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April 24, 2023

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

*Re: PJM Interconnection, L.L.C., Docket No. ER23-1700-000*
*Proposed Updates to the Default Gross Cost of New Entry and Default Gross Avoidable Cost Rate for the Minimum Offer Price Rule*

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d (2000), and the Federal Energy Regulatory Commission's ("Commission") Regulations,[1] 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 ("CONE") and default Gross Avoidable Cost Rate ("ACR") used for purposes of the Minimum Offer Price Rule ("MOPR") and Market Seller Offer Cap ("MSOC") rule.[2] Specifically, the primary components of the proposed updates in this filing are: (1) updating a default Gross CONE value for nine resource types for MOPR purposes starting with the 2026/2027 Delivery Year, and (2) updating a default Gross ACR value for eight resource types for MOPR and MSOC purposes starting with the 2026/2027 Delivery Year.[3]

[1] 18 C.F.R. Part 35.

[2] For the purpose of this filing, capitalized terms not defined herein shall have the meaning as contained in the PJM Open Access Transmission Tariff, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., or the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region.

[3] Both offshore wind and battery energy storage have default Gross CONE values, but not default Gross ACR values. There are not enough active offshore wind projects or battery energy storage systems to calculate the avoidable ongoing costs for these resource types. With increased penetration of these resources in the future, PJM will be able to calculate values. Steam oil & gas have a default Gross ACR value, but not a default Gross CONE value. There are not enough new steam oil & gas units entering PJM to require this resource type.

This filing is submitted in accordance with a Tariff requirement for PJM to review every default CONE and ACR values every fourth Delivery Year beginning with the 2022/2023 Delivery Year.[4] To that end, PJM is proposing updated default CONE and ACR values in advance of the Base Residual Auction associated with the 2026/2027 Delivery Year.[5] This filing represents the culmination of a successful stakeholder process that began on October 6, 2022. During this process, PJM incorporated nearly all of the input from stakeholder feedback received at the various stakeholder meetings. Ultimately, the Markets and Implementation Committee ("MIC") endorsed this proposal on March 8, 2023 by acclimation with no objection or abstention.[6] Thereafter, the proposed revisions were endorsed by PJM stakeholders at the March 22, 2023 Markets and Reliability Committee ("MRC") meeting by acclimation with no objection or abstention.[7] After endorsement at the MRC, the Members Committee endorsed the proposal on March 22, 2023 also by acclamation with no objection or abstention.[8]

PJM requests that the Commission issue its order accepting the enclosed revisions by no later than June 23, 2023, sixty (60) days from the date of this filing, with an effective date of June 23, 2023 for all revisions.

[4] *See* Tariff, Attachment DD, section 5.14(h-2)(3).

[5] While PJM has recently proposed to delay the upcoming Reliability Pricing Model ("RPM") Auctions beginning with the 2025/2026 Delivery Year, it is uncertain that the Commission will accept the proposed delay. *See PJM Interconnection, L.L.C.*, Delay Upcoming RPM Auctions and Requests for Waiver and Expedited Action, Docket No. ER23-1609-000 (Apr. 11, 2023). Therefore, PJM is submitting this filing to update default CONE and ACR values effective with the 2026/2027 Base Residual Auction currently scheduled to commence in November of 2023. Under the existing schedule, PJM would be required to post updated net CONE values for the 2026/2027 Base Residual Auction by the end of June 2023.

[6] PJM Market Implementation Committee, Consent Agenda of Minutes (Mar. 8, 2023), https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230412/20230412-draft-minutes---mic---382023.ashx.

[7] PJM Markets & Reliability Committees, Consent Agenda of Minutes (Mar. 22, 2023), https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20230426/20230426-consent-agenda-a---draft-mrc-minutes---3222023.ashx.

[8] PJM Members Committee, Consent Agenda of Minutes (Mar. 22, 2023), https://www.pjm.com/-/media/committees-groups/committees/mc/2023/20230501/20230501-item-04a---consent-agenda---draft-mc-minutes---3222023.ashx.

## 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 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 new (CONE) or existing resource (ACR) and the technology type.

The current values in the Tariff are applicable beginning with the 2022/2023 Delivery Year, and are escalated for each subsequent Delivery Year. In advance of each auction, PJM posts the default values for the various resource types. For New Entry 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 Capacity Resources that are subject to the 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, PJM is required to review and update these values effective with the 2026/2027 Delivery Year. In

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

complying with this Tariff requirement, PJM engaged with an independent consultant, The Brattle Group, in reviewing and proposing updated default ACR values, while PJM independently reviewed publicly available sources in updating the default CONE values. After the review of the updated Gross CONE and Gross ACR values, PJM stakeholders unanimously supported PJM's proposal to update both the default Gross CONE and default Gross ACR values beginning with the 2026/2027 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 CONE and ACR values are specified under the MOPR provisions,[10] 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 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 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 for the applicable delivery year. There are default Gross ACR values for seven resource types for the 2022/2023, with PJM

[10] *Id*.

proposing to add one resource type for a total of eight resource types starting with the 2026/2027 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 "nominal-levelized" annual cost to construct and develop new construction for the resource type.[11] The table below shows the reference resources with technology description that was selected for this update. The selected specific technology types used as the reference resource is reasonable because they best align with the expected new entry resources within PJM based on market trends and/or what already entered PJM's queue.[12]

[11] Marzewski Aff. ¶ 4.

[12] The combined cycle resource type was updated to reflect the updated reference technology from the quadrennial review. The onshore wind resource type was updated from a 50 MW to 200 MW reference resource to reflect market trends. All other resource types aligned with the initial reference resources used in the existing default values.

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

| Resource Type | Technology Description | Source of Information | Fixed O&M ($/kW-Year) | Installed Capital Costs ($/kW) |
|---|---|---|---|---|
| **Nuclear** | 2x Westinghouse AP1000 pressurized water reactor (2,156 MW) | EIA (Case 11) | 127.35 | 6,695 |
| **Coal** | Ultra-Supercritical coal (650 MW) | EIA (Case 1) | 42.49 | 4,074 |
| **Combined Cycle** | Double train 1x1 GE Frame 7HA.02 with evaporative cooling, SCR and CO catalyst (1,155 MW) | As-filed Quadrennial Review | 38.5 | 1,270 |
| **Combustion Turbine** | GE Frame 7HA.02 with evaporating cooling and SCR (357 MW) | As-filed Quadrennial Review | 40 | 927 |
| **Solar PV – Tracking** | Single-axis tracking (150 MW AC) | EIA (Case 24) | 15.97 | 1,327 |
| **Solar PV – Fixed** | Fixed tilt (100 MW AC) | EIA, LBNL | 14.85 | 1,234 |
| **Onshore Wind** | 71 x 2.8 MW WTGs (200 MW) | EIA (Case 20) | 27.57 | 1,718 |
| **Offshore Wind** | 40 x 10 MW WTGs, 100' deep (400 MW) | EIA (Case 22) | 115.16 | 4,833 |
| **Battery Energy Storage** | 50 MW utility-scale, lithium-ion, 200 MWh rating | As-filed Quadrennial Review | 36.85 | 1,681 |

As explained by PJM's Senior Market Design Specialist, Skyler Marzewski, PJM developed the updated default gross CONE values based on review of cost data from sources such as the U.S. Energy Information Administration ("EIA") and Lazard. Each of these sources are publicly available.[13] Ultimately, PJM used the EIA data "for all of the technologies, except for solar PV (fixed), combustion turbine, combined cycle, and battery energy storage resource types,"[14] as the EIA data "represents the most recent (published in March 2022) publicly available source and is well-documented."[15] "Further, the EIA data includes Capex and FOM values for nuclear, coal, solar PV (tracking), onshore wind, and offshore wind technologies,"[16] which provides transparency into the Gross CONE determination. The combustion turbine and battery energy storage Gross CONE values were calculated using the Capex and FOM based on the values

[13] Lazard, Lazard's Levelized Cost of Energy Analysis-Version 15.0 (Oct. 2021), https://www.lazard.com/media/sptlfats/lazards-levelized-cost-of-energy-version-150-vf.pdf; U.S. Energy Information Administration, Assumptions to the Annual Energy Outlook 2022: Electricity Market Module (Mar. 2022), https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

[14] Marzewski Aff. ¶ 10.

[15] *Id.*

[16] *Id.*

that Brattle developed for PJM's recent quadrennial review filing.[17] Notwithstanding, the after-tax weighted average cost of capital ("ATWACC") was updated by the Brattle Group ("Brattle") after publishing the 2022 CONE Report, so the default gross CONE values were updated accordingly for the combustion turbine and battery energy storage resource types. Likewise, the default gross CONE value for the combined cycle is also based on the same value the commission approved in the 2022 quadrennial review proceeding but revised to reflect an updated ATWACC.[18]

The general use of information from EIA and PJM's recent quadrennial review for calculating the default gross CONE values is consistent with PJM's previous approach approved by the Commission.[19] Likewise, as shown in the table below, PJM adopted the same financial assumptions from the recent 2022 quadrennial review proceeding in calculating the default gross CONE values.[20] These values have already been reviewed by the Commission with the 2022 quadrennial review.[21] Mr. Marzewski also provides additional explanation and supporting documentation for these gross CONE values.[22]

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[17] *See PJM Interconnection, L.L.C.*, Docket No. ER22-2984-000 (2022), https://www.pjm.com/directory/etariff/FercDockets/6885/20220930-er22-2984-000.pdf.

[18] *See* PJM Interconnection, L.L.C., 182 FERC ¶ 61,073 (2023).

[19] *Id.*

[20] Marzewski Aff ¶ 14 & Table 3.

[21] *See PJM Interconnection, L.L.C.*, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, Docket No. ER22-2984-000 (Sept. 30, 2022), https://www.pjm.com/directory/etariff/FercDockets/6885/20220930-er22-2984-000.pdf.

[22] *See generally* Marzewski Aff. Mr. Marzewski also separately provides the installed capital cost ("Capex"), fixed operating and maintenance cost ("FOM") reviewed from different sources of data, the actual values used for each resource in developing CONE. The worksheet also shows the EFORd values for conventional resources, and ELCC values for solar, wind, and battery energy storage resources used to convert Net CONE from ICAP to UCAP.

**Table 2.**

| Financial Assumptions | |
|---|---|
| Expected Life | 20 Years |
| Debt Ratio | 55% |
| Debt Rate | 6.30% |
| Equity Rate | 14.10% |
| Total Tax Rate | 27.20% |
| ATWACC | 8.85% |
| Inflation Rate | 2.20% |

The proposed default gross CONE calculations are based on publicly available data, which have the added benefit of providing transparency and 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.[23] Therefore, as Mr. Marzewski explains that, with access to a pro forma analysis tool, "any member of the public can use the publicly available Capex and FOM data plus the financial assumptions provided by PJM to produce the CONE values PJM calculated."[24]

Of note, some resources types are eligible for different tax incentives under the Inflation Reduction Act that was signed into law on August 16, 2022, and included Investment Tax Credits ("ITC") allowable to wind, solar, and battery energy storage resources.[25] Eligibility for the ITC results in a range from a 6% ITC value by simply building the eligible resource type, or up to 50%

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[23] *See* PJM Independent Market Monitor, CONE Template Version 2, Monitoring Analytics, https://www.monitoringanalytics.com/tools/docs/IMM_MOPR_Gross_CONE_Template_v2.xlsx.

[24] Marzewski Aff. ¶ 17.

[25] *See* H.R. 5376 - Inflation Reduction Act of 2022, https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

ITC value by meeting the prevailing wage and apprenticeship requirements (30%), the domestic content requirements (10%), and building in an energy community (10%). Utilizing the prevailing wage and apprenticeship requirements will increase a resource's wage component in the FOM, but this small increase in cost will likely be more than offset by the large increase to 30% ITC value. Since Market Sellers are expected to maximize profits, it is reasonable to assume that they will meet the prevailing wage and apprenticeship requirements to obtain the 30% ITC value for determining Gross CONE values.[26] Indeed, throughout the stakeholder process, various participants voiced support for using a 30% ITC value for eligible resource types.[27] By contrast, the additional 10% credit for domestic content requirement would be difficult, as most materials do not currently meet this requirement. The separate 10% credit for building within an energy community is also unlikely as it requires the resource to be built in a very specific location in order to qualify.[28] Therefore, in determining the values for wind, solar, and battery energy storage resources, PJM reasonably accounted for a federal ITC, and utilized a 30% ITC value for determining Gross CONE values. Of course, the IRA is relatively new legislation. More information will develop as to how companies are using the various tax credits in future years. In the interim, PJM's approach is conservative and based on input from the Independent Market Monitor, stakeholder feedback, and business expectations.[29]

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[26] The prevailing wage and apprenticeship values are available on www.sam.gov or by emailing the project specifications to IRAprevailingwage@dol.gov.

[27] "Numerous cities and states have enacted their own prevailing wage laws…." Center for American Progress, The Clean Economy Revolution will be Unionized (Jul. 7, 2021), https://www.americanprogress.org/article/clean-economy-revolution-will-unionized.

[28] Marzewski Aff. ¶ 15.

[29] "Wood Mackenzie has assumed most projects will earn the 30% ITC…." Wood Mackenzie, The US solar industry waits (Dec. 13, 2022), https://www.woodmac.com/news/opinion/the-us-solar-industry-waits.

Based on the foregoing and as further supported in Mr. Marzewski's affidavit, the resulting updated default Gross CONE values being proposed in this filing, are shown in the table below. These updated values are reflected in the proposed updates to Tariff, Attachment DD, section 5.14(h-2)(3)(A).

**Table 3.**

| **Resource Type** | **For the 2026/2027 Delivery Year and Subsequent Delivery Years: Gross Cost of New Entry (2026/2027 $/ MW-day) (Nameplate)** |
|---|---|
| Nuclear | $2,568 |
| Coal | $1,480 |
| Combined Cycle | $540 |
| Combustion Turbine | $427 |
| Fixed Solar PV | $298 |
| Tracking Solar PV | $321 |
| Onshore Wind | $438 |
| Offshore Wind | $1,351 |
| Battery Energy Storage | $502 |

***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 including as Attachment D of this filing. Brattle's report provides a comprehensive description of the analysis and methodology employed.[30] As with the CONE updates, the updated ACR values were developed with stakeholder input through three rounds of presentations at the MIC special sessions which concluded January 2023.[31]

Briefly, 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 plant" that is widely representative of the cost of most of the fleet. 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.[32] 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.[33] 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.[34] 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

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[30] *See* The Brattle Group and Sargent & Lundy, Gross Avoidable Cost Rates Existing (Jan. 9, 2023) ("Brattle Report"). The Brattle Report is included as Attachment D.

[31] PJM Market Implementation Committee, Minutes from MIC Special Session: Periodic Review of Default CONE & ACR Values (Jan. 13, 2023), https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230113-special/agenda.ashx.

[32] Brattle Report at 8.

[33] *Id* at iv.

[34] *Id* at 8.

plants are based on NEI's latest "Nuclear Costs in Context" study, with adjustments to reflect the representative plant. Intermittent plants used FERC Form 1 data and S&L's project database where FERC Form 1 data was insufficient.

Brattle's updated default ACR values include all avoidable costs to operate the resource for another year and aligns with the Tariff-based approach for determining 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.[35] Default gross ACRs include Fixed Capital Costs and FOM costs, but not major maintenance costs for systems directly related to electric production.[36]

During the stakeholder process, a new resource type, steam oil and gas, was requested to be added as a default resource type. In response to this request, Brattle was able to add this resource type, as there were enough resources in PJM to select a representative plant. However, not all resource types tend to be idiosyncratic, primarily due to older technology or non-standard technology, and do not lend themselves to have a default value. As a result, PJM is not proposing to include additional default gross ACR values for other new resource types besides steam oil and gas resources at this time. The resulting Brattle-determined default gross ACR values, are shown in the table below,[37] which is also stated in the Tariff.

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[35] Brattle Report at 9. Brattle explains that "Therefore, consistent with tariff, our estimated gross costs include Fixed Capital Costs and Fixed Operation & Maintenance (FOM) costs but not major maintenance costs for systems directly related to electric production."

[36] *Id*.

[37] Because the E&AS calculation is unit-specific for purposes of calculating a Net ACR value, no illustrative Net ACR values can be provided here.

**Table 4.**

| Existing Resource Type | For the 2026/2027 Delivery Year and Subsequent Delivery Years: Default Gross ACR (2026/2027) ($/MW-day) (Nameplate) |
|---|---|
| Nuclear - single | $591 |
| Nuclear - dual | $537 |
| Coal | $94 |
| Combined Cycle | $113 |
| Combustion Turbine | $52 |
| Steam Oil & Gas | $64 |
| Solar PV (fixed and tracking) | $70 |
| Wind Onshore | $147 |

## III. STAKEHOLDER PROCESS

This filing is the culmination of a Tariff requirement to review every MOPR prices every fourth delivery year, and the stakeholder process that started October 6, 2022 with the MIC ultimately endorsing this package on March 8, 2023 with the committee voting in acclimation with no objection or abstention.[38] Thereafter, the proposed revisions were endorsed by PJM stakeholders at the March 22, 2023 MRC meeting by acclimation with no objection or abstention.[39]

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[38] PJM Market Implementation Committee, Consent Agenda of Minutes (Mar. 8, 2023), https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230412/20230412-draft-minutes---mic---382023.ashx.

[39] PJM Markets & Reliability Committee, Consent Agenda of Minutes (March 22, 2023), https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20230426/20230426-consent-agenda-a---draft-mrc-minutes---3222023.ashx.

After endorsement at the MRC, the Members Committee endorsed the proposal on March 22, 2023 by acclamation with no objection or abstention.[40]

## IV. PROPOSED EFFECTIVE DATES

PJM proposes an effective date of June 23, 2023, for the proposed Operating Agreement revisions referenced herein. PJM requests that the Commission issue an order on this filing by June 23, 2023.

## V. DESCRIPTION OF SUBMITTAL

This filing consists of the following:

1. This transmittal letter;
2. Attachment A – Revisions to the Tariff in redline format;
3. Attachment B – Revisions to the Tariff in clean format;
4. Attachment C – Skyler Marzewski Affidavit; and
5. Attachment D – Brattle Gross Avoidable Costs for Existing Generation report.

## VI. CORRESPONDENCE

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

| | |
|---|---|
| Chenchao Lu<br>Associate General Counsel<br>PJM Interconnection, L.L.C.<br>2750 Monroe Boulevard<br>Audubon, Pennsylvania 19403<br>(610) 666-2255<br>chenchao.lu@pjm.com | Craig Glazer<br>Vice President - Federal Government Policy<br>PJM Interconnection, L.L.C.<br>1200 G Street, N.W, Suite 600<br>Washington, D.C. 20005<br>(202) 423-4743<br>craig.glazer@pjm.com |

[40] PJM Members Committee, Consent Agenda of Minutes (March 22, 2023), https://www.pjm.com/-/media/committees-groups/committees/mc/2023/20230501/20230501-item-04a---consent-agenda---draft-mc-minutes---3222023.ashx.

## VII. 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,[41] 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 Region[42] alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

[41] *See* 18C.F.R §§ 35.2(e) and 385.2010(f)(3).

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

## VIII. CONCLUSION

Based on the foregoing, PJM respectfully requests that the Commission accept the proposed revisions to PJM's, Operating Agreement by no later than June 23, 2023, effective June 23, 2023.

Respectfully submitted,
*/s Chenchao Lu*____

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Attachment A

Revisions to the
PJM Open Access Transmission Tariff

(Marked / Redline Format)

## 5.14 Clearing Prices and Charges

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

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

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 Delivery Year and subsequent Delivery Years, to determine the applicable UCAP MW-day value, the net cost of new entry is adjusted as follows: 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.  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 bonus depreciation scheduled under federal corporate tax law.  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 2025/2026 Delivery Years: Default Gross ACR (2022/2023) ($/MW-day) (Nameplate) | For the 2026/2027 Delivery Year and Subsequent Delivery Years: Default Gross ACR (2026/2027) ($/MW-day) (Nameplate) |
|---|---|---|
| Nuclear - single | $697 | $591 |
| Nuclear - dual | $445 | $537 |
| Coal | $80 | $94 |
| Combined Cycle | $56 | $113 |
| Combustion Turbine | $50 | $52 |
| Steam Oil & Gas | NA | $64 |
| Solar PV (fixed and tracking) | $40 | $70 |
| Wind Onshore | $83 | $147 |

The default gross Avoidable Cost Rate 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 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 2023/2024 Delivery Year and subsequent Delivery Years, 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 and on. 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.

## 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. 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-1).

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

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.

Attachment B

Revisions to the
PJM Open Access Transmission Tariff

(Clean Format)

## 5.14 Clearing Prices and Charges

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

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

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 Delivery Year and subsequent Delivery Years, to determine the applicable UCAP MW-day value, the net cost of new entry is adjusted as follows: 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. 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 bonus depreciation scheduled under federal corporate tax law. 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 2025/2026 Delivery Years: Default Gross ACR (2022/2023) ($/MW-day) (Nameplate) | For the 2026/2027 Delivery Year and Subsequent Delivery Years: Default Gross ACR (2026/2027) ($/MW-day) (Nameplate) |
|---|---|---|
| Nuclear - single | $697 | $591 |
| Nuclear - dual | $445 | $537 |
| Coal | $80 | $94 |
| Combined Cycle | $56 | $113 |
| Combustion Turbine | $50 | $52 |
| Steam Oil & Gas | NA | $64 |
| Solar PV (fixed and tracking) | $40 | $70 |
| Wind Onshore | $83 | $147 |

The default gross Avoidable Cost Rate 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 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 2023/2024 Delivery Year and subsequent Delivery Years, 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 and on. 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.

## 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. 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-1).

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

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.

Attachment C

Skyler Marzewski Affidavit

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

| | | |
|---|---|---|
| **PJM Interconnection, L.L.C.** | ) ) ) | **Docket No. ER23-____-000** |

**AFFIDAVIT OF SKYLER MARZEWSKI**
**ON BEHALF OF PJM INTERCONNECTION, L.L.C.**

## A. Introduction

1. My name is Skyler Marzewski. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I currently serve as the Senior Market Design Specialist, in the Market Design group for PJM Interconnection, L.L.C. ("PJM").

## B. Work Experience and Responsibilities

2. My core function is to support the development of significant market design enhancements across all of PJM's markets including the energy, ancillary services, and capacity markets. My responsibilities include leading cross-divisional teams in the development of such enhancements, offering subject matter expertise and insight in these conversations while driving the team towards consensus, and supporting the stakeholder process in related areas.

3. I received Bachelor's of Science degrees in Energy Business and Finance from the Pennsylvania State University in State College, PA. I received a Master's of Science degree in Applied Economics from the Johns Hopkins University in Baltimore, MD. Prior to PJM, I was with Monitoring Analytics and worked on various market design changes and monitoring PJM's markets.

## C. Updated Default Prices for Capacity Resources Subject to the MOPR and MSOC

### a. Updated Default Offer Floor Prices for New Entry Capacity Resources Subject to the MOPR shall be Based on the Construction and Development Cost of that Resource Type

4. As directed by the Tariff, PJM is proposing updated default Minimum Offer Price rule ("MOPR") Floor Offer Prices for New Entry Capacity Resources starting in the 2026/2027 Delivery Year.[1] PJM is required to post the default values for nine distinct

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[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

generation resource types in advance of the relevant Reliability Pricing Model ("RPM") Auction. For New Entry Capacity Resources, these values will be 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 ("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").

5. In this filing, PJM is proposing to update in the Tariff the default Gross CONE value for each resource type, shown in Table 1. The updated default values are proposed to be effective starting with the 2026/2027 Delivery Year. The table includes the most recent net E&AS revenues and the resulting MOPR Floor Offer prices derived from the Gross CONE and average of zonal net E&AS revenues for each resource type. Table 1 uses the average of all of the most recent zonal Net E&AS values to determine the RTO-wide averages for illustrative purposes. These values will not be used in practice, but provide the best estimate to date as to Net CONE values for the 2026/2027 Delivery Year.

6. The Gross CONE and net E&AS revenue offset values presented in Table 1 are expressed in terms of nameplate megawatts ("MW") rating, while the MOPR Floor Offer Prices are expressed on an Unforced Capacity ("UCAP") MW basis where the UCAP MW of a resource represents the deliverable capacity value of the Capacity Resource.

7. The UCAP MW value for nuclear, coal, combined cycle, and combustion turbine resource types are calculated using the most recent class average Equivalent Demand Forced Outage Rate ("EFORd").[2] The UCAP MW value for solar photovoltaic ("PV") (Tracking), solar PV (Fixed), onshore wind, offshore wind, and battery energy storage resource types are calculated using the most recent class rating Effective Load Carrying Capability ("ELCC") for the affected resource for the 2026/2027 BRA.[3]

8. The UCAP MW value of the battery energy storage resource of Table 1 is assumed to be 95% of the resource's nameplate rating because the Gross CONE of the battery energy storage resource was developed for a resource capable of providing output at its nameplate MW for a 10-hour continuous period before depleting its entire stored

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 § 5.14 (h-2)(3)(A), https://agreements.pjm.com/oatt/5156.

2 *See* PJM, 2017-2021 Weighted Average EFORd by Fuel Type, https://www.pjm.com/-/media/planning/res-adeq/res-reports/2017-2021-pjm-generating-unit-class-average-values.ashx.

3 *See* PJM, Effective Load Carrying Capability (ELCC) Class Ratings, https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-class-ratings-for-2023-2025-2026.ashx.

energy capability.[4] Currently, PJM uses a 10-hour period of continuous operation as the minimum requirement for Capacity Storage Resources. Because the reference storage resource can only provide 4-hours of continuous operation based on the definition, for purposes of determining the default value, the Net CONE in ICAP of this resource is then multiplied by 2.5 times the Net CONE to convert to a 10-hour resource.[5]

**Table 1**: Illustrative Estimated Average New Entry Default MOPR Floor Offer Prices

| | **Illustrative Default MOPR Floor Offer Prices** | | |
|---|---|---|---|
| **Planned Resource Type** | **Gross CONE (Cost of New Entry) $/MW-Day (Nameplate)** | **Estimated Average Zonal E&AS Revenue Offset $/MW-day (Nameplate)** | **Illustrative MOPR Floor Offer Prices net of E&AS Revenue $/UCAP MW-day** |
| Nuclear | $2,568 | $795 | $1,790 |
| Coal | $1,480 | $195 | $1,473 |
| Combined Cycle | $540 | $356 | $191 |
| Combustion Turbine | $427 | $143 | $297 |
| Solar PV (Tracking) | $321 | $273 | $106 |
| Solar PV (Fixed) | $298 | $174 | $375 |
| Onshore Wind | $438 | $334 | $799 |
| Offshore Wind | $1,351 | $487 | $2,787 |
| Battery Energy Storage | $502 | $191 | $818 |

9. The values in Table 1 above are provided for illustration purposes only, as these values are based on an "average Zonal E&AS revenue offset" for the 2025/2026 BRA, while the actual Net CONE values used for a given resource will reflect the E&AS revenue offset for the Zone in which that resource resides. The Zonal E&AS revenue offsets for the 2026/2027 BRA will not be calculated until next year based on the current

4 The ELCC Class Rating for the 10-hour storage for the 2026/2027 Delivery Year is 100%, with an assumed 5% Class Average EFORd, resulting in a 95% Capacity Factor. $100\% \times (1 - 5\%) = 95\%$.

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

auction schedule.[6] Additionally, PJM recently submitted a filing to delay the BRA auctions, which would also delay the actual final Zonal E&AS revenue offsets.[7]

10. In developing the updated values, we reviewed cost data sources from the National Renewable Energy Laboratory ("NREL"), Lazard, U.S. Environmental Protection Agency ("EPA"), and U.S. Energy Information Agency ("EIA"). PJM selected EIA as the primary data source for all of the technologies, except the solar PV (fixed), combustion turbine, combined cycle, and battery energy storage resource types.[8] The use of EIA data is appropriate because this data represents the most recent (published in March 2022) publicly available source and is well-documented.[9] Further, the EIA data includes Capex and FOM values for nuclear, coal, solar PV (tracking), onshore wind, and offshore wind technologies. PJM used EIA's 2022 costs (the most recent cost data available), 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 0.93 fixed-to-tracking cost ratio to the Capex and 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.[10]

11. Table 2 shows the reference resources with technology description, source of information, installed capital costs ("Capex"), and fixed operating and maintenance costs ("FOM") for each resource type. The selected specific technology types used as the reference resource are reasonable because they best align with the expected new entry resources within PJM based on market trends and/or what has already entered PJM's queue. The source of the reference resources are based on the identification of the case number from the EIA report, or other applicable source citation, are provided. The

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6 *See* PJM, Auction Schedule, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-auction-schedule.ashx.

7 *See PJM Interconnection L.L.C.,* Delay Upcoming RPM Auctions and Requests for Waiver and Expedited Action, ER23-1609-000 (Apr. 11, 2023), https://www.pjm.com/directory/etariff/FercDockets/7255/20230411-er23-1609-000.pdf.

8 *See* U.S. Energy Information Administration, Assumptions to the Annual Energy Outlook 2022: Electricity Market Module, https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

9 In preparing the report for the EIA, Sargent & Lundy "developed the characteristics of the power generating technologies in this study based on information about similar facilities recently built or under development in the United States and abroad," which included "the specification of representative plant sizes, configurations, major equipment, and emission controls." U.S. Energy Information Administration, Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, at 1 (Feb. 2020) ("EIA AEO 2022"), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf. The 2022 update "adjusted for learning cost adjustments for any capacity added since 2019." EIA AEO 2022 at 4.

10 *See* Lawrence Berkeley National Laboratory, Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, PPA Pricing, and Value in the United States – 2022 Edition (Sept. 2022), https://emp.lbl.gov/utility-scale-solar.

reference resources for combined cycle, combustion turbine, and battery energy storage are those used that were recently studied as part of PJM's 2022 quadrennial study.

**Table 2**: Reference Resources with Technology Description, Source of Information, and Costs

| Resource Type | Technology Description | Source of Information | Fixed O&M ($/kW-Year) | Installed Capital Costs ($/kW) |
|---|---|---|---|---|
| Nuclear | 2x Westinghouse AP1000 pressurized water reactor (2,156 MW) | EIA (Case 11) | 127.35 | 6,695 |
| Coal | Ultra-Supercritical coal (650 MW) | EIA (Case 1) | 42.49 | 4,074 |
| Combined Cycle | Double train 1x1 GE Frame 7HA.02 with evaporative cooling, SCR and CO catalyst (1,155 MW) | As-filed Quadrennial Review | 38.5 | 1,270 |
| Combustion Turbine | GE Frame 7HA.02 with evaporating cooling and SCR (357 MW) | As-filed Quadrennial Review | 40 | 927 |
| Solar PV – Tracking | Single-axis tracking (150 MW AC) | EIA (Case 24) | 15.97 | 1,327 |
| Solar PV – Fixed | Fixed tilt (100 MW AC) | EIA, LBNL | 14.85 | 1,234 |
| Onshore Wind | 71 x 2.8 MW WTGs (200 MW) | EIA (Case 20) | 27.57 | 1,718 |
| Offshore Wind | 40 x 10 MW WTGs, 100' deep (400 MW) | EIA (Case 22) | 115.16 | 4,833 |
| Battery Energy Storage | 50 MW utility-scale, lithium-ion, 200 MWh rating | As-filed Quadrennial Review | 36.85 | 1,681 |

12. PJM is using the Gross CONE data for the combined cycle resource type determined by PJM, and approved by the Commission, in the quadrennial review of the Variable Resource Requirement ("VRR") Curve and related inputs in Docket No. ER22-2984.[11] PJM is using the Capex and FOM costs for combustion turbine and battery energy storage resource types determined by PJM through the last quadrennial review process, but has updated the Gross CONE for these resource types to account for a revised after tax weighted average cost of capital, due to the effects of short term interest rate increases,[12] used in the initial quadrennial review report.[13]

13. After having identified the reference technologies for each resource class and assessed the respective Capex 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, which was benchmarked against the quadrennial study of CONE.[14] This analysis determines the nominal-levelized annual revenue requirements for a resource to recover Capex 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 2022 quadrennial study and shown in Table 3 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

11 *PJM Interconnection L.L.C.*, 182 FERC ¶ 61,073 (2023).

12 *See PJM Interconnection L.L.C.*, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, ER22-2984-000, at 28 (Sept. 30, 2022).

13 The as-filed quadrennial review updated the Gross CONE value for the CC resource type, but did not calculate updated the Gross CONE values for CT and battery energy storage resource types.

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

its February 2023 Order accepting PJM's quadrennial review filing.[15] Further, based on an evaluation of asset life for battery energy storage resources published in the 2022 quadrennial review, PJM determined that the assumed applicable asset life for battery storage resource should be 15 years.

**Table 3: Financial Assumptions**

| | |
|---|---|
| Expected Life | **20 Years** |
| Debt Ratio | **55%** |
| Debt Rate | **6.30%** |
| Equity Rate | **14.10%** |
| Total Tax Rate | **27.20%** |
| ATWACC | **8.85%** |
| Inflation Rate | **2.20%** |

14. To develop the gross CONE values, PJM used 20% Bonus Depreciation, with the remaining 80% used in Modified Accelerated Cost Recovery System (MACRS), for units built to be in service by December 2026 (declining by 20% every year thereafter) and the following financial assumptions from the as filled 2022 quadrennial review.

15. The Inflation Reduction Act ("IRA") was signed into law on August 16, 2022, and included Investment Tax Credits ("ITC") allowable to wind, solar, and battery energy storage resources.[16] The level of the ITC varies depending on whether the resource meets wage and apprenticeship requirements, domestic content minimum requirements, and certain energy community siting requirements, as follows:

- **6% ITC base tax credit**
- **Additional 24% ITC if meeting the prevailing wage and apprenticeship" requirement.** To satisfy the prevailing wage requirements, all laborers and mechanics employed by the resource developer, any contractor, and any subcontractor, must be paid wages at rates not less than the prevailing rates for construction, alteration, or repair of a similar character in the locality in which the project is located as most recently determined by the Secretary of Labor, both (i) during the construction of the project, and (ii) in the alteration and repair of the project for five years after the project has been placed in service. To satisfy the apprenticeship requirements, a certain minimum (12.5% to 15%, depending on the year construction begins) of total labor hours for construction, alteration or repair work on the qualified project must be performed by qualified apprentices.

15 *PJM Interconnection L.L.C.*, 182 FERC ¶ 61,073, at PP 63-65 (2023).

16 *See* H.R. 5376 – Inflation Reduction Act of 2022, section 13702, https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

- **Additional 10% ITC if meeting domestic content requirements** are satisfied, which requires the resource developer to use steel or iron produced entirely in the U.S., and that 40% of the manufactured product costs be attributable to components produced in the U.S.
- **Additional 10% if the resource is built within an "energy community"** as defined by the IRA.

16. In total, the ITC amount claimable by resource is between 6% and 50%, and it is reasonable to that expect market participants to qualify for the 30% ITC as it is generally profit maximizing to satisfy the prevailing wage and apprenticeship requirement.[17] By contrast, PJM believes most developers are unlikely to pursue the additional credit adders: most developments and components do not currently meet the domestic sourcing requirements, and most projects are not developed in the very specific location required to qualify for the energy community requirements. Therefore, it is reasonable to assume a 30% ITC value for purposes of determining default gross CONE values for wind, solar, and battery energy storage resources.

17. The combined cycle CONE value is the average of the four CONE areas as determined in the 2022 quadrennial review for the 2026/2027 Delivery Year.

18. PJM has found its approach for determining the Gross CONE values provides a great deal of transparency and is replicable. In fact, any member of the public can use the publicly available Capex and FOM data plus the financial assumptions provided by PJM to produce the CONE values PJM calculated.

19. The Net CONE values for the 2026/2027 Delivery Year will not be known until after having finalized E&AS values, ELCC values, and EFORd values for each resource type. However, by taking the currently available values, PJM has calculated illustrative Net CONE values. Table 4 shows these illustrative values for the 2026/2027 Delivery Year, by using the 2025/2026 Average Zonal Net Energy Revenues,[18] the current EFORd values,[19] and estimated 2026/2027 ELCC values.[20] The green columns include the FOM, CapEx, and ITC percent by resource type, the orange columns show the calculation for Net CONE in ICAP terms, and the blue columns convert the Net CONE to UCAP terms.

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17 "Wood Mackenzie has assumed most projects will earn the 30% ITC…." Wood Mackenzie, The US solar industry waits (Dec. 13, 2022), https://www.woodmac.com/news/opinion/the-us-solar-industry-waits.

18 *See* PJM, Default New Entry MOPR Offer Prices: 2025/2026, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-default-new-entry-mopr-offer-prices.ashx.

19 *See* PJM, 2017-2021 Weighted Average EFORd by Fuel Type, https://www.pjm.com/-/media/planning/res-adeq/res-reports/2017-2021-pjm-generating-unit-class-average-values.ashx.

20 *See* PJM, ELCC Class Ratings for 2023/2024 3rd IA, 2025/2026 BRA and 2026/2027 BRA, https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-class-ratings-for-2023-2025-2026.ashx.

**Table 4: Illustrative Net CONE values: 2026/2027 Delivery Year**

| Resource Type | Fixed O&M Cost ($/kW-Year) | Installed Capital Cost ($/kW) | Investment Tax Credit % | Gross CONE ($/MW-Day) (Nameplate) | Average Zonal Net Energy Revenue Offset ($/MW-Day) (Nameplate) | Average Zonal Net Ancillary Services Revenue Offset ($/MW-Day) (Nameplate) | Net CONE ($/ICAP-MW-Day) | Capacity Value Percentages or Factors | Net CONE ($/UCAP-MW-Day) |
|---|---|---|---|---|---|---|---|---|---|
| Nuclear | $127 | $6,695 | 0% | $2,568 | $786 | $9 | $1,773 | 99.10% | $1,790 |
| Coal | $42 | $4,074 | 0% | $1,480 | $186 | $9 | $1,285 | 87.20% | $1,473 |
| Combined Cycle | | | 0% | $540 | $347 | $9 | $184 | 96.40% | $191 |
| Combustion Turbine | $40 | $927 | 0% | $427 | $137 | $6 | $284 | 95.50% | $297 |
| Solar PV – Tracking | $16 | $1,327 | 30% | $298 | $264 | $9 | $25 | 47.00% | $53 |
| Solar PV – Fixed | $16 | $1,234 | 30% | $321 | $165 | $9 | $147 | 31.00% | $474 |
| Onshore Wind | $28 | $1,718 | 30% | $438 | $325 | $9 | $104 | 14.00% | $742 |
| Offshore Wind | $115 | $4,833 | 30% | $1,351 | $478 | $9 | $864 | 34.00% | $2,541 |
| Battery Energy Storage | $37 | $1,681 | 30% | $502 | $182 | $9 | $311 | 95.00% | $818 |

### 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

20. As directed by the Tariff, PJM is also proposing updated 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 2026/2027 Delivery Year.[21] PJM will annually post the default values for eight distinct generation resource types 150 days in advance of the relevant Reliability Pricing Model ("RPM") Auction. 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 which PJM will subtract the unit-specific historical net energy and

[21] "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 § 5.14 (h-2)(3)(B), https://agreements.pjm.com/oatt/5156.

ancillary services ("E&AS") revenues for each resource to determine the Net Avoidable Cost Rate ("Net ACR").

21. The default MOPR Floor Offer Price for Sell Offers from existing resources with a State Subsidy will be based on the Net Avoidable Cost Rate ("ACR") values determined for the resource type. The net E&AS revenue for existing resources subject to MOPR is based on the unit-specific resource's historical net E&AS.[22]

22. In developing updated gross ACR values, PJM enlisted the help of the Brattle Group ("Brattle"), which prepared the Brattle Report, included with this filing as Attachment D, detailing how the updated values were developed.[23] PJM contracted Brattle, along with Sargent & Lundy ("S&L"), to determine the Gross ACRs for the following resource types: nuclear, coal, combined cycle, combustion turbine, steam oil & gas, solar PV, and onshore wind.[24] As has been done in the past, Brattle used a bottom up analysis to determine the various costs associated with a "reference plant" of each resource type. Brattle also provided costs associated with "representative low-cost" and "representative high-cost" plants. These costs were then used to estimate the Gross ACRs and variable operations and maintenance costs. Importantly, Brattle's "classification of costs categories as gross versus variable align with PJM's current market rules concerning the costs that are includable in the Gross ACRs versus those that can be included in cost-based energy offers (and thus accounted for in the E&AS revenue component of Net ACRs)."[25]

23. 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.

24. 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

22 *See* Tariff, Attachment DD § 5.14 (h-2)(3)(B), https://agreements.pjm.com/oatt/5156.

23 *See* The Brattle Group and Sargent & Lundy, Gross Avoidable Cost Rates Existing, (Jan. 9, 2023) ("Brattle Report"). The Brattle Report is included as Exhibit No. A.

24 *Id.* at 10.

25 *Id.* at iv.

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.

25. Distinguishing which costs to include in gross costs and which to consider as variable costs required careful consideration. Only avoidable economic fixed costs would be accounted for to determine resources' Default Gross ACRs, while variable costs would be accounted for in resources' Default Net ACRs for capacity offer mitigation purposes so long as generators reflect them in their cost-based energy offers. To avoid double counting any such costs, the estimated gross costs include only Fixed Capital Costs and Fixed Operation & Maintenance (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).

26. 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 it is appropriate to adopt the updated ACR values contained in the report in PJM's default ACR table. 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. This final ranges provided in the Brattle report are provided in Table 4. From these ranges PJM selected the "Representative Plant" values for use as the Gross ACR value 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 resource in each class (resulting in potential under-mitigation of market power).

**Table 4: Illustrative Existing Resource Default Avoidable Cost Rates**

| Technology | Representative Low-Cost Plant ($/MW-day) (Nameplate) | Representative Plant ($/MW-day) (Nameplate) | Representative High-Cost Plant ($/MW-day) (Nameplate) |
|---|---|---|---|
| Multi-unit nuclear | $476 | $537 | $552 |
| Single-unit nuclear | -- | $591 | -- |
| Coal | $88 | $94 | $142 |
| Gas CC | $94 | $113 | $160 |
| Gas CT | $43 | $52 | $69 |
| Steam oil & gas | $53 | $64 | $102 |
| Onshore Wind | $140 | $147 | $204 |
| Solar PV | $65 | $70 | $74 |

While the Net CONE and Net 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, Capex, 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 these calculations as determining default values for these components would require additional stakeholder consultation outside the scope of this review.

27. This concludes my Affidavit.

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

| | | |
|---|---|---|
| | ) | |
| **PJM Interconnection, L.L.C.** | ) | **Docket No. ER23-____-000** |
| | ) | |

I, Skyler Marzewski, state that I am the Skyler Marzewski referred to in the foregoing document entitled "Affidavit of Skyler Marzewski," that I have read the same and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief. Additionally, I possess the full power and authority to sign the filing.

*/s/ Skyler Marzewski*
____________________________

Skyler Marzewski
Senior Analyst, Capacity Market & Demand Response Operations – Market Services
PJM Interconnection, L.L.C.
2750 Monroe Boulevard
Audubon, Pennsylvania 19403

Attachment D

Brattle Gross Avoidable Costs for Existing Generation report

# Gross Avoidable Costs for Existing Generation


**PREPARED BY**

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January 9, 2023

**PREPARED FOR**

PJM Interconnection, L.L.C

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.
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# Executive Summary

Starting with the 2022/23 Delivery Year, PJM Interconnection, L.L.C. (PJM) is required under the Open Access Transmission Tariff (OATT or tariff) to update Default Gross Avoidable Cost Rates (ACRs) every four years.[1] This study informs PJM's filing by developing updated gross cost estimates for various existing generation types.

PJM uses Default Gross ACRs (minus unit-specific net energy and ancillary services (E&AS) revenues) to determine default offer thresholds for mitigating market power in its capacity market. For several years, the Default Gross ACRs were used only for mitigating so-called "buyer-side" market power; capacity resources that were subject to the Minimum Offer Price Rule (MOPR) were subject to default offer floors and could offer at lower prices only if accepted through a unit-specific review of actual costs.[2] However, in March 2021, the Federal Energy Regulatory Commission (FERC) ordered PJM to expand the application of Default ACRs to its mitigation of supplier market power, after finding that the existing offer caps were excessive.[3] Any resources subject to Market Seller Offer Caps (MSOCs) could now offer above the default ACRs only by demonstrating higher costs through unit-specific reviews. Thus, PJM's updated Default Gross ACRs will be used for mitigating supplier market power (via MSOC) as well as for MOPR purposes in PJM's Base Residual Auctions for 2026/27 and the following three delivery years.

To conduct this update of the Default ACRs, PJM retained The Brattle Group (Brattle) and Sargent & Lundy (S&L) to analyze the gross avoidable 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 and incorporated stakeholder input through three rounds of presentations before the Market Implementation Committee (MIC) between October and December.

Our approach recognizes that existing generation resources vary considerably in their characteristics and costs, both across resource types and even within each type. This variability

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

[2] See Minimum Offer Price Rule (MOPR)—Attachment DD § 5.14(h-2).

[3] See Market Seller Offer Cap (MSOC)—Attachment DD § 6.4.

must be considered in developing coherent “types” and in developing default offer thresholds for each, trading off the risks of under-mitigation against the risks of over-mitigation and/or a burdensome amount of unit-specific reviews.

To inform PJM’s determination of a single Default Gross ACR for each resource type, we reviewed the range of characteristics of resources in the PJM market and identified the primary cost drivers among those characteristics for each resource type. We 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. We 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, we then estimated the 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.

We also provide estimates for the Variable Operation and Maintenance (VOM) costs as a benchmark to inform PJM’s E&AS net revenue analysis when determining Net ACRs. The classification of costs categories as gross versus variable align with PJM’s current market rules concerning the costs that are includable in the Gross ACRs versus those that can be included in cost-based energy offers (and thus accounted for in the 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.”

Table ES-1 below shows the resulting gross costs for each existing generation resource type, expressed in 2022 dollars per-megawatt (MW) of nameplate capacity. Variable costs are presented separately, within the body of this report. Note that throughout this report, our results are presented as “gross costs” rather than “Gross ACRs” because the formal term reflects a tariff rate filed by PJM and approved by FERC, and our study only informs those rates.

**TABLE ES-1: EXISTING GENERATION GROSS COSTS**
(IN 2022 DOLLARS PER NAMEPLATE MW PER DAY)

| Resource Type | Representative Plant $/MW-day |
|---|---|
| Multi-unit Nuclear | **$537** |
| Single-unit Nuclear | **$591** |
| Coal | **$94** |
| Natural Gas CC | **$113** |
| Simple Cycle CT | **$52** |
| ST O&G | **$64** |
| Onshore Wind | **$147** |
| Solar PV | **$70** |

# 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 bounds of competitive levels. Concerns surround both supplier market power and buyer market power. Supplier market power is deemed a threat where jointly-pivotal market sellers fail the Three Pivotal Supplier ("TPS") test, which all typically do.[4] Under such circumstances, resource offers would be subject to Market Seller Offer Caps (MSOC). Buyer market power—in the form of resources being offered at artificially lower prices—is deemed a concern under special circumstances and applicable resources would be subject to the Minimum Offer Price Rule (MOPR). MOPR applicability has recently been narrowed after much litigation.[5]

PJM will approach both instances by setting default offer thresholds for various resource types, such that higher-priced offers on MSOC-applicable resources could trigger a unit-specific review to consider setting a higher unit-specific MSOC; lower-priced offers on MOPR-applicable resources could trigger a unit-specific review to set a lower unit-specific MOPR. Default thresholds will be determined by a generic resource type-specific Gross Avoidable Cost Rate (ACR) minus resource-specific net revenues from energy and ancillary services markets (net E&AS offset).

Until recently, MSOCs were set uniformly across all existing resources, given by the Net Cost of New Entry (Net CONE) times an average "balancing ratio" of 85% based on an assumed number of Performance Assessment Intervals (PAIs). However, in March 2021, the Federal Energy Regulatory Commission (FERC) found the MSOCs to be unjust and unreasonable.[6] FERC found those rates to be too high, due to an unrealistically high estimate of the number of expected PAIs. FERC ordered PJM to use more specific Avoidable Cost Rates, as it uses for MOPR, and as it had used for MSOC purposes prior to the implementation of Capacity Performance in 2016.

4 PJM, Market Seller Offer Cap (MSOC) Reform, February 28, 2022.

5 Federal Energy Regulatory Commission, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582-000, September 29, 2021.

6 Federal Energy Regulatory Commission, Order Granting Complaints and Ordering Additional Briefing, Docket Nos. EL 19-47-000 and EL 19-63-000, March 18, 2021.

Thus, this updated ACR study will be used for both purposes, in fulfillment of PJM's requirement to periodically update its Default Avoidable Cost Rates (ACRs) every four years.[7] The last such study was conducted by us in 2020, but future studies will be conducted every four years.

For this study, PJM requested that we estimate Gross Costs for existing generation resource types. The types would be defined to span most of the PJM fleet, where each type includes similar resources with similar cost structures; types would not be defined for resource classes that exhibit highly idiosyncratic and varying avoidable costs. For each type, we were asked to develop bottom-up cost estimates of the gross fixed costs for a "representative" plant, For informational purposes we also provided a "representative low" and "representative high" for lower and higher-cost sub-groups within each type. Additionally, PJM requested that we determine the Variable Operation and Maintenance (VOM) costs for each resource type for informational purposes to aide PJM in determining E&AS revenues.

As PJM applies the study results to determine default offer thresholds, it will need to balance the need to mitigate the exercise of market power against the administrative burden and risks of over-mitigation. Over-mitigation is possible due to information asymmetries between PJM and capacity sellers, even in unit-specific reviews. That could result, for example, in a resource's MSOC being set below its true competitive costs—which could discourage participation in the market. Over-mitigation 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; and by setting default MOPRs reasonably low for symmetrical reasons.

## B. Analytical Approach

To calculate the gross default costs we first identified types that span most of the installed capacity in the PJM footprint and have sufficiently little variation of gross fixed costs within the type. We then analyzed the fleet and identified defining characteristics of the median plant by capacity; and then calculated the gross costs that would be avoided if such a plant retired. The calculations are consistent with PJM's tariff for the scope of costs allowable in Gross ACRs.

For the definition of types, we received an initial list from PJM that was based on the previously identified types from the 2020 Gross ACR study. These types were chosen to span a large

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

portion of the overall PJM fleet and such that each type is coherent and has common cost characteristics within it. We then iterated upon the defined types with PJM and market stakeholders and included one additional type due to stakeholder feedback. A small remaining portion of the fleet that we did not characterize as "types" with a Default Gross ACR had more idiosyncratic cost characteristics among individual plants (e.g., due to older, non-standard technology) so did not lend themselves well to defining a standardized estimate of costs; absent a Gross ACR, these plants will have to rely on unit-specific reviews for nonzero capacity offers.

For each defined resource type, we identified the characteristics of a "representative plant" that is widely representative of the individual plants within that type. The "representative plant" standard that we agreed on with PJM staff and reviewed with stakeholders was 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, we instead identified the median plant as one with median 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. We then estimated the costs for such a plant as described below.

While we agreed with PJM and stakeholders that the representative plant would be used to determine the Default Gross ACRs, we also sought to inform the range of costs PJM might see for each type. We thus defined a "representative high-cost" and a "representative low-cost" plant for each type, considering the range of characteristics and especially clusters thereof. This was unnecessary, however, for single-unit nuclear plants since the population consists of only two plants.

Given the assumed representative characteristics, we then estimated the costs of the representative plants to inform the gross costs, as well as the variable O&M costs to inform PJM's net E&AS analysis. Gross costs reflect the fixed costs of operating an existing generation resource for an additional year that could be avoided if the plant retires.[8] Our cost estimates for most types of thermal plants are based on S&L's regression analyses of FERC Form 1 filings 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, where FERC Form 1 submissions were deemed inconsistent, we relied on NEI's

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[8] 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.

latest "Nuclear Costs in Context" study, with adjustments to reflect the representative plant. For wind and solar plants, for which FERC Form 1 data is sparse, we relied on S&L's extensive project database.

For most types, property taxes and insurance constitute a relatively small fraction of total cost, but they are less straightforward to quantify uniformly, and we have refined our approach since our 2020 study and over the course of this study based on stakeholder feedback. Our approach to estimating these costs varies by resource type given data availability, and is described under each type presented below.

One aspect of this study that required careful consideration was to distinguish which costs to include in the gross costs and which to consider as variable costs. Only the gross costs would determine resource types' Default Gross ACRs, while variable costs would presumably be accounted for in resources' Default Net ACRs for capacity offer mitigation purposes if generators include them in their cost-based energy offers. To avoid double counting any such costs, it is important to categorize these costs consistently with PJM's rules regarding energy market offers. We followed PJM guidance regarding its tariff and operating agreements.[9] Among other cost categories, PJM's tariff specifies that major maintenance costs can be included in variable costs in cost-based energy offers, under a maintenance adder that includes activities such as repair, replacement, and major inspection.[10] Therefore, consistent with tariff, our estimated gross costs include Fixed Capital Costs and Fixed Operation & Maintenance (FOM) costs but not major maintenance costs for systems directly related to electric production. In the case of nuclear plants, however, we provide an indicative estimate of the gross costs with major maintenance included for informational purposes in the hypothetical case if PJM were to determine that major maintenance should be included in the Gross ACR

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[9] 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 Gross 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 included in the Gross ACR. We understand that PJM interprets this to mean that all maintenance costs for systems directly related to electric 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, PJM Open Access Transmission Tariff, Attachment DD, Section 6 Market Power Mitigation, Section 6.8(c).

[10] PJM, Operating Agreement of PJM Interconnection, L.L.C., Schedule 2, Section 4.

and adapts its tariff accordingly. For the remainder of plant types, given PJM's guidance, we identify the types of maintenance costs included in the gross costs and those included in the variable cost maintenance adder, and estimate the costs of each accordingly, as reported below.

# II. Selection of Plant Types within PJM Fleet

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

- Multi-unit nuclear
- Single-unit nuclear
- Coal
- Natural gas-fired combined-cycle turbines (NG CC)
- Simple-cycle combustion turbines (Simple Cycle CT), previously limited to natural gas combustion turbines
- Oil and gas-fired steam turbines (ST O&G), new type based on stakeholder feedback
- Onshore wind
- Large-scale (>1 MW) solar photovoltaic plants (Solar PV)

These types are similar to those in the 2020 ACR study, but expanded based on stakeholder feedback. We added an oil and gas-fired steam turbine type and amplified the simple-cycle combustion turbine type to include oil peaker plants as well as gas plants compared to the 2020 ACR determination.[11] Table 1 shows a breakdown of the current capacity of the PJM fleet. The chosen resource types combined cover about 94% of the entire PJM fleet.

[11] Newell, et al., Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency, March 17, 2020 ("2020 Gross ACR Study").

**TABLE 1: PJM FLEET CAPACITY BY PLANT TYPE**

| Plant Type | Total MW (Summer ICAP) | % of Total PJM Capacity | Recommendation |
|---|---|---|---|
| **NGCC** | **55,828** | **28%** | **Included** |
| **Coal** | **41,554** | **21%** | **Included** |
| **Nuclear** | **32,556** | **16%** | **Included** |
| **Simple Cycle CT** | **28,496** | **14%** | **Included** |
| **Wind** | **9,911** | **5%** | **Included** |
| **ST O&G** | **9,240** | **5%** | **Included** |
| **Solar** | **7,790** | **4%** | **Included** |
| Pumped Storage | 5,243 | 3% | Unit-specific review |
| Hydro | 3,319 | 2% | Unit-specific review |
| Other | 3,427 | 2% | Unit-specific review |
| **PJM Total Installed Capacity** | **197,364** | 100% | |

Notes and Sources: ABB, Energy Velocity Suite.

The remaining resource types, for which gross costs were not determined, 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 rather than a standardized ACR.

# III. Gross Costs for Existing Generation

## A. Multi-Unit Nuclear Plants

Most nuclear plants in PJM have multiple units installed at the same site. In total, there are currently 14 multi-unit nuclear plants operating in the PJM footprint. The capacity of multi-unit nuclear plants in PJM are mostly in the range of 1,750–2,500 MW, and in most cases these plants are 30–50 years old. There are six states in PJM with nuclear plants, with the most located in Illinois and Pennsylvania.[12] Figure 1 below summarizes the age, size, and locations of these plants.

[12] 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.

Based on our experience estimating costs for nuclear plants, 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 impacts property taxes and operating costs), the business model (merchant generation vs. regulated cost-of-service generation), and the operator's fleet size.

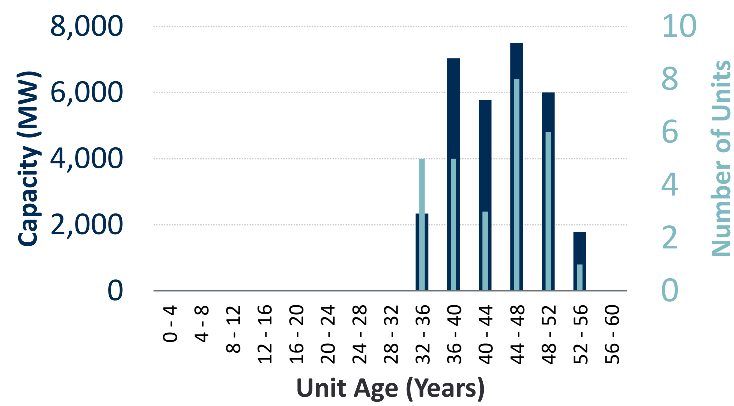
*Representative Multi-Unit Nuclear Plant Characteristics*

To choose a representative multi-unit nuclear plant we first determined the median plant size of the most frequent size bin of the nuclear fleet, which was between 2,200 MW to 2,400 MW as shown in Figure 1, Panel (B). We then filtered the multi-unit fleet data by this size bin (2,200 MW to 2,400 MW) and compared the median age of the filtered population to the median age of the unfiltered total multi-unit nuclear fleet and found that both were aligned, so we defined the representative age as the median of the fleet (44-years old). We then compared the reactor types, the locations, and the owners' business model and size in this filtered population to the overall fleet. Based on this approach, the representative multi-unit nuclear plant is a 44-year-old 2,400 MW (comprised of two 1,200 MW units) BWR merchant plant in Illinois with an owner that operates multiple plants.

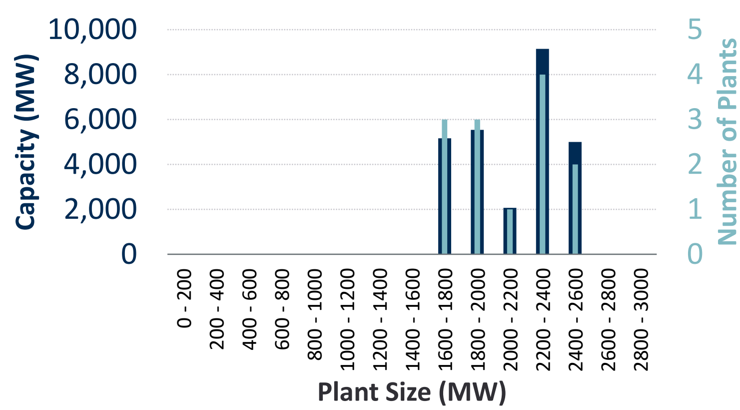
Given the limited number of nuclear plants and limited size variation, we did not alter the plant size for the representative low and high cost plants. For the representative low-cost plant, we chose a pressurized water reactor plant in Virginia, since PWRs have lower operating costs and Virginia has lower labor costs. For the representative high-cost plant, we assumed a plant similar 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.

**FIGURE 1: MULTI-UNIT NUCLEAR FLEET CHARACTERIZATION**

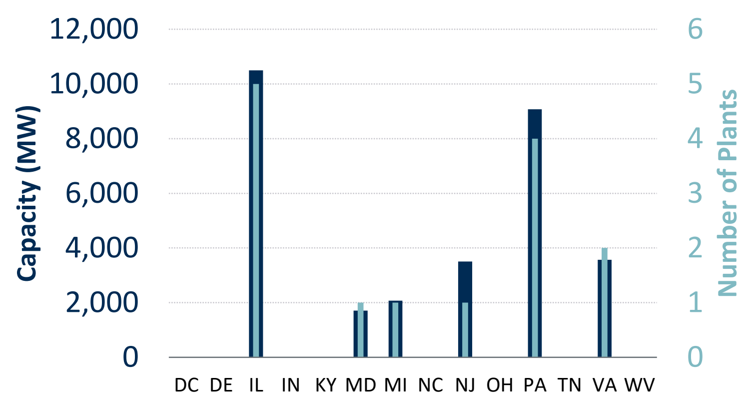
**(A) UNIT AGE**




**(B) PLANT SIZE**




**(C) PLANT LOCATION**




Notes and Sources: ABB, Energy Velocity Suite.

*Cost Estimates for the Representative Multi-Unit Nuclear Plant*

Our cost estimates for nuclear plants rely the 2022 NEI "Nuclear Plants in Context" study, with adjustments to best reflect the representative plant and PJM's characterization of "gross" versus variable costs, as described below.[13] Corresponding to the NEI report's , we present nuclear cost components as ongoing capital expenditures and operating costs, then add property taxes, which NEI did not estimate.

**Ongoing Capital Expenditures:** NEI's capital cost category includes capital spares, regulatory, infrastructure, information technology, enhancements, and sustaining costs (including insurance costs). To estimate the capital cost contribution to gross costs (and variable costs) for PJM multi-unit nuclear plants, we started with the 2021 average capital costs for all U.S. nuclear plants of $5.50/MWh, plus a year of inflation at 7.66%.[14] We then adjusted this value downward by 16.73% 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.[15] These adjustments yielded a total capital cost of $4.93/MWh in 2022 dollars. From this total, Capital Spares (1.2% of total capital costs) are excluded from the gross costs and counted as variable costs instead, consistent with PJM's tariff. Sustaining costs (37.2% of total capital costs) also are considered variable and excluded from the gross costs, since this category reflects investments in systems directly related to electric production that are necessary to maintain plant performance. In contrast to our prior approach in the 2020 Gross ACR Study, and in response to stakeholder feedback, we included the Enhancements component (36.3% of total capital costs) in the gross costs. These costs are part of continuing the life the plant, and they are incurred fairly consistently by the fleet over time; and they belong in gross costs as opposed to variable costs because they are not directly related to electricity production. The remaining 25.3% of capital costs include upgrades to the plant that are expected to occur on an annual basis and are not directly related to electricity production, so they too are included as a gross case. The resulting contribution of capital costs to multi-unit nuclear plants' gross costs is $3.04/MWh, and $1.89/MWh as part of variable costs (all in 2022 dollars).

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13 Nuclear Energy Institute, Nuclear Costs in Context, October 2022 ("NEI Report").

14 U.S. Bureau of Labor Statistics, Consumer Price Index US City Average. Value obtained from 2022 January to October average CPI divided by 2021 average CPI or 291.735/270.970 = 1.0766.

15 NEI tabulated values included sensitivities for these characteristics, each of which were considered as a percentage change from the national average. The averages of these percentages were applied to the national average CapEx to yield the 16.73% net adjustment.

**Non-Fuel Operating Costs:** NEI's operating cost category includes engineering, loss prevention, materials and services, fuel management, operations, support services, training, and work management. We started with the 2021 average operating costs for all nuclear plants in the U.S. of $18.07/MWh, plus a year of GDP inflation at 7.66%.[16] We then adjusted this value upward by 1.74% 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. These adjustments yielded a total operating cost for our reference technology of $19.79/MWh in 2022 dollars. The components of operating costs primarily reflect labor costs that are not directly attributable to the production of electricity and so are included in the gross costs. We interpret the Materials & Services costs (1.5% of total operating costs) to account for consumables required to operate the nuclear plants and thus include those costs as variable operating costs but exclude them from the gross costs. The remaining 98.5% of the total operating costs are included in the gross costs. We applied these percentages to the total operating costs for a multi-unit BWR plant to calculate the variable and fixed operating costs. The resulting contribution of operating costs to multi-unit nuclear plants' gross costs is $19.50/MWh, and $0.30/MWh as part of variable costs (all in 2022 dollars).

**Property Taxes:** Property tax costs were determined using S&L's project database and expertise. S&L's discussions with operators of nuclear facilities determined broad ranges of taxes are assessed on nuclear facilities depending on the location. We selected a median annual value of $1.01/MWh from this dataset and applied the same value to all nuclear units.

These capital, operating, and property tax cost components are combined to estimate the total gross costs shown in Table 2. The result for the representative multi-unit nuclear plant in PJM is $537/MW-day (in 2022 dollars). The estimated variable costs for the representative multi-unit nuclear plant are $2.19/MWh. For the representative low-cost plant, estimated gross costs are $476/MW-day and variable costs are $2.22/MWh. For the representative high-cost plant, estimated gross costs are $552/MW-day and variable costs are $2.20/MWh.

[16] See footnote 14.

TABLE 2: MULTI-UNIT NUCLEAR GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

| | | Multi-Unit Nuclear Plant | | |
|---|---|---|---|---|
| | **Units** | **Representative Low-Cost Plant** | **Representative Plant** | **Representative High-Cost Plant** |
| **Capacity** | *Nameplate MW* | 2,400 | 2,400 | 2,400 |
| **Gross Costs** | *$/MW-day* | $476 | **$537** | $552 |
| Capital Costs | *$/MW-day* | $72 | **$69** | $69 |
| Fixed Operating Costs | *$/MW-day* | $381 | **$445** | $460 |
| Property Taxes | *$/MW-day* | $23 | **$23** | $23 |
| **Non-Fuel Variable Costs** | *$/MWh* | $2.22 | $2.19 | $2.20 |
| Operating Costs | *$/MWh* | $0.25 | $0.30 | $0.31 |
| Major Maintenance | *$/MWh* | $1.96 | $1.89 | $1.90 |

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. The major maintenance costs per MWh depend on the capacity factor, which we assumed to be 95% corresponding to the average nuclear capacity factor in 2021.[17]

As described in Section I.A above, PJM's tariff specifies that major maintenance costs can be included in variable costs in cost-based energy offers, under a maintenance adder and includes activities such as repair, replacement, and major inspection. If PJM were to determine that major maintenance should instead be considered in gross costs and adapts its tariff accordingly, this would move the major maintenance adder ($1.89/MWh) out of variable costs and increase the gross costs of the representative multi-unit nuclear plant by $43/MW-day, to $580/MW-day. For the representative low-cost plant, this would move $1.96/MWh out of variable costs and increase the gross costs by $45/MW-day to result in $521/MW-day. For the representative high-cost plant, this would move $1.90/MWh out of variable costs and increase the gross costs by $43/MW-day to result in $596/MW-day.

## B. Single-Unit Nuclear Plants

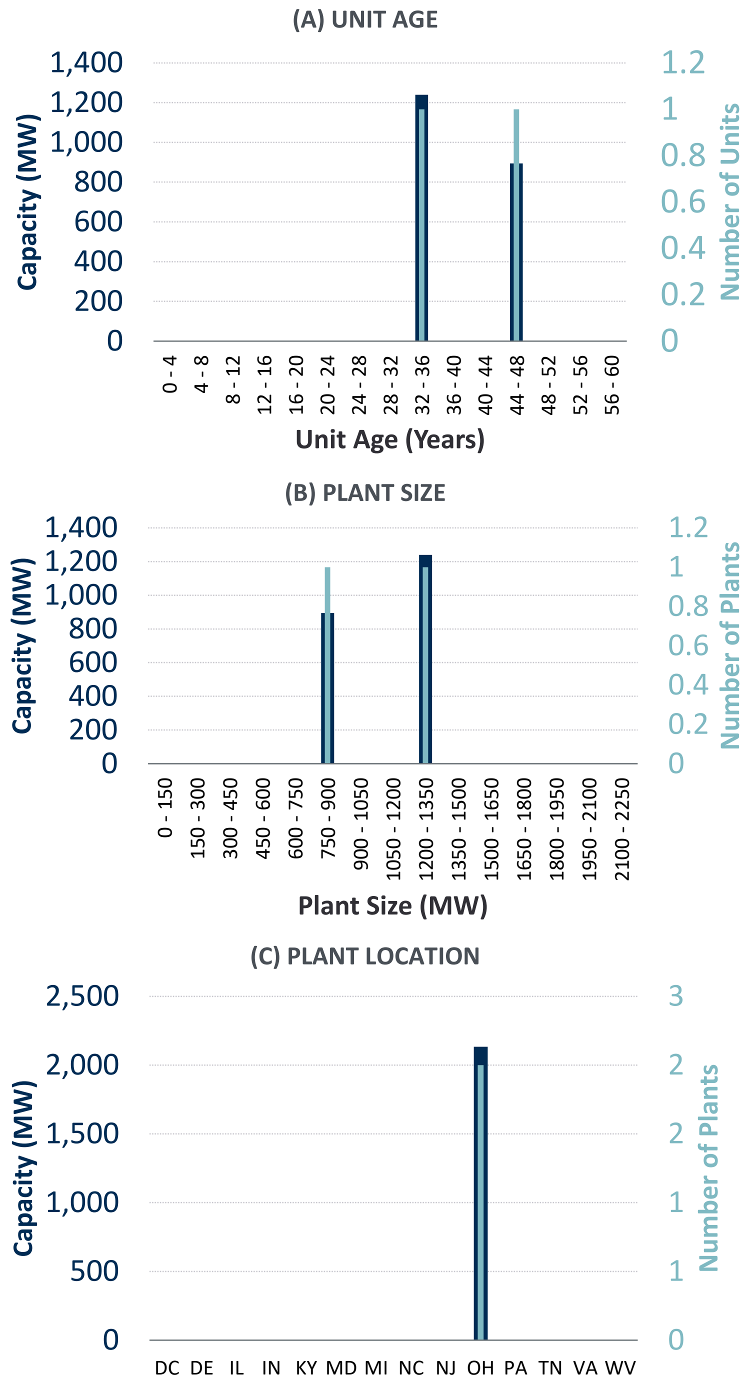
There are currently only two single-unit nuclear plants in the PJM market: the 894 MW Davis Besse plant and 1,240 MW Perry plant in Ohio.[18] Due to the small number of plants and the limited variation among them, we specified a single representative plant to be a 38-year-old 1,200 MW Boiling Water Reactor (BWR) unit in Ohio. With such a small population, we did not

[17] Monitoring Analytics LLC, PJM's Independent Market Monitor, 2021 State of the Market Report for PJM Volume 2: Detailed Analysis, March 10, 2022.

[18] See footnote 12, on the treatment of the Hope Creek plant in New Jersey.

designate a representative high or representative low-cost plant. Figure 2 below summarizes the age, size, and locations of these plants.

**FIGURE 2: SINGLE-UNIT NUCLEAR FLEET CHARACTERIZATION**




Notes and Sources: ABB, Energy Velocity Suite.

*Cost Estimates for the Representative Single-Unit Nuclear Plant*

Costs for the single-unit nuclear plant are estimated from NEI data in the same way as for multi-unit plants. The capital and operating costs are higher per MWh, but the property taxes are assumed to be the same per MWh.

**Ongoing Capital Expenditures:** following the same approach outlined above for multi-unit nuclear plants, we estimated annual avoidable capital costs of $3.38/MWh as part of gross costs and $2.11/MWh as variable costs based. We started with the 2021 average capital costs for all U.S. nuclear plants of $5.50/MWh, plus a year of GDP inflation at 7.66%.[19] We then adjusted this value downward by 7.27% to account for the representative plant characteristics, 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, the gross costs exclude Capital Spares and Sustaining costs but include Enhancements and the remaining capital costs, using the same percentages as for multi-unit nuclear plants.

**Non-Fuel Operating Costs:** We estimated avoidable fixed operating costs of $21.52/MWh and variable operating costs of $0.33/MWh for a single-unit BWR nuclear plant, just as described above for multi-unit nuclear plants. We started with the 2021 average operating costs for all U.S. nuclear plants of $18.07/MWh, plus a year of GDP inflation at 7.66%.[20] We then adjusted this value upward by 12.32% to account for the representative plant characteristics including its location, boiling water reactor, single-unit, and merchant status within a multiple-plant portfolio of the operator. These adjustments yielded a total operating cost for our reference technology of $21.85/MWh in 2022 dollars. As with multi-unit nuclear plants, the gross costs includes 98.5% of that, with only Materials & Services costs attributed to variable costs.

Table 3 below shows the resulting gross costs for a representative single-unit nuclear plant in PJM to be $591/MW-day (in 2022 dollars). The estimated variable costs for a single-unit nuclear plant are $2.44/MWh (in 2022 dollars).

[19] See footnote 14.

[20] See footnote 14.

**TABLE 3: SINGLE-UNIT NUCLEAR GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)**

| | Units | Single-Unit Nuclear Plant |
|---|---|---|
| **Capacity** | *Nameplate MW* | 1,200 |
| **Gross Costs** | *$/MW-day* | **$591** |
| Capital Costs | *$/MW-day* | **$77** |
| Fixed Operating Costs | *$/MW-day* | **$491** |
| Property Taxes | *$/MW-day* | **$23** |
| **Non-Fuel Variable Costs** | *$/MWh* | $2.44 |
| Operating Costs | *$/MWh* | $0.33 |
| Major Maintenance | *$/MWh* | $2.11 |

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. The major maintenance costs per MWh depend on the capacity factor, which we assumed to be 95% corresponding to the average nuclear capacity factor in 2021.[21]

Similar to the multi-unit plant, if PJM determines major maintenance should be considered in gross costs instead of variable energy costs and adapts its tariff accordingly, this would move the major maintenance adder ($2.11/MWh) out of variable costs and increase the gross costs of the representative multi-unit nuclear plant by $48/MW-day, to $639/MW-day.

## C. Coal Plants

The fleet of existing coal plants in PJM comprises a wide range of sizes, ages, and locations. There are over 120 existing coal units currently in the PJM market at approximately 60 different plant sites. Plant capacities range from less than 100 MW to nearly 3,000 MW with the average plant size of about 700 MW across all plants and 1,100 MW for plants that are at least 100 MW. Over half of the coal capacity is between 35–60 years old, with one plant dating back to 1942, and a few plants having come online in the last 10 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 these plants.

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,

[21] Monitoring Analytics LLC, PJM's Independent Market Monitor, 2021 State of the Market Report for PJM Volume 2: Detailed Analysis, March 10, 2022.

configuration, and technology), followed by the location and the types of post-combustion controls installed at the plant.

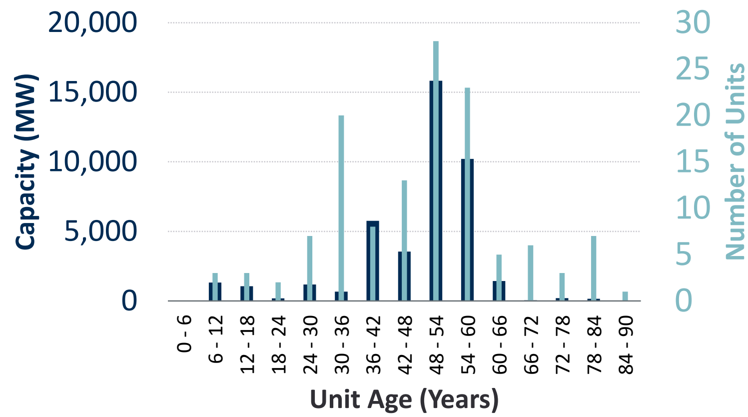
*Representative Coal Plant Characteristics*

Given that the age of a coal plant influences other cost drivers, we first determined the median plant age within the most frequent age bin of the coal fleet, which was between 48 to 54 years old as shown in Figure 3, Panel (A). We then filtered the coal fleet data by this age bin (48 to 54 years old) and compared the median age of the filtered population to the median age of the unfiltered total fleet. Both measurements were well aligned and were approximately 52 years old. Next, we determined the median capacity of the filtered population and reviewed the plant configurations of the filtered population. Then we reviewed the location of the filtered population and the installed pollution controls these plants had. Based on this approach, the representative coal plant is a 52-year-old 1,500 MW plant (with two 750-MW units) in Pennsylvania that burns Appalachian coal and has a wet limestone FGD unit.

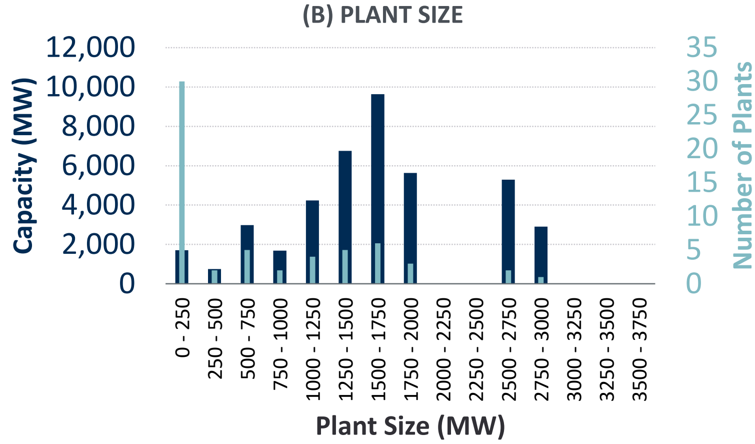
For the representative low-cost plant and representative high-cost plant, we varied the age and capacity of the plant as the main cost differentiators. Because most coal plants in PJM have some type of sulfur dioxide control technology and the majority of them have wet FGD units, we did not change that assumption from the representative plant. To determine the representative high-cost plant, we filtered the fleet data for plants 30-years or younger and determined the median plant size and configuration of this filtered population, which was approximately a 100 MW plant consisting of one unit. We then reviewed the locations of these filtered plants. Based on this approach, the representative high-cost plant is a 30-year old 100-MW plant (one 100-MW unit) with FGD in West Virginia. For the representative low-cost plant, we only varied the capacity of the plant from the representative plant since larger plants would have lower per MW costs, and defined it as a 52-year-old 1,800 MW plant (with two 900-MW units) with FGD in Pennsylvania.

**FIGURE 3: COAL FLEET CHARACTERIZATION**

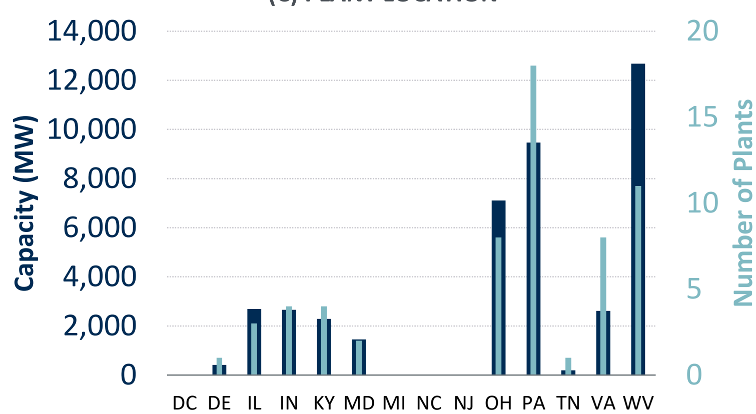
**(A) UNIT AGE**

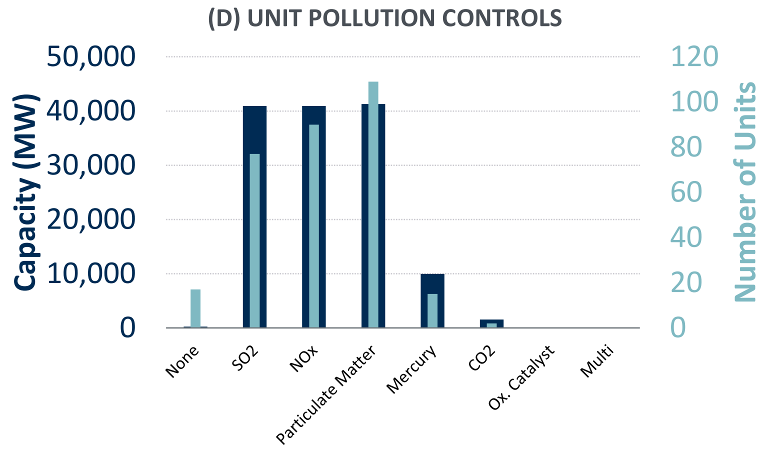



**(B) PLANT SIZE**




**(C) PLANT LOCATION**






Notes and Sources: ABB, Energy Velocity Suite.

*Cost Estimates for the Representative Coal Plant*

We estimated the total annual costs for operating the representative coal plant using data recently released by the EIA and FERC.[22] We reviewed the O&M costs, ongoing capital spending, and cost relationships across a broad range of plant configurations and developed our cost estimates by accounting for differences in unit sizes, number of units at the site, and ages in the reported costs relative to the representative plants. Our adjustments to the reported costs included estimation of staffing requirements, consumption of FGD reagent and other items, and disposal of ash and FGD sludge. The costs of staffing and other fixed expenses account for the economies of scale associated with larger unit sizes and multiple units at a site. We then validated the results against S&L's proprietary data for similar operating coal plants. Finally, where dollar values were referenced from a different year, we escalated the costs to 2022 using annual GDP inflation.[23]

Similar to the nuclear plants, we separated the costs that can be included in the gross costs from those included in the variable cost component of cost-based energy offers. Based on S&L's analysis of FERC Form 1 data and regression model for technically similar plants, a 52-year-old 1,500 MW coal plant would be expected to invest about $36 million in capital expenditures per year into the systems directly attributable to electricity production, which would be accounted

[22] EIA, [Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modeling Aging-Related Capital and O&M Costs](), prepared by Sargent & Lundy, May 2018; Federal Energy Regulatory Commission, FERC Form 1, Plant Cost Data, 2010 through 2019.

[23] See footnote 14.

for in the variable cost "maintenance adder" based on PJM's current market rules.[24] Assuming a 50% capacity factor, the maintenance adder contributes about $5.47/MWh to variable costs.[25] Meanwhile, the gross costs estimate includes fixed operating costs that are not directly attributable to electricity production, such as labor, administrative costs, preventative maintenance to auxiliary equipment (buildings, HVAC, water treatment), insurance, and support services.

Property tax rates vary by municipality or even by property where sometimes there are negotiated payment in lieu of taxes (PILOT) agreements, and plant values are not assessed in a uniform manner. To estimate property taxes for the representative coal plant, we surveyed actual property taxes payed by plants that were close to the representative plant size and applied the median value. We also leveraged this analysis to estimate insurance costs. Like property taxes, insurance costs depend on the value of the plant, although the costs are generally not publicly available. S&L has in the past shown that insurance costs tend to be roughly three times as high as property taxes paid by large thermal plants in S&L's project database, and we applied this multiplier. Both turned out to be very small.

Table 4 below shows that the estimated gross costs for the representative coal plant are $94/MW-day (in 2022 dollars), and the variable costs are estimated at $10.92/MWh. For the representative low-cost coal plant, estimated gross costs are $88/MW-day variable costs are $10.47/MWh. For the representative high-cost coal plant, estimated gross costs are $142/MW-day, and variable costs are $9.61/MWh.

[24] PJM, Operating Agreement of PJM Interconnection, L.L.C., Schedule 2, Section 4.

[25] The capacity factors estimated are based on Figure 3-1 Capacity Factor vs. Age for All Coal Plants from the EIA's Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modelling Aging-Related Capital and O&M Costs, prepared by Sargent & Lundy, May 2018.

TABLE 4: COAL PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

| | | Coal Plant | | |
|---|---|---|---|---|
| | Units | Representative Low-Cost Plant | Representative Plant | Representative High-Cost Plant |
| **Capacity** | *Nameplate MW* | 1,800 | 1,500 | 100 |
| **Gross Costs** | *$/MW-day* | $88 | **$94** | $142 |
| Labor | *$/MW-day* | $38 | **$41** | $60 |
| Fixed Expenses | *$/MW-day* | $48 | **$51** | $79 |
| Property Taxes | *$/MW-day* | $0.5 | **$0.5** | $0.5 |
| Insurance | *$/MW-day* | $1.5 | **$1.5** | $1.5 |
| **Non-Fuel Variable Costs** | *$/MWh* | $10.47 | $10.92 | $9.61 |
| Operating Costs | *$/MWh* | $5.00 | $5.45 | $5.62 |
| Maintenance Adder | *$/MWh* | $5.47 | $5.47 | $3.99 |

Notes and Sources: gross costs are expressed in 2022 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. The estimated maintenance adder costs per MWh are variable based on the capacity factor. The maintenance adders assume a 50% capacity factor for the low-cost and median representative plants, and 62% for the high-cost representative plant.[26]

## D. Natural Gas-Fired Combined-Cycle Plants

Nearly all natural gas-fired combined-cycle (CC) plants have been built over the past 25 years, with more than 22,000 MW installed in the past 5 years, and most of the rest built in the early 2000s. Plants built in the early 2000s are in the 500 MW to 1,000 MW range while more recent projects typically exceed 1,000 MW. Many of the gas CCs have been built in regions with access to low-cost gas via pipelines or within gas supply basins, predominantly in Pennsylvania, followed by Virginia, Ohio, and New Jersey. Most are equipped with Selective Catalytic Reduction (SCR) to reduce emissions of nitrogen oxides ($NO_x$). Figure 4 below summarizes the age, size, locations, and pollution controls of these plants.

The main drivers of cost variability among CCs are the capacity, age, turbine type, plant configuration, and whether or not 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.

[26] The capacity factors estimated are based on Figure 3-1 Capacity Factor vs. Age for All Coal Plants from the EIA's Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modelling Aging-Related Capital and O&M Costs, prepared by Sargent & Lundy, May 2018.

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

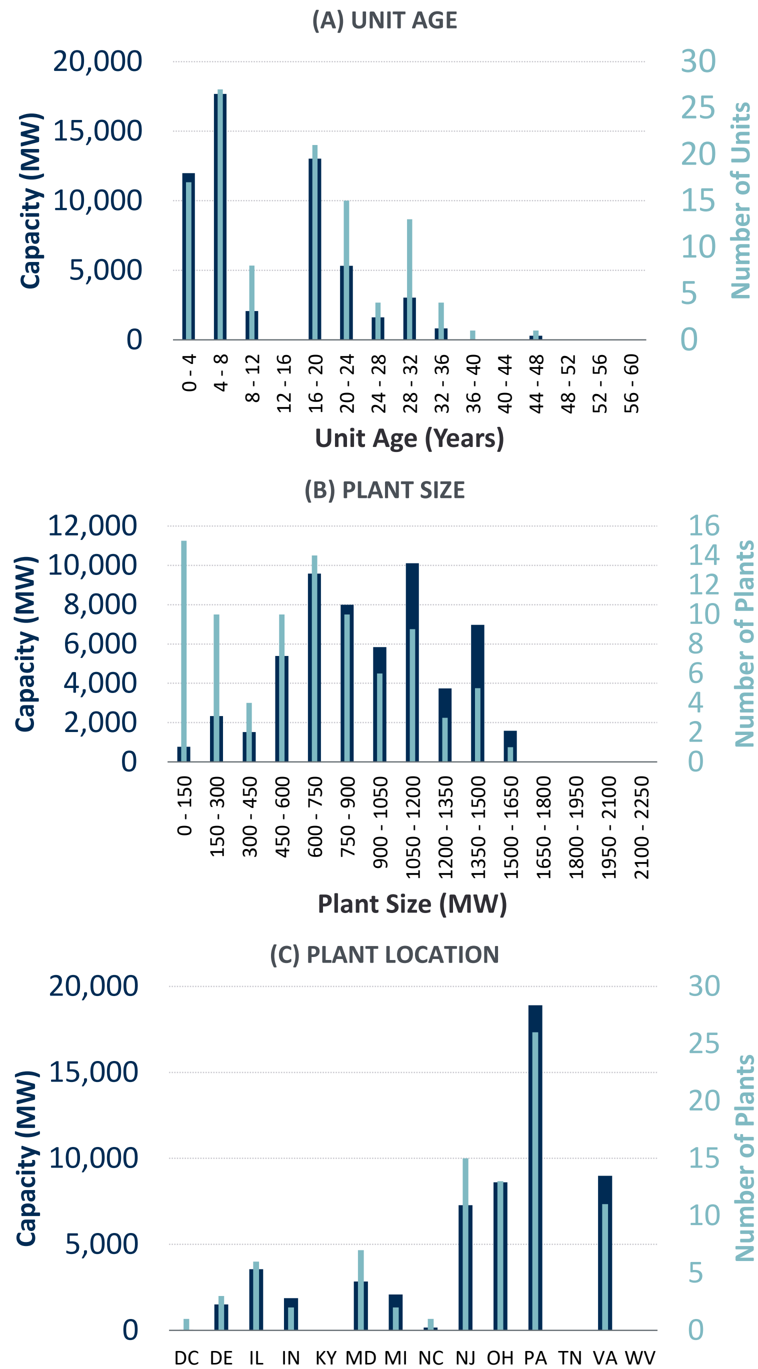
We relied on input from PJM indicating that the majority of existing CC plants have firm gas transportation contracts up to their economic maximum (EcoMax), and therefore the representative plant would be subject to this cost. Then we determined the median plant size of the CC fleet, which was 669 MW in the 600 MW to 750 MW bin as shown in Figure 4, Panel (B). We then filtered the CC fleet data for plants between 600 MW to 750 MW and compared the median age of the filtered population to the median age of the unfiltered total CC fleet and found that both were aligned, so we defined the representative age as the median of the fleet (11-years old). We then compared the plant configuration, location and the installed pollution controls in this filtered population to determine that most plants are in a 2×1 configuration, nearly all plants have SCR installed, and most are located 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 size to 750 MW to account for this standardization. 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 (2×1) configuration in Pennsylvania that has SCR technology installed and has firm gas transportation service.

The representative high-cost and low-cost plants reflect the two modes of the bi-modal distribution of ages of CC plants in PJM. The older plants are smaller and have higher costs per MW-day, where newer plants are larger and have lower costs per MW-day with their economies of scale. Since nearly all CC plants in PJM have SCR installed for $NO_x$ pollution control, we did not vary this assumption for the representative high or low-cost plants. Because the majority of the CC feet has firm gas up to EcoMax we also assume that the representative low-cost and representative high-cost plants have firm gas transport service as well.

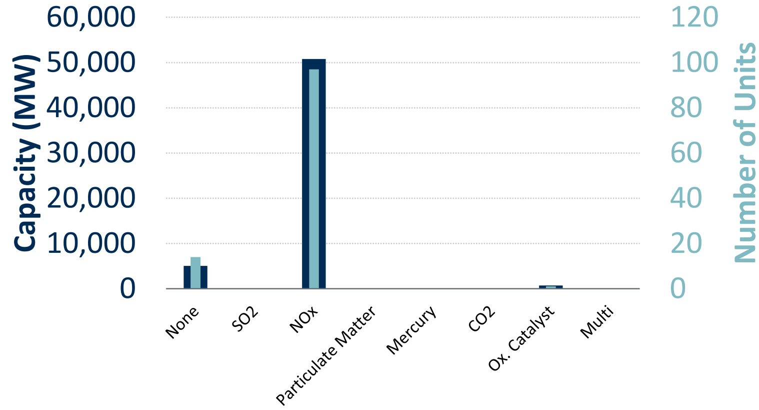
For the representative high-cost plant, we first identified a plant size that was representative of the smaller plants in the fleet. We split the CC fleet into plants smaller than 750 MW and found the median of this sub-population, which were plants between 300 MW to 450 MW. We then filtered the CC sub-population for plants between 300 MW to 450 MW and chose a 400 MW median to represent the smaller/older CCs. New Jersey has the second most CCs in PJM so we chose this location for the representative older/smaller plant. The median CC plant age in New Jersey is approximately 30-years old. We assessed the plant configuration and turbine type of plants in this size range to be an F-class single unit. Based on this approach, the representative high-cost CC plant is a 30-year-old, 400 MW plant, with one F-class turbine in a 1×1 configuration in New Jersey.

For the representative low-cost plant, we identified plants in the 1,050–1,200 MW range, which represents a large proportion of the capacity and a high number of plants as shown in Figure 4, Panel (B). We filtered the CC fleet data by this size bin to obtain the representative low-cost age at a median of 5 years old. We used the CC fleet data filtered by this size to determine the plant configuration, turbine type, and location of the remaining plants. CC plants around this size and age tended to be larger with H-class turbines in a 2×1 configuration. Based on this approach, the representative low-cost CC plant is a 5-year-old 1,100 MW plant with two 550 MW H-class turbines in a 2×1 configuration in Pennsylvania.

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



(D) UNIT POLLUTION CONTROLS




Notes and Sources: ABB, Energy Velocity Suite.

*Cost Estimates for the Representative Natural Gas-Fired Combined-Cycle Plants*

To estimate the costs of the representative plants, we relied on the same methodology used to develop cost estimates for gas CCs in the PJM 2022 CONE Study.[27] Similar to how costs are specified in the 2022 CONE Study, we included the hours-based major maintenance costs specified in Long-Term Service Agreements (LTSAs) under variable O&M costs alongside operating costs associated with chemicals and consumables.

We used the cost information from the 2022 CONE Study to estimate components of the fixed O&M, variable O&M, and major maintenance for the representative low-cost plant (H-class 2×1). Other public sources and S&L's project database containing a broad range of CC configurations were used for estimating the cost components for the 750 MW and 400 MW F-class representative plants.

We adjusted the cost data from public sources to account for differences in turbine sizes, configurations, locations, and ages relative to the representative plants based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation.[28] These adjustments accounted for staffing requirements and the economies of scale associated with larger turbine sizes and multiple turbines at a site. The costs of major maintenance and consumables were derived using a 62% capacity factor, representative of CCs in PJM. Property taxes and insurance were estimated using the values

27 Newell, et al., PJM CONE 2026/2027 Report, April 21, 2022 ("2022 CONE Study").

28 Adjustments come from S&L project database and public sources including FERC Form 1 and EIA, Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modeling Aging-Related Capital and O&M Costs, prepared by Sargent & Lundy, May 2018.

from the 2022 CONE study[29] with downward adjustments made for the older, less valuable plant.

Firm gas transportation costs were estimated at updated average tariff rate of $8.06/Dth per month incorporating reservation and usage charges for major pipelines servicing Pennsylvania under the FT-1 rate schedules.[30] We calculated the average heat rate for all natural gas-fired combined-cycle plants in the PJM fleet to be 7,212 Btu/kWh.[31] We then multiplied the nameplate plant capacity for the representative plants with the heat rate to estimate the average annual gas requirement. We then calculated the annual firm gas cost of $46/MW-day using the average tariff rate of $8.06/Dth per month applied to the annual gas requirement.

Table 5 below shows that the estimated gross costs for the representative plant are $113/MW-day and variable costs are $2.71/MWh (in 2022 dollars). The estimated gross costs for the representative low-cost plant are $94/MW-day and variable costs are $2.36/MWh. Estimated gross costs are higher for the smaller 400 MW representative high-cost plant at $160/MW-day due to the reduced economies of scale. The variable costs for the representative high-cost plant are $2.60/MWh.

Note that the $113/MW-Day gross costs of the representative existing CC plant are similar to the Fixed O&M costs for new CCs from the 2022 CONE Study as part of the Quadrennial Review.[32] Accounting for updates incorporated into the final submitted CONE values[33] and deflating those estimates to 2022 dollars, the Fixed Operation & Maintenance cost for the new CCs in the WMACC CONE Areas (most closely corresponding to the "PA" location of the representative existing CC) plant is $83/MW-day. This is $11/MW-day less than the $94/MW-day we are estimating for the gross costs of the comparably sized "Low-Cost" existing plant. The difference is primarily attributable to updated tariffed rates used to estimate the costs of firm fuel, partially offset by lower property taxes and insurance, and other adjustments.

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29 2022 CONE Study.

30 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 August 1, 2022, and Transcontinential Gas Pipeline Company FERC Gas Tariff, Delivery Zone 6 and Receipt Zone 6 effective November 1, 2022.

31 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.

32 PJM Interconnection, L.L.C., Docket No. ER22-2984-000 Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, pdf page 364.

33 *Ibid*, Attachment D.

TABLE 5: COMBINED-CYCLE PLANTS' GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

| | | Natural Gas Combined Cycle Plant | | |
|---|---|---|---|---|
| | Units | Representative Low-Cost Plant | Representative Plant | Representative High-Cost Plant |
| **Capacity** | *Nameplate MW* | 1,100 | 750 | 400 |
| **Gross Costs** | *$/MW-day* | $94 | **$113** | $160 |
| Labor | *$/MW-day* | $17 | **$21** | $32 |
| Fixed Expenses | *$/MW-day* | $52 | **$72** | $120 |
| Property Taxes | *$/MW-day* | $6 | **$5** | $2 |
| Insurance | *$/MW-day* | $19 | **$15** | $6 |
| **Non-Fuel Variable Costs** | *$/MWh* | $2.36 | $2.71 | $2.60 |
| Operating Costs | *$/MWh* | $0.75 | $0.52 | $0.94 |
| Maintenance Adder | *$/MWh* | $1.61 | $2.19 | $1.66 |

Notes and Sources: gross costs are expressed in 2022 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 62% capacity factor.

## E. Simple-Cycle Combustion Turbines

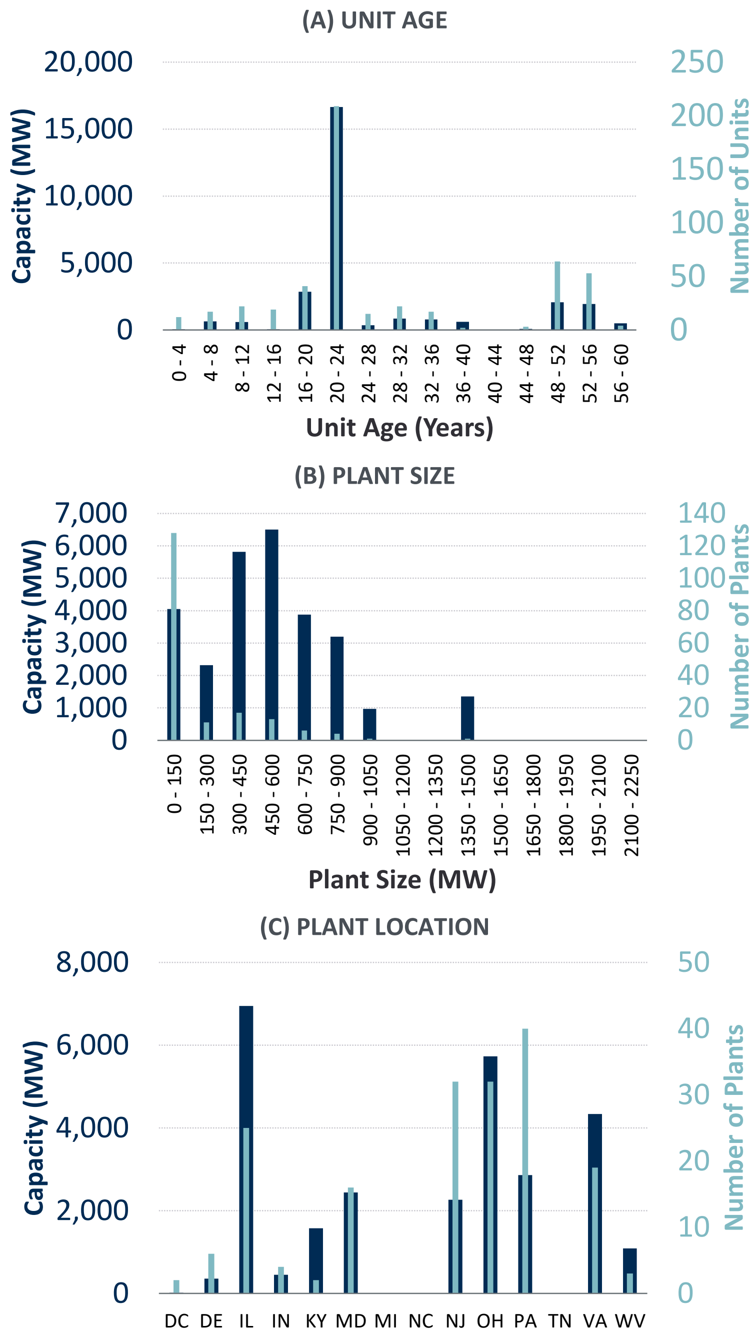
Simple-cycle combustion turbine (CT) plants include oil- and gas-fired CTs. Nearly all CTs were built around the early 2000s, but there is a wider range of sizes due to differences in the turbine technology and the number of turbines installed at each plant. There are many CT plants in the PJM fleet under 150 MW, but these plants cumulatively do not constitute a large amount of capacity compared to the larger plants in the 300–600 MW range. Most were built 20–24 years ago and the states with the most CTs include Ohio, Illinois, Pennsylvania, New Jersey, and Virginia. Unlike CCs, most CTs are not built with an SCR unit. Figure 5 below summarizes the age, size, locations, and pollution controls of these plants. The primary cost drivers for CTs are capacity, age, turbine type and configuration, and location.

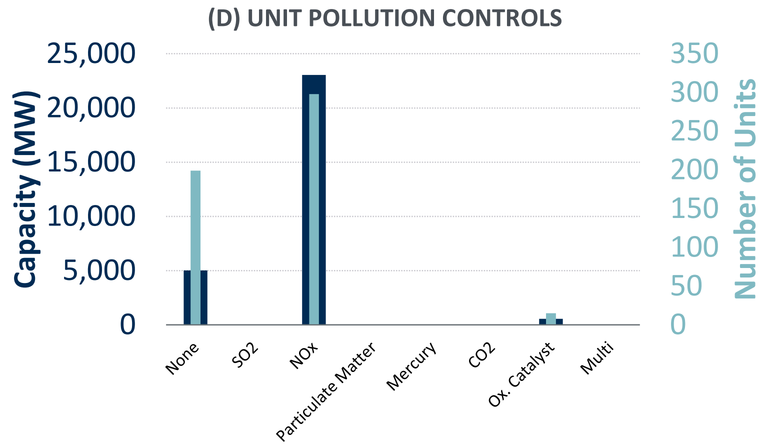
*Determination of Representative Simple-Cycle Combustion Turbine Plant Characteristics*

The median size of the fleet was 320 MW between the 300 MW to 450 MW size bin, as shown in Figure 5, Panel (B). We compared the median age of the CT fleet to the median age of the filtered population and found that both were approximately 20 years old. 20 years ago, F-class turbines were the predominant turbine technology. We then reviewed the location and configuration of the filtered population. Based on this approach, the representative CT plant is a 20-year-old 320 MW plant with two F-class turbines (2×160 MW) located in Illinois. Unlike CC plants, the majority of existing CT plants do not have firm gas transportation contracts up to EcoMax, according to PJM, so transportation costs were not included.

Because nearly all CT plants were built around the same time, we did not vary the age for the representative low-cost and representative high-cost plants and instead chose the low and high cost representative plant based on other factors. As shown in Figure 5 Panel (B), there are many plants that are less than 150 MW. To determine the representative low-cost plant, we filtered the 20-year-old CT fleet for plants smaller than 150 MW and determined the median capacity of this filtered population, which was 100 MW. Plants of this size were most frequently in Pennsylvania and typically use two LM600 aeroderivative turbines. Based on this approach, the representative high-cost CT is a 100 MW plant with two LM6000 aeroderivative turbines (2×50 MW) in Pennsylvania. To determine the representative low-cost plant, we filtered 20-year-old plants for sizes above 450 MW and found the median size of this filtered population, which was approximately 640 MW. These plants were most frequently in Illinois. Many plants of this size use several E-class turbines. Therefore, the representative low-cost CT is a 640 MW plant with eight E-class turbines (8×80 MW) in Illinois.

**FIGURE 5: SIMPLE CYCLE COMBUSTION TURBINE FLEET CHARACTERIZATION**






Notes and Sources: ABB, Energy Velocity Suite.

*Cost Estimates for Representative Simple-Cycle Combustion Turbine Plants*

To estimate costs, we reviewed cost estimates reported by the 2022 CONE Study, cost estimates from the EIA, and S&L's project database.[34] We then developed the cost estimates for existing CTs similar to the representative plants by adjusting the publicly reported costs for differences in turbine sizes, configurations, locations, and ages. We validated the results of our cost estimates against proprietary data in S&L's project database for similar plants in operation. The adjustments account for staffing requirements and the economies of scale associated with larger turbine sizes and multiple turbines at a site.

The CT technologies included in the ACR study are significantly different from the selected single GE model 7HA.02 reference technology from the 2022 PJM CONE study, thus estimation of their property taxes and insurance was performed using the most representative references available in S&L's project database. Both property taxes and insurance were estimated based on a regression analysis of similar technologies with adjustments made for the size, type, and age of the CTs in this study. The high-cost plant is an aeroderivative, which is a fundamentally different technology, so costs were estimated from a different data set of similar plants.

The E-class and F-class turbines that operate as peaking units would be expected to trigger major maintenance events based on the number of starts. For this reason, we estimated the variable cost maintenance adder assuming a 10% capacity factor and 12 hours of operation per start. The LM6000 turbines however, would likely trigger major maintenance based on hours of operation therefore their maintenance adder is independent of the number of starts per year.

[34] 2022 CONE Study; U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, March 2022.

Table 6 below shows the resulting gross and variable costs for the simple cycle CT plants. The estimated gross costs of the representative CT are $52/MW-day and the variable costs are $4.29/MWh (in 2022 dollars). For the representative low-cost plant, the estimated gross costs are $43/MW-day and variable costs are $4.29/MWh. For the representative high-cost plant, estimated gross costs are $69/MW-day and variable costs are $5.39/MWh.

We also validated these costs against the Fixed O&M costs accepted in PJM's tariff as part of the 2022 CONE Study.[35] Accounting for subsequent updates in later affidavits, and deflating those estimates to 2022 dollars, the published Fixed Operation & Maintenance cost for the same area as the representative plant is $93/MW-day. This value included the cost of firm gas contracts, which amounted to approximately $49/MW-day in 2022 dollars. Excluding the firm gas cost, the 2022 CONE study Fixed Operation & Maintenance cost for new CTs becomes $44/MW-day, which is close to our representative plant gross costs of $52/MW-day. This difference is primarily attributable to the staffing assumptions made for the representative 2×160 MW existing plant compared to the 1×353 MW new plant in the CONE study.

**TABLE 6: SIMPLE-CYCLE COMBUSTION TURBINE PLANTS GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)**

| | | Simple Cycle Combustion Turbine Plant | | |
|---|---|---|---|---|
| | **Units** | **Representative Low-Cost Plant** | **Representative Plant** | **Representative High-Cost Plant** |
| **Capacity** | *Nameplate MW* | 640 | 320 | 100 |
| **Gross Costs** | *$/MW-day* | $43 | **$52** | $69 |
| Labor | *$/MW-day* | $6 | **$10** | $23 |
| Fixed Expenses | *$/MW-day* | $8 | **$12** | $28 |
| Property Taxes | *$/MW-day* | $16 | **$16** | $3 |
| Insurance | *$/MW-day* | $13 | **$13** | $16 |
| **Non-Fuel Variable Costs** | *$/MWh* | $4.29 | $4.29 | $5.39 |
| Operating Costs | *$/MWh* | $0.42 | $0.42 | $0.97 |
| Maintenance Adder | *$/MWh* | $3.88 | $3.88 | $4.43 |

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses in the gross costs includes preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, and administrative and general. The maintenance adder assumes a 10% capacity factor with 12 hours per start. Actual major maintenance costs will vary with the number of starts, not strictly with MWh as expressed in this table, and will depend on actual duty cycles and maintenance agreement terms.

35 PJM Interconnection, L.L.C., Docket No. ER22-2984-000 Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, pdf page 364.

## F. Oil- and Gas-Fired Steam Turbines

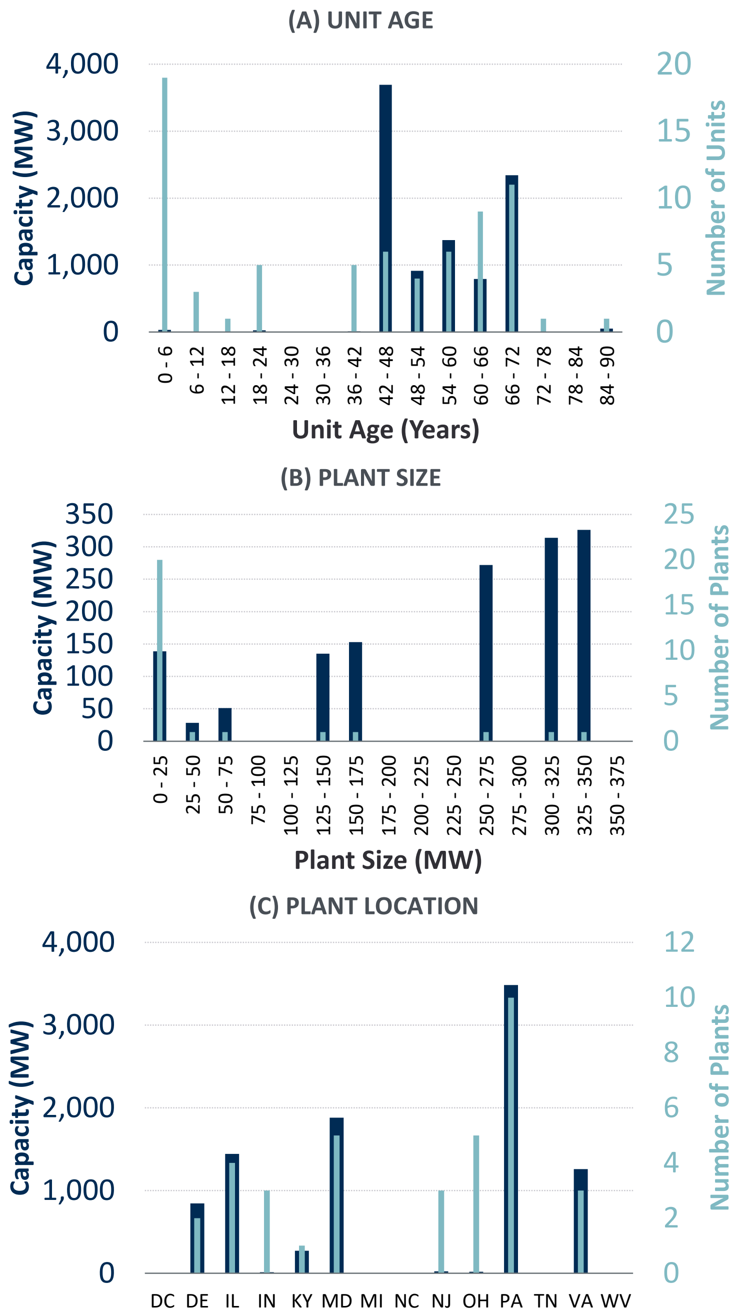
Steam turbine plants fueled by oil and gas (ST O&G) have a wide range of sizes. The majority of ST O&G plants are less than 25 MW but collectively do not contribute much capacity to the fleet. The average size is about 250 MW, which is skewed by a few very large plants on the order of 700 to 1,700 MW. Most of the larger plants and thus most of the capacity is located in Pennsylvania. Smaller plants are in Ohio, Maryland, and New Jersey. Ages of ST O&G plants range from 2–85 years old, with most capacity being 40–50 years old. Figure 6 below summarizes the age, size, locations, and pollution controls of these plants. The primary drivers of cost for ST O&G plants are age, capacity, location, and plant configuration.

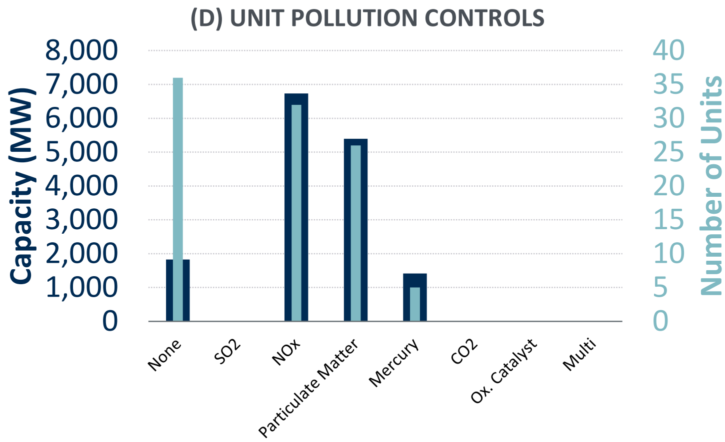
*Determination of Representative Oil- and Gas-Fired Steam Turbine Plant Characteristics*

The median MW in PJM's ST O&G fleet is in a 900 MW plant. We filtered the ST O&G fleet by this approximate size and compared the age of the filtered fleet with the age of the whole fleet. The age bucket contributing the most capacity to the ST O&G fleet are plants aged 42–48 years old, shown in Figure 6, Panel (A). We defined the representative age to be in this bucket (47-years old), which aligned with the ages of the filtered fleet. After further filtering for age, we ensured that the location of our representative plant reflected the location distribution of the whole fleet. The majority of existing ST O&G plants do not have firm gas transportation contracts up to EcoMax, according to PJM. Based on this approach, the representative ST O&G plant is a 47-year-old, 900 MW plant in Pennsylvania, without firm gas.

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. To reflect the many small plants in the fleet, we filtered for plants under 900 MW. For plants in Pennsylvania under this size, we chose an approximate median of 350 MW to be the representative high-cost plant size. We then filtered the fleet for plants of approximately 350 MW and found that the median age of these smaller plants was 65 years old. Based on this approach, the representative high-cost ST O&G plant is a 65-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 above 900 MW. We determined a representative high-cost plant size of 1,300 MW. These larger plants have a median age of 47-years old. Based on this approach, the representative low-cost ST O&G plant is a 47-year old, 1,300 MW plant in Pennsylvania.

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






Notes and Sources: ABB, Energy Velocity Suite. In Panel (B), the distribution is truncated at 375 MW to maintain legibility, but ST O&G plants range up to 1,700 MW with nine plants above 375 MW.

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

To estimate the costs of the representative plants, we relied primarily on public cost information from the FERC Form 1, and S&L's project database.[36] We then developed the cost estimates for the representative plants accounting for differences in plant sizes, plant location, and ages based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation. For property taxes and insurance, we used the same survey approach as for coal described in Section III.C above, but in this case based on actual ST O&G plants in PJM. We again estimated insurance costs at three times as high as property taxes. Both turned out to be very small.

Table 7 below shows that the estimated total gross costs for the representative plant are $64/MW-day (in 2022 dollars) and variable costs are $5.81/MWh. For the representative low-cost ST O&G plant, estimated gross costs are $53/MW-day and variable costs are $5.51/MWh. For the smaller 350 MW representative high-cost plant, gross costs are significantly higher, at $102/MW-day, due to the reduced economies of scale; variable costs are $16.26/MWh.

[36] Federal Energy Regulatory Commission, FERC Form 1, Plant Cost Data, 2010 through 2019.

TABLE 7: STEAM OIL & GAS PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

| | | Oil and Gas-Fired Steam Turbine Plant | | |
|---|---|---|---|---|
| | Units | Representative Low-Cost Plant | Representative Plant | Representative High-Cost Plant |
| **Capacity** | *Nameplate MW* | 1,300 | 900 | 350 |
| **Gross Costs** | *$/MW-day* | $53 | **$64** | $102 |
| Labor | *$/MW-day* | $21 | **$26** | $43 |
| Fixed Expenses | *$/MW-day* | $26 | **$32** | $53 |
| Property Taxes | *$/MW-day* | $1.6 | **$1.6** | $1.6 |
| Insurance | *$/MW-day* | $4.8 | **$4.8** | $4.8 |
| **Non-Fuel Variable Costs** | *$/MWh* | $5.51 | $5.81 | $16.26 |
| Operating Costs | *$/MWh* | $1.19 | $1.19 | $1.19 |
| Maintenance Adder | *$/MWh* | $4.32 | $4.62 | $15.07 |

Notes and Sources: gross costs are expressed in 2022 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 adders for the low-cost and representative plant assume a 20% capacity factor and the maintenance adder for the high-cost plant assumes a 10% capacity factor.

## G. Onshore Wind Plants

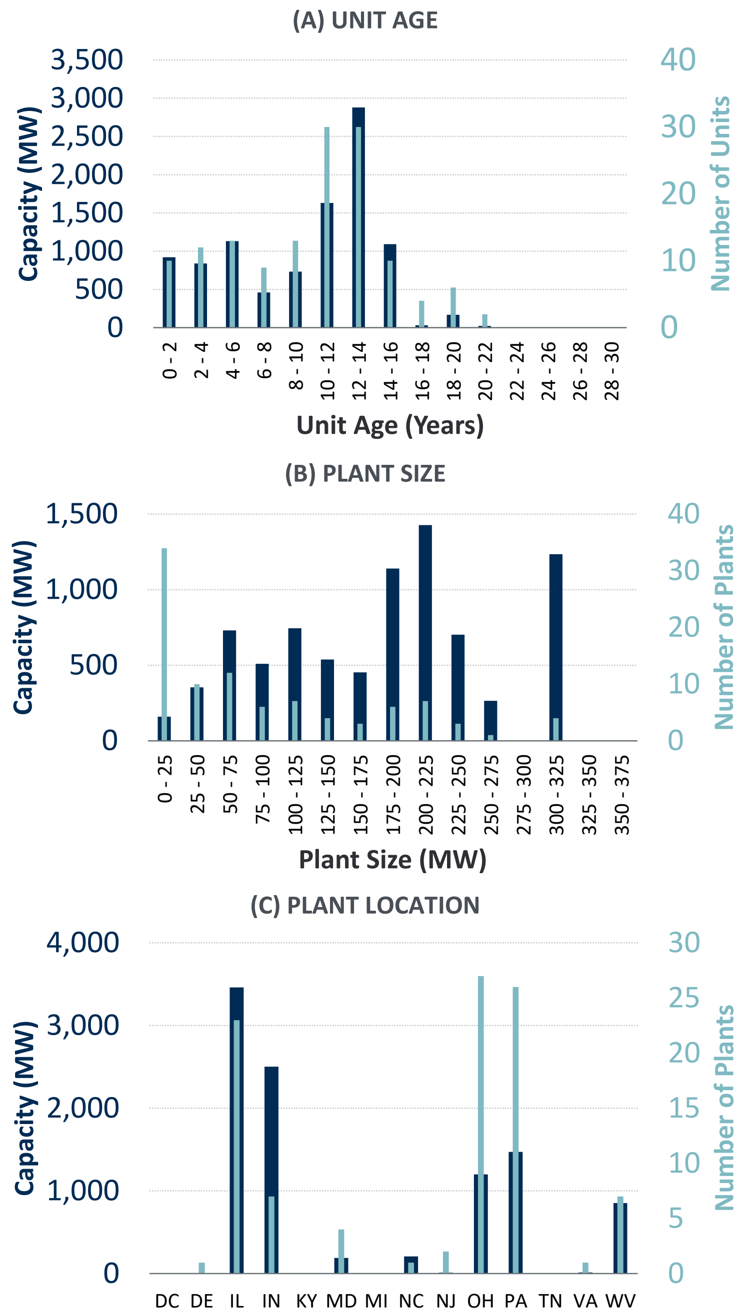
Over the past 15 years, nearly 10,000 MW of onshore wind plants have been built in PJM. The average size is 100 MW, which is skewed by the numerous small plants (less than 25 MW); however, 17 are at least 200 MW as shown in Figure 7 Panel (B) below. Plants larger than 100 MW make up of over 80% of the total capacity in PJM, and most are located in Illinois and Indiana, while smaller plants are located in Pennsylvania and Ohio. Ages of wind plants range from less than a year old to 20 years old. Figure 7 below summarizes the age, size, and locations of these plants. The primary cost drivers for wind plants tend to be 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 greater than 100 MW (since these plants contribute to more than 80% of the total 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 approximately 12 years old and reviewed the most frequent location, which was Illinois. Based on this approach, the representative onshore wind plant is a 12-year-old, 200 MW plant in Illinois.

To account for the size and age variation of the fleet, we varied these characteristics when determining the representative low-cost and representative high-cost plant. We filtered the wind fleet for plants less than 100 MW and determined a median size of 30 MW for the representative high-cost plant. We then found the median age of this filtered fleet, which was similar to the age for representative plants, so we maintained a 12-year-old plant. The most frequent location of these smaller plants was Pennsylvania. Based on this approach, the representative high-cost plant is a 12-year-old 30 MW plant in Pennsylvania. We increased the capacity for the representative low-cost plant to be a 300 MW plant, the median size for plants above 200 MW. By filtering for larger plants, we determined that the median age was slightly younger than the representative high-cost plant (10 years old) and the most frequent location was in Illinois. Based on this approach, the representative low-cost plant is a 10-year-old 300 MW plant in Illinois.

**FIGURE 7: ONSHORE WIND PLANTS FLEET CHARACTERIZATION**




Notes and Sources: ABB, Energy Velocity Suite. In panel (B), the distribution is truncated at 375 MW to maintain legibility, but wind plants range up to about 900 MW with two plants larger than 375 MW.

*Cost Estimates for Representative Onshore Wind Plants*

We estimated fixed and variable O&M and capital costs for the representative wind plants by first reviewing recent public sources and S&L's project database.[37] We then developed the cost estimates for the representative plants accounting for differences in MW capacity, plant location, and ages relative to the representative plants based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation.

The representative wind plants were assumed to pay property taxes or have a negotiated payment in lieu of taxes (PILOT) agreement with the local jurisdiction. S&L found these costs to be accurately represented as a fixed fraction of the total fixed operating expenses based on S&L's project database for similar sized wind plants. Insurance includes liability insurance, property insurance, and equipment insurance, and the cost of insurance will depend on the location's specific risks. Values in the table below represent S&L's estimates based on systems in locations without any atypical regional risks, and have not been adjusted for any other regional cost sensitivities.

Table 8 below shows resulting gross costs for the representative plant of $147/MW-day (in 2022 dollars). We assumed that all of the costs necessary to operate a wind plant (and a solar PV plant) are fixed and belong in the gross costs, with no variable costs. The representative low-cost plant's estimated gross costs are $140/MW-day, and the representative high-cost plant's gross costs are $204/MW-day.

[37] National Renewable Energy Laboratory (NREL), 2022 Annual Technology Baseline, 2022; U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, March 2022.

TABLE 8: ONSHORE WIND PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

| | | Onshore Wind Plant | | |
|---|---|---|---|---|
| | Units | Representative Low-Cost Plant | Representative Plant | Representative High-Cost Plant |
| **Capacity** | *Nameplate MW* | 300 | 200 | 30 |
| **Gross Costs** | *$/MW-day* | $140 | **$147** | $204 |
| Labor | *$/MW-day* | $26 | **$27** | $50 |
| Fixed Expenses | *$/MW-day* | $95 | **$99** | $126 |
| Property Taxes | *$/MW-day* | $12 | **$13** | $17 |
| Insurance | *$/MW-day* | $8 | **$8** | $11 |
| **Non-Fuel Variable Costs** | *$/MWh* | $0.00 | $0.00 | $0.00 |
| Operating Costs | *$/MWh* | $0.00 | $0.00 | $0.00 |
| Maintenance Adder | *$/MWh* | $0.00 | $0.00 | $0.00 |

Notes and Sources: gross costs are expressed in 2022 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 most plants under 10 MW and a few in the 50–100 MW range. All of the solar PV plants have been built in the past 15 years, with the most capacity added in Virginia, New Jersey, and North Carolina. Figure 8 below summarizes the age, size, and locations of these plants.

The age of a solar plant influences the plant capacity since more recent plants have tended to be built larger than in the past. Location also impacts the costs of solar PV plants due to differences in labor costs and property taxes.

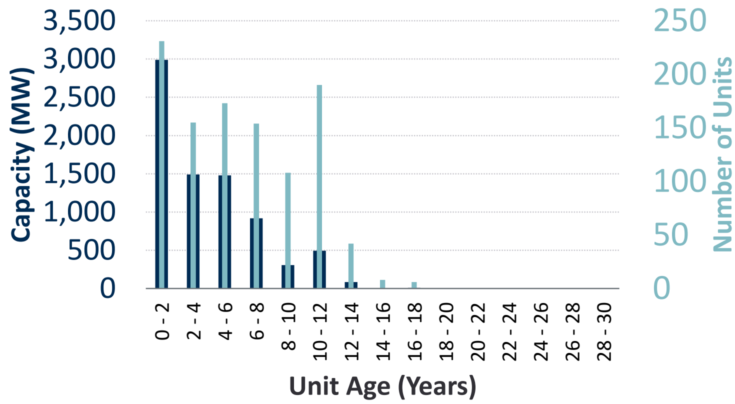
*Determination of Representative Large Scale Solar Photovoltaic Plant Characteristics*

Because the age of a solar plant influences the plant size, to choose a representative solar plant we first determined the median age of the fleet, which was 5 years old. We filtered the solar fleet data by this age and compared the median plant size of this population to the median plant size of the fleet, which was approximately 10 MW. Then we reviewed the location of the fleet and the population with age and size filters. Based on this approach, the representative plant is a 10 MW single-axis tracking solar PV plant in New Jersey built 5 years ago.

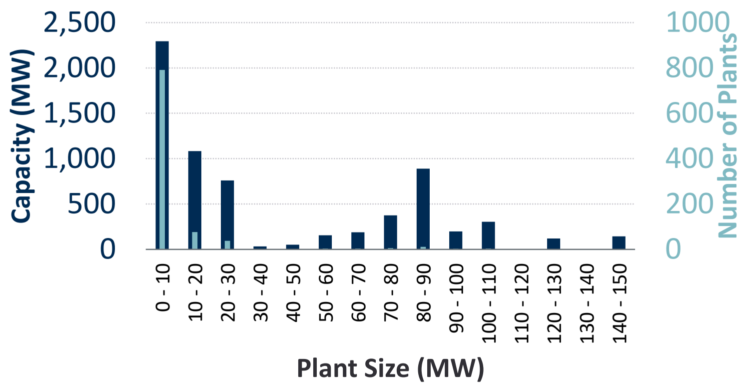
For the representative high and low-cost plants, we varied size and age as the cost differentiators. The solar fleet is largely small plants 10 MW and under. For higher-cost plants under 10 MW, the median capacity is 2 MW. We filtered the solar fleet for plants of this size and determined these plants were slightly older than our representative plant (7 years old). We then analyzed the location of these smaller plants and found that they aligned with the most common location of the overall fleet, so we maintained the location as New Jersey. The representative low-cost plant would be much larger, but we avoided plants less than 5 years old because of the maintenance warranties that apply to younger plants and are not representative of the entire fleet. We filtered the entire fleet data by plants between 80–90 MW. The larger plants were most frequently located in North Carolina. Based on this approach, the representative low-cost plant is an 80 MW 5-year-old plant in North Carolina.

FIGURE 8: LARGE SCALE SOLAR FLEET CHARACTERIZATION

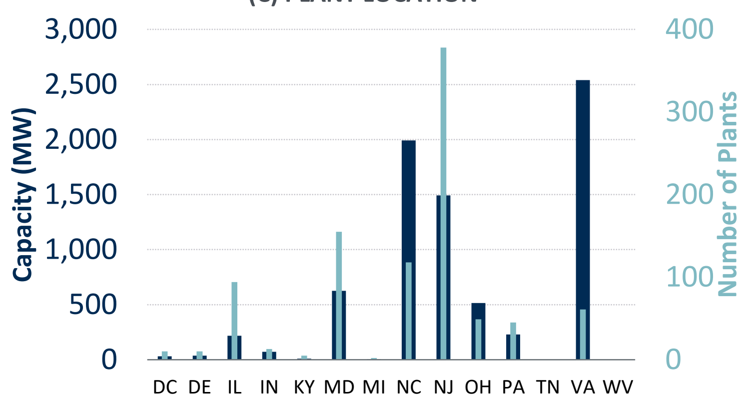
(A) UNIT AGE




(B) PLANT SIZE




(C) PLANT LOCATION




Notes and Sources: ABB, Energy Velocity Suite. In panel (B), the distribution is truncated at 150 MW to maintain legibility, but Solar PV plants range up to 500 MW with five plants larger than 150 MW.

*Cost Estimates for Representative Large Scale Solar Photovoltaic Plants*

We estimated fixed and variable O&M and capital costs for the representative solar PV plants by reviewing recent public sources and S&L's project database.[38] We then developed the cost estimates for the representative solar PV plants accounting for differences in the solar panel type, tracking type, plant size, location, and ages relative to the representative plants based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation.

The representative solar plants were assumed to pay property taxes or have a negotiated payment in lieu of taxes (PILOT) agreement with the local jurisdiction. S&L found these costs to be accurately represented as a fixed fraction of the overnight capital cost of the installation based on S&L's project database for similar sized solar plants. Insurance includes liability insurance, property insurance, and equipment insurance, and the cost of insurance will depend on the location's specific risks such as potential for damage from hail, or other natural disasters. Values in the table below represent S&L's estimates based on systems in locations without any atypical regional risks, and have not been adjusted for any other regional cost sensitivities.

Table 9 below shows that we estimated gross costs for the representative solar PV plant to be $70/MW-day (in 2022 dollars). Similar to onshore wind plants, we assumed that all of the costs necessary to operate a solar PV plant are fixed costs that are not directly attributable to the production of electricity, and thus did not include any variable costs for the solar PV plants. We estimated the representative low-cost gross costs to be $65/MW-day and the representative high-cost plant to be $74/MW-day.

[38] National Renewable Energy Laboratory (NREL), 2022 Annual Technology Baseline, 2022; U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, March 2022.

TABLE 9: SOLAR PV PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

| | | Large Scale Solar Photovoltaic Plant | | |
|---|---|---|---|---|
| | Units | Representative Low-Cost Plant | Representative Plant | Representative High-Cost Plant |
| **Capacity** | *Nameplate MW* | 80 | 10 | 2 |
| **Gross Costs** | *$/MW-day* | $65 | **$70** | $74 |
| Labor | *$/MW-day* | $20 | **$22** | $25 |
| Fixed Expenses | *$/MW-day* | $30 | **$33** | $36 |
| Property Taxes | *$/MW-day* | $5 | **$4** | $4 |
| Insurance | *$/MW-day* | $10 | **$10** | $10 |
| **Non-Fuel Variable Costs** | *$/MWh* | $0.00 | $0.00 | $0.00 |
| Operating Costs | *$/MWh* | $0.00 | $0.00 | $0.00 |
| Maintenance Adder | *$/MWh* | $0.00 | $0.00 | $0.00 |

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses include scheduled and unscheduled PV and BOP equipment maintenance, vegetation management, module cleaning, major maintenance reserve funds, land lease, general and administrative costs.