plants

Avoidable fixed costs represent the avoidable costs of maintaining and operating an existing simple-cycle combustion turbine plant that are not directly attributable to incremental electricity production. For the representative plants, these costs include labor, fixed operating expenses, property taxes, and insurance. Fixed operating expenses include recurring support and administrative activities and preventive maintenance for auxiliary equipment such as buildings, HVAC, water treatment, and freeze protection. The estimates were developed using cost information from the 2025 PJM CONE Study, EIA and FERC data, and S&L's project database, with adjustments for turbine size, configuration, location, age, staffing requirements, and the economies of scale associated with larger turbine sizes and multiple turbines at a site. Costs directly attributable to incremental production are classified as non-fuel variable costs.

Labor: As with the other technologies, S&L estimated labor costs by applying staffing requirements and plant-scale relationships to the representative combustion turbine plant.³⁴ The estimate reflects the staffing requirements and economies of scale associated with the representative plant's configuration and was validated against S&L's project database for similar plants in operation. The resulting annual labor estimate is \$17/MW-day for the representative combustion turbine plant.

³⁴ See FN 29. The baseline staffing requirements and labor rates were developed using S&L's internal reference databases. We then utilized BLS data to inform and validate the locational adjustments specific to the state in each case.

Fixed Expenses: Fixed expenses include recurring non-labor operating costs that are not directly attributable to incremental electricity production, including preventive maintenance on auxiliary equipment, information technology, miscellaneous supplies, support services, and administrative and general expenses. S&L derived the representative value from the 2025 PJM CONE Study, EIA and FERC data, and S&L's project database, adjusting the observed cost relationships for turbine size, configuration, location, age, staffing requirements, and economies of scale, and validating the result against comparable operating plants. The resulting annual estimate for fixed expenses is \$16/MW-day for the representative combustion turbine plant.

Property Taxes: Property taxes were estimated from the most similar projects to the representative plants available in S&L's project database. S&L applied regression-based adjustments for the size, technology type, and age of the representative plants to estimate property taxes accounting for depreciation. The resulting annual estimate for property taxes is \$16/MW-day for the representative combustion turbine plant.

Insurance: Insurance costs were estimated using the most representative references available in S&L's project database. S&L applied regression-based adjustments for the size, technology type, and age of the representative plants to estimate insurance cost. The resulting annual estimate for insurance is \$15/MW-day for the representative combustion turbine plant.

Table 6 below shows the resulting avoidable fixed costs for simple-cycle CT plants. The estimated avoidable fixed cost of the representative CT is \$64/MW-day (in 2026 dollars). For the representative low-cost plant, the estimated avoidable fixed cost is \$53/MW-day, and that for the high-cost plant is \$98/MW-day.

For context, Table 6 also shows non-fuel variable costs, including production-related operating costs and the maintenance adder. Operating costs were estimated from the EIA, FERC, 2025 PJM CONE Study, and S&L project database cost information for similar combustion turbines, then converted to a \$/MWh basis using the assumed capacity factor. For the representative plant, S&L estimated operating costs to be \$0.81/MWh. S&L estimated the variable cost maintenance adder assuming a 10% capacity factor, equivalent to 73 starts per year at approximately 12 hours of operation per start. For the E- and F-class turbine representative plants that operate as peaking units, major maintenance costs are expected to be driven

primarily by the number of starts.³⁵ For the representative combustion turbine plant, the maintenance adder is \$5.03/MWh.

TABLE 6: SIMPLE-CYCLE CT PLANT AVOIDABLE FIXED AND NON-FUEL VARIABLE COSTS (2026 DOLLARS)

Simple-Cycle Combustion Turbine Plant				
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	<i>Nameplate MW</i>	640	320	100
Avoidable Fixed Costs	<i>\$/MW-day</i>	\$53	\$64	\$98
Labor	<i>\$/MW-day</i>	\$12	\$17	\$27
Fixed Expenses	<i>\$/MW-day</i>	\$14	\$16	\$34
Property Taxes	<i>\$/MW-day</i>	\$15	\$16	\$17
Insurance	<i>\$/MW-day</i>	\$12	\$15	\$19
Non-Fuel Variable Costs	<i>\$/MWh</i>	\$6.44	\$5.84	\$7.51
Operating Costs	<i>\$/MWh</i>	\$0.72	\$0.81	\$0.84
Maintenance Adder	<i>\$/MWh</i>	\$5.73	\$5.03	\$6.67

Notes and Sources: avoidable fixed costs are expressed in 2026 dollars per nameplate MW. Fixed expenses included in avoidable fixed costs include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, and administrative and general expenses. The maintenance adder assumes a 10% capacity factor with 12 hours per start for all three representative plant configurations. For the low-cost and representative plants, the major maintenance adder is assessed based on the number of starts. For the high-cost plant with LM6000 aeroderivative units, major maintenance is assumed to be driven primarily by hours of operation. Actual major maintenance costs will not vary strictly with MWh as expressed in this table and will depend on actual duty cycles and maintenance agreement terms.

F. Oil- and Gas-Fired Steam Turbines

Oil- and gas-fired steam turbine (ST O&G) plants have a wide range of sizes. The majority of ST O&G plants are less than 25 MW, but most capacity is contained in plants 250 MW and above. The average size is about 250 MW, which is skewed by a couple of very large plants on the order of 1,500 to 1,750 MW. Most of the larger plants and thus most of the capacity is located in Pennsylvania. Smaller plants are in Ohio, Maryland, New Jersey, Virginia, and Indiana. Ages of ST O&G plants range from 6 to 88 years old, with most capacity from plants that are 50–60 years old. Figure 6 below summarizes the age, size, locations, and pollution controls of the ST

³⁵ However, the LM6000 aeroderivative units for the high-cost plant would trigger major maintenance based on hours of operation.

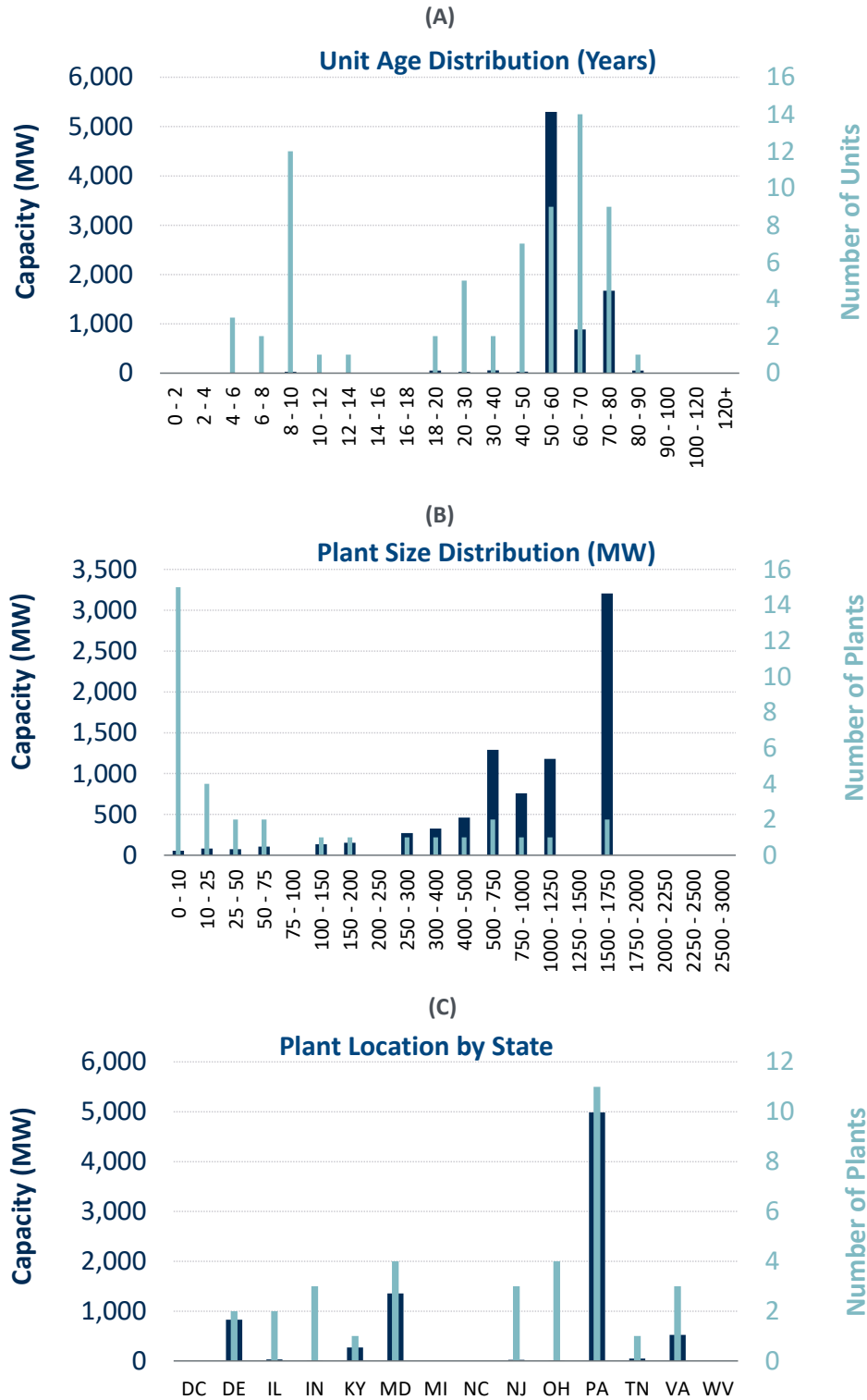
O&G fleet. The primary drivers of cost for ST O&G plants are age, capacity, location, and plant configuration.

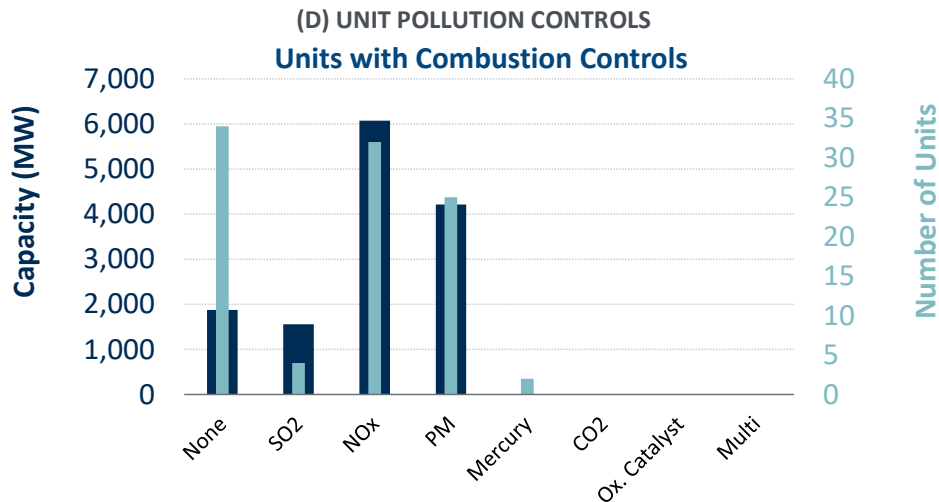
Determination of Representative Oil- and Gas-Fired Steam Turbine Plant Characteristics

Since the ST O&G fleet has changed substantially from 2022 with around 1 GW of retirements, we reassessed the representative plant as follows. First, we filtered the fleet for plants in the 50-60 year age range, where the majority of capacity is concentrated. Next, we assessed the median age and capacity of plants in this age bucket and found them to be 51 years old and approximately 1,200 MW, respectively. We observed that the most common location in the 50-60 year old age group was Pennsylvania. Finally, based on input from PJM, we determined that the majority of existing ST O&G plants do not have firm gas transportation contracts. Based on this approach, the representative plant is a 51-year-old, 1,200 MW plant in Pennsylvania without firm gas service.

Since the majority of both ST O&G plants and capacity are in Pennsylvania, we did not vary the location for the representative low- and high-cost plants. For the high-cost plant, to reflect the many small plants in the fleet, we filtered for plants in Pennsylvania greater than 50 MW and less than 900 MW and chose an approximate median of 350 MW to be the representative high-cost plant size. We observed one plant in Pennsylvania with this approximate capacity, which is 73 years old, falling in the age group with the second most capacity of 70-80 years old. Based on this approach, the representative high-cost ST O&G plant is a 73-year-old, 350 MW plant in Pennsylvania. To identify a representative low-cost plant, we began by selecting a larger plant to reflect economies of scale and filtered for plants in the 1,500 to 1,750 MW range. There were two plants in this range, both located in Pennsylvania. We chose to adopt the characteristics of the larger, younger plant as the representative low-cost plant. Based on this approach, the representative low-cost ST O&G plant is a 50-year old, 1,700 MW plant in Pennsylvania. Neither the low- nor high-cost plants are assumed to have firm gas transportation service.

FIGURE 6: OIL- AND GAS-FIRED STEAM TURBINE FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for Representative Oil- and Gas-Fired Steam Turbine Plant

Cost estimates for ST O&G plants were developed primarily from public FERC Form 1 cost information and S&L's project database, with regression-based adjustments for plant size, location, and age, and validated against proprietary data for similar plants in operation. Costs directly attributable to incremental production are classified as non-fuel variable costs.

Labor: As with the other technologies, S&L estimated labor costs by applying staffing requirements and plant-scale relationships to the representative ST O&G plant.³⁶ The estimate reflects the staffing requirements and economies of scale associated with the representative plant's configuration and was validated against S&L's project database for similar plants in operation. The resulting annual labor estimate is \$27/MW-day for the representative plant.

Fixed Expenses: Fixed expenses include recurring non-labor operating costs that are not directly attributable to incremental electricity production. S&L derived the representative value from FERC Form 1 data and S&L's project database, using regression-based adjustments for plant size, location, and age and validating the result against comparable operating plants. The resulting fixed expenses estimate is \$41/MW-day for the representative ST O&G plant.

³⁶ See FN 29. The baseline staffing requirements and labor rates were developed using S&L's internal reference databases. We then utilized BLS data to inform and validate the locational adjustments specific to the state in each case.

Property Taxes: For property taxes, S&L used the same survey approach as for the coal plant, based on actual ST O&G plants in PJM. The resulting property tax estimate is \$1/MW-day for the representative ST O&G plant.

Insurance: Insurance costs were estimated using the same survey approach as for the coal plant (but for actual ST O&G plants in PJM) since insurance costs depend on plant value but are generally not publicly available. The resulting insurance estimate is \$3/MW-day for the representative ST O&G plant.

Table 7 below shows that the estimated total avoidable fixed cost for the representative plant is \$72/MW-day (in 2026 dollars). For the representative low-cost ST O&G plant, the estimated avoidable fixed cost is \$62/MW-day, and that for the smaller representative high-cost plant is significantly higher, at \$121/MW-day, due to the reduced economies of scale.

For context, Table 7 also shows variable costs. Variable operating costs were derived from the non-fuel operating expenses including water, chemicals, consumables, and operations-based variable maintenance activities for comparable oil- and gas-fired steam turbine plants from S&L's project database, all converted to a \$/MWh basis using the representative plant's capacity factor. For the representative plant, operating costs are \$1.58/MWh. The maintenance adder reflects maintenance and capital expenditures for systems directly attributable to incremental electricity production. For the representative plant, the maintenance adder is \$6.19/MWh. Total non-fuel variable costs are therefore \$7.78/MWh.

TABLE 7: ST O&G PLANT AVOIDABLE FIXED AND NON-FUEL VARIABLE COSTS (2026 DOLLARS)

		Oil- and Gas-fired Steam Turbine Plant		
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	<i>Nameplate MW</i>	1700	1200	350
Avoidable Fixed Costs	<i>\$/MW-day</i>	\$62	\$72	\$121
Labor	<i>\$/MW-day</i>	\$25	\$27	\$49
Fixed Expenses	<i>\$/MW-day</i>	\$33	\$41	\$65
Property Taxes	<i>\$/MW-day</i>	\$1	\$1	\$2
Insurance	<i>\$/MW-day</i>	\$2	\$3	\$5
Non-Fuel Variable Costs	<i>\$/MWh</i>	\$7.25	\$7.78	\$9.90
Operating Costs	<i>\$/MWh</i>	\$1.48	\$1.58	\$2.03
Maintenance Adder	<i>\$/MWh</i>	\$5.78	\$6.19	\$7.87

Notes and Sources: avoidable fixed costs are expressed in 2026 dollars per nameplate MW. Fixed Expenses include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.),

information technology, miscellaneous supplies, support services, administrative and general expenses. The estimated maintenance adder costs per MWh are variable based on the capacity factor. The maintenance adder for the representative plant assumes a 17% capacity factor, for the low-cost plant an 18% capacity factor, and for the high-cost plant a 16% capacity factor.

G. Onshore Wind Plants

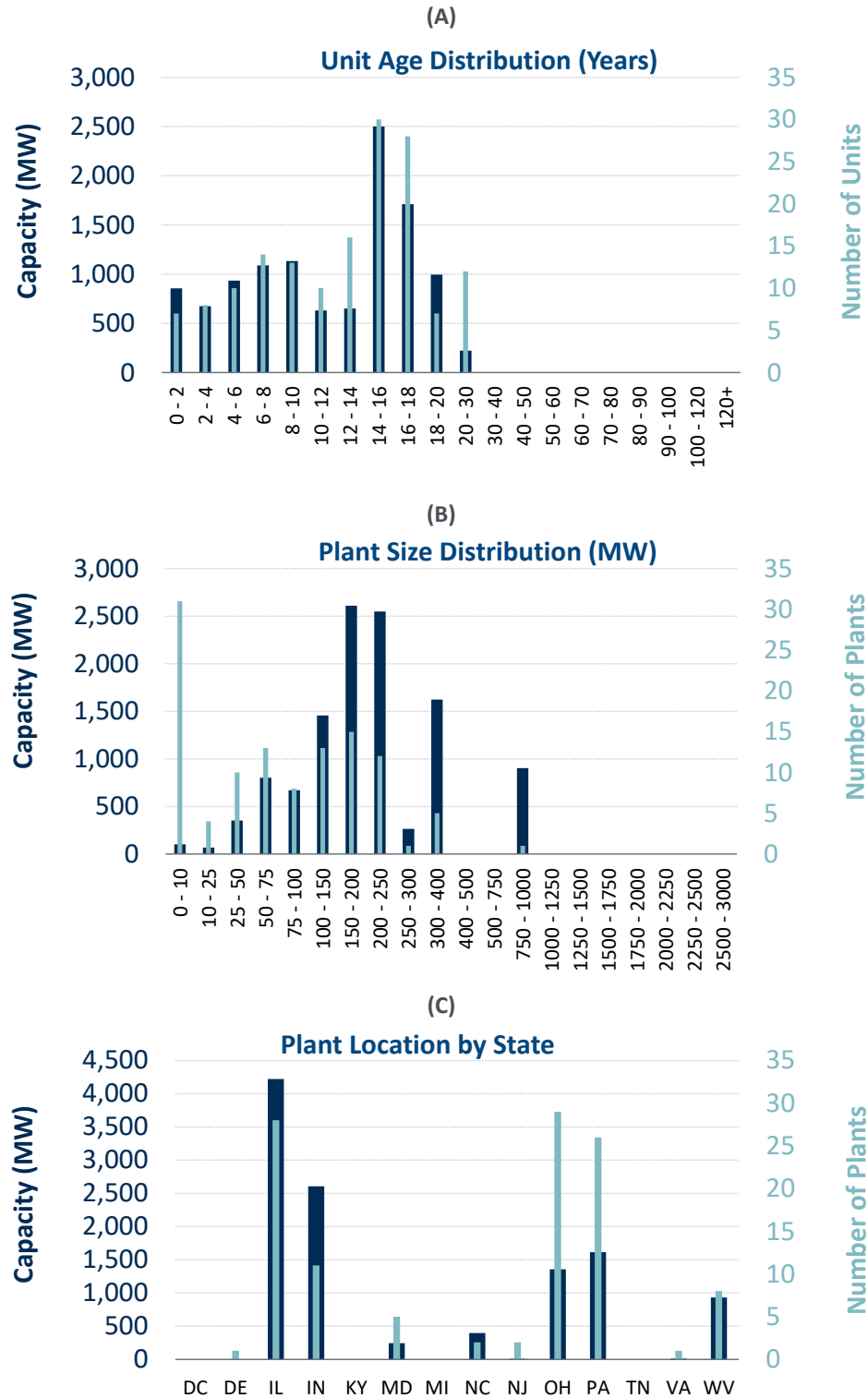
Over the past 20 years, over 11 GW of onshore wind plants have been built in PJM. The average size is 100 MW, which is skewed by numerous small plants (less than 25 MW); however, 19 plants are 200 MW or greater as shown in Figure 7, Panel B below. Plants larger than 100 MW make up over 80% of the total capacity in PJM, and most are located in Illinois and Indiana, while smaller plants are located in Pennsylvania and Ohio. Wind plants range from less than a year old to 24 years old. Figure 7 below summarizes the age, size, and locations of the onshore wind fleet. The primary cost drivers for wind plants are the size and location, then the age and density of individual wind turbines at a plant site.

Determination of Representative Onshore Wind Plant Characteristics

To determine the representative onshore wind plant, we filtered the wind fleet for plants 100 MW or larger (since these plants contribute to more than 80% of the total capacity) between 14 and 18 years old (the age range with the most capacity) and determined the median plant size of this filtered population, which was approximately 200 MW. We then found the median age of this filtered fleet, which was 16 years old and then reviewed the most frequent location, which was Illinois. Based on this approach, the representative onshore wind plant is a 16-year-old, 200 MW plant in Illinois. This is the same representative plant as in the 2022 ACR Study, but four years older, indicating that the median characteristics have not changed substantially.

We accounted for the size and age variation of the fleet when determining the representative low- and high-cost plant. For the representative high-cost plant, we filtered the wind fleet for plants less than 150 MW and determined a median size of approximately 30 MW. We then found the median age of this filtered fleet, which was similar to the age for the representative plant. The most frequent location of these smaller plants was Pennsylvania. Based on this approach, the representative high-cost plant is a 16-year-old 30 MW plant in Pennsylvania. For the representative low-cost plant, we filtered for plants 250 MW and larger and found the median capacity to be 300 MW, equivalent to our findings in the 2022 PJM ACR Report. We further determined that the median age and most common location had not diverged from the 2022 PJM ACR Report, so we maintained the same plant, adding four years to the age. Therefore, the representative low-cost plant is a 14-year-old 300 MW plant in Illinois.

FIGURE 7: ONSHORE WIND PLANT FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for Representative Onshore Wind Plants

Fixed costs for onshore wind plants include labor, fixed operating expenses, property taxes, and insurance. S&L estimated fixed costs for the representative wind plants by reviewing recent public sources (BLS Occupational Employment and Wage Statistics, and Lawrence Berkeley National Laboratory's Wind Technologies Market Report) and validating against S&L's project database.³⁷ Adjustments for the representative low- and high-cost plant scenarios were based on variations in plant capacity and local cost indices.

Labor: As with the other technologies, S&L estimated labor costs by applying staffing requirements and plant-scale relationships to the representative wind plant.³⁸ The estimate reflects the staffing requirements and economies of scale associated with the representative plant's configuration and was validated against S&L's project database for similar plants in operation. The resulting labor estimate is \$36/MW-day for the representative wind plant.

Fixed Expenses: S&L estimated fixed expenses based on historical operation and maintenance data from recent public sources (Lawrence Berkeley National Laboratory's Wind Technologies Market Report) and S&L's project database, adjusting for plant size and regional factors. The total fixed expense estimate was scaled and converted based on the representative plant characteristics. The resulting fixed expenses estimate is \$131/MW-day for the representative wind plant.

Property Taxes: Property taxes were modeled as a fixed fraction of annual fixed O&M based on S&L project data, then normalized and converted based on the characteristics of the representative plant.³⁹ The resulting property taxes estimate is \$13/MW-day for the representative wind plant.

Insurance: Insurance was estimated as a fixed fraction of annual fixed O&M based on S&L's project database for similar plants, then normalized and converted in the same way as property taxes. The resulting insurance estimate is \$9/MW-day for the representative wind plant.

³⁷ Barbose et al., "Land-Based Wind Energy Technology Update: 2026 Edition," Lawrence Berkeley National Laboratory, August 2026.

³⁸ See FN 29. The baseline staffing requirements and labor rates were developed using S&L's internal reference databases. We then utilized BLS data to inform and validate the locational adjustments specific to the state in each case.

³⁹ Normalization refers to regressing costs based on capacity, and conversion is translating units into \$/MW-day.

Table 8 below shows the resulting avoidable fixed costs for the representative plant of \$190/MW-day (in 2026 dollars). The representative low-cost plant's estimated avoidable fixed costs are \$159/MW-day and the representative high-cost plant's avoidable fixed costs are \$258/MW-day. For context, the table also shows variable costs. Variable costs are minimal and are estimated at \$0/MWh based on the standard operation of wind facilities where maintenance and operational expenses are treated as fixed annual costs.

TABLE 8: ONSHORE WIND PLANT AVOIDABLE FIXED AND NON-FUEL VARIABLE COSTS (2026 DOLLARS)

Onshore Wind Plant				
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	<i>Nameplate MW</i>	300	200	30
Avoidable Fixed Costs	<i>\$/MW-day</i>	\$159	\$190	\$258
Labor	<i>\$/MW-day</i>	\$30	\$36	\$62
Fixed Expenses	<i>\$/MW-day</i>	\$108	\$131	\$166
Property Taxes	<i>\$/MW-day</i>	\$12	\$13	\$17
Insurance	<i>\$/MW-day</i>	\$9	\$9	\$13
Non-Fuel Variable Costs	<i>\$/MWh</i>	\$0.00	\$0.00	\$0.00

Notes and Sources: avoidable fixed costs are expressed in 2026 dollars per nameplate MW. Fixed Expenses include scheduled and unscheduled wind turbine and balance-of-plant maintenance, parts and consumables, operations monitoring, land lease, general and administrative costs.

H. Large-Scale Solar Photovoltaic Plants

Large-scale solar photovoltaic (PV) plants tend to be fairly small in PJM, with many plants under 10 MW, though a large amount of capacity comes from plants in the 100-150 MW range. Almost all the solar PV plants have been built in the past 20 years, with the most capacity added in Virginia and Ohio. Figure 8 below summarizes the age, size, and locations of the solar PV fleet.

Age is a primary cost driver for solar plants and is related to the plant capacity given that more recent plants tend to be larger than those built in the past. Location also impacts the costs of solar PV plants due to differences in labor costs and property taxes.

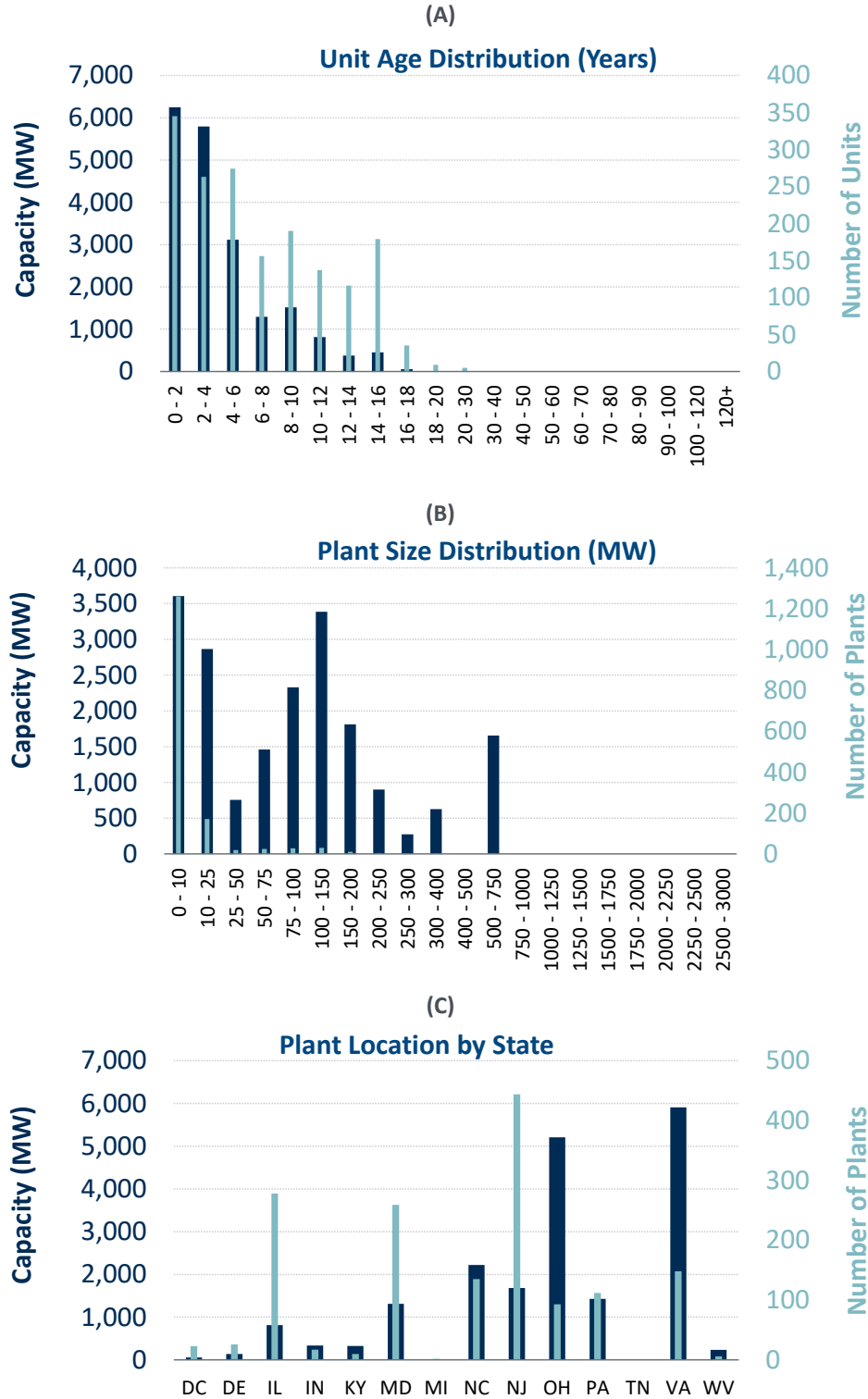
Determination of Representative Large-Scale Solar Photovoltaic Plant Characteristics

The solar PV fleet has changed significantly from four years ago with many larger plants being built in recent years, so we reassessed the representative plant as follows. Since most capacity

is contained in larger plants, we first filtered for plants sized 10 MW and greater and identified the median capacity of plants in this range as 20 MW. We then observed that the most common location in this range was Virginia. Next, we found that the median age had not diverged significantly from the value determined in the 2022 PJM ACR Report (5 years old). Finally, we maintained our assumption from the 2022 PJM ACR Report that the majority of solar PV in PJM is single-axis tracking technology. Based on this approach, the representative solar PV plant is a 5-year-old, 20 MW plant in Virginia with single-axis tracking.

For the representative low- and high-cost plants, we aimed to capture the ends of the capacity distribution. For the low-cost plant, we filtered for plants in the 100-150 MW range and found the median capacity in this range to be 120 MW. Next, we identified the median age in the filtered population to be 2 years old, and the most common location to be Virginia. Based on this approach, the low-cost plant is a 2-year-old, 120 MW plant in Virginia with single-axis tracking. For the high-cost plant, we aimed to capture the smaller capacity end of the size distribution since these would have smaller economies of scale. First, we filtered for plants under 10 MW and found the median capacity to be 2 MW. Next, we determined the median age of plants in this range, which was 5 years old, and found the most common location to be New Jersey. Therefore, the representative high-cost plant is a 5-year-old, 2 MW plant in New Jersey with single-axis tracking.

FIGURE 8: LARGE-SCALE SOLAR PHOTOVOLTAIC FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for Representative Large-Scale Solar Photovoltaic Plants

Fixed costs for solar PV plants consist of labor, fixed operating expenses, property taxes, and insurance. S&L estimated these costs utilizing data from BLS Occupational Employment and Wage Statistics, the U.S. Utility-Scale Solar 2025 Data Update, and S&L's project database.⁴⁰ Similar to onshore wind plants, all the costs necessary to operate a solar PV plant are fixed costs that are not directly attributable to the production of electricity, thus non-fuel variable costs for solar PV are considered negligible and estimated as \$0/MWh. Variations for the low- and high-cost plant scenarios reflect differences in plant scale and regional pricing factors.

Labor: As with the other technologies, S&L estimated labor costs by applying staffing requirements and plant-scale relationships to the representative solar plant.⁴¹ The estimate reflects the staffing requirements and economies of scale associated with the representative plant's configuration and was validated against S&L's project database for similar plants in operation. The resulting labor estimate is \$7/MW-day for the representative solar plant.

Fixed Expenses: Fixed expenses include recurring operating costs such as preventive maintenance, information technology, miscellaneous supplies, support services, and administrative and general expenses. S&L derived fixed expenses by analyzing O&M costs from the U.S. Utility-Scale Solar 2025 Data Update and S&L's project database and then adjusting for the specific size and configuration of the representative solar plant.⁴⁰ The resulting fixed expenses estimate is \$17/MW-day for the representative solar plant.

Property Taxes: Property taxes were estimated based on a fixed fraction of overnight capital costs using standard industry metrics and S&L internal data, then normalized based on capacity to yield a final estimate of \$5/MW-day in property taxes for the representative solar plant.

Insurance: Similar to property taxes, insurance costs were estimated as a fixed fraction of overnight capital costs using standard industry metrics and S&L internal data. The resulting insurance estimate is \$6/MW-day for the representative solar plant.

Table 9 below shows the resulting avoidable fixed costs for the representative plant of \$35/MW-day (in 2026 dollars). The representative low-cost plant's estimated avoidable fixed

⁴⁰ Cheyette et al., "U.S. Utility-Scale Solar, 2025 Data Update," Lawrence Berkeley National Laboratory, October 2025.

⁴¹ See FN 29. The baseline staffing requirements and labor rates were developed using S&L's internal reference databases. We then utilized BLS data to inform and validate the locational adjustments specific to the state in each case.

costs are \$29/MW-day and the representative high-cost plant’s avoidable fixed costs are \$51/MW-day. For context, the table also shows variable costs. Consistent with industry standards for solar PV generation, non-fuel variable costs are negligible; thus, the variable costs are estimated at \$0/MWh.

**TABLE 9: LARGE-SCALE SOLAR PV PLANT AVOIDABLE FIXED AND NON-FUEL VARIABLE COSTS
(2026 DOLLARS)**

Large-Scale Solar Photovoltaic Plant				
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	<i>Nameplate MW</i>	120	20	2
Avoidable Fixed Costs	<i>\$/MW-day</i>	\$29	\$35	\$51
Labor	<i>\$/MW-day</i>	\$5	\$7	\$14
Fixed Expenses	<i>\$/MW-day</i>	\$12	\$17	\$21
Property Taxes	<i>\$/MW-day</i>	\$3	\$5	\$4
Insurance	<i>\$/MW-day</i>	\$8	\$6	\$12
Non-Fuel Variable Costs	<i>\$/MWh</i>	\$0.00	\$0.00	\$0.00

Notes and Sources: avoidable fixed costs are expressed in 2026 dollars per nameplate MW. Fixed Expenses include scheduled and unscheduled PV and balance-of-plant (BOP) equipment maintenance, vegetation management, module cleaning, major maintenance reserve funds, land lease, general and administrative costs.

I. Standalone BESS

As of June 2026, PJM has approximately 800 MW of BESS.⁴² Of this total, 40% are standalone BESS and the remainder are hybrid BESS resources. Over 4 GW of BESS, however, are currently in PJM’s Expedited Process (a “fast track” interconnection process) with the majority expected to come online between 2027 and 2029.⁴³ Additionally, over 60 GW of storage projects have been selected as part of PJM’s first cycle of the reformed interconnection process, with a substantial portion expected to be online before 2030.⁴⁴ Given the volume of BESS projects

⁴² Hitachi Energy ABB Velocity Suite, June 2026.

⁴³ Orelowitz, Aaron, “PJM: The next wave of battery energy storage systems,” Modo Energy, September 24, 2025, <https://modoenergy.com/research/en/pjm-fast-lane-major-players-battery-storage-bess-buildout-duration-spreads-arbitrage>; The most updated status of Expedited Process projects is tracked on PJM’s Serial Service Request Status page (“PJM Serial Request Status page”), PJM, <https://www.pjm.com/planning/service-requests/serial-service-request-status>

⁴⁴ “Over 700 New Generation Projects Accepted Into First Cycle of Reformed Interconnection Process,” PJM Inside Lines, August 3, 2026, <https://insidelines.pjm.com/over-700-new-generation-projects-accepted-into-first-cycle-of-reformed-interconnection-process/>.

expected to reach commercial operations before the 2030/31 delivery year, we determined in conversation with PJM and stakeholders that it would be prudent to establish an ACR for standalone BESS. The alternative would be to leave the ACR as zero and require individual review of each resource, which would be administratively burdensome.

Utility-scale BESS uses standardized, modular equipment for which fixed costs are less influenced by geography than other technologies. Given that CAISO and ERCOT have extensive recent deployment, ample information has accumulated on the fixed costs associated with utility-scale BESS across configurations.⁴⁵ Leveraging this information provides a credible basis for bottom-up fixed-cost estimates for BESS in PJM despite the relatively small existing fleet.

In our analysis, we focused on standalone BESS projects, which represent over 60% of the Expedited Process queue capacity. Of the standalone BESS resources that reported duration, approximately 65% of the capacity is from 4-hour resources, 30% is from 10-hour resources, and 5% is from 6-hour resources.⁴⁶ Overall, there are many smaller BESS resources less than 25 MW, but much of the capacity is contained in resources 100 MW and greater. Specifically for 4-hour BESS, resource sizes vary widely between 20 MW and 300 MW, but approximately 75% of the capacity is contributed by 100-300 MW batteries. Most of the expected capacity for all BESS durations is in New Jersey and Virginia, followed by Ohio and Maryland. Most of the BESS capacity is expected to have commercial operation dates (CODs) during the 2027-2029 period. The primary cost drivers for BESS resources are the duration, size, augmentation approach, age, and location.

Determination of Representative Standalone BESS Plant Characteristics

Since approximately 75% of 4-hour standalone BESS capacity is from resources in the 100-300 MW range, we first filtered the 4-hour duration subsample for 100 MW or greater and determined the median capacity of this filtered subset to be 200 MW. Next, we calculated the median expected COD year of the 4-hour BESS subset which was 2028. We observed that this

⁴⁵ As of September 2, 2026, CAISO has approximately 17 GW of installed battery capacity, see “Key Statistics,” CAISO, September 2026, <https://www.caiso.com/documents/key-statistics-aug-2026.pdf>; As of February 9, 2026, ERCOT reported 15.7 GW of installed and operating BESS capacity. See “Understanding Battery Energy Storage Systems – Current and Future,” Texas Solar + Storage Association, February 9, 2026, <https://www.ercot.com/files/docs/2026/02/02/4-Understanding-Battery-Energy-Storage-Systems-Current-and-Future.pdf>

⁴⁶ Of 40 standalone BESS projects (totaling approximately 2,850 MW) in the fast-track queue, 18 (approximately 760 MW) did not report their duration, representing about 25% of the total population in capacity terms. We assume that the characteristics of the plants that report their duration and capacity are representative of the remaining projects in the fast lane queue.

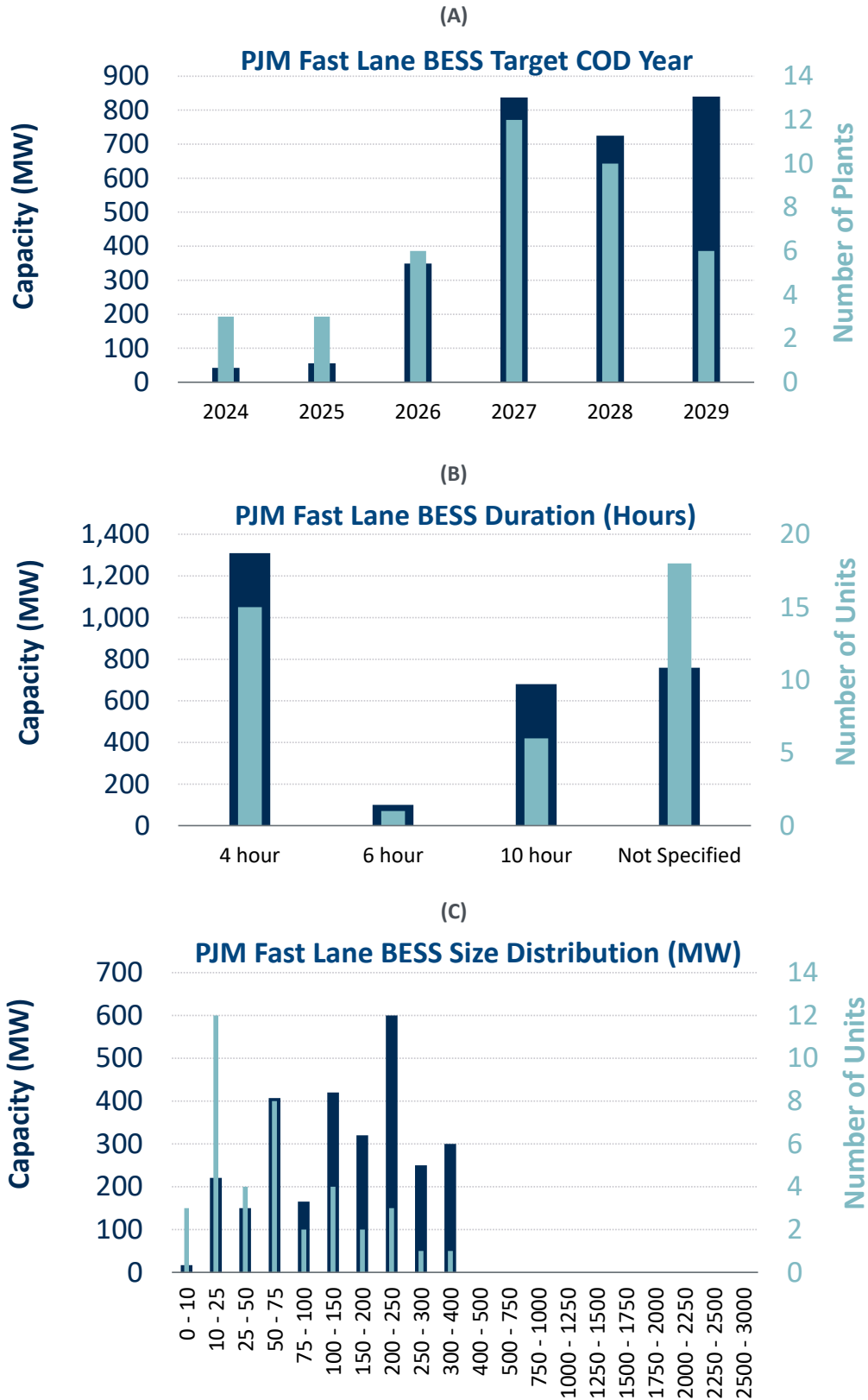
was consistent with the broader standalone BESS population, given that over 80% of the capacity is expected to reach commercial operations between 2027 and 2029. Lastly, we found that the most common location for the 100 MW and greater 4-hour BESS resources was New Jersey. Therefore, the representative resource is a 4-hour duration, 200 MW capacity battery in New Jersey with COD achieved in 2028. Since this was the same capacity and duration as the BESS resource we previously assessed in the 2025 PJM CONE Study, we adopted the same additional resource characteristics, including the battery chemistry, augmentation approach, and other specifications.⁴⁷

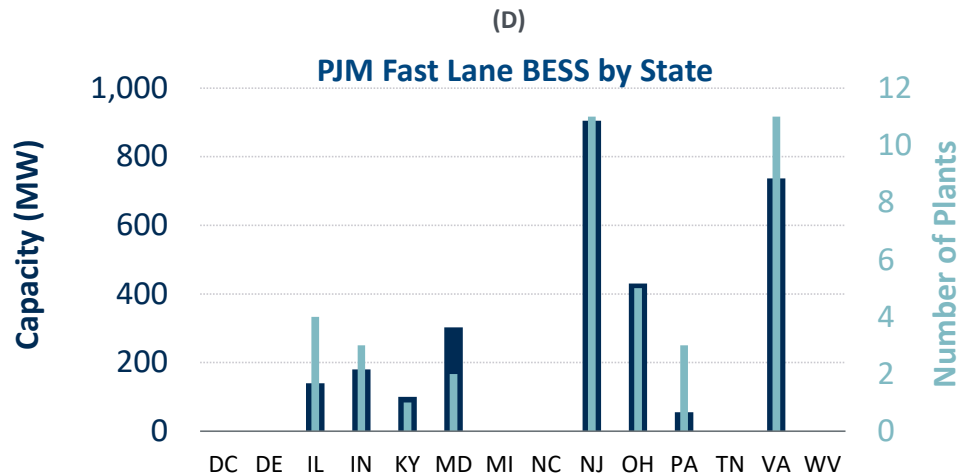
To identify the representative high- and low-cost resources, we also relied on the Expedited Process queue data. To determine the representative high-cost resource, we first observed that the second most prevalent duration was 10 hours, which merited a separate representative resource definition. Next, we found the median size of 10-hour BESS resources to be approximately 100 MW. Given the relatively small number of 10-hour duration batteries, we elected to adopt the characteristics of the single 100 MW plant in the subset, which is in Virginia (the location with the second-highest capacity) and has an expected COD year of 2029. Based on this approach, the representative high-cost plant is a 10-hour duration, 100 MW plant located in Virginia achieving COD in 2029.

To determine the low-cost resource, we decided to alter the characteristics of the representative plant since most BESS resources are 4-hour. We maintained the same characteristics for duration and capacity as the representative plant but chose Virginia as the location since this was the state with the second most expected capacity. Finally, since augmentation is a key cost driver, we altered the augmentation approach for the low-cost resource. Therefore, the representative low-cost plant is also a 4-hour duration, 200 MW battery with expected COD in 2028, but with more overbuild and less augmentation than the representative plant and located in Virginia.

⁴⁷ For a complete list of the Standalone BESS technical specifications, see 2025 PJM CONE Study, p. 60.

FIGURE 9: STANDALONE BESS FLEET CHARACTERIZATION





Notes and Sources: Modo Energy, PJM Serial Request Status page

Cost Estimates for Representative Standalone BESS Plants

Our derivation of avoidable fixed costs for standalone BESS projects was consistent with related approaches for estimating fixed O&M costs in the 2025 PJM CONE Study, given the overlap in the representative plant characteristics. Fixed costs for standalone BESS are comprised of labor, fixed operating expenses (which include routine O&M, auxiliary power, software licensing, and administrative costs), property taxes, insurance, and levelized augmentation costs (which account for the equipment needed to replace degrading battery cells). These were determined using S&L's recent BESS experience and internal project database. Variable costs for BESS are assessed at \$0/MWh, as major maintenance and capacity augmentations are levelized into fixed costs rather than treated as variable. Adjustments for the low- and high-cost plants account for variations in storage duration, location (e.g., Virginia versus New Jersey), and overbuild ratios.

Labor: As with the other technologies, S&L estimated labor costs by applying staffing requirements and plant-scale relationships to the representative BESS plant.⁴⁸ The estimate reflects the staffing requirements and economies of scale associated with the representative plant's configuration and was validated against S&L's project database for similar plants in operation. The resulting labor estimate is \$4/MW-day for the representative plant.

Fixed Expenses: Fixed expenses were calculated by aggregating routine O&M, auxiliary power, software licensing, and general administrative costs using S&L's internal databases and project

⁴⁸ See FN 29. The baseline staffing requirements and labor rates were developed using S&L's internal reference databases. We then utilized BLS data to inform and validate the locational adjustments specific to the state in each case.

experience. Augmentation costs are explicitly excluded from this bucket and are accounted for in a separate cost category. The resulting total fixed expenses estimate is \$67/MW-day for the representative standalone BESS plant.

Property Taxes: Property taxes were modeled as a fixed fraction of initial capital costs based on standard industry metrics and S&L internal data. Because the representative BESS resources are relatively new installations with high upfront capital that is not depreciated compared to older, heavily depreciated thermal plants, property taxes per MW are notably higher. The resulting total property taxes estimate is \$53/MW-day for the representative standalone BESS plant.

Insurance: Insurance costs (covering liability, property, and equipment) were estimated as a fixed fraction of initial capital costs based on standard industry metrics and S&L internal data. The resulting total insurance estimate is \$26/MW-day for the representative plant.

Levelized Augmentations: The augmentation approach impacts avoidable fixed costs because developers make design trade-offs between how much capacity to overbuild initially to combat the higher initial rates of battery degradation versus how much and how frequently to augment capacity later as the battery cells degrade more gradually over time.⁴⁹ While lithium-ion batteries also degrade based on how they are used (which could be considered a variable cost), the primary driver of degradation is time-based (regardless of how the battery is operated) and augmentation is typically expressed as a levelized fixed cost over the lifetime of the resource in LTSAs. Since the representative plant was the same as the 2025 PJM CONE Study, we assumed a similar augmentation approach of an initial 29% overbuild with augmentation occurring in 3-year intervals starting with year 5 and increasing in size from 45 MWh to 62 MWh over time.⁵⁰ S&L calculated the augmentation costs based on an S&L internal battery augmentation cost model using battery cost projection information from NREL's Cost Projections for Utility-Scale Battery Storage: 2025 Update to account for future declines in battery module costs.⁵¹ For the representative low-cost plant, we assumed a plant that has a much higher overbuild such that no augmentations are required over the life of the plant.

Table 10 below shows the resulting avoidable fixed costs for the representative standalone BESS plant of \$187/MW-day (in 2026 dollars). The representative low-cost plant's estimated avoidable fixed costs are \$177/MW-day and the representative high-cost plant's avoidable fixed

⁴⁹ For a more in-depth discussion of overbuilding versus augmentation see 2025 PJM CONE Study, p. 60.

⁵⁰ See 2025 PJM CONE Study, pp. 60-61.

⁵¹ Cole et al., "Cost Projections for Utility-Scale Battery Storage: 2025 Update," National Renewable Energy Laboratory, June 2025.

costs are \$447/MW-day. For context, the table also shows variable costs. For BESS, non-fuel variable costs are estimated at \$0/MWh. While battery augmentation and routine maintenance incur significant expenses over the life of the asset, these are typically levelized and incorporated into the fixed costs rather than modeled as variable \$/MWh charges.⁵²

TABLE 10: STANDALONE BESS PLANT AVOIDABLE FIXED AND NON-FUEL VARIABLE COSTS (2026 DOLLARS)

Standalone BESS Plant				
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	<i>Nameplate MW</i>	200	200	100
Avoidable Fixed Costs	\$/MW-day	\$177	\$187	\$447
Labor	\$/MW-day	\$3	\$4	\$6
Fixed Expenses	\$/MW-day	\$84	\$67	\$168
Property Taxes	\$/MW-day	\$60	\$53	\$121
Insurance	\$/MW-day	\$30	\$26	\$61
Levelized Augmentations	\$/MW-day	\$0	\$37	\$91
Non-Fuel Variable Costs	\$/MWh	\$0.00	\$0.00	\$0.00

Notes and Sources: avoidable fixed costs are expressed in 2026 dollars per nameplate MW. Fixed Expenses include routine O&M, auxiliary power, software licensing, and general administrative costs.

Standalone BESS Plant Avoidable Fixed Cost Adjustment Factors for Alternative Durations

To derive the BESS Adjustment Factors, S&L developed bottom-up cost estimates for a 200 MW plant at each system duration (2, 6, 8, and 10 hours). S&L then calculated the avoidable fixed costs using S&L's internal O&M model based on recent BESS projects. The resulting avoidable fixed cost values for each duration were used to establish an adjustment factor relative to the reference 4-hour BESS case (see Table 11 below). To adjust the 4-hour BESS avoidable fixed cost to other durations, these adjustment factors can be applied directly to the baseline 4-hour avoidable fixed cost estimate.

TABLE 11: STANDALONE BESS PLANT COST ADJUSTMENT FACTORS FOR ALTERNATIVE DURATIONS

	4-Hour (Reference)	2-Hour	6-Hour	8-Hour	10-Hour
Adjustment Factor	1.000	0.574	1.436	1.866	2.297

⁵² For more information on the cost derivation process for standalone BESS, see 2025 PJM CONE Study, pp. 60-70.