2026 Avoidable Fixed Costs for Existing Resources

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

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Executive Summary

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

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

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

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

2 Newell et al., Gross Avoidable Costs for Existing Generation, ("2022 PJM ACR Study"), January 9, 2023.

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

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

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

To conduct this update of the ACRs, PJM retained The Brattle Group (Brattle) and Sargent & Lundy (S&L) to analyze the avoidable fixed costs for several types of existing generation. We have done so based on bottom-up analysis of costs for representative plants, drawing on data and the combined experience of Brattle and S&L. We also solicited stakeholder input through four rounds of presentations before the Markets Implementation Committee (MIC), Markets and Reliability Committee (MRC), and Members Committee (MC) between June and August 2026.[6]

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

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

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

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

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

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

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

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

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

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

I. Introduction

A. Purpose of ACRs and this Analysis

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

PJM approaches both instances by setting default offer thresholds for various resource types. Resources may only offer higher than their default MSOC price if they are approved for a higher price through unit-specific reviews of their costs. Similarly, resources subject to MOPR may only offer lower than their default MOPR price if they are approved for a lower price through a unit-specific review. Default thresholds are determined by a generic resource-type-specific Avoidable Cost Rate, minus resource-specific net revenues from energy and ancillary services markets. This updated ACR study will be used for both MSOC and MOPR purposes, in fulfillment of PJM's requirement to periodically update its ACRs every four years.[9] The last such study was conducted by us in 2022.[10] These ACRs will be in place for PJM's Base Residual Auctions for 2030/31 and the following three delivery years.

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

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

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

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

10 2022 PJM ACR Study.

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

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

B. Analytical Approach

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

11 Similarly, by setting default MOPRs reasonably low.

12 The converse applies for MOPRs.

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

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

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

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

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

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

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

Continued on next page

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

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

II. Selection of Plant Types within PJM Fleet

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

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

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

16 PJM, Operating Agreement of PJM Interconnection, L.L.C., Schedule 2, Section 4.

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

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

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

TABLE 1: 2026 PJM FLEET CAPACITY BY PLANT TYPE

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

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

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

[18] 2022 PJM ACR Study.

III. Avoidable Fixed Costs for Existing Resources

A. Multi-Unit Nuclear Plants

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

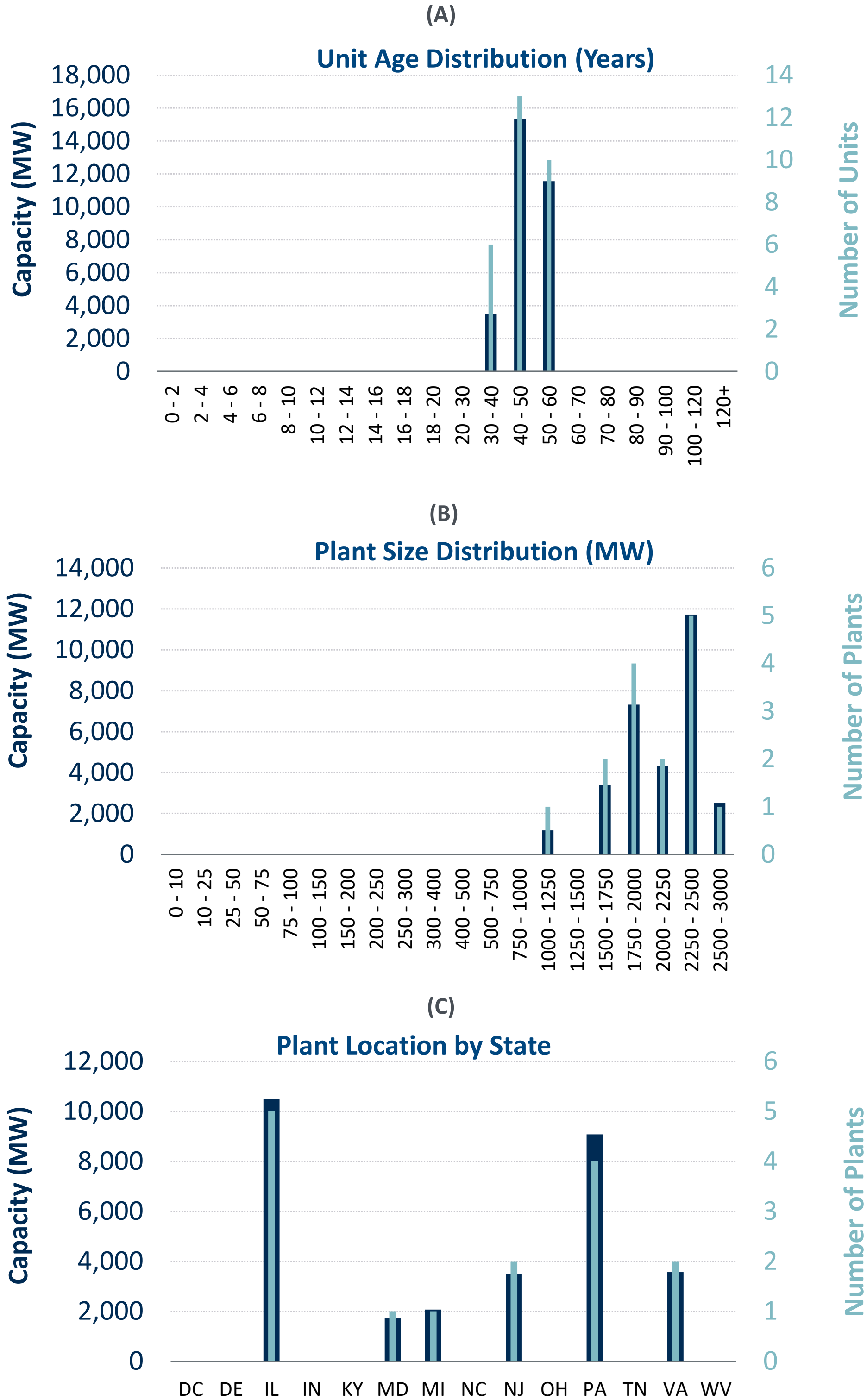
Based on our combined experience, the most significant cost drivers for nuclear plants are the plant size and number of units, reactor type such as the boiling water reactor (BWR) versus the pressurized water reactor (PWR), the location (which affects property taxes and operating costs), the business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

Representative Multi-Unit Nuclear Plant Characteristics

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

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

FIGURE 1: MULTI-UNIT NUCLEAR FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Multi-Unit Nuclear Plant

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

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

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

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

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

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

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

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

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

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

Notes and Sources: avoidable fixed costs are expressed in 2026 dollars per nameplate MW. The major maintenance costs per MWh depend on the capacity factor, which we assumed to be 92% corresponding to the average nuclear capacity factor in 2025.[22]

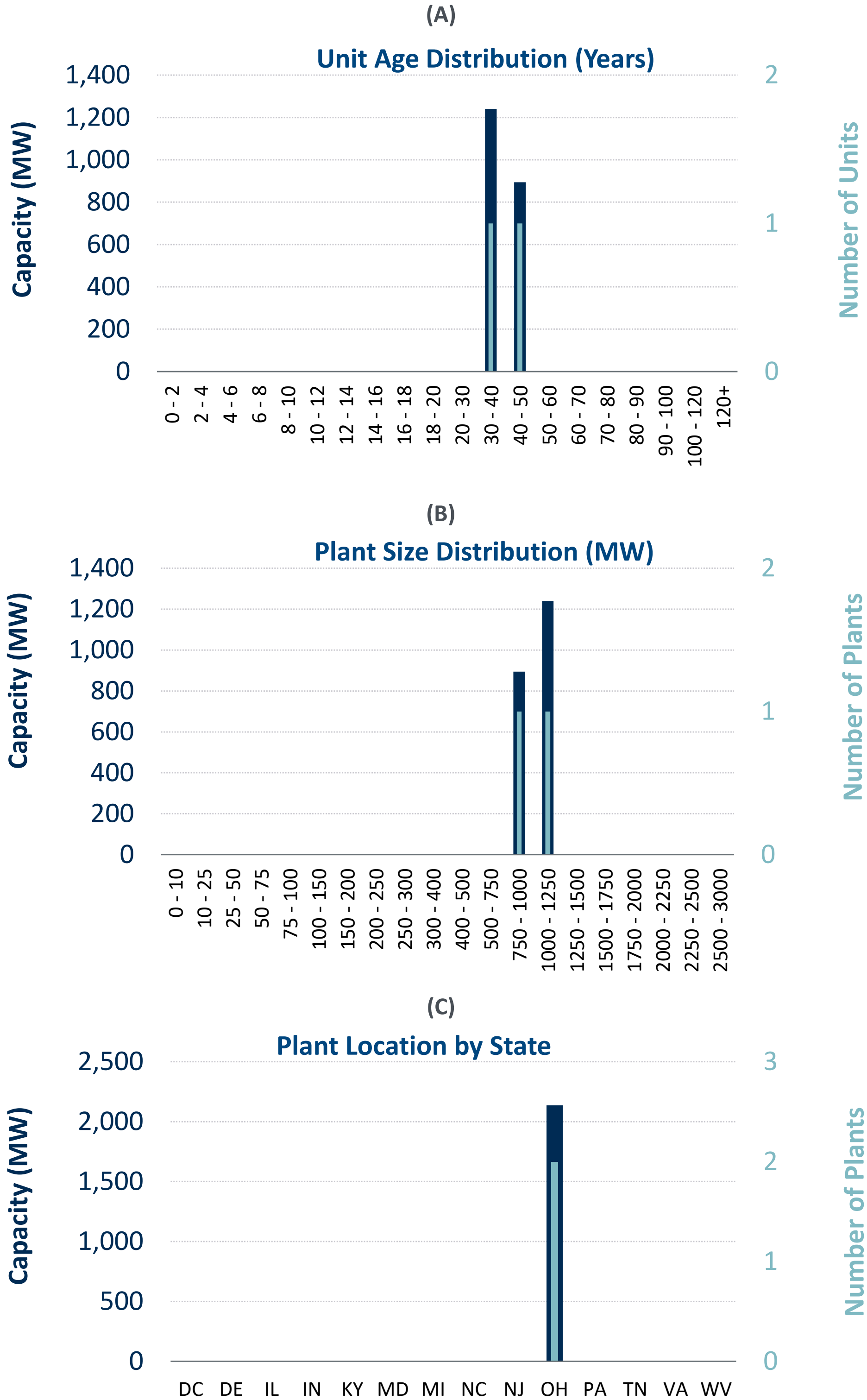
B. Single-Unit Nuclear Plants

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

[22] 2026 NEI Report.

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

FIGURE 2: SINGLE-UNIT NUCLEAR FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Single-Unit Nuclear Plant

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

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

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

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

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

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

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

Notes and Sources: avoidable fixed costs are expressed in 2026 dollars per nameplate MW. The major maintenance costs per MWh depend on the capacity factor, which we assumed to be 92% corresponding to the average nuclear capacity factor in 2025.[25]

C. Coal Plants

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

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

25 2026 NEI Report.

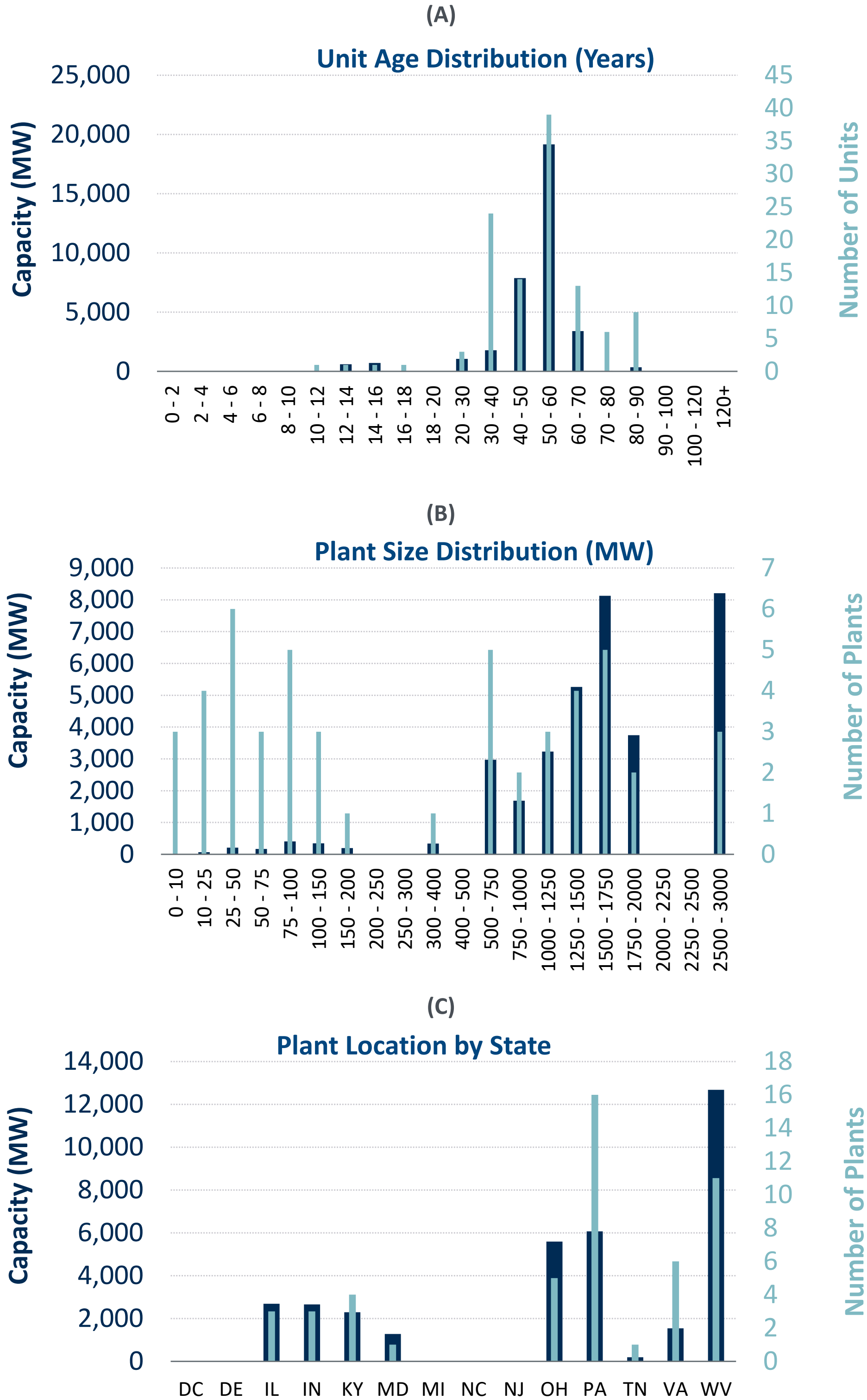
Representative Coal Plant Characteristics

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

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

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

FIGURE 3: COAL FLEET CHARACTERIZATION



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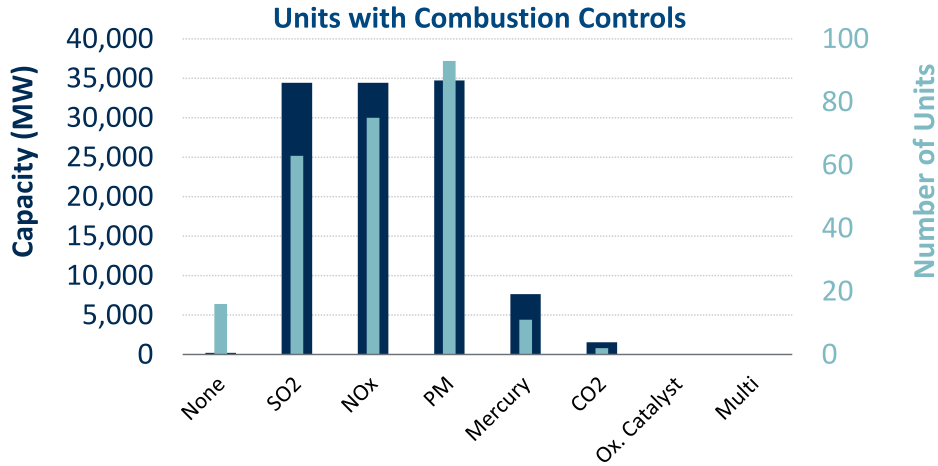


Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Coal Plant

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

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

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

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

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

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

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

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

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

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

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

For context, Table 4 also shows non-fuel variable costs, including production-related operating costs and maintenance. Production-related operating costs include consumables and production-linked handling or disposal costs, including FGD reagent and ash and FGD sludge disposal. These costs were converted to a $/MWh basis using the representative plant's assumed capacity factor. The maintenance adder was derived from S&L's analysis of FERC Form 1 data for similar coal plants, including only capital expenditures for systems directly attributable to incremental electricity production. The resulting annual estimates were normalized using a 52% capacity factor for the representative plant, a 49% capacity factor for the low-cost plant, and a 55% capacity factor for the high-cost plant. For the representative plant, operating costs are $6.16/MWh, and the maintenance adder is $6.19/MWh, for total non-fuel variable costs of $12.35/MWh.

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

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

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

D. Natural Gas-Fired Combined-Cycle Plants

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

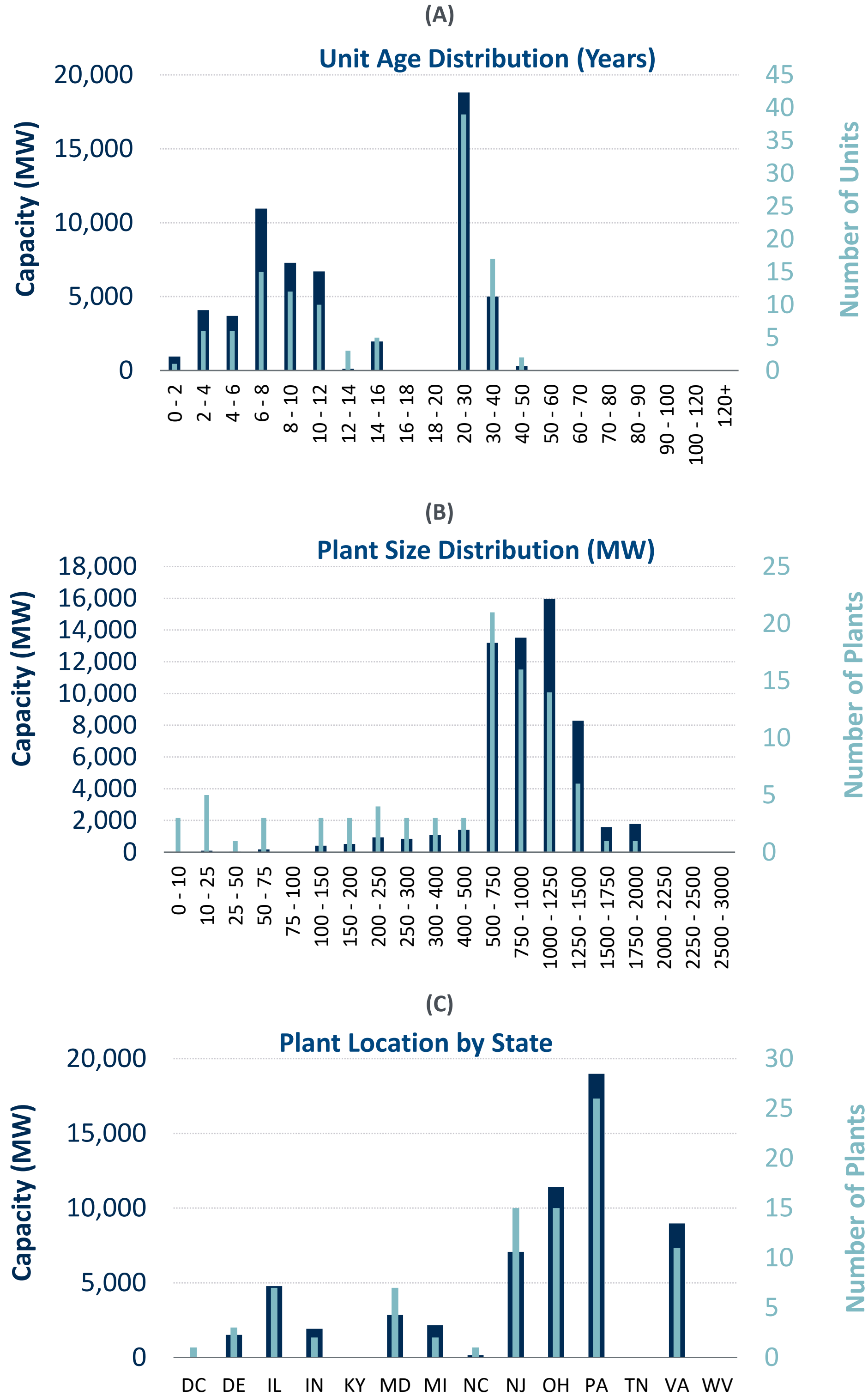
The main cost drivers among CCs are the capacity, age, turbine type, plant configuration, and whether a plant has firm gas transportation service. Location is a secondary driver through its effects on the costs of labor, property taxes, and firm fuel.

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

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

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

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



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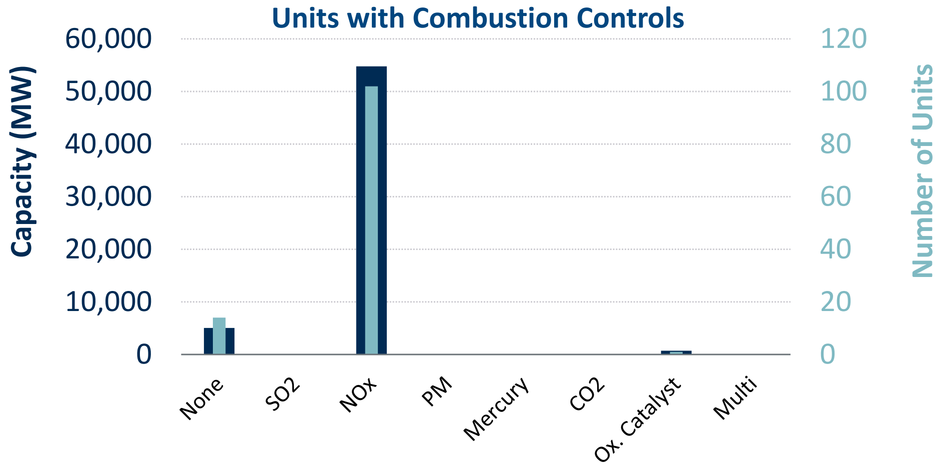

Notes and Sources: ABB, Energy Velocity Suite.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

E. Simple-Cycle Combustion Turbines

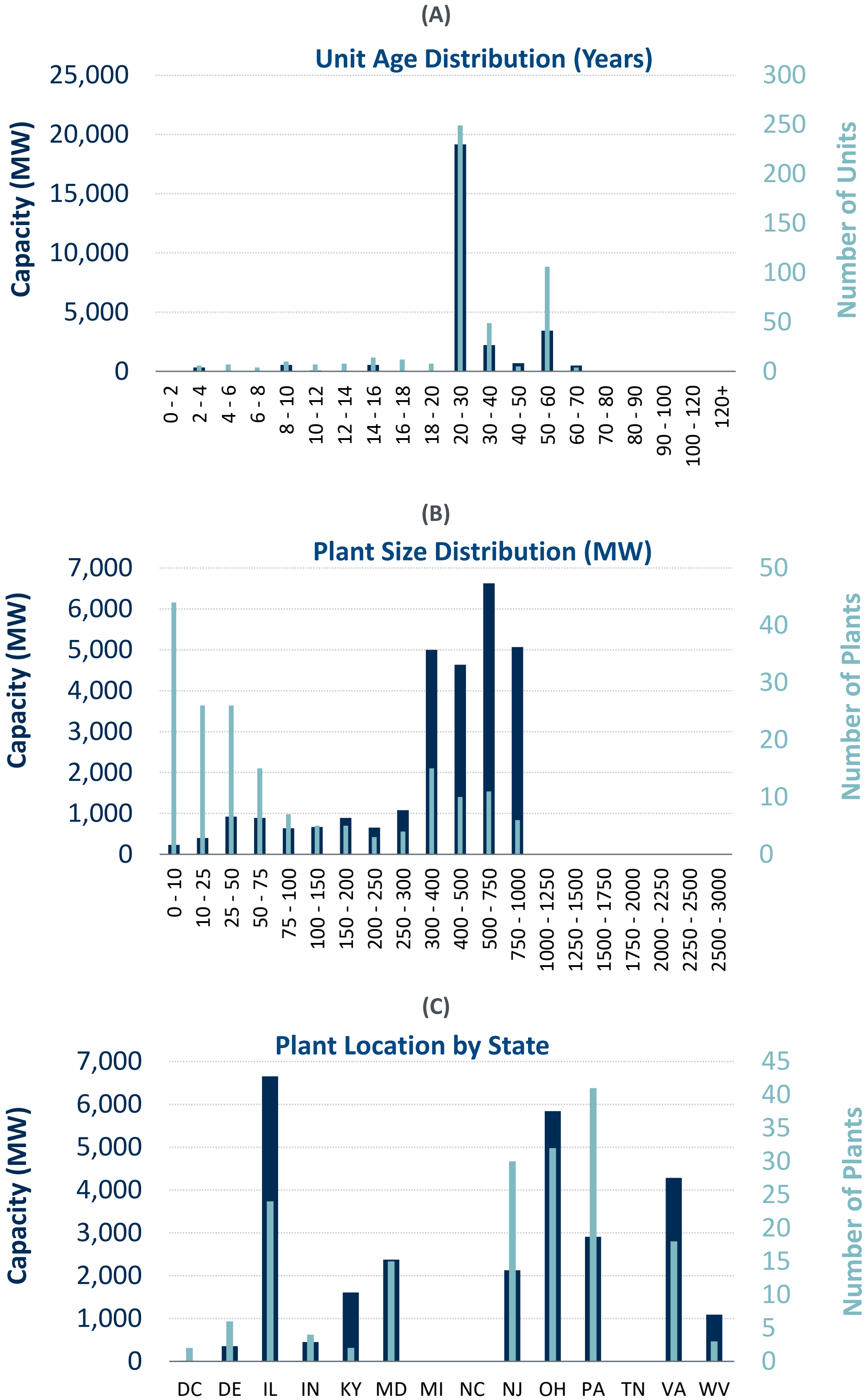
Simple-cycle combustion turbine (CT) plants include oil- and gas-fired CTs. Nearly all CTs were built around the early 2000s, but there is a wide capacity range due to differences in turbine technology and configurations. There are many CT plants in the PJM fleet under 100 MW, but these plants cumulatively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

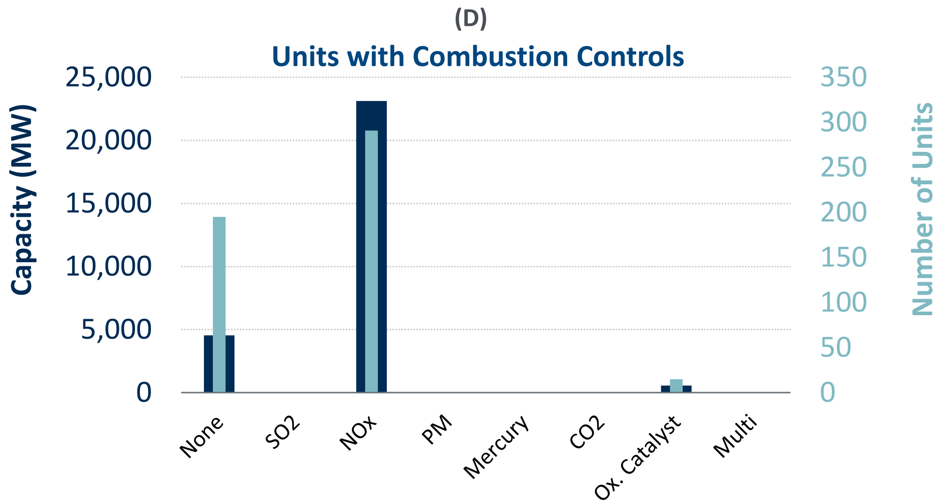
Determination of Representative Simple-Cycle Combustion Turbine Plant Characteristics

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

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

FIGURE 5: SIMPLE-CYCLE COMBUSTION TURBINE FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for Representative Simple-Cycle Combustion Turbine Plants

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

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

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

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

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

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

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

For context, Table 6 also shows non-fuel variable costs, including production-related operating costs and the maintenance adder. Operating costs were estimated from the EIA, FERC, 2025 PJM CONE Study, and S&L project database cost information for similar combustion turbines, then converted to a $/MWh basis using the assumed capacity factor. For the representative plant, S&L estimated operating costs to be $0.81/MWh. S&L estimated the variable cost maintenance adder assuming a 10% capacity factor, equivalent to 73 starts per year at approximately 12 hours of operation per start. For the E- and F-class turbine representative plants that operate as peaking units, major maintenance costs are expected to be driven primarily by the number of starts.[35] For the representative combustion turbine plant, the maintenance adder is $5.03/MWh.

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

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

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

F. Oil- and Gas-Fired Steam Turbines

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

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

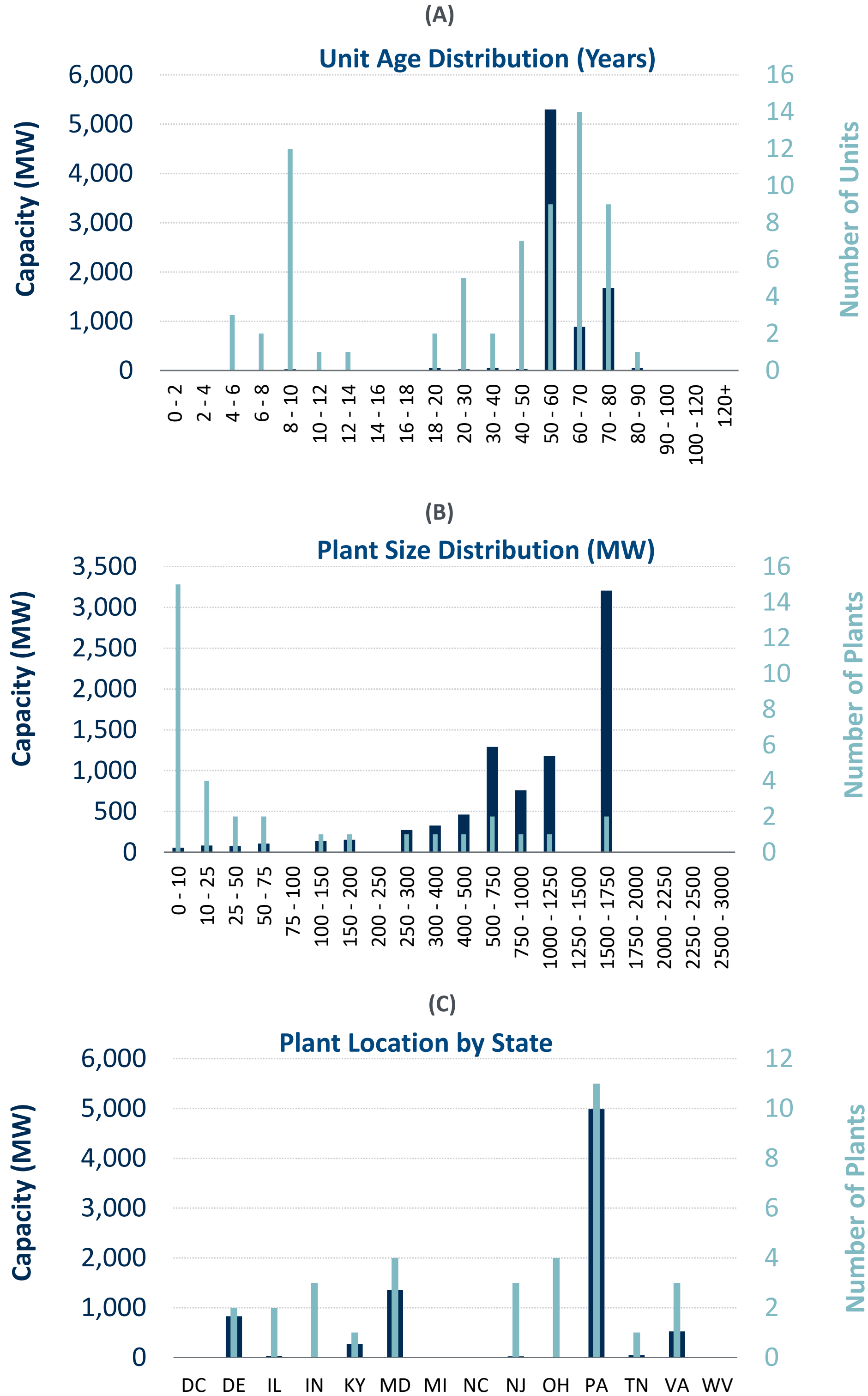
O&G fleet. The primary drivers of cost for ST O&G plants are age, capacity, location, and plant configuration.

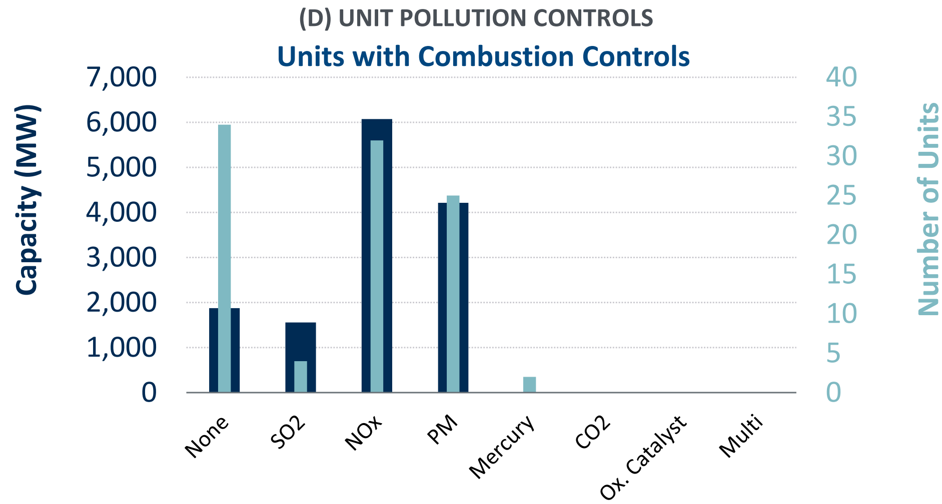
Determination of Representative Oil- and Gas-Fired Steam Turbine Plant Characteristics

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

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

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





Notes and Sources: ABB, Energy Velocity Suite.

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

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

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

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

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

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

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

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

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

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

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

Notes and Sources: avoidable fixed costs are expressed in 2026 dollars per nameplate MW. Fixed Expenses include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, administrative and general expenses. The estimated maintenance adder costs per MWh are variable based on the capacity factor. The maintenance adder for the representative plant assumes a 17% capacity factor, for the low-cost plant an 18% capacity factor, and for the high-cost plant a 16% capacity factor.

G. Onshore Wind Plants

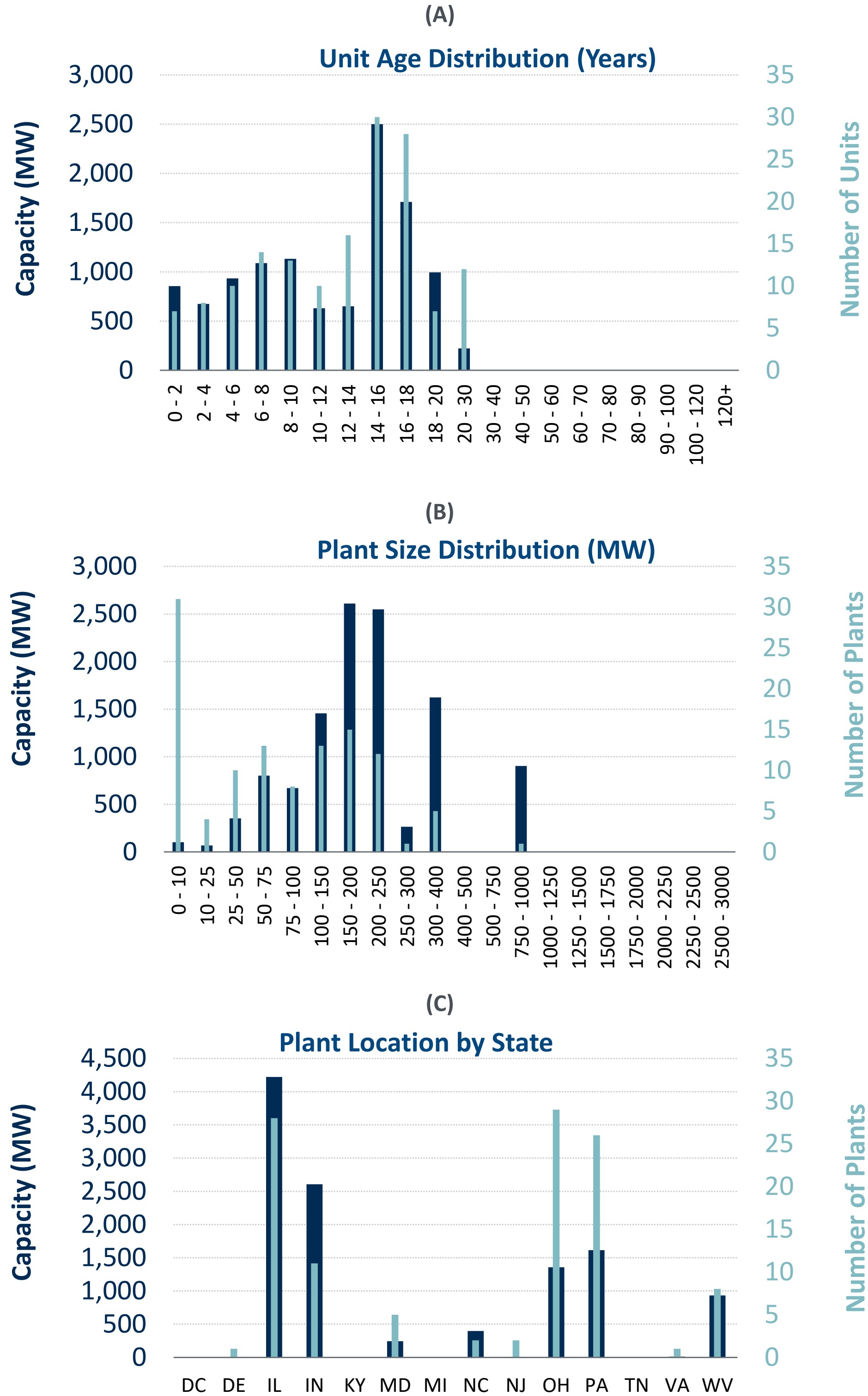
Over the past 20 years, over 11 GW of onshore wind plants have been built in PJM. The average size is 100 MW, which is skewed by numerous small plants (less than 25 MW); however, 19 plants are 200 MW or greater as shown in Figure 7, Panel B below. Plants larger than 100 MW make up over 80% of the total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

Determination of Representative Onshore Wind Plant Characteristics

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

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

FIGURE 7: ONSHORE WIND PLANT FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for Representative Onshore Wind Plants

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

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

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

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

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

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

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

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

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

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

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

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

H. Large-Scale Solar Photovoltaic Plants

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

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

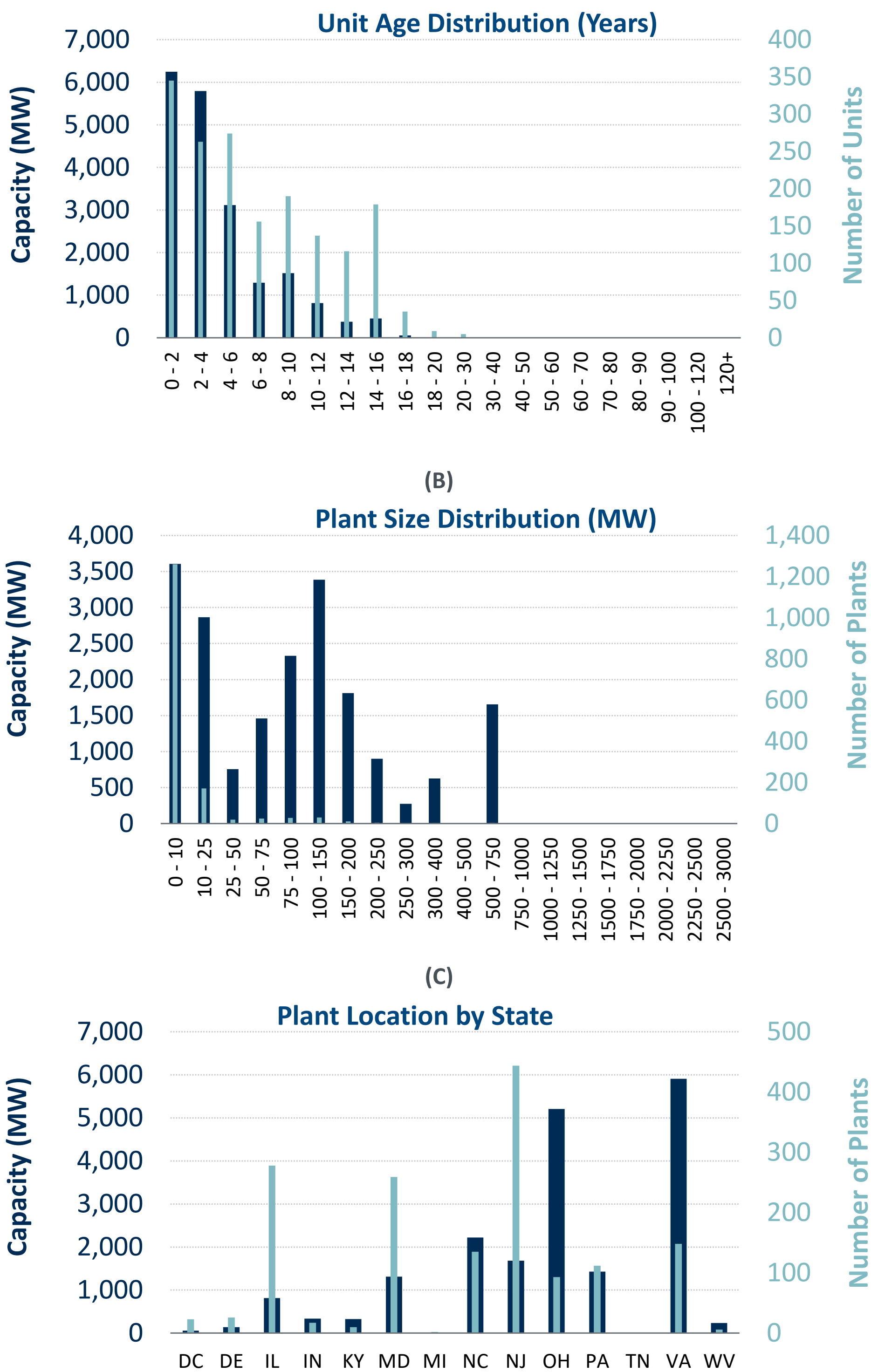
Determination of Representative Large-Scale Solar Photovoltaic Plant Characteristics

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

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

FIGURE 8: LARGE-SCALE SOLAR PHOTOVOLTAIC FLEET CHARACTERIZATION

(A)



Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for Representative Large-Scale Solar Photovoltaic Plants

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

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

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

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

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

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

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

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

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

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

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

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

I. Standalone BESS

As of June 2026, PJM has approximately 800 MW of BESS.[42] Of this total, 40% are standalone BESS and the remainder are hybrid BESS resources. Over 4 GW of BESS, however, are currently in PJM's Expedited Process (a "fast track" interconnection process) with the majority expected to come online between 2027 and 2029.[43] Additionally, over 60 GW of storage projects have been selected as part of PJM's first cycle of the reformed interconnection process, with a substantial portion expected to be online before 2030.[44] Given the volume of BESS projects

[42] Hitachi Energy ABB Velocity Suite, June 2026.

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

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

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

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

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

Determination of Representative Standalone BESS Plant Characteristics

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

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

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

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

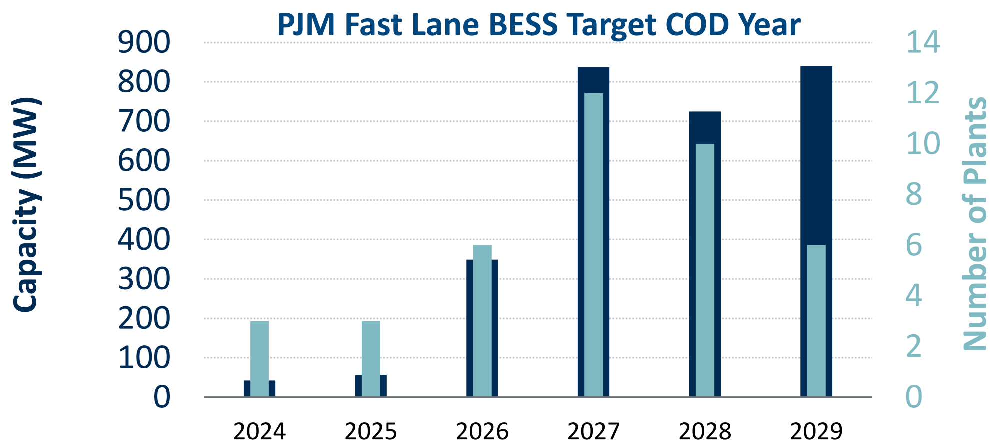
To identify the representative high- and low-cost resources, we also relied on the Expedited Process queue data. To determine the representative high-cost resource, we first observed that the second most prevalent duration was 10 hours, which merited a separate representative resource definition. Next,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

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

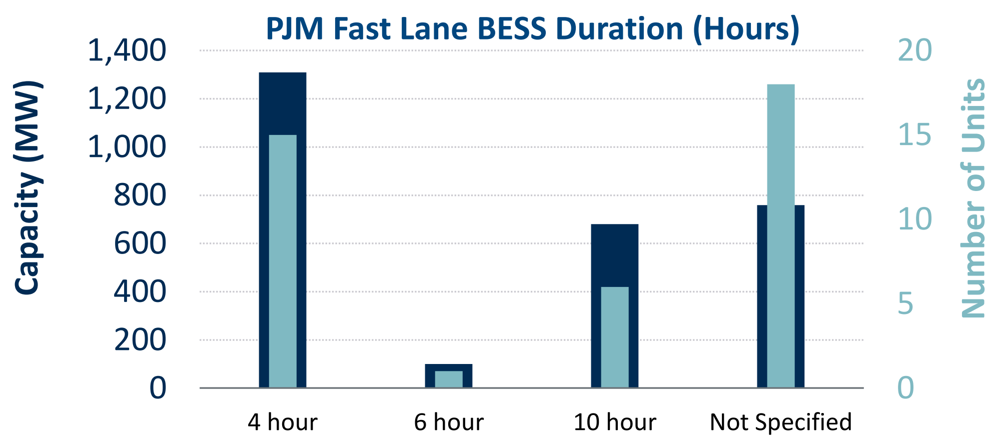
[47] For a complete list of the Standalone BESS technical specifications, see 2025 PJM CONE Study, p. 60.

FIGURE 9: STANDALONE BESS FLEET CHARACTERIZATION

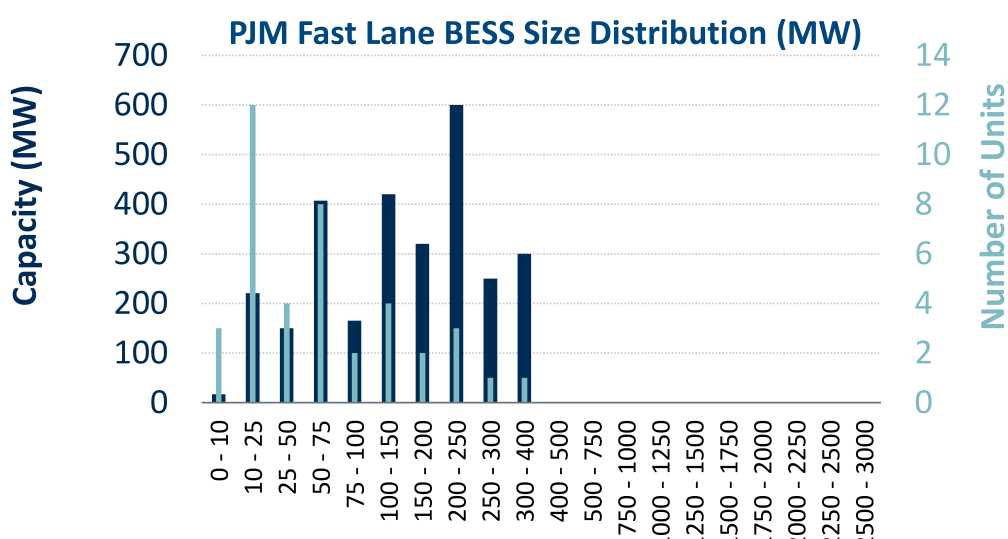
(A)



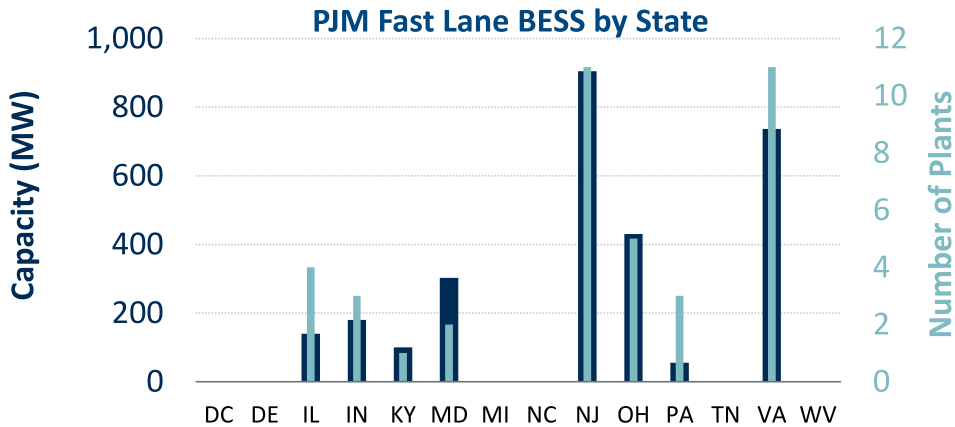
(B)



(C)



(D)



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

Cost Estimates for Representative Standalone BESS Plants

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Standalone BESS Plant Avoidable Fixed Cost Adjustment Factors for Alternative Durations

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

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

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

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