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July 18, 2024

Public Utility Commission of Texas
Chairman, Thomas J. Gleeson
Commissioner Kathleen Jackson
Commissioner Lori Cobos
Commissioner Jimmy Glotfelty
Commissioner Courtney Hjaltman
1701 N. Congress Avenue
Austin, TX 78711

Re: PUC Project No. 54584, *Reliability Standard for the ERCOT Market*

Dear Chairman and Commissioners:

As a follow-up to the Public Utility Commission of Texas' (Commission) discussion at the July 11, 2024 Open Meeting, Electric Reliability Council of Texas, Inc. (ERCOT) submits the additional sensitivity information requested in regard to Cost of New Entry (CONE) Study.

Real-Levelization versus Nominal-Levelization Method

ERCOT's contractor, The Brattle Group (Brattle), determined a levelization "shape" when calculating values for the CONE Study. Brattle's CONE Study includes a "levelization approach" sensitivity for the proposed LM6000 aeroderivative combustion turbine (Aero CT) reference technology. Projecting CONE is not an exact science, and Brattle recognizes that levelization depends on developer views of revenue trajectory.

While Brattle used level-nominal as the base case levelization method, it also demonstrated the impact on CONE of using a level-real, an intermediate, and a more front-loaded levelization approach. Under the level-real levelization method, revenues are constant in real terms, meaning that they increase overtime at the rate of long-term inflation (2.2%) in nominal terms. The 'intermediate' levelization sensitivity reflects an annual 0.8% real cost decline in overnight capital costs for the Aero CT from the National Renewable Energy Laboratory's (NREL) 2023 Annual Technology Baseline (ATB) moderate case, without any consideration of performance improvements.[1] The 'more front-loaded' sensitivity reflects a more aggressive 3.0% annual long-term real cost decline in overnight capital costs for the hybrid photovoltaic (PV) solar plus battery energy storage system (BESS) alternative reference technology resource, which is also based on

[1] National Renewable Energy Laboratory, ***2023 Electricity ATB Technologies and Data Overview*** (accessed May 27, 2024) ("2023 NREL ATB"), available at: https://atb.nrel.gov/electricity/2023/index.

the NREL ATB moderate case. The level-real and intermediate sensitivities for the Aero CT and the more front-loaded sensitivity for the PV+BESS are shown in Table 1.

Table 1: CONE Sensitivity to Levilization

Levelization Method	Assumed Nominal Revenue Escalation Rate	Assumed Real Revenue Escalation Rate	CONE 6x0 LM6000 (2026 $/kW-yr)	CONE PV + BESS (2026 $/kW-yr)
Level-Real	2.2%	0.0%	$253	
Intermediate	1.4%	-0.8%	$268	
Level-Nominal	**0.0%**	**-2.2%**	**$293**	**$263**
More front-loaded	-0.8%	-3.0%		$277

For the Aero CT, changing from a level-nominal to level-real method reduces CONE by $40 per kilowatt year (kW-yr). The magnitude of this impact is less than one-third of the impact of changing the reference technology to a frame-type combustion turbine (Frame CT) with an indicative CONE of $162 per kW-yr. Moving from a level-nominal to the intermediate levelization scenario reduces the Aero CT CONE by $25 per kW-yr, which is less than one-fifth of the impact of changing the reference technology to a Frame CT. For the PV+BESS alternative reference technology, going from a level-nominal to a more front-loaded levelization method increases the CONE by $14 per kW-yr.

Economic Life Assumption

Brattle utilized a 20-year economic lifetime assumption when conducting the CONE calculation. This is because developers commonly expressed a preference to recover their capital over 20 years; it does not mean the useful life is only 20 years—new natural gas-fired plants can typically operate for 30 years or longer.

As requested, ERCOT used Brattle's CONE model to estimate the impact of increasing the assumed economic life assumption from 20 to 25 years. Increasing the economic life to 25 years decreased the CONE for the Aero CT reference technology from $293 per kW-yr to $280 per kW-yr.

Next Steps

Additionally, Brattle has completed work on its CONE Study Final Report for ERCOT in accordance with the terms of Brattle's engagement. The CONE Study Final Report is intended to be a tool in the assessment of CONE for the ERCOT Region and is included here as **Attachment A** for your review. In support of the CONE Study, Brattle developed a "2026 ERCOT CONE Model" that calculates CONE for an Aero CT and PV+BESS entering the ERCOT market with a

June 2026 Commercial Online Date (COD). The model, included here as **Attachment B**, incorporates Brattle's relevant assumptions for capital costs, fixed operations & maintenance costs, taxes, tax credits, and depreciation.

ERCOT appreciates Commission feedback on the further development of any new CONE value or values to ensure that market needs are appropriately addressed. ERCOT representatives will be available at the July 25, 2024 Open Meeting to present this information and answer any questions that you may have regarding the CONE Study.

Respectfully submitted,

/s/ Woody Rickerson

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Attachment A

ERCOT CONE for 2026

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Electric Reliability Council of Texas, Inc. (ERCOT)

JULY 18, 2024

NOTICE

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Executive Summary

The Electric Reliability Council of Texas, Inc. (ERCOT) retained consultants at The Brattle Group (Brattle) and Sargent & Lundy (S&L) to develop an updated estimate of the Cost of New Entry (CONE) for use in setting the Peaker Net Margin (PNM) threshold, evaluating the cost of proposed reliability standards, analyzing the Market Equilibrium Reserve Margin (MERM) and Economically Optimal Reserve Margin (EORM), and potentially setting demand curves for a Performance Credit Mechanism (PCM). ERCOT requested a "Leaner Study Option" with scope for one dispatchable thermal reference resource and one alternative technology, a simplified calculation of the after-tax weighted-average cost of capital (ATWACC), and limited scope for analytical iteration based on stakeholder feedback. This report presents our resulting estimates of CONE for a June 2026 Commercial Operations Date (COD), a discussion of uncertainties, and a recommended method for updating the CONE values annually. An accompanying Excel workbook contains our calculations to enable ERCOT and stakeholders to conduct sensitivity analyses and the annual CONE updates.

APPROACH

CONE represents the expected levelized first-year net revenues a representative resource would need to earn for a merchant developer to be willing to build in the ERCOT market. The calculation does not account for subsidies offered temporarily by the Texas Energy Fund (TEF), in order to fully express how high prices would need to be to support unsubsidized merchant entry beyond the TEF.

CONE is estimated in three steps by: (1) identifying an appropriate reference resource and alternative reference resource that can economically enter the ERCOT market; (2) conducting a detailed bottom-up analysis of each one's capital costs and ongoing fixed operation and maintenance (FOM) costs; then (3) for each, calculating a first-year revenue estimate needed for entry, given likely trajectories of future total revenues over the economic life of the plant, discounted at an appropriate ATWACC.

REFERENCE AND ALTERNATIVE RESOURCES

As agreed with ERCOT and presented to ERCOT stakeholders at Supply Analysis Working Group (SAWG) meetings in spring 2024, CONE should be calculated for a reference resource that is dispatchable, economically viable, and likely to be developed in ERCOT in the next few years. To identify such a resource type and its characteristics, we relied on market evidence rather than speculating about which kinds of plants should be built. Our review of actual merchant plants built recently and under construction pointed clearly to an LM6000PC aeroderivative natural gas-fired combustion turbine (Aero CT) plant. This is the predominant thermal technology type being built in ERCOT, accounting for 98% of capacity for recent/ongoing merchant entry of thermal dispatchable resources (although some other technologies are in an earlier or more tentative development phase that did not meet study criteria for inclusion). Corresponding to the typical plant configurations, the reference plant is assumed to have six LM6000PC units with a total capacity of 291 MW under International Standards Organization (ISO) conditions and other specifications described herein.

ERCOT also requested a CONE estimate for an alternative resource that is prevalent even if not an always-dispatchable fuel-based resource. A photovoltaic (PV) plus battery energy stationary storage (BESS) hybrid plant (PV+BESS) was selected because it is prevalent in the ERCOT Region, and it is both dispatchable and produces primary energy. To represent the population of plants being built, the alternative reference plant is assumed to have 200 MW PV and 100 MW BESS with 2-hour duration.

BOTTOM-UP COST ANALYSIS AND CONE CALCULATION

For the Aero CT and the PV+BESS plants, we conducted comprehensive, bottom-up analyses of capital costs, consisting of: 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. Also included are the annual FOM costs. Variable operation & maintenance (VOM) costs are not part of the CONE but are provided for informational purposes.[1]

For a COD date of June 1, 2026, the overnight capital and FOM costs are derived by assessing all of the constituent costs today (as of April 2024), then escalating cost components to the midpoint of the construction period, as if they occurred "overnight" then. A capital drawdown schedule distributes those costs among the many months required to construct the plant, with the same nominal sum. Those monthly expenditures are then translated, at the cost of capital for the project, into a present value as of the commercial online date, yielding the "installed cost.". Finally, the installed cost and the present value of FOM costs are used to calculate CONE as the

[1] See Section III for more details on the FOM and VOM costs for both the Aero CT and PV+BESS.

revenue net of variable costs the project would have to earn in its first year to have zero net present value (NPV), assuming a 20-year economic life with constant net revenues in nominal terms. Net revenues and costs are discounted at an ATWACC of 10.35% for a merchant generation investment. This value is approximated from a recent estimate of ATWACC for merchant generation in PJM adjusted for an ERCOT-specific corporate income tax and accounting for the increase in the risk-free rate using 20-year treasury bond yields.[2]

Table ES-1 below shows the resulting CONE estimates for the Aero CT and PV+BESS plants. The cost of the Aero CT plant is comparable to the Energy Information Administration's (EIA's) latest estimates for 2024.[3] The CONE of the Aero CT is much higher than in the PJM 2022 study ($110/kW-yr higher than the combined-cycle estimate and $146/kW-yr higher than the frame combustion turbine) primarily because aeroderivative plants cost more per kW and because the ATWACC in this study is 150 basis points (bps) higher.[4] The PV+BESS is presented in terms of levelized cost per kW of PV capacity, rather than BESS capacity or some combination. The PV+BESS appears to have a lower CONE than the Aero CT, but it serves a different purpose in the market.

2 Some stakeholders argued that there could be higher, non-diversifiable risk in ERCOT compared to PJM due to the market regulatory environment that could warrant a 100-bps risk premium adder, which would result in an ATWACC of 11.35%. We do not adopt this as our base case but do show the implications for CONE as another sensitivity.

3 EIA, "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies, prepared by Sargent & Lundy," January 2024.

4 When comparing against the PJM "Rest of RTO" values. See Newell, et al., "PJM CONE 2026/2027 Report," April 21, 2022.

TABLE ES-1: ESTIMATED CONE FOR REFERENCE AND ALTERNATIVE TECHNOLOGY

				Aero CT
[1]	**Capacity at ISO conditions**	*MW*		**291**
[2]	Overnight Cost	*Nominal $ million*		$513
[3]	Overnight Cost	*Nominal $/kW*	= [2] x 1000 / [1]	$1,764
[4]	Capital Charge Rate	*%*		14.0%
[5]	Levelized Capital Cost	*Nominal $/kW-yr*	= [3] x [4]	$246
[6]	Levelized FOM	*Nominal $/kW-yr*		$47
[7]	**Levelized CONE**	***Nominal $/kW-yr***	= [5] + [7]	**$293**

				PV + BESS
[1]	**Plant Capacity**	*MW*		**200**
[2]	Overnight Cost	*Nominal $ million*		$349
[3]	Overnight Cost	*Nominal $/kW*	= [2] x 1000 / [1]	$1,743
[4]	Capital Charge Rate	*%*		12.1%
[5]	Levelized Capital Cost	*Nominal $/kW-yr*	= [3] x [4]	$210
[6]	Levelized FOM	*Nominal $/kW-yr*		$49
[7]	Levelized Augmentation	*Nominal $/kW-yr*		$3
[8]	**Levelized CONE**	***Nominal $/kW-yr***		**$263**

INTERPRETATION AND APPLICATION OF CONE

Policymakers should recognize the uncertainty in estimating CONE and understand the implications of under- and over-estimates. The greatest uncertainty drivers for the thermal reference resource are the choice of reference technology. The 6×0 LM6000PC reference resource's CONE is nearly twice as high as a 1×0 frame combustion turbine (Frame CT) would be, based on relative estimates from the EIA. The Frame CT was not selected as the reference resource for this study because developers are not building Frame CTs in the ERCOT Region. Developers evidently prefer the costlier aeroderivative plants, and some reported that they value the relative flexibility and lower "shaft risk" that aeroderivative turbines provide whereby multiple smaller units diversify exposure to inopportune unavailability in a market that sharply punishes outages during system shortages.

The aeroderivative plants being developed in the ERCOT Region also enjoy cost advantages since they are being built with refurbished LM6000PC turbines, although the magnitude of savings is not publicly available. Recognizing that and the likelihood that the supply of refurbished turbines is limited, this study assumes a new unit of the same type. We acknowledge that this could overstate entry costs relative to those of current entrants and other options that competitive developers might pursue absent refurbished turbines, such as the new larger LM6000PF turbines, frame turbines, virtual power plants, or other technologies. Our adherence to the "revealed preference" approach avoids speculating on what other technologies might be built under different market circumstances, or trying to account for disadvantageous characteristics of a given technology that may be deterring developers from building it.

Smaller uncertainty drivers, including the ATWACC, the economic life and levelization approach, and future input costs, are discussed herein, as are uncertainties about the CONE value for the PV + BESS alternative reference resource. To help stakeholders assess the sensitivity of CONE to these and other assumptions, our CONE calculation model and underlying data will be posted alongside this report.

Under- or over-forecasts of CONE will affect outcomes wherever CONE is applied. For the Peaker Net Margin, a higher CONE increases the "3×CONE" PNM threshold where offer caps are lowered, which could increase costs for consumers.[5] For the Reliability Standard cost impact estimation, a higher CONE increases estimated system costs; higher CONE decreases estimated MERM and EORM benchmarks. For potential PCM purposes, a higher CONE could raise Net CONE, which could increase the demand curve and boost reliability but increase costs. For all of these purposes, CONE accuracy matters, but so too does the estimation of net energy and ancillary services (E&AS) revenues incorporated into these studies.

ANNUAL CONE UPDATES

This report provides indexing approaches to enable ERCOT staff to update CONE estimates annually until it conducts the next full CONE study. For updates to capital, FOM, and VOM costs, we recommend that ERCOT update the LM6000 reference technology CONE value each year based on a composite of the U.S. Department of Commerce's Bureau of Labor Statistics indices for labor, turbines, and materials. For updates to the ATWACC, we recommend ERCOT adjust the ATWACC by the difference between the prevailing 15-day average of 20-year U.S. treasury bills as of the updated estimate date and the previous estimated date. This adjustment is consistent with the concept that ATWACC is the sum of the risk-free rate and the industry's market risk premium, and it captures changes in the risk-free rate. It would not account for possible changes in industry risk premium, which would be harder to capture in a simple index formula.

[5] *See* 16 TEX. ADMIN. CODE (TAC) § 25.509(b)(6)(C) (requiring the PNM threshold to be three times CONE); *see also*, ERCOT Nodal Protocols § 4.4.11(1) (setting the value for the PNM threshold).

I. Introduction

A. Study Objective

Electric Reliability Council of Texas, Inc. (ERCOT) retained consultants at The Brattle Group (Brattle) and Sargent & Lundy (S&L) to develop an updated estimate of the Cost of New Entry (CONE) for use in setting the Peaker Net Margin (PNM) threshold, evaluating a proposed reliability standard, studying the Market Equilibrium Reserve Margin (MERM) and the Economically Optimal Reserve Margin (EORM), and determining a demand curve for a potential future Performance Credit Mechanism (PCM).

CONE represents the expected levelized first-year net revenues a representative resource would need to earn for a merchant developer to be willing to build in the ERCOT market. The concept does not account for temporary and limited subsidies, such as those offered by the Texas Energy Fund (TEF), so that CONE expresses how high prices would need to be to support unsubsidized merchant beyond such limited subsidies as needed for resource adequacy, particularly in ERCOT's high-growth environment.

To that end, this report:

- Recommends a **reference resource** whose levelized cost will best indicate the price at which developers would be willing to add capacity, as well as an alternative resource for use in sensitivity analyses. The reference resource should represent a technology, configuration, location of plant that is actually being built.
- Develops **bottom-up cost estimates** of the reference resources for a June 2026 Commercial Operations Date (COD). Costs should represent those of a competitive developer of new merchant generation facilities at generic sites, not unique sites with unusual characteristics.
- Calculates **CONE** as the reference resources' first-year revenue estimate needed for entry, given likely trajectories of future total revenues over the economic life of the plant, discounted at an appropriate after-tax weighted-average cost of capital (ATWACC).
- Recommends an approach for **annual updates** to the CONE value if desired.

This report explains the relevant research and empirical analysis used to inform our recommendations, while recognizing where judgments must be made in specifying the reference resource characteristics and translating its estimated costs into levelized revenue requirements. In such cases, we discuss trade-offs and provide our own recommendations for best meeting ERCOT's objectives to inform policy decisions. Therefore, our recommendations include not only our best estimate of CONE, but also a view on the range of uncertainty inherent in this estimation.

B. Analytical Approach

Our starting point was to identify the most appropriate technology to serve as the reference resource for CONE as well as an alternative as a sensitivity of the CONE estimate. Section II explains the criteria used for selecting the reference and alternative resources and how those criteria were then applied to the analysis of the empirical data. We relied on the "revealed preferences" of actual developers of projects that have been built recently or are under construction in ERCOT with a COD between 2021 and 2026.

This resulted in a clear choice of an Aero CT comprised of a multi-unit aeroderivative natural gas-fired plant, since over 98% of all capacity in the ERCOT Region is from GE LM6000 aeroderivative combustion turbines in that timeframe. For the alternative resource, the analysis narrowed the choices to either a photovoltaic plus battery energy stationary storage (PV+BESS) hybrid or a standalone BESS. Ultimately, the PV+BESS was chosen as the alternative reference resource since it is both dispatchable and produces primary energy, and the majority of renewable generation or standalone storage capacity in that timeframe was from solar hybrid plants.

For the two identified resources, we estimated the CONE starting with a characterization of plant size and configuration, detailed specifications, and locations where developers are most likely to build. The specific plant and site characteristics are based on: (1) analysis of the recently built or plants under construction in the ERCOT Region (COD 2021–2026); (2) analysis of plant designs, technologies, regulations, and infrastructure in the ERCOT Region; and (3) our experience from previous CONE analyses, which is outlined in Section II of this report.

We developed comprehensive, bottom-up cost estimates for constructing and maintaining the reference Aero CT resource and alternative PV+BESS resource. S&L estimated plant 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. The bottom-up cost estimates also include annual fixed and variable operation and maintenance (O&M) costs (labor, materials, property tax, insurance, asset management costs, and working capital).

These costs were estimated using current market prices for the materials, equipment, and labor inputs as of April 2024. The next step is to escalate those costs to the midpoint of the construction period for achieving a COD of June 2026. The resulting cost is spread in nominal terms according to a monthly capital drawdown schedule for each technology type. The present value of these costs (at the full ATWACC) as of June 2026 yields the "installed costs," which account for the time value of money spent on the project during construction and the project's risk.

Finally, the CONE is calculated as the net revenue the resource owner would have to earn in its first year to enter the market to be "net present value (NPV) zero" and cover the installed cost and the present value of fixed operation and maintenance (FOM) costs. This calculation assumes a 20-year economic life and that net revenues on average remain constant in nominal terms over that timeframe.

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 capital, O&M and major maintenance costs, and Brattle taking responsibility for various owner's and fixed O&M costs, and for translating the cost estimates into the CONE values.

C. Background on the Use of CONE

The ERCOT market supports investment for resource adequacy through energy and ancillary services prices that can rise very high when supplies become tight. Pricing is determined by market clearing of resource offers that are allowed up to a System-wide Offer Cap (SWCAP) subject to market power rules, plus an administratively determined Operating Reserve Demand Curve (ORDC) and other adders that can add much greater resource adequacy signals when reliability is threatened. Currently, pursuant to 16 TEXAS ADMINISTRATIVE CODE (TAC) § 25.509(b), the SWCAP is set at the beginning of each calendar year to the High Cap (HCAP) of $5,000/MWh and transitions to the Low Cap (LCAP) of $2,000/MWh for the remainder of the calendar year when the system achieves the $315,000/MW-year Peaker Net Margin (PNM) threshold.[6] The

[6] *See also* ERCOT Nodal Protocols § 4.4.11, *System-Wide Offer Caps*.

PNM threshold is ultimately a regulated safety valve to prevent extreme one-year results and is set at three times CONE.[7]

Additionally, CONE is used as an input for estimating the Market Equilibrium Reserve Margin (MERM) and the Economically Optimal Reserve Margin (EORM). The MERM describes the reserve margin that the market can be expected to support in equilibrium, as investment in new supply resources responds to expected market conditions. This approach creates changes in supply in response to changes in energy market prices toward a market equilibrium; low reserve margins cause high energy and ancillary service (E&AS) prices and attract investment in new resources that will continue until high reserve margins result in prices too low to support further investment. The EORM is a benchmark sometimes used to establish the sufficiency of the expected MERM, where the marginal benefits of new supply are just equal to the marginal costs of new supply. More recently, ERCOT has proposed resource adequacy reliability standards, and the cost of meeting it can be evaluated through market simulations that include estimates of CONE.

The CONE value ERCOT uses has not been updated since 2012 from the $105,000/MW-year value we previously approximated based on estimates produced for PJM and an ATWACC requested by ERCOT.[8] The Texas Legislature required that an evaluation of CONE be conducted as a prerequisite to adoption of the PCM.[9] Stakeholders and the Public Utility Commission of Texas have recently requested that ERCOT update the CONE value, which is accordingly provided herein.

[7] 16 TAC § 25.509(b)(6)(C); *see also,* ERCOT Nodal Protocols § 4.4.11(1)(c).

[8] Newell, et al., "ERCOT Investment Incentives and Resource Adequacy," June 1, 2012.

[9] *See* Tex. H.B. 1500 § 23, 88th Leg., R.S. (2023) (codified as Public Utility Regulatory Act, TEX. UTIL. CODE § 39.1594(d)(1)).

II. Reference and Alternative Resource Selection

A. Summary of Technical Specifications

To estimate CONE, we identified a thermal dispatchable plant that is most likely to be developed in ERCOT in the next few years. The aim is to describe a representative plant including technology type, turbine model, plant size, configuration, and location of new merchant generation facilities. The technical specifications were determined using the "revealed preference" of market developers by reviewing plants recently built and under development in the ERCOT Region. From this analysis a 6×0 aeroderivative LM6000PC (Aero CT) plant with 291 MW (at ISO conditions) in Harris County results as our reference resource as shown in Table 1.

We determined the representative technology type, turbine model, plant configuration, and location by reviewing plants recently built or under construction in the ERCOT Region with CODs between 2021 and 2026. Ninety-eight percent of all thermal dispatchable capacity in ERCOT in this timeframe is from GE LM6000 aeroderivative combustion turbines, making it the clear technology choice based on the data sources and filtering criteria we describe in the following section. While the LM6000 is the dominant technology among thermal projects recently built or under construction, there are other technologies in earlier or more tentative stages of development.[10] Further, it is possible that the Texas Energy Fund (TEF), which is expected to begin publishing awards later in 2024, will affect the choice of technologies built, but in any case, as noted above, this study aims to estimate the cost of unsubsidized merchant entry.

Most of the recently built and under construction thermal dispatchable capacity has been built by WattBridge using a standardized turnkey natural gas-fired plant design (PROENERGY LM6000PC with SPRINT) that informed the technical characteristics of the Aero CT. The county with the most planned natural gas capacity served as the location for our reference plant.

10 For example, NRG's THW GT Electric Generating Station development project that is a frame CT plan in the permitting phase but described as being contingent on "legislative conditions and long-term regulatory certainty" or the Cedar Bayou frame CT plant that is expected to come online in 2027. See NRG, "Powering Texas," accessed June 3, 2024.

The WattBridge projects do have a characteristic that complicates this study: they are constructed from refurbished LM6000PC ("PC") turbines. The cost savings of refurbished relative to new turbines is not publicly available, nor would it be appropriate to include such savings for the reference resource that is intended to capture an economic capacity resource without idiosyncratic advantages that cannot be replicated at scale, since opportunities for using refurbished turbines are limited. Therefore, we estimate costs for a new LM6000PC turbine gas-fired plant, while acknowledging that current entrants likely have cost advantages by an unknown amount. We further acknowledge that once refurbishment opportunities are exhausted, we do not know whether developers would opt to build new PCs, newer LM6000PF ("PF") turbines, or other technologies. It is notable that PF turbines have greater economies of scale, with 13% more capacity per unit, at only a slightly greater cost per unit (and implications for the balance of plant cost). Frame type CTs are substantially cheaper per kW but have different operating characteristics and risks versus aeroderivative turbines. Overall, while our approach estimates reasonable costs based on what is built and under construction in the market today, it is possible that competitive developers in the future will find lower cost ways to add capacity than the reference plant identified here.

TABLE 1: TECHNICAL SPECIFICATIONS FOR AERO CT

Technology and Size	
Generation Technology	Aeroderivative Combustion Turbine (Aero CT)
Turbine Model	GE LM6000PC
Configuration	6 x 0
Net Capacity (MW) **Summer / ISO / Winter**	244.2 / 291.0 / 300.8
Detailed Design	
Fuel Type	Natural gas, no secondary fuel
Combustion Controls	Selective Catalytic Reduction (SCR)
Power Augmentation	Spray Intercooling (SPRINT)
Other Project Details	
Location	Harris County
Firm Gas Contract	Yes

Notes and Sources: Confidential data provided by ERCOT staff; Hitachi ABB Velocity Suite, Generating Unit Capacity Dataset, January 22, 2024; Hitachi ABB Velocity Suite, Generating Unit Capacity Dataset, January 22, 2024. ERCOT, “Report on the Capacity, Demand, and Reserves in the ERCOT region (2024–2033),” December 8, 2023. Texas Commission on Environmental Quality, “Issued Air Permits for Gas Turbines 20 MW or Greater,” July 1, 2023.

In determining the **alternative resource**, ERCOT’s objective was to describe a dispatchable renewable plant that is most likely to be developed in the ERCOT Region in the next few years as a basis for sensitivity analyses in applications of CONE. We determined the alternative technology type, turbine model, plant configuration, and location by reviewing plants recently built or planned with a signed interconnection agreement in the ERCOT Region with CODs between 2021 and 2026. This review pointed to a solar photovoltaic + battery energy stationary storage (PV+BESS) hybrid with a 200 MW PV plant paired with a 100 MW, 2-hr BESS. Other representative characteristics are shown in Table 2. The representative storage augmentation frequency was based on a review of similar sized solar hybrid plants and S&L expertise. Brazoria County was the county with the most capacity and was the representative location.

TABLE 2: TECHNICAL SPECIFICATIONS FOR PV + BESS

Technology and Size	
Configuration	Solar PV + Battery Energy Storage System Hybrid (PV+BESS)
PV Capacity (MW)	200
BESS Storage Capacity (MW)	100
Storage Duration (Hours)	2
Detailed Design	
PV Module Technology	Monocrystalline Bi-facial Passivation Emitter Rear Contact (PERC)
PV Tracking System	Single-axis tracker
BESS Technology	Lithium-ion
AC or DC Coupled	AC Coupled
DC / AC Ratio	1.3
Other Project Details	
Location	Brazoria County
Design Life (years)	20

Notes and Sources: ERCOT, "Battery Energy Storage Summary Based on January 2024 Generator Interconnection Status (GIS) Report," February 12, 2024; confidential data provided by ERCOT staff.

It is important to note that specifying these reference characteristics is useful for developing a representative cost of such a plant, but that doing so in no way asserts that such a plant should be built or that other types of plants in other locations should not. Nor does the result of our "revealed preference" approach always show the lowest-cost source of capacity under all conditions. For example, if refurbished turbines become unavailable in the future, developers could switch to other technologies. Those could include, for example, other natural gas-fired combustion turbine technologies, natural gas-fired turbines that can co-fire with hydrogen, "virtual power plants," hybrid PV+BESS plants, or some combination thereof.[11]

B. Process for Selecting Aero CT Reference Resource

We constructed our "Primary Thermal Dataset" of recently built and under construction thermal dispatchable generation with an actual or planned COD between 2021 to 2026 by cross-

[11] See, for example, Ryan Hledik and Kate Peters, "Real Reliability—the Value of Virtual Power," The Brattle Group, May 2023.

referencing confidential data provided by ERCOT and WattBridge with public sources, including Hitachi ABB Velocity Suite (which is primarily based on ERCOT's Generator Interconnection Status report in addition to other sources), ERCOT's 2024 CDR Report, and the Texas Commission on Environmental Quality (TCEQ).[12] Small co-generation or internal combustion (ICE) generation plants were excluded from our sample as these tend to be small or designed for on-site generation and would not be representative of a grid capacity resource. This filtering criteria resulted in fourteen natural gas-fired plants with 5.1 GW of nameplate capacity as shown in Table 3.

TABLE 3: THERMAL DISPATCHABLE GENERATION IN ERCOT (COD 2021 – 2026)

Plant Name	Notes	Technology	Turbine Type	County	Online Date	Number of Units	Nameplate Capacity (MW)
Existing							
Topaz	[1]	Combustion Turbine	GE LM6000	Galveston	10/31/21	10	605
HO Clarke Generating	[2]	Combustion Turbine	GE LM6000	Harris	11/11/21	8	484
Victoria Port Power II	[3]	Combustion Turbine	GE LM6000	Victoria	01/12/22	2	100
Rabbs (Braes Bayou)	[4]	Combustion Turbine	GE LM6000	Fort Bend	05/02/22	8	484
Chamon Power	[5]	Combustion Turbine	GE LM6000	Harris	06/20/22	2	100
Beachwood (Mark One)	[6]	Combustion Turbine	GE LM6000	Brazoria	11/30/22	6	363
Colorado Bend	[7]	Combustion Turbine	GE Frame 6B	Wharton	05/31/23	2	78
Brotman	[8]	Combustion Turbine	GE LM6000	Brazoria	10/23/23	8	484
Planned							
Remy Jade	[9]	Combustion Turbine	GE LM6000	Harris	04/01/24	6	363
Beachwood II (Mark One)	[10]	Combustion Turbine	GE LM6000	Brazoria	06/01/24	2	121
Remy Jade II	[11]	Combustion Turbine	GE LM6000	Harris	11/30/24	4	242
Sibyl	[12]	Combustion Turbine	GE LM6000	Fort Bend	07/01/25	6	300
Elmax	[13]	Combustion Turbine	GE LM6000	Harris	06/01/26	10	605
LongLeaf	[14]	Combustion Turbine	GE LM6000	Angelina	2026	12	726
	[15] = SUM ([1] to [14]) if LM6000			**Total LM6000 Nameplate Capacity (MW)**			**4,977**
	[16] = SUM ([1] to [14])			**Total Dispatchable Generation Capacity (MW)**			**5,055**
	[17] = [15] / [16]			**LM6000 Share of Total Nameplate Capacity (%)**			**98%**

Notes and Sources: Confidential data provided by ERCOT staff; Hitachi ABB Velocity Suite, Generating Unit Capacity Dataset, January 22, 2024; Hitachi ABB Velocity Suite, Generating Unit Capacity Dataset, January 22, 2024. ERCOT, "Report on the Capacity, Demand, and Reserves in the ERCOT region (2024–2033)," December 8, 2023. Texas Commission on Environmental Quality, "Issued Air Permits for Gas Turbines 20 MW or Greater," July 1, 2023.

From this analysis it was clear the technology type and turbine model should be based on a GE LM6000 aeroderivative natural gas-fired plant, given that 98% of the capacity in the Primary Thermal Dataset was from this resource type. The majority of these plants were developed by WattBridge, which all use the same turnkey natural gas-fired plant design (PROENERGY LM6000PC with SPRINT). Therefore, to determine the most representative configuration and

12 Hitachi ABB Velocity Suite, Generating Unit Capacity Dataset, January 22, 2024. ERCOT, "Report on the Capacity, Demand, and Reserves in the ERCOT region (2024-2033)," December 8, 2023. Texas Commission on Environmental Quality, "Issued Air Permits for Gas Turbines 20 MW or Greater," July 1, 2023.

plant capacity, we filtered the Primary Thermal Dataset for planned plants by WattBridge resulting in five plants with 2.1 GW of nameplate capacity shown in Table 4. From this filtering, a 6×0 configuration was selected for the Aero CT based on the median number of turbines of planned WattBridge plants and stakeholder feedback.

TABLE 4: PLANNED THERMAL DISPATCHABLE GENERATION IN ERCOT BY WATTBRIDGE (COD 2023–2026)

Plant Name	Notes	Technology	Turbine Type	County	Online Date	Number of Units	Nameplate Capacity (MW)
Planned							
Remy Jade	[1]	Combustion Turbine	PROENERGY GE LM6000PC with SPRINT	Harris	04/01/24	6	363
Beachwood II (Mark One)	[2]	Combustion Turbine	PROENERGY GE LM6000PC with SPRINT	Brazoria	06/01/24	2	121
Remy Jade II	[3]	Combustion Turbine	PROENERGY GE LM6000PC with SPRINT	Harris	11/30/24	4	242
Elmax	[4]	Combustion Turbine	PROENERGY GE LM6000PC with SPRINT	Harris	06/01/26	10	605
LongLeaf	[5]	Combustion Turbine	PROENERGY GE LM6000PC with SPRINT	Angelina	2026	12	726
	[6] = Median([1] to [5])				**Median**	**6**	**363**

Notes and Sources: Confidential data provided by ERCOT staff; Hitachi ABB Velocity Suite, Generating Unit Capacity Dataset, January 22, 2024; Hitachi ABB Velocity Suite, Generating Unit Capacity Dataset, January 22, 2024. ERCOT, "Report on the Capacity, Demand, and Reserves in the ERCOT region (2024-2033)," December 8, 2023. Texas Commission on Environmental Quality, "Issued Air Permits for Gas Turbines 20 MW or Greater," July 1, 2023.

The net capacity (MW) of each LM6000 unit depends on environmental operating conditions, including the ambient temperature, humidity, altitude, and other factors. To provide a net capacity value for different seasons, S&L estimated the net capacity as: 244 MW at Summer conditions with ambient temperature of 94°F; 291 MW at ISO conditions with ambient temperature of 59°F, and 301 MW at Winter conditions with ambient temperature of 37°F. Table 5 displays the net turbine capacities and the net capacity of the reference Aero CT plant for each season.

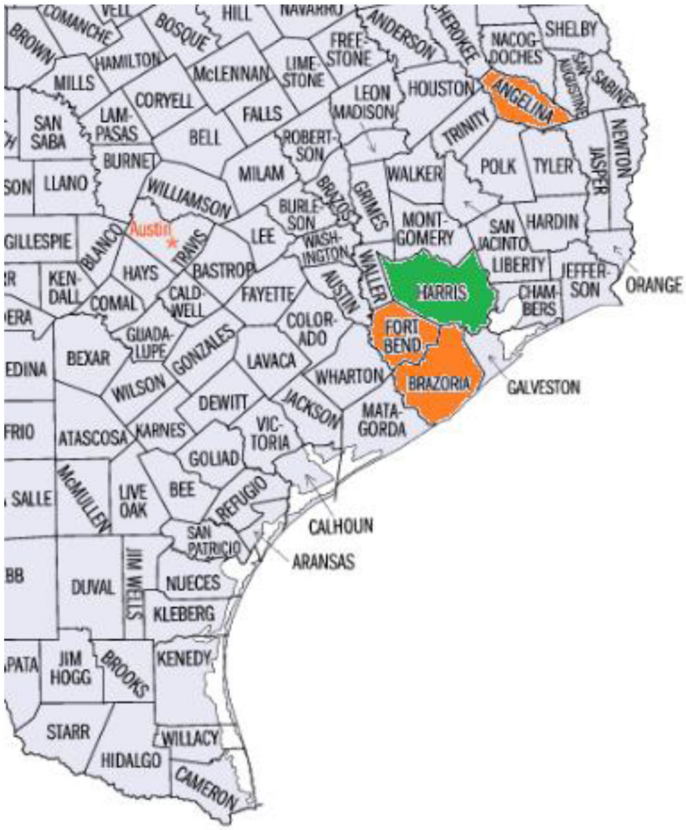
TABLE 5: NET CAPACITY BY SEASONAL CONDITION

Seasonal Condition	Ambient Temperature (°F)	Net Capacity (MW) Turbine	Net Capacity (MW) Plant
Summer	94°F	40.7	244.2
ISO	59°F	48.5	291.0
Winter	37°F	50.1	300.8

Notes and Sources: Data provided by Sargent & Lundy.

We determined the location of the Aero CT based on the county with the most planned natural gas plant capacity from the Primary Thermal Dataset filtered for only planned plants (COD 2023–2026). All of the planned natural gas-fired plants are located in 4 counties in Southeast Texas, with Harris County containing 51%. Harris County was therefore selected as the location for assessing the cost of the reference resource. Figure 1 is a map of the counties where this capacity is planned to be built while Table 6 summarizes the planned natural gas-fired capacity by county.

FIGURE 1: LOCATIONS OF PLANNED GAS-FIRED CAPACITY (COD 2023–2026)



Notes and Sources: Confidential data provided by ERCOT staff; Hitachi ABB Velocity Suite, Generating Unit Capacity Dataset, January 22, 2024; Hitachi ABB Velocity Suite, Generating Unit Capacity Dataset, January 22, 2024. ERCOT, "Report on the Capacity, Demand, and Reserves in the ERCOT region (2024-2033)," December 8, 2023. Texas Commission on Environmental Quality, "Issued Air Permits for Gas Turbines 20 MW or Greater," July 1, 2023.

TABLE 6: LOCATIONS OF PLANNED GAS-FIRED CAPACITY BY COUNTY (COD 2023–2026)

County	Notes	Planned Generation Nameplate Capacity (MW)	Share of Capacity (%)
Harris	[1]	1,210	51%
Angelina	[2]	726	31%
Fort Bend	[3]	300	13%
Brazoria	[4]	121	5%
Total	**[5] = SUM([1]:[4])**	**2,357**	**100%**

Notes and Sources: Confidential data provided by ERCOT staff; Hitachi ABB Velocity Suite, Generating Unit Capacity Dataset, January 22, 2024; Hitachi ABB Velocity Suite, Generating Unit Capacity Dataset, January 22, 2024. ERCOT, "Report on the Capacity, Demand, and Reserves in the ERCOT region (2024-2033)," December 8, 2023. Texas Commission on Environmental Quality, "Issued Air Permits for Gas Turbines 20 MW or Greater," July 1, 2023.

C. Process for Selecting PV+BESS Hybrid Alternative Resource

We constructed our "Primary Solar Hybrid Dataset" by filtering the ERCOT January 2024 GIS Report and confidential duration data provided by ERCOT staff to include only plants that had a storage component and a COD between 2021 and 2026. Table 7 shows this data decomposed into existing capacity and planned capacity with and without a signed Interconnection Agreement (IA).[13] Our alternative reference characteristics are based on plants that have a signed IA as an indicator that the plant is likely to be built than plants without one. There is 20 GW of solar PV capacity across 70 existing and planned plants with signed IAs. While both solar hybrid and standalone storage were prevalent in the interconnection queue, ERCOT agreed to use the solar hybrid because it is dispatchable and produces primary energy.

TABLE 7: COMPARISON OF EXISTING OR PLANNED STORAGE AND GENERATOR CAPACITIES FOR HYBRID AND STANDALONE STORAGE PLANTS IN ERCOT (COD 2021–2026)

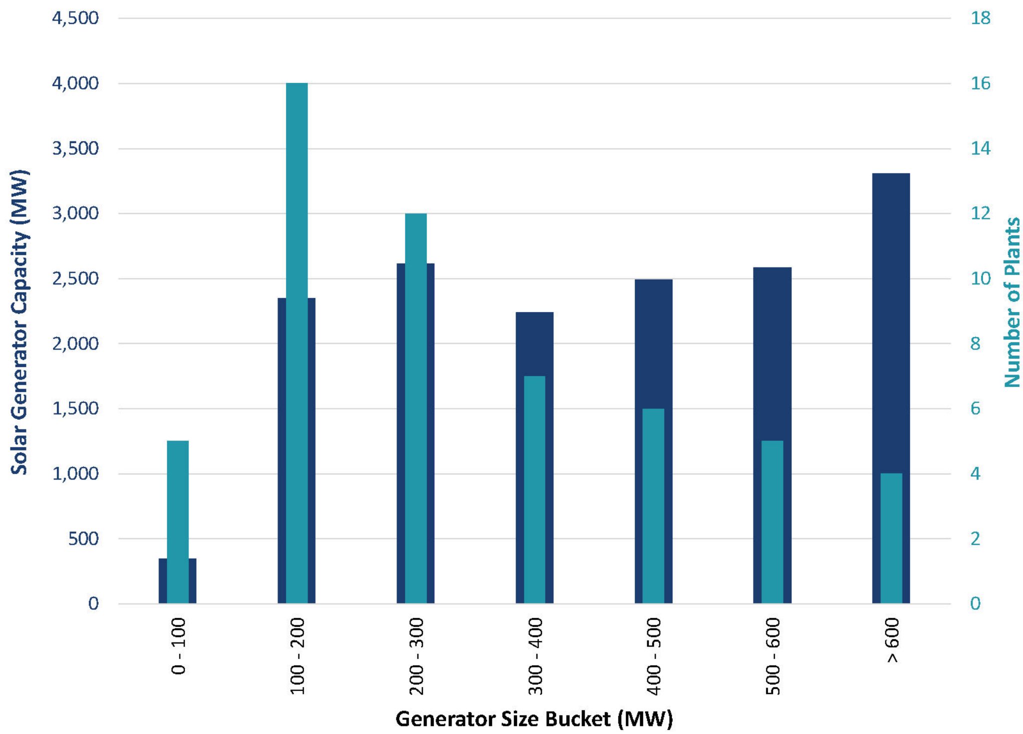
Technology	Notes	Existing		Planned with IA		Planned without IA	
		Storage Capacity (MW)	Generator Capacity (MW)	Storage Capacity (MW)	Generator Capacity (MW)	Storage Capacity (MW)	Generator Capacity (MW)
Solar Hybrid	[1]	1,264	4,214	8,881	15,928	16,736	25,332
Wind Hybrid	[2]	224	698	195	582	100	435
Thermal Hybrid	[3]	263	358	0	0	0	0
Standalone Storage	[4]	2,468	0	13,495	0	64,422	0

Notes and Sources: IA = Interconnection Agreement. [1] to [4]: ERCOT January 2024 GIS Report, and confidential data provided by ERCOT staff.

Next, we filtered the Primary Solar Hybrid Dataset for only planned plants with a signed IA, which resulted in 55 plants with 16 GW of solar capacity. Figure 2 shows a histogram that displays the number of plants (**teal**, right axis) and solar generation portion capacity (**blue**, left axis) for the planned solar hybrid plants. The histogram shows a grouping around 200 MW, with the median generator size of 204 MW. Based on the distribution of solar generator sizes, 200 MW was the representative solar capacity.

[13] ERCOT, "Battery Energy Storage Summary Based on January 2024 Generator Interconnection Status (GIS) Report," February 12, 2024 ("ERCOT January 2024 GIS Report"), and confidential data provided by ERCOT staff.

FIGURE 2: PLANNED ERCOT SOLAR GENERATION CAPACITY AND SOLAR HYBRID PLANT SIZE DISTRIBUTION (COD 2023–2026)



Notes and Sources: ERCOT January 2024 GIS Report, and confidential data provided by ERCOT staff.

To determine the PV module technology, type, and tracking system, we cross-referenced the Primary Solar Hybrid Dataset with confidential solar project data prepared by ERCOT, which resulted in 29 solar hybrid plants with 7.8 GW of solar capacity that overlapped between the two datasets. Based on these 29 solar hybrid plants, 58% of solar hybrid capacity had monocrystalline solar panels, 54% had bifacial solar panels, and 74% had a single-axis tracking system as shown in Table 8. Additionally, S&L reviewed their extensive project database and public sources (Form EIA-860) for ERCOT solar hybrid projects, confirming our results, so the representative PV system was one with monocrystalline and bifacial solar panels with a single-axis tracking system.

TABLE 8: PV TECHNOLOGY CHARACTERISTICS OF EXISTING OR PLANNED SOLAR HYBRID PLANTS (COD 2021–2026)

PV Module Technology	Notes	Plants	Total Capacity (MW)	Share of Capacity (%)
Monocrystalline	[1]	17	4,534	58%
Polycrystalline	[2]	1	601	8%
Thin Film	[3]	3	698	9%
Unknown	[4]	8	1,936	25%
Sum	**[5] = SUM([1]:[4])**	**29**	**7,769**	**100%**

Solar Panel Type	Notes	Plants	Total Capacity (MW)	Share of Capacity (%)
Bifacial	[1]	14	4,174	54%
Not Bifacial	[2]	7	1,659	21%
Unknown	[3]	8	1,936	25%
Sum	**[4] = SUM([1]:[3])**	**29**	**7,769**	**100%**

Tracking System	Notes	Plants	Total Capacity (MW)	Share of Capacity (%)
Single	[1]	21	5,769	74%
Dual	[2]	1	210	3%
Unknown	[3]	7	1,791	23%
Sum	**[4] = SUM([1]:[3])**	**29**	**7,769**	**100%**

Notes and Sources: ERCOT January 2024 GIS Report and confidential data provided by ERCOT staff.

From our Primary Solar Hybrid Dataset (70 plants total), all storage systems are lithium-ion (Li-ion). A comparison of existing solar hybrid and standalone storage plants to future planned plants with signed IAs shows that storage systems are trending to be longer duration and that hybrid systems are trending to have a larger storage-to-solar capacity ratio, as shown in Table 9. Based on this observation, a storage duration of 2 hours and a storage-to-solar capacity ratio of 50% were selected based on the median values for planned solar hybrid plants with a signed IA. Therefore, based on the 200 MW PV generator size, the 50% storage-to-solar capacity ratio resulted in a 100 MW storage capacity for the alternative reference plant.

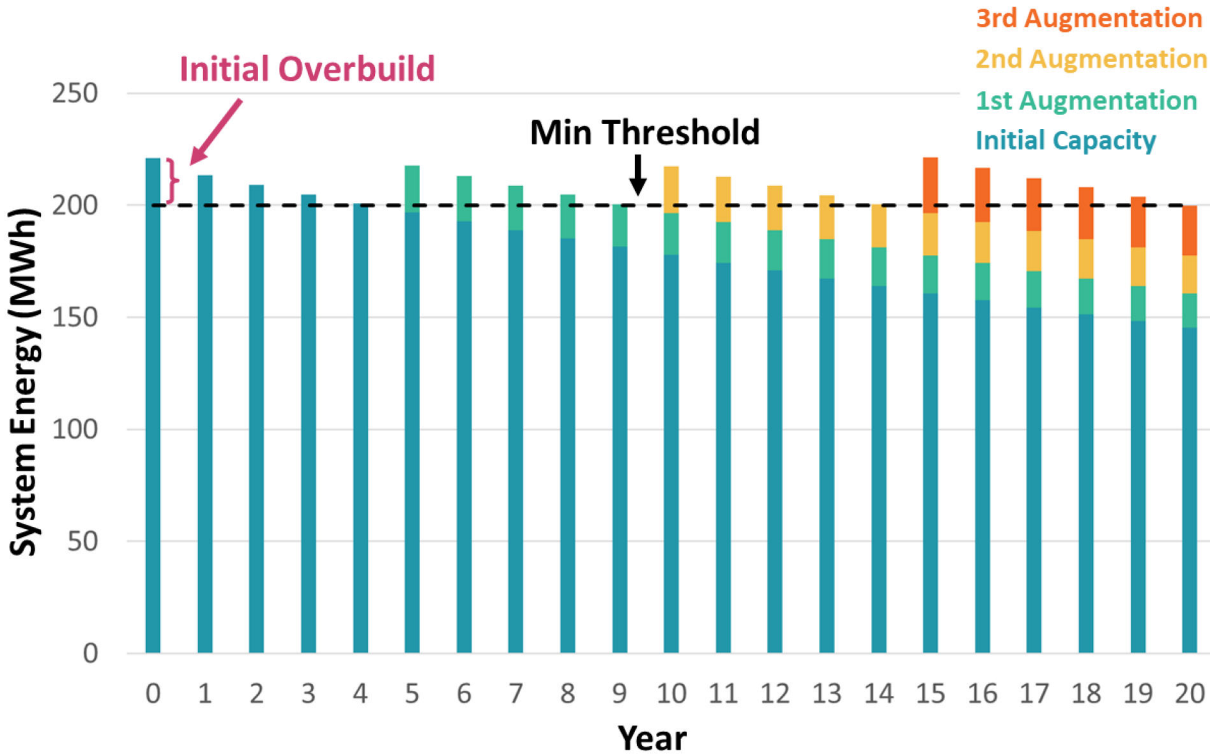
TABLE 9: STORAGE DURATIONS FOR EXISTING OR PLANNED SOLAR HYBRID PLANTS VS. STANDALONE STORAGE IN ERCOT (COD 2021–2026)

Technology	Existing		Planned with IA	
	Median Storage Duration (Hrs)	Median Storage / Solar Capacity Ratio (%)	Median Storage Duration (Hrs)	Median Storage / Solar Capacity Ratio (%)
Solar Hybrid	1.5	34%	2.0	50%
Standalone Storage	1.0		1.1	

Notes and Sources: IA = Interconnection Agreement. ERCOT January 2024 GIS Report, and confidential data provided by ERCOT staff.

Li-ion battery systems degrade due to time, usage, and environmental factors. This degradation impacts the capacity, duration, and efficiency of the storage system, so mitigation techniques are needed to maintain system capabilities as sized for the interconnection and hybrid system (as well as contract and warranty terms). Storage augmentation is a common practice for Li-ion storage systems to manage normal degradation. This entails over-building a fixed percentage of design capacity and over-designing some system components (such as battery module rack space) to later enable battery modules to be added during the project lifetime to offset degradation during normal system operations. An illustrative example of storage augmentation is shown in Figure 3.

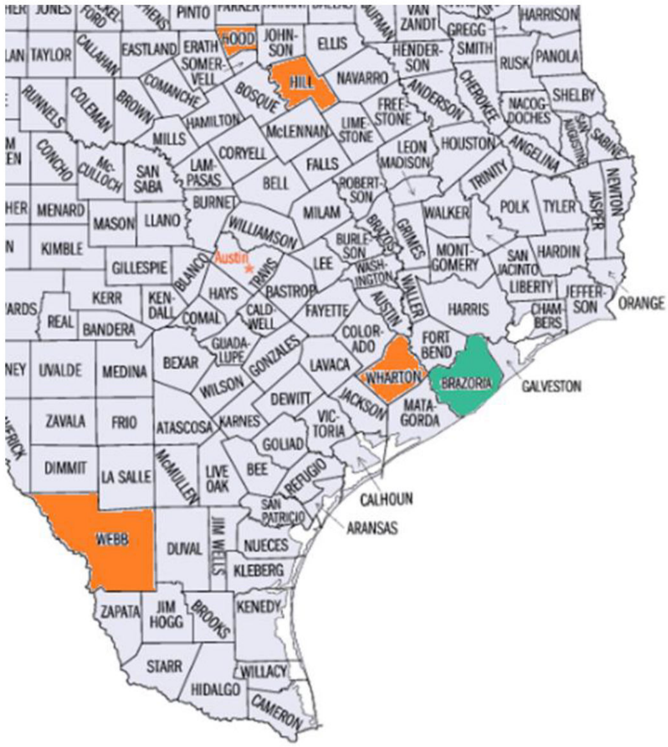
FIGURE 3: ILLUSTRATIVE EXAMPLE OF BESS OVERBUILD AND AUGMENTATION APPROACH



To determine the storage augmentation frequency and overbuild, S&L reviewed financial models from several PV+BESS installations similar to the alternative reference resource and determined the median augmentation period. In the ERCOT Region, solar hybrid plants are currently being designed primarily for ancillary services and increasingly—with penetration of solar PV—for energy shifting. With this understanding, S&L estimated that the battery storage system of the alternative reference plant would be subject to one cycle per day on average over the life of the plant. From this usage profile, S&L predicted annual degradation based on battery manufacturer warranty curves for the anticipated system lifetime and energy throughput, which resulted in an augmentation frequency of every 5 years with an initial overbuild to ensure the energy capacity exceeds the minimum required system output.

To determine the alternative plant location, we reviewed the location of the 16 GW of planned capacity from the Primary Solar Hybrid Dataset and identified that 37% (5.8 GW) of solar generator capacity is in 5 counties. Brazoria County is the county with the most capacity and contains 12% (1.9 GW) of the total, so Brazoria was the reference location. Figure 4 is a map of planned solar hybrid plants in ERCOT and Table 10 displays amount of solar generator capacity in each of these 5 counties compared to the total.

FIGURE 4: LOCATIONS OF PLANNED SOLAR HYBRID PLANTS (COD 2023–2026)



Notes and Sources: [ERCOT January 2024 GIS Report](), and confidential data provided by ERCOT staff.

TABLE 10: LOCATIONS OF PLANNED SOLAR PV CAPACITY BY COUNTY (COD 2023–2026)

County	Notes	Solar Capacity (MW)	Share of Capacity (%)
Brazoria	[1]	1,906	12%
Hill	[2]	1,137	7%
Hood	[3]	1,004	6%
Wharton	[4]	962	6%
Webb	[5]	823	5%
Top 5 County	**[6] = SUM([1]:[5])**	**5,831**	**37%**
Total	**[7]**	**15,928**	

Notes and Sources: ERCOT January 2024 GIS Report, and confidential data provided by ERCOT staff.

III. Bottom-up Costs for Reference and Alternative Resource

A. Aero CT Reference Technology

1. Capital Costs

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; non-EPC or "owner's costs" include development costs, startup costs, interconnection costs, and inventories.

All equipment and material costs were initially estimated by S&L using S&L proprietary data, vendor catalogs, or publications of current nominal prices in April 2024. Labor rates were estimated for the specific counties chosen for the representative and alternative plants. Estimates for the number of labor hours and quantities of material and equipment needed to construct simple-cycle plants are based on S&L experience from similarly sized and configured facilities and are explained in further detail below. Table 11 summarizes the EPC and non-EPC costs for the Aero CT. Each category is explained in the sections below.

TABLE 11: OVERNIGHT CAPITAL COSTS FOR AERO CT, AS OF APRIL 2024

Cost Component	**Units**	**Amount (2024$)**
EPC Costs		
Equipment		
CTG Equipment	$	204,913,000
SCR & CEMS Equipment	$	39,108,000
Other Equipment	$	36,603,000
Construction Labor	$	56,125,000
Other Labor	$	31,845,000
Materials	$	17,081,000
Sales Tax	$	1,281,000
Subtotal - EPC Costs w/o EPC Fee and Contingency	$	386,956,000
EPC Contractor Fee	$	34,826,000
EPC Contingency	$	38,696,000
Total EPC Costs	**$**	**460,478,000**
Non-EPC Costs		
Project Development	$	23,024,000
Mobilization and Start-Up	$	4,605,000
Net Start-up Fuel Costs	$	0
Electrical Interconnection	$	0
Gas Interconnection	$	1,750,000
Land	$	759,000
Non-Fuel Inventories	$	6,907,000
Owner's Contingency	$	3,704,500
Total Non-EPC Costs	**$**	**40,749,500**
Total Overnight Capital Cost		
Total Overnight Capital Cost	**$**	**501,227,500**
Overnight Capital Cost per 244 MW Summer Capacity	$/kW	2,053
Overnight Capital Cost per 291 MW ISO Capacity	**$/kW**	**1,722**
Overnight Capital Cost per 301 MW Winter Capacity	$/kW	1,666

S&L estimated that the EPC contractor fee and contingency costs are 19% of other EPC costs, informed by its extensive experience with actual projects. Similarly, some non-EPC cost line items were based on total EPC costs, including project development (5% of EPC costs), mobilization and startup (1%), and non-fuel inventories (1.5%). Owner's contingency costs were 10% of other non-EPC costs (and this level of contingency costs is expected to be spent on average).

Net start-up fuel costs are assumed to be zero since the revenues gained for production of electricity during testing would offset costs for the Aero CT.[14] S&L reviewed the electrical interconnection costs of similar plants and determined that these costs are well below the generation interconnection threshold allowance established by 16 TAC § 25.195(f) in accordance with Texas House Bill (H.B.) 1500 § 9, therefore electrical interconnection costs of the reference resource would be covered by the allowance.[15] The estimated gas interconnection costs assume a ½ mile lateral at $3.5m/mile based on their expertise and a review of data from the EIA's Capital Cost and Performance Characteristics for Utility Scale Power Generating Technologies.[16] A compression station is not needed because Harris County is one of the most dense natural gas networks in the country that has sufficient access to the gas network at high-enough pressure for CT operation. Estimated land costs are based on a 30-acre land requirement for the Aero CT and a purchase cost of $25,300/acre.[17]

Combustion turbine generator (CTG) costs are the largest single cost line-item accounting for 41% of the total overnight capital cost. This assumed cost is partially driven by the choice of GE's "PC" version of the LM6000 turbine model based on revealed preferences of the actual projects in the interconnection queue, as discussed above.

2. Operations and Maintenance Costs

a. FOM 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 costs. Annual FOM costs increase the CONE and include costs directly related to

[14] Before commencing full commercial operations, new generation equipment 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 the Aero CT based on typical schedule durations and testing protocols for plant startup and commissioning, as observed for actual projects. During testing, a plant will pay for the natural gas commodity and will receive revenues for its energy production. S&L determined that the costs and revenues associated with these activities for the Aero CT would generally offset one another with bands of uncertainty corresponding to the spot fuel prices and real-time energy market offerings at the time of commissioning. For this reason, the net startup fuel costs in the capital cost estimate were assumed to be zero.

[15] *See* Tex. H.B. 1500 § 9, 88th Leg., R.S. (2023) (codified as Public Utility Regulatory Act, TEX. UTIL. CODE § 35.004(d-1) - (d-3)).

[16] U.S. Energy Information Administration, "Capital Cost and Performance Characteristics for Utility Scale Power Generating Technologies," January 2024.

[17] Land & Farm, "Harris County, TX Undeveloped Land for Sale over 20 Acres – Page 1 of 1," Accessed March 8, 2024.

the turbine design (such as labor, materials, contract services for routine O&M, administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance). Table 12 shows the fixed O&M costs by line-item for the Aero CT.

TABLE 12: FIXED O&M COSTS FOR AERO CT, AS OF APRIL 2024

Cost Component	Units	Amount (2024$)
Fixed O&M		
LTSA Fixed Payments	$	511,000
Labor	$	2,413,000
Maintenance and Minor Repairs	$	51,000
Asset Management	$	367,000
Administrative and General	$	166,000
Property Taxes	$	1,585,000
Insurance	$	3,170,000
Firm Gas Contract	$	3,078,000
Total FOM	**$**	**11,341,000**
FOM per 244 MW Summer Capacity	$/kW-yr	46
FOM per 291 MW ISO Capacity	**$/kW-yr**	**39**
FOM per 301 MW Winter Capacity	$/kW-yr	38

S&L reviewed the expected emissions rate for the reference Aero CT based on similar plant designs and determined that the selective catalytic reduction system (accounted for in capital costs) would be sufficient to meet existing air emissions standards at no additional FOM cost. Property taxes and insurance costs are based on overnight capital costs, where insurance is 0.6% and property taxes are assumed to be 0.3% of overnight costs based on S&L's experience with projects. Similarly, maintenance and minor repairs are estimated at 10% of LTSA fixed costs. Firm gas contract costs were estimated from an analysis of firm fuel costs at existing and planned WattBridge facilities.

Insurance and firm gas contract costs are the largest line items collectively resulting in 55% of annual FOM costs. Labor and property taxes are the next largest line items while maintenance and administrative costs are just 2% of annual FOM costs.

b. Variable O&M (VOM) Costs

VOM costs are not used in calculating CONE, but they are inputs for modeling the operation and revenues of the reference resource, whether in tracking the PNM, or evaluating the reliability standard, estimating MERM and EORM, or developing a PCM demand curve. VOM costs are directly proportional to plant generating output, such as Selective Catalytic Reduction (SCR) catalyst and ammonia, carbon monoxide oxidation catalyst, water, and other chemicals and consumables. Table 13 summarizes the VOM costs for the Aero CT. The majority of VOM costs (over 90%) are due to major maintenance.

TABLE 13: VARIABLE O&M COSTS FOR AERO CT, AS OF APRIL 2024

Cost Component	Units	Amount (2024$)
Variable O&M		
VOM in Summer	**$/MWh**	**9.00**
Major Maintenance - Hours Based	$/MWh	8.26
Consumables, Waste Disposal, and Other VOM	$/MWh	0.74
VOM at ISO Conditions	**$/MWh**	**7.66**
Major Maintenance - Hours Based	$/MWh	6.93
Consumables, Waste Disposal, and Other VOM	$/MWh	0.73
VOM in Winter	**$/MWh**	**7.44**
Major Maintenance - Hours Based	$/MWh	6.71
Consumables, Waste Disposal, and Other VOM	$/MWh	0.73

B. PV+BESS Hybrid Reference Technology

1. Capital Costs

All equipment and material costs were initially estimated by S&L in 2024 dollars using proprietary data, vendor catalogs, or publications. Table 14 shows the EPC and non-EPC costs for the PV+BESS.

TABLE 14: CAPITAL COSTS FOR PV + BESS, AS OF APRIL 2024

Cost Component	Units	Amount (2024$)
EPC Costs		
PV Module Supply	$	70,963,000
PV Inverter Supply	$	14,735,000
PV Racking, Tracker and BOP Equipment Supply	$	63,741,000
Batteries and Enclosures	$	82,125,000
BESS BOP Equipment Supply	$	10,686,000
Main Power Transformer & Substation	$	8,610,000
Construction and Installation	$	35,095,000
SCADA Subcontract	$	1,220,000
Civil/Structural/Architectural Subcontract	$	18,353,000
Subtotal - EPC Costs w/o EPC Fee and Contingency	$	305,528,000
EPC Contractor Fee	$	15,276,400
EPC Contingency	$	16,040,000
Total EPC Costs	**$**	**336,844,400**
Non-EPC Costs		
Project Development	$	16,842,220
Mobilization and Start-Up	$	3,368,444
Electrical Interconnection	$	0
Owner's Contingency	$	2,021,000
Subtotal - Non-EPC Costs w/o Financing Fees	$	22,231,664
Financing Fees	$	0
Total Non-EPC Costs	**$**	**22,231,664**
Total Overnight Capital Cost		
Total Overnight Capital Cost	**$**	**359,076,064**
Overnight Capital Cost per 200 MW Plant Capacity	**$/kW**	**1,795**

S&L estimated that the EPC contractor fee is 5% of other EPC costs and the EPC contingency is 5% of other EPC costs plus the contractor fee. Contractor fees and contingency costs are proportionally lower for the PV+BESS (~10% of total EPC costs vs. 19% of total EPC costs for the Aero CT) because EPC is less risky for the PV+BESS technology type. Similar to the reference thermal plant, owner's contingency costs are 10% of other non-EPC costs, project development is 5% of EPC costs, and mobilization and start-up costs are 1% of EPC costs.

Nearly 70% of capital costs comes from PV and BESS equipment supply costs, even though these cost components have enjoyed steep cost declines over the past several years (other than a temporary increase in about 2022). On a per-kW basis, PV modules are $355/kW whereas BESS is $928/kW or $464/kWh for a 2-hour battery.[18] Construction and installation costs are about 10% of the overnight capital cost and project development costs are responsible for 75% of non-EPC costs.

2. Operations and Maintenance Costs

a. FOM Costs

As a dispatchable renewable resource, the PV+BESS incurs FOM costs that differ from the Aero CT. For example, the PV+BESS does not have a firm gas contract, but it does have a higher cost for scheduled and unscheduled maintenance. Table 15 shows the FOM costs for the PV+BESS.

TABLE 15: FIXED O&M COSTS FOR PV + BESS, AS OF APRIL 2024

Cost Component	Units	Amount (2024$)
Fixed O&M		
Maintenance (scheduled and unscheduled)	$/year	4,370,000
Land Lease	$/year	700,000
Property Taxes	$/year	2,154,000
Insurance	$/year	1,077,000
Total FOM (without augmentation)	**$/year**	**8,301,000**
FOM per 200 MW Plant Capacity	**$/kW-yr**	**41.5**

Maintenance costs are the largest cost category, comprising over half of total FOM costs. Land lease costs are based on a lease cost of $500 per acre, and 1,400 acres needed.[19] Property taxes and insurance costs, as with the Aero CT, are based on 0.3% and 0.6% of overnight capital costs respectively. Overall, FOM costs are $42/kW-year before augmentation costs are considered.

The costs of augmentation to counter degradation of the battery system, as described in Section II.C above, are included in two ways, as: (1) FOM based on an annualized cost of storage augmentation over the project lifetime; and (2) overnight capital cost based on the additional

18 BESS equipment includes the 'Batteries and Enclosures' and 'BESS BOP Equipment Supply' line items.

19 Land & Farm, "Brazoria County, TX Undeveloped Land for Sale over 20 Acres – Page 1 of 1," Accessed March 8, 2024.

balance of plant equipment (e.g., reserved rack space and conductors) included in the initial construction to accommodate future augmentation.

S&L estimated that 28 MWh of augmentation were required every five years after the COD for the battery to maintain its 100 MW/2-hour duration capacity throughout the 20-year economic life of the PV+BESS.[20] S&L also estimated that unit augmentation costs (in $/kWh) are $313/kWh in April 2024, which are then escalated over time based on the moderate case for the overnight capital cost trajectory for 2-hour BESS from the National Renewable Energy Laboratory's 2023 Annual Technology Baseline (2023 NREL ATB).[21] Based on these cost declines, the nominal augmentation costs (at the time of the midpoint construction date) are $4.8 million in 2031 and decline to $4.1 million by 2041. Table 16 illustrates the levelized first-year augmentation cost for the PV+BESS.

TABLE 16: LEVELIZED AUGMENTATION COSTS FOR PV + BESS

Cost Component	Units	Quantity
Augmentation		
Year 5 Costs (2031)	Nominal $	$4,773,294
Year 10 Costs (2036)	Nominal $	$4,440,332
Year 15 Costs (2041)	Nominal $	$4,105,957
Present Value of Augmentation Cost	Nominal $	$5,247,563
Capital Charge Rate	%	12.1%
Levelized Augmentation Cost	Nominal $/yr	$633,446
Levelized Augmentation Cost per 200 MW Plant Capacity	**Nominal $/kW-yr**	**$3.2**

Notes and Sources: 2023 NREL ATB.

Next, the present value of augmentation costs is based on the augmentation schedule and the 10.35% ATWACC. The levelized cost for the first year is then calculated by multiplying the first-year augmentation cost with the capital charge rate for the PV+BESS and obtaining the nominal $/kW-yr cost by dividing the levelized cost by the PV capacity.

20 Based on its 2026 online date and 20-year life, the battery augmentations for the PV+BESS occur in 2031 ("Year 5"), 2036 ("Year 10") and 2041 ("Year 15").

21 National Renewable Energy Laboratory, "2023 Electricity ATB Technologies and Data Overview," Accessed May 27, 2024 ("2023 NREL ATB").

C. Comparison to 2024 EIA Cost Benchmark

To validate the estimated capital costs for the Aero CT, we compared unit capital costs with recent estimates of a similar natural gas-fired plant. In January 2024, S&L prepared a report for the EIA detailing cost and performance estimates for numerous types of electric generators.[22] The 4×0 Aeroderivative CT natural gas plant (211 MW of capacity) with LM6000PF turbines is the closest to our reference resource and serves as a basis for comparison. Table 17 below compares the unit overnight costs of the Aero CT with the LM6000PF EIA reference plant.

TABLE 17: COMPARISON TO EIA BENCHMARK

	Units	EIA	This Study	Difference
Reference Plant	2024$/kW	4x0 LM6000PF	6x0 LM6000PC	
Total EPC Costs	2024$/kW	$1,435	$1,596	$161
Total Non-EPC Costs	2024$/kW	$226	$147	-$79
Overnight Capital Costs	**2024$/kW**	**$1,661**	**$1,743**	**$82**

Notes and Sources: EIA, "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies," January 2024.

Our estimated overnight capital costs for the Aero CT are $82/kW higher than the LM6000PF EIA reference plant. EPC costs are $161/kW higher because PF models deliver ~13% more power (MW) for a relatively small cost premium on the turbines themselves as compared to PC models. Yet non-EPC costs are $79/kW lower because our bigger (2 units more) Aero CT benefits from economies of scale on non-EPC costs, and our Aero CT has much lower interconnection costs due to the allowance afforded by Texas H.B. 1500. Additionally, our reference Aero CT does not include costs for compression due to the widespread availability of high-pressure gas pipelines in Harris County. By contrast, the reference LM6000PF EIA reference plant assumes $2.4 million in electrical interconnection costs and $2.2 million in compression station costs.

22 EIA, "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies," January 2024.

IV. CONE for Reference and Alternative Resources

A. CONE Results

1. LM6000 Plant CONE

As explained in Section I.B above, the levelized CONE reflects the annual net revenues a new generation resource needs to earn on average to cover its capital investment and annual fixed costs, given reasonable expectations about future cost recovery over its economic life. Table 18 summarizes the levelized capital cost, FOM and CONE for the Aero CT 6×0 LM6000 reference plant for a June 1, 2026 online date.

TABLE 18: CONE CALCULATION FOR AERO CT, JUNE 2026 ONLINE DATE

				6x0 LM6000
[1]	**Capacity at ISO conditions**	*MW*		**291**
	Capital Costs			
[2]	Overnight Cost	*Nominal $ million*		$513
[3]	Overnight Cost	*Nominal $/kW*	= [2] x 1000 / [1]	$1,764
[4]	Capital Charge Rate	*%*		14.0%
[5]	Levelized Capital Cost	*Nominal $/kW-yr*	= [3] x [4]	$246
	O&M Costs			
[6]	First Year FOM	*Nominal $ million/yr*		$12
[7]	Levelized FOM	*Nominal $/kW-yr"*		$47
[8]	**Levelized CONE**	***Nominal $/kW-yr***	= [5] + [7]	**$293**

Overnight cost is the cost of all the inputs in April 2024, escalated to middle of the construction period and expressed in nominal dollars. Installed cost includes overnight cost plus the cost of capital between construction and the online date. Our CONE estimate is calculated based on a 10.35% nominal ATWACC and accounts for both taxes and depreciation.

The capital charge rate (14%) is fairly high because of the 10.35% ATWACC, combined with 20-year level-nominal approach. Nearly half of the CONE comes from turbine equipment costs, and 20% of the CONE comes from labor costs.

2. PV+BESS Hybrid CONE

Table 19 summarizes the levelized capital cost, FOM, Augmentation and CONE for the solar hybrid alternative reference resource for a June 1, 2026 online date.

TABLE 19: CONE CALCULATION FOR PV + BESS, JUNE 2026 ONLINE DATE

				PV + BESS
[1]	**Plant Capacity**	*MW*		**200**
	Capital Costs			
[2]	Overnight Cost	*Nominal $ million*		$349
[3]	Overnight Cost	*Nominal $/kW*	= [2] x 1000 / [1]	$1,743
[4]	Capital Charge Rate	*%*		12.1%
[5]	Levelized Capital Cost	*Nominal $/kW-yr*	= [3] x [4]	$210
	O&M Costs			
[6]	First Year FOM	*Nominal $ million/yr*		$9
[7]	Levelized FOM	*Nominal $/kW-yr*		$49
[8]	Levelized Augmentation	*Nominal $/kW-yr*		$3
[9]	**Levelized CONE**	***Nominal $/kW-yr***	= [5] + [7] + [8]	**$263**

As shown below, PV and BESS equipment costs were escalated at a negative nominal rate because the magnitude of real cost declines for these components exceed inflation. Remaining capital cost line-items were escalated at the rate of inflation. Roughly two-thirds of the CONE for the solar hybrid plant comes from PV and BESS equipment costs.

We assumed that BESS equipment costs are eligible for the 30% ITC while PV opts for the PTC. The ITC reduces the PV+BESS CONE estimation by $18/kW-year, but the PTC does not since it enhances energy and ancillary services revenues instead.

B. Escalation to 2026 Costs

We escalated the overnight capital and FOM cost estimates as of April 2024 provided by S&L using a three-step process: (1) establish a midpoint construction date for both the Aero CT and PV+BESS; (2) estimate appropriate cost escalation rates based on short-term inflation and real cost declines; and (3) escalate costs for each line item to the midpoint of the construction period. This approach translates overnight capital and FOM costs forward into a future estimate of costs in nominal terms at the midpoint of construction using cost escalation rates particular to each cost category and technology.

Later we applied the capital drawdown schedules to calculate debt and equity costs during construction to arrive at a complete installed cost to derive CONE. The installed cost for each technology was calculated by first applying the monthly construction drawdown schedule for the project to the nominal overnight capital costs and then calculating 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 the present value, the installed costs will include the full cost of capital of the project during construction, reflecting the riskiness of the future cash flows for which the construction dollars are being spent to earn.

In the first step we established the midpoint construction date for both resources using capital drawdown schedules provided by S&L for the Aero CT and PV+BESS. The capital drawdown schedule shows the cash flow by construction month, months needed for construction, and months needed to achieve a 50% capital drawdown for both resources (the "midpoint construction date"). The Aero CT has a 30-month construction period, with its midpoint construction date occurring 19 months after breaking ground. Working backwards from a June 2026 COD, construction would have started in December 2023 and the midpoint construction date would be July 2025. Thus, the 2024 cost estimates from S&L for the Aero CT were escalated over a 15-month period from April 2024 to July 2025. The PV+BESS has a midpoint construction date at October 2025 so the 2024 cost estimates were escalated over an 18-month period from April 2024 to October 2025.[23]

In the second step, we estimated monthly cost escalation rates based on short-term inflation and real cost declines forecasted by NREL. The annual inflation rate is 3.0% in 2024 and 2.3% in 2025 based on forecasts of the Consumer Price Index (CPI) from Wolters Kluwer.[24] For each resource, a blended monthly inflation rate is used based on the number of escalation months to arrive at the midpoint of the construction period. This results in a monthly inflation rate of 0.23% for the

[23] The PV+BESS has 16-month construction period with its midpoint construction date happening eight months after breaking ground. Working backwards from a June 2026 COD, construction would have started in February 2025 and the midpoint construction date would be October 2025.

[24] Wolters Kluwer, "Blue Chip Economic Indicators," Accessed May 3, 2024.

Aero CT and 0.22% for the PV+BESS.[25] Then real cost declines were calculated for technology-specific cost components in the NREL ATB. For the Aero CT, the moderate case from the 2023 ATB projects that per kW capital costs of an aeroderivative gas-fired plant will decline by 0.8% per year (0.07% per month) in real terms in the 2024–2025 timeframe.[26] For the PV+BESS, per kW capital costs decline at 5.7% per year (0.27% per month) over the same timeframe. The nominal near-term cost escalation rates (0.16% for the Aero CT and -0.27% for the PV+BESS) were calculated by adding the monthly real cost decline rates to the monthly inflation rates to derive the nominal near-term cost escalation rates for capital costs.

For the third step, overnight capital and FOM costs for each line item are escalated to the midpoint of the construction period. The nominal near-term cost escalation rates were only applied to capital cost components that would be subjected to the real cost declines estimated by NREL while the remaining line-items are escalated by inflation only, as follows:

- For the Aero CT the 0.16% nominal monthly cost escalation rate was applied only to EPC capital costs (turbine equipment, emissions systems, other equipment, construction labor, other labor, and materials).
- For the PV+BESS the −0.27% nominal monthly escalation rate was applied to EPC capital costs for PV or BESS components (batteries and enclosures equipment, BESS balance of plant, and PV modules, inverters, racking, and balance of plant equipment); other EPC costs (main power transformers & substation, construction/installation, SCADA subcontract, and professional services contracts) were escalated only at the monthly inflation rates discussed above.
- For both the Aero CT and the PV+BESS, FOM and non-EPC capital costs were escalated only using the monthly inflation rates.[27]

Table 20 and Table 21 show the escalated capital costs and O&M costs for the Aero CT, while Table 22 and Table 23 show the escalated capital costs and O&M costs for the PV+BESS.

[25] For the Aero CT, the midpoint of construction is July 2025, which has nine months occurring in 2024 and six months in 2025 from April 2024. Based on this timeframe and the established annual inflation rates, the blended nominal inflation rate is 3.44% over this period that results in a nominal monthly inflation rate of 0.23%. For the PV+BESS, the midpoint of construction is October 2025, which has nine months occurring in 2024 and nine months in 2025 from April 2024. The blended total nominal inflation rate is 4.04% over this period that results in a nominal monthly inflation rate of 0.22%.

[26] 2023 NREL ATB.

[27] For more details, see the "Supporting Analysis" section of the public ERCOT CONE model accompanying this report.

TABLE 20: CAPITAL COSTS FOR AERO CT RESOURCE (NOMINAL$)

Capital Costs (in $millions)	6x0 LM6000 Harris County *291 MW*
EPC Costs	
Equipment	
CTG Equipment	$209.8
SCR & CEMS Equipment	$40.1
Other Equipment	$37.5
Construction Labor	$57.5
Other Labor	$32.6
Materials	$17.5
Sales Tax	$1.3
EPC Contractor Fee	$35.7
EPC Contingency	$39.6
Total EPC Costs	$471.6
Non-EPC Costs	
Project Development	$23.6
Mobilization and Start-Up	$4.7
Net Start-Up Fuel Costs	$0.0
Electrical Interconnection	$0.0
Gas Interconnection	$1.8
Land	$0.8
Non-Fuel Inventories	$7.1
Owner's Contingency	$3.8
Total Non-EPC Costs	$41.8
Total Capital Costs	**$513.3**
Overnight Capital Costs ($million)	**$513**
Overnight Capital Costs per 291 MW ISO Capacity	**$1,764**
Installed Capital Costs per 291 MW ISO Capacity	**$1,934**

Note: All costs are shown in nominal$ and based on ISO capacity conditions.

TABLE 21: OPERATIONS & MAINTENANCE COSTS FOR AERO CT RESOURCE (NOMINAL$)

O&M Costs	6x0 LM6000 Harris County
Fixed O&M ($ million)	
LTSA Fixed Payments	$0.5
Labor	$2.5
Maintenance and Minor Repairs	$0.1
Administrative and General	$0.2
Asset Management	$0.4
Property Taxes	$1.6
Insurance	$3.2
Firm Gas Contract	$3.2
Total FOM	**$11.7**
FOM per 291 MW ISO Capacity ($/kW-yr)	**$40.2**
Variable O&M ($/MWh)	
Total Variable O&M ($/MWh)	**$7.92**
Major Maintenance - Hours Based	7.17
Consumables, Waste Disposal, Other VOM	0.76

Note: All costs are shown nominal$ and based on ISO capacity conditions.

TABLE 22: CAPITAL COSTS FOR PV + BESS RESOURCE (NOMINAL$)

Capital Costs (in $millions)	PV + BESS Brazoria County *200 MW*
EPC Costs	
BESS Equipment	
Batteries and Enclosures	$78.2
PCS and BOP Equipment	$10.2
PV Equipment	
Module Supply	$67.6
Inverter Supply	$14.0
Racking, Tracker and BOP	$60.7
Main Power Transformer	$9.0
Construction	$36.5
SCADA Subcontract	$1.3
Architectural Subcontract	$19.1
EPC Contractor Fee	$14.8
EPC Contingency	$15.6
Total EPC Costs	**$327.0**
Non-EPC Costs	
Project Development	$16.3
Mobilization and Start-Up	$3.3
Owner's Contingency	$2.0
Total Non-EPC Costs	**$21.6**
Total Capital Costs	**$348.6**
Overnight Capital Costs ($million)	**$349**
Overnight Capital Costs per 200 MW Plant Capacity	**$1,743**
Installed Capital Costs per 200 MW Plant Capacity	**$1,864**

Note: All costs are shown nominal$ in terms of only the PV capacity of the hybrid plant.

TABLE 23: OPERATIONS & MAINTENANCE COSTS FOR PV + BESS RESOURCE (NOMINAL$)

O&M Costs (in $millions)	**PV + BESS** **Brazoria County** *200 MW*
Fixed O&M Cost Components	
Maintenance	$4.5
Land Lease	$0.7
Property Taxes	$2.1
Insurance	$1.0
Total FOM (without augmentation)	**$8.4**
FOM without augmentation per 200 MW plant capacity ($/kW-yr)	**$42.1**
Augmentation Cost Components	
Year 5 Costs (2031)	**$4.8**
Year 10 Costs (2036)	**$4.4**
Year 15 Costs (2041)	**$4.1**
Levelized augmentation cost per 200 MW plant capacity ($/kW-yr)	**$3.2**
FOM with augmentation per 200 MW plant capacity ($/kW-yr)	**$45.2**

Note: All costs are shown nominal$ and in terms of only the PV capacity of the hybrid plant.

C. Economic Life and Levelization Approach

To provide a benchmark of how high prices have to be to support entry, CONE is calculated as the first-year net revenues a resource owner would expect to earn in order to be willing to enter the market. CONE is calculated from the installed costs and FOM cost, the shape and timeframe of the projected future net revenue trajectory, and the risk-appropriate cost of capital. The CONE calculation requires a levelization "shape" and economic lifetime to be established for both resources. Although new natural gas-fired plants can physically operate for 30 years or longer, developers commonly express a preference to recover their capital in 20 years, and this is taken as the economic life. The PV+BESS CONE calculation also assumes a 20-year economic life based on S&L's review of a representative degradation profile and warranty terms typically offered by Original Equipment Manufacturers (OEMs).

We adopted the commonly used "level-nominal" levelization approach for both the Aero CT and PV+BESS, which reflects a view that future net revenues remain constant on average in nominal terms. A level-nominal approach assumes net revenues decline in real terms by the rate of inflation, due to continued improvements in costs and performance. This is because future entrants will have increasingly competitive costs that will set market prices lower and reduce the revenues of a plant built today. As discussed above, NREL projects that per-kW capital costs of an aeroderivative gas-fired plant will decline by 0.8% per year in real terms, as turbines increase in size and have better economics of scale. That plus assumed performance improvements suggests that the assumed 2.2% real decline rate is reasonable (i.e., constant in nominal terms, with a long-term inflation rate of 2.2%).

For the PV+BESS alternative resource, technology progress is so rapid that a new entrant would likely need a more front-loaded revenue recovery to compensate for sharply decreasing revenues due to competition of future entrants. Based on the long-term real decline rate from NREL of 3.0% over the next 20 years, one could adopt a steeper levelization, but we approximated with level-nominal since that already assumes a 2.2% real decline.[28] This approach was agreed to by ERCOT and is consistent with Brattle's approach to estimating CONE for PJM in 2022.[29]

D. ATWACC and Financial Assumptions

1. Development of ATWACC

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 counting interest payments in cash flows or deducting it from taxable income) using an after-tax weighted-average cost of capital (ATWACC).[30] The ATWACC reflects the systemic financial market risks of the project's future cash flows and is used to derive the first-year revenue requirement. Our ATWACC methodology, which has been used consistently for many years in Brattle's work involving CONE

[28] The long-term escalation rate for the PV+BESS was calculated from estimates of annual real cost declines from the NREL ATB for a utility-scale PV and a 2-hour BESS. First, the unitary ($/kW) cost trajectories for PV and 2-hour BESS were summed together to calculate the real escalation rate of the combined resource which has the same capacity as the alternative resource (200 MW PV + 100 MW BESS). Then the long-term equivalent cost escalation rate from 2025 to 2050 was calculated by determining the fixed cost decline rate that results in the same NPV as the variable cost decline rates from the previous step at the real ATWACC. The real ATWACC was calculated as: 8.0% = ((1 + 10.35%) / (1 + 2.2%)) − 1. See 2023 NREL ATB.

[29] Newell, et al., "PJM CONE 2026/2027 Report," April 21, 2022.

[30] 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).

estimations and cost of capital for merchant generation before regulators, is derived from a transparent, highly vetted approach and market-based evidence.[31]

ERCOT agreed for this CONE study to leverage Brattle's 2022 ATWACC estimate for merchant generation in PJM and to adjust it to account for: (1) ERCOT-specific state corporate income tax; and (2) changes in the risk-free rate. The previous estimate was an 8.85% ATWACC for a new entry plant in PJM based on an as-of date of August 31, 2022.[32]

To make our ATWACC reflective of ERCOT conditions for the present study, we first adjusted for the difference in corporate income tax rates. In place of a corporate income tax, Texas issues a gross receipts tax that can range from 0.331% to 0.75%.[33] The approximate midpoint of the gross receipts tax (0.5%) was used as a proxy for corporate tax in ERCOT. Reducing the state tax rate from 8.5% (PJM) to 0.5% (ERCOT) leads to a 21.4% combined tax rate and increases the ATWACC by 22 bps to 9.07%, reflecting a less valuable debt-tax shield. Although the lower tax rate raises the ATWACC, it also lowers tax liabilities accounted for in the cash flows in the CONE model, resulting in a lower CONE overall, as one would expect.

The second adjustment was to update the ATWACC for the prevailing risk-free rate based on a 15-day average of the 20-year treasury bond yield. For PJM the risk-free rate was 3.43% as of August 31, 2022.[34] For this analysis, we selected the as-of date to be April 19, 2024, which resulted in a risk-free rate of 4.69%, or 126 bps higher than when the base ATWACC was estimated. Adding the 126-bps increase in the risk-free rate to the ATWACC results in 10.33%, which was rounded up to a final ATWACC of 10.35%.[35]

[31] For a full description of the ATWACC estimation approach see, Newell, et al., "PJM CONE 2026/2027 Report," April 21, 2022.

[32] Only the ATWACC, not the components, affect CONE, but we presented the following components consistent with the ATWACC and with prevailing capital structures and rates: D/E ratio of 55/45, a cost of debt of 6.3% and a cost of equity of 14.1%. ATWACC = 6.3% × 55% × (1 – 27.2%) + 14.1% × 45% = 8.85%, where 27.2% (= 8.5% + (1 – 8.5%) × 21%) is the combined federal-state tax rate, with 8.5% state taxes deductible for federal taxes. See Wright & Talisman, "Docket No. ER22-2984-000: Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters," September 30, 2022.

[33] Tax Foundation, "Gross Receipts Taxes by State, 2022," Accessed May 27, 2024.

[34] FRED, "Market Yield on U.S. Treasury Securities at 20-Year Constant Maturity, quoted on an Investment Basis," Accessed April 23, 2024.

[35] The Brattle Group is currently conducting a fully updated study of ATWACC for PJM, which may result in a different value from the simple adjustment agreed upon with ERCOT.

Although recommended financing components are specified, only the ATWACC impacts the CONE calculation, not the individual components of ATWACC, since these are inter-related and cannot be estimated in isolation.[36]

Some stakeholders mentioned that there could be higher, non-diversifiable risk in ERCOT versus PJM due to the market regulatory environment that could warrant a 100 bps risk premium adder, which would result in an ATWACC of 11.35%. We do not adopt this as our base case but do show the implications for CONE in the sensitivity analyses in Section IV.E.

2. Other Financial Assumptions

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

As discussed above, annual inflation was based on forecasts from Wolters Kluwer' Blue Chip Economic Indicators.[37] Based on consensus forecasts, the annual inflation rates are 3.0% in 2024, 2.3% in 2025, and 2.2% in 2026 and going forward. Income tax rates affect both the cost of capital and cash flows in the financial model used to calculate CONE. Income tax rates were based on the current federal tax rate of 21% and the 0.5% gross receipts tax proxy for Texas state income tax rate discussed previously.

Depreciation for CONE was calculated 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 a 20% bonus depreciation in the first year of service, which decreases CONE by $5/kW-year relative to no

[36] This is derived from two fundamental principles of corporate finance: Modigliani and Miller (MM) Theorems I and II. Simply put, MM Theorem I states that a project's value or its overall cost of capital is determined by the use of the capital (i.e., the overall risk of the project), not the source of the capital (i.e., not the parties funding the investment). In addition, MM Theorem II states that a company's cost of debt and cost of equity both increase with the amount of debt relative to the value of the project ("financial leverage"). Because a project's overall business risk is not affected by financial leverage (at least not within a reasonable range of capital structures), the increases in the cost of equity and cost of debt associated with financial leverage are largely offset by the change in relative weights of debt and equity such that the overall weighted-average cost of capital is approximately constant. The original MM result holds in a perfect capital market with no taxes, no bankruptcy costs, no information barriers, and other assumptions. Numerous subsequent theoretical and empirical studies have shown that the basic MM theorem is robust to relaxations of their restrictive assumptions, and financing decisions usually have a secondary impact on a company's or a project's value or cost of capital. In other words, a company's cost of capital is largely constant for a broad range of capital structures within the same industry. See Brealey, Myers & Allen, "Principles of Corporate Finance (10th Ed.), Chapter 17, 2009 and F. Modigliani and M. H. Miller, "The Cost of Capital, Corporation Finance and the Theory of Investment," American Economic Review 48, June 1958, pp. 261–297.

[37] Wolters Kluwer, "Blue Chip Economic Indicators," Accessed May 3, 2024.

bonus depreciation. The bonus depreciation phases out completely by the following year.[38] The Modified Accelerated Cost Recovery System (MACRS) was applied to the remaining depreciable costs (i.e., 20% bonus depreciation, 80% MACRS).

The annual value of depreciation was calculated using the depreciable basis for the Aero CT or PV+BESS, relevant MACRs schedule, and bonus depreciation. For both resources, depreciable costs are the sum of depreciable assets and interest during construction.[39] The Aero CT used the 15-year MACRS for a second quarter in-service date due to the assumed June 2026 COD.[40]

We calculated depreciation differently for the PV + BESS to account for a shorter depreciation period used by developers and the impacts that the section 48 Investment Tax Credit ("ITC") has on depreciable costs.[41] The PV+BESS used the 7-year MACRS for a second quarter in-service date, instead of the 15-year MACRS. The impact of the ITC was also accounted for, which provides a first-year tax credit worth 30% of applicable capital costs and reduces the depreciable basis of the PV+BESS resource by half the value of the first-year tax credit.[42] Due to our assumption that the BESS portion receives the ITC (which impacts CONE) while the PV receives the Production Tax Credit (which impacts E&AS revenues but not CONE), the ITC was applied only to BESS equipment costs. This results in a first-year tax credit of $26.5 million and reduces the depreciable basis by $13.3 million.[43] Overall, the ITC decreases the PV+BESS CONE by $16/kW-year. The effect is limited by applying the ITC only to dedicated storage components of the plant (no facilities shared with the PV) and by the assumption that the storage capacity is only half of the PV capacity, which is used to normalize the costs.

We calculated interest during construction over the duration of the construction period using the overnight capital cost, capital drawdown schedule, construction debt fraction, and monthly debt rate.[44] The construction debt fraction is equal to the debt ratio (55%) and the interest rate during construction based on the cost of debt (7.6%) consistent for parameters for the 10.35% ATWACC.

[38] Thomson Reuters, "Bonus depreciation – Tax & Accounting glossary," Accessed May 23, 2024.

[39] Depreciable assets include all capital costs except land.

[40] Department of Treasury—Internal Revenue Service, "Publication 946: How to Depreciate Property, for use in preparing 2023 returns," February 14, 2024.

[41] Holland & Knight, "Breaking Down the Section 48 Investment Tax Credit Proposed Regulations," November 28, 2023.

[42] Wilson Sonsini, "Energy and Climate Solutions White Paper: Solar, Wind, and Energy Storage Incentives in the Inflation Reduction Act of 2022," August 2023.

[43] Specifically, the 30% capital cost tax credit of the ITC is applied to the 'Batteries and Enclosures Equipment' and 'BESS BOP Equipment' line items.

[44] For the Aero CT, the construction period is 30 months while for the PV+BESS, the construction period is 16 months.

In each month, interest during construction was calculated based on cumulative spend as of the previous month multiplied by the construction debt fraction and monthly debt rate.

The annual financing cost debt rate to calculate working capital in the FOM was based on the short-term debt borrowing rate for corporates with a "BB" credit rating from Bloomberg (6.21%).

E. CONE Sensitivity and Comparisons to Benchmarks

1. Uncertainty Drivers of CONE and Indicative Sensitivity Analyses

To explore uncertainty drivers, this section provides indicative estimates of CONE under alternative assumptions about the technology type and ATWACC and show the sensitivity of CONE to the levelization method. Sensitivities relating to plant configuration or input costs are not assessed here.

a. Technology Sensitivity

We estimated an indicative CONE for a natural gas plant with a frame type combustion turbine (Frame CT) by scaling capital and FOM costs for the Aero CT by the ratio of costs relative to a recent estimate for a Frame CT and applying the capital charge rate from our CONE estimate. The capital and fixed O&M cost ratios were calculated from recent estimates of capital costs from the EIA for aero and Frame CTs, also prepared by S&L.[45] These cost ratios were then applied to the capital and FOM costs for our Aero CT to get indicative capital and fixed O&M costs for a Frame CT and then multiplied by the capital charge rate to develop an indicative CONE.[46]

The indicative CONE of the Frame CT is $162/kW-year, which is $131/kW-year lower than the Aero CT CONE. This large difference raises the question whether the Aero CT is the correct technology if there is such a large cost difference. The Frame CT was not selected as the reference resource for this study because developers are not building Frame CTs in the ERCOT Region. Developers evidently prefer the costlier aeroderivative plants, and some reported that they value their relative flexibility and lower "shaft risk" whereby multiple smaller units diversify exposure

[45] This is based on Case 4 of Sargent & Lundy's study prepared for the EIA, which consists of a Frame CT plant with one industrial frame Model H combustion turbine in simple-cycle configuration. See EIA, "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies," prepared by Sargent & Lundy, January 2024.

[46] Using the following formula: CONE = (Capital Cost) × (Capital Charge Rate) + (Fixed O&M Cost).

to inopportune unavailability in a market that sharply punishes outages during system shortages. The aeroderivative plants being developed in the ERCOT Region have also enjoyed cost advantages with refurbished turbines. That savings relative to our generic estimates for all-new plants is not publicly available (nor in S&L's non-public databases) so not included in our CONE estimates. Our adherence to the "revealed preference" approach avoids speculating on what other technologies might be built under different market circumstances, or trying to account for disadvantageous characteristics of a given technology that may be deterring developers from building it. The possibility of developers finding lower cost opportunities with other technologies could be evaluated in further study.

b. ATWACC Sensitivity

Stakeholders asked that we consider a sensitivity analysis in which the ATWACC is higher than a generic merchant generation ATWACC, due to the energy-only market's volatility and a perceived vulnerability to political interference. Some suggested evaluating a 100-bp premium. Taking that suggestion increases the ATWACC to 11.35%. This raises the CONE of the Aero CT by $19/kW-year to $313/kW-yr. The magnitude of this impact is less than one-sixth of the impact of change in the reference technology from an Aero CT to a Frame CT, so ATWACC is not the largest uncertainty driver.

c. Levelization Sensitivity

While we used level-nominal as the base case levelization method, we also demonstrated the impact on CONE of using a level-real, an intermediate, and a more front-loaded levelization approach. Under the level-real levelization, revenues are constant in real terms meaning that they increase overtime at the rate of long-term inflation (2.2%) in nominal terms. Our 'intermediate' levelization sensitivity reflects an annual 0.8% real cost decline in overnight capital costs for the Aero CT from the NREL ATB moderate case, without any consideration of performance improvements. The 'more front-loaded' sensitivity reflects a more aggressive 3.0% annual long-term real cost decline in overnight capital costs for the PV+BESS resource also based on the NREL ATB moderate case. The level-real and intermediate sensitivities for the Aero CT and the more front-loaded sensitivity for the PV+BESS are shown in Table 24.

TABLE 24: CONE SENSITIVITY TO LEVELIZATION

Levelization Method	Assumed Nominal Revenue Escalation Rate	Assumed Real Revenue Escalation Rate	CONE 6x0 LM6000 (2026 $/kW-yr)	CONE PV + BESS (2026 $/kW-yr)
Level-Real	2.2%	0.0%	$253	
Intermediate	1.4%	-0.8%	$268	
Level-Nominal	**0.0%**	**-2.2%**	**$293**	**$263**
More front-loaded	-0.8%	-3.0%		$277

For the Aero CT, changing from a level-nominal to level-real method reduces CONE by $40/kW-yr. The magnitude of this impact is less than one-third of the impact of changing the reference technology shown in the technology sensitivity analysis above. Moving from a level-nominal to the intermediate levelization scenario reduces the Aero CT CONE by $25/kW-yr, which is less than one-fifth of the impact of changing the reference technology. For the PV+BESS, going from a level-nominal to a more front-loaded levelization increases the CONE by $14/kW-yr.

The results of these sensitivity analyses imply that the choice of ATWACC and levelization approach have a considerably smaller impact on CONE than the choice of the reference technology.

2. Comparison to CONE Benchmarks

To provide another reference point, we compared our Aero CT in ERCOT to additional CONE benchmarks. In 2022, Brattle developed a CONE estimate for PJM for both a combined-cycle frame (Frame CC) and Frame CT reference resource for a 2026 online year.[47] Similar to the Frame CT sensitivity above, the CONE for our Aero CT is substantially higher than the CONE for a Frame CT or Frame CC in PJM, shown in Table 25.

Both the Frame CC and Frame CT from the PJM study consist of GE 7HA turbines. The CONE for the Aero CT is $110/kW-year higher than the CONE for the Frame CC and $146/kW-year higher than the Frame CT, which is explained by two factors. Aeroderivative LM6000 turbines cost more than 7HA turbines on a per kW basis so lower capital costs result in lower CONE for the Frame CC and Frame CT. Additionally, the ATWACC in this study (10.35%) is 150 bps higher than the ATWACC Brattle developed for PJM in 2022 (8.85%), which further increases the difference between the Aero CT and the Frame CC/CT.

[47] Newell, et al., "PJM CONE 2026/2027 Report," April 21, 2022.

TABLE 25: COMPARISON OF ERCOT AERO CT VS. PJM FRAME CC AND FRAME CT

Resource Description	Notes	CONE (2026$/kW-yr)
Aero CT w/GE LM6000PC in ERCOT	[1]	$293
CC w/GE 7HA in PJM	[2]	$183
CT w/GE 7HA in PJM	[3]	$147
Aero CT Cost Premium vs. PJM CC	**[4] = [1] - [2]**	**$110**
Aero CT Cost Premium vs. PJM CT	**[5] = [1] - [3]**	**$146**

Notes and Sources: CONE values shown in nominal terms (2026$/kW-year) for a June 1, 2026 online date for the Aero CT with the CONEs of a Frame CC and Frame CT in the 'Rest of RTO' subregion of PJM from Newell, et al., "PJM CONE 2026/2027 Report," April 21, 2022.

Brattle conducted a study of resource CONE for ERCOT in 2012 which estimated that the midpoint CONE for a new Frame CT entering the market would be $105/kW-year for an online date of June 1, 2015.[48] This CONE estimate still serves as the basis for ERCOT's current PNM threshold of $315/kW-year. Bringing the 2012 CONE estimate forward to nominal 2026 dollars results in $149/kW-year that is $147/kW-year lower than the CONE for the Aero CT (see Table 26). This is very close to the value we estimate at a high level by scaling current EIA estimates for Frame CTs in Section IV.E.1.a above and also similar to the recent Frame CT estimate for PJM (see Table 25). Thus, the primary reason for the higher CONE estimate in this report is the change in technology of the reference unit to the Aero CT, based on current industry evidence.

TABLE 26: 2024 ERCOT CONE ESTIMATE VS. 2012 ERCOT CONE ESTIMATE

Resource Description	Notes	CONE (2026$/kW-yr)
Aero CT in ERCOT (2024 Study)	[1]	$293
Frame CT in ERCOT (2012 Study)	[2]	$146
2024 Aero CT vs. 2012 Frame CT	**[3] = [1] - [2]**	**$147**

Notes and Sources: CONE values shown in nominal terms (2026 $/kW-year) for a June 1, 2026 online date. The 2012 Frame CT value is from Newell, et al., "ERCOT Investment Incentives and Resource Adequacy," June 1, 2012.

48 Newell, et al., "ERCOT Investment Incentives and Resource Adequacy," June 1, 2012.

V. Annual CONE Updates

ERCOT requested that we propose a method for updating CONE values annually using simplified, indexing-based approaches to capture major changes in costs without having to conduct a full CONE study every year. To that end, we recommend adjusting the cost components using relevant cost indexes for materials, equipment, and labor; adjusting the ATWACC using readily observable changes in capital market conditions; and then entering the updated values into the CONE model provided with this study.

We recommend that ERCOT update the LM6000 reference technology CONE value each year based on a composite of the Department of Commerce's Bureau of Labor Statistics (BLS) indices for labor, turbines, and materials. ERCOT should calculate the composite index based on 35% labor, 25% materials, and 40% turbine. S&L recommends the selection of the following indices for each component of this composite: BLS Quarterly Census of Employment and Wages *Utility System Construction* for the state of Texas to be used for "labor;" BLS Producer Price Index *Turbines and Turbine Generator Sets* to be used for "turbines;" and BLS Producer Price Index *Construction Materials and Components for Construction* to be used for "materials."

For updates to the ATWACC, we recommend ERCOT adjust the ATWACC by the difference between the prevailing 15-day average of 20-year U.S. treasury bills as of the updated estimate date and the previous estimated date. This adjustment reflects the concept that ATWACC is the sum of the risk-free rate and the industry's market risk premium, and it captures changes in the risk-free rate. It would not account for possible changes in industry risk premium, which would be harder to capture in a simple index formula.To update the ATWACC for a new 'as of' date, ERCOT would only have to take the difference between the current risk-free rate and the 4.69% risk-free rate used in this report.

List of Acronyms

AC	Alternating Current
AERO CT	Aeroderivative Natural Gas-Fired Combustion Turbine
ATB	Annual Technology Baseline
ATWACC	After-Tax Weighted-Average Cost Of Capital
BESS	Battery Energy Stationary Storage
CC	Combined-Cycle
COD	Commercial Operation Date
CONE	Cost of New Entry
CPI	Consumer Price Index
CT	Combustion Turbine
CTG	Combustion Turbine Generator
DC	Direct Current
E&AS	Energy and Ancillary Services
EIA	Energy Information Administration
EORM	Economically Optimal Reserve Margin
EPC	Engineering, Procurement, and Construction
ERCOT	Electric Reliability Council of Texas
FIP	Fuel Index Price
FOM	Fixed Operation & Maintenance
Frame CT	Frame Combustion Turbine
HCAP	High Cap
IA	Interconnection Agreement
ICE	Internal Combustion Engine
ISO	International Standards Organization
ITC	Investment Tax Credit
LCAP	Low Cap
MACRS	Modified Accelerated Cost Recovery System
MERM	Market Equilibrium Reserve Margin
NREL	National Renewable Energy Laboratory

O&M	Operation & Maintenance
OEM	Original Equipment Manufacturer
ORDC	Operating Reserve Demand Curve
PCM	Performance Credit Mechanism
PNM	Peaker Net Margin
PV	Photovoltaic
PV+BESS	Photovoltaic Plus Battery Energy Stationary Storage
S&L	Sargent & Lundy
SCADA	Supervisory Control and Data Acquisition
SCR	Selective Catalytic Reduction
SWCAP	System-Wide Offer Cap
VOM	Variable Operation & Maintenance

Cover Page

Disclaimer

Table of Contents

CONE Model Read Me

Model Description

This model calculates the Cost of New Entry (CONE) for a reference resource and alternative resource entering the ERCOT market with a June 1, 2026 Commercial Operations Date (COD). The reference resource is an LM6000PC aeroderivative natural gas-fired combustion turbine (“Aero” in the model). The alternative resource is a solar photovoltaic plus battery energy stationary storage hybrid plant (“PV + BESS”). CONE represents the levelized first-year net revenues a representative resource would need to be willing to enter the ERCOT market. The calculation of CONE incorporates relevant capital costs, fixed operations & maintenance (O&M) costs, taxes, tax credits, and depreciation.

Model Layout and Usage

As shown in the [ToC] tab, the model has four main sections: ‘Report Tables’, ‘Main Analysis’, ‘Supporting Analysis’ and ‘Raw Data’. CONE is calculated in the ‘Main Analysis’ section while the ‘Supporting Analysis’ section is the buildup analyses for CONE. ‘Report Tables’ are the summary tables and the ‘Raw Data’ section contains initial data sources. In the following sections we explain how users can modify the model inputs and data for additional analyses.

Control Tab Layout

The control tab of the model enables the user to modify inputs and displays the key assumptions underlying the CONE calculation as well as the CONE results. The switches section controls the technology (Aero or

PV+BESS), the levelization approach (level-real, intermediate, level-nominal, and more front-loaded), and the seasonal net capacity (only for the Aero). The “Financial Assumptions Inputs” are user-definable as explained more below while the line items in the “Calculated Scalars” section are determined from the model inputs automatically. The results are shown in the “Model Outputs” section spanning line items [29] – [34], the final CONE result is shown in row [34].

The user can adjust any parameter in the “Financial Assumptions Inputs” section in accordance with the notes explained below the Control Table.

- The **Economic Life** parameter can be adjusted to a shorter or longer life out to maximum of 25 years; note that the “Tax Depreciation Schedule” should also be updated such that the chosen tax depreciation schedule is not longer than the economic life.

- The **Levelization** approach is adjusted through the “Assumed Revenue Escalation Rate” parameter, which defaults to the revenue escalation rates associated with the levelization switch, however this parameter is also user definable.

- To adjust the After-Tax Weighted-Average Cost of Capital (**ATWACC**), a user can adjust any of the components (Risk Premium Adder, Debt Fraction, Debt Rate, Equity Rate, Federal Tax Rate or State Tax Rate) which will automatically update the ATWACC throughout the model.

Cost Buildup Tables

Overnight Costs are calculated in Table B5 for the Aero and Table B6 for the PV+BESS from raw data inherited from Table C. Fixed O&M Costs are calculated in Table B1 for the Aero, Table B2 for the PV+BESS, and Table B3 for both resources. To adjust Overnight Cost and Fixed O&M Costs

B5 for both resources. To adjust Overnight Cost and Fixed O&M Costs, users can adjust the raw data contained in Tables C8 – C16. If using cost estimates from a different time than 1-April-2024 the “Cost Estimate Date” line item in the Control Table must also be updated accordingly.

Control Table

Control Table

Model Inputs

Switches

	Technology				Aero	Aero	PV + BESS		
	Levelization Method				Level-Nominal	Level-Real	Intermediate	Level-Nominal	More front-loaded
	Seasonal Net Capacity for Aero				ISO	Summer	ISO	Winter	

	Dates				
1	Cost Estimate Date		[1]	See notes	1-Apr-2024
2	Mid-Point Construction Date		[2]	See notes	1-Jul-2025
3	Online Date		[3]	See notes	1-Jun-2026
	Plant Characteristics Inputs				
4	Plant Capacity	MW	[4]	See notes	291
	Financial Assumptions Inputs				
5	Economic Life	Years	[5]	See notes	20
6	Assumed Revenue Escalation Rate	%	[6]	See notes	0.00%
	ATWACC Components				
7	Risk Premium Adder	%	[7]	See notes	0.00%
8	Debt Fraction	%	[8]	See notes	55.00%
9	Debt Rate	%	[9]	See notes	7.60%
10	Equity Rate	%	[10]	See notes	15.70%
11	Federal Tax Rate	%	[11]	Table C1	21.00%
12	State Tax Rate	%	[12]	Table C1	0.50%
	Depreciation				
13	Tax Depreciation Schedule		[13]	See notes	15-year MACRS
14	Bonus Depreciaton	%	[14]	See notes	20.00%
	Inflation				
15	Inflation Forecast, 2024	%	[15]	Table C4	3.02%
16	Inflation Forecast, 2025	%	[16]	Table C4	2.33%
17	Inflation Forecast, 2026 and Beyond	%	[17]	Table C4	2.20%
	Tax Credit				
18	Investment Tax Credit	%	[18]	See notes	30.00%
19	Impact of Investment Tax Credit on Depreciable Basis	%	[19]	See notes	50.00%
	Calculated Scalars				
20	Total Income Tax Rate	%	[20]	See notes	21.40%
21	ATWACC Nominal	%	[21]	See notes	10.35%
22	ATWACC Real	%	[22]	See notes	7.12%
23	Interest During Construction	%	[23]	[9]	7.60%
24	Construction Debt Fraction	%	[24]	[8]	55.00%
25	Long-Term Real Cost Escalation Rate for Aero	%	[25]	Table C6	-0.80%
26	Long-Term Nominal Cost Escalation Rate for Aero	%	[26]	[17] + [25]	1.40%
27	Long-Term Real Cost Escalation Rate for PV + BESS	%	[27]	Table C5	-3.02%
28	Long-Term Nominal Cost Escalation Rate for PV + BESS	%	[28]	[17] + [27]	-0.82%

Model Outputs

29	Installed Cost	2026$	[29]	Table A1	$562,860,546
30	Depreciable Cost	2026$	[30]	Table A1	$532,108,356
31	Overnight Cost	2026$	[31]	Table A1	$513,328,930
32	Installed Cost	2026$/kW	[32]	Table A1	$1,934.23
33	Depreciable Cost	2026$/kW	[33]	Table A1	$1,828.55
34	**Cost of New Entry**	**2026$/kW-yr**	**[34]**	**Table A1**	**$293**

Notes and Sources:

[1]: Date of cost estimates.
[2]: Based on commercial online date from [3] and capital drawdown schedule established in Table C16.
[3]: Estimated commercial online date for reference and alternative resources.

[4]: If the technology selected is Aero, plant capacity is from Table C8 and depends on the seasonal net capacity switch (Summer - 244 MW, ISO - 291 MW, Winter - 301 MW). If the technology selected is PV + BESS, plant capacity is from Table C11.

[5]: 20-year economic life is assumed for both the Aero and PV + BESS resources.
[6]: If the levelization method selected is Level-Real, the revenue escalation rate is set equal to [17]. If Intermediate, the revenue escalation rate is set equal to [26]. If Level-Nominal, the revenue escalation rate is set equal to 0%. If More front-loaded, the revenue escalation rate is set equal to [28].

[7]: User input for risk premium adder.
[8]: Assumed based on Brattle analysis, see ERCOT CONE report.
[9]: Assumed based on Brattle analysis, see ERCOT CONE report.
[10]: Assumed based on Brattle analysis, see ERCOT CONE report.

[13]: If the technology selected is Aero, the default tax depreciation schedule is the 15-year MACRS. If PV + BESS, the default tax depreciation schedule is the 7-year MACRS. Users can designate a different depreciation schedule from the following options for MACRS: 3-year, 5-year, 7-year, 10-year, 15-year and 20-year by using the format '5-year MACRS'. Additionally depreciation schedules based on Straight Line Depreciation (SLD) are avalable including: 5-year, 10-year, 20-year, 30-year, 40-year and 50-year; e.g. '10-year SLD'. See Table C3 for more details. The selected tax depreciation schedule must be shorter than the economic life of the resource.

[14]: Thomson Reuters, 'Bonus depreciation – Tax & Accounting glossary,' Accessed May 23, 2024.

[18]: Per the Inflation Reduction Act of 2022, the base credit amount for the ITC is 6% of qualified project costs, which increases to 30% if prevailing wage and apprenticeship requirements are satisfied or deemed satisfied, assumed to be 30% for the PV + BESS resource for BESS components only.
[19]: Internal Revenue Service, 26 U.S.C. § 168, Accessed May 23, 2024.

[20]: [11] + ((1 - [11]) x [12]).
[21]: ([10] x (1 - [8])) + ([9] x [8] x (1 - [20])) + [7].
[22]: (1 + [21]) / (1 + [15]) - 1.

Table T1: CONE Summary for Aero Resource (Nominal$)

				6x0 LM6000
[1]	**Capacity at ISO conditions**	*MW*		**291**
	Capital Costs			
[2]	Overnight Cost	*Nominal $ million*		$513
[3]	Overnight Cost	*Nominal $/kW*	= [2] x 1000 / [1]	$1,764
[4]	Capital Charge Rate	*%*		14.0%
[5]	Levelized Capital Cost	*Nominal $/kW-yr*	= [3] x [4]	$246
	O&M Costs			
[6]	First Year FOM	*Nominal $ million/yr*		$12
[7]	Levelized FOM	*Nominal $/kW-yr*		$47
[8]	**Levelized CONE**	***Nominal $/kW-yr***	= [5] + [7]	**$293**

Note: All costs are shown in nominal$.

Technology Aero

Table T2

Table T2: Capital Costs for Aero Resource (Nominal$)

Capital Costs (in $millions)	6x0 LM6000 Harris County *291 MW*
EPC Costs	
Equipment	
CTG Equipment	$209.8
SCR & CEMS Equipment	$40.1
Other Equipment	$37.5
Construction Labor	$57.5
Other Labor	$32.6
Materials	$17.5
Sales Tax	$1.3
EPC Contractor Fee	$35.7
EPC Contingency	$39.6
Total EPC Costs	$471.6
Non-EPC Costs	
Project Development	$23.6
Mobilization and Start-Up	$4.7
Net Start-Up Fuel Costs	$0.0
Electrical Interconnection	$0.0
Gas Interconnection	$1.8
Land	$0.8
Non-Fuel Inventories	$7.1
Owner's Contingency	$3.8
Total Non-EPC Costs	$41.8
Total Capital Costs	**$513.3**
Overnight Capital Costs ($million)	**$513**
Overnight Capital Costs ($/kW)	**$1,764**
Installed Cost ($/kW)	**$1,934**

Note: All costs are shown in nominal$ and based on ISO capacity conditions.

Technology Aero

Table T3

Table T3: Operations & Maintenance Costs for Aero Resource (Nominal$)

O&M Costs	6x0 LM6000 Harris County
Fixed O&M ($ million)	
LTSA Fixed Payments	$0.5
Labor	$2.5
Maintenance and Minor Repairs	$0.1
Administrative and General	$0.2
Asset Management	$0.4
Property Taxes	$1.6
Insurance	$3.2
Firm Gas Contract	$3.2
Total Fixed O&M ($ million)	$11.7
Levelized Fixed O&M ($/MW-yr)	**$40**
Variable O&M ($/MWh)	
Total Variable O&M ($/MWh)	**$7.92**
Major Maintenance - Hours Based	7.17
Consumables, Waste Disposal, Other VOM	0.76

Note: All costs are shown in nominal$ and based on ISO capacity conditions.

Technology Aero

Table T4

Table T4: CONE Summary for PV + BESS Resource (Nominal$)

				PV + BESS
[1]	**Plant Capacity**	***MW***		**-**
	Capital Costs			
[2]	Overnight Cost	*Nominal $ million*		-
[3]	Overnight Cost	*Nominal $/kW*	= [2] x 1000 / [1]	-
[4]	Capital Charge Rate	*%*		-
[5]	Levelized Capital Cost	*Nominal $/kW-yr*	= [3] x [4]	-
	O&M Costs			
[6]	First Year FOM	*Nominal $ million/yr*		-
[7]	Levelized FOM	*Nominal $/kW-yr*		-
[8]	Levelized Augmentation	*Nominal $/kW-yr*		-
[9]	**Levelized CONE**	***Nominal $/kW-yr***	= [5] + [7] + [8]	**-**

Note: All costs are shown nominal $.

Technology Aero

Table T5

Table T5: Capital Costs for PV + BESS Resource (Nominal$)

Capital Costs (in $millions)	**PV + BESS** **Brazoria County** *200 MW*
EPC Costs	
BESS Equipment	
Batteries and Enclosures	-
PCS and BOP Equipment	-
PV Equipment	
Module Supply	-
Inverter Supply	-
Racking, Tracker and BOP	-
Main Power Transformer	-
Construction	-
SCADA Subcontract	-
Architectural Subcontract	-
EPC Contractor Fee	-
EPC Contingency	-
Total EPC Costs	-
Non-EPC Costs	
Project Development	-
Mobilization and Start-Up	-
Owner's Contingency	-
Total Non-EPC Costs	-

Total Capital Costs	-
Overnight Capital Costs ($million)	-
Overnight Capital Costs ($/kW)	-
Installed Capital Costs ($/kW)	-

Note: All costs are shown nominal $.

Table T6

Table T6: Operations & Maintenance Costs for PV + BESS Resource (Nominal$)

O&M Costs	**PV + BESS** **Brazoria County** *200 MW*
Fixed O&M Components	
Maintenance	-
Land Lease	-
Property Taxes	-
Insurance	-
Fixed O&M ($ million)	**-**
Fixed O&M ($/kW-yr)	**-**
Augmentation Costs	
Year 5 Costs ($ million)	-
Year 10 Costs ($ million)	-
Year 15 Costs ($ million)	-
Levelized Augmentation Costs ($/kW-yr)	**-**
Total Levelized Fixed Costs ($/kW-yr)	**-**

Note: All costs are shown nominal 2026$.

Table A1

Table A1: Cash Flows

#	Item	Unit	Ref	Source	Value
	Dates				
1	Mid-Point Construction Date		[1]	Control Table	1-Jul-2025
2	Online Date		[2]	Control Table	1-Jun-2026
3	Months To Completion		[3]	Table C16	30
4	Months To Construction Midpoint		[4]	Table C16	19
5	Months between Construction Midpoint and Online Date		[5]	[3] - [4]	11
6	Start of Year for Online Date		[6]	See notes	1-Jan-2026
7	Months of Cost Escalation in 2025		[7]	See notes	6
8	Months of Cost Escalation in 2026		[8]	See notes	5
	Technical Assumptions				
9	Technology		[9]	Control Table	Aero
10	Plant Capacity	MW	[10]	Control Table	291
11	Economic Life	Years	[11]	Control Table	20
12	Overnight Cost	Nominal$	[12]	Table A2	$513,328,930
13	Installed Cost	Nominal$	[13]	Table A2	$562,860,546
14	Depreciable Cost	Nominal$	[14]	Table A2	$532,108,356
15	Unit Overnight Cost	Nominal$/kW	[15]	See notes	$1,764
16	Unit Installed Cost	Nominal$/kW	[16]	See notes	$1,934
17	Unit Depreciable Cost	Nominal$/kW	[17]	See notes	$1,829
	Financial Assumptions				
18	Revenue Escalation Rate	%	[18]	Control Table	0.00%
19	ATWACC Nominal	%	[19]	Control Table	10.35%
20	ATWACC Real	%	[20]	Control Table	7.12%
21	Total Income Tax Rate	%	[21]	Control Table	21.40%
22	Inflation Forecast, 2024	%	[22]	Control Table	3.02%
23	Tax Depreciation Schedule		[23]	Control Table	15-year MACRS
24	Bonus Depreciaton	%	[24]	Control Table	20.00%
25	Investment Tax Credit	%	[25]	Control Table	30.00%
26	Impact of Investment Tax Credit on Depreciable Basis	%	[26]	Control Table	50.00%
	Tax Credit and Depreciable Basis Reduction from ITC				
27	Overnight Capital Cost subject to ITC	Nominal$	[27]	See notes	$0
28	First Year Tax Credit from ITC	Nominal$	[28]	See notes	$0
29	Reduction in Depreciable Basis from ITC	Nominal$	[29]	See notes	$0

Lookup 1	Lookup 2
15-year	MACRS

Additional Components to First Year Revenue Requirement

#	Item	Unit	Ref	Source	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
30	Year		[30]		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
31	Year for Annual FOM Cost		[31]	[30] - 2025	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
32	Total FOM Cost	Nominal$	[32]	Table B3	$11,844,915	$12,105,503	$12,371,824	$12,644,004	$12,922,173	$13,206,460	$13,497,003	$13,793,937	$14,097,403	$14,407,546	$14,724,512	$15,048,451	$15,379,517	$15,717,867	$16,063,660	$16,417,060	$16,778,236	$17,147,357	$17,524,599	$17,910,140	$0	$0	$0	$0	$0
33	Depreciable Basis	Nominal$	[33]	See notes	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$0	$0	$0	$0	$0
34	15-year MACRS	%	[34]	Table C3	6.25%	9.38%	8.44%	7.59%	6.83%	6.15%	5.91%	5.90%	5.91%	5.90%	5.91%	5.90%	5.91%	5.90%	5.91%	2.21%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
35	Tax Depreciation	Nominal$	[35]	See notes	$133,027,089	$39,929,411	$35,927,956	$32,309,619	$29,074,401	$26,179,731	$25,158,083	$25,115,514	$25,158,083	$25,115,514	$25,158,083	$25,115,514	$25,158,083	$25,115,514	$25,158,083	$9,407,676	$0	$0	$0	$0	$0	$0	$0	$0	$0

CONE Calculations

(1 + ATWACC)/(1 + Revenue Escalation Rate) - 1 = 10.35%

	Present Value EOY 0 (2026$m)	First Year Revenue Req. MOY 1 (2026$m/yr)	First Year Revenue Req. MOY 1 (2026$/kW-yr)
(+) Investment Costs	$563	$82	$282
(+) Operating Costs	$94	$14	$47
(-) Tax Credit	$0	$0	$0
(-) Depreciation	-$71	-$10	-$35
Total	$586	$85	$293

Summary of Cash Flows

#	Item	Unit	Ref	Source	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
36	Revenue Requirement	2026$/kW-yr	[36]	See notes	$293	$293	$293	$293	$293	$293	$293	$293	$293	$293	$293	$293	$293	$293	$293	$293	$293	$293	$293	$293	$0	$0	$0	$0	$0
37	**Revenue Requirement**	**2026$**	**[37]**	**See notes**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$85,386,403**	**$0**	**$0**	**$0**	**$0**	**$0**
38	Total FOM Cost	2026$	[38]	[32]	$11,844,915	$12,105,503	$12,371,824	$12,644,004	$12,922,173	$13,206,460	$13,497,003	$13,793,937	$14,097,403	$14,407,546	$14,724,512	$15,048,451	$15,379,517	$15,717,867	$16,063,660	$16,417,060	$16,778,236	$17,147,357	$17,524,599	$17,910,140	$0	$0	$0	$0	$0
39	**Operating Costs**	**2026$**	**[39]**	**[38]**	**$11,844,915**	**$12,105,503**	**$12,371,824**	**$12,644,004**	**$12,922,173**	**$13,206,460**	**$13,497,003**	**$13,793,937**	**$14,097,403**	**$14,407,546**	**$14,724,512**	**$15,048,451**	**$15,379,517**	**$15,717,867**	**$16,063,660**	**$16,417,060**	**$16,778,236**	**$17,147,357**	**$17,524,599**	**$17,910,140**	**$0**	**$0**	**$0**	**$0**	**$0**
40	Tax Depreciation	2026$	[40]	[35]	$133,027,089	$39,929,411	$35,927,956	$32,309,619	$29,074,401	$26,179,731	$25,158,083	$25,115,514	$25,158,083	$25,115,514	$25,158,083	$25,115,514	$25,158,083	$25,115,514	$25,158,083	$9,407,676	$0	$0	$0	$0	$0	$0	$0	$0	$0
41	**Gross Income Tax**	**2026$**	**[41]**	**See notes**	**-$12,726,964**	**$7,135,551**	**$7,934,683**	**$8,650,593**	**$9,283,254**	**$9,841,745**	**$9,998,165**	**$9,943,744**	**$9,869,710**	**$9,812,462**	**$9,735,540**	**$9,675,340**	**$9,595,401**	**$9,532,119**	**$9,449,029**	**$12,743,219**	**$14,678,717**	**$14,599,744**	**$14,519,033**	**$14,436,547**	**$0**	**$0**	**$0**	**$0**	**$0**
42	Investment Tax Credit	2026$	[42]	See notes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
43	**Net Income Tax**	**2026$**	**[43]**	**[41] - [42]**	**-$12,726,964**	**$7,135,551**	**$7,934,683**	**$8,650,593**	**$9,283,254**	**$9,841,745**	**$9,998,165**	**$9,943,744**	**$9,869,710**	**$9,812,462**	**$9,735,540**	**$9,675,340**	**$9,595,401**	**$9,532,119**	**$9,449,029**	**$12,743,219**	**$14,678,717**	**$14,599,744**	**$14,519,033**	**$14,436,547**	**$0**	**$0**	**$0**	**$0**	**$0**
44	All-Equity Cash Flow	2026$	[44]	[37] - [39] - [43]	$86,268,452	$66,145,349	$65,079,896	$64,091,806	$63,180,976	$62,338,197	$61,891,235	$61,648,723	$61,419,290	$61,166,395	$60,926,351	$60,662,611	$60,411,484	$60,136,417	$59,873,714	$56,226,124	$53,929,450	$53,639,302	$53,342,771	$53,039,717	$0	$0	$0	$0	$0

Assessment of Cost Recovery

#	Item	Unit	Ref	Source	Value
45	All-Equity Cash Flow, NPV Discounted at ATWACC	2026$	[45]	See notes	$562,860,546
46	Installed Cost	2026$	[46]	See notes	-$562,860,546
47	Cash Flow Recovers Installed Cost?		[47]	See notes	TRUE

Notes and Sources:

[6]: Start of year for online date.
[7]: Number of months between [1] and [6].
[8]: Number of months between [6] and [2].
[15]: [12] / ([10] x 1000).
[16]: [13] / ([10] x 1000).
[17]: [14] / ([10] x 1000).
[27]: If technology is PV + BESS: equals sum of BESS equipment overnight capital costs. If technology is Aero: set to 0.
[28]: If technology is PV + BESS: [25] x [27]. If technology is Aero: set to 0.
[29]: If technology is PV + BESS: [26] x [28]. If technology is Aero: set to 0.
[33]: If technology is PV + BESS: [14] - [29]. If technology is Aero, this cell equals [14]. Depreciable costs are only non zero if [31] is less than the economic life.
[35]: In 2026: ([24] x [33]) + ((1 - [24]) x [33] x [34]). After 2026: ((1 - [24]) x [33] x [34]).

Cone Calculations

Present Value (EOY 0) of Investment Costs: ([10] x [16]) / 1000.
Present Value (EOY 0) of Operating Costs: ((1 - [21]) x NPV([19], [32]) x (1 + [19])^0.5) / 1000000.
Present Value (EOY 0) of Tax Credit: -(NPV([19], [42]) x (1 + [19])^0.5) / 1000000.
Present Value (EOY 0) of Depreciation: -[21] x NPV([19], [35]) x (1 + [19])^0.5.

First Year Revenue Req. (MOY 1) of Investment Costs: (-PMT(ATWACC Adjusted by Revenue Escalation Rate, [11], Present Value (EOY 0) of Investment Costs, 0, 1) x (1 + [19])^0.5) / (1 - [21]).
First Year Revenue Req. (MOY 1) of Operating Costs: (-PMT(ATWACC Adjusted by Revenue Escalation Rate, [11], Present Value (EOY 0) of Operating Costs, 0, 1) x (1 + [19])^0.5) / (1 - [21]).
First Year Revenue Req. (MOY 1) of Tax Credit: (-PMT(ATWACC Adjusted by Revenue Escalation Rate, [11], Present Value (EOY 0) of Tax Credit, 0, 1) x (1 + [19])^0.5) / (1 - [21]).
First Year Revenue Req. (MOY 1) of Depreciation: (-PMT(ATWACC Adjusted by Revenue Escalation Rate, [11], Present Value (EOY 0) of Depreciation Costs, 0, 1) x (1 + [19])^0.5) / (1 - [21]).
First Year Revenue Req. (MOY 1) of Investment Costs (2026$/kW-yr): (1000 x First Year Revenue Req. (MOY 1) of Investment Costs) / Plant Capacity.
First Year Revenue Req. (MOY 1) of Operating Costs (2026$/kW-yr): (1000 x First Year Revenue Req. (MOY 1) of Operating Costs) / Plant Capacity.
First Year Revenue Req. (MOY 1) of Tax Credit (2026$/kW-yr): (1000 x First Year Revenue Req. (MOY 1) of Tax Credit) / Plant Capacity.
First Year Revenue Req. (MOY 1) of Depreciation (2026$/kW-yr): (1000 x First Year Revenue Req. (MOY 1) of Depreciation) / Plant Capacity.
Total = Investment Costs + Operating Costs + Tax Credit + Depreciation.

[36]: If year <= [11]: First Year Revenue Req. Total x (1 + [18]) ^ ([31] - 1). If year > [11]: 0.
[37]: [10] x [36] x 1000.
[41]: [21] x ([37] - [39] - [40]).
[42]: If technology is PV + BESS: [28] in year 1 and 0 in subsequent years. If technology is Aero: set to 0 in all years.
[45]: NPV([44] at [19]) x (1 + [19])^0.5.
[46]: -([10] x [16] x 1000).
[47]: Checks if [45] is within 0.1% of [46].

CHECK - Total Payments to Debt & Equity Holders

#	Item	Unit	Ref	Source	Value
	Inputs				
48	Debt Rate	%	[48]	Control Table	7.60%
49	Debt Fraction	%	[49]	Control Table	55.00%
50	Equity Rate	%	[50]	Control Table	15.70%
	Calculated Scalars				
51	Equity Fraction	%	[51]	1 - [49]	45.00%

Discretionary Cash by Year

#	Item	Unit	Ref	Source	Scalar	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
52	Year		[52]	[31]		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
53	Interest Payments	$	[53]	[59]		$11,548,384	$21,101,819	$20,521,127	$19,924,865	$19,308,189	$18,665,754	$17,992,052	$17,267,300	$16,477,668	$15,615,893	$14,675,491	$13,647,783	$12,524,726	$11,295,921	$9,951,425	$8,478,745	$7,006,101	$5,477,030	$3,801,817	$1,965,604	$0	$0	$0	$0	$0
54	Taxable Income	$	[54]	See notes		-$71,033,985	$12,249,670	$16,565,496	$20,507,914	$24,081,641	$27,334,457	$28,739,266	$29,209,652	$29,653,249	$30,247,449	$30,828,317	$31,574,654	$32,324,077	$33,257,101	$34,213,236	$51,082,923	$61,602,066	$62,762,017	$64,059,987	$65,510,660	$0	$0	$0	$0	$0
55	Net Income Tax	$	[55]	See notes		-$15,197,721	$2,620,817	$3,544,188	$4,387,668	$5,152,267	$5,848,207	$6,148,766	$6,249,405	$6,344,313	$6,471,442	$6,595,718	$6,755,397	$6,915,736	$7,115,357	$7,319,922	$10,929,191	$13,179,762	$13,427,933	$13,705,634	$14,016,006	$0	$0	$0	$0	$0
56	ROE Payments	$	[56]	[65]		$19,158,481	$35,666,112	$34,684,632	$33,676,836	$32,634,534	$31,548,697	$30,410,011	$29,185,041	$27,850,412	$26,393,848	$24,804,388	$23,067,366	$21,169,184	$19,092,269	$16,819,812	$14,330,701	$11,841,652	$9,257,228	$6,425,799	$3,322,246	$0	$0	$0	$0	$0
57	Discretionary Cash	$	[57]	See notes		$58,032,344	$13,892,152	$14,264,632	$14,753,029	$15,369,241	$16,117,284	$17,338,572	$18,890,721	$20,616,608	$22,497,674	$24,586,294	$26,867,405	$29,397,240	$32,164,990	$35,231,584	$35,230,706	$36,580,653	$40,076,855	$43,928,554	$48,172,408	$0	$0	$0	$0	$0
58	Debt Balance	$	[58]	See notes		$309,573,300	$277,655,511	$270,014,828	$262,169,280	$254,055,114	$245,602,031	$236,737,525	$227,201,311	$216,811,415	$205,472,280	$193,098,560	$179,576,098	$164,799,025	$148,630,543	$130,939,799	$111,562,428	$92,185,539	$72,066,180	$50,023,910	$25,863,205	$0	$0	$0	$0	$0
59	Interest Payments	$	[59]	See notes		$11,548,384	$21,101,819	$20,521,127	$19,924,865	$19,308,189	$18,665,754	$17,992,052	$17,267,300	$16,477,668	$15,615,893	$14,675,491	$13,647,783	$12,524,726	$11,295,921	$9,951,425	$8,478,745	$7,006,101	$5,477,030	$3,801,817	$1,965,604	$0	$0	$0	$0	$0
60	Principal Repayment	$	[60]	[49] x [57]	-$309,573,300	$31,917,789	$7,640,683	$7,845,548	$8,114,166	$8,453,082	$8,864,506	$9,536,214	$10,389,896	$11,339,134	$12,373,720	$13,522,462	$14,777,073	$16,168,482	$17,690,744	$19,377,371	$19,376,888	$20,119,359	$22,042,270	$24,160,705	$26,494,824	$0	$0	$0	$0	$0
61	Total Payments to Debt Holders	$	[61]	[59] + [60]	-$309,573,300	$43,466,173	$28,742,502	$28,366,675	$28,039,031	$27,761,271	$27,530,261	$27,528,266	$27,657,196	$27,816,802	$27,989,614	$28,197,952	$28,424,856	$28,693,208	$28,986,666	$29,328,796	$27,855,633	$27,125,460	$27,519,300	$27,962,522	$28,460,428	$0	$0	$0	$0	$0
62	Net Present Value Discounted at Debt Rate	$	[62]	See notes	$309,724,697																									
63	Payments to Debt Holders Recover Principal?		[63]	See notes	TRUE																									
64	Equity Balance	$	[64]	See notes		$253,287,245	$227,172,691	$220,921,223	$214,502,138	$207,863,275	$200,947,117	$193,694,339	$185,891,982	$177,391,157	$168,113,684	$157,989,731	$146,925,898	$134,835,566	$121,606,808	$107,132,563	$91,278,350	$75,424,532	$58,963,239	$40,928,654	$21,160,804	$0	$0	$0	$0	$0
65	ROE Payments	$	[65]	See notes		$19,158,481	$35,666,112	$34,684,632	$33,676,836	$32,634,534	$31,548,697	$30,410,011	$29,185,041	$27,850,412	$26,393,848	$24,804,388	$23,067,366	$21,169,184	$19,092,269	$16,819,812	$14,330,701	$11,841,652	$9,257,228	$6,425,799	$3,322,246	$0	$0	$0	$0	$0
66	Dividend Payments	$	[66]	[51] x [57]	-$253,287,245	$26,114,555	$6,251,468	$6,419,084	$6,638,863	$6,916,158	$7,252,778	$7,802,357	$8,500,824	$9,277,474	$10,123,953	$11,063,832	$12,090,332	$13,228,758	$14,474,245	$15,854,213	$15,853,818	$16,461,294	$18,034,585	$19,767,849	$21,677,583	$0	$0	$0	$0	$0
67	Total Payments to Equity Holders	$	[67]	[65] + [66]	-$253,287,245	$45,273,036	$41,917,581	$41,103,716	$40,315,699	$39,550,692	$38,801,475	$38,212,368	$37,685,865	$37,127,885	$36,517,801	$35,868,220	$35,157,698	$34,397,942	$33,566,514	$32,674,025	$30,184,519	$28,302,945	$27,291,813	$26,193,648	$24,999,830	$0	$0	$0	$0	$0
68	Net Present Value Discounted at Equity Rate	$	[68]	See notes	$253,317,327																									
69	Payments to Equity Holders Recover Dividend?		[69]	See notes	TRUE																									

Notes and Sources:

[54]: [37] - [39] - [40] - [53].
[55]: ([21] x [54]) - [42].
[57]: [37] - [39] - [53] - [55] - [56].
[58]: If year <= [11]: ([58], Previous Year) - ([60], Previous Year). If year > [11]: 0.
[59]: If year = 1: [58] x ((1 + [48])^0.5 - 1). If year > 1, [58] x [48].
[62]: NPV([61] at [48]) x (1 + [48])^0.5.
[63]: Checks if [61] is within 0.1% of [62].
[64]: If year <= [11]: ([64], Previous Year) - ([66], Previous Year). If year > [11]: 0.
[65]: If year = 1: [64] x ((1 + [50])^0.5 - 1). If year > 1, [64] x [50].
[68]: NPV([67] at [50]) x (1 + [50])^0.5.
[69]: Checks if [67] is within 0.1% of [68].

Table A2

Table A2: Construction Costs

	Dates				
1	Beginning Construction Date		[1]	See notes	1-Dec-2023
2	Mid-Point Construction Date		[2]	Control Table	1-Jul-2025
3	Online Date		[3]	Control Table	1-Jun-2026
4	Months To Completion		[4]	Table C16	30
	Technical Assumptions				
5	Technology		[5]	Control Table	Aero
6	Construction Completion Date		[6]	[3]	6/1/2026
7	Overnight Capital Costs	Nominal$	[7]	See notes	$513,328,930
8	Non-Depreciable Cost	Nominal$	[8]	See notes	$785,000
	Financial Assumptions				
9	ATWACC Nominal	%	[9]	Control Table	10.35%
10	Construction Debt Fraction	%	[10]	Control Table	55.00%
11	Interest During Construction	%	[11]	Control Table	7.60%
12	Monthly ATWACC	%	[12]	See notes	0.82%
13	Monthly Debt Rate	%	[13]	See notes	0.61%

	Month													
14	Month of Construction		[14]		1	2	3	4	5	6	7	8	9	10
15	Date		[15]	See notes	12/1/2023	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	6/1/2024	7/1/2024	8/1/2024	9/1/2024
	Cumulative Dollars Spent													
16	Cash Flow	%	[16]	Table C16	0.01%	0.06%	0.06%	1.86%	1.82%	0.26%	0.40%	1.60%	1.68%	1.41%
17	Capital Cost Cash Flow	Nominal$	[17]	[7] x [16]	$51,333	$307,997	$307,997	$9,547,918	$9,342,587	$1,334,655	$2,053,316	$8,213,263	$8,623,926	$7,237,938
18	Non-Depreciable Assets	Nominal$	[18]	[8] x [16]	$79	$471	$471	$14,601	$14,287	$2,041	$3,140	$12,560	$13,188	$11,069
19	Interest During Construction	Nominal$	[19]	See notes	$0	$173	$1,209	$2,248	$34,360	$65,890	$70,599	$77,741	$105,620	$134,973
20	IDC + Depreciable Assets	Nominal$	[20]	See notes	$51,254	$307,699	$308,735	$9,535,566	$9,362,660	$1,398,504	$2,120,775	$8,278,444	$8,716,358	$7,361,842
21	Cumulative Dollars Spent	Nominal$	[21]	See notes	$51,254	$358,953	$667,689	$10,203,254	$19,565,914	$20,964,418	$23,085,193	$31,363,637	$40,079,995	$47,441,837

14	Month of Construction	11	12	13	14	15	16	17	18	19	20
15	Date	10/1/2024	11/1/2024	12/1/2024	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	6/1/2025	7/1/2025
16	Cash Flow	1.70%	2.16%	3.03%	4.28%	4.66%	5.32%	5.86%	6.86%	7.00%	6.84%
17	Capital Cost Cash Flow	$8,726,592	$11,087,905	$15,553,867	$21,970,478	$23,921,128	$27,309,099	$30,081,075	$35,214,365	$35,933,025	$35,111,699
18	Non-Depreciable Assets	$13,345	$16,956	$23,786	$33,598	$36,581	$41,762	$46,001	$53,851	$54,950	$53,694
19	Interest During Construction	$159,764	$189,645	$227,566	$280,631	$355,450	$437,080	$530,377	$633,309	$753,847	$877,208
20	IDC + Depreciable Assets	$8,873,011	$11,260,594	$15,757,647	$22,217,511	$24,239,997	$27,704,417	$30,565,451	$35,793,822	$36,631,922	$35,935,213
21	Cumulative Dollars Spent	$56,314,848	$67,575,441	$83,333,088	$105,550,599	$129,790,597	$157,495,014	$188,060,465	$223,854,288	$260,486,210	$296,421,423

14	Month of Construction	21	22	23	24	25	26	27	28	29	30
15	Date	8/1/2025	9/1/2025	10/1/2025	11/1/2025	12/1/2025	1/1/2026	2/1/2026	3/1/2026	4/1/2026	5/1/2026
16	Cash Flow	6.72%	6.06%	6.22%	6.21%	5.87%	5.29%	4.76%	1.42%	0.34%	0.24%
17	Capital Cost Cash Flow	$34,495,704	$31,107,733	$31,929,059	$31,877,727	$30,132,408	$27,155,100	$24,434,457	$7,289,271	$1,745,318	$1,231,989
18	Non-Depreciable Assets	$52,752	$47,571	$48,827	$48,749	$46,080	$41,527	$37,366	$11,147	$2,669	$1,884
19	Interest During Construction	$998,223	$1,117,574	$1,225,935	$1,337,423	$1,449,113	$1,555,312	$1,651,856	$1,739,578	$1,769,946	$1,781,775
20	IDC + Depreciable Assets	$35,441,175	$32,177,736	$33,106,168	$33,166,401	$31,535,442	$28,668,885	$26,048,947	$9,017,702	$3,512,595	$3,011,880
21	Cumulative Dollars Spent	$331,862,599	$364,040,335	$397,146,502	$430,312,903	$461,848,345	$490,517,231	$516,566,178	$525,583,880	$529,096,476	$532,108,356

14	Month of Construction	31	32	33	34	35	36	37	38	39	40
15	Date	6/1/2026	7/1/2026	8/1/2026	9/1/2026	10/1/2026	11/1/2026	12/1/2026	1/1/2027	2/1/2027	3/1/2027
16	Cash Flow	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
17	Capital Cost Cash Flow	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Non-Depreciable Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Interest During Construction	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	IDC + Depreciable Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	Cumulative Dollars Spent	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356	$532,108,356

	Overall Cost				
22	Overnight Cost	Nominal$	[22]	SUM([17])	$513,328,930
23	Installed Cost	Nominal$	[23]	See notes	$562,860,546
24	Depreciable Cost	Nominal$	[24]	SUM([20])	$532,108,356

Notes and Sources:
All currency amounts shown in nominal$.

[1]: Calculated based on online date and months to completion from Table C16.
[7]: If technology is Aero: Table B5. If PV + BESS: Table B6.
[8]: If technology is Aero: Table B5. If PV + BESS: Table B6.
[12]: (1 + [9])^(1/12) - 1.
[13]: (1 + [11])^(1/12) - 1.
[14]: Organizes the rest of the table to be a month-level cash flow.
[15]: Derived based on [1] and [14].
[19]: [10] x [13] x [21]t-1.
[20]: [19] + ([17] - [18]).
[21]: Cumulative sum of [20].
[23]: NPV([12] at [17]) x (1 + [12])^[4].

Table B1

Table B1: Aero Operations and Maintenance Cost Escalation

	Dates						
1	Cost Estimate Date		[1]	Control Table	1-Apr-2024		
2	Mid-Point Construction Date		[2]	See notes	1-Jul-2025		
3	Months to Escalate		[3]	See notes	15		
4	Start of Year for Mid-Point Construction Date		[4]	See notes	1-Jan-2025		
5	Months of Cost Escalation in 2024		[5]	See notes	9		
6	Months of Cost Escalation in 2025		[6]	See notes	6		
	Technical Assumptions						
7	Technology		[7]	Control Table	Aero		
8	Net Capacity (MW), based on Summer condition (94°F)	MW	[8]	Table C8	244		
9	Net Capacity (MW), based on ISO condition (59°F)	MW	[9]	Table C8	291		
10	Net Capacity (MW), based on Winter condition (37°F)	MW	[10]	Table C8	301		
	Percentage Cost Assumptions						
11	Property Taxes	% of Overnight Capital Costs	[11]	Table C8	0.32%		
12	Insurance	% of Overnight Capital Costs	[12]	Table C8	0.63%		
	Escalation Rates						
13	Inflation Forecast, 2024	%	[13]	Control Table	3.02%		
14	Inflation Forecast, 2025	%	[14]	Control Table	2.33%		
15	Average Monthly Inflation, 2024	%	[15]	See notes	0.25%		
16	Average Monthly Inflation, 2025	%	[16]	See notes	0.19%		
17	Overall Inflation between Cost Estimate Date and Mid-Point Construction Date	%	[17]	See notes	3.44%		
18	Monthly Escalation Rate for CT O&M	%	[18]	See notes	0.23%		
					Before Cost Escalation	**Nominal Monthly Cost Escalation Rate**	**After Cost Escalation**
					2024$	%	Nominal$
					[A]	[B]	[C]
						See notes	See notes
19	**Overnight Capital Costs**	Nominal $	[19]	Table B5	$501,227,500		$513,328,930
20	**Fixed O&M Cost Components**						
21	Long-term Service Agreement (LTSA)	Nominal $/year	[21]	Table C10	$511,000	0.23%	$529,000
22	Labor	Nominal $/year	[22]	Table C10	$2,413,000	0.23%	$2,496,000
23	Maintenance and Minor Repairs	Nominal $/year	[23]	Table C10	$51,000	0.23%	$53,000
24	Administrative and General	Nominal $/year	[24]	Table C10	$166,000	0.23%	$172,000
25	Asset Management	Nominal $/year	[25]	Table C10	$367,000	0.23%	$380,000
26	Property Taxes	Nominal $/year	[26]	[19] x [11]	$1,585,000		$1,623,000
27	Insurance	Nominal $/year	[27]	[19] x [12]	$3,170,000		$3,247,000
28	Firm Gas Contract	Nominal $/year	[28]	Table C10	$3,078,000	0.23%	$3,184,000

	Total FOM						
29	**Total Fixed O&M Cost**	**Nominal $/year**	**[29]**	**SUM([21]:[28])**	**$11,341,000**		**$11,684,000**
30	Total Fixed O&M Cost, Summer	Nominal $/kW-yr	[30]	See notes	$46.44		$47.85
31	**Total Fixed O&M Cost, ISO**	**Nominal $/kW-yr**	**[31]**	**See notes**	**$38.97**		**$40.15**
32	Total Fixed O&M Cost, Winter	Nominal $/kW-yr	[32]	See notes	$37.70		$38.84
	Variable O&M Costs						
33	**Variable O&M Costs, based on Summer Capacity**	**Nominal $/MWh**	**[33]**	**[34] + [35]**	**$9.00**		**$9.31**
34	Major Maintenance - Hours Based	Nominal $/MWh	[34]	Table C10	$8.26	0.23%	$8.54
35	Consumables	Nominal $/MWh	[35]	Table C10	$0.74	0.23%	$0.77
36	**Variable O&M Costs, based on ISO Capacity**	**Nominal $/MWh**	**[36]**	**[37] + [38]**	**$7.66**		**$7.92**
37	Major Maintenance - Hours Based	Nominal $/MWh	[37]	Table C10	$6.93	0.23%	$7.17
38	Consumables	Nominal $/MWh	[38]	Table C10	$0.73	0.23%	$0.76
39	**Variable O&M Costs, based on Winter Capacity**	**Nominal $/MWh**	**[39]**	**[40] + [41]**	**$7.44**		**$7.70**
40	Major Maintenance - Hours Based	Nominal $/MWh	[40]	Table C10	$6.71	0.23%	$6.94
41	Consumables	Nominal $/MWh	[41]	Table C10	$0.73	0.23%	$0.76

Notes and Sources:

[B]: All cost components are escalated at the monthly escalation rate in [18].

[C]: [A] x (1 + [B]) ^ [3]. Rounded to the nearest 1000$.

[2]: Calculated based on online date from Control Table minus the number of months to completion from Table C16 plus the number of months to 50% capital drawdown from Table C16.

[3]: Number of months between [1] and [2].

[4]: Start of Year for Mid-Point Construction Date.

[5]: Number of months between [1] and [4].

[6]: Number of months between [4] and [2].

[15]: (1 + [13]) ^ (1/12) - 1.

[16]: (1 + [14]) ^ (1/12) - 1.

[17]: ((1 + [15]) ^ [5]) x ((1 + [16]) ^ [6]) - 1.

[18]: (1 + [17]) ^ (1 / [3]) - 1.

[30]: [29] / ([8] x 1000).

[31]: [29] / ([9] x 1000).

[32]: [29] / ([10] x 1000).

Table B2

Table B2: PV + BESS Operations and Maintenance Cost Escalation

	Dates						
1	Cost Estimate Date		[1]	Control Table	1-Apr-2024		
2	Mid-Point Construction Date		[2]	See notes	1-Oct-2025		
3	Months to Escalate		[3]	See notes	18		
4	Start of Year for Mid-Point Construction Date		[4]	See notes	1-Jan-2025		
5	Months of Cost Escalation in 2024		[5]	See notes	9		
6	Months of Cost Escalation in 2025		[6]	See notes	9		
	Technical Assumptions						
7	Technology		[7]	Control Table	PV + BESS		
8	Plant PV Capacity	MW	[8]	Table C11	200		
	Percentage Cost Assumptions						
9	Property Taxes	% of Overnight Capital Costs	[9]	Table C11	0.60%		
10	Insurance	% of Overnight Capital Costs	[10]	Table C11	0.30%		
	Escalation Rates						
11	Inflation Forecast, 2024	%	[11]	Control Table	3.02%		
12	Inflation Forecast, 2025	%	[12]	Control Table	2.33%		
13	Average Monthly Inflation, 2024	%	[13]	See notes	0.25%		
14	Average Monthly Inflation, 2025	%	[14]	See notes	0.19%		
15	Overall Inflation between Cost Estimate Date and Mid-Point Construction Date	%	[15]	See notes	4.04%		
16	Monthly Escalation Rate for PV + BESS O&M	%	[16]	See notes	0.22%		
					Before Cost Escalation	**Nominal Monthly Cost Escalation Rate**	**After Cost Escalation**
					[A]	[B]	[C]
					2024$	%	Nominal$
						See notes	See notes
17	**Overnight Capital Costs**	Nominal $	[17]	Table B6	$359,076,064		$348,571,935
	Fixed O&M Cost Components						
18	Maintenance	Nominal $/year	[18]	Table C14	$4,370,000	0.22%	$4,546,000
19	Land Lease	Nominal $/year	[19]	Table C14	$700,000	0.22%	$728,000
20	Property Taxes	Nominal $/year	[20]	[9] x [17]	$2,154,000		$2,091,000
21	Insurance	Nominal $/year	[21]	[10] x [17]	$1,077,000		$1,046,000
	Fixed O&M Costs, No Augmentation						
22	**Total Fixed O&M Cost, No Augmentation**	**Nominal $/year**	**[22]**	**SUM([18]:[21])**	**$8,301,000**		**$8,411,000**
23	Unit Fixed O&M Cost, No Augmentation	Nominal $/kW-yr	[23]	See notes	$41.51		$42.06

Notes and Sources:

[B]: All cost components are escalated at the monthly escalation rate in [16].

[C]: [A] x (1 + [B]) ^ [3]. Rounded to the nearest 1000$.

[2]: Calculated based on online date from Control Table minus the number of months to completion from Table C16 plus the number of months to 50% capital drawdown from Table C16.

[3]: Number of months between [1] and [2].

[4]: Start of Year for Mid-Point Construction Date.
[5]: Number of months between [1] and [4].
[6]: Number of months between [4] and [2].
[13]: (1 + [11]) ^ (1/12) - 1.
[14]: (1 + [12]) ^ (1/12) - 1.
[15]: ((1 + [13]) ^ ([5]) x ((1 + [14]) ^ ([6]) - 1.
[16]: (1 + [15]) ^ (1 / [3]) - 1.
[23]: [22] / ([8] x 1000).

Table B3

Table B3: Annual Fixed Operations and Maintenance Costs

	Dates				
1	Cost Estimate Date		[1]	Control Table	1-Apr-2024
2	Mid-Point Construction Date		[2]	Control Table	1-Jul-2025
3	Online Date		[3]	Control Table	1-Jun-2026
4	Months to Escalate		[4]	See notes	15
	Inputs				
5	Technology		[5]	Control Table	Aero
6	Plant Capacity	MW	[6]	Control Table	291
7	Inflation Forecast, 2026 and Beyond	%	[7]	Control Table	2.20%
8	Overnight Capital Costs	Nominal$	[8]	See notes	$513,328,930
9	First Year Fixed O&M	Nominal$	[9]	See notes	$11,684,000
10	First Year Property Tax	Nominal$	[10]	Table B4	$1,623,268
11	First Year Firm Gas Cost	Nominal$	[11]	Table B1	$3,184,000
12	Working Capital	% of Overnight Capital Costs	[12]	Table C1	0.50%
13	Annual Financing Costs Debt Rate	%	[13]	Table C1	6.21%
	Calculated Scalars				
14	First Year Working Capital	Nominal$	[14]	See notes	$160,915
15	First Year FOM (excl. prop. tax, firm gas and working capital)	Nominal$	[15]	See notes	$6,876,732
16	Monthly Escalation Rate for O&M	%	[16]	See notes	0.18%
17	Overall Cost Escalation	%	[17]	See notes	2.76%

	Augmentation Costs																
18	Year		[18]		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
19	Year for Cost Escalation		[19]	[18] - 2025	1	2	3	4	5	6	7	8	9	10	11	12	13
20	Augmentation Schedule		[20]	See notes	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Augmentation Costs	2024$	[21]	See notes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Annual Fixed O&M Costs (Nominal)																
22	FOM (excl. prop. tax, firm gas and working capital)	Nominal$	[22]	See notes	$6,876,732	$7,028,021	$7,182,637	$7,340,655	$7,502,149	$7,667,197	$7,835,875	$8,008,264	$8,184,446	$8,364,504	$8,548,523	$8,736,590	$8,928,795
23	Augmentation	Nominal$	[23]	See notes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Property Tax	Nominal$	[24]	Table B4	$1,623,268	$1,658,979	$1,695,477	$1,732,778	$1,770,899	$1,809,858	$1,849,675	$1,890,368	$1,931,956	$1,974,459	$2,017,897	$2,062,291	$2,107,662
25	Firm Gas (CT only)	Nominal$	[25]	See notes	$3,184,000	$3,254,048	$3,325,637	$3,398,801	$3,473,575	$3,549,993	$3,628,093	$3,707,911	$3,789,485	$3,872,854	$3,958,057	$4,045,134	$4,134,127
26	Working Capital	Nominal$	[26]	See notes	$160,915	$164,455	$168,073	$171,771	$175,550	$179,412	$183,359	$187,393	$191,516	$195,729	$200,035	$204,436	$208,933
27	**Total FOM Cost**	**Nominal$**	**[27]**	**SUM([22]:[26])**	**$11,844,915**	**$12,105,503**	**$12,371,824**	**$12,644,004**	**$12,922,173**	**$13,206,460**	**$13,497,003**	**$13,793,937**	**$14,097,403**	**$14,407,546**	**$14,724,512**	**$15,048,451**	**$15,379,517**

	Augmentation Costs												
18	Year	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
19	Year for Cost Escalation	14	15	16	17	18	19	20	21	22	23	24	25
20	Augmentation Schedule	0	0	0	0	0	0	0	0	0	0	0	0
21	Augmentation Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Annual Fixed O&M Costs (Nominal)												
22	FOM (excl. prop. tax, firm gas and working capital)	$9,125,229	$9,325,984	$9,531,156	$9,740,841	$9,955,140	$10,174,153	$10,397,984	$10,626,740	$10,860,528	$11,099,460	$11,343,648	$11,593,208
23	Augmentation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Property Tax	$2,154,030	$2,201,419	$2,249,850	$2,299,347	$2,349,932	$2,401,631	$2,454,467	$2,508,465	$2,563,651	$2,620,051	$2,677,693	$2,736,602
25	Firm Gas (CT only)	$4,225,078	$4,318,029	$4,413,026	$4,510,113	$4,609,335	$4,710,741	$4,814,377	$4,920,293	$5,028,540	$5,139,167	$5,252,229	$5,367,778
26	Working Capital	$213,530	$218,228	$223,029	$227,935	$232,950	$238,075	$243,312	$248,665	$254,136	$259,727	$265,441	$271,280
27	**Total FOM Cost**	**$15,717,867**	**$16,063,660**	**$16,417,060**	**$16,778,236**	**$17,147,357**	**$17,524,599**	**$17,910,140**	**$18,304,163**	**$18,706,854**	**$19,118,405**	**$19,539,010**	**$19,968,868**

Notes and Sources:

[4]: Number of months between [1] and [2].
[8]: If technology selected is Aero: Table B5. If PV + BESS: Table B6.
[9]: If technology selected is Aero: Table B1. If PV + BESS: Table B2.
[14]: [8] x [12] x [13].
[15]: [9] - [10] - [11].
[16]: (1 + [7]) ^ (1/12) - 1.
[17]: ((1 + [16]) ^ [4]) - 1.
[20]: Based on a five-year augmentation schedule for PV + BESS resource.
[21]: If technology selected is PV + BESS: Table C7. If Aero: 0.
[22]: [15] x (1 + [7])^ ([19] - 1).
[23]: (1 + [17]) x [21].
[25]: [11] x (1 + [7]) ^ ([19] - 1).
[26]: [14] x (1 + [7]) ^ ([19] - 1).

Table B4

Table B4: Annual Property Tax Costs

	Inputs				**Aero**	**PV + BESS**
1	Overnight Capital Costs	Nominal$	[1]	See notes	$513,328,930	$348,571,935
2	Property Tax Rate	%	[2]	See notes	0.32%	0.60%
3	Inflation Forecast, 2026 and Beyond	%	[3]	Control Table	2.20%	2.20%

4	Year		[4]		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
5	Year for Cost Escalation		[5]	[4] - 2025	1	2	3	4	5	6	7	8	9	10	11	12
	Annual Property Tax Costs (Nominal)															
6	Aero	Nominal$	[6]	See notes	$1,623,268	$1,658,979	$1,695,477	$1,732,778	$1,770,899	$1,809,858	$1,849,675	$1,890,368	$1,931,956	$1,974,459	$2,017,897	$2,062,291
7	PV + BESS	Nominal$	[7]	See notes	$2,091,432	$2,137,443	$2,184,467	$2,232,525	$2,281,641	$2,331,837	$2,383,137	$2,435,566	$2,489,149	$2,543,910	$2,599,876	$2,657,073

4	Year	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
5	Year for Cost Escalation	13	14	15	16	17	18	19	20	21	22	23	24	25
	Annual Property Tax Costs (Nominal)													
6	Aero	$2,107,662	$2,154,030	$2,201,419	$2,249,850	$2,299,347	$2,349,932	$2,401,631	$2,454,467	$2,508,465	$2,563,651	$2,620,051	$2,677,693	$2,736,602
7	PV + BESS	$2,715,529	$2,775,270	$2,836,326	$2,898,726	$2,962,498	$3,027,673	$3,094,281	$3,162,355	$3,231,927	$3,303,030	$3,375,696	$3,449,962	$3,525,861

Notes and Sources:

[1]: If technology is Aero: Table B5. If PV + BESS: Table B6.
[2]: If technology is Aero: Table C8. If PV + BESS: Table C11.
[4]: Resource first incurs property taxes during online year (2026) and throughout its economic life.
[6] and [7]: [1] x [2] x (1+[3]) ^ ([5]-1).

Table B5

Table B5: Aero Capital Cost Escalation

	Dates						
1	Cost Estimate Date		[1]	Control Table	1-Apr-2024		
2	Mid-Point Construction Date		[2]	See notes	1-Jul-2025		
3	Months to Escalate		[3]	See notes	15		
4	Start of Year for Mid-Point Construction Date		[4]	See notes	1-Jan-2025		
5	Months of Cost Escalation in 2024		[5]	See notes	9		
6	Months of Cost Escalation in 2025		[6]	See notes	6		
	Technical Assumptions						
7	Technology		[7]	Control Table	Aero		
8	Net Capacity (MW), based on Summer condition (94°F)	MW	[8]	Table C8	244		
9	Net Capacity (MW), based on ISO condition (59°F)	MW	[9]	Table C8	291		
10	Net Capacity (MW), based on Winter condition (37°F)	MW	[10]	Table C8	301		
	Percentage Cost Assumptions						
11	Sales Tax Rate	%	[11]	Table C9	7.50%		
12	EPC Contractor Fee	% of other EPC costs	[12]	Table C8	9.00%		
13	EPC Contingency	% of other EPC costs	[13]	Table C8	10.00%		
14	Project Development Cost	% of EPC costs	[14]	Table C8	5.00%		
15	Mobilization and Start-Up	% of EPC costs	[15]	Table C8	1.00%		
16	Non-Fuel Inventories	% of EPC costs	[16]	Table C8	1.50%		
17	Owner's Contingency	% of other owner's costs	[17]	Table C8	10.00%		
	Escalation Rates						
18	Inflation Forecast, 2024	%	[18]	Control Table	3.02%		
19	Inflation Forecast, 2025	%	[19]	Control Table	2.33%		
20	Average Monthly Inflation, 2024	%	[20]	See notes	0.25%		
21	Average Monthly Inflation, 2025	%	[21]	See notes	0.19%		
22	Overall Inflation between Cost Estimate Date and Mid-Point Construction Date	%	[22]	See notes	3.44%		
23	Nominal Monthly Escalation Rate for Inflation	%	[23]	See notes	0.23%		
24	Real NGCT Cost Escalation (2024 - 2025)	%	[24]	Table C5	-0.80%		
25	Real Monthly Escalation Rate for NGCT Components	%	[25]	See notes	-0.07%		
26	Monthly Escalation Rate for CT Components	%	[26]	[23] + [25]	0.16%		
27	Monthly Escalation Rate for Other Components	%	[27]	[23]	0.23%		
					Before Cost Escalation	**Nominal Monthly Cost Escalation Rate**	**After Cost Escalation**
					[A]	[B]	[C]
					2024$	%	Nominal$
						See notes	See notes
	EPC Costs						
28	CTG Equipment Costs	$	[28]	Table C9	$204,913,000	0.16%	$209,849,000
29	SCR & CEMS Equipment Costs	$	[29]	Table C9	$39,108,000	0.16%	$40,050,000
30	Other Equipment	$	[30]	Table C9	$36,603,000	0.16%	$37,485,000
31	Construction Labor	$	[31]	Table C9	$56,125,000	0.16%	$57,477,000
32	Other Labor	$	[32]	Table C9	$31,845,000	0.16%	$32,612,000
33	Materials	$	[33]	Table C9	$17,081,000	0.16%	$17,492,000
34	Sales Tax	$	[34]	Table C9	$1,281,000		$1,312,000
35	Subtotal - EPC Costs w/o EPC Fee and Contingency	$	[35]	SUM([28]:[34])	$386,956,000		$396,277,000
36	EPC Contractor Fee	$	[36]	[12] x [35]	$34,826,000		$35,664,930

37	EPC Contingency	$	[37]	[13] x [35]	$38,696,000		$39,627,700
38	**Total EPC Costs**	**$**	**[38]**	**SUM([35]:[37])**	**$460,478,000**		**$471,569,630**
	Non-EPC Costs						
39	Project Development	$	[39]	[14] x [38]	$23,024,000		$23,578,000
40	Mobilization and Start-Up	$	[40]	[15] x [38]	$4,605,000		$4,716,000
41	Net Start-Up Fuel Costs	$	[41]	Table C9	$0	0.23%	$0
42	Electrical Interconnection	$	[42]	Table C9	$0	0.23%	$0
43	Gas Interconnection	$	[43]	Table C9	$1,750,000	0.23%	$1,810,000
44	Land	$	[44]	Table C9	$759,000	0.23%	$785,000
45	Non-Fuel Inventories	$	[45]	[16] x [38]	$6,907,000		$7,074,000
46	Owner's Contingency	$	[46]	See notes	$3,704,500		$3,796,300
47	**Total Non-EPC Costs**	**$**	**[47]**	**SUM([39]:[46])**	**$40,749,500**		**$41,759,300**
	Overnight Costs						
48	Overnight Capital Costs	$	[48]	[38] + [47]	$501,227,500		$513,328,930
49	Overnight Capital Costs, Summer	$/kW	[49]	See notes	$2,053		$2,102
50	**Overnight Capital Costs, ISO**	**$/kW**	**[50]**	**See notes**	**$1,722**		**$1,764**
51	Overnight Capital Costs, Winter	$/kW	[51]	See notes	$1,666		$1,707

Notes and Sources:

[B]: [26] or [27].

[C]: [A] x (1 + [B]) ^ ([3]). Rounded to the nearest 1000$.

[2]: Calculated based on online date from Control Table minus the number of months to completion from Table C16 plus the number of months to 50% capital drawdown from Table C16.

[3]: Number of months between [1] and [2].

[4]: Start of Year for Mid-Point Construction Date.

[5]: Number of months between [1] and [4].

[6]: Number of months between [4] and [2].

[20]: (1 + [18]) ^ (1/12) - 1.

[21]: (1 + [19]) ^ (1/12) - 1.

[22]: ((1 + [20]) ^ [5]) x ((1 + [21]) ^ [6]) - 1.

[23]: ((1 + [22]) ^ (1 / [3]) - 1.

[25]: ((1 + [24]) ^ (1/12) - 1.

[46]: [17] x SUM([39]:[45]).

[49]: [48] / ([8] x 1000).

[50]: [48] / ([9] x 1000).

[51]: [48] / ([10] x 1000).

Table B6

Table B6: PV + BESS Capital Cost Escalation

	Dates				
1	Cost Estimate Date		[1]	Control Table	1-Apr-2024
2	Mid-Point Construction Date		[2]	See notes	1-Oct-2025
3	Months to Escalate		[3]	See notes	18
4	Start of Year for Mid-Point Construction Date		[4]	See notes	1-Jan-2025
5	Months of Cost Escalation in 2024		[5]	See notes	9
6	Months of Cost Escalation in 2025		[6]	See notes	9
	Technical Assumptions				
7	Technology		[7]	Control Table	PV + BESS
8	Plant PV Capacity	MW	[8]	Table C11	200
	Percentage Cost Assumptions				
9	EPC Contractor Fee	% of subtotal EPC costs	[9]	Table C11	5.00%
10	EPC Contingency	% of other EPC costs	[10]	Table C11	5.00%
11	Project Development Cost	% other EPC costs	[11]	Table C11	5.00%
12	Mobilization and Start-Up Cost	% other EPC costs	[12]	Table C11	1.00%
13	Owner Contingency	% of owner's costs	[13]	Table C11	10.00%
	Escalation Rates				
14	Inflation Forecast, 2024	%	[14]	Control Table	3.02%
15	Inflation Forecast, 2025	%	[15]	Control Table	2.33%
16	Average Monthly Inflation, 2024	%	[16]	See notes	0.25%
17	Average Monthly Inflation, 2025	%	[17]	See notes	0.19%
18	Overall Inflation between Cost Estimate Date and Mid-Point Construction Date	%	[18]	See notes	4.04%
19	Nominal Monthly Escalation Rate for Inflation	%	[19]	See notes	0.22%
20	Real PV + BESS Cost Escalation (2024 - 2025)	%	[20]	Table C5	-5.72%
21	Real Monthly Escalation Rate for PV + BESS Components	%	[21]	See notes	-0.49%
22	Nominal Monthly Escalation Rate for PV + BESS Components	%	[22]	[19] + [21]	-0.27%
23	Nominal Monthly Escalation Rate for Other Components	%	[23]	[21]	0.22%

Before Cost Escalation	Nominal Monthly Cost Escalation Rate	After Cost Escalation
[A]	[B]	[C]
2024$	%	Nominal$
	See notes	See notes

	EPC Costs						
24	Batteries and Enclosures Equipment	$	[24]	Table C12	$82,125,000	-0.27%	$78,229,000
25	BESS BOP Equipment	$	[25]	Table C12	$10,686,000	-0.27%	$10,179,000
26	PV Module Supply Equipment	$	[26]	Table C12	$70,963,000	-0.27%	$67,596,000
27	PV Inverter Supply Equipment	$	[27]	Table C12	$14,735,000	-0.27%	$14,036,000
28	PV Racking, Tracker and BOP Equipment Supply	$	[28]	Table C12	$63,741,000	-0.27%	$60,717,000
29	Main Power Transformer & Substation	$	[29]	Table C12	$8,610,000	0.22%	$8,958,000
30	Construction and Installation	$	[30]	Table C12	$35,095,000	0.22%	$36,512,000
31	SCADA Subcontract	$	[31]	Table C12	$1,220,000	0.22%	$1,269,000
32	Civil/Structural/Architectural Subcontract	$	[32]	Table C12	$18,353,000	0.22%	$19,094,000
33	Subtotal - EPC Costs w/o EPC Fee and Contingency	$	[33]	SUM([24]:[32])	$305,528,000		$296,590,000
34	EPC Contractor Fee	$	[34]	[9] x [33]	$15,276,400		$14,829,500
35	EPC Contingency	$	[35]	See notes	$16,040,000		$15,571,000
36	**Total EPC Costs**	**$**	**[36]**	**SUM([33]:[35])**	**$336,844,400**		**$326,990,500**
	Non-EPC Costs						
37	Project Development	$	[37]	[11] x [36]	$16,842,220		$16,349,530
38	Mobilization and Start-Up	$	[38]	[12] x [36]	$3,368,444		$3,269,905
39	Electrical Interconnection	$	[39]	Table C12	$0		$0
40	Owner's Contingency	$	[40]	See notes	$2,021,000		$1,962,000
41	Subtotal Non-EPC Costs w/o Financing Fees	$	[41]	SUM([37]:[40])	$22,231,664		$21,581,435
42	Financing Fees	$	[42]	Table C12	$0		$0
43	**Total Non-EPC Costs**	**$**	**[43]**	**[41] + [42]**	**$22,231,664**		**$21,581,435**
	Overall Costs						
44	Overnight Capital Costs	$	[44]	[36] + [43]	$359,076,064		$348,571,935
45	**Overnight Capital Costs**	**$/kW**	**[45]**	**See notes**	**$1,795**		**$1,743**

Notes and Sources:

[B]: [22] or [23].

[C]: [A] x (1 + [B]) ^ ([3]). Rounded to the nearest 1000$.

[2]: Calculated based on online date from Control Table minus the number of months to completion from Table C16 plus the number of months to 50% capital drawdown from Table C16.

[3]: Number of months between [1] and [2].

[4]: Start of Year for Mid-Point Construction Date.

[5]: Number of months between [1] and [4].

[6]: Number of months between [4] and [2].

[16]: (1 + [14]) ^ (1/12) - 1.

[17]: (1 + [15]) ^ (1/12) - 1.

[18]: ((1 + [16]) ^ [5]) x ((1 + [17]) ^ [6]) - 1.

[19]: (1 + [18]) ^ (1 / [3]) - 1.

[21]: (1 + [20]) ^ (1/12) - 1.

[35]: [10] x ([33] + [34]).

[40]: [13] x ([37] + [38] + [39]).

[45]: [44] / ([8] x 1000).

Table C1

Table C1: Inputs for Reference and Alternative Technology

		Input Category	Units	Variable [A]
1	[1]	Working Capital	% of Overnight Capital Cost	0.50%
2	[2]	Annual Financing Costs Debt Rate	%	6.21%
3	[3]	Corporate Income Tax Rate, Federal	%	21.00%
4	[4]	Corporate Income Tax Rate, State	%	0.50%
5	[5]	Sales Tax Rate	%	7.50%

Notes and Sources:

[1]: https://www.brattle.com/wp-content/uploads/2022/05/PJM-CONE-2026-27-Report.pdf

[2]: Short-Term Debt Borrowing Rate for corporates with a BB credit rating, Bloomberg.

[3]: https://www.govinfo.gov/content/pkg/BILLS-115hr1enr/pdf/BILLS-115hr1enr.pdf

[4]: https://taxfoundation.org/data/all/state/state-gross-receipts-taxes-2022/

[5]: https://www.austinchamber.com/economic-development/taxes-incentives/sales-use-tax
https://comptroller.texas.gov/taxes/sales/city.php

Table C2

Table C2: Land Cost

		Input Category	Units	Reference Technology Harris County Aero [A]	Alternative Technology Brazoria County PV + BESS [B]
1	[1]	Observations	Count	2	9
2	[2]	Range of Land Prices	2024$/Acre	$20,834 to $69,079	$10,000 to $68,000
3	[3]	Average Land Price	2024$/Acre	$25,299	$22,084

Notes and Sources:
[1] - [3]: https://www.loopnet.com/
https://www.landandfarm.com/

Table C3

Table C3: Tax Depreciation for Property

Year	Modified Accelerated Cost Recovery System (MACRS)						Straight Line Deprecation (SLD)					
	3-year	5-year	7-year	10-year	15-year	20-year	5-year	10-year	20-year	30-year	40-year	50-year
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
	See notes	See notes	See notes	See notes	See notes	See notes	See notes	See notes	See notes	See notes	See notes	See notes
1	41.67%	25.00%	17.85%	12.50%	6.25%	4.69%	12.50%	6.25%	3.13%	2.08%	1.56%	1.25%
2	38.89%	30.00%	23.47%	17.50%	9.38%	7.15%	20.00%	10.00%	5.00%	3.33%	2.50%	2.00%
3	14.14%	18.00%	16.76%	14.00%	8.44%	6.61%	20.00%	10.00%	5.00%	3.33%	2.50%	2.00%
4	5.30%	11.37%	11.97%	11.20%	7.59%	6.12%	20.00%	10.00%	5.00%	3.33%	2.50%	2.00%
5		11.37%	8.87%	8.96%	6.83%	5.66%	20.00%	10.00%	5.00%	3.33%	2.50%	2.00%
6		4.26%	8.87%	7.17%	6.15%	5.23%	7.50%	10.00%	5.00%	3.33%	2.50%	2.00%
7			8.87%	6.55%	5.91%	4.84%		10.00%	5.00%	3.33%	2.50%	2.00%
8			3.34%	6.55%	5.90%	4.48%		10.00%	5.00%	3.33%	2.50%	2.00%
9				6.56%	5.91%	4.46%		10.00%	5.00%	3.33%	2.50%	2.00%
10				6.55%	5.90%	4.46%		10.00%	5.00%	3.33%	2.50%	2.00%
11				2.46%	5.91%	4.46%		3.75%	5.00%	3.33%	2.50%	2.00%
12					5.90%	4.46%			5.00%	3.33%	2.50%	2.00%
13					5.91%	4.46%			5.00%	3.33%	2.50%	2.00%
14					5.90%	4.46%			5.00%	3.33%	2.50%	2.00%
15					5.91%	4.46%			5.00%	3.33%	2.50%	2.00%
16					2.21%	4.46%			5.00%	3.33%	2.50%	2.00%
17						4.46%			5.00%	3.33%	2.50%	2.00%
18						4.46%			5.00%	3.33%	2.50%	2.00%
19						4.46%			5.00%	3.33%	2.50%	2.00%
20						4.46%			5.00%	3.33%	2.50%	2.00%
21						1.67%			1.88%	3.33%	2.50%	2.00%
22										3.33%	2.50%	2.00%
23										3.33%	2.50%	2.00%
24										3.33%	2.50%	2.00%
25										3.33%	2.50%	2.00%
26										3.33%	2.50%	2.00%
27										3.33%	2.50%	2.00%
28										3.33%	2.50%	2.00%
29										3.33%	2.50%	2.00%
30										3.33%	2.50%	2.00%
31										1.25%	2.50%	2.00%
32											2.50%	2.00%
33											2.50%	2.00%
34											2.50%	2.00%
35											2.50%	2.00%

36	2.50%	2.00%
37	2.50%	2.00%
38	2.50%	2.00%
39	2.50%	2.00%
40	2.50%	2.00%
41	0.94%	2.00%
42		2.00%
43		2.00%
44		2.00%
45		2.00%
46		2.00%
47		2.00%
48		2.00%
49		2.00%
50		2.00%
51		0.75%

Notes and Sources:

How To Depreciate Property: For use in preparing 2023 Returns (Publication 946), Internal Revenue Service, Department of the Treasury.

https://www.irs.gov/pub/irs-pdf/p946.pdf

[A] - [F]: Table A-3. 3-, 5-, 7-, 10-, 15-, and 20-Year Property Mid-Quarter Convention Placed in Service in Second Quarter.

[G] - [L]: Table A-10. Straight Line Method Mid Quarter Convention Placed in Service in Second Quarter.

Table C4

Table C4: Inflation Forecast

Year [A]	Forecasted Inflation Rate [B]
2024	3.0%
2025	2.3%
2026	2.2%
2027	2.2%
2028	2.2%
2029	2.2%
2030	2.2%
2031	2.2%
2032	2.2%
2033	2.2%
2034	2.2%
2035	2.2%
2036	2.2%
2037	2.2%
2038	2.2%
2039	2.2%
2040	2.2%
2041	2.2%
2042	2.2%
2043	2.2%
2044	2.2%
2045	2.2%
2046	2.2%
2047	2.2%
2048	2.2%

2049	2.2%
2050	2.2%

Notes and Sources:
March 2024 and May 2024 Blue Chip Economic Indicators, Wolters Kluwer.

Table C5

Table C5: PV + BESS Cost Trends

	Year					2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1	Overnight Capital Cost for Utility PV, Moderate Case	2021$/kW	[1]	See notes		$1,245	$1,204	$1,164	$1,123	$1,083	$1,043	$1,002	$962	$921	$881	$841	$800	$788
2	Overnight Capital Cost for 2-hour BESS, Moderate Case	2021$/kW	[2]	See notes		$980	$862	$839	$817	$794	$771	$749	$739	$728	$718	$708	$697	$687
3	PV Capacity	MW	[3]	Table C11		200	200	200	200	200	200	200	200	200	200	200	200	200
4	BESS Capacity	MW	[4]	Table C11		100	100	100	100	100	100	100	100	100	100	100	100	100
5	Total Overnight Capital Cost	2021$	[5]	See notes		$346,909,423	$327,058,571	$316,704,129	$306,353,902	$296,008,398	$285,668,213	$275,334,045	$266,228,543	$257,122,326	$248,015,366	$238,907,633	$229,799,097	$226,235,342
6	Real Cost Escalation Rate	%	[6]	See notes			-5.72%	-3.17%	-3.27%	-3.38%	-3.49%	-3.62%	-3.31%	-3.42%	-3.54%	-3.67%	-3.81%	-1.55%
7	**Real PV + BESS Cost Escalation (2024 - 2025)**	%	**[7]**	**See notes**	**-5.72%**													
8	**Long-Term Real PV + BESS Cost Escalation (2025 - 2050)**	%	**[8]**	**See notes**	**-3.02%**													

	Year	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
1	Overnight Capital Cost for Utility PV, Moderate Case	$775	$762	$750	$737	$724	$712	$699	$686	$674	$661	$648	$636	$623	$610
2	Overnight Capital Cost for 2-hour BESS, Moderate Case	$677	$666	$656	$646	$635	$625	$615	$604	$594	$583	$573	$562	$552	$541
3	PV Capacity	200	200	200	200	200	200	200	200	200	200	200	200	200	200
4	BESS Capacity	100	100	100	100	100	100	100	100	100	100	100	100	100	100
5	Total Overnight Capital Cost	$222,670,716	$219,105,184	$215,538,707	$211,971,245	$208,402,755	$204,833,192	$201,262,507	$197,690,649	$194,117,565	$190,543,197	$186,967,484	$183,390,360	$179,811,757	$176,231,600
6	Real Cost Escalation Rate	-1.58%	-1.60%	-1.63%	-1.66%	-1.68%	-1.71%	-1.74%	-1.77%	-1.81%	-1.84%	-1.88%	-1.91%	-1.95%	-1.99%
7	**Real PV + BESS Cost Escalation (2024 - 2025)**														
8	**Long-Term Real PV + BESS Cost Escalation (2025 - 2050)**														

Notes and Sources:

[1]: Solar Utility PV, 2023 NREL ATB (Moderate Case).
[2]: Utility-Scale Battery Storage, 2023 NREL ATB (Moderate Case).
[5]: ([1] x [3] x 1000) + ([2] x [4] x 1000).
[6]: [5]/[5]t-1 - 1.
[7]: [6] at 2025.
[8]: Long-term equivalent fixed cost escalation rate from 2025 to 2050 that results in the same NPV as variable cost decline rates from NREL ATB at the real ATWACC. See 2026 ERCOT CONE Report .

Table C6

Table C6: Aero CT Cost Trends

						2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
	Year					2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
1	Overnight Capital Cost for NGCT (F-Frame), Moderate Case	2021$/kW	[1]	See notes		$987	$979	$971	$963	$955	$947	$939	$931	$923	$915	$908	$900	$892	$884
2	Index (2024 = 100)		[2]	See notes		100	99	98	98	97	96	95	94	94	93	92	91	90	90
3	NREL ATB Annual Escalation Rate	%	[3]	See notes			-0.80%	-0.81%	-0.82%	-0.82%	-0.83%	-0.83%	-0.84%	-0.86%	-0.86%	-0.86%	-0.87%	-0.89%	-0.89%
4	Average Escalation Rate	%	[4]	See notes			-0.80%	-0.80%	-0.81%	-0.81%	-0.82%	-0.82%	-0.82%	-0.83%	-0.83%	-0.83%	-0.84%	-0.84%	-0.84%
5	**Real NGCT Cost Escalation (2024 - 2025)**	**%**	**[5]**	**See notes**	**-0.80%**														

		2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
	Year	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
1	Overnight Capital Cost for NGCT (F-Frame), Moderate Case	$876	$868	$860	$852	$844	$836	$828	$820	$812	$805	$797	$789	$781
2	Index (2024 = 100)	89	88	87	86	86	85	84	83	82	82	81	80	79
3	NREL ATB Annual Escalation Rate	-0.89%	-0.90%	-0.92%	-0.92%	-0.93%	-0.94%	-0.94%	-0.97%	-0.96%	-0.97%	-0.98%	-1.00%	-1.00%
4	Average Escalation Rate	-0.85%	-0.85%	-0.86%	-0.86%	-0.86%	-0.87%	-0.87%	-0.88%	-0.88%	-0.88%	-0.89%	-0.89%	-0.90%
5	**Real NGCT Cost Escalation (2024 - 2025)**													

Notes and Sources:

[1]: Natural Gas FE, 2023 NREL ATB (Moderate Case).
[2]: [1] / [1]2024 - 1.
[3]: [2] / [2]t-1 - 1.
[4]: Average cost decline starting in 2024, calculated based on [2].
[5]: [4] at 2025.

Table C7

Table C7: BESS Augmentation Cost Trends

	Inputs				
1	Base Year BESS Augmentation Costs	2024$/kWh	[1]	Table C15	$313.16
2	Augmentation Required	kWh	[2]	Table C15	27,964
3	Investment Tax Credit	%	[3]	Control Table	30%

	BESS Augmentation Cost Calculation																
4	Year				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
5	Overnight Capital Cost for 2-hour BESS, Moderate Case	2021$/kW	[5]	See notes	$980	$862	$839	$817	$794	$771	$749	$739	$728	$718	$708	$697	$687
6	Index (2024 = 100)	%	[6]	See notes	100	88	86	83	81	79	76	75	74	73	72	71	70
7	BESS Augmentation Costs per kWh	2024$/kWh	[7]	See notes	$313.16	$275.53	$268.26	$260.99	$253.75	$246.52	$239.30	$236.02	$232.73	$229.44	$226.15	$222.85	$219.55
8	Total BESS Augmentation Costs	2024$	[8]	See notes	$6,129,974	$5,393,512	$5,251,076	$5,108,903	$4,967,025	$4,825,480	$4,684,311	$4,619,999	$4,555,642	$4,491,238	$4,426,786	$4,362,284	$4,297,730

		2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
5	Overnight Capital Cost for 2-hour BESS, Moderate Case	$677	$666	$656	$646	$635	$625	$615	$604	$594	$583	$573	$562	$552	$541
6	Index (2024 = 100)	69	68	67	66	65	64	63	62	61	60	58	57	56	55
7	BESS Augmentation Costs per kWh	$216.25	$212.95	$209.64	$206.33	$203.02	$199.70	$196.38	$193.06	$189.73	$186.40	$183.07	$179.73	$176.38	$173.03
8	Total BESS Augmentation Costs	$4,233,121	$4,168,455	$4,103,730	$4,038,944	$3,974,093	$3,909,176	$3,844,188	$3,779,127	$3,713,989	$3,648,770	$3,583,468	$3,518,077	$3,452,594	$3,387,014

Notes and Sources:

[5]: Utility-Scale Battery Storage, 2023 NREL ATB (Moderate Case).
[6]: ([5] / [5]2024) x 100.
[7]: [1] x ([6] / 100).
[8]: [2] x [7] x (1 - [3]).

Table C8

Table C8: Aero Cost Assumptions

Technical Assumptions	
Plant Characteristic	**Specification**
Generation Technology	Aeroderivative Combustion Turbine
Turbine Model	GE LM6000PC
Configuration	6 x 0
Net Capacity (MW), based on Summer condition (94°F)	244.2
Net Capacity (MW), based on ISO condition (59°F)	291.0
Net Capacity (MW), based on Winter condition (37°F)	300.8
Fuel Type	Natural gas, no secondary fuel
Combustion Controls	Selective Catalytic Reduction (SCR)
Power Augmentation	SPRay INTercoooling (SPRINT)
Location	Harris County
Firm Gas Contract	Yes

Capital Cost Assumptions		
Cost Category		**Specification**
EPC Contractor Fee	*% of other EPC costs*	9%
EPC Contingency	*% of other EPC costs*	10%
Sales Tax	*% of Equipment & Materials*	7.5%
Project Development Cost	*% of EPC costs*	5%
Mobilization and Start-Up Cost	*% of EPC costs*	1%
Non-Fuel Inventories *(Note 1)*	*% of EPC costs*	1.5%
Owner Contingency	*% of other Owner costs*	10%
Electric Interconnection	*2024$*	*Note 2*
Gas Interconnection Pipeline Cost	*2024$/mile*	$3,500,000
Gas Pipeline Length	*miles*	0.5
Land Purchase Cost	*2024$/acre*	$25,299
Acreage	*acre*	30

O&M Cost Assumptions		
Cost Category		**Specification**
Maintenance and Minor Repairs	*% of LTSA fixed costs*	10%
Firm Gas Annual Fee	*2024$/year*	$3,078,000

Property Tax - Plant *(Note 3)*	*% of overnight capital costs*	0.3%
Insurance	*% of overnight capital costs*	0.6%

Note 1. Non-fuel inventories refer to the initial inventories of consumables and spare parts that are normally capitalized. We assume non-fuel working capital is 1.5% of EPC costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs. This includes 1.0% for financial working capital and 0.5% for spare parts and consumables.

Note 2. Electrical interconnection costs covered by Texas Senate Bill 1500 allowance for generation facilities to interconnect with the Texas transmission system.

Note 3. Property taxes are assessed on the plant's land and improved value combined in the local assessor's calculated market value. A property tax rate of 1.99% was determined based on a survey of blended county, city, and school district taxes in Harris County, Texas. The market value to which these are applied is approximately 15% of the estimated overnight capital cost for plants of similar size and technologies, thus the property tax value assumed for this study is calculated as 0.3% of the estimated overnight capital costs.

Table C9

Table C9: Aero Capital Costs

Capital Cost Estimate (2024$)		
EPC Cost		
Cost Component	**Unit**	**Amount**
Owner Furnished Equipment - CTGs	$	204,913,000
Owner Furnished Equipment - SCR & CEMS	$	39,108,000
Other Equipment	$	36,603,000
Construction Labor	$	56,125,000
Other Labor	$	31,845,000
Materials	$	17,081,000
Sales Tax	$	1,281,000
Subtotal - EPC Costs w/o EPC Fee and Contingency	*$*	*386,956,000*
EPC Contractor Fee	$	34,826,000
EPC Contingency	$	38,696,000
Total EPC Costs	**$**	**460,478,000**
Non-EPC Cost		
Cost Component	**Unit**	**Amount**
Project Development	$	23,024,000
Mobilization and Start-Up	$	4,605,000
Net Start-up Fuel Costs	$	-
Electrical Interconnection	$	-
Gas Interconnection	$	1,750,000
Land	$	759,000
Fuel Inventories	$	-
Non-Fuel Inventories	$	6,907,000
Owner's Contingency	$	3,704,500
Emission Reduction Credit	$	-

Total Non-EPC Costs	**$**	**40,749,500**

Total Overnight Capital Cost		
Total Overnight Capital Cost	**$**	**501,227,500**
Total Overnight Capital Cost, based on Summer Capacity	$/kW	2,053
Total Overnight Capital Cost, based on ISO Capacity	**$/kW**	**1,722**
Total Overnight Capital Cost, based on Winter Capacity	$/kW	1,666

Table C10

Table C10: Aero Operations and Maintenance Costs

O&M Cost Estimate (2024$)		
Fixed O&M Cost		
Cost Component	Unit	Amount
LTSA Fixed Payments	$	511,000
Labor	$	2,413,000
Maintenance and Minor Repairs	$	51,000
Asset Management	$	367,000
Administrative and General	$	166,000
Property Taxes	$	1,585,000
Insurance	$	3,170,000
Firm Gas Contract	$	3,078,000
Fixed O&M Costs	**$**	**11,341,000**
Fixed O&M Costs, based on Summer Capacity	$/kW-yr	46.4
Fixed O&M Costs, based on ISO Capacity	**$/kW-yr**	**39.0**
Fixed O&M Costs, based on Winter Capacity	$/kW-yr	37.7
Variable O&M Cost		
Cost Component	Unit	Amount
Variable O&M Costs, based on Summer Capacity	$/MWh	**9.00**
Major Maintenance - Hours Based	$/MWh	8.26
Consumables, Waste Disposal, and Other VOM	$/MWh	0.74
Variable O&M Costs, based on ISO Capacity	$/MWh	**7.66**
Major Maintenance - Hours Based	$/MWh	6.93
Consumables, Waste Disposal, and Other VOM	$/MWh	0.73
Variable O&M Costs, based on Winter Capacity	$/MWh	**7.44**
Major Maintenance - Hours Based	$/MWh	6.71
Consumables, Waste Disposal, and Other VOM	$/MWh	0.73

Table C11

Table C11: PV + BESS Cost Assumptions

Technical Assumptions		
Plant Characteristic		**Specification**
Configuration	**-**	**Solar PV + Battery Energy Storage System (BESS) Hybrid**
Location	**-**	Brazoria County
PV Module Technology	**-**	Monocrystalline Bi-facial PERC
PV Tracking System	**-**	Single-axis tracker
PV Capacity (MW)	**MW**	200
BESS Technology	**-**	Lithium-ion
BESS Storage Capacity (MW)	**MW**	100
Storage Duration (Hours)	**hr**	2
AC or DC Coupled	**-**	AC Coupled
DC/AC Ratio	**-**	1.3
Design Life (amortization period)	**years**	20
Rated Output Frequency	**Hz**	60
EFOR (annual)	**%**	2.00%
AC Losses		
Line Loss GSU to POI	*%*	*0.05%*
GSU Loss	*%*	*0.50%*
Auxuliary Load	*%*	*3.00%*
Line Loss PCS XFMR to GSU	*%*	*0.30%*
PCS XFMR Loss	*%*	*0.73%*
Total AC Loss (for PCS Inverter Sizing)	*%*	***4.58%***
Gross Inverter Output Power Required	**MWac**	105
Inverter Power	**MW**	2.65
Inverter Loss	**%**	1.6%
Battery Capacity Losses		
Battery Capacity Loss (1st year)	%	4.00%
Annual Degradation (after 1st year)	%	2.00%
Augmentation Period	yrs	5
Battery Capacity Loss (at 1st aug)	%	12.00%
Maximum State of Charge	**%**	100.00%
Minimum State of Charge	**%**	5.00%
Total Output Restriction at BOL	**%**	11.18%
Gross Energy Initial Installation	**MWh**	233
Gross MWh Differential Initial Installatio	**%**	14.18%
Number of Augmentations	**-**	3

Gross MWh per Augmentation	**MWh**	28

Capital Cost Assumptions

Cost Category		Specification
EPC Contractor Fee	*% of subtotal EPC costs*	5%
EPC Contingency	*% of other EPC costs*	5%
Project Development Cost	*% of EPC costs*	5%
Mobilization and Start-Up Cost	*% of EPC costs*	1%
Owner Contingency	*% of Owner's costs*	10%
Financing Fees	*% of subtotal EPC costs*	0%

O&M Cost Assumptions

Cost Category		Specification
Property Tax	*% of Overnight Capital Costs*	0.6%
Insurance	*% of Overnight Capital Costs*	0.3%
Land Lease Cost	*2024$/acre*	500
Acreage	*acres*	1,400