PJM CONE 2026/2027 Report

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APRIL 21, 2022

NOTICE

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Executive Summary

PJM Interconnection, L.L.C (PJM) retained consultants at The Brattle Group (Brattle) and Sargent & Lundy (S&L) to review key elements of the Reliability Pricing Model (RPM), as required periodically under PJM's tariff. This report presents our estimates of the Cost of New Entry (CONE) for the 2026/2027 commitment period, recommendations regarding the methodology for calculating the net energy and ancillary service revenue offset (E&AS Offset), and our recommendation for the selection of the reference resource. A separate, concurrently-released report presents our review of the VRR curve shape.

Background

The Variable Resource Requirement (VRR) curves set the price at the target reserve margin at approximately Net Cost of New Entry (Net CONE), such that the resource adequacy requirement will be achieved if suppliers enter the market when prices are at least Net CONE. In a downward-sloping curve, slightly lower reliability will be tolerated only when prices exceed Net CONE and some incremental capacity will be procured when the incremental cost is relatively low.

Net CONE is estimated by selecting an appropriate reference resource that economically enters the PJM market, determining its characteristics and its capital costs and ongoing operating and maintenance costs; then estimating a first-year capacity payment needed for entry, given likely trajectories of future total revenues and E&AS offsets.

A common misconception is that by selecting a reference resource, PJM promotes the development of that specific type of resource. In fact, other technologies may enter alongside the reference resource or instead of the reference resource, depending on which resources are most competitive and/or enjoy policy support. Another common misconception is that the Net CONE parameter sets capacity prices. In fact, capacity prices are determined by the intersection of the VRR curves and the supply curves. Long-run market clearing prices depend on the actual prices at which new competitive supply is willing to enter rather than the administrative Net CONE estimates, while the VRR curve determines only the quantity of capacity procured (short-term price impacts of changes in administrative Net CONE may be larger, depending on the elasticity of supply).

Reference Resource

The reference resource should be feasible to build within the three-year period between the Base Residual Auction and the delivery year; economically viable, as indicated by actual merchant entry and competitive costs; and amenable to accurate estimation of its Net CONE.

We recommend shifting the reference resource from the current natural gas-fired combustion turbine (CT) to a natural gas-fired combined cycle (CC) because the CC best meets these criteria in PJM. The CC is clearly economically viable, as it has the largest amount of recent merchant entry and a lower estimated Net CONE than the other candidate resources. CTs continue to be less economic than CCs, consistent with their extremely limited entry in the recent past. Selecting the CT as the reference resource would set the demand curve in a way that would perpetuate excess supply in PJM (although could be considered a way to buy extra reliability insurance for a premium). We considered BESS as a potential source of "clean capacity" for areas with more stringent environmental regulations that could limit the feasibility of developing new natural gas-fired resources. However, its estimated Net CONE is much higher than the CC without there being a clear enough indication at this time that the CC could not be built. We recommend that PJM, its stakeholders, and the states within the PJM footprint continue to monitor the viability of building new gas-fired resources and, if needed, consider developing a clean reference resource cost estimate.

For each resource evaluated, we developed technical specifications of a complete plant reflecting the locations, technology choices, and plant configurations that developers are likely to choose, as indicated by actual projects and current environmental requirements. The CC specifications are for a 1,182 MW plant with two trains of a single-shift combined cycle plant, each with a single combustion turbine, heat recovery steam generator, and steam turbine (i.e., two "single-shaft 1x1"s) including 123.9 MW of duct-firing capacity. The CC plant includes GE 7HA.02 turbines, selective catalytic reduction (SCR), dry cooling, and a firm gas transportation contract instead of dual-fuel capability.[1] The CC has a higher-heating value (HHV) average heat rate of 6,293 Btu/kWh at full load without duct firing and 6,537 Btu/kWh with (and 7,866 Btu/kWh at minimum stable level of 33% of full load) at standard conditions. CT specifications included a single simple cycle GE 7HA.02 with 367 MW capacity and a 9,189 Btu/kWh full-load average heat rate. BESS specifications are for a 200 MW 4-hour battery with 13% initial oversizing and capacity augmentation planned every 5 years to maintain charge capability and duration.

[1] These capacities and heat rates refer to an average over the four CONE Areas. Area-specific values reflecting local ambient conditions are provided within the report.

Cost Analysis

For CC and CTs in each CONE Area, we conducted a comprehensive, bottom-up analysis of the capital costs to build the plant: the engineering, procurement, and construction (EPC) costs, including equipment, materials, labor, and EPC contracting; and non-EPC owner's costs, including project development, financing fees, gas and electric interconnection costs, and inventories. We separately estimate annual fixed operation and maintenance (O&M) costs, including labor, materials, property taxes, and insurance. For BESS, we performed a top-down cost analysis based on a less detailed plant design and recent experience estimating costs for developers.

We translate the estimated costs into the net revenues the resource owner would have to earn in its first year to enter the market, assuming a 20-year economic life for the CC and CT and net revenues on average remain constant in nominal terms over that timeframe. We believe these assumptions are reasonable given widespread concern expressed by developers in the stakeholder community that gas-fired generation has limited value beyond the assumed 20-year life in a policy environment that increasingly disfavors greenhouse gas-emitting generation (and even capacity). For the BESS, we assumed a shorter 15-year economic life based on a representative degradation profile and warranty term typical for the selected battery technology.

To estimate the net revenue the reference resource would need to earn to achieve the required return on and return of capital, we estimated the cost of capital. We estimate an after-tax weighted-average cost of capital (ATWACC) of 8.0% for a merchant generation investment, based on analysis of publicly-traded merchant generation companies and other reference points. An ATWACC of 8.0% is equivalent to a return on equity of 13.6%, a 4.7% cost of debt, and a 55/45 debt-to-equity capital structure with an effective combined state and federal tax rate of 27.7%.

Table ES-1 below shows the resulting 2026/27 CONE estimates for CCs for each CONE Area. The CONE values are 56% higher (or $180/MW-day ICAP) than PJM's 2022/23 values from the 2018 CONE Study, averaged across all four CONE Areas. Three factors explain this increase:[2]

- Declining Bonus Depreciation**:** Bonus depreciation decreased from 100% to 20% under U.S. tax law, adding $25/MW-Day (ICAP) to CONE.
- Cost Escalation: The costs of materials, equipment, and labor have escalated and will continue to escalate at a faster rate than expected at the time of the last study. These cost increases add $92/MW-Day (ICAP) to CONE, relative to the 2022/23 estimate.

[2] These factors add to more than $180/MW-day (ICAP) due to offsets from a slightly lower cost of capital that reduces CONE by $4/MW-day (ICAP).

- Plant Design Changes: The use of dry-cooling, building a gas-only plant (without dual fuel capability) with firm gas transportation contracts under more constrained environmental permitting regimes (along with smaller increases from 2x1 to double-train 1x1 CCs) adds $66/MW-Day (ICAP).

TABLE ES-1: ESTIMATED CONE FOR CC PLANTS

				1 x 1 Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$1,359	$1,240	$1,263	$1,308
[2]	Installed (inc. IDC)	*$m*		$1,470	$1,343	$1,367	$1,415
[3]	First Year FOM	*$m/yr*		$37	$53	$47	$39
[4]	**Net Summer ICAP**	***MW***		**1,171**	**1,174**	**1,144**	**1,133**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$1,160	$1,057	$1,104	$1,154
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$1,255	$1,144	$1,195	$1,248
[7]	Levelized FOM	*$/kW-yr*		$39	$49	$47	$42
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		12.4%	12.2%	12.3%	12.3%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$182,700**	**$178,700**	**$183,100**	**$184,500**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$501**	**$490**	**$502**	**$506**

There is considerable uncertainty in the development of the estimated CONE values for the reference resources, particularly regarding volatile inflation, relevant technologies and plant designs, and the analyst's judgment on economic life and long-term cost recovery. For example, a less constrained plant design with dual fuel and cooling towers could cost as much as $87/MW-day less; or a shorter 15-year economic life could add $52/MW-day, and the costs could be greater still if technologies are more constrained by environmental regulations. For BESS, the uncertainty in levelized costs is even greater because of rapidly-changing cost of equipment, currently unresolved applicability of tax credits, and other complications if combined into hybrid plants (and even greater uncertainty with E&AS offsets).

E&AS Methodology

We continue to recommend using a forward-looking E&AS offset, as described in our 2020 testimony and as PJM implemented for its 2022/2023 capacity auction. This approach reflects future market conditions that developers face and avoids distortions from anomalous conditions in a backward-looking approach. We recommend continuing to use the same liquid hubs for natural gas and electricity, and scaling ancillary services prices to energy prices. We recommend that PJM should not include regulation revenues in its estimation of the E&AS offset since the market for regulation is too small to provide substantial additional revenue to capacity entering the PJM market at scale. These recommendations all apply equally to the CT, along with a recommended 10% increase in the estimated day-ahead gas costs to account for having to buy gas in the less liquid intraday market when committed in the real-time market. For BESS, we recommend using the same forward prices along with a virtual dispatch as PJM has been performing with the PLEXOS model.

Application of this forward methodology to CCs leads to indicative E&AS offset values for the CC of \$209/MW-day for the RTO, \$222 for MAAC, \$189 for EMAAC, and \$249 for SWMAAC (all denominated in 2026 dollars per UCAP MW-day). This is about \$10-30/MW-day greater than the values used for MOPR reviews for the 2022/23 auction, with inflation more than offsetting other factors that tend to decrease the E&AS offset.

Implications for Net CONE and VRR Curve

Elevated Net CONE. With substantially higher CONE and only slightly higher indicative E&AS offsets, indicative CC Net CONE is correspondingly higher, at \$307/MW-day for the RTO, \$294 for MAAC, \$329 for EMAAC, and \$257 for SWMAAC (all denominated in 2026 dollars and UCAP MW). This is about \$154 higher than CC Net CONE for 2022/23; it is similarly above recent capacity market clearing prices when new CCs entered, and this is consistent with cost escalation, more constrained plant designs, and tax laws; plus likely increased reluctance to invest given a regulatory and market environment that is increasingly favoring clean energy.

Slightly elevated VRR Curve. In spite of significant cost increases, updated CC Net CONE is only \$47/MW-day higher than CT Net CONE for 2022/23, since CCs are more economic than CTs. Inefficiently maintaining the CT as the reference resource would increase Net CONE by much more. Thus, switching the reference resource to CCs would moderate the increase and should support procuring reserves closer to target.

Heightened Uncertainty. For the VRR curve to achieve resource adequacy objectives without procuring much below or above the target reserve margin, estimated Net CONE must accurately reflect the capacity price at which new capacity would enter. Yet uncertainty is endemic, particularly for an industry transitioning to new cleaner technologies with declining costs. Our indicative uncertainty analysis based on alternative assumptions noted above indicates a range of -29% to +16%; the uncertainty range may be greater when considering uncertainties beyond those we analyzed. In that context, the VRR curve must be steeper to perform well even if Net CONE is mis-estimated, and we tested robustness under stress tests of +/-40%, as discussed in our parallel VRR Curve report.

I. Introduction

I.A. Background

PJM's capacity market, the Reliability Pricing Model (RPM), features a three-year forward auction and subsequent incremental auctions in which the Variable Resource Requirement (VRR) curve sets the "demand" for capacity. The VRR curve is designed primarily to procure sufficient capacity for maintaining resource adequacy according to traditional standards. The longstanding resource adequacy objectives are to avoid supply shortages in expectations all but once in ten years system-wide (i.e., Loss of Load Expectation or LOLE of 0.1 events/yr), with no more than 0.04 LOLE incremental risk in the Locational Deliverability Areas (LDAs). With probabilistic modeling conducted by PJM, these objectives are translated into Reliability Requirements expressed in terms of megawatts of unforced capacity (MW UCAP).

The VRR curves are centered approximately on a target point corresponding to the Reliability Requirements, at a price given by the estimated long-run marginal cost of capacity, termed the "Net Cost of New Entry (Net CONE)." Rather than a vertical line, the VRR is a curve with nonzero demand above the target to recognize the value of incremental capacity, and with a slope to help mitigate price volatility (as addressed in a separate VRR Curve Study report we are publishing concurrently with this report).

For the VRR curve to procure sufficient capacity, the Net CONE parameter must accurately reflect the price at which developers would be willing to enter the market if needed. Estimated Net CONE should reflect the first-year capacity revenue an economically-efficient new generation resource would require (in combination with its expected net revenues from the energy and ancillary services markets) to recover its capital and fixed costs, given reasonable expectations about future cost recovery. Thus, Net CONE is given by gross CONE minus the projected Energy and Ancillary Services revenue (E&AS Offset).

Following its tariff, PJM has traditionally estimated Net CONE for a new gas-fired combustion turbine (CT) entering in each of four CONE Areas.[3] Gross CONE values have been determined through quadrennial CONE studies such as this one, with escalation rates applied in the intervening years.[4] Shortly before each Base Residual Auction, PJM estimates an E&AS Offset for each zone, then calculates a relevant Net CONE value to use in each locational VRR curve being represented in the auction.

PJM also develops Net CONE estimates for a variety of technologies in order to develop offer price screens under the Minimum Offer Price Rule (MOPR) for new generation offering capacity into RPM.[5] This has less relevance than in past since PJM filed and FERC accepted a revision to MOPR rules that limit its applicability.

I.B. Study Objective and Scope

PJM retained consultants at The Brattle Group and Sargent & Lundy to assist PJM and stakeholders in its quadrennial review. Per the PJM tariff, the scope of the Quadrennial Review is to review the VRR curve and its parameters, including the Cost of New Entry and the E&AS Offset methodology. To that end, a separate, concurrently issued report addresses the shape of the VRR curve. This report:

- Develops CONE estimates for new CT and CC plants and one "clean technology" in each of the four CONE Areas for the 2026/27 Base Residual Auction (BRA) and proposes a process to update these estimates for the following three BRAs;
- Reviews the E&AS offset methodology
- Recommends the most appropriate reference resource whose cost will best indicate the price at which developers would be willing to add capacity.

To estimate CONE for each resource type, we aim to represent the plant configuration, location, and costs that a competitive developer of new generation facilities will be able to achieve at generic sites, not unique sites with unusual characteristics. We estimate costs by specifying the

[3] The four CONE Areas are: CONE Area 1 (EMAAC), CONE Area 2 (SWMAAC), CONE Area 3 (Rest of RTO), and CONE Area 4 (WMAAC). PJM reduced the CONE Areas from five to four following the 2014 triennial review and incorporated Dominion (formerly CONE Area 5) into the Rest of RTO region.

[4] PJM 2017 OATT, Section 5.10 a.

[5] PJM 2017 OATT, Section 5.14 h.

reference resource and site characteristics, conducting a bottom-up analysis of costs, and translating the costs to a first-year CONE.

We provide relevant research and empirical analysis to inform our recommendations, but recognize where judgments have to be made in specifying the reference resource characteristics and translating its estimated costs into levelized revenue requirements. In such cases, we discuss the trade-offs and provide our own recommendations for best meeting RPM's objectives to inform PJM's decisions in setting future VRR curves. We provide not only our best estimate of CONE, but also inform the range of uncertainty, a key consideration in designing the VRR curve, as discussed in our separate report.

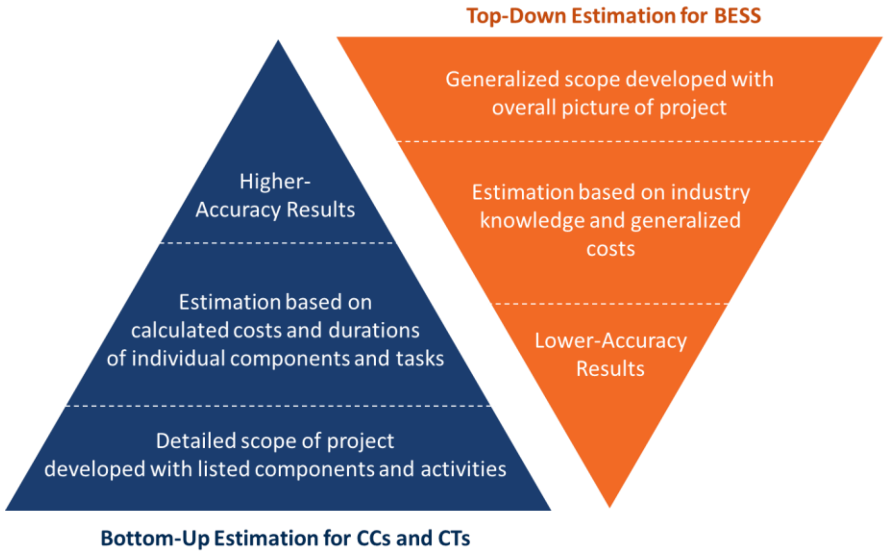
I.C. Analytical Approach

Our starting point is to identify the most appropriate technology to serve as the reference resource for the VRR curve. As discussed in Section II, we identified criteria for selecting the reference resource then evaluated a broad range of resource types against those criteria in an initial screening analysis. This narrowed the choices to a CC, a CT, and BESS, for each of which we analyzed the costs more extensively further—and ultimately recommended using the CC as the reference resource for all locations.

For each of the three identified resources, we estimated CONE for the four CONE Areas, starting with a characterization of plant configurations, detailed specifications, and locations where developers are most likely to build. We identified specific plant characteristics and site characteristics based on: (1) our analysis of the predominant practices of recently developed plants; (2) our analysis of technologies, regulations, and infrastructure; and (3) our experience from previous CONE analyses. Our analysis for selecting plant characteristics for each CONE Area is presented in Section 0 of this report.

We developed comprehensive, bottom-up cost estimates of building and maintaining the reference CC and CT in each of the four CONE Areas. To present a reasonable order-of-magnitude cost estimate for the BESS, we utilized a generalized, top-down approach. Figure 1 describes the attributes of each approach.

FIGURE 1: ATTRIBUTES FOR BOTTOM-UP AND TOP-DOWN ESTIMATION METHODS



Sargent & Lundy (S&L) estimated plant proper capital costs—equipment, materials, labor, and the engineering, procurement, and construction (EPC) contracting costs—based on a complete plant design and S&L's proprietary database on actual projects. S&L and Brattle then estimated the owner's capital costs, including owner-furnished equipment, gas and electric interconnection, development and startup costs, land, inventories, and financing fees using S&L's proprietary data and additional analysis of each component. We further estimated annual fixed and variable O&M costs, including labor, materials, property tax, insurance, asset management costs, and working capital.

Next, we translated the total up-front capital costs and other fixed-cost recovery of the plant into an annualized estimate of fixed plant costs, which is the Cost of New Entry, or CONE. CONE depends on the estimated capital investment and fixed going-forward costs of the plant as well as the estimated financing costs (cost of capital, consistent with the project's risk) and the assumed economic life of the asset. The annual CONE value for the first delivery year depends on developers' long-term market view and how this long-term market view impacts the expected cost recovery path for the plant—specifically whether a plant built today can be expected to earn as much in later years as in earlier years.

The Brattle and S&L authors collaborated on this study and report. The specification of plant characteristics was jointly developed by both teams, with S&L taking primary responsibility for developing the plant proper capital, plant O&M and major maintenance costs, and the Brattle authors taking responsibility for various owner's costs and fixed O&M costs, and for translating the cost estimates into the CONE values.

II. Reference Resource Selection

The purpose of selecting a reference resource and developing administrative Net CONE estimates is only to set a VRR curve that aims to procure enough resource adequacy credits. The choice of reference resource does not dictate which resources will enter the market. The administrative Net CONE value does not determine capacity prices; long-run prices depend primarily on the supply curve. Still, as the VRR curve is likely to remain sloped and anchored on our estimate of Net CONE, we aim to estimate Net CONE as accurately as possible, and that starts with a choice of the reference resource.

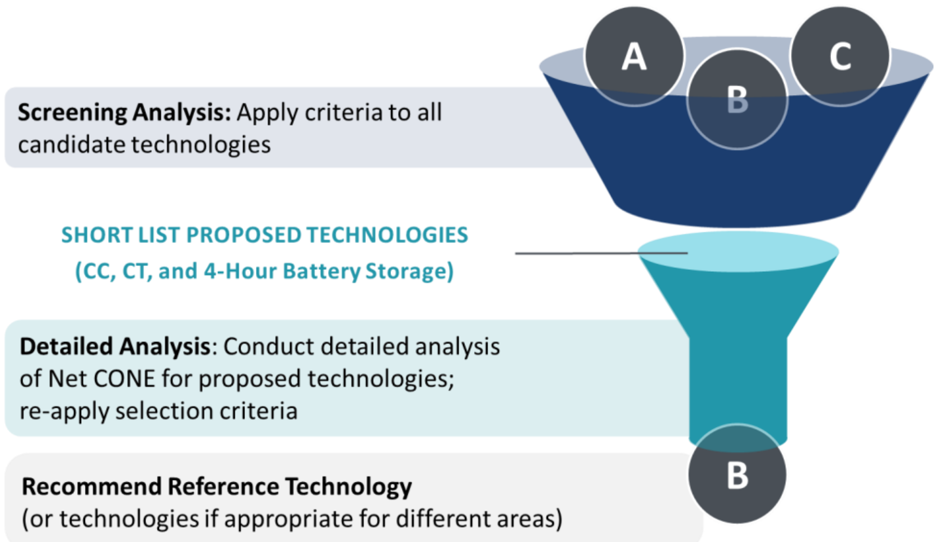
PJM has always used a reference resource, specifically a CT, to estimate Net CONE but asked us to evaluate its continued suitability for representing the cost at which suppliers are willing to bring significant amounts of capacity to PJM. We also considered CCs and a range of other technologies, including BESS as a possible "clean technology" for areas with more stringent environmental regulations. Finally, we also considered the possibility of relying on "empirical Net CONE," i.e. the price at which suppliers have willingly offered new capacity into recent auctions, rather than identifying a specific technology and estimating its net cost for future entry into the market. All possibilities were evaluated against a set of criteria for meeting RPM objectives.

In order to meet RPM reliability objectives with least risk of procuring far above or below target, we recommend switching to a CC as the reference resource. This aligns the VRR curve with observed entry of a technology that is feasible and most economic to build on a merchant basis, and whose Net CONE can be estimated relatively accurately. By contrast, CTs are not being built and are estimated to cost 20% more, on net, for capacity. Other technologies are similarly less economic or otherwise did not meet our selection criteria. Even in areas with more stringent environmental regulations, we did not identify a clear need to adopt a non-emitting reference resource at this time. Finally, empirical Net CONE is a useful benchmark but is not directly suitable because it does not reflect current market conditions affecting the costs of materials, equipment, and labor, nor the regulatory outlook that affects the design of the resources and their future revenue recovery.

II.A. Process for Selecting Reference Resource

We conducted the analysis in several steps, as shown in Figure 2 below. First, we developed criteria for choosing a reference resource; second, we identified a broad range of technologies to evaluate at a high-level against those criteria, resulting in a short list for detailed cost and E&AS analysis; finally, we applied the selection criteria again to select the single most appropriate technology to serve as the reference resource, reflecting the updated net costs of those resources.

FIGURE 2: REFERENCE RESOURCE SELECTION PROCESS



In consultation with PJM and its stakeholders, we developed the reference resource selection criteria. The foundational objective of the selection criteria was to identify the resource that best supports the RPM's broader objective of procuring enough capacity to meet resource adequacy goals. Given that, we developed three selection criteria.

The first and most basic of these criteria is that the resource has to be feasible to build in the (slightly more than) three-year timeframe between the Base Residual Auction and the Delivery Year, so that high clearing prices in an auction can draw in potential projects when needed/economic.

The second criterion is that the resource must be an economic source of incremental capacity. Otherwise, anchoring the VRR curve on uneconomic sources of capacity would unnecessarily shift the VRR curve upward (like a shift outward) and procure more capacity than needed, at the quantity where the true Net CONE of economic resources intersects the VRR curve. Resources that are economic should exhibit actual merchant development and lower estimated Net CONE, and they should not be subject to factors that will likely render them uneconomic over the next several auctions governed by this Quadrennial Review. The reason for focusing on merchant entrants is partly to ensure that the VRR curve is set high enough to attract merchant entry in the future. It is also to avoid including policy-supported payments (such as renewable energy credits, or RECs) in the E&AS Offset, since such payments are difficult to assess absent broad competitive markets and are limited to the amount of capacity that the policy is intended to achieve. Moreover, such an exercise would suffer from circularity since the necessary level of policy payments needed to support target reasons are in part set by capacity price itself.

The third criterion is that the resource's Net CONE can be estimated accurately. If Net CONE is mis-estimated, the VRR curve will procure more or less capacity than desired. Accurate estimation depends on the certainty of plant designs and their costs and the ability to estimate E&AS offsets using market data. It also depends on the scalability of a standardized resource, not subject to rapid increases in costs as the best sites are exhausted, in which case the cost would depend strongly on penetration. Finally, estimation accuracy also depends on the capacity rating of resources relative to their nameplate. Lower ratings (i.e., low ELCC) magnify the effect of estimation errors on the cost per qualified MW.

Figure 3 summarizes these criteria and sub-criteria for evaluating each candidate resource type.

FIGURE 3: REFERENCE RESOURCE SELECTION CRITIERIA

Feasible to build for the delivery year, given local laws/regulations and technical factors

Economic source of incremental capacity

- Demonstrated by recent merchant entry, not in anomalous situations
- Not having a Net CONE much higher than other candidates
- Likely to remain economic through the end of the review period (2029/30)

Costs, net E&AS revenues, and RA contribution per MW can be assessed accurately

- Evidence of capital and operating costs exists from commercial experience
- Costs are uniform when scaled, rather than increasing steeply as best sites are exhausted
- Has stable UCAP/ICAP ratio or ELCC, rather than changing steeply with penetration or fleet composition
- Has high UCAP/ICAP ratio or ELCC, else uncertainties are amplified per kW UCAP
- Not largely dependent on revenues that are difficult to forecast (AS, energy volatility, RECs)

II.B. Evaluation of Candidates against Criteria

The list of candidate technologies included gas-fired CTs and CCs, battery energy storage systems (BESS), hybrid photovoltaic (PV)-BESS, utility-scale PV, onshore wind, energy efficiency and demand response, uprates/conversions, and emerging technologies. Screening each of these against the evaluation criteria was straightforward in most cases, as shown in Table 1 below. For example, wind resources currently are not entering as a merchant resource without policy support in PJM, corresponding to its relatively high costs, and its Net CONE would be difficult to assess accurately due to its low ELCC rating that magnifies cost estimation errors. Energy efficiency, DR, and uprates/conversions were eliminated because of highly non-uniform costs across measures and sites, and scalability challenges with any particular type of measure.

TABLE 1: INITIAL REFERENCE RESOURCE SCREENING ANALYSIS

Technology	Feasible to Build for DY	Economic Source of Capacity	Accuracy of Net CONE Estimates	Screening Decision
Gas CC	Yes	Yes	High	Consider as leading candidate
Gas CT	Yes	Unclear (few built, higher Net CONE)	High	Consider for further analysis
Battery Storage	Yes	Unclear (not standalone cleared in RPM)	Medium (falling costs; AS-dependence; ELCC stability?)	Consider for further analysis
Hybrid PV-BESS	Yes	Unclear (is any entering as merchant?)	Medium (REC-dependence; ELCC stability?)	Eliminate: Higher Net CONE uncertainty
Utility-Scale PV	Yes	Unclear (is any entering as merchant?)	Medium (REC-dependence; ELCC stability?)	Eliminate: Higher Net CONE uncertainty
Wind	Yes	Unclear (is any entering as merchant?)	Low (REC-dependence; low ELCC, stability)	Eliminate: Net CONE much higher than other technologies based on 2023/2024 MOPR
Energy Efficiency/ DR	Yes	Yes	Low (varies by site)	Eliminate: Inability to accurately estimate Net CONE
Uprates/ Conversions	Yes	Yes	Low (varies by site)	Eliminate: Inability to accurately estimate Net CONE
Emerging Technologies	No	None	Low	Eliminate: Infeasible to build

Based on stakeholder feedback, we included one non-emitting resource in our CONE and E&AS analysis, selecting BESS due to its lower uncertainty in accurately estimating its Net CONE value compared to utility-scale solar PV and hybrid PV-BESS. Utility-scale solar PV ELCC values are highly uncertain as they decline significantly over the next 5-10 years based on the amount of entry that occurs in the PJM market, which is currently unknown. In addition, solar PV investments in PJM depend on RECs, the price of which is uncertain, which increases Net CONE uncertainty; REC prices also depend on capacity prices, creating a circularity that confounds estimating the capacity price at which PVs will enter. Hybrid PV-BESS resources are similarly uncertain as utility-scale solar PV in terms of the ELCC value and dependence on RECs for entry, plus the additional uncertainty of the configurations in which they will be built, including the relative scale of solar capacity to battery storage capacity and whether they will be AC-coupled versus DC-coupled or open-loop versus closed-loop.

That left CC, CT, and BESS as finalists. Ultimately, CCs best met the selection criteria, as summarized in Table 2 below. They are the most economic and are being built by developers. CTs continue not to be built, consistent with our estimate that their RTO Net CONE is about 20% higher than the CC, as shown in this report. In addition, CC Net CONE can be estimated relatively accurately. The conventional wisdom used to be that CCs are subject to more estimation error in E&AS Offsets, since their E&AS Offsets are larger. We disagree. The benchmark for "accuracy" should be the value that investors anticipate in the market. That benchmark is not directly observable, but there is more market data available to anticipate E&AS Offsets for CCs than CTs. CCs' net E&AS revenues can be fairly accurately approximated assuming 5x16 operation and applying observable futures prices for 5x16 on-peak blocks. No such benchmark is available for CTs that run less frequently when prices spike, so we rely on historical estimates that may not be representative of the future delivery year due to historical anomalies and evolving market conditions. Finally, CTs face less transparent gas procurement costs since they are committed and dispatched day-of.

TABLE 2: BASIS FOR SELECTING THE RECOMMENDED REFERENCE RESOURCE

Technology	Feasible to Build for Delivery Year	Economic Source of Capacity	Accuracy of Net CONE Estimates
Gas CC	**Yes**	**Yes** (significant recent entry; lowest 2026/27 Net CONE)	**Highest**
Gas CT	**Yes** (may be infeasible to build in NJ)	**Unclear** (few recently built; Net CONE 20% higher than CC)	**High** (higher forward E&AS uncertainty due to lack of forward pricing matching CT dispatch)
Battery Storage	**Yes**	**Unclear** (no cleared capacity to date; highest 2026/27 Net CONE among candidates)	**Low** (uncertain future AS revenues; falling costs)

We also considered "empirical Net CONE" based on the clearing price at which new capacity has proven willing to enter in the past several auctions. Historical data do indeed provide a useful reference point for Net CONE, although we rejected using it directly because it is backward-looking at a time when fundamentals are changing profoundly due to cost escalation and clean energy policies.

III. Natural Gas-Fired Combined-Cycle Plants

III.A. Technical Specifications

Similar to our approach in the 2014 and 2018 PJM CONE Study, we determined the characteristics of the reference resources primarily based on developers' "revealed preferences" for what is most feasible and economic in actual projects. However, because technologies and environmental regulations continue to evolve, we supplement our analysis with additional consideration of the underlying economics, regulations, infrastructure, and S&L's experience.

For determining most of the reference resource specifications, we updated our analysis from the 2018 study by examining CC plants built in PJM and the U.S. since 2018, including plants currently under construction. Plant location and emissions control technical specification assumptions across all CONE areas are based on the detailed analysis conducted in the 2018 PJM CONE study for the reference CC.[6] We characterized these plants by size, configuration, turbine type, cooling system, emissions controls, and fuel-firming.

For the specified locations within each CONE Area, we estimate the performance characteristics at a representative elevation and at a temperature and humidity that reflects peak conditions in the median year.[7] The assumed ambient conditions for each location are shown in Table 3.

6 For a more detailed discussion on analysis related to reference CC location selection and Emissions control technology requirements, please refer to the 2018 PJM CONE study.

7 The 50/50 summer peak day ambient condition data developed from National Climatic Data Center, Engineering Weather 2000 Interactive Edition, Asheville, NC, 2000. Adjustments were made for adapting the values to representative site elevation using J.V. Iribarne, and W.L. Godson, *Atmospheric Thermodynamics*, Second Edition (Dordrecht, Holland: D. Reidel Publishing Company, 1981).

TABLE 3: ASSUMED PJM CONE AREA AMBIENT CONDITIONS

CONE Area	Elevation	Max. Summer Temperature	Relative Humidity
	(ft)	*(°F)*	*(%RH)*
1 EMAAC	330	92.2	55.3
2 SWMAAC	150	96.2	44.2
3 Rest of RTO	990	89.9	49.7
4 WMAAC	1,200	91.4	48.9

Sources and notes: Elevation estimated by S&L based on geography of specified area. Summer conditions developed by S&L based on data from the National Climatic Data Center's Engineering Weather dataset.

Based on the assumptions discussed later in this section, the technical specifications for the CC reference resource is shown in Table 4. Net plant capacity and heat rate are calculated at the ambient air conditions listed above in Table 3.

TABLE 4: CC REFERENCE RESOURCE TECHNICAL SPECIFICATIONS

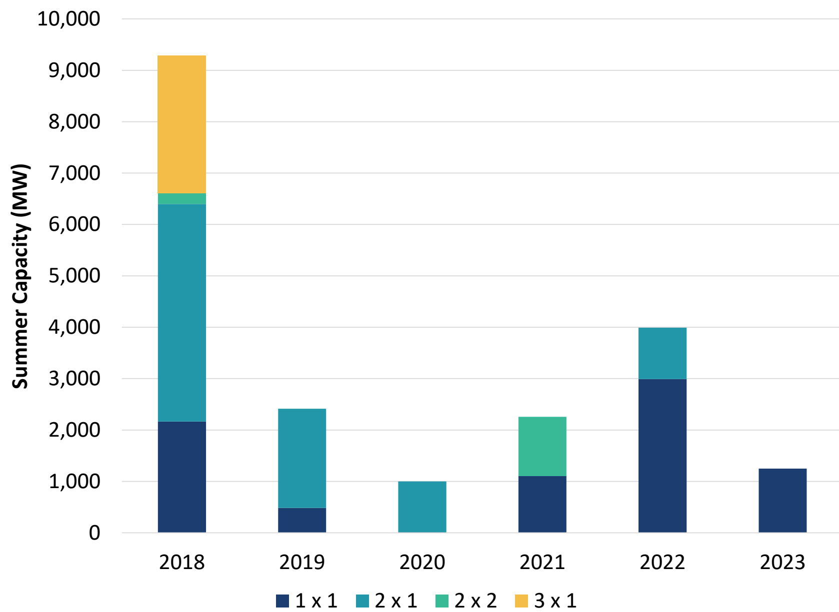
Plant Characteristic	Specification
Turbine Model	GE 7HA.02 (CT), STF-A650 (ST)
Configuration	Double Train 1 x 1
Cooling System	Dry Air-Cooled Condenser
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	
without Duct Firing	1043 / 1047 / 1020 / 1011*
with Duct Firing	1171 / 1174 / 1144 / 1133*
Net Heat Rate (HHV in Btu/kWh)	
without Duct Firing	6365 / 6383 / 6359 / 6368*
with Duct Firing	6602 / 6619 / 6593 / 6601*
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	No
Firm Gas Contract	Yes
Special Structural Requirements	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and notes: See Table 3 for ambient conditions assumed for calculating net summer ICAP and net heat rate.
* For EMAAC, SWMAAC, Rest of RTO, and WMAAC, respectively.

III.A.1. Plant Size, Configuration, and Turbine Models

Since 2018, CC development has shifted from being primarily 2×1 configurations (two gas combustion turbines, one steam turbine) to 1×1 configurations (one gas combustion turbine, one steam turbine), as shown in Figure 4 below.

FIGURE 4: GAS CC CONFIGURATIONS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018



Sources and notes: Data is from Ventyx Energy Velocity Suite, Accessed August 2021.

1×1 CCs are in most cases being constructed with multiple trains at the same plant. Table 5 shows that double-train 1×1 CCs make up 42% of the capacity for 1×1 CCs that have been built or under construction since 2018 and the majority of the capacity currently under construction.

TABLE 5: 1×1 GAS CC CAPACITY BY TRAINS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018

Number of Trains	2018 *(MW)*	2019 *(MW)*	2020 *(MW)*	2021 *(MW)*	2022 *(MW)*	2023 *(MW)*	Total Capacity *(MW)*	Capacity Share *(%)*
1	1,184	485	0	1,104	0	0	2,774	35%
2	980	0	0	0	1,116	1,250	3,346	42%
3	0	0	0	0	1,875	0	1,875	23%
All CC Plants	**2,164**	**485**	**0**	**1,104**	**2,991**	**1,250**	**7,994**	**100%**

Sources and notes: Data is from Ventyx Energy Velocity Suite, accessed August 2021. Double and triple train entries in represent a single plant, whereas single train 1×1 CCs represent multiple plants.

Based on the above empirical observations, we specify the CC reference resource to be a double-train 1×1. At the ambient conditions noted in Table 3, the double-train 1×1 CC maximum summer capacity ranges from 1,011 MW to 1,047 MW prior to considering supplemental duct firing, which is similar to the 2x1 CCs assumed in the previous PJM CONE studies.

While the turbine technology for each plant is specified in the tariff (*i.e.*, GE 7HA as the turbine model), we reviewed the most recent gas-fired generation projects and trends in turbine technology in PJM and the U.S. to consider whether to adjust this assumption.[8] For the reference CC, we maintain the assumption of GE H-class turbines from the 2018 PJM CONE study based on continuing shifts away from the F-class and G-class frame type turbines toward the similar but larger H-class and J-class turbines. We provide a more detailed discussion on recent developer preferences for H-class and J-class turbine since 2018 in Appendix A.

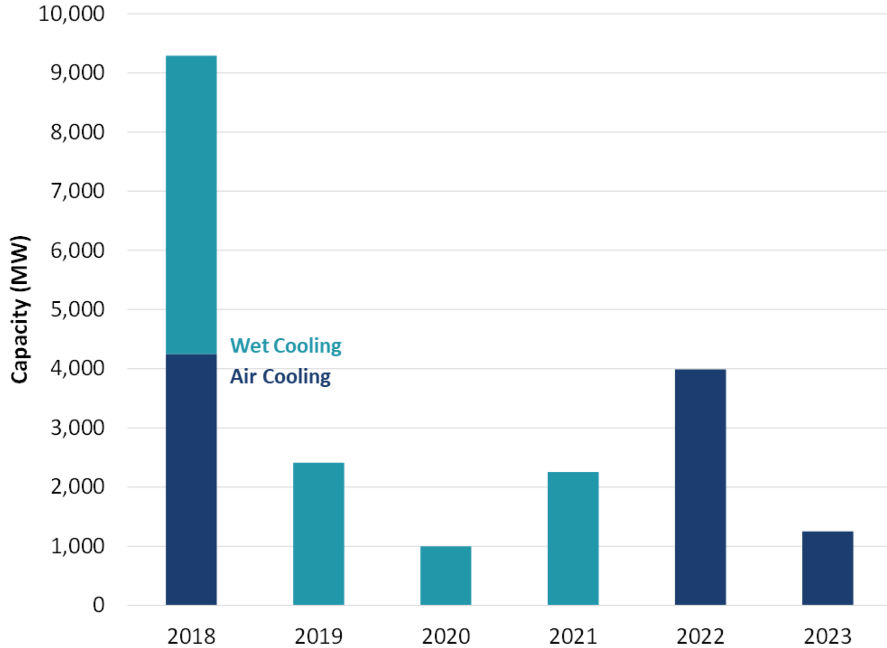
III.A.2. Cooling System

For the reference CC plant, we assumed a closed-loop circulating water cooling system with a multiple-cell dry air-cooled condenser (ACC). ACC technology differs from traditional water-cooled condensers that utilize "wet" cooling towers for heat rejection. Dry ACCs will tend to be larger and more costly but minimize the water usage. Reduced water consumption is advantageous in areas where water is scarce, expensive to procure, or where it may be difficult to obtain withdrawal permits for the volumes expended by a wet cooling system.

Figure 5 shows the recent trends among actual projects with all of the plants under construction now having dry air-cooled condensers, reflecting that cooling towers have become more difficult to permit.

[8] PJM 2017 OATT, Part 1 - Common Services Provisions, Section 1 - Definitions.

FIGURE 5: COOLING SYSTEM FOR CC CAPACITY IN PJM BUILT OR UNDER CONSTRUCTION SINCE 2018



Sources and notes: Data downloaded from Ventyx's Energy Velocity Suite August 2021. Includes only status operational plants (operating, under construction, site prep, converted, standby, testing, steam only, restarted)

III.A.3. Emissions Controls

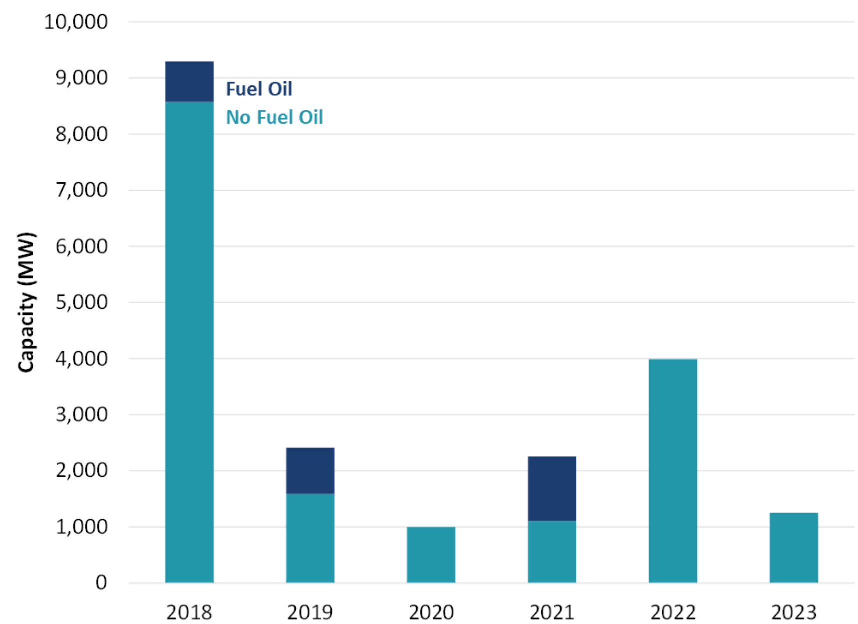
The reference CC is assumed to utilize selective catalytic reduction (SCR) systems as a nitrogen oxide (NOx) emissions control technology and CO catalyst systems as a carbon monoxide (CO) emissions control technology. The SCR system and CO catalyst adds an incremental cost of $72 million (in 2021 dollars) to the capital costs. A more detailed discussion of emissions controls can be found in the 2018 PJM CONE study.

III.A.4. Fuel Supply

Natural gas-fired plants can be designed to operate solely on gas or with “dual-fuel” capability to burn either gas or diesel fuel oil. Dual-fuel plants can switch to oil when gas becomes unavailable or prohibitively costly due to pipelines becoming fully utilized and congested. Plants without dual-fuel capability can ensure access to their fuel supply through firm transportation contracts, although such contracts cost more than dual-fuel capability in most locations.[9]

Developers have moved away from installing dual-fuel capability on new CCs. Figure 6 below shows that only 13% of CC capacity built or under construction in PJM installed fuel oil as a secondary fuel since 2018; data from PJM confirms that almost all are instead firming their availability with firm gas transportation contracts.

FIGURE 6: DUAL-FUEL CAPABILITY FOR CC CAPACITY IN PJM BUILT OR UNDER CONSTRUCTION SINCE 2018



Sources and notes: Data downloaded from Ventyx's Energy Velocity Suite August 2021. Includes only status operational plants (operating, under construction, site prep, converted, standby, testing, steam only, restarted).

Instead, we assume that the CC will obtain firm transportation service to ensure fuel supply during tight market conditions. Based on confidential data provided by PJM, nearly all new gas-fired plants that entered the market since the 2016/2017 BRA obtain firm transportation service to ensure adequate fuel supply.[10] Based on these trends, we updated our assumption from the

9 Eastern Interconnection Planning Collaborative, "Fuel Assurance: Dual Fuel Capability and Firm Transportation Alternatives," accessed September, 2017, http://nebula.wsimg.com/ef3ad4a531dd905b97af83ad78fd8ba7?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1

10 PJM provided the fuel supply arrangements for 20,848 MW of new gas plants that first cleared the capacity market in the 2016/2017 BRA to the 2020/2021 BRA, including firm transportation, dual fuel capability, and installing gas laterals to multiple pipelines.

2018 PJM CONE study for the CC reference resource to obtain firm gas supply across all CONE areas.[11] The costs of firm transportation service are incurred annually, so we include these costs as fixed operations and maintenance costs in the following section.

III.B. Capital Costs

Plant capital costs are costs incurred when constructing the power plant before the commercial online date. Power plant developers typically hire an engineering, procurement, and construction (EPC) company to complete construction and to ensure the plant operates properly. EPC costs include major equipment, labor, and materials, and non-EPC or owner's costs include development costs, startup costs, interconnection costs, and inventories.

All equipment and material costs are initially estimated by S&L in 2021 dollars using S&L proprietary data, vendor catalogs, or publications. Both labor rates and materials costs have been estimated for the specific counties chosen as representative of each CONE Area. Estimates for the number of labor hours and quantities of material and equipment needed to construct combined-cycle plants are based on S&L experience on similarly sized and configured facilities and are explained in further detail in Appendix A.

Based on the monthly construction drawdown schedule, we estimate the overnight capital cost for an online date of June 1, 2026 by escalating the 2021 costs using escalation rates provided by Sargent & Lundy. The 2026 "installed cost" is the present value of the construction period cash flows as of the end of the construction period, using the monthly drawdown schedule and the cost of capital for the project.

Based on the technical specifications for the reference CC described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 6 below. The maximum variation between overnight capital costs between CONE areas is $100/kW, similar to the $94/kW from the 2018 PJM CONE study. The methodology and assumptions for developing the capital cost line items are described further below.

[11] We recommended in the 2018 PJM CONE study dual-fuel capabilities in all CONE Areas except SWMAAC. PJM chose to adopt CONE values that incorporated dual-fuel capabilities.

TABLE 6: PLANT CAPITAL COSTS FOR CC REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*1171 MW*	*1174 MW*	*1144 MW*	*1133 MW*
Owner Furnished Equipment				
Gas Turbines	$155.3	$155.3	$155.3	$155.3
HRSG / SCR	$80.7	$80.7	$80.7	$80.7
Sales Tax	$0.0	$0.0	$0.0	$0.0
Total Owner Furnished Equipment	**$320.7**	**$320.7**	**$320.7**	**$320.7**
EPC Costs				
Equipment				
Other Equipment	$86.3	$86.3	$86.3	$86.3
Construction Labor	$365.5	$283.3	$297.1	$330.5
Other Labor	$75.5	$69.0	$70.1	$72.7
Materials	$75.5	$75.5	$75.5	$75.5
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	$98.5	$89.6	$91.1	$94.7
EPC Contingency	$108.4	$98.6	$100.2	$104.2
Total EPC Costs	**$871.4**	**$763.9**	**$782.0**	**$825.6**
Non-EPC Costs				
Project Development	$59.6	$54.2	$55.1	$57.3
Mobilization and Start-Up	$11.9	$10.8	$11.0	$11.5
Net Start-Up Fuel Costs	-$13.9	-$14.0	-$9.8	-$13.5
Electrical Interconnection	$25.3	$25.4	$24.7	$24.5
Gas Interconnection	$33.7	$33.7	$33.7	$33.7
Land	$2.2	$1.8	$1.0	$1.8
Fuel Inventories	$0.0	$0.0	$0.0	$0.0
Non-Fuel Inventories	$6.0	$5.4	$5.5	$5.7
Owner's Contingency	$10.0	$9.4	$9.7	$9.7
Emission Reduction Credit	$2.3	$2.3	$2.3	$2.3
Financing Fees	$29.2	$26.7	$27.2	$28.1
Total Non-EPC Costs	**$166.4**	**$155.8**	**$160.6**	**$161.3**
Total Capital Costs	**$1,358.5**	**$1,240.5**	**$1,263.3**	**$1,307.6**
Overnight Capital Costs ($million)	**$1,359**	**$1,240**	**$1,263**	**$1,308**
Overnight Capital Costs ($/kW)	**$1,160**	**$1,057**	**$1,104**	**$1,154**
Installed Cost ($/kW)	**$1,255**	**$1,144**	**$1,195**	**$1,248**

III.B.1. EPC Capital Costs

III.B.1.i. Project Developer and Contract Arrangements

Costs that are typically within the scope of an EPC contract include the major equipment (gas turbines, heat recovery steam generator (HRSG), condenser, and steam turbine), other equipment, construction and other labor, materials, sales tax, contractor's fee, and contractor's contingency.

The contracting scheme for procuring professional EPC services in the U.S. is typically implemented with a single contractor at a single, fixed, lump-sum price. A single contract reduces the owner's responsibility with construction coordination and reduces the potential for missed or duplicated scope compared to multiple contract schemes. The estimates and contractor fees herein reflect this contracting scheme.

III.B.1.ii. **Equipment and Materials**

"Major equipment" includes costs associated with the gas turbines, HRSG, SCR, condenser, and steam turbines. The major equipment includes "owner-furnished equipment" (OFE) purchased by the owner through the EPC. OFE costs include EPC handling costs contingency on logistics, installation, delivery, *etc.*, with no EPC profit markup on the major equipment cost itself. "Other equipment" includes inside-the-fence equipment required for interconnection and other miscellaneous equipment and associated freight costs. Equipment costs, including the combustion turbine costs, are based on S&L's proprietary database and continuous interaction with clients and vendors regarding equipment costs and budget estimates. We assume all purchases for plant equipment are exempt from sales tax.

The balance of plant EPC equipment and material costs were estimated using S&L proprietary data, vendor catalogs, and publications. The balance of plant equipment consists of all pumps, fans, tanks, skids, and commodities required for operation of the plant. Estimates for the quantity of material and equipment needed to construct simple- and combined-cycle plants are based on S&L experience on similarly sized and configured facilities.

III.B.1.iii. **Labor**

Labor consists of "construction labor" associated with the EPC scope of work and "other labor," which includes engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services. "Materials" include all construction materials associated with the EPC scope of work, material freight costs, and consumables during construction.

Similar to the 2018 PJM CONE Study, the labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Instead, S&L developed labor rates through a survey of the prevalent wages in each region in 2021, including both union and non-union labor. The labor costs are based on average labor rates weighted by the combination of trades required for each plant type. We provide a more detailed discussion of the inputs into the labor cost estimates in Appendix A.

III.B.1.iv. EPC Contractor Fee and Contingency

The "EPC Contractor's fee" is added compensation and profit paid to an EPC contractor for coordination of engineering, procurement, project services, construction management, field engineering, and startup and commissioning. This fee is applied to the Owner Furnished Equipment to account for the EPC costs associated with the tasks listed above once the equipment is turned over by the Owner to the EPC contractor. Capital cost estimates include an EPC contractor fee of 10% of total EPC and OFE costs for CC facilities based on S&L's proprietary project cost database.

"Contingency" covers undefined variables in both scope definition and pricing that are encountered during project implementation. Examples include nominal adjustments to material quantities in accordance with the final design; items clearly required by the initial design parameters that were overlooked in the original estimate detail; and pricing fluctuations for materials and equipment. Our capital cost estimates include an EPC contingency of 10% of total EPC and OFE costs, including the contractor fee. The overall contingency rate in this analysis (including the Owner's Contingency presented in the next section) is 9.7% to 9.8% of the pre-contingency overnight capital costs.

III.B.2. Non-EPC Costs

"Owner's capital costs" include all other capital costs not expected to be included in the EPC contract, including development costs, legal fees, gas and electric interconnections, and inventories.

III.B.2.i. Project Development and Mobilization and Startup

Project development costs include items such as development costs, oversight, and legal fees that are required prior to and generally through the early stages of plant construction. We assume project development costs are 5% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

Mobilization and startup costs include those costs incurred by the owner of the plant towards the completion of the plant and during the initial operation and testing prior to operation, including the training, commissioning, and testing by the staff that will operate the plant going forward. We assume mobilization and startup costs are 1% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

III.B.2.ii. Net Startup Fuel Costs

Before commencing full commercial operations, the new CC plants must undergo testing to ensure the plant is functioning and producing power correctly. This occurs in the months before the online date and involves testing the turbine generators on natural gas. S&L estimated the fuel consumption and energy production during testing for each plant type based on typical schedule durations and testing protocols for plant startup and commissioning, as observed for actual projects. A plant will pay for the natural gas, and will receive revenues for its energy production. We provide additional detail on the calculation of the net startup fuel costs in Appendix A.

III.B.2.iii. Emission Reduction Credits

Emission Reduction Credits (ERCs) must be obtained for new facilities located in non-attainment areas. ERCs may be required for projects located in the ozone transport region even if the specific location is in an area classified as attainment. ERCs must be obtained prior to the start of operation of the unit and are typically valid for the life of the project; thus, ERC costs are considered to be a one-time expense. ERCs are determined based on the annual NOx and volatile organic compounds (VOC) emissions of the facility and offset ratio which is dependent on the specific plant location. Similar to our assumption from the 2018 PJM CONE study, we assumed a cost of $5,000/ton for all CONE Areas and an offset ratio of 1.15 for NOx and VOC emissions, resulting in a one-time cost of $2 million (in 2021 dollars) prior to beginning operation of the CC plants. While ERC costs are likely to vary by project and by location, there is insufficient publicly available cost data to support a more refined cost estimate for each CONE Area.

III.B.2.iv. Gas and Electric Interconnection

We estimated gas interconnection costs based on cost data for gas lateral projects similar to the interconnection of a greenfield plant. We assume the gas interconnection will require a metering station and a five-mile lateral connection, similar to the 2018 PJM CONE Study. From the data summarized in Appendix A, we estimate that gas interconnection costs will be $29.5 million (in 2021 dollars) based on $5.1 million/mile and $4.0 million for a metering station. Similar to the 2011, 2014, and 2018 PJM CONE studies, we found no relationship between pipeline width and per-mile costs in the project cost data.

We estimated electric interconnection costs based on historic electric interconnection cost data provided by PJM. Electric interconnection costs consist of two categories: direct connection costs and network upgrade costs. Direct connection costs will be incurred by any new project connecting to the network and includes all necessary interconnection equipment such as generator lead and substation upgrades. Network upgrade costs may be incurred when improvements, such as replacing substation transformers, are required. Using recent project data provided by PJM with the online service year between 2018 and 2021, we selected 17 projects (3,700 MW of total capacity) that are representative of interconnection costs for a new gas CCs and calculated a capacity-weighted average electrical interconnection cost of $18.9/kW (in 2021 dollars) for these projects, 5% lower than the 2018 PJM CONE Study. The estimated electric interconnection costs are between $21.4 and $22.2 million for CCs (in 2021 dollars). Appendix A presents additional details on the calculation of electric interconnection costs.

III.B.2.v. **Land**

We estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. We assume that 60 acres of land are required for the CC. Table 7 shows the resulting costs (see Appendix A for more detail).

TABLE 7: COST OF LAND PURCHASED FOR REFERENCE CC

CONE Area	Land Price *($/acre)*	Plot Size Gas CC *(acres)*	Cost Gas CC *($m)*
1 EMAAC	$36,600	60	$2.20
2 SWMAAC	$29,500	60	$1.77
3 Rest of RTO	$16,400	60	$0.98
4 WMAAC	$30,600	60	$1.84

Sources and notes: We assume land is purchased in 2022, i.e., 6 months to 1 year before the start of construction.

III.B.2.vi. **Non-Fuel Inventories**

Non-fuel inventories refer to the initial inventories of consumables and spare parts that are normally capitalized. We assume non-fuel inventories are 0.5% of EPC costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

III.B.2.vii. **Owner's Contingency**

Owner's contingencies are needed to account for various unknown costs that are expected to arise due to a lack of complete project definition and engineering. Examples include permitting complications, greater than expected startup duration, *etc.* Similar to our assumption in the 2018 PJM CONE Study, we assumed an owner's contingency of 8% of Owner's Costs based on S&L's review of the most recent projects for which it has detailed information on actual owner's costs.

III.B.2.viii. Financing Fees

Financing fees are the cost of acquiring the debt financing, including associated financial advisory and legal fees. Financing fees are considered part of the plant overnight costs, whereas interest costs and equity costs during construction are part of the total capital investment cost, or "installed costs" but not part of the overnight costs. We assume financing costs are 4% of the EPC and non-EPC costs financed by debt, which is typical of recent projects based on S&L's review of similar projects for which it has detailed information on actual owner's costs. As explained below, the project is assumed to be 55% debt financed and 45% equity financed.

III.B.3. Escalation to 2026 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period of 32 months for CCs.[12] We escalated the 2021 estimates of overnight capital cost components forward to the construction period for a June 2026 online date using cost escalation rates particular to each cost category.

We estimated real escalation rates based on long-term historical trends relative to the general inflation rate for equipment and materials and labor. We forecast that labor costs will continue to climb at recent rates (1.6% real per year) over the next several years, while materials and equipment suppliers will lock in the higher costs but not rise as quickly as they have over the past few years.

We calculated the inflation rate for escalating the capital costs estimated in January 2022 to the middle of the project development period (November 2024) based on the inflation that occurred since January, as reported by the Bureau of Labor Statistics, and the inflation forecasted by the Blue Chip Economic Indicators in March 2022, in which inflation starts at over 4% on an annualized basis before levelling off at 2.2% in the longer-term. Based on these sources, we assumed for the CONE calculations an annualized long-term inflation rate of 2.91% for 2022 to

12 The construction drawdown schedule occurs over 32 months with 82% of the costs incurred in the final 18 months prior to commercial operation.

2026.[13] The real escalation rate for each cost category was then added to the assumed inflation rate to determine the nominal escalation rates, as shown in Table 8.

TABLE 8: CC AND CT CAPITAL COST ESCALATION RATES (% PER YEAR)

Capital Cost Component	Real Escalation Rate	Nominal Escalation Rate
Equipment and Materials	0.00%	2.91%
Labor	1.60%	4.51%

Sources and notes: Escalation rates on equipment and materials costs are derived from the BLS Producer Price Index.

To reflect the timing of the costs a developer accrues during the construction period, we escalated most of the capital cost line items from the current overnight costs to the month they would be incurred using the monthly capital drawdown schedule developed by S&L for an online date in June 2026.

We escalated several cost items in a different manner:

- Land: assume land will be purchased 6 months to 1 year prior to the beginning of construction; for a June 2026 online date, the land is thus assumed to be purchased in late 2022 such that current estimates are escalated 1 year using the long-term inflation rate of 2.9%.
- Net Start-Up Fuel and Fuel Inventories: no escalation was needed as we forecasted fuel and electricity prices in 2026 dollars.
- Electric and Gas Interconnection: assume the construction of electric interconnection occurs 7 months prior to project completion while gas interconnection occurs 8 months prior to completion, consistent with the 2018 PJM CONE Study; the interconnection costs have been escalated specifically to these months.
- Emission Reduction Credits: escalated to the online start date of June 2026 using the long-term inflation rate of 2.91%.

We used the drawdown schedule to calculate debt and equity costs during construction to arrive at a complete "installed cost." The installed cost for each technology is calculated by first applying the monthly construction drawdown schedule for the project to the 2026 overnight capital cost and then finding the present value of the cash flows as of the end of the construction period using the assumed cost of capital as the discount rate. By using the ATWACC to calculate

[13] The near-final CONE results presented on March 25, 2022 assumed an inflation rate of 2.0%.

the present value, the installed costs will include both the interest during construction from the debt-financed portion of the project and the cost of equity for the equity-financed portion.

III.C. Operations and Maintenance Costs

Once the plant enters commercial operation, the plant owners incur fixed O&M costs each year, including contracted services, property tax, insurance, labor, maintenance, and asset management. Annual fixed O&M costs increase the CONE. Separately, we calculated *variable* O&M costs (including maintenance, consumables, and waste disposal costs) tied directly to unit operations to inform PJM's future E&AS margin calculations.

III.C.1. Summary of O&M Costs

Table 9 summarizes the fixed and variable O&M for CCs with an online date of June 1, 2026.

TABLE 9: O&M COSTS FOR CC REFERENCE RESOURCE

	CONE Area			
O&M Costs	**1** **EMAAC** *1171 MW*	**2** **SWMAAC** *1174 MW*	**3** **Rest of RTO** *1144 MW*	**4** **WMAAC** *1133 MW*
Fixed O&M (2026$ million)				
LTSA Fixed Payments	$0.8	$0.8	$0.8	$0.8
Labor	$5.2	$5.6	$4.0	$4.1
Maintenance and Minor Repairs	$6.6	$6.7	$6.0	$6.1
Administrative and General	$1.4	$1.4	$1.2	$1.2
Asset Management	$1.6	$1.7	$1.2	$1.2
Property Taxes	$3.0	$16.4	$9.5	$2.9
Insurance	$8.2	$7.4	$7.6	$7.8
Firm Gas Contract	$10.0	$12.4	$16.4	$14.5
Working Capital	$0.2	$0.1	$0.1	$0.1
Total Fixed O&M (2026$ million)	**$36.8**	**$52.6**	**$46.8**	**$38.8**
Levelized Fixed O&M (2026$/MW-yr)	**$31,500**	**$44,900**	**$40,900**	**$34,200**
Variable O&M (2026$/MWh)				
Consumables, Waste Disposal, Other VOM	0.76	0.76	0.77	0.77
Total Variable O&M (2026$/MWh)	**2.08**	**2.07**	**2.12**	**2.14**

III.C.2. Annual Fixed Operations and Maintenance Costs

Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance).

III.C.2.i. Plant Operation and Maintenance

We estimated the labor, maintenance and minor repairs, and general and administrative costs based on a variety of sources, including S&L's proprietary database on actual projects, vendor publications for equipment maintenance, and data from the Bureau of Labor Statistics.

Major maintenance is assumed to be completed through a long-term service agreement (LTSA) with the original equipment manufacturer that specifies when to complete the maintenance based on either fired-hours or starts. Consistent with past CONE studies and PJM market rules, we include the monthly payments specified in the LTSA as fixed O&M costs and the larger costs associated with run-time and starts as variable O&M.

III.C.2.ii. Insurance and Asset Management Costs

We estimate insurance cost of 0.6% of the overnight capital cost per year, from the 2018 PJM CONE study based on a sample of independent power projects recently under development in the Northeastern U.S. and discussions with a project developer. We estimated the asset management costs from typical costs incurred for fuel procurement, power marketing, energy management, and related services from a sample of natural gas-fired plants in operation.

III.C.2.iii. Property Tax

We maintained our bottom-up approach for estimating property and personal taxes from the 2018 PJM CONE study. We researched tax regulations for the locations selected in each CONE Area, averaging the tax rates in the areas that include multiple states.[14] The tax rates assumed for each CONE Area are summarized in Table 10 with additional details in Appendix A.

[14] See the 2018 PJM CONE study for a detailed discussion on our bottom up approach.

TABLE 10: PROPERTY TAX RATE ESTIMATES FOR EACH CONE AREA

	Real Property Tax	Personal Property Tax	
	Effective Tax Rate	Effective Tax Rate	Depreciation
	(%)	*(%)*	*(%/yr)*
1 EMAAC			
New Jersey	3.8%	n/a	n/a
2 SWMAAC			
Maryland	1.1%	1.3%	3.30%
3 RTO			
Ohio	1.9%	1.3%	See "SchC-NewProd (NG)" Annual Report
Pennsylvania	2.7%	n/a	n/a
4 WMAAC			
Pennsylvania	3.8%	n/a	n/a

Sources and notes: See Appendix A for additional detail on inputs and sources.

We assume that assessed value of real property will escalate in future years with inflation. We assume that the initial assessed value of the property is the plant's total capital cost (exclusive of real property). The assessed value of personal property is subject to depreciation in future years.

III.C.2.iv. **Working Capital**

Based on our approach in the 2018 PJM CONE study, we estimate the costs of maintaining the working capital requirement assuming that the working capital requirement is approximately 0.5% of overnight costs and a borrowing rate for short-term debt of 2.1%.[15]

III.C.2.v. **Firm Transportation Service Contracts**

We maintained our approach for estimating firm transportation service contracts from the 2018 PJM CONE study for the SWMAAC CONE Area for the reference CC. However, we utilized the reservation and usage charges for pipelines servicing EMAAC, Rest of RTO, and WMAAC under FT-1 rate schedules. Table 11 summarizes the pipelines we assumed for each CONE area and the representative firm gas capacity costs. We assume the reference CC commit to procuring firm gas transportation on an annual basis.

15 15-day average 3-month bond yield as of January 31, 2022, BFV USD Composite (BB), from Bloomberg.

TABLE 11: CONE AREA PIPLEINES AND FIRM GAS CAPACITY COSTS

	CONE Area	Pipelines	Representative Firm Gas Capacity Cost *(2026$ per Dth/d per Mth)*
1	**EMAAC**	Transco Zone 6 (non-NY), Transco Zone 6 (NY)	$4.50
2	**SWMAAC**	Dominion Cove Point	$5.56
3	**Rest of RTO**	Chicago, Columbia-Appalachia TCO, Dominion South, Michcon, Transco Zone 5	$7.54
4	**WMAAC**	Tennessee 500L, TETCO M3	$6.73

To estimate the costs of acquiring firm transportation service for SWMAAC we escalated the Cost of Firm Gas Capacity per Month of $4.96 (2022$ per Dth/d) from the 2018 PJM CONE study by 2.9% annually to 2026. For the EMAAC, Rest of RTO, and WMAAC CONE Areas, we combined the reservation and usage rates, resulting in a tariff rate for each pipeline. Then the pipeline tariff rates are averaged and escalated by 2.9% annually to 2026 by CONE area to calculate the representative firm gas capacity. We provide additional detail on the cost calculation of acquiring firm transportation service in Appendix A.

III.C.3. Variable Operation and Maintenance Costs

Variable O&M costs are not used in calculating CONE, but they are inputs to the calculation of the E&AS revenue offset performed by PJM. Variable O&M costs are directly proportional to plant generating output, such as SCR catalyst and ammonia, CO oxidation catalyst, water, and other chemicals and consumables. As discussed above, we assume that the major maintenance costs related to the unit run-time and starts are variable O&M costs, consistent with past CONE studies.

III.C.4. Escalation to 2026 Costs

Inflation rates affect our CONE estimates by forming the basis for projected increases in various fixed O&M cost components over time. We escalated the components of the O&M cost estimates from 2021 to 2026 on the basis of cost escalation indices particular to each cost category. The same real escalation rates used to escalate the overnight capital costs in the previous section (see Table 8) have been used to escalate the O&M costs. The assumed real escalation rate for O&M line items that are primarily labor-based is 1.6% per year, while those for other O&M costs remain constant in real terms.

III.D. Financial Assumptions

III.D.1. Cost of Capital

An appropriate discount rate is needed for translating uncertain future cash flows into present values and deriving the CONE value that makes the project net present value (NPV) zero. It is standard practice to discount future all-equity cash flows (*i.e.*, without deducted interest payments) using an after-tax weighted-average cost of capital (ATWACC).[16] Consistent with our approach in previous CONE studies, we developed our recommended cost of capital by an independent estimation of the ATWACC for publicly-traded merchant generation companies or independent power producers (IPPs), supplemented by additional market evidence from recent merger and acquisition transactions.[17] Based on our empirical analysis as of March 31, 2022, we recommend 8.0% as the appropriate ATWACC to set the CONE price for a new merchant plant that will commence operation by 2026 (4.5 years from now assuming a mid-year commercial operation). Consistent with this ATWACC determination, we recommend the following specific components for a new merchant plant: a capital structure of 55/45 debt-equity ratio, cost of debt 4.7%, a combined federal and state tax rate of 27.7%, and return on equity (ROE) of 13.6%.[18] It is important to emphasize that the exact capital structure and corresponding cost of debt and ROE do not significantly affect the CONE calculation as long as they amount to the empirically-based 8.0% ATWACC.[19] This is because the CONE value is determined by the 8.0% ATWACC, not by the ATWACC components. Nonetheless, we use market observations and judgements to select a set of self-consistent components of the ATWACC.

As a point of reference, we compare our current ATWACC recommendation to recommendations in our prior PJM CONE studies in Figure 7. The red circles (35% federal tax rate for 2011 and

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[16] The ATWACC is so-named because it accounts for both the cost of equity and the cost of debt, net of the tax deductibility of interest payments on debt, with the weights corresponding to the debt-equity ratio in the capital structure. Cash flows to which the ATWACC is applied must include revenues, costs, and taxes on income net of depreciation (but not accounting for interest payments or their deductibility, since that is incorporated into the ATWACC itself).

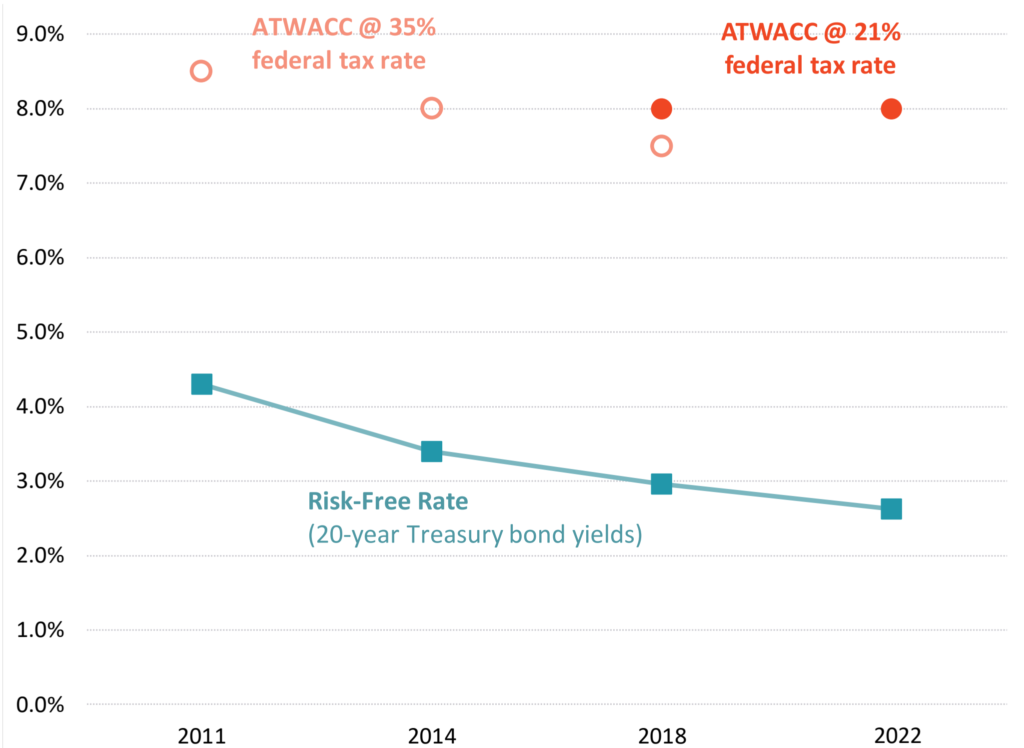
[17] Supplementing our ATWACC analysis with estimates from other financial analysts is valuable as others' methodologies may account for market risks and estimation uncertainties differently from ours.

[18] 4.7% × 55% × (1 – 27.7%) + 13.6% × 45% = 8.0%. The tax rate of 27.7% is a combined federal-state tax rate, where state taxes are deductible for federal taxes (= 8.5% + (1 – 8.5%) × 21%). Note that the ATWACC applied to the four CONE Areas varies slightly with applicable state income tax rates, as discussed in the next section.

[19] Finance theory posits that, over a reasonable range, capital structure does not affect the cost of capital: for a given project or business, greater leverage will increase the cost of debt and cost of equity such that the ATWACC would remain the same.

2014) and dots (21% tax rate for 2018 and 2022) represent the recommended ATWACCs, and the line is the prevailing risk-free rate (20-year Treasury rate).

FIGURE 7: COMPARISON OF BRATTLE ATWACC RECOMMENDATIONS FOR PJM



Sources: 2011, 2014, and 2018 values based on previous PJM CONE studies.

Over the last decade, our recommended ATWACC of merchant generation was 8.5% in 2011, then dropped and stayed at 8% between 2014 and 2022. These changes are driven by changes in both business risks of the industry, and market risks such as the risk-free rate and corporate income tax rates.

- We lowered the ATWACC from 8.5% to 8% in 2014 because the 20-year Treasury rate dropped from 4.3% in 2011 to 3.4% in 2014.
- The 20-year Treasury rate dropped further in 2018 to 3.0%. However, we kept our ATWACC recommendation at 8%, because the reduction in federal corporate income tax rate, from 35% to 21% starting from 2018, increases the ATWACC.
- The 20-year Treasury rate dropped again in 2022 to 2.6% as of March 2022. However, the top of the ATWACC range from the sample (the business risk of the merchant generation industry) and the additional reference points approximates 8.0% (Figure 8).

In Table 12, we compare our current recommended costs of capital components to those in our prior PJM CONE studies. The changes in the return of equity (ROE) are based on a number of factors: our recommended ATWACC, the federal-state combined tax rate, cost of debt, and the debt/equity ratios.

TABLE 12: COMPARISON OF COST OF CAPITAL RECOMMENDATIONS

Study Year	Tax Rate	Return on Equity	Equity Ratio	Cost of Debt	Debt Ratio	ATWACC
2011	40.5%	12.5%	50%	7.5%	50%	8.5%
2014	40.5%	13.8%	40%	7.0%	60%	8.0%
2018	27.7%	13.0%	45%	5.5%	55%	8.0%
2022	27.7%	**13.6%**	45%	**4.7%**	55%	8.0%

The rest of this section further describes our approach to developing the recommended ATWACC. First, we perform an independent cost of capital analysis for U.S. IPPs. Second, we present evidence on the discount rates disclosed in fairness opinions for two recent merger and acquisition transactions involving U.S. IPPs.[20] Third, we discuss how considerations of the specific dynamics of PJM markets affect cost of capital recommendations.

ATWACC for Publicly Traded Companies as of March 31, 2022: We estimated ATWACC using the following standard techniques, with the base-case results summarized in Table 13 and charted with sensitivities in Figure 8. Base-case estimates are derived from three publicly-traded companies with significant portfolios of merchant generation. The sample ATWACC ranges from 6.3% for AES to 7.6% for NRG. Additional details about the sample and key inputs are discussed next.

[20] We do not include private equity investors in our sample because their cost of equity cannot be observed in market data and private equity investment portfolios typically consist of investments in many different projects in many different industries. Nor do we include electric utilities in cost-of-service regulated businesses, as their businesses are mostly cost-of-service regulated with lower risks and a lower cost of capital than merchant generation.

TABLE 13: BASE-CASE ATWACC - 2022

Company	S&P Credit Rating [1]	Market Capitalization [2]	Long Term Debt [3]	Beta [4]	CAPM Cost of Equity [5]	Equity Ratio [6]	Cost of Debt [7]	ATWACC [8]
AES Corp	BBB-	$15,862	$17,754	1.10	10.8%	41%	4.3%	6.3%
NRG Energy Inc	BB+	$9,179	$8,202	1.15	11.2%	53%	4.9%	7.6%
Vistra Corp	BB	$10,117	$10,515	1.10	10.8%	47%	5.2%	7.1%

Sources & Notes:
[1]: S&P Research Insight.
[2] and [3]: Bloomberg as of 3/31/2022, millions USD.
[4]: Value Line.
[5]: RFR (2.62%) + [4] × MERP (7.46%).
[6]: Equity as a percentage of total firm value.
[7]: Cost of Debt based on Company Cost of Debt for AES, NRG and Vistra.
[8]: [5] × [6] + [7] × (1 - [6]) × (1 - tax rate).

Sample: Our sample consists of three companies: NRG, Vistra, and AES. Since 2018, there are no longer any pure-play merchant generation companies in the US. In 2018, Calpine was taken private by a consortium of private investors, and Dynegy was acquired by Vistra. The new Vistra includes both electricity generation and retail electricity supply. In addition, NRG expanded into competitive retail electricity supply. NRG and Vistra do not currently report their operating segments along the generation and retail supply lines of business. Their business mixes in terms of operating profits in 2019 are shown in Table 14.[21] Our sample also includes AES, a diversified global energy company holding assets in both utilities and the construction and generation of electricity. However, its annual financials only disclose its business segments by geography, not by line of business.[22]

TABLE 14: BUSINESS MIX OF NRG AND VISTRA IN 2019

Company [1]	Retail [2]	Generation [3]
NRG	38%	62%
Vistra	8%	92%

21 NRG changed its segment reporting in 2020 such that the split between power generation and retail is not available.

22 AES discloses its annual financials for each of its strategic business units: US and Utilities (which covers the United States, Puerto Rico and El Salvador); South America (which covers Chile, Colombia, Argentina and Brazil); MCAC (which covers Mexico, Central America and the Caribbean); and Eurasia (which covers Europe and Asia). Source: The AES Corporation. (December 31, 2019). Form 10-K. https://s26.q4cdn.com/697131027/files/doc_financials/2019/q4/2019-Form-10-K-FINAL.pdf.

Cost of Equity: We estimate the return on equity (ROE) of the sample companies using the Capital Asset Pricing Model (CAPM). As shown in column [5] of Table 13, the resulting return on equity ranges from 10.8-11.2% for the companies included in the analysis. The ROE for each company is derived as the risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta." The "beta" describes each company stock's (five-year) historical correlation with the overall market, where the "market" is taken to be the S&P 500 index.

Each of these inputs is discussed below:

- We estimated the expected risk premium of the market to be 7.46% based on the long-term average of values provided by Kroll, *fka* Duff and Phelps.[23]
- In Table 13, we use a risk-free rate of 2.62%, a 15-day average of 20-year U.S. treasuries as of March 31, 2022, as the base case. In addition to our base analysis under current market conditions, we also consider the use of forecasted risk-free rates applicable five years from now to estimate the offer of a new merchant entrant that starts operating in 2026. Blue Chip Economic Indicators forecasts a 3.0% yield for 10-year Treasury yields between 2023 and 2026.[24] Adding a maturity premium (20-year bond yields over 10-year bond yields) of 0.5%, we estimate the 20-year risk-free rate to be 3.5% and use this as a sensitivity analysis, as shown in Figure 8 below.
- We use betas (column [4] in Table 13) reported by Value Line.[25] They are calculated using 2-year weekly returns.

Cost of Debt: In our previous analyses, we estimated the cost of debt (COD) of the sample companies by the average bond yields corresponding to the unsecured senior credit ratings for each company (issuer ratings).[26] The rating-based average yields, based on a sample of similarly-

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[23] Kroll Cost of Capital Navigator 2021, as of February 2022 (arithmetic average of excess market returns over 20-year risk-free rate from 1926-2021).

[24] Blue Chip Economic Indicators (March 2022), *Blue Chip Economic Indicators, Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, New York: Aspen Publishers.

[25] The 3-year period is chosen over the standard 5-year period to limit the period under the new tax law, which went into effect in 2018, and also to limit the period to be post integration of the 2017 Dynegy / Vistra merger and the spinoff of NRG Yield in 2018.

[26] In Standard and Poor's (S&P) credit ratings, a company receives a higher rating based on its ability to meet financial commitments.

rated long-term (10 plus years) corporate bonds, are generally preferable than the company's actual COD, which could be more influenced by company- and issue-specific factors.[27]

TABLE 15: COST OF DEBT

Company	S&P Credit Rating	Ratings-Based Cost of Debt	Company-Specific Cost of Debt
[1]	[2]	[3]	[4]
AES Corp	BBB-	2.5%	4.3%
NRG Energy Inc	BB+	2.8%	4.9%
Vistra Corp	BB	3.1%	5.2%

However, company-specific CODs could carry real-time industry-wide credit information that the typically static credit ratings for a broad swath of industries are slow to incorporate. This is the case for the merchant generation corporations: the average yields for the BBB-, BB+, and BB rated corporate bonds are barely higher than the current risk-free rate and lower than the Blue Chip forecast for the risk-free rate in 2022 and 2023. In contrast, U.S.-based IPPs' company-specific bond yields are consistently higher than the rating-based yields. Therefore, in the base-case estimation in Table 13, we use the company-specific bond yield, but in the sensitivity analysis (Figure 8 below) we also use rating-based cost of debt.

Debt/Equity Ratio: We estimate the five-year average debt/equity ratio for each merchant generation company using data from Bloomberg. They are reported in Table 13 above.

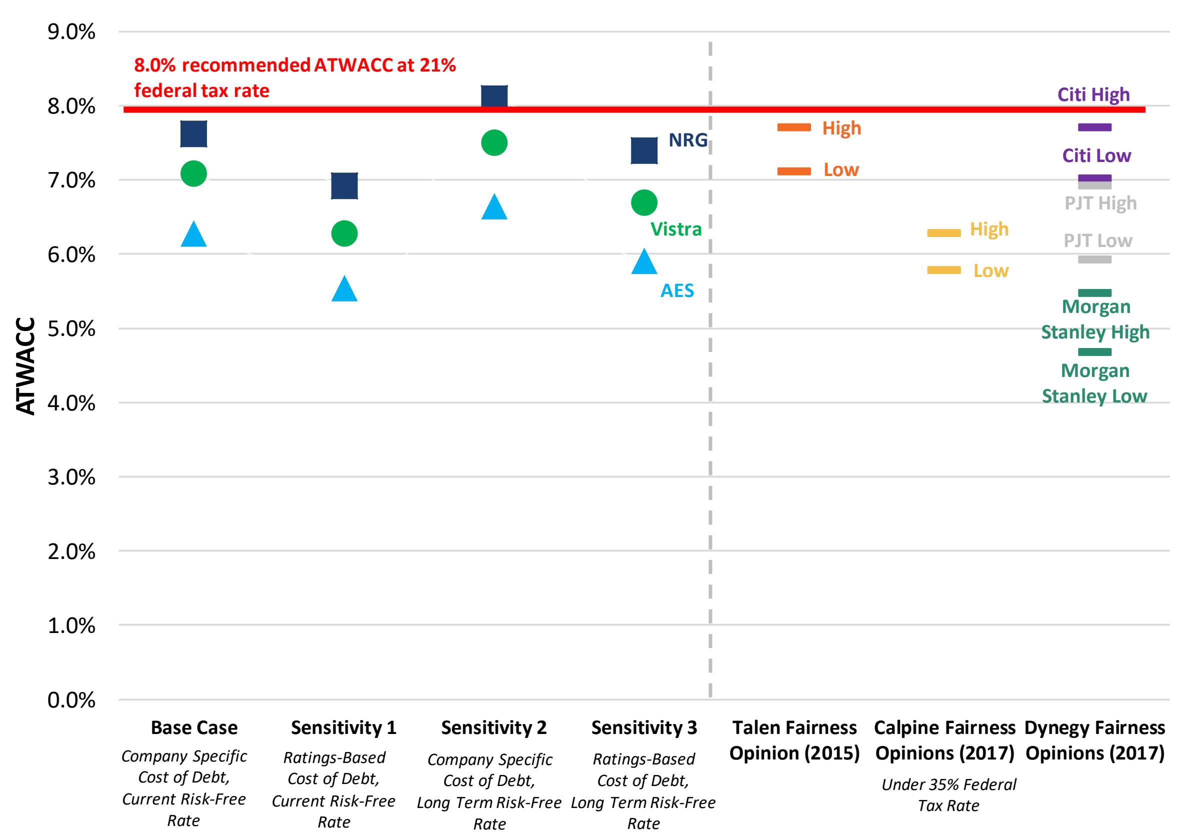
ATWACC Sensitivities and Cost of Capital Benchmarks from Recent Fairness Opinions:
Figure 8 reports the ATWACC for the sample under alternative assumptions for the COD and risk-free rate, along with the discount rates used in fairness opinions (discussed below) as additional reference points:

- *Baseline Case* uses the inputs and results shown in Table 13 above.
- *Sensitivity 1* uses the ratings-based COD, as used in previous PJM CONE studies.
- *Sensitivity 2* uses the forecasted long-term risk-free rate.
- *Sensitivity 3* uses both the ratings-based COD and the forecasted long-term risk-free rate.
- *Fairness Opinions* are from recent transactions (as discussed below).

[27] These idiosyncratic factors include the issuers' competitive positions within the industry, and the debt issues' seniority, callability, availability of collateral, *etc*. By construction, these factors tend to be averaged out in the ratings-based average CODs.

For the Base Case and each sensitivity, the colored marks represent each of three U.S. IPPs' ATWACCs. For example, under Sensitivity 1, the ATWACCs range from 5.5% (AES) to 6.9% (NRG). Under the other two scenarios when the forecasted risk-free rate is used, the upper ends of the ATWACC approach 8.1% (Sensitivity 2) and 7.4% (Sensitivity 3).

FIGURE 8: SUMMARY OF BASE CASE AND ALTERNATIVE CASES



Additional cost of capital reference points shown on the right side of Figure 8 above come from publicly-available discount rates used by financial advisors and analysts in valuations associated with mergers and divestitures. While there are no details provided on how these ranges were developed, these values still provide useful reference points for estimating the cost of capital. As in our 2018 analysis, we rely on three transactions with publicly-disclosed discount rates, and adjust them for the changes in the risk-free rates between the as of dates of the fairness opinions and March 31, 2022. These three transactions are

- *Acquisition of Talen Energy by Riverstone Holdings*: the disclosed range of discount rate is 6.7% to 7.3%, released in June 2016.[28] Between the fairness opinion date (March 31, 2016)

[28] Preliminary Proxy Statement, Schedule 14A, filed by Talen Energy Corporation with SEC on July 1, 2016.

and March 31, 2022, the risk-free rate increased about 0.4%. As a result, the range of 7.1% to 7.7% is shown in Figure 8.

- *Acquisition of Calpine by Energy Capital Partners*: the range of discount rate range disclosed in the June 2017 fairness opinion is 5.75% to 6.25%;[29] this is also the range shown in Figure 8, as the risk-free rates between June 2017 and March 31, 2022 are almost the same;
- *Acquisition of Dynegy by Vistra*: each of the three financial advisors (Citi for Vistra, Morgan Stanley and PJT for Dynegy) involved in that transaction used a distinct range of discount rates for evaluating the Dynegy acquisition: 4.7% to 5.5% as used by Morgan Stanley, 5.95% to 6.95% as used by PJT, and 7.0% to 7.7% as used by Citi.[30] This rather wide range of discount rates (4.7% to 7.7%) reflects the uncertainty in cost of capital estimates for the U.S. merchant generation industry. Because the risk-free rates between the fairness opinion dates and March 31, 2022 are almost the same, the originally disclosed range is shown in Figure 8.

We should note that all these acquisitions were announced before the 2018 tax law change, so their discount rates were based on the 35% federal corporate income tax rate. All else equal, the discount rate would be higher under a lower federal income tax rate. In other words, the ranges shown in Figure 8 under-estimates the ATWACC from the transactions under the current 21% tax rate.

ATWACC for Merchant Generators in PJM Markets and the Recommended Components: The appropriate ATWACC for the CONE study should reflect the systematic financial market risks of a merchant generating project's future cash flows from participating in the PJM wholesale power market. As a pure merchant project in PJM, the risks would be larger than for the average portfolio of independent power producers that have some long-term contracts in place.[31] As we have done in previous studies, we make an upward adjustment toward the upper end of the range from the comparable company results to reflect the relatively higher risk of pure merchant operations. Based on the set of reference points shown in Figure 8 above and the recognition of PJM merchant generation risk that exceeds the average risk of the publicly-traded generation

[29] Definitive Proxy Statement, Schedule 14A, filed by Calpine Corporation with the SEC on November 14, 2017.

[30] Definitive Proxy Statement, Schedule 14A, filed by Dynegy Inc. with the SEC on January 25, 2018.

[31] This is not to say that the reference merchant project would not arrange some medium-term financial hedging tools.

companies, we believe that an 8.0% ATWACC is the most reasonable estimate for the purpose of estimating CONE.[32]

III.D.2. Other Financial Assumptions

Calculating CONE requires several other financial assumptions about general inflation rates, tax rates, depreciation, bonus depreciation, and interest during construction.

Income tax rates affect both the cost of capital and cash flows in the financial model used to calculate CONE. We calculated income tax rates based on current federal tax rates of 21%. The state tax rates assumed for each CONE Area are shown in Table 16.

TABLE 16: STATE CORPORATE INCOME TAX RATES

CONE Area	Representative State	Corporate Income Tax Rate
1 Eastern MAAC	New Jersey	11.50%
2 Southwest MAAC	Maryland	8.25%
3 Rest of RTO	Pennsylvania	9.99%
4 Western MAAC	Pennsylvania	9.99%

Sources and notes: State tax rates retrieved from www.taxfoundation.org. Machinery and equipment for electricity generation are exempt from state sales taxes.

We calculated depreciation for the 2026/27 CONE parameter based on the bonus depreciation provisions of the 2017 Tax Cuts and Jobs Act. New units put in service before January 1, 2027 can apply 20% bonus depreciation in the first year of service, which decreases CC CONE on average by $10/MW-day relative to no bonus depreciation. The bonus depreciation phases out completely by the following year. Similar to the 2018 PJM CONE study, we apply the Modified Accelerated Cost Recovery System (MACRS) of 20 years for the reference CC to the remaining depreciable costs (*i.e.*, 20% bonus depreciation, 80% MACRS in 2026/27).[33]

To calculate the annual value of depreciation, the “depreciable costs” (different from the overnight and installed costs referred to earlier in the report) for a new resource are the sum of

[32] The weighted average cost of capital (WACC) without considering the tax advantage of debt payments is 8.0%. We report this value because it is comparable to values reported in other recently released CONE studies in ISO-NE and NYISO.

[33] Internal Revenue Service (2021), *Publication 946, How to Depreciate Property,* March 3, 2022. Available at http://www.irs.gov/pub/irs-pdf/p946.pdf.

the depreciable overnight capital costs and the accumulated interest during construction (IDC). Several capital cost line items are non-depreciable, including fuel inventories and working capital, and have not been included in the depreciable costs. IDC is calculated based on the assumption that the construction capital structure is the same as the overall project, *i.e.*, 55% debt and 4.7% COD.

III.E. Economic Life and Levelization Approach

Translating investment costs into annualized costs for the purpose of setting annual capacity price benchmarks requires an assumption about how net revenues are received over an assumed economic life, such that the investor recovers capital and annual fixed costs.

For economic life, we recommend continuing the prior assumption of a 20-year economic life. Although new natural gas-fired plants can physically operate for 30 years or longer, developers in the stakeholder community expressed doubt in any value beyond 20 years in the current and projected policy environment. The policy environment is increasingly disfavoring generation resources that emit greenhouse gases. For example, Illinois and New Jersey have passed legislation or are considering regulations to limit the operation of natural gas-fired plants.[34]

We continue to assume "level-nominal" cost recovery with net revenues constant in nominal terms (*i.e.*, decreasing in real, inflation-adjusted dollar terms), based on our prior analysis of the drivers of long-term cost recovery and updated analysis of the long-term trends in gas turbine costs. Clearly, assuming such a steady stream of revenues then terminating them after an assumed 20-year life is a simplification. Our concurrent VRR Report tests the robustness of the recommended VRR curve to an uncertainty range that encompasses different assumptions on cost recovery.

[34] In Illinois, the 2021 Climate and Equitable Jobs Act (CEJA) phases out of privately-owned gas generation by 2045. While the CEJA does not limit the ability of new CCs to enter, alternative ownership structures may be required with public entities to maintain operation over a 20-year economic life. In New Jersey, the Department of Environmental Protection proposed rules in 2021 that would limit CO_2 emissions for new gas generation units to below 860 lbs CO_2/MWh starting in 2025. Despite this proposed rule, the reference CC will be able to meet the emissions requirements.

III.F. CONE Results and Comparisons

III.F.1. Summary of CONE Estimates

The administrative Gross CONE value reflects the total annual net revenues a new generation resource needs to earn on average to recover its capital investment and annual fixed costs, given reasonable expectations about future cost recovery over its economic life. Table 17 summarizes our plant capital costs, annual fixed costs, and levelized CONE estimates for the CC reference plants for the 2026/27 delivery year. The level-nominal CONE estimates range from $506/MW-day in WMAAC to $490/MW-day in SWMAAC.

TABLE 17: ESTIMATED CONE FOR CC PLANTS IN 2026/27

				1 x 1 Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$1,359	$1,240	$1,263	$1,308
[2]	Installed (inc. IDC)	*$m*		$1,470	$1,343	$1,367	$1,415
[3]	First Year FOM	*$m/yr*		$37	$53	$47	$39
[4]	**Net Summer ICAP**	***MW***		**1,171**	**1,174**	**1,144**	**1,133**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$1,160	$1,057	$1,104	$1,154
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$1,255	$1,144	$1,195	$1,248
[7]	Levelized FOM	*$/kW-yr*		$39	$49	$47	$42
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		12.4%	12.2%	12.3%	12.3%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$182,700**	**$178,700**	**$183,100**	**$184,500**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$501**	**$490**	**$502**	**$506**

Sources and notes: CONE values expressed in 2026 dollars and ICAP terms.

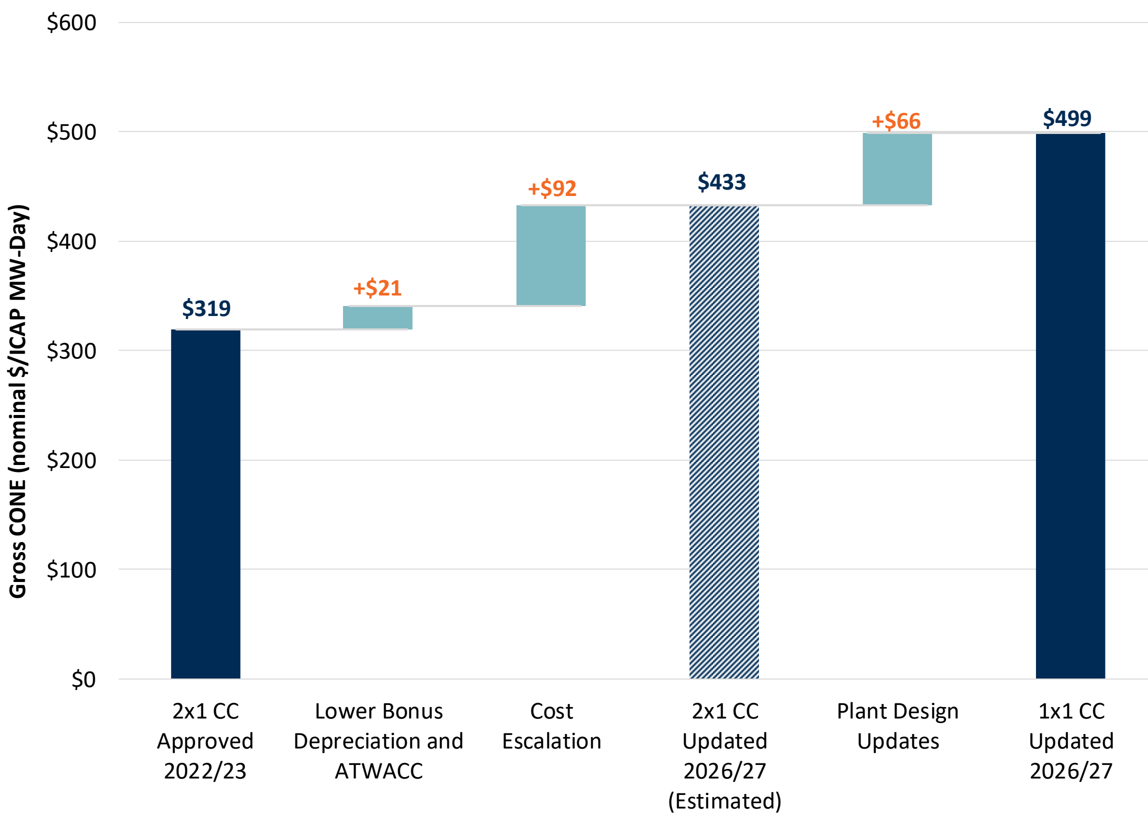
The CC CONE estimates vary slightly by CONE Area, primarily due to differences in labor rates (highest in EMAAC), firm gas contracts (highest in Rest of RTO), total income tax rates (highest in Rest of RTO and WMAAC), and property taxes (highest in SWMAAC).

III.F.2. Comparison to Prior CONE Estimates

The 2026/27 CC CONE estimates are considerably higher than the values derived from the 2018 Study that were used (as MOPR parameters) in PJM's Base Residual Auction for the 2022/23

Delivery Year as shown in Figure 9. To explain those increases in terms of individual drivers, we sequentially estimated the impact of changes in bonus depreciation and ATWACC, then cost escalation, and finally, plant design updates.

FIGURE 9: DRIVERS OF HIGHER CC 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)



The drivers for higher CONE are explained below:

- Bonus Depreciation and ATWACC: The temporary 100% bonus depreciation included in the 2022/23 CONE value decreases to 20% by 2026, increasing CONE by $25/MW-Day (ICAP).[35] The ATWACC decreased from 8.2% in the prior CONE value to 8.0% currently, decreasing CONE by $4/MW-Day (ICAP), for a net effect of $21/MW-Day (ICAP).
- Cost Escalation: Since the development of the 2022/23 CONE value in our 2018 Study (based on overnight costs of a plant built in 2017), the costs of materials, equipment, and labor costs have escalated along with generalized inflation at a faster rate than expected. For example, from December 2017 to December 2021, material costs increased by 36% compared to

[35] 115th United State Congress, "Tax Cuts and Jobs Act," Signed into law December 22, 2017

expectations of only 10%.[36] With that unexpected escalation over that time period, plus projected escalation to a 2026 installation, total cost escalation to 2026/27 adds $92/MW-Day (ICAP) to the 2x1 CC 2022/23 CONE value.

- Plant Design Updates: The use of dry-cooling ACCs, firm gas transportation contracts (and to a small degree the switch from a 2x2 CC to a double-train 1x1 CCs) as discussed in Section III.A above, adds $66/MW-Day (ICAP) to the 2x1 CC Updated 2026/27 (Estimated) CONE.

III.G. Annual CONE Updates

The PJM tariff specifies that prior to each auction PJM will escalate CONE for each year between the CONE studies during the RPM Quadrennial Review. The updates will account for changes in plant capital costs based on a composite of Department of Commerce's Bureau of Labor Statistic indices for labor, turbines, and materials.

We recommend that PJM continue to update the CONE value prior to each auction using this approach with slight adjustments to the index weightings based on the updated capital cost estimates. As shown in Table 18 below, we recommend that PJM re-weight the components to account for the increasing portion of total plant costs that are from the costs of labor. For the CC, PJM should calculate the composite index based on 40% labor, 45% materials, and 15% turbine. For the CT, PJM should calculate the composite index based on 30% labor, 45% materials, and 25% turbine.

TABLE 18: CONE ANNUAL UPDATE COMPOSITE INDEX

	Combustion Turbine			Combined Cycle		
Component	PJM Tariff Composite Index	CONE Study Capital Cost Weightings	Recommended Composite Index	PJM Tariff Composite Index	CONE Study Capital Cost Weightings	Recommended Composite Index
Labor	20%	30%	30%	25%	43%	40%
Materials	50%	45%	45%	60%	45%	45%
Turbine	30%	25%	25%	15%	12%	15%

PJM will need to account for bonus depreciation declining from 20% for the 2026/2027 BRA to 0% in the 2027/2028 BRA and subsequent auctions. We calculate that a reduction in the bonus depreciation by 20% increases the CT CONE by 1.7% and the CC CONE by 2.1% due to the decreasing depreciation tax shield. We recommend just for the 2027/2028 BRA that after PJM

[36] Material and turbine costs increases are based on BLS Producer Price Index for *Construction Materials* and *Components for Construction* and *Turbines and Turbine Generator Sets* between December 2017 and December 2021. Values may not add to 100% due to rounding.

has escalated CONE by the composite index, as noted above, PJM account for the declining tax advantages of no longer receiving bonus depreciation by applying an additional gross up of 1.017 for CT and 1.021 for CCs. For subsequent auctions, no further gross up will be necessary.

III.H. E&AS Offset Methodology

The VRR Curve prices are indexed to Net CONE, which is derived by subtracting the reference resource's net energy and ancillary service (E&AS) revenues from its Gross CONE. This E&AS offset could be estimated in a variety of ways. PJM originally estimated it based on actual historical electricity and natural gas prices over the past 3 years. In 2020, PJM adopted a forward-looking approach to calculating the E&AS offset based on forward prices for electricity and natural gas, with hourly shapes based on historical data. FERC subsequently ordered PJM in December 2021 to revert back to the historical method because the forward methodology had been implemented along with PJM's proposed Reserve Pricing Reforms that FERC eventually rejected.

We continue to recommend calculating E&AS on a forward basis over a historical approach. As discussed in our prior reviews, the forward E&AS offset is superior because it reflects expected market conditions that developers will face upon entry into the market. The methodology we helped PJM develop is analytically rigorous, based on forward market data for electricity and natural gas. It is similar to approaches we have implemented for clients and have seen other investors use to estimate their future net E&AS revenues (and, by extension, to estimate how much they would need to earn from the capacity market to enter). By contrast, the backward looking approach reflects past conditions that may be unrepresentative and irrelevant to the future investments that RPM is supposed to attract (with a willingness-to-pay indexed to estimated Net CONE). Not only are past prices reflective of outdated fundamentals regarding demand, supply, fuel prices, and transmission; worse, they may include anomalous weather conditions that substantially distort the calculation and make it unduly volatile.[37]

However, both historical and forward methods rely on market prices that recently have reflected installed capacity well above the reserve requirement, which can perpetuate disequilibria. When supply is scarce, for example, the E&AS offset will increase and scale down the VRR curve thus

[37] For the same reasons, we recommend forward E&AS offsets for "Net ACR" based offer caps in its market power mitigation, which PJM could consider in its upcoming broader review of RPM. However, even if this is not implemented, we still recommend using a forward E&AS for the VRR curve to reflect expected forward market conditions. The VRR is designed to support new entry until the target reserve margin is met, with developers expecting to just earn CONE from the combination of capacity and expected E&AS revenues.

buy less capacity just when it is needed. This could be avoided by adjusting the E&AS offset to what they would be at the target reserve margin, as NYISO and ISO-NE attempt to do. However, the need for an adjustment is not necessarily clear, without knowing what beliefs about reserve margins underlie forward market prices. Any equilibrium E&AS offset would rely on market simulations, which tend not to be transparent and are difficult to fully calibrate to produce realistic market prices.

Assuming PJM pursues a forward approach again, we reviewed several aspects of its approach and provide the following recommendation:

- Electric Hub Mapping: Maintain current mapping of electricity futures hubs to zones, as the mapping is supported by recent prices;
- Natural Gas Hub Mapping: Switch EKPC gas hub from Columbia-App TCO to MichCon; otherwise current gas hub mapping supported by recent prices;
- Ancillary Service Prices: Remove regulation revenues from the calculation of the E&AS offset and scale historical hourly sync and non-sync reserve prices by forward energy prices.

Regarding ancillary services, we determined that regulation revenues should not be included in the calculation because the market is too small at only 500-800 MW (some of which is already absorbed by BESS plants providing the premium RegD product). By contrast, the capacity market has to be able to attract thousands of MW as needed if retirements and load growth occur. Such large amounts of new entrants could not earn major revenues from the small market. If the revenues per plant were high, the first few plants would use up that opportunity quickly; if the revenues were low, accounting for them (versus selling more energy) would not change the Net CONE estimate.

PJM also requested that we review the approach for calculating the energy efficiency wholesale energy savings to determine whether the utility EE programs included in the analysis continue to be reasonable. Based on our review of the available public data on EE programs, we recommend maintaining the sample of utilities included in the current Net CONE analysis (ComEd, BG&E, and PPL), but updating the inputs based on the most recent program costs and impacts. The current sample includes the largest utilities in each state that provides sufficient detail for the analysis. Our review of public program-level data for EE programs across PJM did not identify any additional utility-run programs with similar level of detail to include them in the sample.

III.I. Implications for Net CONE

III.I.1. Indicative E&AS Offsets

The application of the E&AS offset methodology in Section III.H results in an updated E&AS due to a reduced ramp rate, the removal of transportation costs, removal of regulation revenue, and updates to other operating characteristics associated with the technical specifications for the CC.[38] Table 19 shows the effect of each of these changes on the forward-looking 2023/24 E&AS revenue offset by zone for the CC based on simulations provided by PJM staff.

[38] Other parameter updates include updated operating characteristics associated with the most recent turbine models, the addition of dry-cooling, and the 1x1 single shaft CC configuration.

TABLE 19: UPDATED 2023/24 CC E&AS REVENUE OFFSET BY ZONE ($/MW-DAY ICAP)

All values in nominal $/MW-day ICAP	CC			
	Current 2023/24 EAS	Updated Operating Costs	Removed Regulation	Updated 2023/24 EAS
CONE Area 1				
AECO	$168	$2	-$24	$146
DPL	$216	$3	-$23	$196
JCPL	$166	$2	-$24	$143
PECO	$184	$14	-$23	$174
PSEG	$162	$2	-$24	$140
RECO	$172	$2	-$23	$151
CONE Area 2				
BGE	$254	$4	-$20	$239
PEPCO	$197	$10	-$21	$185
CONE Area 4				
METED	$212	$15	-$22	$205
PENELEC	$320	$7	-$17	$310
PPL	$190	$15	-$22	$182
CONE Area 3				
AEP	$242	$8	-$21	$229
APS	$281	$5	-$19	$267
ATSI	$208	$44	-$21	$231
COMED	$179	$11	-$22	$168
DAY	$223	$45	-$21	$247
DEOK	$214	$43	-$21	$237
DUQ	$225	$15	-$20	$219
DOM	$195	$9	-$21	$183
EKPC	$246	$14	-$21	$239
RTO	**$189**	**$11**	**-$23**	**$177**

Note: The "Current 2023/24 E&AS" reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020. The "Updated 2023/24 EAS" values do not reflect changes to scaling historical hourly sync and non-sync reserve prices by forward energy prices, nor updating gas prices in EKPC's zone.

III.I.2. Indicative Net CONE

Net CONE is the estimated annualized fixed costs of new entry, or Gross CONE, of the reference resource, net of estimated E&AS margins and expected performance bonus. PJM calculates the Net CONE by subtracting the net energy and ancillary service (E&AS) revenues from the Gross CONE. We present in Table 20 below indicative CC Net CONE estimates for all LDAs relative to the parameters used in the 2022/23 MOPR (adjusted here to differentiate CONE values by area).

We say "indicative" because the scope of our assignment includes estimating Gross CONE values and recommending changes to the E&AS approach, but does not include estimating the E&AS offsets for the 2026/27 BRA.

TABLE 20: INDICATIVE CC NET CONE ($/MW-DAY UCAP)

All values in nominal $/MW-day UCAP	CC 2022/23 MOPR			CC 2026/27 Brattle Estimate		
	CONE	EAS	Net CONE	CONE	EAS	Net CONE
CONE Area 1						
AECO	$335	$167	$163	$517	$174	$343
DPL	$335	$208	$122	$517	$231	$286
JCPL	$335	$165	$165	$517	$172	$346
PECO	$335	$186	$144	$517	$206	$311
PSEG	$335	$161	$169	$517	$168	$349
RECO	$335	$171	$159	$517	$180	$337
EMAAC	**$335**	**$181**	**$154**	**$517**	**$189**	**$329**
CONE Area 2						
BGE	$345	$254	$76	$506	$279	$227
PEPCO	$345	$191	$139	$506	$219	$287
SWMAAC	**$345**	**$238**	**$107**	**$506**	**$249**	**$257**
CONE Area 4						
METED	$323	$207	$123	$522	$241	$281
PENELEC	$323	$306	$24	$522	$359	$163
PPL	$323	$185	$145	$522	$216	$307
MAAC	**$334**	**$204**	**$130**	**$517**	**$222**	**$294**
CONE Area 3						
AEP	$316	$233	$97	$518	$268	$251
APS	$316	$272	$58	$518	$311	$208
ATSI	$316	$224	$106	$518	$271	$248
COMED	$316	$195	$135	$518	$199	$319
DAY	$316	$235	$95	$518	$288	$230
DEOK	$316	$224	$106	$518	$277	$242
DUQ	$316	$223	$107	$518	$257	$261
DOM	$316	$181	$149	$518	$216	$303
EKPC	$316	$232	$98	$518	$279	$239
OVEC	$316	$260	$70	$518	$303	$216
RTO	**$330**	**$185**	**$146**	**$516**	**$209**	**$307**

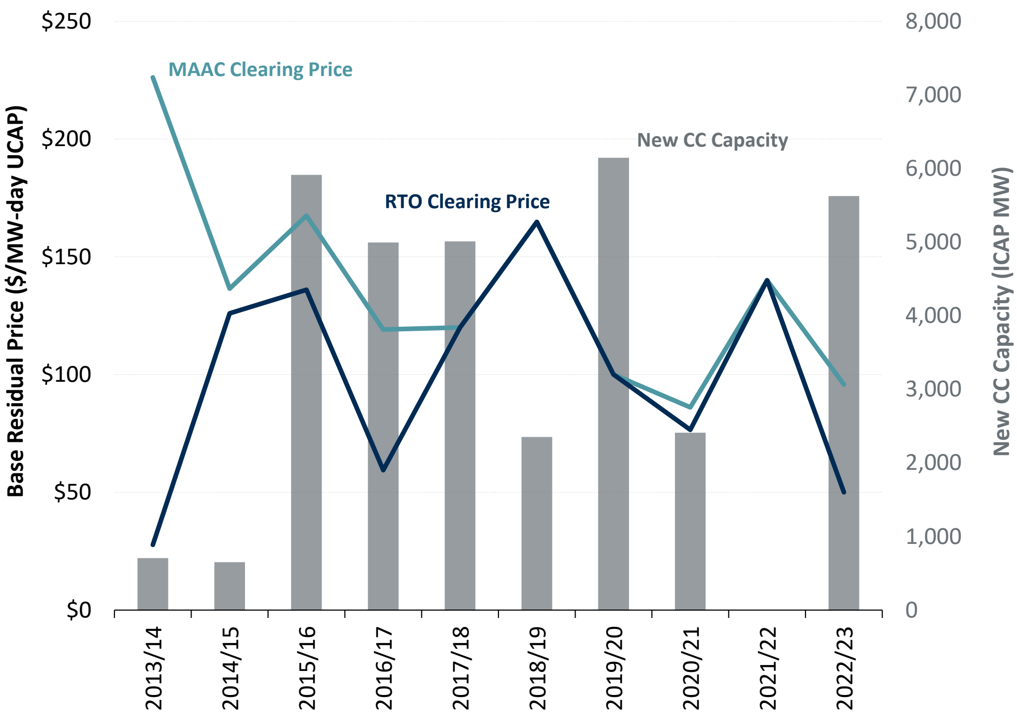
Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

Net CONE is $257–$329/MW-Day (UCAP) across all parent LDAs. Compared to the 2022/23 BRA, the Net CONE roughly doubled for all parent LDAs. Increases in Net CONE are due to the increases in Gross CONE described in Section III.F (cost escalation, decreases in bonus depreciation, and plant design changes) with a slight offset from higher E&AS values. The differences among modeled LDAs and the RTO are similar to the prior.

III.I.3. Comparison to "Empirical Net CONE"

Another informative comparison is to the prices at which actual CCs have been willing to enter the market in past capacity auctions (sometimes referred to as "empirical Net CONE"). Those prices ranged from $75 to $165/MW-Day UCAP in most of the recent auctions, as shown in Figure 10 below. Note that 2022/23 prices should be disregarded as an indicator of willingness to enter since the compressed forward period for that auction meant that new entrants' decisions were already made by the time the auction occurred.

FIGURE 10: HISTORICAL BRA CAPACITY PRICES AND NEW CC CAPACITY



Sources and notes: PJM Base Residual Auction Reports and Planning Parameters. See PJM BRA results 2013/14-2022/23. Please note that the 2022/23 BRA was a compressed auction.

Empirical Net CONE is not a perfect indicator of "true Net CONE" at which capacity could enter at scale—even at the time that capacity entered—because of variability across locations, limited entry in any single auction, and observing only a single clearing price. Some entrants would have entered at prices below the clearing price, whereas uncleared projects, which might have been needed if more retirements or load growth had occurred, would require a higher price. Some may be willing to enter the market at low prices because of their idiosyncratic advantages that cannot be replicated at scale. For example, some past entrants may have enjoyed special opportunities to access natural gas at anomalously low costs earlier in the development of the

Marcellus Shale and export pipelines. Despite these limitations, empirical Net CONE is still a useful benchmark.

Extrapolating backward-looking empirical Net CONE to the future, however, must consider how costs and market conditions have changed. As discussed above, the true cost of entry is in fact increasing due to cost escalation, changes in environmental regulations and plant configurations, and tax laws—by $180/MW-day in our estimation compared to a few years ago. In addition, since the long-term prospects for cash flows have diminished with the industry's transition toward clean energy, entrants may need to front-load their revenues more so than in the past. For example, if they used to assume a 30-year economic life but now assume 20 years, that would further increase Net CONE by $44/MW-day ICAP. Altogether, adding that $180 + $44 to historical empirical Net CONE of $100-165/MW-day, suggests an adjusted benchmark for 2026 of as much as $324-389/MW-day, or $280-345 MW-day without the adjustment for economic life. This is not far from our estimated Net CONE of $257-$329/MW-day across modeled LDAs.

III.I.4. Uncertainty Analysis

There is considerable uncertainty in estimating Net CONE. Most of the uncertainty surrounds volatile inflation, relevant technologies and plant designs, and the analyst's judgment on economic life and long-term cost recovery. For example, a less constrained plant design with dual fuel and cooling towers could cost as much as $87/MW-day less; or a shorter 15-year economic life could add $52/MW-day, or more if technologies are more constrained by environmental regulations. These examples indicate an uncertainty range on Net CONE of -29% to +16%; the full uncertainty range may be greater when considering uncertainties beyond those we analyzed. In that context, the VRR curve must be steeper to perform well even if Net CONE is mis-estimated, and we recommend testing robustness under stress tests of +/-40%, as discussed in our parallel VRR Curve report.

IV. Natural Gas-Fired Combustion Turbines

IV.A. Technical Specifications

We used a similar approach discussed in Section III.A as the reference CC to determine the technical specifications for the reference CT. The technical specifications for the reference CT shown in Table 21 are based on the assumptions discussed later in this section.

TABLE 21: CT REFERENCE RESOURCE TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Turbine Model	GE 7HA.02 60HZ
Configuration	1 x 0
Cooling System	n/a
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	361 / 363 / 353 / 350*
Net Heat Rate (HHV in Btu/kWh)	9320 / 9317 / 9304 / 9311*
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	No
Firm Gas Contract	Yes
Special Structural Requirements	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and notes: See Table 3 for ambient conditions assumed for calculating net summer installed capacity (ICAP) and net heat rate.
* For EMAAC, SWMAAC, Rest of RTO, and WMAAC, respectively.

For the reference CT, there has been very limited development of frame-type CTs in PJM since 2011, as shown in Table 22, to support a specific turbine model. While aeroderivative-type turbines such as the GE LM6000 have been the most common since 2011, they have higher Net CONE than 7HA turbines. The 7HA turbine is the current model assumed for the PJM reference resource, it is the most built turbine for CCs, and the IMM has used the same turbine for its evaluation of Net Revenues in the annual State of the Market report since 2014. For these reasons, the frame-type GE 7HA turbine is a reasonable choice for the CT in PJM. Due to the larger size of the 7HA turbine, we assume that the reference CT plant includes only a single turbine ("1×0" configuration). The majority of the specifications have remained the same as the 2018 CONE Study.

TABLE 22: TURBINE MODEL OF CT PLANTS BUILT OR UNDER CONSTRUCTION IN PJM AND THE U.S. SINCE 2011

Turbine Model	Turbine Class	PJM		US	
		(count)	*(MW)*	*(count)*	*(MW)*
General Electric LM6000	Aeroderivative	7	331	69	3,101
General Electric 7FA	Frame	2	330	14	2,462
Pratt & Whitney FT4000	Aeroderivative	2	120	2	120
Rolls Royce Corp Trent 60	Aeroderivative	2	119	2	119
Pratt & Whitney FT8	Aeroderivative	1	57	4	189
Siemens Unknown	N.A.	1	28	2	545
General Electric LMS100	Aeroderivative	0	0	47	4,664
Siemens SGT6-5000F	Frame	0	0	10	1,892
Rolls Royce Corp Unknown	N.A.	0	0	10	599
General Electric 7EA	Small Frame	0	0	7	417
Siemens AG SGT	Frame	0	0	7	401
General Electric 7HA	Frame	0	0	1	330
All Other Turbine Models		0	0	14	1,297
Total		**15**	**985**	**189**	**16,136**

Sources and notes: Data downloaded from ABB Inc.'s Energy Velocity Suite August 2021.

IV.B. Capital Costs

For the CT, we relied on a similar approach for estimating capital costs that are specified for the reference CC in Section III.B with a few exceptions. The following assumptions differ for estimating the capital costs for the CT:

- Emission Reduction Credits: Similar to the 2018 CONE Study, we assumed the CT would not be required to purchase ERCs because they are not projected to exceed the new source review (NSR) threshold. This assumption is supported by the run-time operational limit that the Perryman Unit 6 CT plant built in 2015 in Maryland included in its operating permit to avoid exceeding emissions thresholds.[39]

- Land: Similar to the reference CC, we estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. shows the resulting land prices we assumed for each CONE Area and the final estimated cost for the land in each location. We assume that 10 acres of land are for the reference CT.

TABLE 23: COST OF LAND PURCHASED FOR REFERENCE CT

CONE Area	Land Price *($/acre)*	Plot Size Gas CT *(acres)*	Cost Gas CT *($m)*
1 EMAAC	$36,600	10	$0.37
2 SWMAAC	$29,500	10	$0.30
3 Rest of RTO	$16,400	10	$0.16
4 WMAAC	$30,600	10	$0.31

Sources and notes: We assume land is purchased in 2022, i.e., 6 months to 1 year before the start of construction.

Based on the technical specifications for the CT described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 24 below.

[39] The Perryman Unit 6 operating permit is available here: https://mde.maryland.gov/programs/Permits/AirManagementPermits/Test/Constellation%20Perryman%20Renewal%20Title%20V%202018.pdf

TABLE 24: PLANT CAPITAL COSTS FOR CT REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*361 MW*	*363 MW*	*353 MW*	*350 MW*
Owner Furnished Equipment				
Gas Turbines	$78.6	$78.6	$78.6	$78.6
HRSG / SCR	$33.5	$33.5	$33.5	$33.5
Sales Tax	$0.0	$0.0	$0.0	$0.0
Total Owner Furnished Equipment	**$112.1**	**$112.1**	**$112.1**	**$112.1**
EPC Costs				
Equipment				
Other Equipment	$24.1	$24.1	$24.1	$24.1
Construction Labor	$50.6	$37.8	$40.6	$45.0
Other Labor	$16.4	$15.4	$15.6	$16.0
Materials	$8.1	$8.1	$8.1	$8.1
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	$21.1	$19.8	$20.1	$20.5
EPC Contingency	$23.2	$21.7	$22.1	$22.6
Total EPC Costs	**$143.6**	**$127.0**	**$130.6**	**$136.3**
Non-EPC Costs				
Project Development	$12.8	$12.0	$12.1	$12.4
Mobilization and Start-Up	$2.6	$2.4	$2.4	$2.5
Net Start-Up Fuel Costs	-$0.6	-$0.6	$0.1	-$0.5
Electrical Interconnection	$7.8	$7.8	$7.6	$7.6
Gas Interconnection	$33.7	$33.7	$33.7	$33.7
Land	$0.4	$0.3	$0.2	$0.3
Fuel Inventories	$0.0	$0.0	$0.0	$0.0
Non-Fuel Inventories	$1.3	$1.2	$1.2	$1.2
Owner's Contingency	$4.6	$4.6	$4.6	$4.6
Emission Reduction Credit	$0.0	$0.0	$0.0	$0.0
Financing Fees	$7.0	$6.6	$6.7	$6.8
Total Non-EPC Costs	**$69.6**	**$68.0**	**$68.7**	**$68.6**
Total Capital Costs	**$325.3**	**$307.1**	**$311.4**	**$317.0**
Overnight Capital Costs ($million)	**$325**	**$307**	**$311**	**$317**
Overnight Capital Costs ($/kW)	**$902**	**$846**	**$882**	**$906**
Installed Cost ($/kW)	**$945**	**$887**	**$925**	**$949**

IV.B.1. Escalation to 2026 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period of 20 months for CTs.[40] We escalated the 2021 estimates of overnight capital cost components forward to the construction period for a June 2026 online date using the nominal cost escalation rates presented in Table 8. We maintained the same escalation approach for Land, Net Start-up Fuel and Fuel Inventories, and Electric and Gas Interconnection as the CC

IV.C. Operations and Maintenance Costs

Table 25 summarizes the fixed and variable O&M for CTs with an online date of June 1, 2026. Additional details on Plant Operation and Maintenance, Insurance and Asset Management Costs, Property Taxes, Working Capital, and Firm Transportation Service Contracts can be found in the above Section III.C.2. Details on Variable O&M costs can be found in Section III.C.3. With their lower expected capacity factor, the CTs are assumed to undergo major maintenance cycles tied to the factored starts of the unit, as opposed to the factored fired hours maintenance cycles of the CCs. For this reason, the major maintenance cost component for the CTs is reported in "$/factored start" and not the $/MWh used for other consumables. We escalated the components of the O&M cost estimates from 2021 to 2026 on the basis of cost escalation indices particular to each cost category, same as the reference CC, using the real escalation rates shown in Table 8 to escalate the O&M costs.

[40] The construction drawdown schedule occurs over 20 months with 84% of the costs incurred in the final 11 months prior to commercial operation.

TABLE 25: O&M COSTS FOR CT REFERENCE RESOURCE

O&M Costs	CONE Area 1 EMAAC *361 MW*	2 SWMAAC *363 MW*	3 Rest of RTO *353 MW*	4 WMAAC *350 MW*
Fixed O&M (2026$ million)				
LTSA Fixed Payments	$0.3	$0.3	$0.3	$0.3
Labor	$1.2	$1.2	$0.9	$0.9
Maintenance and Minor Repairs	$0.5	$0.5	$0.5	$0.5
Administrative and General	$0.2	$0.3	$0.2	$0.2
Asset Management	$0.5	$0.6	$0.4	$0.4
Property Taxes	$0.3	$4.1	$2.2	$0.3
Insurance	$2.0	$1.8	$1.9	$1.9
Firm Gas Contract	$4.4	$5.4	$7.1	$6.3
Working Capital	$0.0	$0.0	$0.0	$0.0
Total Fixed O&M (2026$ million)	**$9.5**	**$14.4**	**$13.5**	**$10.9**
Levelized Fixed O&M (2026$/MW-yr)	**$26,300**	**$39,600**	**$38,300**	**$31,300**
Variable O&M (2026$/MWh)				
Consumables, Waste Disposal, Other VOM	1.19	1.18	1.15	1.22
Total Variable O&M (2026$/MWh)	**1.19**	**1.18**	**1.15**	**1.22**
Major Maintenance - Starts Based ($/factored start, per turbine)	**21,170**	**21,170**	**21,170**	**21,170**

IV.D. CONE Results and Comparisons

Table 26 shows plant capital costs, annual fixed costs, and levelized CONE estimates for the CT reference plant for the 2026/27 delivery year. CONE estimates range from $378/MW-day in EMAAC to $403/MW-day in the Rest of RTO. Note that we assumed accelerated tax depreciation based on the 15-year MACRS for the CT to the depreciable costs after accounting for bonus depreciation.

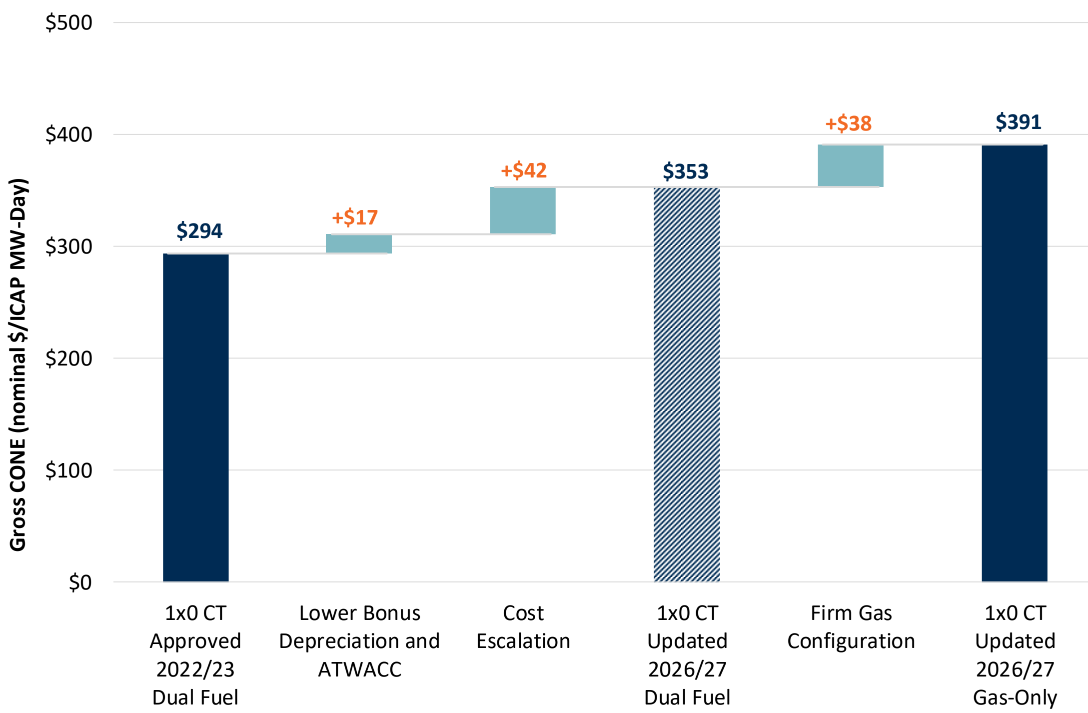
TABLE 26: ESTIMATED CONE FOR CT PLANTS FOR 2026/27 IN 2026$ AND ICAP MW

				Simple Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$325	$307	$311	$317
[2]	Installed (inc. IDC)	*$m*		$341	$322	$326	$332
[3]	First Year FOM	*$m/yr*		$9	$14	$14	$11
[4]	**Net Summer ICAP**	***MW***		**361**	**363**	**353**	**350**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$902	$846	$882	$906
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$945	$887	$925	$949
[7]	Levelized FOM	*$/kW-yr*		$33	$44	$45	$39
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		11.7%	11.6%	11.6%	11.6%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$138,000**	**$141,700**	**$147,100**	**$144,000**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$378**	**$388**	**$403**	**$395**

Similar to the CC, the CT CONE estimates vary by CONE Area primarily due to differences in labor rates (highest in EMAAC), firm gas contracts (highest in Rest of RTO), total income tax rates (highest in Rest of RTO and WMAAC), and property taxes (highest in SWMAAC).

The 2026/27 CT CONE estimates are considerably higher than in PJM's Base Residual Auction for the 2022/23 Delivery Year as shown in Figure 11. Similar to the presentation of CC CONE drivers, the attribution of changes to each element depends on the order in which the changes are implemented in our model. We estimated the impact of changes in bonus depreciation and ATWACC, then cost escalation, and finally, firm gas configuration.

FIGURE 11: DRIVERS OF HIGHER CT 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)



The drivers for higher CONE are explained below:

- Bonus Depreciation and ATWACC: The decline to 20% bonus depreciation by 2026 increases CONE by $21/MW-day (ICAP). The ATWACC decreased to 8.0%, decreasing CONE by $4/MW-day (ICAP), for a net effect of $17/MW-Day (ICAP).
- Cost Escalation: Cost escalation is lower relative to the CC due to a lower portion of materials and labor costs associated with the CT. As a result, the total cost escalation to 2026/27 adds $42/MW-Day (ICAP) to the 1x0 CT 2022/23 Dual Fuel CONE value.
- Firm Gas Configuration: The use of firm gas transportation contracts, adds $38/MW-Day (ICAP) to the 1x0 CT Updated Dual Fuel 2026/27 CONE.

IV.E. Implications for Net CONE

IV.E.1. Indicative E&AS Offsets

The E&AS offset methodology described for CCs would also apply to CTs, but recognizing two differences related to CTs' operation as peaking plants that are generally committed day-of. As peaking plants, their dispatch depends more on the hourly volatility of prices that cannot be observed directly in forward markets and are instead taken from historical hourly price shapes. Since historical prices do not fully reflect future conditions, the E&AS offset estimates for CTs may be subject to more uncertainty than for CCs (at least on a percentage basis). This observation does not lead to an obvious recommendation for improving the E&AS offset methodology for CTs but does contribute to our assessment of uncertainty in selecting a suitable reference resource, as discussed above.

The fact that CTs are generally committed day-of does require a slight adjustment to fuel cost inputs in the E&AS offset calculation. As we noted in our 2018 Study, “PJM commits and dispatches CTs during the operating day just a few hours before delivery, forcing them to arrange gas deliveries or to balance pre-arranged gas deliveries on the operating day. Generators may thus incur balancing penalties or have to buy or sell gas in illiquid intra-day markets. This may increase the average cost of procuring gas above the price implied by day-ahead hub prices. However, these costs are not transparent and may not follow regular patterns that are easily amenable to analysis. Our interviews with generation companies provided mixed reactions. Some with larger fleets claimed that they can manage their gas across their fleets without paying any more on average than the prices implied by the day-ahead hub prices. Others suggested that they might incur extra costs of up $0.30/MMBtu. We recommend that PJM investigate this further and consider applying the 10% cost offer adder allowed under PJM’s Operating Agreement to the variable operating costs of the CTs in the simulations.”[41] This time, we are not recommending a “10% adder” that FERC has recently rejected but, more precisely a 10% increase over (day-ahead) gas daily index prices (and no adder on CT VOM costs). This should provide reasonable and necessary adjustment to get more accurate fuel cost inputs.

The application of the CT E&AS offset methodology discussed above results in an updated E&AS due to a reduced ramp rate, the removal of transportation costs, then removal of regulation revenue. Table 27 shows the 2023/24 E&AS revenue offset by zone using the updated methodology.

[41] 2018 VRR Curve Study, pp. 23-24.

TABLE 27: UPDATED 2023/24 CT E&AS REVENUE OFFSET BY ZONE

All values in nominal $/MW-day ICAP	CT			
	Current 2023/24 EAS	Updated Operating Costs	Removed Regulation	Updated 2023/24 EAS
CONE Area 1				
AECO	$45	-$4	-$8	$33
DPL	$76	-$2	-$8	$65
JCPL	$43	-$4	-$8	$32
PECO	$48	$4	-$7	$45
PSEG	$41	-$4	-$8	$30
RECO	$48	-$3	-$8	$36
CONE Area 2				
BGE	$93	$6	-$9	$89
PEPCO	$57	-$1	-$7	$49
CONE Area 4				
METED	$65	$8	-$8	$65
PENELEC	$150	$28	-$12	$166
PPL	$52	$5	-$7	$49
CONE Area 3				
AEP	$83	$9	-$12	$79
APS	$114	$17	-$13	$118
ATSI	$66	$16	-$8	$75
COMED	$47	-$6	-$7	$34
DAY	$70	$21	-$8	$83
DEOK	$74	$17	-$8	$83
DUQ	$81	$15	-$8	$89
DOM	$56	-$1	-$7	$48
EKPC	$80	$11	-$10	$81
RTO	**$48**	**-$1**	**-$8**	**$39**

Sources and notes: The "Current 2023/24 E&AS" reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020, including a 10% adder on all variable costs. The "Updated 2023/24 EAS" values do not reflect recommended changes to scaling historical hourly sync and non-sync reserve prices by forward energy prices, nor updating gas prices in EKPC's zone.

IV.E.2. Indicative Net CONE

We apply the same methodology and assumptions to estimate the Net CONE shown for the reference CC. Table 28 shows the indicative CT Net CONE estimates for all LDAs relative to the parameters PJM used in the 2022/23 BRA.

TABLE 28: INDICATIVE 2026/27 CT NET CONE

All values in nominal $/MW-day UCAP	CT 2022/23 BRA			CT 2026/27 Brattle Estimate		
	CONE	EAS	Net CONE	CONE	EAS	Net CONE
CONE Area 1						
AECO	$312	$47	$265	$397	$48	$349
DPL	$312	$76	$236	$397	$85	$312
JCPL	$312	$45	$267	$397	$47	$351
PECO	$312	$54	$258	$397	$62	$336
PSEG	$312	$43	$268	$397	$44	$353
RECO	$312	$50	$262	$397	$52	$346
EMAAC	**$312**	**$52**	**$259**	**$397**	**$56**	**$341**
CONE Area 2						
BGE	$317	$90	$226	$408	$113	$315
PEPCO	$317	$57	$260	$408	$67	$315
SWMAAC	**$317**	**$74**	**$243**	**$408**	**$93**	**$315**
CONE Area 4						
METED	$305	$67	$238	$415	$85	$315
PENELEC	$305	$139	$166	$415	$200	$210
PPL	$305	$54	$250	$415	$67	$315
MAAC	**$311**	**$66**	**$245**	**$404**	**$79**	**$320**
CONE Area 3						
AEP	$305	$77	$227	$424	$101	$315
APS	$305	$102	$203	$424	$146	$315
ATSI	$305	$74	$230	$424	$96	$315
COMED	$305	$57	$248	$424	$49	$421
DAY	$305	$78	$226	$424	$105	$315
DEOK	$305	$81	$224	$424	$106	$315
DUQ	$305	$80	$224	$424	$112	$315
DOM	$305	$54	$250	$424	$65	$315
EKPC	$305	$76	$229	$424	$103	$315
OVEC	$305	$89	$216	$424	$130	$315
RTO	**$309**	**$49**	**$260**	**$411**	**$55**	**$356**

Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

V. Battery Energy Storage Systems (BESS)

During the stakeholder process, several stakeholders raised concerns about whether natural-gas-fired resources (either CCs or CTs) will be feasible to build in certain zones due to state policies that require a decreasing portion of the generation mix to come from GHG-emitting resources. Based on this input, we reviewed several non-emitting resources to include as possible reference resources and determined that the 4-hour BESS best meets the reference resource screening criteria described in Section II above.

While 4-hour BESS is currently not recommended as the reference resource in any zone, its CONE value provides an initial estimate for PJM and its stakeholders a starting point for future reviews or before then if the recommended reference resource, the gas-fired CC, is determined to be infeasible to be built within the Quadrennial Review period.

V.A. Technical Specifications

We developed the cost estimates for the 4-hour BESS based on the specifications listed in Table 29 below. We assumed the facility is sized for 200 MW at the point of interconnection, based on a review of the capacity of battery storage facilities currently in the PJM interconnection queue, utilizing lithium-ion battery chemistry and a containerized installation.

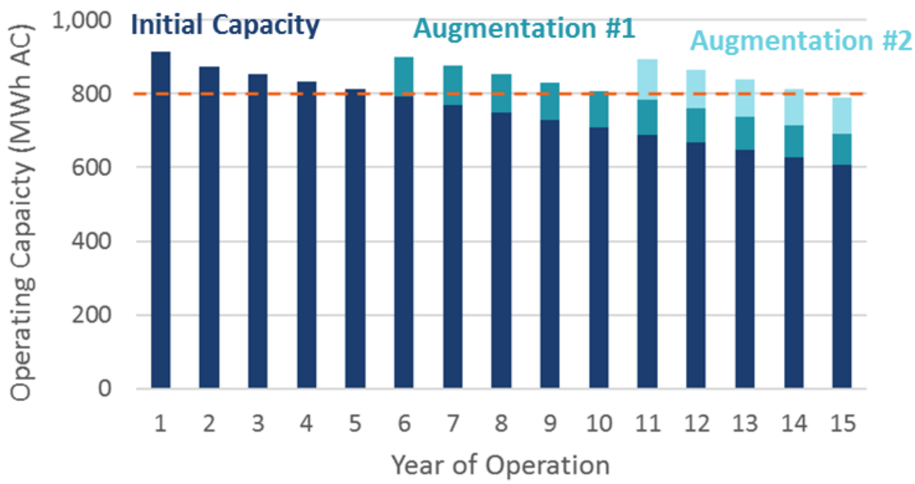
TABLE 29: BESS TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Chemistry	Lithium-ion
Installation Configuration	Containerized
Rated Output Power (at POI)	200 MW-ac
Duration	4 Hours
Installed Energy Capacity	1,030 MWh-dc
Annual Capacity Degradation	4% in Year 1, then 2% per year
Augmentations	Year 5 and Year 10
Use Case	Daily Cycling
Round Trip Efficiency	85%
Economic Life	15 Years
Salvage Value	$0

S&L estimates that BESS energy capacity (in MWh or duration at full power) degrades by 4% in the first year and 2% in subsequent years, assuming daily cycling and a 5% minimum state of charge.[42] Developers are currently using a range of approaches to maintain sufficient capacity to provide the rated AC output at the POI over a four-hour period, including overbuilding the initial capacity and augmenting the capacity in future years. Overbuilding the initial capacity provides the developer greater cost certainty and reduces the frequency and costs of frequent augmentation events. On the other hand, a smaller overbuild defers capital expenditures to future augmentations that reduces the initial capital costs of the facility and may allow the owner to take advantage of declining module costs, depending on future cost trends. To account for degradation of the energy capacity, our cost estimate assumes that the facility will include an initial 13% overbuild, or 135 MWh-dc, with augmentations planned for Year 5 and Year 10. This is currently a common approach developers are taking, based on S&L's recent project experience, to reduce mobilization costs of frequent augmentation while still taking advantage of future costs declines.

[42] Degradation occurs due to many factors, including time, ambient conditions, state-of-charge, operational profiles, depth of discharge and manufacturing defects.

FIGURE 12: BESS EENRGY CAPCITY OVER 15 YEAR LIFE



Accounting for the assumed overbuild, minimum state of charge, and on-site losses, the total installed energy capacity is 1,030 MWh-dc, accounting for AC and inverter losses of 6.2%.[43]

TABLE 30: BESS SIZING ASSUMPTIONS

Component	Value
Rated AC Output Power (at POI)	**200 MW-ac**
AC Losses	4.6%
Inverter Losses	1.6%
Gross DC Power Output	**212 MW-dc**
Minimum State of Charge	5.0%
Duration	4 hours
Gross Energy Capacity	**895 MWh-dc**
Overbuild due to Degradation	13%, or 135 MWh-dc
Installed Energy Capacity	**1,030 MWh-dc**

Note: Gross Energy Capacity represents the required capacity to achieve nameplate rated output power on the first day of operation

[43] AC losses include power control system and generator step-up transformer losses, line losses, and auxiliary load.

V.B. Capital Costs

As explained in more detail below, we estimated the 4-hour BESS CONE value using a top-down cost estimating approach that involves less detailed specification of the resource and its location for developing cost estimates. S&L estimated the EPC costs based on recent project data, establishing unitized costs for project components and scaling to the selected reference technology specifications with adjustments to account for labor rates in each CONE Area. S&L then verified the total installed costs against publicly available cost estimates for similar BESS resources.

We estimated the non-EPC costs using similar assumptions as the CC and CT for the per-kW costs of electrical interconnection and per-acre land costs. The remaining non-EPC costs components are estimated based on a percentage of total EPC with the same assumption as the CC and CT for project development, mobilization and start-up, and financing fees. We assumed a lower Owner's Contingency of 5% of BESS equipment costs instead of 8% for the CC and CT based on the larger share of costs covered by the EPC contract.

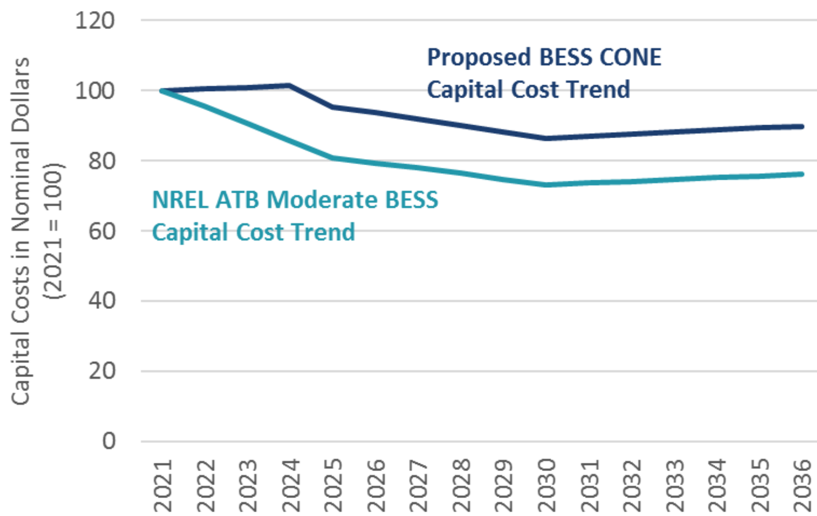
Based on the technical specifications for the reference BESS described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 31 below. EPC costs are primarily driven by the costs of the batteries and enclosures, which is currently estimated to be about $190/kWh-dc (in 2021 dollars). The EPC Contractor Fee and Contingency costs are assumed to be incorporated into the other BESS EPC costs.

TABLE 31: PLANT CAPITAL COSTS FOR BESS REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*200 MW*	*200 MW*	*200 MW*	*200 MW*
EPC Costs				
BESS Equipment				
Batteries and Enclosures	$193.5	$193.5	$193.5	$193.5
PCS and BOP Equipment	$29.0	$29.0	$29.0	$29.0
Project Management	$11.8	$9.4	$10.0	$10.8
Construction & Materials	$58.7	$46.9	$49.6	$53.6
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	Included	Included	Included	Included
EPC Contingency	Included	Included	Included	Included
Total EPC Costs	**$293.0**	**$278.8**	**$282.0**	**$286.9**
Non-EPC Costs				
Project Development	$14.7	$13.9	$14.1	$14.3
Mobilization and Start-Up	$2.9	$2.8	$2.8	$2.9
Owner's Contingency	$11.1	$11.1	$11.1	$11.1
Electrical Interconnection	$4.1	$4.1	$4.1	$4.1
Land	$0.4	$0.3	$0.2	$0.4
Working Capital	$0.0	$0.0	$0.0	$0.0
Financing Fees	$1.3	$1.3	$1.3	$1.3
Total Non-EPC Costs	**$34.6**	**$33.6**	**$33.6**	**$34.1**
Total Capital Costs	**$327.6**	**$312.4**	**$315.7**	**$321.0**
Overnight Capital Costs ($million)	**$328**	**$312**	**$316**	**$321**
Overnight Capital Costs ($/kW)	**$1,638**	**$1,562**	**$1,578**	**$1,605**
Installed Capital Costs ($/kW)	**$1,725**	**$1,646**	**$1,663**	**$1,691**
Installed Capital Costs ($/kWh)	**$409**	**$390**	**$395**	**$401**

Similar to the CC and CT, all equipment and material costs are initially estimated by S&L in 2021 dollars and escalated to the construction period for an online date of June 1, 2026 based on a 16-month construction drawdown schedule for BESS resources. We estimate the overnight capital cost for the BESS incurred during the construction period, as shown in Figure 13 below. S&L estimates that costs will decline in real terms by -1.5% per year from 2021 to 2024 (or +1.4% per year in nominal terms, given assumed inflation of 2.9% per year), based on contract data, trends, and expectations expressed by suppliers for projects currently in development. From 2024 to 2026, we then assume costs will decline in nominal terms based on the 2021 NREL Annual Technology Baseline Moderate cost projections. We use this approach as well for estimating augmentation costs in 2031 (Year 5) and 2036 (Year 10).

FIGURE 13: PROJECTED BESS CAPITAL COST TRENDS



V.C. Operation and Maintenance Costs

Once the BESS plant enters commercial operation, the plant owners incur fixed O&M costs each year. Table 9 summarizes the annual fixed O&M costs, variable O&M costs, and augmentation costs in Year 5 and Year 10 for BESS with an online date of June 1, 2026. The annual O&M costs primarily include the fixed costs of the O&M contract for the facility and the costs of operating insurance.

As shown in Figure 12 above, the BESS storage capacity will fall below 800 MWh-ac in Year 6 based on the assumed initial overbuild and degradation rates. To maintain its 4-hour duration at 200 MW of output power through the economic life of the asset, we assume the developer will add 124 MWh-dc of additional battery modules in Year 5 at a cost of $30.5 million (in 2031 dollars) and another 124 MWh-dc of capacity in Year 10 at $33.1 million (in 2036 dollars).[44]

[44] Augmentation costs reflect the current estimate of module of $190/kWh plus a 20% markup for mobilization and installation costs and the projected trend in module costs shown in Figure 13.

TABLE 32: O&M COSTS FOR BESS REFERENCE RESOURCE

O&M Costs	CONE Area 1 EMAAC *200 MW*	2 SWMAAC *200 MW*	3 Rest of RTO *200 MW*	4 WMAAC *200 MW*
Fixed O&M Components				
O&M Contract Fixed Payments	$2.7	$2.7	$2.7	$2.7
BOP and Substation O&M	$0.1	$0.1	$0.1	$0.1
Station Load / Aux Load	$0.4	$0.3	$0.3	$0.4
Miscellaneous Owner Costs	$0.3	$0.2	$0.3	$0.3
Operating Insurance	$1.3	$1.2	$1.3	$1.3
Land Lease or Property Taxes	$2.3	$4.4	$2.1	$2.0
Fixed O&M (2026$ million)	**$7.1**	**$9.0**	**$6.7**	**$6.7**
Fixed O&M ($/kW-yr)	**$35.3**	**$44.8**	**$33.6**	**$33.7**
Augmentation				
Year 5 Costs (2031$ million)	**$30.5**	**$30.5**	**$30.5**	**$30.5**
Year 10 Costs (2036$ million)	**$33.1**	**$33.1**	**$33.1**	**$33.1**
Levelized Augmentation Costs ($/kW-yr)	**$22.3**	**$22.3**	**$22.3**	**$22.3**
Total Levelized Fixed Costs ($/kW-yr)	**$57.7**	**$67.1**	**$55.9**	**$56.1**

The total levelized fixed O&M costs represent the total contribution of these costs to the CONE value, including both the annual fixed costs ($23/kW-year to $42/kW-year) and the levelized costs of the two capacity augmentations (about $28/kW-year). While some O&M costs may vary with operation, these estimates were prepared with static operational assumptions and commensurate auxiliary loads, degradation, and augmentation profiles. All O&M and augmentation costs for the BESS are accounted for in Table 32 and the variable O&M costs are assumed to be $0.

V.D. CONE Estimates

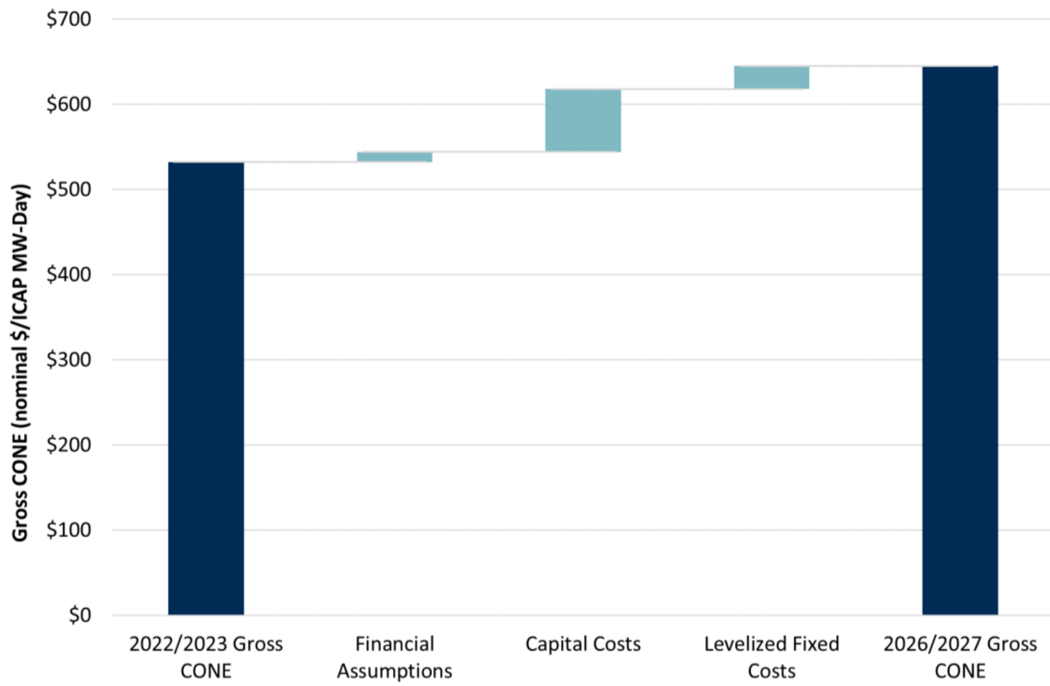
The administrative Gross CONE value reflects the total annual net revenues a new generation resource needs to earn on average to recover its capital investment and annual fixed costs, given reasonable expectations about future cost recovery over its economic life. Table 33 summarizes plant capital costs, annual fixed costs, and levelized CONE estimates for the BESS reference resource for the 2026/27 delivery year. The CONE estimates range from $653/MW-day in Rest of RTO to $678/MW-day in EMAAC.

TABLE 33: ESTIMATED CONE FOR BESS FOR 2026/27 IN 2026$ AND ICAP MW

			4-Hour Battery Storage			
			EMAAC	SWMAAC	Rest of RTO	WMAAC
	Net Summer ICAP	***MW***	**200**	**200**	**200**	**200**
	Gross Costs					
[1]	Overnight	*$m*	$328	$312	$316	$321
[2]	Installed (inc. IDC)	*$m*	$345	$329	$333	$338
[3]	First Year FOM	*$m/yr*	$7	$9	$7	$7
[4]	Year 5 Augmentation	*$m*	$31	$31	$31	$31
[5]	Year 10 Augmentation	*$m*	$33	$33	$33	$33
	Unitized Costs					
[7]	Overnight	*$/kW*	$1,638	$1,562	$1,578	$1,605
[8]	Installed (inc. IDC)	*$/kW*	$1,725	$1,646	$1,663	$1,691
[9]	Levelized Fixed Costs	*$/kW-yr*	$66	$69	$64	$64
[10]	**After-Tax WACC**	***%***	**7.9%**	**8.0%**	**8.0%**	**8.0%**
[11]	Effective Charge Rate	*%*	11.1%	11.0%	11.1%	11.1%
[12]	**Updated CONE**	***$/MW-yr***	**$247,400**	**$240,900**	**$238,400**	**$241,500**
[13]	**Updated CONE**	***$/MW-day***	**$678**	**$660**	**$653**	**$662**

Similar to the CC and CT, the 2026/27 BESS CONE estimates are considerably higher than PJM's estimated CONE for the 2022/23 Delivery Year Base Residual Auction, as shown in Figure 14. PJM estimated the 2022/23 CONE based on cost estimates from the NREL Annual Technology Baseline. As described above, the updated estimates for the 2026/27 auction reflect more detailed specifications for a 200 MW facility in the PJM market and recent cost estimates based on actual projects currently under development, including recent cost escalation. As shown in Figure 13 above, the current outlook for BESS capital costs are about 15% higher than those projected by NREL in its latest ATB. The higher capital costs also reflect the assumed overbuild of capacity to account for degradation, whereas NREL assumed no overbuild and annual augmentation. The higher O&M costs reflect the recent costs of maintenance contracts as well as a more up-to-date outlook for future augmentation costs.

FIGURE 14: DRIVERS OF HIGHER BESS 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)



V.E. Implications for Net CONE

V.E.1. Indicative E&AS Offsets

Similar to the CC and CT, we recommend removing regulation revenues from the calculation of the E&AS offset for BESS. The regulation market is unlikely to continue to support similar prices in the future with the addition of significant BESS resources, especially in the case in which BESS resource are one of the primary resources that enter the market to meet future reserve requirements.

Removing regulation revenues has a greater impact on BESS E&AS offset than the CC and CT though because it currently makes up the majority of its revenues. Table 34 shows the current and updated 2023/24 E&AS revenue offset by zone with the steep decrease caused by the removal of regulation revenues.

TABLE 34: UPDATED 2023/24 BESS E&AS REVENUE OFFSET BY ZONE ($/MW-DAY ICAP)

All values in nominal $/MW-day ICAP	**4-Hour BESS**		
	Current 2023/24 EAS	Removed Regulation	Updated 2023/24 EAS
CONE Area 1			
AECO	$414	-$294	$120
DPL	$427	-$285	$142
JCPL	$413	-$295	$118
PECO	$413	-$295	$118
PSEG	$414	-$294	$120
RECO	$419	-$291	$128
CONE Area 2			
BGE	$428	-$267	$161
PEPCO	$423	-$274	$149
CONE Area 4			
METED	$417	-$286	$132
PENELEC	$419	-$290	$128
PPL	$416	-$292	$124
CONE Area 3			
AEP	$418	-$286	$132
APS	$418	-$284	$134
ATSI	$419	-$284	$135
COMED	$425	-$281	$144
DAY	$420	-$281	$139
DEOK	$421	-$280	$141
DUQ	$421	-$283	$139
DOM	$424	-$276	$149
EKPC	$418	-$285	$134
OVEC	$407	-$295	$113
RTO	**$343**	**-$215**	**$128**

Sources and notes: The "Current 2023/24 E&AS" reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020.

V.E.2. Indicative Net CONE

We apply the same methodology and assumptions to estimate the BESS Net CONE shown for the reference CC. Table 28 Table 35 shows the indicative BESS Net CONE estimates for all LDAs relative to the parameters PJM used in the 2022/23 BRA.

TABLE 35: INDICATIVE BESS 2026/2027 NET CONE ($/MW-DAY UCAP)

All values in nominal $/MW-day UCAP	BESS 2026/27 Brattle Estimate		
	CONE	EAS	Net CONE
CONE Area 1			
AECO	$858	$178	$679
DPL	$858	$208	$649
JCPL	$858	$175	$682
PECO	$858	$175	$683
PSEG	$858	$179	$679
RECO	$858	$189	$668
EMAAC	**$858**	**$184**	**$674**
CONE Area 2			
BGE	$875	$234	$641
PEPCO	$875	$219	$656
SWMAAC	**$875**	**$227**	**$648**
CONE Area 4			
METED	$843	$194	$648
PENELEC	$843	$190	$653
PPL	$843	$184	$659
MAAC	**$857**	**$193**	**$663**
CONE Area 3			
AEP	$830	$195	$635
APS	$830	$198	$632
ATSI	$830	$199	$631
COMED	$830	$211	$619
DAY	$830	$204	$625
DEOK	$830	$208	$622
DUQ	$830	$204	$626
DOM	$830	$218	$612
EKPC	$830	$197	$633
OVEC	$830	$168	$662
RTO	**$851**	**$189**	**$662**

Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

VI. List of Acronyms

ATWACC	After-Tax Weighted-Average Cost of Capital
BACT	Best Available Control Technology
BLS	Bureau of Labor Statistics
BRA	Base Residual Auction
Btu	British Thermal Units
CAISO	California Independent System Operator
CC	Combined Cycle
CO	Carbon Monoxide
COD	Cost of Debt
CONE	Cost of New Entry
CPI	Consumer Price Index
CT	Combustion Turbine
DCP	Dominion Cove Point
DJIA	Dow Jones Industrial Average
E&AS	Energy and Ancillary Services
EIA	Energy Information Administration
EMAAC	Eastern Mid-Atlantic Area Council
EPC	Engineering, Procurement, and Construction
FERC	Federal Energy Regulatory Commission
HRSG	Heat Recovery Steam Generator
ICAP	Installed Capacity
IDC	Interest During Construction
ISO	Independent System Operator
ISO-NE	ISO New England
kW	Kilowatt
kWh	Kilowatt-Hours
LDA	Locational Deliverability Area
LAER	Lowest Achievable Emissions Rate
LTSA	Long-Term Service Agreement
m	Million

MAAC	Mid-Atlantic Area Council
MACRS	Modified Accelerated Cost Recovery System
MMBtu	One Million British Thermal Units
MOPR	Minimum Offer Price Rule
MW	Megawatt(s)
MWh	Megawatt-Hours
NNSR	Non-Attainment New Source Review
NO_x	Nitrogen Oxides
NPV	Net Present Value
NSR	New Source Review
NYISO	New York Independent System Operator
O&M	Operation and Maintenance
OATT	Open Access Transmission Tariff
OFE	Owner-Furnished Equipment
OTR	Ozone Transport Region
PILOT	Payment in Lieu of Taxes
PJM	PJM Interconnection, LLC
PPI	Producer Price Index
PSD	Prevention of Significant Deterioration
ROE	Return on Equity
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
S&L	Sargent & Lundy
SCR	Selective Catalytic Reduction
SWMAAC	Southwestern Mid-Atlantic Area Council
ULSD	Ultra-Lower Sulfur Diesel
VOC	Volatile Organic Compounds
VRR	Variable Resource Requirement
WMAAC	Western Mid-Atlantic Area Council

Appendix A: Combined-Cycle and Combustion Turbine Cost Details

A.1 Technical Specifications

The 2018 PJM CONE study demonstrated that the market was shifting away from the F-class and G-class frame type turbines that had been the dominant turbines over the prior several decades and with over half of the CC plants installed or under construction in PJM. Today, developers even more definitively exhibit preference for H/J-class turbines. Table 36 shows 72% and 58% of CC capacity under construction (since 2018) is from H/J-class turbines in PJM and the U.S., respectively. Among all such turbines, developers continue to select GE 7HA turbine, building on the industry's many turbine-years of operating experience with that make and model. Other equivalent machines to the GE H-class machine such as the Siemens SGT6-8000H or the Mitsubishi M501J currently have lower market penetration.

TABLE 36: TURBINE MODEL OF COMBINED-CYCLE PLANTS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018

Turbine Model	PJM Installed Capacity *(MW)*	US Installed Capacity *(MW)*
General Electric 7HA	7,211	12,203
Mitsubishi M501J	3,645	3,645
Siemens SGT6-8000H	1,856	1,856
Mitsubishi M501G	1,444	4,015
General Electric 7F	828	4,130
Siemens SGT6-5000F	755	1,426
General Electric A650	717	717
Siemens SGT6-500	703	703
General Electric 6B.03	276	276
General Electric GRT	210	210
General Electric MS7001	0	1,000
Siemens SGT6-2000	0	232
Siemens SGT6-800	0	224
Solar Turbines Titan 130	0	29
Total	**17,645**	**30,666**
F/G Class Total	3,940	10,485
H/J Class Total	12,712	17,704

Sources and notes: Data is from Ventyx Energy Velocity Suite and S&P Global Market Intelligence, Accessed August 2021.

Sargent & Lundy reviewed the operational characteristics of starting up each reference resource and updated the parameters PJM includes in its historical simulations for setting the Net E&AS revenue offset in Table 37.

TABLE 37: RECOMMENDED OPERATING PARAMETERS FOR REFERENCE RESOURCES

Parameter	Unit	CT	CC
Installed Capacity	*MW*	367	1,182
Minimum Stable Level	*MW*	140	176
Ramp Rate	*MW/min*	15	30
Time to Start	*mins*	21	120
Minimum Runtime	*hours*	2	4
NOx Rate	*lb/MMBtu*	0.0093	0.0074
SO2 Rate	*lb/MMBtu*	0.0006	0.0006
Startup Gas Usage	*MMBtu/start*	456	7,988
Startup NOx Emissions	*lb/start*	55	160

A.2 Construction Labor Costs

Labor costs are comprised of "construction labor" associated with the EPC scope of work and "other labor" that includes engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services. The labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Labor rates have been developed by S&L through a survey of prevalent wages in each region in 2021. The labor costs for a given task are based on trade rates weighted by the combination of trades required. In areas where multiple labor pools can be drawn upon the trade rates used are the average of the possible labor rates. The labor costs are based on a 5-day 10-hour workweek with per-diem included to attract skilled labor. Site overheads are carried as indirect costs, which is consistent with current industry practice whereas in 2014 site overheads were carried in the labor rates.

A summary of construction labor cost assumptions is shown below in Table 38.

TABLE 38: CONSTRUCTION LABOR COST ASSUMPTIONS

		EMAAC	SWMAAC	Rest of RTO	WMAAC
1x0 CT Plant					
2021 Construction Labor Hours	*hours*	256,453	239,508	243,744	256,453
2021 Weighted Average Crew Rates	*$*	137.66	118.34	122.59	122.44
2021 Productivity Factor	--	1.18	1.10	1.12	1.18
2021 Construction Labor Costs	*$*	$41,657,600	$31,178,500	$33,466,500	$37,051,400
2021 Construction Labor Costs	*$/kW*	115	86	95	106
Double Train 1x1 CC Plant					
2021 Construction Labor Hours	*hours*	1,809,038	1,687,939	1,718,213	1,809,038
2021 Weighted Average Crew Rates	*$*	143.62	127.97	129.48	129.85
2021 Productivity Factor	--	1.18	1.10	1.12	1.18
2021 Construction Labor Costs	*$*	$306,589,500	$237,598,100	$249,164,300	$277,181,900
2021 Construction Labor Costs	*$/kW*	294	227	244	274

Engineering, procurement, and project services are taken as 5% of project direct costs. Construction management and field engineering is taken as 2% of project direct costs. Start-up and commissioning is taken as 1% of project direct costs. These values are consistent with the 2018 CONE Study and are in-line with recent projects in which S&L has been involved.

A.3 Net Startup Fuel Costs

We made the following assumptions to calculate net start-up fuel costs:

- **Natural Gas**: assume zone-specific gas prices, including Transco Zone 6 Non-New York prices for EMAAC, Transco Zone 5 prices for SWMAAC, Columbia Appalachia prices for Rest of RTO, and Transco Leidy Receipts for WMAAC. All gas prices were calculated by using future/forward natural gas prices from OTC Global Holdings as of 10/10/2021 to estimate 2022 gas prices.
- **Electric Energy:** estimate prices based on zone-specific energy prices for the location of the reference resources in each CONE Area: AECO for EMAAC, PEPCO for SWMAAC, AEP for Rest of RTO, and PPL for WMAAC;[45] average the resulting estimates for locational day-ahead on-peak and off-peak energy prices to estimate the average revenues that would be received during testing.

45 Electricity prices were estimated following the approach discussed in Section II.B of the concurrently released VRR Curve report.

TABLE 39: STARTUP PRODUCTION AND FUEL CONSUMPTION DURING TESTING

	Energy Production			Fuel Consumption			
	Energy Produced	Energy Price	Energy Sales Credit	Natural Gas	Natural Gas Price	Natural Gas Cost	Total Cost
	(MWh)	*($/MWh)*	*($m)*	*(MMBtu)*	*($/MMBtu)*	*($m)*	*($m)*
Gas CT							
1 Eastern MAAC	178,130	$36.24	$6.46	1,636,480	$3.61	$5.9	-$0.6
2 Southwest MAAC	179,290	$36.24	$6.50	1,647,134	$3.61	$5.9	-$0.6
3 Rest of RTO	173,913	$32.45	$5.64	1,598,262	$3.61	$5.8	$0.1
4 Western MAAC	172,584	$36.24	$6.25	1,586,224	$3.61	$5.7	-$0.5
Gas CC							
1 Eastern MAAC	1,027,945	$36.24	$37.26	6,468,335	$3.61	$23.3	-$13.9
2 Southwest MAAC	1,034,170	$36.24	$37.48	6,509,687	$3.61	$23.5	-$14.0
3 Rest of RTO	1,003,905	$32.45	$32.57	6,316,673	$3.61	$22.8	-$9.8
4 Western MAAC	996,320	$36.24	$36.11	6,269,141	$3.61	$22.6	-$13.5

Sources and notes: Energy production and fuel consumption estimated by S&L. Energy prices estimated by Brattle based on approach discussed in Section II.B of VRR curve report. Gas prices from OTC Global Holdings as of 10/10/2021.

A.4 Gas and Electric Interconnection Costs

Similar to the 2018 PJM CONE Study, we identified representative gas pipeline lateral projects from the EIA U.S. Natural Gas Pipeline Projects database and obtained project-specific costs from each project's FERC docket for calculating the average per-mile lateral cost and metering station costs. We escalated the project-specific costs to 2021 dollars based on the assumed long-term inflation rate of 2.4% (see Table 8 above). We then calculated the average per-mile costs of the laterals ($5.1 million/mile) and the station costs ($4.1 million). The summary of project costs and the average per-mile pipeline cost and metering station cost are shown in Table 40.[46]

[46] The gas lateral projects were identified from the EIA's "U.S. natural gas pipeline projects" database available at http://www.eia.gov/naturalgas/data.cfm. The detailed costs are from each project's FERC application, which can be found by searching for the project's docket at http://elibrary.ferc.gov/idmws/docket_search.asp.

TABLE 40: GAS INTERCONNECTION COSTS

Gas Lateral Project	State	In-Service Year	Pipeline Width *(inches)*	Pipeline Length *(miles)*	Pipeline Cost *(service year $m)*	Pipeline Cost *(2021$m)*	Pipeline Cost *(2021$m/mile)*	Meter Station *(Y/N)*	Station Cost *(service year $m)*	Station Cost *(2021$m)*
Panda Power Lateral Project	TX	2014	16	16.5	$26	$31	$2	Y	$2.2	$2.6
Woodbridge lateral	NJ	2015	20	2.4	$32	$37	$15	Y	$3.5	$4.0
Rock Springs Expansion	PA,MD	2016	20	11.0	$80	$90	$8	Y	$3.3	$3.7
Western Kentucky Lateral Project	KY	2016	24	22.5	$81	$91	$4	Y	$4.8	$5.4
UGI Sunbury Pipeline	PA	2017	20	35.0	$178	$196	$6	Y	n.a.	n.a.
Willis Lateral Project	TX	2020	24	19.0	$96	$98	$5	Y	$4.3	$4.4
Average							**$5.1**			**$4.0**

Sources and notes: A list of recent gas lateral projects were identified based on an EIA dataset (http://www.eia.gov/naturalgas/data.cfm) and detailed cost information was obtained from the project's application with FERC, which can be retrieved from the project's FERC docket (available at http://elibrary.ferc.gov/idmws/docket_search.asp).

Table 41 below summarizes the average electrical interconnection costs of recently installed gas-fired resources that we identified as representative of the CC reference resources. The costs are based on confidential, project-specific cost data provided by PJM for both the direct connection facilities and all necessary network upgrades. In the case where plants chose to build their own direct connection facilities and did not report their costs to PJM, we calculated the capacity-weighted average of the units with direct connection costs and applied them to the units without direct connection costs. We escalated the direct connection and network upgrade costs from the online service dates to 2021 dollars based on the assumed long-term inflation rate of 2.9%. We then calculated the capacity-weighted average costs. We used the capacity-weighted average across all representative plants of $18.9/kW for setting the electrical interconnection of the CC reference resource.

TABLE 41: ELECTRIC INTERCONNECTION COSTS IN PJM

Plant Size	Observations *(count)*	Electrical Interconnection Cost Capacity Weighted Average *(2021$m)*	*(2021$/kW)*
< 500 MW	5	$7.2	$18.3
500-750 MW	5	$12.2	$20.7
> 750 MW	7	$23.9	$18.3
Capacity Weighted Average	**17**	**$18.8**	**$18.9**

Source and notes: Confidential project-specific cost data provided by PJM.

A.5 Land Costs

We estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. We collected all publicly-available land listings for counties within each CONE area. We then calculated the acre-weighted average land price for each CONE area and escalated 1 year using the long-term inflation rate of 2.2%. There is a wide range of prices within the same CONE Area as shown in Table 42.

TABLE 42: CURRENT LAND ASKING PRICES

CONE Area	**Current Asking Prices**		
	Observations *(count)*	Range *(2022$/acre)*	Land Price *(2022$/acre)*
1 EMAAC	7	$14,430 - $206,620	$96,361
2 SWMAAC	2	$13,148 - $42,785	$29,504
3 RTO	6	$9,867 - $37,429	$16,376
4 WMAAC	6	$22,49 - $68,14	$30,628

Sources and notes: We researched land listing prices on LoopNet's Commercial Real Estate Listings (www.loopnet.com) and on LandAndFarm (www.landandfarm.com).

A.6 Property Taxes

Table 43 summarizes the calculations for the effective tax rates of each CONE area. We collected nominal tax rates, assessment ratios, and depreciation rates for counties of each CONE area. Using the nominal tax rates and assessment ratios, the effective tax rate for each CONE area was calculated by multiplying the average nominal tax rate and assessment ratio for counties within each CONE area state.

TABLE 43: PROPERTY TAX RATE ESTIMATES FOR EACH CONE AREA

		Real Property Tax			Personal Property Tax			
		Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Depreciation
		[a]	[b]	[a] X [b]	[c]	[d]	[c] X [d]	[e]
		(%)	*(%)*	*(%)*	*(%)*	*(%)*	*(%)*	*(%/yr)*
1 EMAAC								
New Jersey	[1]	4.0%	96.2%	3.8%	n/a	n/a	n/a	n/a
2 SWMAAC								
Maryland	[2]	1.1%	100.0%	1.1%	2.7%	50.0%	1.3%	3.3%
3 RTO								
Ohio	[3]	5.5%	35.0%	1.9%	5.5%	24.0%	1.3%	See "SchC-NewProd (NG)" Annual Report
Pennsylvania	[4]	2.7%	100.0%	2.7%	n/a	n/a	n/a	n/a
4 WMAAC								
Pennsylvania	[5]	3.8%	99.0%	3.8%	n/a	n/a	n/a	n/a

Sources and Notes:

[1a],[1b] New Jersey rates estimated based on the average effective tax rates from Gloucester and Camden counties. For Gloucester County see:
https://tax1.co.monmouth.nj.us/cgi-bin/prc6.cgi?&ms_user=monm&passwd=data&srch_type=0&adv=0&out_type=0&district=0801
For Camden county see:
https://www.camdencounty.com/wp-content/uploads/2020/11/04CAMDEN.2021-Ratios.pdf
https://www.camdencounty.com/wp-content/uploads/2020/11/2021-County-Tax-Rates.pdf

[1c],[1d] No personal property tax assessed on power plants in New Jersey; NJ Rev Stat § 54:4-1 (2016).

[2a],[2c] Maryland tax rates estimated based on average county tax rates in Charles county and Prince George's county in 2017-2018. Data obtained from Maryland Department of Assessments & Taxation website:
https://dat.maryland.gov/Documents/statistics/Taxrates_2021.pdf

[2d] MD Tax-Prop Code § 7-237 (2016)

[2e] Phone conversation with representative at Charles County Treasury Department.

[3a],[3c] Ohio rates estimated based on the average effective tax rates from Trumbull and Carroll counties. For Trumbull county see:
http://auditor.co.trumbull.oh.us/pdfs/2020%20RATE%20OF%20TAXATION.pdf
For Caroll County see:
http://www.carrollcountyauditor.us/auditorsadvisory/Rates%20of%20Taxation%202020.pdf

[3b],[3d] Assessment ratios for real property and personal property taxes found on pages 124 and 129:
http://www.tax.ohio.gov/Portals/0/communications/publications/annual_reports/2016AnnualReport/2016AnnualReport.pdf

[3e] Depreciation schedules for utility assets found in Form U-El by Ohio Department of Taxation:
http://www.tax.ohio.gov/portals/0/forms/public_utility_excise/2017/PUE_UEL.xls

[4a] Pennsylvania county tax rates for RTO based on the county of Lawrence, available at:
https://lawrencecountypa.gov/wp-content/uploads/2021/07/2021-millage.pdf

[4b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf

[4c]-[4e] According to *Pennsylvania Legislator's Municipal Deskbook Taxation & Finance (Real Estate Assessment Process, pg. 1)* , only real estate tax assessed by local governments.

[5a] Pennsylvania county tax rates for WMAAC based on average effective tax rate between Luzerne, Lycoming, and Bradford counties:
https://www.luzernecounty.org/DocumentCenter/View/26403/2021-MILLAGES-JULY
https://www.lyco.org/Portals/1/Assessment/Documents/2021%20Millage.pdf?ver=2021-01-29-090920-517
https://bradfordcountypa.org/wp-content/uploads/2021/09/Bradford-County-Mill-Rates.pdf

[5b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf
Note assessment ratios above 100% are capped at 100% in our calculations.

[5c]-[5e] According to Pennsylvania Legislator's Municipal Deskbook Taxation & Finance (Real Estate Assessment Process, pg. 1), only real estate tax assessed by local governments.

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