MISO Reference Technology Study

Prepared for the Midcontinent Independent System Operator (MISO)

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Energy+Environmental Economics

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Acronyms

Acronym	Definition
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
ATWACC	After-Tax Weighted Average Cost of Capital
BLS	Bureau of Labor Statistics
BOS	Balance of System
BRA	Base Residual Auction (PJM)
Capex	Capital Expenditures
CCGT	Combined-Cycle Gas Turbine
COD	Commercial Operation Date
CONE	Cost of New Entry
CPI-U	Consumer Price Index for All Urban Consumers
CT	Combustion Turbine
DC	Direct Current
DOE	Department of Energy
DLOL	Direct Loss of Load
ELCC	Effective Load Carrying Capability
EPRI	Electric Power Research Institute
E+AS	Energy and Ancillary Services
FO&M	Fixed Operations and Maintenance
GHG	Greenhouse Gas
ICAP	Installed Capacity
IEEPA	International Emergency Economic Power Act
IRA	Inflation Reduction Act
ISO	Independent System Operator
ISO-NE	ISO New England
ITC	Investment Tax Credit
IX	Interconnection
LCOE	Levelized Cost of Energy
LCOE+	Lazard's Levelized Cost of Energy Analysis
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LRZ	Load Resource Zone
MW	Megawatt
MW-ac	Megawatt Alternating Current
MWh	Megawatt-hour
MWh-ac	Megawatt-hour Alternating Current
MISO	Midcontinent Independent System Operator
N/A	Not Applicable

Acronym	Definition
NLR	National Laboratory of the Rockies (formerly known as the National Renewable Energy Laboratory "NREL")
NYISO	New York Independent System Operator
OBBBA	One Big Beautiful Bill Act
O&M	Operations and Maintenance
PRA	Planning Resource Auction
PRMR	Planning Reserve Margin Requirement
PTC	Production Tax Credit
PV	Photovoltaic
RBDC	Reliability Based Demand Curve
RRA	Regional Resource Assessment
RTO	Regional Transmission Organization
ST	Steam Turbine
UCAP	Unforced Capacity
WACC	Weighted Average Cost of Capital

1 Executive Summary

1.1 Study Overview

The **Midcontinent Independent System Operator ("MISO")** retained **Energy & Environmental Economics ("E3")** to provide an independent **evaluation of potential reference technology options** for Planning Year 2027-2028 and subsequent planning years. This study provides a framework for evaluating reference technology options and applies it to a set of candidate technologies using both quantitative and qualitative criteria for consideration.

A reference technology is a standardized, scalable resource type used within a resource adequacy framework to represent the long-run cost of new capacity needed to meet a region's reliability requirement. In MISO, the reference technology directly affects key Planning Resource Auction ("PRA") market design parameters—including the Reliability Based Demand Curve ("RBDC") price cap and shape—and therefore influences how the PRA translates reliability needs into price formation over time. Specifically, the reference technology impacts the following PRA parameters:

- RBDC price cap, which is capped at the seasonal gross cost of new entry ("CONE") of the reference technology;
- RBDC shape, which is designed so price equals seasonal net CONE at the Planning Reserve Margin Requirement (PRMR) and yields net CONE on average across Monte Carlo outcomes;
- Annual price cap based on how many seasons are in shortage or near-shortage conditions;
- Offer mitigation threshold, where the Independent Market Monitor (IMM) mitigates all offers that exceed gross CONE by 10%; and
- Non-compliance charge constructs that reference zonal gross CONE.

Several misconceptions commonly arise in discussions of reference technologies. First, selecting a reference technology is sometimes interpreted as an endorsement of a particular resource type or a prediction of what the market "should" build. In practice, the reference technology is an analytical construct used to set certain market parameters; the market can respond to those parameters through any combination of resources it finds economic. Second, net CONE is sometimes assumed to directly determine capacity prices. Market prices ultimately reflect the interaction of the demand curve and competitive offers; to the extent that competitive offers are increasing in ways consistent with the reference technology, this will increase prices. However, to the extent that the market identifies resource options that are more economic than the cost of the reference technology, the outcome is not an increase in price but rather an increase in the quantity of cleared capacity.

The objective of this study is to assess the suitability of candidate technologies for use as reference technologies beginning in Planning Year 2027–2028. The quantitative and qualitative results in this study are provided as an input for MISO's determination of an appropriate reference technology. This study does neither (1) independently establish MISO's reference technology decision or (2) set the gross and net CONE values used in the PRA (which MISO will continue to update through its annual process).

1.2 Methodology and Assumptions

1.2.1 Selection Process Overview

This study evaluated candidate reference technologies using a two-pronged framework that parallels how a reference technology is ultimately used in market parameters: (1) an economic (quantitative) assessment of cost and revenue benchmarks; and (2) a practical (qualitative) assessment of how reliably those benchmarks can be forecasted and maintained over time.

The study follows three core steps:

1. **Candidate technology list.** MISO provided the list of candidate technologies evaluated in this study.
2. **Quantitative evaluation.** For each candidate technology, the study calculates a consistent set of quantitative metrics under a common analytical framework and assumptions.
3. **Qualitative evaluation.** In parallel, the study evaluates qualitative criteria to confirm practical viability and durability that may not be fully captured in the quantitative metrics alone.

1.2.2 Candidate Technologies

The study evaluates eight candidate technologies intended to span the set of resources that could plausibly represent new entry in MISO over the relevant horizon. The candidate technologies evaluated in this study, which were provided by MISO, are:

- Gas Combustion Turbine (“CT”), Frame
- Gas CT, Aero
- Gas Combined-Cycle Gas Turbine (“CCGT”), F Class
- Gas CCGT, H Class
- 4-hour Storage
- 2-hour Storage
- Solar Photovoltaic (“PV”) + 4-hour Storage
- Coal Steam Turbine (“ST”)

1.2.3 Evaluation Criteria

The study evaluates candidate technologies using quantitative criteria that describe the economics of new entry on both an installed capacity (“ICAP”) basis and an accredited/unforced capacity (“UCAP”) basis under MISO’s Direct Loss of Load (“DLOL”) accreditation framework. The two co-primary quantitative criteria used to evaluate technologies are:

- **Gross CONE (UCAP basis)**, nominal levelized

- **Modeled Net CONE (UCAP basis)**[1], nominal levelized

Modeled net CONE per UCAP MW supports identification of the marginal entrant with the lowest effective net cost of accredited capacity, which aligns with how MISO designs its seasonal RBDCs to recover modeled net CONE on average. Gross CONE per UCAP MW is included as a co-primary criterion because gross CONE is also a direct input into MISO's PRA demand curve design (including the price cap) and therefore materially affects price formation and entry incentives.

To support interpretation and transparency, this study also presents intermediate "building block" quantitative metrics that explain differences across technologies, which are: gross CONE (ICAP basis), modeled energy and ancillary service ("E+AS") margins[2], modeled net CONE (ICAP basis), and capacity accreditation (DLOL UCAP %).

Because the reference technology must function as a stable and durable market signal—not merely a least-cost point estimate in a single year—the study pairs quantitative screening with a qualitative assessment of whether each candidate technology can plausibly serve as a marginal, scalable entrant under real-world conditions. The qualitative evaluation analyzes each candidate across five criteria:

- **Feasibility-to-build:** Deployable at scale given siting, permitting, infrastructure, and financing conditions.
- **Speed-to-build:** Ability to respond within planning-relevant timeframes.
- **Market representation:** Alignment with what the market is building for capacity value.
- **Forecast accuracy:** Confidence in forecasted revenues and accreditation.
- **Stability:** Likelihood that costs, margins, and accreditation remain relatively consistent over time.

A favorable reference technology is a candidate that performs strongly on both the quantitative metrics (particularly UCAP-based gross CONE and modeled net CONE) and the qualitative criteria.

1.2.4 Quantitative Evaluation Methodology and Assumptions

1.2.4.1 Time Horizon

This reference technology study supports Planning Year 2027–2028 and presents quantitative results for a 2027 commercial operation date (COD) to align with the upcoming cycle. At the same time, the selection process is designed to support stability beyond a single snapshot year. The quantitative analysis relies on lifetime (20–30 year) projections of key inputs—most notably modeled

[1] "Modeled net CONE" refers to the net CONE values calculated in this study using a forward-looking, production cost modeling–based E+AS margin methodology. Because this approach differs from MISO's methodology in its annual CONE process, these values should not be interpreted as an indication of the net CONE values MISO may calculate.

[2] "Modeled E+AS margins" refers to the forward-looking energy and ancillary services margin values calculated in this study using production cost modeling. Because this approach differs from MISO's inframarginal rents methodology in its annual CONE process, these values should not be interpreted as an indication of the inframarginal rents MISO may calculate.

E+AS margins and capacity accreditation—so technology comparisons reflect long-run economics and support stability of gross and net CONE metrics over time.

1.2.4.2 System Representation

System representation is a key methodological choice in any net CONE evaluation. The reference technology is intended to calibrate demand curve parameters that provide, on average over time, a price signal consistent with the net CONE of the marginal capacity resource to achieve target reliability. As a result, it is often most appropriate to model the system at "target reliability" rather than an "as-is" surplus/deficit condition, because using "as-is" conditions to set parameters can, in some designs, push the system away from target reliability (e.g., surplus conditions suppress E+AS margins and inflate net CONE, which can induce additional entry).

1.2.4.3 Geographic Representation

Resource costs and revenues can differ meaningfully across MISO Load Resource Zones ("LRZs"). For tractability, and because within-region gross CONE variation is relatively limited in the data utilized in this study, the quantitative screening is presented using two aggregate regions: MISO North + Central and MISO South. This analytic choice is intended to capture the most material cost and revenue drivers while avoiding overly fragmented outputs; it should not be interpreted as a recommendation regarding the geographic granularity MISO should ultimately apply for implementation, which can be influenced by policy-driven or qualitative needs.

More granular implementation driven by policy or qualitative considerations could result in different reference technologies, and therefore different gross and net CONE values, across areas. However, those differences would not automatically translate into different capacity prices paid by load. Price outcomes depend on the market clearing result and, in particular, on whether transmission deliverability constraints require capacity to be procured locally.

1.2.4.4 Forecasting Uncertainty

Forward-looking cost estimates are inherently uncertain—particularly in the current environment, where federal policy, trade policy, inflation, and supply-chain dynamics can materially affect technology economics over relatively short time horizons. Rather than assuming a specific "reversion path" for these uncertainties, the study evaluates gross CONE under Low / Mid / High cost scenarios and uses the Mid case as the primary point of comparison (with Low/High providing context for robustness). This study suggests that MISO monitor these transient conditions in future updates to confirm whether changes in tax credits, tariffs, or supply constraints materially alter parameter values or conclusions.

1.2.4.5 Modeled E+AS Margins and Capacity Accreditation

For modeled E+AS margins, the study uses results derived from MISO's Regional Resource Assessment (RRA) modeling platform to ensure that revenue forecasts are consistent with the broader system representation and accreditation assumptions applied in this analysis. RRA was run for 2027, 2030, 2033, and 2043; results are interpolated for intervening years, and margins are held constant in real dollars beyond 2043. Modeled E+AS margins are calculated as total energy and ancillary service revenues minus variable operating costs.

1.3 Quantitative Evaluation Results

A summary of the main quantitative criteria under the Mid scenario is provided in Table 1. To support interpretation, the table groups technologies by relative cost performance within each region based on the UCAP-based CONE results presented in this study (gross and net). UCAP-based metrics are emphasized because capacity market comparisons are intended to reflect the cost of providing reliable, accredited capacity rather than nameplate capacity. Differences within 5% of the lowest-cost technology in a region are treated as effectively comparable for screening purposes; differences between 5% and 25% indicate moderately higher costs; and differences above 25% indicate materially higher costs. For additional context, Table 1 also includes MISO's gross CONE values for Planning Year 2025/2026 (both on an ICAP and UCAP basis), shown for reference alongside the study results.

Table 1. Summary of Quantitative Evaluation Results by Technology and Region, 2027 COD (Mid Scenario, 2027$, Nominal Levelized) and MISO Gross CONE for PY 2026/2027 (Reference, 2026$)

	Candidate Technology	MISO Value, PY 2026/2027[3]		Reference Technology Study, 2027 COD	
		Gross CONE (ICAP)	Gross CONE (UCAP)	Gross CONE (UCAP)	Modeled Net CONE (UCAP)[4]
		2026$/kW-yr ICAP	2026$/kW-yr UCAP	2027$/kW-yr UCAP	2027$/kW-yr UCAP
North + Central	**Gas CT, Frame**	$134	$166	$229	$225
North + Central	**Gas CT, Aero**	N/A	N/A	$248	$242
North + Central	**Gas CCGT, F Class**	N/A	N/A	$251	$217
North + Central	**Gas CCGT, H Class**	N/A	N/A	$251	$217
North + Central	**4-hour Storage[5]**	N/A	N/A	$232	$216
North + Central	**2-hour Storage[5]**	N/A	N/A	$296	$276
North + Central	**Solar PV + Storage[6]**	N/A	N/A	$324	$245
North + Central	**Coal ST**	N/A	N/A	$669	$629
South	**Gas CT, Frame**	$124	$154	$208	$205
South	**Gas CT, Aero**	N/A	N/A	$224	$219
South	**Gas CCGT, F Class**	N/A	N/A	$245	$218
South	**Gas CCGT, H Class**	N/A	N/A	$245	$218
South	**4-hour Storage[5]**	N/A	N/A	$251	$235
South	**2-hour Storage[5]**	N/A	N/A	$334	$314
South	**Solar PV + Storage[6]**	N/A	N/A	$330	$246
South	**Coal ST**	N/A	N/A	$631	$600

Legend

Within 5% of lowest cost technology in region (green)
Within 25% of lowest cost technology in region (yellow)
Beyond 25% of lowest cost technology in region (red)

[3] Midcontinent Independent System Operator (MISO), *MISO Cost of New Entry (CONE) Presentation* (Report to the Reliability Assessment Subcommittee, October 1, 2025), https://cdn.misoenergy.org/20251001%20RASC%20Item%2006%20MISO%20Cost%20of%20New%20Entry%20(CONE)%20Presentation720296.pdf. Capacity requirements and capacity market values are based on UCAP because the objective is to procure reliable, accredited capacity rather than nameplate capacity. Because MISO publishes gross CONE values on an ICAP basis, those values were converted to a UCAP basis using the same levelized DLOL UCAP % for Gas CT, Frame applied in this analysis. MISO values were averaged by LRZ to develop regional values.

[4] "Modeled net CONE" refers to the net CONE values calculated in this study using a forward-looking, production cost modeling–based E+AS margin methodology. Because this approach differs from MISO's methodology in its annual CONE process, these values should not be interpreted as an indication of the net CONE values MISO may calculate.

[5] E3 assumes standalone storage resources claim the Investment Tax Credit (ITC), at a rate of 30%.

[6] E3 assumes that both the solar and storage components of the co-located plant claim a 30% Investment Tax Credit (ITC). This reflects (i) the OBBBA requirement that solar begin construction by July 4, 2026 to retain credit eligibility (which is assumed to be met for a 2027 COD project based on typical timelines), and (ii) continued ITC eligibility for stand-alone storage through at least 2032 (COD year); Foreign Entity of Concern (FEOC) compliance requirements for post-2025 project starts are not assumed to automatically preclude eligibility.

Key Quantitative Findings

- In North + Central, modeled net CONE (UCAP basis) shows the expected convergence among multiple plausible entrants in a system modeled at target reliability. Four technologies cluster tightly between $216/kW-yr and $225/kW-yr UCAP: 4-hour Storage ($216/kW-yr), Gas CCGT, F Class ($217/kW-yr), Gas CCGT, H Class ($217/kW-yr), and Gas CT, Frame ($225/kW-yr). This narrow spread is consistent with competitive entry dynamics, where resources tend to enter until expected net returns converge toward the level needed to support new investment.
- When multiple technologies fall within a similar modeled net CONE band, gross CONE (UCAP basis) becomes a practical differentiator because it highlights the lowest up-front fixed cost per incremental UCAP MW. In North + Central, the lowest gross CONE (UCAP basis) candidates are Gas CT, Frame ($229/kW-yr) and 4-hour Storage ($232/kW-yr).
- In MISO South, the quantitative results more clearly differentiate one technology as lowest cost. The Gas CT, Frame has the lowest modeled net CONE (UCAP basis) at $205/kW-yr. The next closest options—Gas CCGTs ($218/kW-yr) and Gas CT, Aero ($219/kW-yr)—are approximately 6–7% higher on a modeled net CONE (UCAP) basis.
- Storage shows relatively low gross CONE (ICAP basis) in both regions (particularly in North + Central), driven in part by the Investment Tax Credit ("ITC"). However, this advantage is counterbalanced by lower DLOL UCAP% relative to thermal technologies (70–71% for 4-hour storage vs. 81–85% for gas). As a result, 4-hour storage generally lands at similar or higher gross CONE and modeled net CONE on a UCAP basis relative to a frame CT.
- While 2-hour storage has low gross CONE on an ICAP basis, its 35% DLOL UCAP% drives much higher UCAP-based costs (gross CONE UCAP $296–$334; modeled net CONE UCAP $276–$314), making it materially less competitive as a reference technology candidate.
- Solar PV + storage exhibits relatively high modeled E+AS margins (reflecting energy value), but UCAP-based costs remain high due to low accredited capacity (39% DLOL UCAP), leading to gross CONE (UCAP basis) of ~$324–$330/kW-yr and modeled net CONE (UCAP basis) of ~$245–$246/kW-yr.
- Coal ST has very high gross CONE and modeled net CONE on both ICAP and UCAP bases in both regions, roughly ~1.9× to ~2.3× higher than the next-highest candidate on a UCAP basis. Its significantly higher CONE (both gross and net) make it a clear outlier in the screening results.
- On an ICAP gross CONE basis, Gas CCGTs carry a premium relative to a frame CT, but that premium varies by region: ~15% in North + Central versus ~24% in South (Mid scenario). Where the premium is smaller, CTs and CCGTs fall into closer parity on a modeled net CONE (UCAP) basis; where it is larger, the frame CT remains the lowest modeled net CONE (UCAP) option. This underscores that CT vs. CCGT competitiveness as the marginal capacity entrant can shift as the capex spread changes, particularly if CT costs rise faster than CCGT costs.
- On an ICAP gross CONE basis (detailed results in Section *Gross Cost of New Entry (CONE), ICAP Basis*), storage is lower-cost in North + Central than in South (e.g., 4-hour storage: $164/kW-yr vs. $177/kW-yr), while gas technologies are generally lower-cost in South (e.g., gas CT, frame: $168/kW-yr vs. $185/kW-yr). Accordingly, gas CTs show the largest North + Central premium among candidates (frame and aero CTs ~10% higher), while CCGTs are

only ~2% higher and storage is cheaper in North + Central. Although the overall conclusions are consistent across regions, these patterns show how a single footprint-wide assessment can mask technology-specific regional cost drivers that may affect relative rankings over time.

1.4 Qualitative Evaluation Results

A summary of qualitative evaluation results is provided in Table 2. The table evaluates each candidate technology across five qualitative criteria (feasibility-to-build, speed-to-build, market representation, forecasts accuracy, and stability) using a Low, Mid, or High rating.

Table 2. Summary of Qualitative Evaluation Results by Technology

Candidate Technology	Feasibility-to-build	Speed-to-build	Market Representation	Forecasts Accuracy	Stability
Gas CT, Frame	High	Mid	High	High	High
Gas CT, Aero	High	Mid	High	High	High
Gas CCGT, F Class	High	Mid	High	High	High
Gas CCGT, H Class	High	Mid	High	High	High
4-hour Storage	High	High	High	Mid	Low
2-hour Storage	High	High	Mid	Mid	Low
Solar PV + Storage	High	Mid	High	Mid	Low
Coal ST	Mid	Low	Low	Mid	Mid

Key Qualitative Findings

- Across the gas technologies (both CT and both CCGT configurations), the qualitative results are consistently strong. Gas resources are rated High on feasibility-to-build, market representation, forecasts accuracy, and stability, with speed-to-build as the primary tradeoff (rated Mid), reflecting longer development and construction timelines than storage.
- Storage-based resources (4-hour storage, 2-hour storage, and solar PV + storage) score highest on speed-to-build (generally High) and are rated High on feasibility-to-build. However, they score lower on forecasts accuracy (Mid) and stability (Low), reflecting that their revenues and accredited capacity are more sensitive to evolving system conditions, including storage penetration and broader portfolio mix.
- Coal ST is qualitatively less competitive overall. It is rated Low on speed-to-build and Low on market representation, and only Mid on feasibility-to-build and stability, reflecting higher-friction, longer-lead development characteristics and limited evidence of near-term developer interest relative to other candidates.
- Market representation results are consistent with observed developer behavior in MISO: recent historical additions show steady development of gas CTs and gas CCGTs, alongside growth in storage (predominantly 4-hour duration), supporting these technologies as representative candidates within a reference technology framework.

- Taken together, the qualitative screening differentiates technologies that are both widely deployable and structurally durable over time (gas CTs and gas CCGTs) from those whose economics and accredited capacity are more sensitive to evolving system conditions (storage and hybrid configurations), with storage's primary advantage being speed-to-build rather than durability as a long-run reference signal.

1.5 Sensitivity Analysis

1.5.1 Alternative Reference Technology Configurations for Fuel-supply Risk

The study also evaluated whether alternative configurations designed to mitigate fuel-supply risk would materially change the UCAP-based economics of a standard frame gas CT (see Section *Alternative Reference Technology Configurations for Fuel-supply Risk*).

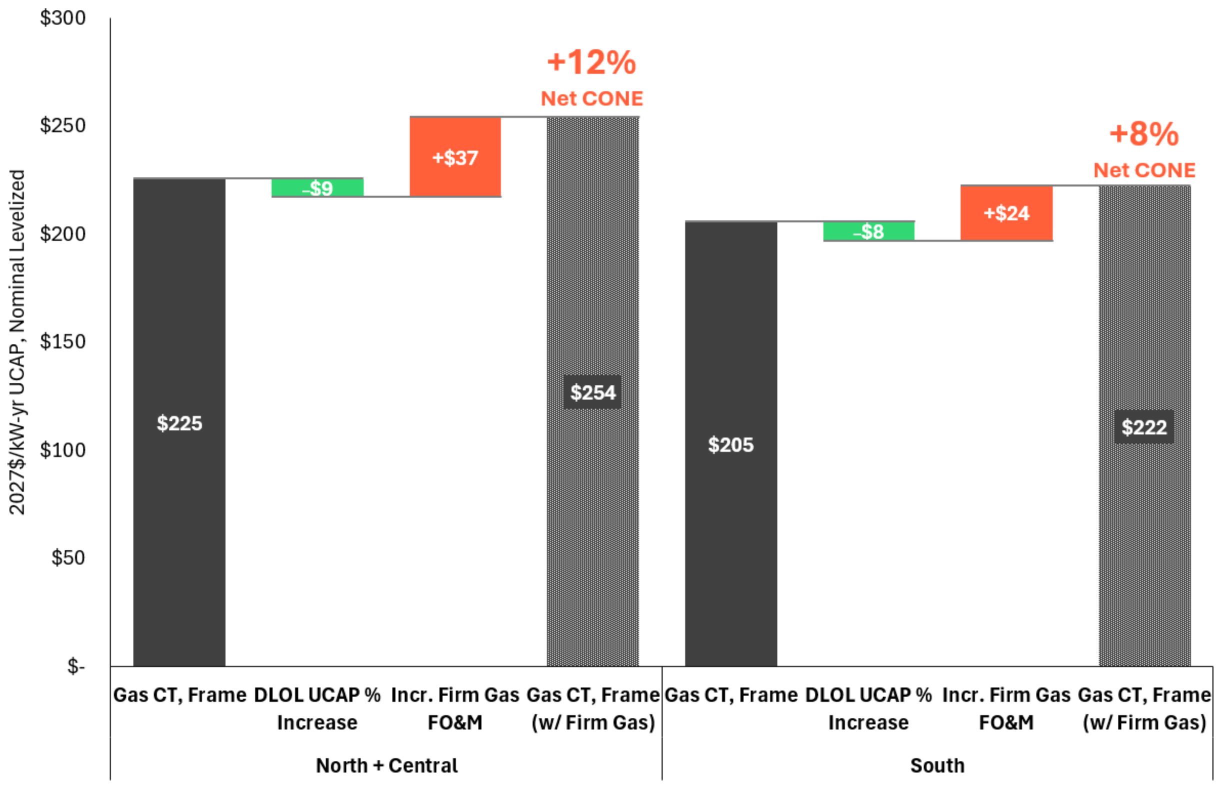
Under MISO's DLOL accreditation framework, fuel non-delivery risk can reduce accredited capacity and therefore increase CONE on a UCAP basis. Accordingly, the study evaluated two alternative configurations relative to the standard frame CT:

- **A frame CT with firm gas transportation**; and
- **A frame CT with dual-fuel (oil backup) capability**.

Both configurations modestly increase DLOL UCAP %, producing an accreditation benefit equivalent to approximately $8–9/kW-yr on a modeled net CONE (UCAP basis). However, these benefits are more than offset by incremental fixed costs.

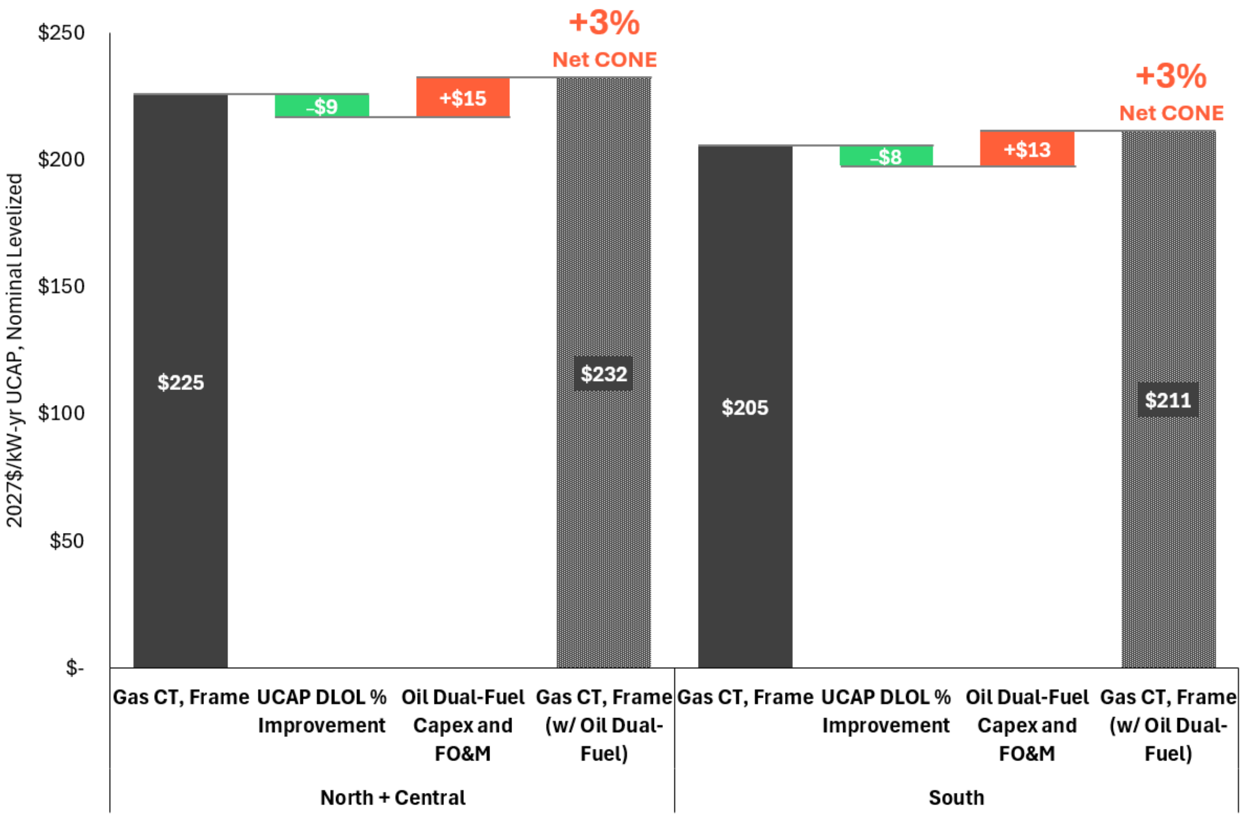
As shown in Figure 1, for the firm gas configuration, incremental reservation charges increase modeled net CONE (UCAP basis) by approximately $37/kW-yr in North + Central and $24/kW-yr in South. After accounting for the accreditation uplift, total modeled net CONE increases from $225 to $254/kW-yr (+12%) in North + Central and from $205 to $222/kW-yr (+8%) in South.

Figure 1. Cost-benefit Analysis of Gas CT, Frame with and without Firm Gas Contract



As shown in Figure 2, for the dual-fuel configuration, incremental capital and fixed O&M costs increase modeled net CONE (UCAP basis) by approximately $15/kW-yr in North + Central and $13/kW-yr in South. After accounting for the accreditation benefit, modeled net CONE remains approximately 3% higher than the standard frame CT in both regions.

Figure 2. Cost-benefit Analysis of Gas CT, Frame with and without Oil Dual-Fuel Capability



Taken together, these results indicate that while fuel-supply mitigation measures improve accredited capacity, the incremental reliability benefit does not offset the incremental fixed cost under current assumptions. **The standard frame CT configuration (without firm transportation and without backup fuel capability) remains the** lowest gross and net cost source of accredited capacity across the possible gas frame CT configurations.

2 Introduction

2.1 Background

The **Midcontinent Independent System Operator ("MISO")** retained **Energy & Environmental Economics ("E3")** to provide an independent **evaluation of potential reference technology options** for Planning Year 2027-2028 and subsequent planning years. This study outlines methodologies for evaluating the region's reference technology options and applies them to candidate options in MISO using both quantitative and qualitative criteria.

A reference technology is a standardized, scalable resource type used within a resource adequacy framework to represent the long-run willingness-to-pay for additional capacity. It forms the basis for market design parameters—such as the gross Cost of New Entry ("CONE") and net CONE—that directly impact price formation. In MISO, the reference technology is used to calibrate key elements of its capacity market (the Planning Resource Auction or "PRA") including:

+ **PRA Reliability Based Demand Curve ("RBDC") price cap.** MISO's RBDC is capped at the Seasonal gross CONE of the reference technology.
+ **PRA Reliability Based Demand Curve (RBDC) shape.** MISO's RBDC is designed such that (1) the price is the seasonal net CONE of the reference technology when the quantity of capacity is equal to the Planning Reserve Marginal Requirement ("PRMR") and (2) the average compensation across many Monte Carlo simulations will yield net CONE of the reference technology.
+ **Annual price cap.** The shortage and near-shortage price cap are established through the net CONE value.
+ **Maximum offer price.** The Independent Market Monitor (IMM) mitigates all offers submitted in the PRA that are 10% above gross CONE.
+ **Capacity replacement non-compliance charge (CRNCC).** Daily penalty assessed when a resource's capacity testing/deferral requirements are not satisfied is based on the sum of the zonal auction clearing price and the daily zonal gross CONE (zone's gross CONE * (1/365) in $/MW-day).
+ **Installed capacity deferral non-compliance charge.** Daily penalty assessed when a capacity replacement obligation is not met is based on the sum of the zonal auction clearing price and the daily zonal gross CONE. Additionally, MISO also requires credit collateral for this potential charge tied to daily zonal CONE.
+ **Demand Resource Deferral Notice (DRDN) charge.** Penalty assessed when a Demand Resource defers its testing obligations and fails to demonstrate full capability. Penalty is equal to alternative compliance penalty (ACP) plus daily zonal gross CONE (zone's gross CONE * (1/365) in $/MW-day).

Several common misconceptions arise in discussions of reference technologies. First, the selection of a reference technology is sometimes interpreted as an endorsement of a specific resource type and/or a prediction of what the market will ultimately develop. In actuality, the reference technology functions as an analytical construct used to estimate some capacity market *price* parameters. The market can respond to these price parameters with any combination of resources that it deems economic. Changing the reference technology (and thus the associated price parameters) will primarily affect the quantity of resources that enter the market, although it can also influence which resource types are economic at the margin and therefore the resource mix of new entrants. Second, reference technologies and their associated parameters—such as gross CONE and net CONE—are sometimes viewed as static. In practice, the reference technology is intended to be stable over time, but it is not immutable: MISO periodically re-evaluates it through studies such as this one to confirm it remains representative of a plausible marginal new entrant as market conditions, technology costs, and revenue expectations evolve. Additionally, the associated parameter values (including gross and net CONE) are updated annually. Third, net CONE is sometimes assumed to directly determine capacity prices; however, market clearing prices are established through the interaction of the resource adequacy demand curve and competitive supply offers. Higher net CONE values will not necessarily result in higher market prices but will result in the market perceiving a larger quantity of resources to be economic, resulting in a larger quantity of capacity.

2.2 Study Objectives and Scope

The objective of this study is to assess the suitability of candidate technologies for use as MISO's reference technology beginning in Planning Year 2027–2028. While reference technology selection is periodically re-evaluated, the expectation is that the selected technology remains stable across study cycles to support a consistent market signal. The study defines a set of candidate technologies and assesses their relative performance using a combination of quantitative and qualitative criteria, described in Section *Evaluation Criteria*.

The quantitative and qualitative analysis presented in this study will be used by MISO as an input to determine its reference technology for Planning Years beginning 2027-2028. Following that determination, MISO will continue to apply its established annual process to calculate gross CONE and net CONE based on the cost and revenue inputs of the reference technology in effect that Planning Year. Accordingly, **this study does not independently determine MISO's reference technology or establish gross CONE and net CONE values**.[7]

In addition, this study outlines a conceptual framework for evaluating reference technologies and examines key considerations related to their determination and use. This includes a discussion of the purpose and role of a reference technology, the key assumptions used to evaluate candidate technologies, and the process by which a reference technology should be selected. The framework addresses several topics commonly considered in reference technology studies, including the use of first-year versus long-run market outcomes, system representation and modeling assumptions, the appropriate level of geographic granularity, the influence of policy, the inclusion of fuel-supply

[7] This study calculates "modeled net CONE," not the specific net CONE values MISO will ultimately apply in its capacity market. These study values use a forward-looking, production cost modeling–based E+AS margin methodology that differs from MISO's net CONE methodology utilized in its annual CONE process.

and other operational risks, and the treatment of transient market conditions that may affect costs and investment signals.

3 Reference Technology Selection Process

3.1 Reference Technology Conceptual Foundation

3.1.1 What is a "Reference Technology"?

The concept of a "reference technology" is not a theoretical economic concept but rather a capacity market design construct. Designing a capacity market demand curve that meets a certain reliability standard requires administratively-defined price and quantity parameters. The reference technology provides a basis for determining a subset of those parameters. Because a reference technology is how its resulting parameters will be used, there is not necessarily one uniquely "correct" reference technology in the abstract.

Both a reference technology construct and the broader capacity market design are predicated on an administratively defined reliability standard. In most U.S. Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs"), this standard is expressed as a Loss of Load Expectation ("LOLE") of 0.1 days/year (i.e., one-day-in-ten years LOLE). This reliability target is itself a policy determination that reflects a choice regarding acceptable reliability risk. The capacity market and its demand curve are then structured to support investment consistent with achieving that reliability standard over time.

From an economic perspective, a capacity market designed to meet an administratively-determined reliability standard (generally one-day-in-ten years LOLE), is designed to provide compensation that equals, on average over the long run, the amount a new entrant must recover after expected energy and ancillary service revenues. This residual revenue requirement is the net cost of new entry (net CONE). Multiple demand curve designs can achieve this outcome. For example, a lower price cap may require prices above net CONE at the reliability target to recover net CONE on average over time. Conversely, a steeper demand curve would require a higher price cap to achieve the same long-run average net CONE recovery. As a result, the appropriate reference technology cannot be evaluated in isolation; it must be considered in the context of how it will be used within the capacity market design (namely the demand curve).

Across U.S. centralized capacity markets, demand curves are generally anchored to the reliability standard, such that the capacity requirement corresponds to the 0.1 days per year LOLE target. The remaining design variables (namely the height (price cap) and slope of the curve) are calibrated to ensure that, across many years and outcomes, the marginal entrant recovers net CONE on average. In practice, these parameters are typically set as a fraction or multiple of gross CONE or net CONE, linking the reference technology directly to the demand curve's price formation mechanics.

In practice, a reference technology is generally used to represent a standardized, scalable, new-build resource that represents the long-run willingness-to-pay for additional capacity. It provides a transparent benchmark for the cost of adding an additional megawatt ("MW") of accredited capacity (also sometimes referred to as unforced capacity, "UCAP") needed to satisfy a RTO's or ISO's reliability standard. Because the market responds to price signals for new capacity with the most economic resource, the long-run marginal cost of capacity is generally interpreted as the resource with the lowest net cost or lowest net CONE.

3.1.2 Installed Capacity (ICAP) vs. Accredited / Unforced Capacity (UCAP)

Capacity markets procure resources based on their contribution to reliability rather than their nameplate output. Installed capacity ("ICAP") represents the physical nameplate capacity of a generator. However, not all resources can reliably deliver their full nameplate output during the system's highest reliability risk hours. As a result, most resource adequacy constructs evaluate capacity on an accredited or unforced UCAP basis, which reflects the expected contribution of a resource to reliability during periods of system stress.

In practice, accreditation factors, such as effective load carrying capability ("ELCC"), translate ICAP into UCAP by accounting for resource availability and performance during tight system conditions. Dispatchable thermal resources generally receive higher accreditation values because they can sustain output when called upon, though their accredited capacity can still be reduced by forced outages, fuel limitations, or extreme weather. By contrast, resources whose output is limited by weather conditions or energy duration constraints, such as solar, wind, or battery storage, typically receive lower accreditation values because their ability to deliver during extended system stress events is more limited.

For purposes of a reference technology study, the relevant economic comparison is therefore the cost per unit of accredited capacity (UCAP), rather than the cost per unit of installed capacity. Two technologies may have similar costs on an ICAP basis but provide different reliability contributions once accreditation is considered. Accordingly, this study evaluates candidate technologies primarily using gross CONE and net CONE on a UCAP basis. ICAP-based metrics should still be reported as intermediate values to provide transparency into cost drivers, but UCAP-based metrics provide the most direct comparison of technologies on a reliability-equivalent basis.

3.1.3 Does a Lowest Effective Net Cost Technology Exist in Practice?

As discussed in Section *What is a "Reference Technology"?*, a reference technology is often interpreted by RTOs and ISOs as the resource type with the lowest net cost of accredited capacity. However, a uniquely identifiable "lowest effective net cost" technology may not exist in practice.

In a system in long-run equilibrium without barriers to entry, rational market participants enter and exit the market such that any new capacity—regardless of technology—is expected to earn revenues that recover its full costs (i.e., zero economic profit). If one technology offered a persistently lower effective net cost of accredited capacity than alternatives, developers would preferentially build it. That incremental entry would increase supply and reduce that technology's expected net market revenues, pushing the system back toward a state of equilibrium where all resources are recovering their costs. Under these conditions, by definition, there is no durable "lowest effective net cost of capacity" resource. Instead, **the market tends to equilibrate around a reference net cost of**

accredited capacity (i.e., a reference price level), rather than sustaining a single technology with persistently lower net costs than others.

While the capacity market must deliver this reference price (net CONE) an average over the long run, *how* the capacity market yields this average is a design choice. For example, steeper capacity market demand curves with a higher price cap can yield the same long run average price as a flatter demand curve with a lower price cap. Several ISO's, including MISO, use the reference resource's gross CONE (not net CONE) in setting the capacity market price cap. Because both net CONE and gross CONE are used in the MISO capacity market demand curve, it is important to consider both values in selecting the reference technology.

3.1.4 First-year vs. Lifetime Forward-looking Metrics

Calculating net CONE requires a forward-looking estimate of resource 1) costs, 2) revenues (i.e., E+AS" margins), and 3) accredited capacity (e.g., ELCC). Forward-looking estimates of these values require an assumption of how far into the future to look. There are two primary approaches used for this question:

1. **Utilizing a single "first-year" snapshot,** generally aligned with the commercial operation date ("COD") of the generator; or
2. **Utilizing the lifetime values,** annual values over the life of the resource levelized into a single value.

Using a first-year approach is comparatively straightforward and transparent. Forecasting E+AS margins and ELCC for the next 1-3 years generally requires fewer assumptions, and the results are more easily tied to observable market conditions. The tradeoff is that market participants do not make investment decisions based on one-year snapshots. To the extent that market conditions are changing significantly over the forecast period (e.g., storage revenues declining as storage saturates the market), a first-year snapshot may under or over-estimate the revenues that a market participant may require to actually enter the market.

By contrast, a lifetime approach is more consistent with how market participants make investment decisions, who seek lifetime revenues that will at least recover the lifetime costs of a resource. The primary disadvantage of this approach is that lifetime forecasting is inherently more uncertain and requires additional assumptions (e.g., about resource buildout, fuel prices, transmission, policy, and technology costs). However, it explicitly recognizes that the resource's economics are driven by its lifetime value.

This choice between these two approaches is increasingly important in a rapidly changing system. With rising penetration of renewables and storage, coupled with increasing adoption of heating and vehicle electrification, the system in the early years may be very different from the system in later years.

In summary, estimating net CONE and effective capacity using a lifetime approach better mirrors the decision-making framework that governs entry. **Practically, this entails evaluating E+AS margins**

and capacity accreditation over a forward horizon consistent with the life of a resource and translating those translating those values into an annual levelized value.

3.1.5 System Representation

Calculating net CONE requires a representation of the market's underlying system, most notably the resource mix and how "long" or "short" the market is relative to target reliability. A system with a capacity surplus/deficit or a different resource mix can produce meaningfully different E+AS margins and ELCC outcomes that are used in the calculation of net CONE (or even gross CONE in the case of ELCC). There are several ways to represent the system with three approaches being most common:

1. **As-is system.** Model the system using the current resource mix and capacity position, including any surplus or shortfall relative to the reliability standard.
2. **Target reliability system.** Start from the current system, then add or subtract capacity until the system is exactly at the planning reliability target.
3. **Long-run equilibrium rebuild.** Construct a lowest-cost portfolio as if the system were being built "from scratch" today to meet reliability and operational constraints.

The long-run equilibrium rebuild is the most hypothetical of the three, and it can produce a system that differs substantially from the actual market due to existing resources that were built without the benefit of perfect foresight. For that reason, it is less relevant in setting capacity market design parameters intended to govern entry in the real, path-dependent system.

The more relevant choice is between the "as-is" and "target reliability" representations. The key consideration to select between both options is how the reference technology will be used in capacity market framework. The reference technology is intended to help calibrate parameters that provides, on average over time, a price signal consistent with the net CONE of the marginal capacity resource in order to achieve target reliability. To the extent that the "as-is" system is used in the determination of these parameter, this can actually push the system away from target reliability in certain designs. For example, a system that has a capacity surplus will yield very low E+AS margins and thus high net CONE values. High net CONE in a capacity market design based on an as-is system representation can increase market prices, inducing additional entry and potentially exacerbating an existing capacity surplus.

For this reason, the design of the capacity market means it is often most appropriate to model the system at "target reliability" instead of "as-is." Short-run deviations from target reliability, meaning periods when the system has a capacity surplus or deficit, are then appropriately captured through the system's position on the demand curve, rather than through shifts in the demand curve parameters themselves.

3.1.6 Geographic Granularity

The appropriate geographic granularity for defining a reference technology should be consistent with the capacity market's design and settlement granularity. If a market clears capacity using footprint-wide supply and demand curves, then the reference technology and its associated parameters should be defined at that same footprint-wide level. If the market instead clears capacity at a zonal or sub-zonal level due to transmission deliverability constraints, then the reference technology framework should be capable of producing parameters that are meaningful at that same geographic level. The reference technology used to parameterize each demand curve should reflect the area's marginal source of scalable new capacity, meaning the lowest effective cost entrant that can be developed at scale within the area's footprint. For the RTO-wide demand curve, this means the lowest scalable, effective net cost resource throughout the entire system.

There are two related dimensions to geographic granularity. First, the granularity of the reference technology selection itself, meaning whether the market identifies a single reference technology for the entire footprint or different reference technologies by zone or constrained area. Second, the granularity at which the cost and revenue inputs used to parameterize the market are calculated for the chosen reference technology. Even where a single reference technology is selected for the full footprint, it can still be appropriate, and often necessary, to calculate key parameters such as gross CONE and net CONE using geographic-specific inputs that reflect the local cost of building a new resource and the localized E+AS margins that a resource would expect to earn.

In practice, many RTOs identify a footprint-wide reference technology and then geographically differentiate cost and E+AS parameters for that resource. One reason for this approach is that the relative ordering of candidate technologies often does not change materially across subregions. Geographic differences in labor and construction costs, or broader shifts in energy prices, frequently affect multiple technologies in the same direction, preserving which technology is the lowest-cost entrant.

However, geographic divergence can arise when regional conditions affect other aspects of selecting a reference technology. Feasibility limitations, such as restrictions on siting or permitting, fuel availability, emissions limits, or runtime constraints, can make an otherwise least-cost technology infeasible or materially alter its expected energy and ancillary service revenues. In those cases, a region-specific reference technology may be warranted because the marginal entrant is shaped not only by relative costs, but also by what can realistically be built and operated in a particular area.

Therefore, the geographic granularity used to define the reference technology should match the geographic construct of the capacity market. If the market operated and clears on a footprint-wide basis, a single reference technology and its associated metrics can be based on the lowest-cost, scalable new entry option within the footprint, since there are no local procurement requirements. If the market includes zonal or sub-zonal procurement, the reference technology framework should be capable of reflecting local conditions, including quantitative drivers (e.g., costs, prices, revenues, and accreditation) and qualitative factors that determine what can realistically be built and operated in each area.

It is important to note that geographic differences, whether different reference technologies or different cost and revenue metrics for the same reference technology, do not automatically translate into different capacity prices paid by load. Price differences depend on the clearing outcome and, in particular, whether transmission deliverability constraints require capacity to be procured locally. If a zone can be reliably served by imports, it will typically clear at the system-wide price even if its local new build option is more expensive. Higher local reference technology costs affect prices only when a local constraint binds and incremental capacity must clear within that constrained area.

3.1.7 Policy Landscape

The existing policy landscape should be incorporated into reference technology selection since it directly affects what technologies can be built and/or operated within a jurisdiction. That is, policy can dictate what technologies are realistically available within a region to serve as the marginal, scalable source of new capacity. This includes federal, state, and local policy constraints.

The specific type of policy will determine whether its impact should be considered qualitatively or quantitatively. For example, certain technologies may be effectively infeasible to build due to policy or regulatory constraints. This includes restrictions on fuel infrastructure or generator siting, technology-specific bans or moratoria, limits on emissions, or permitting requirements that are not practicably achievable. These restrictions are most appropriately incorporated as a qualitative screen to the question: can this technology plausibly be built, at scale, in the relevant area in the near-term? If not, a reference technology study should then consider whether any evaluation assumptions need to be modified to reflect these policies, or whether a different reference technology candidate should be considered for that region.

Even when policy does not outright prohibit a technology, it can affect quantitative evaluation criteria. Some policies impose operational limitations, such as runtime limits, emissions-rate constraints, or seasonal operating restrictions. These limitations can reduce a resource’s ability to earn E+AS revenues, which ultimately increases net CONE and can change the relative attractiveness of the technology as a capacity entrant. Other policies affect the expected economic life of an asset, such as forward-looking carbon-free targets or required retirement mandates beyond a given year. These policies reduce the period over which capital costs can be amortized, increasing the annualized cost, and therefore, gross CONE. In these cases, policies should be quantitatively reflected directly in the modeling assumptions used to estimate costs and other parameters.

3.1.8 Transient Conditions

This reference technology study, supporting Planning Year 2027-2028, evaluates a period characterized by significant differences in several factors that influence generator costs relative to prior studies. Over the next several years, changes in federal policy, macroeconomic conditions, and supply chain dynamics could materially affect resource costs and, in turn, gross CONE and net CONE. Two categories of potential transient conditions are most relevant for this analysis: (1) policy-driven cost impacts and (2) market-driven cost impacts.

First, federal policy uncertainty is a major driver of near-term variability in technology economics, particularly for renewable (solar and wind) and storage resources. Federal tax credit policy, including potential extensions of the Investment Tax Credit ("ITC") and or the Production Tax Credit ("PTC"), could affect the economics of new renewable resources well into the 2030s. If tax credits were extended, the gross CONE of new renewable resources in later years would likely be materially lower than under current law. Trade policy is also a material driver of near-term costs; import tariffs have increased the current capital cost of new resources and have been especially impactful for solar and battery storage projects that rely more heavily on imported equipment. While some tariff duties may persist regardless of future policy decisions (such as the Anti-Dumping and Countervailing Duties), the durability of other tariffs is less certain.

Second, macroeconomic and supply chain conditions have shifted significantly since 2020. Inflation in 2021 through 2023 was the highest experienced in the U.S. economy since 1991, increasing input costs and complicating expectations of future cost declines. In addition, pandemic-related supply chain disruptions proved difficult to fully unwind, particularly in the context of faster-than-expected load growth from large loads such as data centers. This combination has created unexpected cost pressure on critical equipment needed for new resources and has increased uncertainty about the timing and magnitude of cost normalization. These impacts have been especially pronounced for gas turbine supply chains, and in particular for combustion turbines, where manufacturer backlogs and extended lead times can materially affect both cost and project timing. Recent industry reporting indicates that these pressures are already prompting turbine manufacturers to expand production capacity and developers to adjust procurement strategies, suggesting that current cost and supply conditions may represent a temporary market imbalance rather than a permanent shift in cost dynamics.[8]

Given this uncertainty, reference technology studies should focus on reflecting current policy and observable cost drivers as the best available basis for estimating gross CONE and net CONE, while recognizing that the persistence of these conditions is uncertain. Therefore, this study suggests that these factors be monitored and revisited in future updates, with particular attention to whether changes in tax credits, tariffs, or supply chain constraints would materially alter reference technology costs or selection.

3.1.9 Fuel-supply and Other Operational Risks

Fuel supply risks and other operational risks are important considerations in reference technology studies because they can materially affect both a resource's expected economics and its ability to perform when the system is under stress. For technologies whose accredited capacity depends on performance during tight conditions (as is the case in MISO), risks such as fuel non-delivery, forced

[8] Reuters, *Power developers adapt gas turbine strategies to mitigate tight supply* (March 2, 2026), https://www.reuters.com/business/energy/power-developers-adapt-gas-turbine-strategies-mitigate-tight-supply--reeii-2026-03-02/.

outages, and operational limitations can directly affect the appropriate characterization of both costs and accredited capacity.

While some studies treat these risks qualitatively and outside the gross CONE, net CONE, and effective capacity calculations, this study incorporates them quantitatively and endogenously. Doing so makes fuel and operational risk an explicit, measurable tradeoff in the analysis, rather than an external adjustment applied after the fact.

Operational risk can affect reference technology results through at least three channels. First, it can increase gross CONE by requiring additional capital investment or fixed expenditures to mitigate risk, such as on-site fuel storage, dual-fuel capability, redundant equipment, or firm fuel transportation arrangements and associated fixed charges. Second, it can affect net CONE through expected energy and ancillary service margins if risk mitigation increases variable operating costs, for example through higher delivered fuel costs under firm contracts. Thirdly, it can affect a resource's ELCC by changing its expected availability during periods of system stress.

Treating these factors endogenously is critical because it allows this study to evaluate the full economic and reliability tradeoffs consistently. A more resilient configuration may have higher fixed and variable costs but may also provide higher effective capacity. Whether such a configuration is appropriate for the reference technology should therefore depend on whether the incremental cost of mitigating fuel and operational risks is justified by the incremental reliability value delivered, as reflected through higher accredited capacity and the associated impact on net costs.

To preserve a clear and transparent baseline comparison across candidate technologies, the primary quantitative results presented in this report reflect standard configurations of each candidate technology. For gas technologies, this means not including firm fuel and/or on-site storage capabilities. The quantitative treatment of fuel-supply and operational risk is therefore addressed as part of the study's alternative configuration analysis in Section *Alternative Reference Technology Configurations for Fuel-supply Risk*, which tests whether configurations that lower fuel-supply risk could meaningfully change UCAP-based economics relative to the standard configuration.

3.2 Selection Process Overview

This study combines a consistent, quantitative comparison of candidate resources with targeted qualitative screening to assess whether each candidate reference technology is both economic and practically feasible as a marginal, scalable source of new capacity.

The process is summarized below:

1. **Candidate technology list.** MISO provides the list of candidate technologies to be evaluated in the reference technology study.
2. **Quantitative evaluation.** For each candidate technology, this study calculates the key quantitative evaluation criteria described in Section *Quantitative Criteria* using a consistent approach (Section *Analytical Approach*) and a common set of assumptions (Section *Key*

Assumptions). Candidate technologies are then ranked based on performance across the relevant quantitative criteria.

3. **Qualitative evaluation.** In parallel, this study evaluates the qualitative criteria described in Section *Qualitative Criteria* to confirm that each candidate technology satisfies the requirements to serve as a reference technology (e.g., feasible to build) that may not be fully captured in the quantitative metrics.
4. **Synthesis.** This study integrates the relative quantitative results with the qualitative screening to evaluate candidate reference technologies for MISO. The study then includes a discussion that evaluates whether refinements—such as alternative configurations or more granular geographic granularity—may be warranted for implementation.

A core tenet of the reference technology is to provide a stable basis for capacity market parameters and, therefore, higher market certainty. Reference technology studies are conducted periodically to confirm whether the prevailing reference technology remains appropriate as market conditions evolve, and this study serves as MISO's update for the Planning Year 2027/2028 cycle. Accordingly, the quantitative evaluation in this study is presented for a 2027 commercial operation date ("COD") to align with the upcoming planning year.

At the same time, the selection process is designed to support stability beyond a single snapshot year. The quantitative analysis relies on lifetime (20–30 year) projections of key inputs—most notably modeled E+AS margins[9] and capacity accreditation—so that technology comparisons reflect long-run economics and support stability of the key quantitative metrics. In addition, the qualitative evaluation assesses whether a candidate technology's cost and value drivers can be forecasted with confidence and whether its accredited-capacity economics are likely to remain stable over time relative to the 2027 COD values presented in this study. In this way, the long-run stability of the reference technology is addressed through forward-looking quantitative metrics and qualitative evaluation, even when gross CONE and modeled net CONE[10] results are reported for a single COD year.

To keep the analysis tractable and transparent, the quantitative evaluation applies a defined geographic representation (Section *Geographic Representation*) and a set of representative technology configurations (Section *Reference Technology Candidates*). These choices reflect the most material drivers observed in the data and avoid an overly fragmented set of results, but they are not intended to prescribe the geographic granularity or configuration set that MISO must ultimately implement.

Finally, the study includes a discussion on the implementation-relevant sensitivity analysis that may warrant refinement in Section *Sensitivity Analysis*. This includes whether alternative configurations

[9] "Modeled E+AS margins" refers to the forward-looking energy and ancillary services margin values calculated in this study using production cost modeling. Because this approach differs from MISO's inframarginal rents methodology in its annual CONE process, these values should not be interpreted as an indication of the inframarginal rents MISO may calculate.

[10] "Modeled net CONE" refers to the net CONE values calculated in this study using a forward-looking, production cost modeling–based E+AS margin methodology. Because this approach differs from MISO's methodology in its annual CONE process, these values should not be interpreted as an indication of the net CONE values MISO may calculate.

could be more cost-effective (e.g., by mitigating fuel supply risk). This structure supports a clear, evidence-based evaluation while transparently describing circumstances under which MISO may consider adjustments beyond the baseline framing.

3.3 Evaluation Criteria

3.3.1 Survey of Evaluation Criteria Used in Similar Studies

Consistent with the reference technology selection process utilized in this study (outlined in Section *Selection Process Overview*), other RTOs and ISOs apply a combination of quantitative and qualitative criteria to ensure that the selected technology reflects least-cost entry on an accredited capacity basis, realistic development conditions, and operational suitability. This section summarizes recent reference technology approaches used by PJM Interconnection ("PJM")[11], ISO New England ("ISO-NE")[12], and the New York ISO ("NYISO")[13]. Table 3 shows a summary matrix of the criteria applied in the studies reviewed.

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[11] Brattle, *PJM CONE 2026/2027 Report* (report prepared for PJM Interconnection, prepared for PJM (April 21, 2022), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.pdf.

[12] CONCENTRIC ENERGY ADVISORS, INC., and MOTT MACDONALD, *AN EVALUATION OF THE NET COST OF NEW ENTRY AND OFFER REVIEW TRIGGER PRICE PARAMETERS TO BE USED IN THE FORWARD CAPACITY AUCTION,* prepared for ISO-NE (December 31, 2020), https://www.iso-ne.com/static-assets/documents/2020/12/updates_cone_net_cone_cap_perf_pay.pdf.

[13] Analysis Group, Inc., and 1898 & Co., *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2025-2026 through 2028-2029 Capability Years: Final Report* (Updated Version), prepared for NYISO (October 2, 2024), https://www.nyiso.com/documents/20142/47366127/Analysis-Group-2025-2029-DCR-Final-Report-Updated.pdf.

Table 3. Review of Evaluation Criteria Used in Reference Technology Studies in Other Regions

Type	Criteria	Definition	PJM	ISO-NE	NYISO
Quantitative	**Gross CONE, Installed Capacity (ICAP)**	Levelized cost of a new entrant, expressed per MW of installed (nameplate) capacity	✓	✓	✓
	E+AS Margins, Installed Capacity (ICAP)	Expected net revenues from energy and ancillary services	✓	✓	✓
	Capacity Market Performance Bonus	Expected net value from the capacity market's performance incentive and penalty mechanism (bonus net of penalties)		✓	
	Net CONE, Installed Capacity (ICAP)	Gross CONE minus expected non-capacity net revenues, per MW of installed capacity	✓	✓	✓
	Capacity Accreditation	Fraction of accredited capacity a resource provides per installed capacity	✓	✓	✓
	Gross CONE, Accredited Capacity (UCAP)	Gross CONE expressed per MW of accredited capacity	✓	✓	✓
	Net CONE, Accredited Capacity (UCAP)	Net CONE expressed per MW of accredited capacity	✓ ★	✓ ★	✓ ★
Qualitative	**Speed-to-build**	Lead time from development start to commercial operation	✓		
	Dispatchability	Ability to increase, decrease, start, stop, and sustain output on operator command		✓	✓
	Feasibility-to-build	Practical likelihood the resource can be sited, financed, and built at scale in the relevant area	✓	✓	✓
	Market Representation	Alignment with what the market is actually building as the marginal capacity entrant	✓	✓	✓
	Forecasts Accuracy	Confidence that projected revenues and accreditation are robust and not overly sensitive to uncertain future conditions	✓	✓	
	Dual-fuel Capability	Ability to operate on an alternate fuel when the primary fuel is unavailable or constrained		✓	✓
	Environmental Review	Compatibility with environmental permitting and policy for building and operating the resource	✓	✓	✓

★ ***Primary quantitative evaluation criteria***

All three markets evaluate a common set of quantitative metrics. They begin by calculating core building blocks, including gross CONE on an ICAP basis, expected E+AS margins, net CONE on an ICAP basis, and a capacity accreditation metric. These outputs serve as intermediate steps and cross-checks that support interpretation and transparency. For example, gross CONE on an ICAP basis, together with E+AS margins and capacity accreditation, provide the decomposition needed to explain why net CONE per accredited MW differs across technologies and to confirm that assumptions are consistent with the capacity product definition.

These building blocks are then translated into accredited capacity metrics, most notably gross CONE per accredited MW and net CONE per accredited MW. **Across PJM, ISO-NE, and NYISO, net CONE on an accredited capacity basis is used as the primary quantitative evaluation criterion.**

Qualitative criteria are also consistently applied across markets and generally serve as screens to ensure the selected reference technology is buildable at the required speed and scale. Across PJM, ISO-NE, and NYISO studies, feasibility-to-build, market representation, and environmental review emerge as the common criteria. Markets also include additional qualitative screens that reflect their specific context. For example, PJM considers speed-to-build and explicitly evaluates forecast accuracy, while ISO-NE and NYISO place greater emphasis on operational characteristics such as dispatchability and dual-fuel capability.

While this review is helpful for identifying common themes and prevailing practice across markets, the appropriate evaluation criteria should ultimately be influenced based on market-specific considerations. In particular, the capacity market's structure, including how the demand curve is parameterized and how the reference technology inputs are used, will influence which quantitative metric should be treated as primary. Additionally, regional conditions, such as policy, permitting requirements, and the feasibility of scalable entry, should also inform which qualitative screens should be applied.

3.3.2 Evaluation Criteria Used in this Study

This section summarizes the evaluation criteria applied in this analysis and how they are used to evaluate candidate reference technologies for MISO. Table 4 presents a summary of the quantitative and qualitative criteria this study uses to evaluate and rank candidate technologies, including the primary evaluation criteria. The following subsections provide more background on each of these criteria and the rationale for why this study has selected the primary evaluation criteria.

Table 4. Evaluation Criteria Used in this Study

Type	Criteria	Definition	MISO
Quantitative	**Gross CONE, Installed Capacity (ICAP)**	Levelized cost of a new entrant, expressed per MW of installed (nameplate) capacity	✓
	Modeled E+AS Margins, Installed Capacity (ICAP)	Study-specific, levelized net revenues from energy and ancillary services based on forward-looking production cost modeling	✓
	Modeled Net CONE, Installed Capacity (ICAP)	Study-specific net CONE based on modeled E+AS margins, per MW of installed capacity	✓
	Capacity Accreditation (DLOL UCAP %)	Fraction of accredited capacity a resource provides per installed capacity	✓
	Gross CONE, Accredited Capacity (UCAP)	Gross CONE expressed per MW of accredited capacity	✓ ★
	Modeled Net CONE, Accredited Capacity (UCAP)	Study-specific net CONE based on modeled E+AS margins, per MW of accredited capacity	✓ ★
Qualitative	**Feasibility-to-build**	Practical likelihood the resource can be sited, financed, and built at scale in the relevant area	✓
	Speed-to-build	Lead time from development start to commercial operation	✓
	Market Representation	Alignment with what the market is actually building as the marginal capacity entrant	✓
	Forecasts Accuracy	Confidence that projected revenues and accreditation are robust and not overly sensitive to uncertain future conditions	✓
	Stability	Likelihood the technology remains an appropriate reference technology across future selection cycles, with economics remaining consistent with long-term system evolution	✓

★ ***Primary quantitative evaluation criteria***

3.3.2.1 Quantitative Criteria

This study evaluates candidate technologies using a set of quantitative criteria that together describe the economics of new entry on both an ICAP and accredited (also termed unforced capacity "UCAP") basis. As shown in Table 4, the first four quantitative metrics are intermediate building blocks used to calculate the two primary quantitative evaluation criteria. These intermediate metrics are reported to provide transparency into the drivers of relative technology rankings, including whether differences are primarily driven by gross costs, expected energy and ancillary service net revenues, or capacity accreditation.

The two primary quantitative criteria used to evaluate technologies are modeled net CONE[14] on a UCAP basis and gross CONE on a UCAP basis. Modeled net CONE per UCAP MW is included

[14] "Modeled net CONE" refers to the net CONE values calculated in this study using a forward-looking, production cost modeling–based E+AS margin methodology. Because this approach differs from MISO's methodology in its annual CONE process, these values should not be interpreted as an indication of the net CONE values MISO may calculate.

because it is used by MISO in developing its seasonal RBDCs to target long-run capacity market prices that recover net CONE (per UCAP MW) on average. This emphasis on modeled net CONE is consistent with the primary metric used in many of the reference technology studies reviewed in Section *Survey of Evaluation Criteria Used in Similar Studies*. This study also includes gross CONE per UCAP MW as a co-primary criterion because gross CONE is also a direct input into MISO's PRA RBDC shape; gross CONE is used to set the demand curve price cap (demand curve height) and therefore can influence the capacity market pricing. Together, these two metrics provide a consistent basis for evaluating technologies on a capacity-equivalent basis while maintaining alignment with both common industry practice and MISO's market design.

The quantitative criteria evaluated in this study are:

+ **Gross CONE, ICAP basis.** Gross CONE on an ICAP basis represents the annualized fixed revenue requirement per installed (i.e., nameplate) MW that a merchant developer would need to recover, through margins across all revenue streams (including capacity, energy, and ancillary services), in order to justify investment in a new generating resource. Expressed in $/kW-year of installed capacity ("ICAP"), this value includes all up-front capital costs and fixed ongoing expenses, normalized over the nameplate capacity of the resource. This metric serves as an input to calculating gross and modeled net CONE values on a UCAP basis.
+ **Modeled E+AS margins.** Modeled E+AS margins represent the expected net operating revenues a new resource would earn from participation in the energy and ancillary service markets. Expressed in $/kW-year of ICAP, this value reflects market revenues net of variable operating costs, including fuel, variable operations and maintenance ("O&M"), start and stop costs, and emissions costs where applicable. These margins represent the portion of a resource's fixed revenue requirement that is expected to be recovered outside of the capacity market. In this study, modeled E+AS margins are based on forward-looking production cost modeling and therefore differ from the inframarginal rents used by MISO in its annual CONE process.
+ **Modeled net CONE, ICAP basis.** Modeled net CONE on an ICAP basis represents the annualized fixed revenue requirement that remains for a merchant developer to recover through capacity revenues after accounting for expected non-capacity net revenues. Expressed in $/kW-year of ICAP, it is calculated as gross CONE minus modeled E+AS margins. This value serves as an input that is later translated to a UCAP basis for technology comparisons. In this study, modeled net CONE is derived using forward-looking, production cost modeling–based E+AS margins and therefore differs from the net CONE values MISO calculates in its annual CONE process.
+ **Capacity accreditation (DLOL UCAP %).** Capacity accreditation represents the contribution of a resource toward capacity requirements under MISO's Direct Loss of Load ("DLOL") accreditation methodology. Expressed as a percentage (or UCAP MW per ICAP MW), this factor converts metrics from an ICAP basis to a UCAP basis.
+ **Gross CONE, UCAP basis.** Gross CONE on an accredited-capacity (i.e., UCAP) basis represents the annualized fixed revenue requirement that a merchant developer would need to recover to justify investment in a new generating resource, expressed per UCAP MW rather

than nameplate capacity. Expressed in $/kW-year of UCAP, this value reflects the fixed cost of providing one MW of capacity that counts toward resource adequacy requirements.

- **Modeled net CONE, UCAP basis.** Modeled net CONE on a UCAP basis represents the annualized fixed revenue requirement a merchant developer would need to recover through capacity revenues, expressed per UCAP MW rather than nameplate capacity. Expressed in $/kW-year of UCAP, it is calculated by converting modeled net CONE on an ICAP basis using the DLOL-based UCAP percentage. This metric reflects the net system cost of providing one MW of capacity that counts toward the resource adequacy requirement. In this study, modeled net CONE is derived using forward-looking, production cost modeling–based E+AS margins and therefore differs from the net CONE values MISO calculates in its annual CONE process.

3.3.2.2 Qualitative Criteria

The qualitative criteria in this study are applied as screening and reasonableness checks to ensure that each candidate reference technology is not only cost-competitive, but also credible as a scalable resource. These criteria focus on practical considerations that may not be fully captured in gross CONE and modeled net CONE and are intended to ensure that a candidate reference technology is buildable, timely, representative of likely market entry, and supported by defensible forecasts.

The qualitative criteria evaluated in this study are:

- **Feasibility-to-build.** Practical likelihood the technology can be sited, permitted, interconnected, financed, and built at scale in the relevant area. This criterion is essential because the reference technology is intended to represent a marginal entrant that can actually be developed. A technology that appears economic in modeling but faces prohibitive siting, permitting, infrastructure, or supply-chain barriers would not be a credible reference technology.
- **Speed-to-build.** General timeframe to build a new resource, from development start to commercial operation (including permitting, interconnection, procurement, and construction). Speed matters because the reference technology must represent a resource that can respond to reliability needs within a planning-relevant timeframe. Technologies with very long development timelines may be feasible and least-cost in theory but are less suitable as a reference technology if they cannot reasonably be deployed in the timeframe that the reference technology impacts market pricing.
- **Market representation.** Alignment with what the market is building. This criterion serves as a check that the selected technology is consistent with observed entry behavior for reliability needs, rather than reflecting a theoretical least-cost outcome that is not supported by market behavior. Importantly, this focuses on build decisions made for capacity value, which may differ from technologies built primarily for energy production or policy-driven objectives.
- **Forecasts accuracy.** Confidence in the technology's projected revenues and capacity accreditation given available data, commercial operating experience, and potential uncertainty driven by technology penetration. This criterion captures whether the technology's estimated revenues and capacity accreditation are robust, or whether modest

changes in assumptions, penetration levels, or system conditions could materially alter the evaluation.

- **Stability.** Likelihood that the technology's costs, E+AS margins, and accreditation remain relatively consistent over time (regardless of ability to accurately forecast). This criterion captures whether the technology can be a durable option as a reference technology or whether changing market conditions could alter its suitability in the future.

Several qualitative criteria commonly used in other reference technology studies are not applied as standalone criteria here because they are captured elsewhere in the framework. Dispatchability should be reflected in the quantitative analysis through capacity accreditation, which incorporates the technology's ability to generate in times of system stress. Similarly, dual-fuel capability is treated as an input to resource performance and, therefore, capacity accreditation rather than as a separate screen. Finally, environmental review is reflected either through feasibility-to-build, as a screen on the relative feasibility that the technology can be developed, or through policy considerations incorporated in the quantitative framework. This reflects that environmental policy can affect both whether a technology can be built and how its costs and operating assumptions should be modeled.

4 Reference Technology Candidates

4.1 Overview of Candidate Technologies

The candidate technologies evaluated in this study were provided by MISO based on its internal outlook and stakeholder feedback regarding which technologies could credibly serve as reference technology candidates. This study evaluates the following eight candidate technologies:

1. Gas Combustion Turbine (CT), Frame
2. Gas Combustion Turbine (CT), Aero
3. Gas Combined Cycle Gas Turbine (CCGT), F Class
4. Gas Combined Cycle Gas Turbine (CCGT), H Class
5. 4-hour Battery Storage (4-hour Storage)
6. 2-hour Battery Storage (2-hour Storage)
7. Co-located Solar Photovoltaic and Battery Storage (Solar PV + Storage)
8. Coal Steam Turbine (ST)

The configuration and operating parameters for the candidate resources are modeled using commercially available configurations consistent with observed market participant behavior. Technology assumptions used in this study are informed by multiple public cost forecasts, including the National Laboratory of the Rockies ("NLR") Annual Technology Baseline ("ATB"), the Energy Information Administration ("EIA") Annual Energy Outlook ("AEO"), and are supplemented with market-based evidence from Halcyon, which provides robust, real-world cost data supported by regulatory filings. The representative cost and operating assumptions utilized in this study reflect the average and range derived from the most prevalent makes and models observed in these data sources, for each candidate technology. All units are assumed to be greenfield resources with sufficient environmental controls to meet applicable standards, although fossil resources do not include carbon capture. The resource models and specific configurations used for each reference technology candidate are described in more detail in the following subsections.

Several technologies were not included in MISO's candidate set for this study, including standalone wind, standalone solar, nuclear, energy efficiency and demand response ("EE/DR"), and long-duration storage. In general, these technologies do not align as well with the role of a reference technology as a near-term available source of scalable effective capacity. Standalone wind and solar are primarily energy resources and, given their intermittency, are significantly de-rated in their effective capacity (or "firmness") relative to other resources. Nuclear projects typically involve long development timelines, more stringent siting and licensing requirements, making them difficult to scale as a near-term reference resource. EE/DR can contribute to resource adequacy, but if used as the reference technology it could support a price level too low to incent new generation, implying a long-run outcome in which resource adequacy is achieved through permanent load reduction rather than new supply, thereby limiting the system's ability to accommodate new load growth. Finally, long-duration storage remains at an earlier stage of commercial maturity, with limited deployment precedent at scale, which increases uncertainty in both costs and performance for reference technology purposes.

4.2 Gas Combustion Turbine (CT), Frame

Frame combustion turbines are represented as single, simple-cycle units within the F class CT category. To parameterize this candidate, this study reviewed cost and performance information across the most prevalent commercially available makes and models observed in the underlying data, including GE Vernova 7F class, Siemens SGT6-5000F, Siemens SGT-400, Caterpillar (“Cat”) Solar Titan 250, and Cat Solar Titan 350. Consistent with published manufacturer blending limits, these turbines are assumed to be hydrogen-ready at moderate blend levels, up to approximately 30% hydrogen by volume.

For modeling purposes, this study selects a single representative unit configuration to anchor the assumptions for this technology. The GE Vernova 7F.05 is used as the representative F class turbine because it is a mature, extensively deployed unit that is widely cited in reliability, capacity accreditation, and cost-of-new-entry studies. The specific configuration assumptions applied for this representative unit are summarized in Table 5.

Table 5. Gas CT, Frame Technical Specifications

Technology Characteristic	Specification
Turbine Model	GE Vernova 7F.05
Configuration	Simple Cycle (1x0)
Cooling System	Evaporative Cooling
Power Augmentation	No
Net Summer ICAP	237 MW-ac
Net Heat Rate	~8,900 Btu/kWh
Environmental Controls	Selective Catalytic Reduction (SCR) and Carbon Monoxide (CO) Catalyst
Dual Fuel Capability	Oil: Yes;[15] Hydrogen: Yes, up to 30%
Firm Gas Contract	No
Special Structural Requirements[16]	No
Blackstart Capability	No
On-Site Gas Compression[17]	No

[15] While the turbine is original equipment manufacturer (“OEM”)-rated for 100% oil firing, the study specifications exclude the incremental balance-of-plant scope and costs required for oil delivery, unloading, on-site storage/secondary containment, and fuel forwarding/conditioning systems.

[16] Non-standard structural, interconnection, or site/civil works needed to safely install and operate a technology at a specific location (e.g., foundations, supports, seismic/wind hardening, enclosure modifications, fire protection, or other code/site-driven upgrades).

[17] Non-standard, site-specific fuel-supply add-on used when gas delivery pressure/flow at the interconnection is insufficient or unreliable for the selected technology.

4.3 Gas Combustion Turbine (CT), Aero

Aero combustion turbines are represented as a greenfield, simple-cycle configuration consisting of two state-of-the-art aero engines. This configuration reflects typical utility-scale deployments where fast start capability, high ramp rates, and modularity are prioritized, making it well-suited as a capacity resource.

For this candidate technology, the available cost and performance dataset is concentrated on a single commercially prevalent model: the GE Vernova LM6000. The LM6000 is widely deployed in North America and is frequently used as the benchmark aeroderivative peaker configuration in utility planning and capacity market studies across RTOs. The specific configuration assumptions applied are summarized in Table 6.

Table 6. Gas CT, Aero Technical Specifications

Technology Characteristic	Specification
Turbine Model	GE Vernova LM6000
Configuration	Simple Cycle (2x0)
Cooling System	No
Power Augmentation	No
Net Summer ICAP	105 MW-ac
Net Heat Rate	~8,600 Btu/kWh
Environmental Controls	Selective Catalytic Reduction (SCR) and Carbon Monoxide (CO) Catalyst
Dual Fuel Capability	Oil: Yes;[18] Hydrogen: Yes, up to 100%
Firm Gas Contract	No
Special Structural Requirements[19]	No
Blackstart Capability	No
On-Site Gas Compression[20]	No

4.4 Gas Combined Cycle Gas Turbine (CCGT), F Class

Combined CCGT resources are modeled as a greenfield 2x1 configuration, with two combustion turbines paired with two heat recovery steam generators (HRSGs) feeding a single steam turbine. This arrangement reflects a standard industry configuration that is widely used for utility-scale

[18] While the turbine is original equipment manufacturer ("OEM")-rated for 100% oil firing, the study specifications exclude the incremental balance-of-plant scope and costs required for oil delivery, unloading, on-site storage/secondary containment, and fuel forwarding/conditioning systems.

[19] Non-standard structural, interconnection, or site/civil works needed to safely install and operate a technology at a specific location (e.g., foundations, supports, seismic/wind hardening, enclosure modifications, fire protection, or other code/site-driven upgrades).

[20] Non-standard, site-specific fuel-supply add-on used when gas delivery pressure/flow at the interconnection is insufficient or unreliable for the selected technology.

combined-cycle development and provides an appropriate balance of thermal efficiency and operational flexibility.

The frame CT turbines of the CCGTs models reviewed in this study included Mitsubishi Power Americas 501JAC, GE Vernova 7HA.03, GE Vernova 7HA.02, and a Siemens SGT6-5000F-based combined-cycle configuration (with the associated steam turbine). Note that, although a combined-cycle plant is built around combustion turbines, the CT model used for the CCGT benchmark does not need to match the standalone frame CT benchmark. The two cases represent different commercial products optimized for different roles: a simple-cycle peaker is typically selected to minimize installed cost and maximize fast-start and operational flexibility, whereas a CCGT block is selected as an integrated package optimized for combined-cycle efficiency, exhaust conditions, and controls integration.

The Siemens SGT6-5000F-based 2x1 configuration is used as the representative F class CCGT unit. The Siemens SGT6-5000F–based CCGT package is a proven heavy-frame F class platform with extensive fleet operating experience, robust cycling capability, and compatibility with modern emissions controls, and it is commonly used as a benchmark configuration in utility planning and cost-of-new-entry studies. The specific configuration assumptions applied are summarized in Table 7.

Table 7. Gas CCGT, F Class Technical Specifications

Technology Characteristic	Specification
Turbine Model	Siemens SGT6-5000F
Configuration	Combined Cycle (2x1)
Cooling System	Evaporative Cooling
Power Augmentation	No
Net Summer ICAP	500 MW-ac
Net Heat Rate	~5,700 Btu/kWh
Environmental Controls	Selective Catalytic Reduction (SCR) and Carbon Monoxide (CO) Catalyst
Dual Fuel Capability	Oil: Yes; [21] Hydrogen: Yes, up to 30%
Firm Gas Contract	No
Special Structural Requirements[22]	No
Blackstart Capability	No
On-Site Gas Compression[23]	No

[21] While the turbine is original equipment manufacturer ("OEM")-rated for 100% oil firing, the study specifications exclude the incremental balance-of-plant scope and costs required for oil delivery, unloading, on-site storage/secondary containment, and fuel forwarding/conditioning systems.

[22] Non-standard structural, interconnection, or site/civil works needed to safely install and operate a technology at a specific location (e.g., foundations, supports, seismic/wind hardening, enclosure modifications, fire protection, or other code/site-driven upgrades).

[23] Non-standard, site-specific fuel-supply add-on used when gas delivery pressure/flow at the interconnection is insufficient or unreliable for the selected technology.

4.5 Gas Combined Cycle Gas Turbine (CCGT), H Class

As with the F class combined-cycle candidate, H class combined-cycle resources are modeled as a greenfield 2x1 configuration that reflects standard utility-scale CC development and is intended to capture the higher-efficiency segment of modern combined-cycle technology.

The models reviewed in this study included the GE Vernova 7HA.03, Siemens SGT6-9000HL, and Siemens SGT6-8000H. The GE 7HA.03-based combined cycle configuration is used as the representative H class CC unit. The 7HA.03 is a state-of-the-art H class gas turbine, with higher firing temperatures and advanced cooling and materials that enable industry-leading combined-cycle efficiency while maintaining operational flexibility. The specific configuration assumptions applied are summarized in Table 8.

Table 8. Gas CCGT, H Class Technical Specifications

Technology Characteristic	Specification
Turbine Model	GE Vernova 7HA.03
Configuration	Combined Cycle (2x1)
Cooling System	Evaporative Cooling
Power Augmentation	No
Net Summer ICAP	500 MW-ac
Net Heat Rate	~5,300 Btu/kWh
Environmental Controls	Selective Catalytic Reduction (SCR) and Nitrogen Oxide Combustors
Dual Fuel Capability	Oil: Yes; [24] Hydrogen: Yes, up to 50%
Firm Gas Contract	No
Special Structural Requirements[25]	No
Blackstart Capability	No
On-Site Gas Compression[26]	No

4.6 4-hour Battery Storage (4-hour Storage)

The battery storage configurations modeled represent standard lithium-ion battery systems, specifically lithium iron phosphate (LFP) chemistry, which is widely deployed in utility-scale applications due to its low cost, safety profile, cycle life, and thermal stability. These assumptions reflect industry standard battery development and the underlying data derived from the NLR ATB.

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[24] While the turbine is original equipment manufacturer ("OEM")-rated for 100% oil firing, the study specifications exclude the incremental balance-of-plant scope and costs required for oil delivery, unloading, on-site storage/secondary containment, and fuel forwarding/conditioning systems.

[25] Non-standard structural, interconnection, or site/civil works needed to safely install and operate a technology at a specific location (e.g., foundations, supports, seismic/wind hardening, enclosure modifications, fire protection, or other code/site-driven upgrades).

[26] Non-standard, site-specific fuel-supply add-on used when gas delivery pressure/flow at the interconnection is insufficient or unreliable for the selected technology.

4-hour standalone storage is included as a candidate technology because this duration is commonly observed in current utility-scale development in MISO and is frequently used as a planning benchmark that balances cost with the ability to provide effective capacity. The technical specifications for the 4-hour duration battery are captured in Table 9 and form the basis for the cost, performance, and capacity contribution modeling included in this study.

Table 9. 4-hour Storage Technical Specifications

Technology Characteristic	Specification
Storage Duration	4 hours
Battery Chemistry	Lithium Ion; Lithium iron phosphate (LFP)
Power Rating	10 MW-ac
Energy Rating	40 MWh-ac
Configuration	Containerized; Utility-scale
Round-Trip Efficiency	85%
Cycling Rate	Degradation rate assumes 1 cycle per day
Fire Safety Controls	Thermal management system and fire suppression system
Degradation / Augmentation Plan	Augmentation costs included in fixed O&M
Depth of Discharge	90%
Blackstart Capability[27]	Yes

4.7 2-hour Battery Storage (2-hour Storage)

The 2-hour storage configuration modeled represents the same standard utility-scale lithium-ion technology and lithium iron phosphate (LFP) chemistry assumed for the 4-hour storage. All technical and cost assumptions are aligned with the 4-hour configuration except for storage duration.

2-hour storage is included as a candidate technology because shorter-duration storage is still a meaningful segment of the U.S. storage market. In particular, 2-hour systems have seen substantial development in Electric Reliability Council of Texas (ERCOT) and have also been selected as the reference technology in NYISO's capacity market. The technical specifications for the 2-hour duration battery are summarized in Table 10.

[27] Blackstart capability is technically possible for any battery storage asset but is dependent on operational parameters (i.e. maintaining state of charge) that would need to be specified by market or contract terms.

Table 10. 2-hour Storage Technical Specifications

Technology Characteristic	Specification
Storage Duration	2 hours
Battery Chemistry	Lithium Ion; Lithium iron phosphate (LFP)
Power Rating	10 MW-ac
Energy Rating	20 MWh-ac
Configuration	Containerized; Utility-scale
Round-Trip Efficiency	85%
Cycling Rate	Degradation rate assumes 1 cycle per day
Fire Safety Controls	Thermal management system and fire suppression system
Degradation / Augmentation Plan	Augmentation costs included in fixed O&M
Depth of Discharge	90%
Blackstart Capability[28]	Yes

4.8 Co-located Solar Photovoltaic and 4-hour Battery Storage (Solar PV + Storage)

For the co-located solar PV and storage ("Solar PV + Storage") configuration, the storage is paired with a utility-scale, single-axis tracking solar photovoltaic PV system at a 1-to-1 (1:1) ratio of capacities. In this study, capacity (MW) for the solar PV + storage resource refers to the combined co-located facility rating; therefore, 1 MW of solar PV + storage would correspond to 0.5 MW of solar PV and 0.5 MW of storage.

The two technologies are assumed to share a common inverter. The co-located storage is assumed to be 4-hour duration, consistent with industry practices and interconnection configurations that optimize both energy shifting and grid support services. This reflects the industry standard for co-located solar and storage configuration and optimizes to increase round-trip efficiency while reducing costs by utilizing a single, shared inverter, as well as some shared Balance of Plant ("BOP") equipment.

In line with the configuration assumed in the NLR ATB, this study assumes a DC-coupled configuration for the solar PV array and the battery storage system, improving round-trip efficiency but increasing balance of system and fixed O&M costs. According to NLR analysis, DC-coupled configurations results in the lowest overall cost for co-located configurations due to the reduction in need for system oversizing. The configuration and specifications for the Solar PV + Storage are detailed in Table 11, consistent with the NLR ATB data.

[28] Blackstart capability is technically possible for any battery storage asset but is dependent on operational parameters (i.e. maintaining state of charge) that would need to be specified by market or contract terms.

Table 11. Co-Located Solar PV + Storage Technical Specifications

Technology Characteristic	Specification
Solar PV – Configuration	Single-axis tracking
Solar PV – Power Capacity	5 MW-ac
Solar PV – Capacity Factor	23.5% to 26.7%, depending on MISO region
Solar PV – Degradation Rate	0.50% capacity reduction per year
Storage – Battery Chemistry	Lithium Ion; LFP
Storage – Storage Duration	4 hours
Storage – Configuration	Distributed throughout the PV array; Utility-scale
Storage – Power Rating	5 MW-ac
Storage – Energy Rating	20 MWh-ac
Storage – Round-Trip Efficiency	85%
Storage – Cycling Rate	Degradation rate assumes 1 cycle per day
Storage – Degradation / Augmentation Plan	Augmentation costs included in fixed O&M
Storage – Depth of Discharge	90%
Inverter Loading Ratio	1.34
Inverter Rating	5 MW-ac
Inverter Configuration	Shared (DC-coupled), bi-directional
Fire Safety Controls	Thermal management system and fire suppression system, distributed with battery racks
Blackstart Capability[29]	Yes

4.9 Coal Steam Turbine (ST)

A new coal plant technology without carbon capture is included as a reference technology candidate. Design and cost details are sourced from the NLR and are detailed in Table 12.[30]

[29] Blackstart capability is technically possible for any battery storage asset but is dependent on operational parameters (i.e. maintaining state of charge) that would need to be specified by market or contract terms.

[30] National Renewable Energy Laboratory (NREL), *Fossil Energy Technologies*, Annual Technology Baseline (ATB), Electricity (2024), accessed February 6, 2026, https://atb.nrel.gov/electricity/2024/fossil_energy_technologies.

Table 12. Coal ST Technical Specifications

Technology Characteristic	Specification
Plant Type	Pulverized Coal (PC)
Configuration	Single Unit Pulverized Coal (PC) Boiler + Steam Turbine
Steam Cycle	Supercritical Rankine Cycle[31]
Net Summer ICAP	650 MW-ac
Steam Conditions	Single-reheat, 24.1 MPa / 593°C / 593°C
Cooling System	Mechanical Draft Evaporative Cooling
Power Augmentation	No
Environmental Controls	Selective Catalytic Reduction (SCR), particulate controls, mercury, and acid gas controls; Mercury and Air Toxics Standards (MATS) and New Source Performance Standards (NSPS) compliant
Dual Fuel Capability	No
Special Structural Requirements[32]	No
Blackstart Capability	No
On-Site Fuel Handling	Coal handling, storage, and ash disposal systems

[31] As noted in the NLR documentation, the design conditions noted here are characterized as ultra supercritical steam conditions in some sources. Details are provided here for avoidance of confusion in this regard.

[32] Non-standard structural, interconnection, or site/civil works needed to safely install and operate a technology at a specific location (e.g., foundations, supports, seismic/wind hardening, enclosure modifications, fire protection, or other code/site-driven upgrades).

5 Analytical Approach and Assumptions

5.1 Analytical Approach

5.1.1 Overview of Analytical Approach

This section provides a high-level summary of the quantitative analysis used to evaluate candidate reference technologies. The analysis produces the two co-primary evaluation criteria—gross CONE on a UCAP basis and modeled net CONE on a UCAP basis—for each candidate technology and geography evaluated (more details in Section *Geographic Representation*), assuming a 2027 COD. To support interpretation and transparency, the study also reports the intermediate quantitative building blocks that determine these UCAP-based outcomes, including gross CONE on an ICAP basis, levelized modeled E+AS margins, modeled net CONE on an ICAP basis, and the capacity accreditation.

Forward-looking cost estimates are inherently uncertain. Therefore, the study evaluates gross CONE (ICAP basis) under three cost scenarios — Low, Mid, and High — for each technology and geography. These scenarios are intended to reflect a reasonable range of potential cost outcomes and to test whether relative rankings are robust to plausible cost variation. The Mid case is used as the primary point of comparison in the report, with the Low and High cases providing scenario-based context.

To translate gross CONE (ICAP basis) into gross CONE and modeled net CONE (UCAP basis), the study applies two additional forward-looking inputs that are held constant across the cost scenarios: (1) levelized modeled E+AS margins by technology and geography and (2) levelized expected capacity accreditation by technology. The following subsections describe the detailed methods used to calculate each quantitative criteria.

5.1.2 Gross Cost of New Entry (CONE), ICAP Basis

To estimate CONE values, we use a bottom-up cost approach informed by benchmarked data from public and proprietary sources, including technology cost databases, market reports, and historical project data. For this approach, this study uses E3's in-house discounted cash flow model known as RECOST.[33] Given a set of technology- or project-specific assumptions for system performance and operations, upfront and ongoing costs, and financing parameters, RECOST computes gross CONE on an ICAP basis (in $/kW-yr ICAP). RECOST uses data from the National Laboratory of the Rockies (formerly known as NREL), the Department of Energy's Energy Information Administration, the Pacific Northwest National Laboratory, the Lazard Levelized Cost of Energy+ report, and public capital markets to inform assumptions.

[33] For more details on RECOST, see https://www.ethree.com/tools/recost-model/.

The parameters used in RECOST to calculate CONE are described in more detail later in this study and include the following:

- **Capital costs**, including engineering, procurement, construction ("EPC"), and major equipment
- **Financing costs** derived from assumed capital structure and after-tax weighted average cost of capital ("ATWACC"), accounting for tax treatment of depreciation and interest
- **Interconnection costs** encompassing electrical interconnection, based on bulk market data
- **Fixed O&M** costs including labor, insurance, property taxes, and third-party service agreements
- **Income taxes** calculated using state-level effective tax rates
- **Warranty and augmentation costs,** particularly for storage resources, reflecting expected battery performance degradation and periodic augmentation needs
- **Applicable tax credits and financial incentives** such as the ITC, PTC, or accelerated depreciation, modeled as levelized offsets to capital recovery where applicable

These components are combined and levelized in nominal dollars over the assumed economic life of the resource to calculate the total levelized cost. The resulting CONE values reflect the fixed cost of capacity entry, standardized on an ICAP basis, and provide a consistent basis for comparing technologies across market scenarios and planning horizons.

Throughout this report, we account for project-by-project variation and uncertainty in cost forecasting by estimating and comparing Low, Mid, and High scenarios. Further details on the assumptions and rationale for each scenario are provided in Section *Key Assumptions*.

5.1.3 Modeled Energy and Ancillary Services Margins (Modeled E+AS Margins), ICAP Basis

To estimate net CONE, this study must first estimate the E+AS margins that a new capacity entrant would expect to earn. In its annual CONE calculation, MISO estimates a one-year snapshot (for the CONE calculation year) of inframarginal rents (E+AS margins equivalent) for the reference technology (advanced gas frame CT) using historical market outcomes, typically based on a three-year sample.

This study adopts a modeling-based methodology to estimate E+AS margins (referred to as modeled E+AS margins in this study) for three main reasons:

- As discussed in Section First-year vs. Lifetime Forward-looking Metrics, evaluating new capacity entry requires forward-looking revenue projections over the life of the resource. Developers make new entry decisions based on expected lifetime revenues rather than a single first-year snapshot, particularly in a changing system where margins can evolve meaningfully over time.
- The study must apply a consistent E+AS margins methodology across all candidate technologies, including resources that may not yet exist in significant quantities in the MISO

footprint and therefore cannot be evaluated using an inframarginal rent methodology due to lack of historical data.

- As discussed in Section System Representation, the study evaluates candidate technologies in a system represented at the reliability target, and therefore requires E+AS margin assumptions that are consistent with that same system representation, including the underlying load levels, portfolio mix, and capacity accreditation assumptions used elsewhere in the analysis.

For these reasons, **the modeled E+AS margins calculated in this study are not intended to represent the inframarginal rent values that MISO will ultimately calculate and apply as the offset to gross CONE in its annual CONE determination**.

This study forecasts modeled E+AS margins using the raw production cost modeling outputs from MISO's PLEXOS model developed for the Regional Resource Assessment ("RRA"). The RRA framework is MISO's long-term resource adequacy modeling platform, and using these results ensures that the E+AS margin forecasts are consistent with the broader system representation and the capacity accreditation assumptions utilized in this study (see Section *Capacity Accreditation*).

MISO's RRA model was run for 2027, 2030, 2033, and 2043. The study uses the results for these modeled years directly and then interpolates between these modeled years to estimate annual values between 2027 and 2043. For the remaining years in the forecast horizon (2044 through 2056), modeled E+AS margins are assumed to remain constant in real dollars; i.e., nominal modeled E+AS margins are assumed to escalate by inflation. The key underlying assumptions for the modeled years—including resource mix, load, and fuel prices—is detailed in MISO's "2024 Regional Resource Assessment: A Reliability Imperative Report", published January 2025.[34]

For each candidate technology, modeled E+AS margins are calculated as total market revenues from energy and ancillary services less variable operating costs. Variable costs include fuel costs, variable operations and maintenance, start and stop costs, and emissions costs where applicable. The study maps modeled RRA units to the corresponding candidate technology categories (where applicable) and extracts modeled E+AS margins for each technology evaluated.

Where multiple modeled units represent a given candidate technology, this study uses the median E+AS margin across the modeled fleet as the technology-level E+AS margin value for all scenarios (Low, Mid, and High) and regions evaluated. This is consistent with the assumption that the reference technology should be scalable and not represent a resource whose apparent attractiveness is driven by location-specific or otherwise non-replicable factors, such as siting in a high LMP zone. The resulting E+AS margin represents the portion of a resource's fixed revenue requirement expected to be recovered each year outside the capacity market and serves as a key input to the modeled net CONE.

[34] Midcontinent Independent System Operator, Inc., 2024 Regional Resource Assessment: A Reliability Imperative Report—Highlights (January 2025), https://cdn.misoenergy.org/2024%20RRA%20Report_Final676241.pdf.

The resulting annual modeled E+AS margins forecast is then levelized in nominal dollars over the economic life of the generator using the same financing parameters applied to gross CONE (see Sections *Financing Parameters* and *Levelization Convention and Parameters*). This produces a single nominal levelized E+AS margin value for each technology for use in the modeled net CONE calculation.

MISO's RRA PLEXOS outputs are generated using a modeling scope designed for long-term resource adequacy assessment rather than generator economics valuation. Several aspects of the model are therefore important for interpreting the resulting modeled E+AS margins. First, dispatch and pricing are based on day-ahead market constructs and do not explicitly capture real-time market outcomes. Second, ancillary services are not fully modeled on an economic basis, which results in negligible ancillary service revenues for all generators. Thirdly, the model does not explicitly represent scarcity pricing adders that can cause prices to rise above short-run marginal cost during the tightest hours.

Taken together, these features tend to produce modeled E+AS margins that are conservative relative to observed market outcomes, as can be seen by comparing modeled margins to historical realized margins for existing resources. However, because these modeling characteristics apply consistently across technologies, they are not expected to materially affect the relative ordering of modeled E+AS margins across the candidate technologies evaluated, although the understatement may be larger for resources whose value is concentrated in tight system conditions (e.g., natural gas combustion turbines and battery storage). Even with these limitations, the RRA results provide a consistent and internally coherent basis for comparing candidate technologies.

Because the objective of this analysis is to evaluate candidate reference technologies based on their relative economics, rather than to calculate the specific gross and net CONE values MISO will use in the PRA, this study applies a consistent, forward-looking methodology to estimate modeled E+AS margins that differs from the inframarginal rents methodology used in MISO's annual CONE calculation.

5.1.4 Modeled Net Cost of New Entry (Modeled Net CONE), ICAP Basis

For each candidate technology and region, this study calculates modeled net CONE on an ICAP basis by subtracting the single levelized (median) E+AS margin value from the corresponding gross CONE value for each scenario (Low, Mid, and High). Both components are defined in the previous sections and are expressed on an ICAP basis.

The term "modeled net CONE" is used intentionally to refer to the net CONE values calculated in this report and to distinguish them from the net CONE values MISO calculates in its annual CONE process. These values are labeled "modeled" because the E+AS margin offset in this study is derived from forward-looking production cost modeling rather than from MISO's historical-based inframarginal rent methodology. As a result, the net CONE values presented here are intended for comparative evaluation of candidate technologies within this reference technology study and should not be interpreted as an indication of the specific net CONE values MISO will ultimately calculate and apply in capacity market.

5.1.5 Capacity Accreditation (DLOL UCAP %)

To be consistent with MISO's capacity accreditation methodology, **this study utilizes DLOL UCAP % to represent each technology's capacity accreditation**. Under the DLOL framework, a resource's accredited capacity reflects its expected reliability contribution during the system's highest-risk hours, with one DLOL UCAP % by technology across MISO's entire footprint. Capacity accreditation values are developed on an annual basis over the same forecast horizon used for modeled E+AS margins (2027-2056, more details in Section *Modeled Energy and Ancillary Services Margins (Modeled E+AS Margins*), ICAP Basis) to support lifetime, capacity-equivalent comparisons.

Accreditation inputs are also sourced directly from MISO to maintain consistency with other assumptions in this analysis such as load growth and resource portfolio mix over time. For 2027, seasonal DLOL UCAP % inputs are drawn from MISO's "Planning Year 2026-2027: Loss of Load Expectation Study", which is conducted in PowerGEM's SERVM software each year to establish the seasonal various capacity market parameters for the 2026-2027 PRA.[35, 36] For later study years (2030, 2033, and 2043), seasonal accreditation values are taken from MISO's PLEXOS-based modeling outputs, consistent with the model system and years used to develop the E+AS margin forecast.[37]

Because MISO's capacity construct is seasonal, DLOL values are produced by season. However, the economic metrics used in this study (gross CONE and modeled net CONE) are expressed on an annual basis. To ensure consistency, seasonal DLOL values are converted into a single annual accreditation factor using a LOLE-weighted average across seasons. Weights are based on each season's contribution to annual LOLE risk in the calibrated system (at 0.1 day/year LOLE).[38]

MISO also applies a minimum seasonal LOLE criterion (0.01 day/year), which can require additional seasonal capacity adjustments for seasons that are not binding in the annual reliability solution. To avoid overstating the importance of non-binding seasons, seasons that require incremental adjustment to meet the minimum criterion are assumed to have zero weight in the annual value.

To support lifetime, capacity-equivalent comparisons, the resulting annual DLOL UCAP % values are then levelized over each technology's useful life using a nominal levelization approach consistent with that of gross CONE and modeled E+AS margins (described in Section *Levelization Convention and Parameters*). The resulting value is therefore a constant levelized accreditation factor by year.

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[35] Midcontinent Independent System Operator, Inc., *Planning Year 2026-2027 Loss of Load Expectation Study Initial Report* (PDF, accessed February 6, 2026), https://cdn.misoenergy.org/PY%202026-2027%20LOLE%20Study%20Report728909.pdf.

[36] Midcontinent Independent System Operator, Inc., *Planning Year 2026-2027 Indicative DLOL-Based Unforced Capacity and Planning Reserve Margin Requirement Results* (PDF, accessed February 6, 2026), https://cdn.misoenergy.org/PY26-27%20Indicative%20DLOL-based%20UCAP%20%20PRMR%20Results738545.pdf.

[37] Midcontinent Independent System Operator, Inc., *2024 Regional Resource Assessment: Highlights* (A Reliability Imperative Report, January 2025), https://cdn.misoenergy.org/2024%20RRA%20Report_Final676241.pdf.

[38] For illustrative purposes, assume a resource has seasonal DLOL values of 70%, 75%, 80%, and 85%, and the season-level LOLE contributions in the calibrated 0.1 day/year LOLE system are 0.01, 0.02, 0.04, and 0.03 day/year, respectively. The annualized accreditation factor would be: (0.70×0.01 + 0.75×0.02 + 0.80×0.04 + 0.85×0.03) / 0.10 = 79.5%

expressed in nominal terms, intended to represent a flat annual UCAP DLOL % over the technology's life that is present-value-equivalent to the underlying annual trajectory.

5.1.6 Gross Cost of New Entry (CONE), UCAP Basis

Gross CONE on a UCAP basis is derived by converting the ICAP-based gross CONE estimate to reflect each technology's capacity accreditation. Specifically, for each candidate technology, the Low, Mid, and High scenario gross CONE on an ICAP basis values (described in Section *Gross Cost of New Entry (CONE*), ICAP Basis) is divided by the technology's levelized DLOL UCAP % factor (described in Section *Capacity Accreditation*). This yields gross CONE in $/kW-year of UCAP, which reflects the gross cost of each technology on an equivalent-capacity basis. This metric reveals that a lower DLOL UCAP % translates the same fixed cost of entry into a higher cost per UCAP MW, and vice versa.

5.1.7 Modeled Net Cost of New Entry (Modeled Net CONE), UCAP Basis

Modeled net CONE on a UCAP basis is calculated using the same conversion approach applied to gross CONE on a UCAP basis. Specifically, for each candidate technology, the Low, Mid, and High scenario modeled net CONE on an ICAP basis values (calculated as described in Section *Modeled Net Cost of New Entry (Modeled Net CONE),* ICAP Basis) is divided by the technology's annualized DLOL UCAP % (described in Section *Capacity Accreditation*). This calculation yields modeled net CONE in $/kW-year of UCAP and reflects the net cost of supplying one MW of UCAP capacity after accounting for expected non-capacity net revenues, on an equivalent-capacity basis. As with gross CONE, lower accreditation values translate a given ICAP based net cost into a higher net cost per UCAP MW, and vice versa.

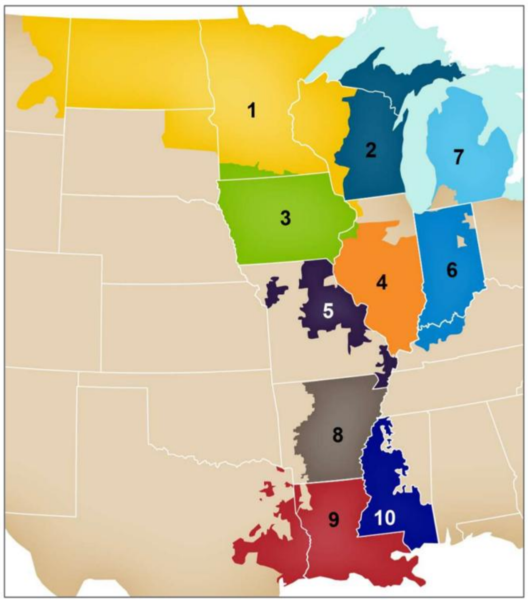
As discussed in Section *Modeled Net Cost of New Entry (Modeled Net CONE), ICAP Basis*, the modeled net CONE values in this study are calculated using a methodology that differs from MISO's annual process. Accordingly, these values are intended only for use within this study and should not be interpreted as an indication of the specific net CONE values MISO will ultimately calculate and apply in its capacity market.

5.2 Key Assumptions

5.2.1 Geographic Representation

Resource costs and revenues can differ meaningfully across states and zones within MISO and, in some cases, even between sites. However, the level of geographic differentiation that is *feasible* to estimate for reference technology purposes is distinct from the level of differentiation that is *useful* for a quantitative screening exercise. In this report, geographic differentiation is used to capture the most material, observable cost and revenue drivers while keeping the quantitative results tractable and interpretable (i.e., avoiding an overly fragmented set of LRZ-level outputs). This analytic choice should not be interpreted as a recommendation regarding the geographic granularity MISO should ultimately apply for reference technology implementation, which may also be informed by qualitative considerations or policy-driven needs discussed elsewhere. Geographic differences in key CONE inputs—including capital costs, interconnection costs, and fixed operations and maintenance costs—can materially affect gross CONE, and variation in state tax rates across the MISO footprint can affect levelized costs through differences in after-tax financing assumptions. For context, MISO's LRZ and regions are shown in Figure 3.

Figure 3. MISO Load Resource Zones (LRZs) and Regions



LRZ	Region
1	North
2	Central
3	North
4	Central
5	Central
6	Central
7	Central
8	South
9	South
10	South

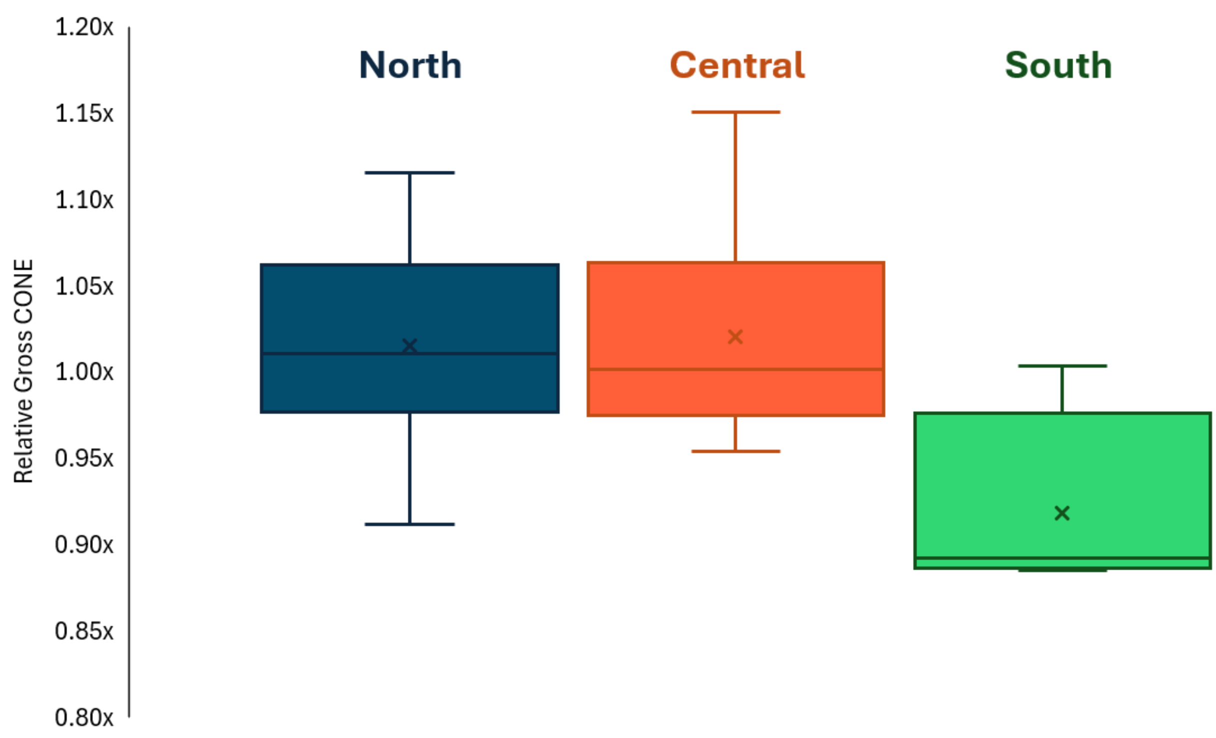
To determine an appropriate geographic representation for the quantitative analysis, this study examined location-driven variation in major gross CONE components across MISO states where sufficient data exists to support subregional differentiation. This regional cost evaluation is shown in Table 13.

Table 13. Location Based Variables

Variable	Data Available?	Range Within MISO	Study Conclusion
State Corporate Income Tax Rate	Yes	0.75% - 12%	Merits differentiation due to impact on WACC and net income
Construction Labor Wages	Yes	$35,660 - $61,350 annual median wage	Merits differentiation due to impact on overnight capital costs
Land Lease Costs	Yes	$2,570/acre - $9,800/acre	Merits differentiation due to impact on Fixed O&M, a component of CONE
Interconnection Cost	Yes	$4/kW - $469/kW[39]	Merits differentiation due to significant variation within MISO

These locational changes can ultimately drive changes in gross CONE, as illustrated in Figure 4, which shows the relative gross CONE of gas CTs (2027 COD) across MISO regions. Each datapoint represents an LRZ, and 1.00x represents the MISO-wide average gross CONE. The figure shows that MISO South is meaningfully shifted relative to the rest of the footprint in terms of location-specific influence on gross CONE.

Figure 4. Gross CONE by MISO Region, Relative to U.S. Average for Gas Combustion Turbine, 2027 COD



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[39] The interconnection cost range is reflective of both regional and technological diversity.

The gross CONE results suggest two key takeaways for purposes of the quantitative evaluation. First, within each MISO region, the spread in gross CONE is relatively limited (generally within ~5% of the regional average), indicating that further disaggregation to the LRZ level would add substantial complexity without materially changing conclusions. Second, the North and Central regions exhibit very similar gross CONE distributions, while the South region is meaningfully shifted relative to North and Central.

Accordingly, **the quantitative results in this study are presented for two regions: the combined MISO North and Central ("North + Central") region and the MISO South region**. As defined in this study, Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Montana, North Dakota, South Dakota, Wisconsin, and the Canadian province of Manitoba constitute "MISO North + Central," while Arkansas, Louisiana, Mississippi, and Texas constitute "MISO South."

5.2.2 Capital Costs Inputs and Scenarios

Capital costs ("capex") represent the total investment required to develop and construct a new generating facility and bring it into commercial operation. These costs are incurred prior to plant operation and include engineering, procurement, construction, and project development activities. For gross CONE estimation, capex is expressed as an overnight cost and then converted to installed cost by accounting for the construction period and the timing of expenditures.

The capex estimate includes both direct and indirect expenditures required to complete a greenfield facility. Direct costs include major equipment (e.g., combustion turbines, heat-recovery steam generators, battery modules, solar modules) and associated balance-of-plant systems, along with construction labor and materials. Indirect costs include engineering, procurement, construction (EPC) services, inclusive of contractor overhead and profit. The estimate also includes owner's costs such as development and permitting, interconnection, land acquisition, and financing fees, as well as standard contingencies to account for design uncertainty, potential scope changes, permitting delays, and other unforeseen development risks. Labor costs embedded in engineering, procurement, construction (EPC) services and land costs within development scope are adjusted for state-specific effects, consistent with the approach described in Section *State-Specific Cost Multipliers*.

Capital cost recovery is modeled assuming 100% bonus depreciation is available in the first year of operation. This treatment can materially reduce the after-tax cost of capital by accelerating depreciation deductions, thereby lowering taxable income and improving project economics. The assumption is consistent with current federal tax law provisions that restored and made permanent 100% bonus depreciation under the One Big Beautiful Bill Act ("OBBBA"), signed into law in July 2025.

Because this study evaluates new-build projects with a 2027 COD, capex values are expressed on a 2027 basis. Where source datasets reflect earlier project vintages, costs are escalated to 2027 as described in Section *Escalation of Cost Values*. To reflect uncertainty in forward cost outcomes, the analysis applies three capex scenarios—Low, Mid, and High—with the scenario construction varying by technology. These scenarios are designed to bracket a reasonable range of capex values and to test whether relative rankings are robust to plausible cost variation, while recognizing that they are not intended to represent every possible future scenario.

Overall, the capex inputs are grounded in public datasets and benchmarked to observed market datapoints to produce robust 2027 COD cost estimates. Additional details on the technology-specific capex values and scenarios are provided in the following subsections.

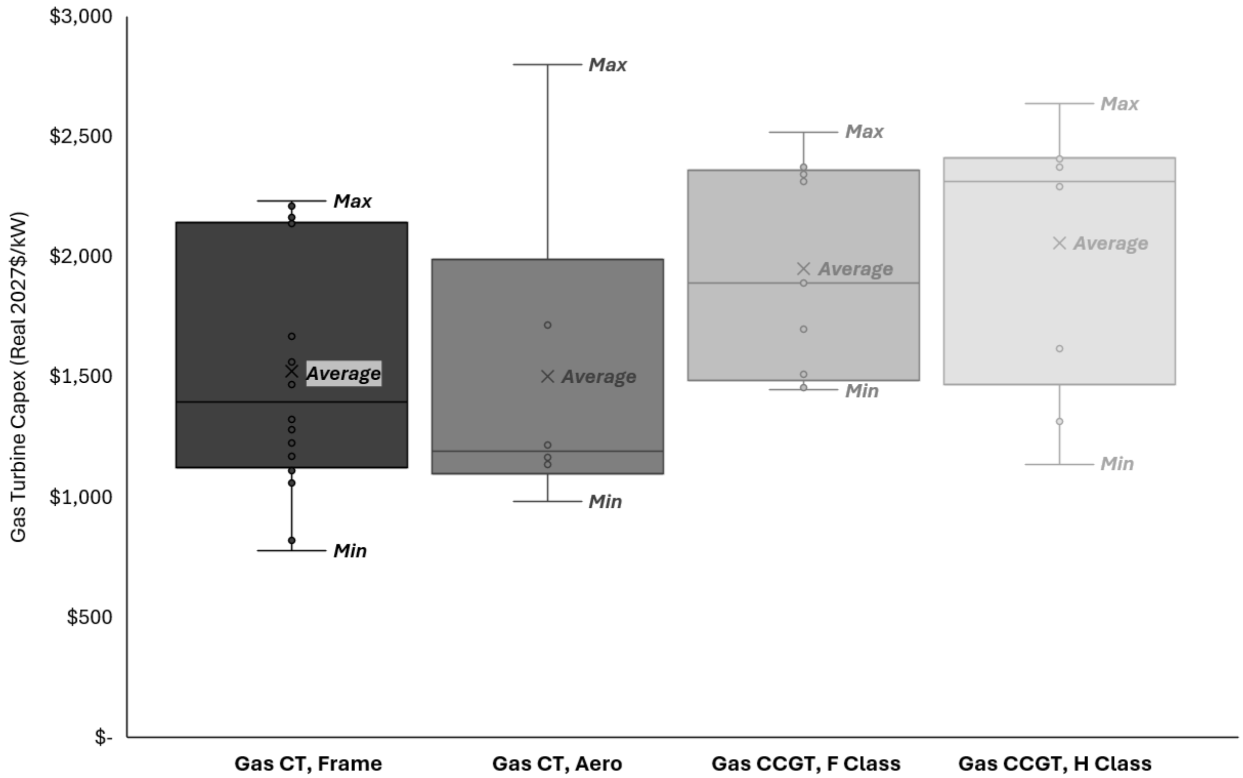
5.2.2.1 Thermal Technologies

Recent experience shows that thermal plant construction costs have been volatile, driven by supply-chain constraints, equipment and labor cost inflation, and tightening engineering, procurement, construction (EPC) capacity amid broader demand growth for new generation. As noted above, this study finds that establishing reasonable capital cost inputs for thermal technologies therefore requires a blended approach that combines empirical project data with published benchmark sources.

For gas-fired technologies, this study leverages Halcyon's Gas Power Plant Tracker for project-level benchmarking and dispersion and supplements those empirical signals with a literature review of widely used public datasets, including the NLR ATB, the EIA AEO capital cost assumptions, and Lazard's Levelized Cost of Energy analysis ("LCOE+"). Together, these sources provide a consistent cross-check on central cost levels and help ensure the 2027 overnight capex inputs reflect both observed market outcomes and established reference benchmarks.

The Halcyon dataset used for this benchmarking includes 73 gas plant filings with in-service dates between 2025 and 2031, of which 40 include capex data and are used in this analysis. Figure 5 shows the distribution of reported capital costs by gas technology. Frame CTs and CCGTs show relatively tight clustering around their central values, while aero CTs exhibit wider capex spread reflecting the smaller number of datapoints. In addition, the aero CT sample includes a higher share of earlier filings, which is relevant given the material increase in gas turbine costs in recent years.

Figure 5. Distribution of Capex Datapoints in Halcyon Dataset by Technology



The key statistics of the Halcyon capex data are summarized in Table 14.

Table 14. Halcyon Natural Gas Plant Tracker Summary

Metric	Unit	Gas Combustion Turbine		Gas Combined-Cycle Gas Turbine	
		Frame, F Class	Aero	F Class	H Class
Data Points	#	16	6	9	9
Minimum Capex	2027$/kW	$778	$982	$1,445	$1,135
Average Capex	2027$/kW	$1,521	$1,502	$1,950	$2,055
Max Capex	2027$/kW	$2,230	$2,799	$2,517	$2,636
Standard Deviation	%	28.4%	33.5%	19.9%	22.7%

To calculate a central estimate for each gas technology type, we compute the average capex across all four sources. This average value serves as the Mid case, intended to reflect a reasonable central estimate for new-build merchant projects under typical development conditions. The inputs to the average capex value determination are shown in 2027 dollars (“2027$”) in Table 15.

Table 15. Average Gas Capex Calculation Inputs, Excluding Allowance for Funds Used During Construction (2027$/kW)

Data Source	Gas Combustion Turbine		Gas Combined-Cycle Gas Turbine	
	Frame, F Class	Aero	F Class	H Class
EIA AEO	N/A(1)	$1,784		N/A(2)
NLR ATB	$1,446		$1,578	$1,741
Lazard LCOE+	$1,389		$1,495	
Halcyon	$1,521	$1,502	$1,950	$2,055
Average Capex	**$1,452**	**$1,643**	**$1,674**	**$1,898**

(1) EIA AEO values for frame turbines are specified as H class.
(2) EIA AEO values for H class CCGTs excluded after review.

To construct the capex scenarios for fossil technologies, the study uses Halcyon's project-level cost dispersion to define the Low and High cases in a transparent, data-driven manner. For each technology type, the analysis calculates the mean capex across recorded projects and then measures each project's percentage deviation from that average. The average absolute percentage deviation is then used to bracket uncertainty around the Mid capex: the Low case is set as the mean minus the average deviation, and the High case is set as the mean plus the average deviation. This approach captures observed variability in reported costs, reflecting differences in project scale, site conditions, permitting complexity, procurement timing, and market conditions, while keeping the scenario range anchored to real project outcomes rather than purely judgmental adjustments.

The Halcyon data used to estimate natural gas generation plant construction costs does not include any coal-fired power plant cost estimates. Furthermore, as of December 2025, no new coal-fired generation facilities are planned for construction in the United States.[40] Therefore, E3 relies on NLR ATB data for our estimate of capital cost input for the coal technology candidate in this report.

The resulting thermal capex values for the Low, Mid, and High scenarios applied in this study are summarized in Table 16.

Table 16. Natural Gas Plant Capex Inputs (2027 COD, 2027$/kW)

Input	Gas Combustion Turbine		Gas Combined-Cycle Gas Turbine		Coal Steam Turbine
	Frame, F Class	Aero	F Class	H Class	
Low	$1,045	$1,092	$1,353	$1,489	$3,673
Mid	$1,462	$1,643	$1,690	$1,925	$3,683
High	$1,877	$2,194	$2,026	$2,362	$3,692

[40] EIA 860M. Reference is to January 26, 2026, release. https://www.eia.gov/electricity/data/eia860m/

5.2.2.2 Non-Thermal Technologies

While capital costs for non-thermal technologies have also been stressed by recent disruptions to global supply chains and demand growth, E3 has not observed the same degree of uncertainty for these technologies as has become evident for thermal technologies. Accordingly, capital cost inputs for utility-scale solar photovoltaic ("PV") and Lithium-ion ("Li-ion") battery storage are developed using a literature-benchmarking approach that synthesizes multiple public data sources, supported by recent market datapoints and industry reporting from 2023 through 2024. Rather than relying on a single publication, this study uses averaged values across the reviewed literature to define representative base-year capex estimates for solar PV, standalone storage, and the storage component of co-located solar PV + storage configurations. The underlying sources and publication years are summarized in Table 17.

Table 17. Capital Cost Input Data Sources

Publication Name	Publication Year	Technologies
National Laboratory of the Rockies (formerly known as NREL) Annual Technology Baseline (ATB)[41]	2024	Utility-scale solar, Li-ion Battery
U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO)[42]	2023	Utility-scale solar, Li-ion Battery
Lazard Levelized Cost of Energy+ (LCOE+)[43]	2024	Utility-scale solar, Li-ion Battery
Electric Power Research Institute (EPRI) Program on Technology Innovation: Generation Technology Options[44]	2024	Utility-scale solar, Li-ion Battery
Solar Energy Industries Association (SEIA) Solar Market Insight Report[45]	2024	Utility-scale solar, Li-ion Battery
Pacific Northwest National Laboratory (PNNL) Energy Storage Cost and Performance Database[46]	2024	Li-ion Battery

Across non-thermal technologies, the Low trajectory reflects an optimistic outlook in which continued learning and supply-chain normalization drive cost declines, with steeper reductions in the near term and a more gradual taper over time. The High trajectory reflects a more conservative outlook in which learning slows and lingering supply-chain or trade/geopolitical risks keep costs elevated relative to the Low case; it is constructed by extending high-end published projections using

[41] National Renewable Energy Laboratory, *2024 Electricity ATB Technologies*, Annual Technology Baseline (ATB), accessed February 6, 2026, https://atb.nrel.gov/electricity/2024/technologies.

[42] U.S. Energy Information Administration, *Annual Energy Outlook 2025* (release date April 15, 2025), accessed February 6, 2026, https://www.eia.gov/outlooks/aeo/.

[43] Lazard, *Levelized Cost of Energy+ (LCOE+)*, accessed February 6, 2026, https://www.lazard.com/research-insights/levelized-cost-of-energyplus-lcoeplus/.

[44] Electric Power Research Institute (EPRI), *Technology Innovation* (web page), accessed February 6, 2026, https://www.epri.com/research/sectors/technology.

[45] Solar Energy Industries Association and Wood Mackenzie, *Solar Market Insight Report Q2 2024* (June 5, 2024), accessed February 6, 2026, https://seia.org/research-resources/solar-market-insight-report-q2-2024/.

[46] Pacific Northwest National Laboratory, *Energy Storage Cost and Performance Database*, accessed February 6, 2026, https://www.pnnl.gov/projects/esgc-cost-performance.

smooth trajectories benchmarked to recent cost levels. The Mid trajectory is defined as the midpoint between the Low and High cases. The resulting capex assumptions for non-thermal technologies used in this study, before any federal tax credits, are summarized in Table 18.

Table 18. Solar and Storage Capex Inputs, Before Tax Credits (2027 COD, 2027$/kW)

Input	Solar	Battery Storage		
		2-Hour, Standalone	4-Hour, Standalone	4-Hour, Co-located[47]
Low	$1,331	$694	$1,157	$1,067
Mid	$1,409	$913	$1,522	$1,403
High	$1,490	$1,132	$1,887	$1,739

On July 4, 2025, the FY2025 Congressional Reconciliation Bill (also known as the One Big Beautiful Bill Act, or "OBBBA") was signed into law, materially curbing the outlook for tax credits for clean energy technologies and foreign sourcing options for U.S. clean energy and energy storage projects. Implementation of the Bill is ongoing but is reflected in this study based on E3's current understanding of the legislation, inclusive of resource-specific safe harbor, Foreign Entity of Concern (FEOC) requirements, and credit phase-out timelines. Solar is most impacted by this legislation with an earlier expiration of tax credit availability, even with safe harbor, while storage is less impacted by the OBBBA specifically.

In this context, this study assumes that both solar and battery storage resources claim tax credits in the study year of 2027. Specifically, **this study assumes that (1) standalone storage resources claim the ITC at a rate of 30% and (2) both components of the co-located project, solar and storage, can claim the ITC at a rate of 30%**. These 30% federal tax credits are applied to the pre-incentive capex values for solar and storage shown in Table 18.

This study assumes that the solar portion of the co-located solar + storage project is eligible to claim the Investment Tax Credit (ITC) for a 2027 COD. Under the OBBBA, solar facilities must begin construction before July 4, 2026, in order to retain eligibility for federal tax credits. Given typical development timelines, a project reaching COD in 2027 would reasonably be expected to begin construction prior to that deadline. While projects beginning construction after December 31, 2025, are subject to Foreign Entity of Concern (FEOC) compliance requirements, those requirements do not inherently preclude ITC eligibility. This study evaluated the potential for solar to claim PTC while the storage portion of the facility claims the ITC before concluding that the project-level ITC election is most reasonable.

[47] Co-located storage costs reflect only the battery component of a hybrid facility (i.e., they exclude the co-located solar/wind component). The co-located storage cost is lower than that of the standalone storage because some balance-of-system and site infrastructure can be shared with the co-located solar/wind resource.

5.2.3 *Allowance for Funds Used During Construction (AFUDC)*

Allowance for Funds Used During Construction (AFUDC) is the opportunity cost of borrowing money to construct a new project. Allowance for Funds Used During Construction (AFUDC) may be stated as an interest rate that applies to funds borrowed or recycled for construction, or as a multiplier of capital cost in the form of a Construction Finance Factor (CFF). This study applies this factor to each technology's capital cost. The Construction Finance Factor (CFF) values used in this study are shown in Table 19 and are source from the NLR ATB. The final capital cost for each technology (before any adjustment for geography) is calculated by multiplying the capital cost input and the Construction Finance Factor (CFF). The same method is used for estimating the final interconnection cost for each technology.

Table 19. Assumed Construction Finance Factor (CCF) by Candidate Technology

Technology	Construction Finance Factor (CFF)
Gas CT (Frame or Aero) and Gas CCGT (F and H Class)	1.11
Storage (4-hour and 2-hour)	1.04
Co-located Solar PV + Storage	1.04
Coal ST	1.24

5.2.4 *State-Specific Cost Multipliers*

For all resource cost analyses, this study utilizes state-specific cost multipliers to account for regional differences in labor cost, site control, and interconnection. These multipliers affect the capex, FO&M, interconnection, and ITC data inputs that are passed to the cost levelization calculator. As discussed in Section *Geographic Representation*, this study concludes that differentiation is most appropriate across two MISO regions: the combination of MISO North + Central regions, and the combination of MISO South region.

For each technology and state, the labor cost multiplier is calculated by applying the state's median construction labor wage, relative to the U.S. national median, to the percentage of resource capex attributable to labor. For solar and onshore wind, the land cost multiplier is calculated by applying the state's average prime non-irrigated agricultural land lease rate, indexed to the U.S. national average, to the percentage of resource FO&M attributable to site control. Finally, interconnection cost multipliers are calculated by reviewing and benchmarking average project interconnection cost data collected by Lawrence Berkeley National Lab [48], explained in more detail in Section *Interconnection Costs*.

State-specific cost multipliers in this study adjust only the components that can be differentiated consistently across locations, such as construction labor wages, land lease costs, and income tax rates. These multipliers do not explicitly add separate premiums for location-specific engineering or construction requirements that are not observable in the input datasets. As a result, any such

[48] Lawrence Berkeley National Laboratory (Berkeley Lab), *Generator Interconnection Costs to the Transmission System*, Energy Markets & Planning, accessed February 6, 2026, https://emp.lbl.gov/interconnection_costs.

requirements are reflected only to the extent they are embedded in the empirical project cost data used for benchmarking.

For example, projects in the New Madrid Seismic Zone may require additional design and construction measures that increase capital costs. Of the 73 plant-specific cost filings reviewed from Halcyon's Gas Power Plant Tracker, 17 are located in Arkansas, Illinois, Mississippi, and Missouri and therefore may implicitly capture some portion of any seismic-related cost premium. However, the available data do not isolate "earthquake-proofing" costs as a distinct line item, so this analysis does not apply a standalone seismic adder. To the extent these additional requirements are material and not fully captured in the empirical benchmarks, gross and net CONE estimates for affected states, and the resulting PRA parameters, could differ from the values presented here.

5.2.5 Interconnection Costs

To estimate interconnection costs, this study relied on a Lawrence Berkeley National Laboratory ("LBNL") dataset of grid-connection costs. Since interconnection conditions differ meaningfully across the MISO footprint, data were separated into MISO North + Central and MISO South, and costs were estimated separately for each region. For both regions, this study developed technology-specific estimates for solar, storage, coal, and natural gas.

The cost ranges are drawn from the 25th, 50th, and 75th percentiles of observed project-level interconnection costs in the LBNL dataset. These values provide a reasonable spread of potential outcomes rather than a single point estimate. One exception was coal in MISO, where limited sample depth for MISO South required aligning the 25th and 75th percentile values with natural gas estimates in both regions.

This study determined that using empirical $/kW values remains the best available approach for a study specific to a given geography.[49] The percentile ranges reflect the variability seen in real-world interconnection outcomes and present a reasonable envelope for expected costs in both regions that is rooted in real-world data.

Table 20 and Table 21 summarize the estimated values by region and technology, including the percentile-based ranges and the sample sizes used to construct them. The 25th percentile values are used in the Low scenario, the 50th percentile values are used in the Mid scenario, and the 75th percentile values are used in the High scenario, with each region's estimates applied to resources identified for those regions in the report.

[49] Sample Sizes in South are around ~20 for thermal and storage and 150+ for solar. Sample sizes are significantly larger in North + Central.

Table 20. Interconnection Costs, MISO North + Central (2027 COD, 2027$/kW)

Technology	Low *25th Percentile*	Mid *50th Percentile*	High *75th Percentile*
Coal	$13	$16	$93
Natural Gas	$13	$34	$93
Solar PV	$49	$95	$170
Storage	$51	$152	$295

Table 21. Interconnection Costs MISO South, (2027 COD, 2027$/kW)

Technology	Low *25th Percentile*	Mid *50th Percentile*	High *75th Percentile*
Coal	$5	$34	$169
Natural Gas	$5	$74	$169
Solar PV	$102	$197	$542
Storage	$127	$296	$542

Across the dataset, MISO South consistently exhibits higher interconnection costs on average than MISO North + Central. This pattern appears across all technologies, with the gap most pronounced for renewables, which in both regions show a noticeable premium over thermal technologies. Solar and storage projects may require more extensive upgrades or new infrastructure when connecting at the distribution or sub-transmission level. These technologies can trigger voltage-control upgrades, transformer replacements, or protection-system modifications that are not always required for thermal additions, which typically interconnect at higher-voltage points with more established infrastructure. In MISO South specifically, higher renewable penetration in certain pockets, legacy system constraints, and localized grid-topology issues may also contribute to higher costs.

5.2.6 Operating Costs

Variable O&M costs and fuel costs are not part of the gross CONE framework, as gross CONE is intended to reflect the capital and fixed annual costs required to make a resource available, independent of its energy output.

This study's fixed O&M assumptions reflect the standard cost elements typically included in Fixed O&M for each resource. Fixed O&M generally captures the annual operating labor requirement that does not vary with plant output, maintenance labor requirements, property taxes, and any periodic replacement of equipment needed to maintain operability over the project's life. The National Lab of the Rockies Annual Technology Baseline estimate of Fixed O&M includes all of the aforementioned costs in a single estimate stated in $/kW-year. As explained in Section *State-Specific Cost Multipliers*, this study adjusts the Annual Technology Baseline estimates state-by-state to reflect the portion of FO&M we can attribute to land lease costs. The Fixed O&M values used for each technology and each scenario are shown in Table 22.

Table 22. MISO North Fixed O&M Mid Scenario Assumptions (2027 COD, 2027$/kW-yr)

Technology	Fixed O&M
Coal	$ 118
Frame CT	$ 36
Aeroderivative (Aero) CT	$ 32
F Class CCGT	$ 46
H Class CCGT	$ 46
Co-Located Solar and Battery Storage	$ 36[50]
4-Hour Battery Storage	$ 49
2-Hour Battery Storage	$ 30

For solar technologies, O&M costs are generally dominated by maintenance and land lease costs. Land lease costs typically represent approximately 15 to 26 % of total Fixed O&M, with the remainder largely attributed to maintenance. Fixed O&M costs for batteries primarily consist of maintenance and augmentation, with augmentation accounting for up to approximately 60% of total costs. In co-located systems (solar + storage), augmentation is expected to account for roughly 20% of total O&M costs, land lease up to approximately 20%, and the remaining costs attributed to maintenance. Fixed O&M for natural gas generation resources can be disaggregated using the ranges shown in Table 23.

Table 23. Natural Gas Detail: Fixed O&M Component Breakdown (%)

Technology	Routine Labor	Materials & Contract Services (Incl. Property Taxes)	Admin & General Expenses
Natural Gas[51]	40-60%	40-50%	8-15%

5.2.7 Financing Parameters

5.2.7.1 Weighted Average Cost of Capital (WACC)

A key input to the CONE is the weighted average cost of capital ("WACC"), which is used to convert upfront capital costs and ongoing fixed operating and maintenance expenses into gross CONE. The method of estimating WACC and inputs used for the calculation should reflect the perspective being represented in the analysis. It is common in studies comparable to this study for the financing parameters to reflect a hypothetical merchant generation developer investing in a new, non-utility project. This study assumes this merchant developer perspective, and the methodology described in this section is intended to capture the risk-adjusted return expectations required to support investment under prevailing market conditions. When WACC increases, future cash flows are discounted more heavily, reducing the investment's value. When WACC decreases, the investment appears more attractive.

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[50] Fixed O&M costs for co-located solar and battery storage resources reflect the fixed O&M costs for both the battery and solar resource per kW of the co-located facility's total capacity.

[51] The following ranges apply to thermal resources. The labor share is sourced from the National Energy Technology Laboratory and solely applies to Natural Gas technologies. The cost share ranges for contracts and administrative expenses are drawn from EIA, where thermal generation is reported as an aggregate category, which includes coal, biomass, gas and nuclear resources.

Regardless of perspective, the WACC reflects the combined cost of debt and equity financing. The calculation depends on the capital structure, the cost of equity, the cost of debt, and the applicable tax rate and is expressed in Equation 1. As part of this calculation, the cost of debt is multiplied by one minus the tax rate to reflect the tax deductibility of interest expenses, which lowers the after-tax cost of debt.

Equation 1. After Tax WACC Formula

$$WACC = \frac{Equity}{Debt + Equity}(Cost\ of\ Equity) + \frac{Debt}{Debt + Equity}(Cost\ of\ Debt)(1 - Tax\ Rate)$$

Using these parameters, this study estimated a market-derived Weighted Average Cost of Capital ("WACC") for this study. This method relies on market data, incorporating both historical information and forward expectations. These parameters are applied consistently across technologies and regions to support comparability and transparency in CONE estimation. The financing parameters used in this analysis are summarized in Table 24 and then detailed in subsequent sections.

Table 24. Summary of Financing Parameters

Financing Parameter	Input Value	
	MISO North + Central	MISO South
Debt / Total Capital	55%	
Equity / Total Capital	45%	
Cost of Debt	5.35%	
Cost of Equity	12.96%	
Effective Tax Rate	26.09%	24.07%
After-Tax Weighted Average Cost of Capital	**8.01%**	**8.07%**

5.2.7.2 Cost of Equity

The cost of (or return on) equity represents the return required by investors who provide capital in exchange for ownership. In this study, the cost of equity is estimated using the Capital Asset Pricing Model (CAPM). This approach allows the incorporation of actual market data while still reflecting fundamental principles associated with the cost of capital. Under the Capital Asset Pricing Model (CAPM)formula, the return on equity equals the risk-free rate plus beta multiplied by the equity risk premium, as detailed in Equation 2.

Equation 2. Capital Asset Pricing Model (CAPM) Formula

$$R_e = R_f + \beta * (R_m - R_f)$$

Where R_e is the return on equity, R_f is the risk-free rate, β represents Beta, and R_m represents the market return on equities. The risk-free rate is the baseline return on an investment with no default risk and is taken from the U.S. Treasury three-month par yield, estimated at 4.36% for the four quarters of trading days from Q4 2024 through Q3 2025. Beta measures the correlation in returns between a specific asset and the overall market. Beta in this study is sourced from New York University research[52], based on analysis published in January 2025. This study reviewed Beta estimates across different groupings of public equity companies in the energy sector applicable to this analysis: utility holding companies, independent power producer companies, and companies developing relatively novel "green" or clean energy generation technologies. The study utilizes a beta of 1.08, representing the median of these company grouping estimates. The equity risk premium, 4.33% for this study and also sourced from New York University, represents the additional return investors expect for holding an index of public equities (the S&P 500) relative to a risk-free asset.

5.2.7.3 Cost of Debt

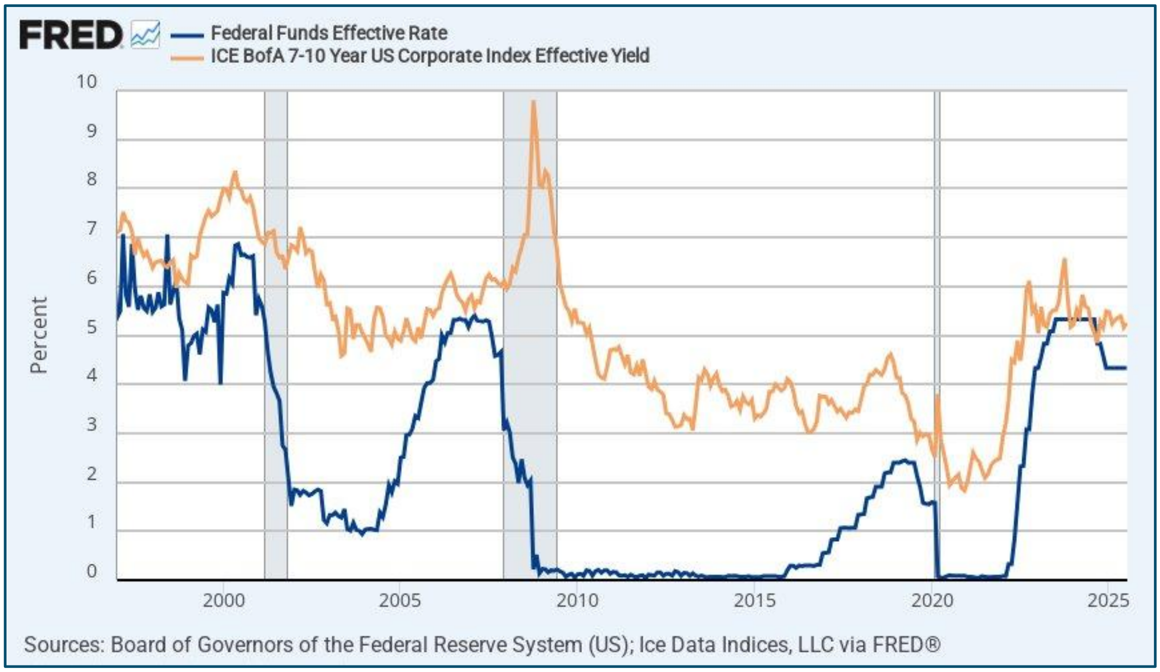
The cost of debt reflects the interest rate a borrower must pay to access debt financing and incorporates both market conditions and credit quality. For this study, cost of debt is derived from current borrowing rates reported in the Federal Reserve Economic Data (FRED) Bank of America U.S. Corporate Index Effective Yield over a 264-day historical trading period (from Q4 2024 through Q3 2025) and is equal to 5.35%.

Long-term borrowing costs are based on the U.S. Treasury 10-year par yield, with the spread to corporate borrowing rates preserved to maintain consistency with current credit conditions. All market inputs are averaged over the most recent four quarters of trading days to smooth short-term volatility.

Rate transitions are modelled using linear ramps from 2025 values to long-term levels. These ramps draw on historical episodes of declining interest rates: 2007 to 2009, 2000 to 2002 for the low-risk path, 1989 to 1992 for the mid-risk path, and longer periods of gradual moderation during the 1990s or 2010s for the high-risk path. While the past is never a perfect predictor of the future, we include these options to capture a range of reasonable outcomes. Figure 6 shows this trend in the underlying cost of debt in the U.S., with shaded regions representing recessions.

[52] Aswath Damodaran, *Cost of Equity and Capital (US)*, Damodaran Online (NYU Stern School of Business, last updated January 2026), accessed February 6, 2026, https://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/wacc.html.

Figure 6. U.S. Historic Interest and Corporate Bonds Rates



5.2.7.4 Effective Tax Rate

The effective tax rate is calculated as the federal corporate income tax rate (21%) plus the state corporate income tax rate net of federal income taxes paid. The effective tax rate has regional differentiation between MISO North + Central and MISO South. Both estimates are averages of effective tax rates comprising each subregion. Table 25 illustrates effective tax rates and the states included in each geography.

Table 25. Effective Tax Rates per Region

Region	Effective Tax Rate	Composite States / Provinces
MISO North + Central	26.09%	Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Montana, North Dakota, South Dakota, Wisconsin, and Manitoba
MISO South	24.07%	Arkansas, Louisiana, Mississippi, and Texas

5.2.8 Levelization Convention and Parameters

Levelization converts a stream of uneven annual values over a resource's useful life into an equivalent constant annual value. In this study, several metrics are levelized so they can be interpreted as a uniform "per-year" value over each resource's useful life. These include: (1) annual fixed costs (to derive gross CONE), (2) annual energy + ancillary services (E+AS) margins (to derive levelized modeled E+AS margins over the asset's life), and (3) annual DLOL UCAP percentages (to derive a levelized UCAP DLOL percentage / capacity value over the asset's life).

All levelization performed in this study is nominal levelization. Specifically, the annual inputs are treated as nominal values and discounted using a nominal discount rate, and the resulting levelized value is expressed as an **annual value that is constant in nominal dollars (or, for non-dollar metrics, a constant annual value in the same units) over the operating life of the resource**. In other words, the levelized result represents a flat nominal value stream that is equivalent—in present value terms—to the underlying uneven series.

For instance, gross CONE presented in this study represent the nominal levelized total annual revenues that a system would need every operating year over its useful life to cover fixed costs, including amortized capital costs, fixed operation and maintenance costs, property taxes, warranty, repowering and augmentation, and investment tax credits (if applicable). The formula used to calculate gross CONE is shown in Equation 3. The discount rate assumed for levelization is equivalent to the nominal WACC, necessary to ensure that the gross CONE accounts for the required rate of return for the resource to enter the market. Similar equations were used to derive the other levelized values.

Equation 3. Gross CONE

$$Gross\ CONE = \frac{NPV(Fixed\ Costs, \$)}{PV(Capacity, MW)}$$

Normalizing the levelized value on a per MW capacity basis allows for effective comparison of capacity costs on a consistent, technology-neutral basis. Costs are levelized over the useful economic life for the applicable asset and then divided by 1,000 to translate to a \$/kW-yr basis. The applicable economic life and capacity for each technology screened are listed in Table 26.

Table 26. Technology Capacity Levelization Inputs

Technology	Useful Economic Life	Unit Capacity
Gas Combustion Turbine *Frame, F Class*	30 years	237 MW-ac
Gas Combustion Turbine *Aero*	30 years	105 MW-ac
Gas Combined Cycle Turbine *F Class*	30 years	500 MW-ac
Gas Combined Cycle Turbine *H Class*	30 years	500 MW-ac
Battery Storage *4-hour*	20 years	10 MW-ac
Battery Storage *2-hour*	20 years	10 MW-ac
Co-Located Solar Photovoltaic + 4-hour Storage	20 years	20 MW-ac *Storage: 10 MW-ac* *Solar: 10 MW-ac*
Coal	30 years	650 MW-ac

5.2.9 *Escalation of Cost Values*

In this study, we adjust any real values from the underlying sources to nominal dollars. For example, the 2024 Annual Technology Baseline from the National Laboratory of the Rockies states all values in 2022 dollars ("2022$"), requiring the application of inflation through 2027 to produce a value that is useful for this study.

Any adjustments to historical inflation values are made using Bureau of Labor Statistics ("BLS") data on Consumer Price Index for All Urban Consumers ("CPI-U") changes over time. This study uses the annual average inflation index values from the CPI-U, specifically the U.S. city average. While inflation in individual MISO states will deviate from the U.S. average, MISO states do not fall neatly into discrete geographic units for which BLS publishes disaggregated price index data. Specifically, MISO states are located in the BLS regions identified as Midwest, Mountain-Plains, Southeast, and Southwest, and the Census regions identified as Midwest and South. The average annual CPI for the Midwest Census region has generally lagged the U.S. city average, while the South region has either kept pace with or slightly lagged behind the U.S. city average. Given that state-level CPI data is not available at sufficient granularity to make MISO region distinctions, this study elects to apply a consistent U.S. city average. For inflation of future values (i.e., from 2025 onward), this study assumes a 5-year linear trend from the most recent available historical data (i.e., 2024) to a long-term inflation assumption of 2.00%. This assumption is applied to all values that are translated to a different dollar year in this study.

No specific real escalation factors are applied to wages or land. We assume any change in wages paid for construction labor are captured in changes to total upfront capital cost values described earlier in this section; we would not expect wage growth to outpace general CPI trends given the persistent gap between productivity and compensation for labor in the United States. Land costs are differentiated by state but are not assumed to escalate in real terms either, as we assume that setting different initial cost levels is sufficient to capture geographically distinct terms thereafter when inflation is applied.

The historical and future inflation assumptions used in this study are summarized in Table 27.

Table 27. Annual Inflation Assumptions (2022 - 2027)

Year	Inflation
2022	8.00%
2023	4.12%
2024	2.95%
2025	2.76%
2026	2.57%
2027	2.38%

5.2.10 *Trade Policy Impacts*

Recent changes in U.S. trade policy have introduced new complexities into the cost forecasting process for energy resources. Wide-ranging tariffs were initially issued under executive authority via the International Emergency Economic Powers Act ("IEEPA"), creating significant uncertainty for technologies with substantial supply chain exposure to China and Southeast Asia, including batteries and solar resources. On February 20, 2026, the U.S. Supreme Court held that IEEPA does not provide authority to impose tariffs, limiting the scope of those IEEPA-based tariff actions.[53] However, trade-related cost uncertainty remains relevant because the Administration has pursued, and may continue to pursue, tariff actions under other statutory authorities (e.g., Sections 201, 232, and 301), among other trade tools.[54]

Consistent with this evolving landscape, this analysis excludes IEEPA-based tariff orders as well as more recent tariff actions issued or contemplated under alternative authorities, given uncertainty regarding their scope, duration, and ultimate implementation over the forecast period. This approach avoids embedding specific tariff-rate assumptions in long-run cost projections while maintaining consistency across technologies. Given current trade patterns, if elevated tariff regimes were to persist or expand under any authority, then wind, solar, and battery resources would likely remain the most exposed to cost increases. Table 28 shows the potential tariff exposure for selected technologies.

Table 28. Potential Tariff Impacts for Selected Resources

Technology	Key Imports (Countries)	Capex at Risk (% Total)
Solar (Utility PV)	Module and BOS (Vietnam, Thailand)	44%
Storage (Standalone, Li-ion)	Cabinets and BOS (China)	73%

We assume that a small share of capex for new natural gas plants is at risk due to import tariffs (roughly 1%), since there is a robust domestic supply chain for these plants and country-specific tariffs most likely to be incurred are specific to countries for which there has been less trade policy volatility in the past year. Additionally, broader supply chain and market pressures are driving cost increases across all resources as demand growth strains existing manufacturing and labor capacity. Market participants are reporting elevated procurement costs and extended delivery schedules. Although long-term expectations anticipate eventual easing in cost pressures as domestic manufacturing capacity scales up, short-term costs remain elevated. As such, this study utilized Halcyon data in its capital cost review to better capture the elevated costs that market participants are reporting.

[53] Supreme Court of the United States, *Learning Resources, Inc., et al. v. Trump, President of the United States, et al., No. 24-1287 (slip opinion)* (February 20, 2026), https://www.supremecourt.gov/opinions/25pdf/24-1287_new_3135.pdf.

[54] The White House, *Imposing a Temporary Import Surcharge to Address Fundamental International Payments Problems* (Presidential Proclamation, February 20, 2026), https://www.whitehouse.gov/presidential-actions/2026/02/imposing-a-temporary-import-surcharge-to-address-fundamental-international-payments-problems/.

5.2.11 Summary of Key Cost Assumptions

Table 29: Summary of Key Cost Assumptions for Candidate Technologies (2027 COD, 2027$ Where Applicable)

Input	*Units*	*Region*	Gas CT, Frame	Gas CT, Aero	Gas CCGT, F Class	Gas CCGT, H Class	Storage, 4-hour	Storage, 2-hour	Co-Loc. Solar PV + Storage	Coal ST
Cost Scenario			Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid
Capital Cost (Capex)[(1)]	*$/kW*	North+Central	$1,633	$1,837	$1,844	$2,101	$1,588	$953	$2,941	$4,540
		South	$1,432	$1,610	$1,751	$1,995	$1,547	$928	$2,848	$4,221
Interconnect. Cost[(2)]	*$/kW*	North+Central	$30	$30	$30	$30	$137	$137	$86	$14
		South	$67	$67	$67	$67	$269	$269	$179	$31
Construction Fin. Factor[(3)]	*x*	MISO	1.11	1.11	1.11	1.11	1.04	1.04	1.04	1.24
Fixed O&M[(4)]	*$/kW-yr*	North+Central	$30	$11	$38	$38	$42	$26	$62	$100
		South	$27	$9	$37	$37	$41	$25	$58	$93
Market Cost of Debt	%	MISO	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%	5.35%
Market Cost of Equity	%	MISO	12.96%	12.96%	12.96%	12.96%	12.96%	12.96%	12.96%	12.96%
Debt / Total Capital	%	MISO	55%	55%	55%	55%	55%	55%	55%	55%
Effective Tax Rate	%	North+Central	26.09%	26.09%	26.09%	26.09%	26.09%	26.09%	26.09%	26.09%
		South	24.07%	24.07%	24.07%	24.07%	24.07%	24.07%	24.07%	24.07%
AT WACC	%	North+Central	8.01%	8.01%	8.01%	8.01%	8.01%	8.01%	8.01%	8.01%
		South	8.07%	8.07%	8.07%	8.07%	8.07%	8.07%	8.07%	8.07%
Installed Capacity	*MW*	MISO	237	105	500	500	10	10	20 (10+10)	650

Note: The methodology for geographic differentiation is described earlier in this chapter of the report.

(1) Reflects capital costs inclusive of construction financing and geographic variation in construction labor wages. Excludes interconnection cost. Sources: EIA, NLR, Lazard, Halcyon, Electric Power Research Institute (EPRI), Solar Energy Industries Association (SEIA), and Pacific Northwest National Laboratory (PNNL).

(2) Reflects the cost before any adjustment for Allowance for Funds Used During Construction (AFUDC). All interconnection cost data is from LBNL.

(3) Source: NLR ATB.

(4) Source before geographic adjustment: NLR.

5.2.12 Forward-Looking Values for Technologies Not Explicitly Modeled

2-hour battery storage is not explicitly represented in the MISO models (the 2024 RRA Study and 2026-2027 LOLE Study) used to develop the forward-looking quantitative criteria. Therefore, this study applies assumptions or supplemental analytical steps to develop estimated E+AS margin and DLOL UCAP % forecasts for these technologies.

To get an E+AS margin forecast for this technology, a small, hypothetical 5 MW 2-hour storage unit was added to MISO 2024 RRA Study's production cost model solely to enable extraction of dispatch, revenues, and variable costs for that technology. The unit is sized to be immaterial to system outcomes, such that the modeled resource mix, prices, and overall market results remain effectively unchanged while still producing a representative set of operating and revenue outputs for the 2-hour storage.

For capacity accreditation, this study assumes that the 2-hour storage accreditation is 50% of the 4-hour storage accreditation for the corresponding year and season. This assumption is intentionally conservative and reflects the fact that storage capacity value is strongly duration-dependent: shorter-duration storage has a more limited ability to sustain output through extended scarcity periods and, therefore, provides a smaller marginal reliability contribution. A 50% haircut provides a reasonable approximation for screening purposes in the absence of explicit modeled accreditation results for 2-hour storage, while avoiding overstatement of its effective capacity contribution relative to the 4-hour benchmark.

6 Quantitative Evaluation Results

6.1 Summary of Quantitative Evaluation

This section evaluates each candidate technology on the five quantitative criteria, with focus on the two primary co-criteria: gross CONE (UCAP basis) and modeled net CONE (UCAP basis). These metrics reflect the combined effect of fixed costs, expected non-capacity revenues, and capacity accreditation, and therefore provide the most direct comparison of technologies on a reliability-equivalent basis. UCAP-based metrics are emphasized because capacity market comparisons are intended to reflect the cost of providing accredited capacity, rather than nameplate capacity. While intermediate metrics are presented in the following subsections to explain the drivers of differences across technologies, the screening comparison is anchored in these two UCAP-based criteria. Table 30 summarizes the co-primary quantitative results by technology and region and also reports MISO's published gross CONE for Planning Year 2025/2026 (both on an ICAP and UCAP basis) for reference.

Table 30. Summary of Quantitative Evaluation Results by Technology and Region, 2027 COD (Mid Scenario, 2027$, Nominal Levelized) and MISO Gross CONE for PY 2026/2027 (Reference, 2026$)

Region	Candidate Technology	MISO Value, PY 2026/2027[55]		Reference Technology Study, 2027 COD	
		Gross CONE (ICAP)	Gross CONE (UCAP)	Gross CONE (UCAP)	Modeled Net CONE (UCAP)[56]
		2026$/kW-yr ICAP	2026$/kW-yr UCAP	2027$/kW-yr UCAP	2027$/kW-yr UCAP
North + Central	Gas CT, Frame	$134	$166	$229	$225
North + Central	Gas CT, Aero	N/A	N/A	$248	$242
North + Central	Gas CCGT, F Class	N/A	N/A	$251	$217
North + Central	Gas CCGT, H Class	N/A	N/A	$251	$217
North + Central	4-hour Storage[57]	N/A	N/A	$232	$216
North + Central	2-hour Storage[57]	N/A	N/A	$296	$276
North + Central	Solar PV + Storage[58]	N/A	N/A	$324	$245
North + Central	Coal ST	N/A	N/A	$669	$629
South	Gas CT, Frame	$124	$154	$208	$205
South	Gas CT, Aero	N/A	N/A	$224	$219
South	Gas CCGT, F Class	N/A	N/A	$245	$218
South	Gas CCGT, H Class	N/A	N/A	$245	$218
South	4-hour Storage[57]	N/A	N/A	$251	$235
South	2-hour Storage[57]	N/A	N/A	$334	$314
South	Solar PV + Storage[58]	N/A	N/A	$330	$246
South	Coal ST	N/A	N/A	$631	$600

Legend

Within 5% of lowest cost technology in region

Within 25% of lowest cost technology in region

Beyond 25% of lowest cost technology in region

To support interpretation, the table color-codes gross CONE (UCAP basis) and modeled net CONE (UCAP basis) relative to the lowest-cost technology in each region. Given the inherent uncertainty in forward-looking cost, revenue, and accreditation projections, differences within 5% of the lowest-

[55] Midcontinent Independent System Operator (MISO), *MISO Cost of New Entry (CONE) Presentation* (Report to the Reliability Assessment Subcommittee, October 1, 2025), https://cdn.misoenergy.org/20251001%20RASC%20Item%2006%20MISO%20Cost%20of%20New%20Entry%20(CONE)%20Presentation720296.pdf. Capacity requirements and capacity market values are based on UCAP because the objective is to procure reliable, accredited capacity rather than nameplate capacity. Because MISO publishes gross CONE values on an ICAP basis, those values were converted to a UCAP basis using the same levelized DLOL UCAP % for Gas CT, Frame applied in this analysis. MISO values were averaged by LRZ to develop regional values.

[56] "Modeled net CONE" refers to the net CONE values calculated in this study using a forward-looking, production cost modeling–based E+AS margin methodology. Because this approach differs from MISO's methodology in its annual CONE process, these values should not be interpreted as an indication of the net CONE values MISO may calculate.

[57] E3 assumes standalone storage resources claim the Investment Tax Credit (ITC), at a rate of 30%.

[58] E3 assumes that both the solar and storage components of the co-located plant claim a 30% Investment Tax Credit (ITC). This reflects (i) the OBBBA requirement that solar begin construction by July 4, 2026 to retain credit eligibility (which is assumed to be met for a 2027 COD project based on typical timelines), and (ii) continued ITC eligibility for stand-alone storage through at least 2032 (COD year); Foreign Entity of Concern (FEOC) compliance requirements for post-2025 project starts are not assumed to automatically preclude eligibility.

cost technology (green shading) are treated as effectively comparable for screening purposes. Differences between 5% and 25% (yellow shading) indicate moderately higher costs, while differences above 25% (red shading) indicate materially higher costs.

In North + Central, modeled net CONE (UCAP basis) results show the expected convergence among plausible entrants in a system modeled at target reliability. Gas frame CT, both gas CCGTs, and 4-hour storage cluster tightly between \$216/kW-yr and \$225/kW-yr, a spread of less than 5%. This tight band is consistent with competitive entry dynamics: resources tend to enter until expected net returns converge toward the level needed to support new investment. For resources in that converged band, gross CONE (UCAP basis) becomes a practical differentiator because it highlights the lowest up-front fixed cost per incremental UCAP MW. On a gross CONE (UCAP basis), frame gas CT and 4-hour storage are the lowest-cost candidates, while most other candidates sit notably higher.

In South, the results point more directly to the frame gas CT. For modeled net CONE (UCAP basis), no technology falls within 5% of the lowest-cost resource (frame gas CT); the remaining candidates sit in a higher modeled net CONE band, indicating they are expected to be less economic sources of accredited capacity. This ranking is reinforced on a gross CONE (UCAP basis) as well: the frame gas CT is again the lowest-cost option, and the gap to the next alternatives is materially larger than in North + Central (for example, the gap to 4-hour storage widens substantially).

Taken together, the region-specific results converge on the same conclusion for different reasons: North + Central shows a “marginal entrant” cluster on modeled net CONE (UCAP basis), while South shows the frame gas CT as the clear lowest-cost option on both net and gross CONE (UCAP basis). Across both regions, the **frame gas CT is the only candidate that consistently appears in the within-5% tier (green) of both primary selection metrics**, pointing it as a potential reference technology selection based on the quantitative results.

The following subsections present the underlying calculations and results by metric and region and describe the drivers behind these patterns.

6.2 Gross Cost of New Entry (CONE), ICAP Basis

This section presents the estimated Low, Mid, and High scenario gross CONE per ICAP MW for the candidate technologies evaluated in this study, calculated as discussed in Section *Gross Cost of New Entry (CONE), ICAP Basis*. The gross CONE values reported reflect technology-specific configurations, which regionally adjusted to account for differences in construction labor costs, land values, and interconnection (“IX”) costs as discussed in Section *State-Specific Cost Multipliers*.

Figure 7 displays the range of gross CONE on an ICAP basis (nominal levelized in 2027 dollars, “2027\$”) for resources built in 2027 by technology. Costs explored in this study include the impact of investment tax credits, resulting in 2-hour storage having the lowest gross CONE per ICAP MW. Frame CTs and aero CTs are the cheapest thermal technologies. Aero CTs show the biggest range in costs driven by increased variability in observed capital costs seen in the market. Among the resources evaluated, coal has the highest gross CONE (ICAP basis), exceeding \$500/kW-yr., which is more than double the cost of the other candidates analyzed. Costs also vary by region; MISO South costs are generally lower for fossil resources and MISO North and Central costs are generally lower for batteries. For reference, the figure also overlays MISO's PY 2026/2027 gross CONE value for a gas frame CT (escalated to 2027$), which falls near the lower end of the study's modeled gross CONE range for this technology.

Figure 7. 2027 Gross CONE (ICAP Basis) by Candidate Technology and Region (2027$, Nominal Levelized)

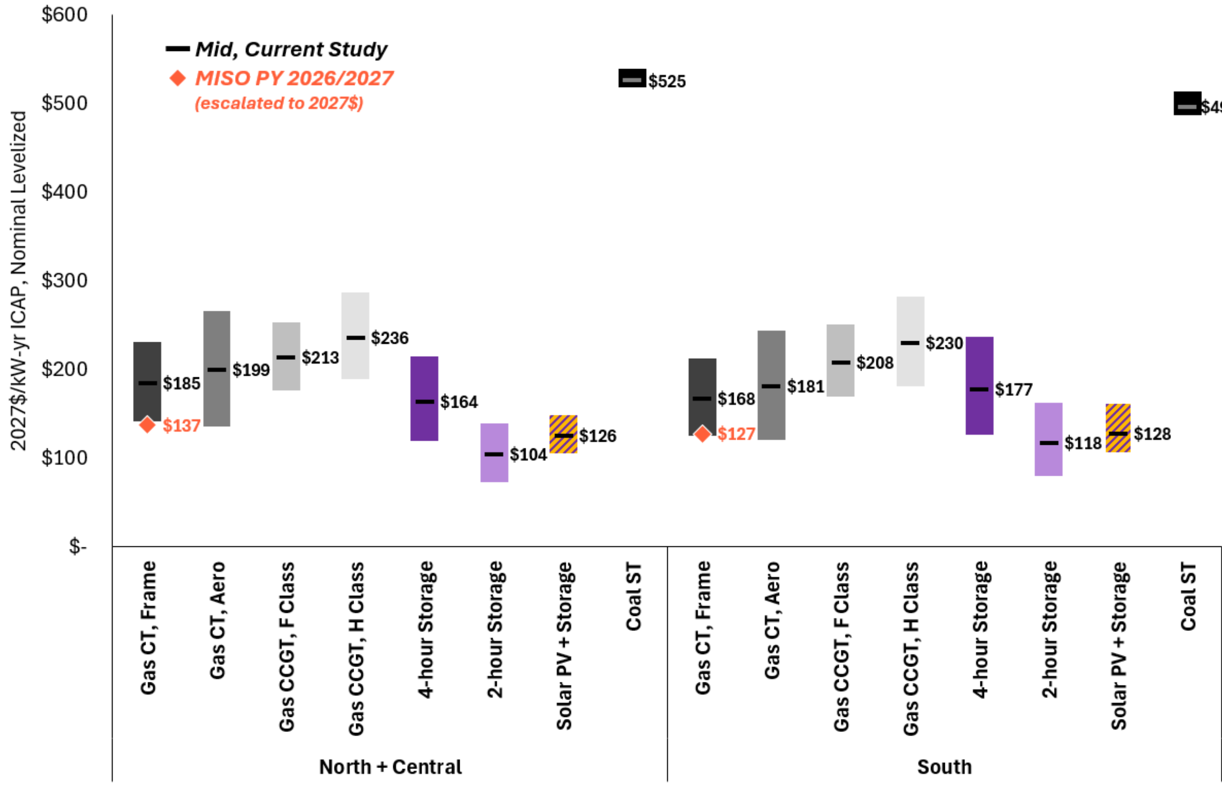


Figure 8 shows only gas candidate resources. Across these resources, costs are lower in MISO South, with a particularly significant locational difference for aero CTs and frame CTs. H class CCGTs remain more expensive than F class CCGTs and observe a larger spread in costs.

Figure 8. 2027 Gross CONE (ICAP Basis) for Gas Candidate Technologies by Region (2027$, Nominal Levelized)

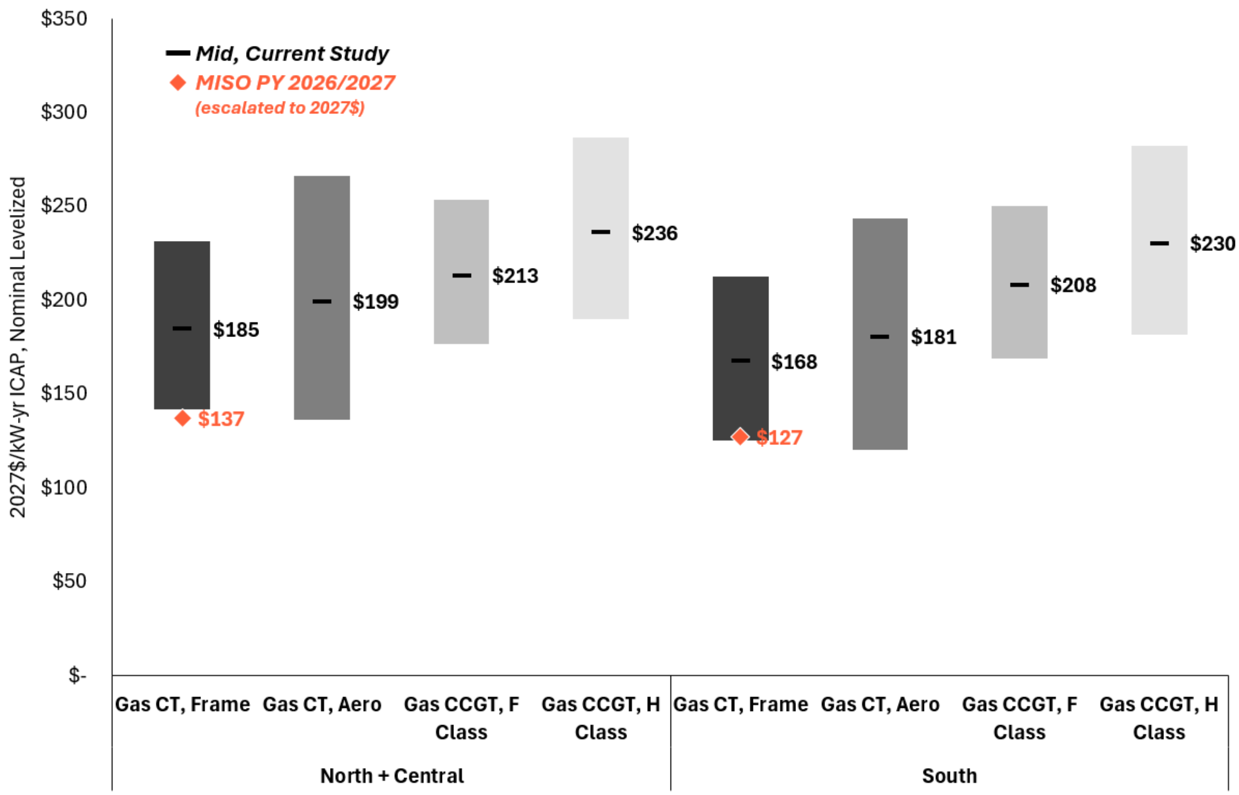
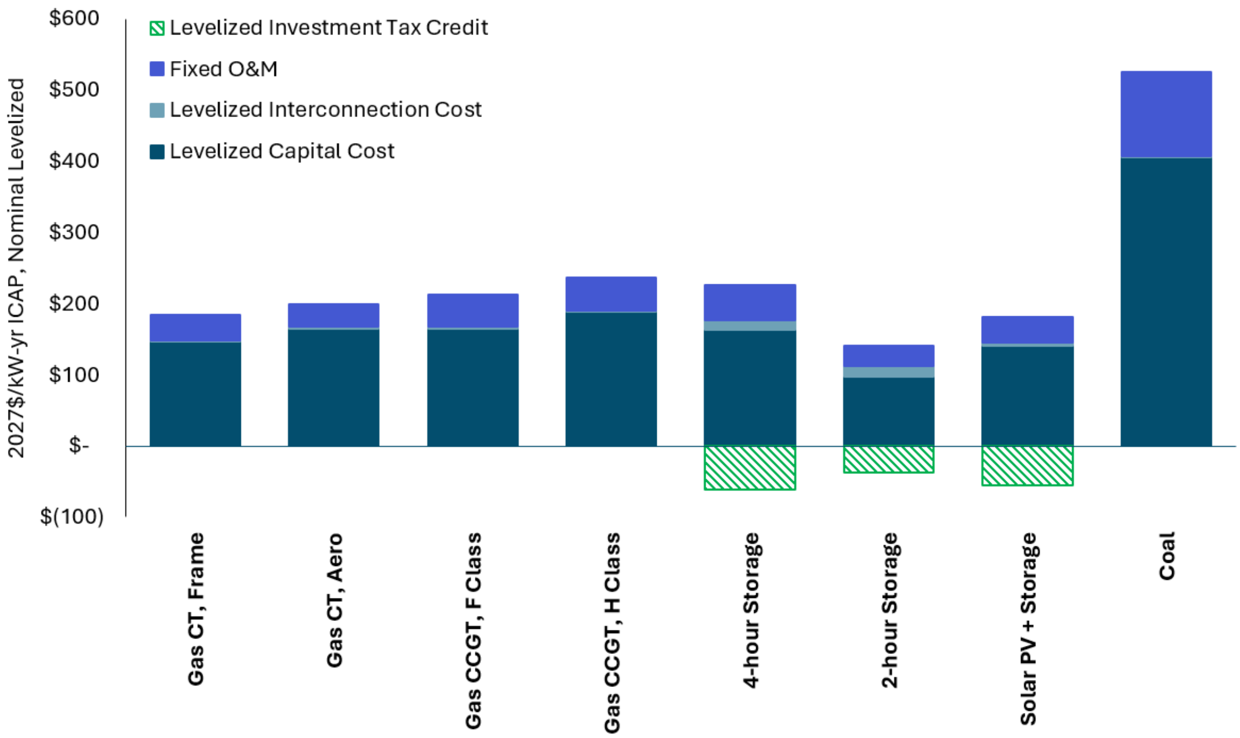


Figure 9 presents the gross CONE by technology for the Mid scenario, for the MISO North + Central region. Gross CONE is broken down into each component of the levelized cost: capital cost, interconnection cost, fixed O&M, and the investment tax credit. 2-hour and 4-hour storage resources benefit from significant reductions in net cost due to the ITC, resulting in the lowest overall CONE. Frame CTs are the cheapest gas resource and carry a lower fixed O&M cost than CCGTs.

Figure 9. 2027 Gross CONE (ICAP Basis) Breakdown by Technology, North + Central (Mid Scenario, 2027$, Nominal Levelized)



The following subsections summarize the gross CONE (ICAP basis) calculations and resulting values for each candidate technology and region evaluated in this study.

6.2.1 Gas Combustion Turbine (CT), Frame

Gross CONE (ICAP basis) estimates for F class frame CTs range from $125/kW-yr in MISO South, Low scenario to $231/kW-yr in MISO North + Central, High scenario. Table 31 displays details of the gross CONE (ICAP basis) results for this technology as well as MISO's PY 2026/2027 gross CONE (ICAP) value for a frame CT (escalated to 2027$) as a reference point.

Table 31. 2027 Gross CONE (ICAP Basis) for Gas CT, Frame (2027$, Nominal Levelized)

	Gross CONE (ICAP), 2027 COD ($2027, Nom Levelized)		North + Central			South		
	Gas CT, H2-Ready		*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
1)	Capital Costs, excl. IX	$/kW	$1,147	$1,602	$2,058	$1,005	$1,404	$1,804
2)	Interconnection Costs	$/kW	$11	$29	$80	$4	$64	$146
3)	After-Tax WACC	%	8.0%	8.0%	8.0%	8.1%	8.1%	8.1%
4)	Installed Capacity	MW-ac	237	237	237	237	237	237
5)	Useful Life	years	30	30	30	30	30	30
6)	Total Capital Costs, incl. IX	$M	$274	$387	$507	$239	$348	$462
7)	Levelized Capital Costs	$/kW-yr	$108	$150	$193	$96	$134	$172
8)	Levelized Interconnection Costs	$/kW-yr	$1	$3	$8	$0	$6	$14
9)	Levelized Fixed O&M	$/kW-yr	$36	$36	$36	$32	$32	$32
10)	Gross CONE, excl. ITC	$/kW-yr	$145	$189	$237	$128	$171	$217
11)	Levelized Investment Tax Credit	$/kW-yr	$0	$0	$0	$0	$0	$0
12)	Gross CONE (ICAP)	$/kW-yr	**$145**	**$189**	**$237**	**$128**	**$171**	**$217**
	MISO PY 2026/2027 Gross CONE (ICAP)	*$/kW-yr*		*$137*			*$127*	

6.2.2 Gas Combustion Turbine (CT), Aero

Gross CONE (ICAP basis) estimates for aero CTs range from $120/KW-yr in MISO South, Low scenario to $266/kW-yr in MISO North and Central, High scenario. Table 32 displays details of the gross CONE (ICAP basis) results for this technology.

Table 32. 2027 Gross CONE (ICAP Basis) for Gas CT, Aero (2027$, Nominal Levelized)

	Gross CONE (ICAP), 2027 COD ($2027, Nom Levelized)		North + Central			South		
	Gas CT, Aero		*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
1)	**Capital Costs, excl. IX**	$/kW	$1,162	$1,749	$2,336	$1,019	$1,533	$2,047
2)	**Interconnection Costs**	$/kW	$11	$29	$80	$4	$64	$146
3)	**After-Tax WACC**	%	8.0%	8.0%	8.0%	8.1%	8.1%	8.1%
4)	**Installed Capacity**	MW-ac	105	105	105	105	105	105
5)	**Useful Life**	years	30	30	30	30	30	30
6)	**Total Capital Costs, incl. IX**	$M	$123	$187	$254	$107	$168	$230
7)	**Levelized Capital Costs**	$/kW-yr	$109	$164	$219	$97	$146	$195
8)	**Levelized Interconnection Costs**	$/kW-yr	$1	$3	$8	$0	$6	$14
9)	**Levelized Fixed O&M**	$/kW-yr	$26	$32	$39	$23	$28	$34
10)	**Gross CONE, excl. ITC**	$/kW-yr	$136	$199	$266	$120	$181	$243
11)	**Levelized Investment Tax Credit**	$/kW-yr	$0	$0	$0	$0	$0	$0
12)	**Gross CONE (ICAP)**	$/kW-yr	**$136**	**$199**	**$266**	**$120**	**$181**	**$243**

6.2.3 Gas Combined Cycle Gas Turbine (CCGT), F Class

Gross CONE (ICAP basis) estimates for F class CCGTs range from $169/KW-yr in MISO South, Low scenario to $253/kW-yr in MISO North and Central, High scenario. Table 33 displays details of the CONE (ICAP basis) results for this technology.

Table 33. 2027 Gross CONE (ICAP Basis) for Gas CCGT, F Class (2027$, Nominal Levelized)

	Gross CONE (ICAP), 2027 COD ($2027, Nom Levelized)		North + Central			South		
	Gas CCGT, F Class		*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
1)	**Capital Costs, excl. IX**	$/kW	$1,394	$1,756	$2,123	$1,324	$1,667	$2,016
2)	**Interconnection Costs**	$/kW	$11	$29	$80	$4	$64	$146
3)	**After-Tax WACC**	%	8.0%	8.0%	8.0%	8.1%	8.1%	8.1%
4)	**Installed Capacity**	MW-ac	500	500	500	500	500	500
5)	**Useful Life**	years	30	30	30	30	30	30
6)	**Total Capital Costs, incl. IX**	$M	$703	$892	$1,102	$664	$865	$1,081
7)	**Levelized Capital Costs**	$/kW-yr	$131	$165	$199	$126	$159	$192
8)	**Levelized Interconnection Costs**	$/kW-yr	$1	$3	$8	$0	$6	$14
9)	**Levelized Fixed O&M**	$/kW-yr	$45	$46	$46	$42	$43	$44
10)	**Gross CONE, excl. ITC**	$/kW-yr	$177	$213	$253	$169	$208	$250
11)	**Levelized Investment Tax Credit**	$/kW-yr	$0	$0	$0	$0	$0	$0
12)	**Gross CONE (ICAP)**	$/kW-yr	**$177**	**$213**	**$253**	**$169**	**$208**	**$250**

6.2.4 Gas Combined Cycle Gas Turbine (CCGT), H Class

Gross CONE (ICAP basis) estimates for H class CCGTs range from $182/kW-yr in MISO South, Low scenario to $286/kW-yr in MISO North and Central, High scenario. Table 34 displays details of the CONE (ICAP basis) results for this technology.

Table 34. 2027 Gross CONE (ICAP Basis) for Gas CCGT, H Class (2027$, Nominal Levelized)

	Gross CONE (ICAP), 2027 COD ($2027, Nom Levelized)		North + Central			South		
	Gas CCGT, H Class		*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
1)	**Capital Costs, excl. IX**	$/kW	$1,534	$2,000	$2,475	$1,456	$1,899	$2,350
2)	**Interconnection Costs**	$/kW	$11	$29	$80	$4	$64	$146
3)	**After-Tax WACC**	%	8.0%	8.0%	8.0%	8.1%	8.1%	8.1%
4)	**Installed Capacity**	MW-ac	500	500	500	500	500	500
5)	**Useful Life**	years	30	30	30	30	30	30
6)	**Total Capital Costs, incl. IX**	$M	$772	$1,015	$1,278	$730	$982	$1,248
7)	**Levelized Capital Costs**	$/kW-yr	$144	$188	$232	$139	$181	$224
8)	**Levelized Interconnection Costs**	$/kW-yr	$1	$3	$8	$0	$6	$14
9)	**Levelized Fixed O&M**	$/kW-yr	$45	$46	$46	$42	$43	$44
10)	**Gross CONE, excl. ITC**	$/kW-yr	$190	$236	$286	$182	$230	$282
11)	**Levelized Investment Tax Credit**	$/kW-yr	$0	$0	$0	$0	$0	$0
12)	**Gross CONE (ICAP)**	$/kW-yr	**$190**	**$236**	**$286**	**$182**	**$230**	**$282**

6.2.5 4-hour Battery Storage (4-hour Storage)

Gross CONE (ICAP basis) estimates for 4-hour lithium-ion battery storage range from $119/kW-yr in MISO North and Central, Low scenario to $237/kW-yr in MISO South, High scenario. Table 35 displays details of the CONE (ICAP basis) results for this technology.

Table 35. 2027 Gross CONE (ICAP Basis) for 4-hour Storage (2027$, Nominal Levelized)

	Gross CONE (ICAP), 2027 COD ($2027, Nom Levelized)		North + Central			South		
	4-hour Storage		*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
1)	**Capital Costs, excl. IX**	$/kW	$1,149	$1,512	$1,875	$1,120	$1,474	$1,828
2)	**Interconnection Costs**	$/kW	$44	$131	$255	$110	$256	$469
3)	**After-Tax WACC**	%	8.0%	8.0%	8.0%	8.1%	8.1%	8.1%
4)	**Installed Capacity**	MW-ac	10	10	10	10	10	10
5)	**Useful Life**	years	20	20	20	20	20	20
6)	**Total Capital Costs, incl. IX**	$M	$12	$16	$21	$12	$17	$23
7)	**Levelized Capital Costs**	$/kW-yr	$124	$163	$202	$122	$161	$199
8)	**Levelized Interconnection Costs**	$/kW-yr	$5	$14	$28	$12	$28	$51
9)	**Levelized Fixed O&M**	$/kW-yr	$38	$49	$62	$37	$47	$60
10)	**Gross CONE, excl. ITC**	$/kW-yr	$167	$226	$291	$171	$236	$310
11)	**Levelized Investment Tax Credit**	$/kW-yr	-$47	-$62	-$77	-$45	-$59	-$73
12)	**Gross CONE (ICAP)**	$/kW-yr	**$119**	**$164**	**$214**	**$126**	**$177**	**$237**

6.2.6 2-hour Battery Storage (2-hour Storage)

Gross CONE (ICAP basis) estimates for 2-hour lithium-ion battery storage range from $73/kW-yr in MISO North and Central, Low scenario to $163/kW-yr in MISO South, High scenario. Table 36 displays details of the CONE (ICAP basis) results for this technology.

Table 36. 2027 Gross CONE (ICAP Basis) for 2-hour Storage (2027$, Nominal Levelized)

	Gross CONE (ICAP), 2027 COD ($2027, Nom Levelized)		North + Central			South		
	2-hour Storage		*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
1)	Capital Costs, excl. IX	$/kW	$689	$907	$1,125	$672	$884	$1,097
2)	Interconnection Costs	$/kW	$44	$131	$255	$110	$256	$469
3)	After-Tax WACC	%	8.0%	8.0%	8.0%	8.1%	8.1%	8.1%
4)	Installed Capacity	MW-ac	10	10	10	10	10	10
5)	Useful Life	years	20	20	20	20	20	20
6)	Total Capital Costs, incl. IX	$M	$7	$10	$14	$8	$11	$16
7)	Levelized Capital Costs	$/kW-yr	$74	$98	$121	$73	$96	$119
8)	Levelized Interconnection Costs	$/kW-yr	$5	$14	$28	$12	$28	$51
9)	Levelized Fixed O&M	$/kW-yr	$23	$30	$37	$22	$29	$36
10)	Gross CONE, excl. ITC	$/kW-yr	$102	$141	$186	$107	$153	$206
11)	Levelized Investment Tax Credit	$/kW-yr	-$28	-$37	-$46	-$27	-$35	-$44
12)	**Gross CONE (ICAP)**	$/kW-yr	**$73**	**$104**	**$139**	**$80**	**$118**	**$163**

6.2.7 Co-located Solar Photovoltaic and 4-Hour Battery Storage (Solar PV + Storage)

Gross CONE estimates for co-located solar PV + battery range from $105/kW-yr in MISO North and Central, Low scenario to $162/kW-yr in MISO South, High scenario. Table 37 displays details of the CONE (ICAP basis) results for this technology.[59]

[59] Gross CONE (ICAP basis) estimate for co-located solar PV + storage represents the gross CONE per kW of installed capacity of the co-located resource's total capacity (20 MW-ac ICAP).

Table 37. 2027 Gross CONE (ICAP Basis) for Solar PV + Storage (2027$, Nominal Levelized)

	Gross CONE (ICAP), 2027 COD ($2027, Nom Levelized)		MISO North and Central			MISO South		
	Solar PV and Storage		*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
1)	Capital Costs, excl. IX	$/kW	$1,193	$1,400	$1,608	$1,155	$1,356	$1,558
2)	Interconnection Costs	$/kW	$42	$82	$147	$88	$170	$469
3)	After-Tax WACC	%	8.0%	8.0%	8.0%	8.1%	8.1%	8.1%
4)	Installed Capacity	MW-ac	10	10	10	10	10	10
5)	Useful Life	years	20	20	20	20	20	20
6)	Total Capital Costs, incl. IX	$M	$24	$29	$34	$24	$29	$36
7)	Levelized Capital Costs	$/kW-yr	$119	$141	$163	$117	$138	$160
8)	Levelized Interconnection Costs	$/kW-yr	$2	$4	$7	$4	$8	$22
9)	Levelized Fixed O&M	$/kW-yr	$31	$36	$43	$29	$34	$40
10)	Gross CONE, excl. ITC	$/kW-yr	$152	$181	$213	$150	$180	$223
11)	Levelized Investment Tax Credit	$/kW-yr	-$47	-$56	-$64	-$44	-$52	-$60
12)	**Gross CONE (ICAP)**	$/kW-yr	**$105**	**$126**	**$149**	**$105**	**$128**	**$162**

6.2.8 Coal Steam Turbine (ST)

Gross CONE (ICAP basis) estimates for coal ST range from $487/kW-yr in MISO South, Low scenario to $538/kW-yr in MISO North + Central, High scenario. Table 38 displays details of the CONE (ICAP basis) results for this technology.

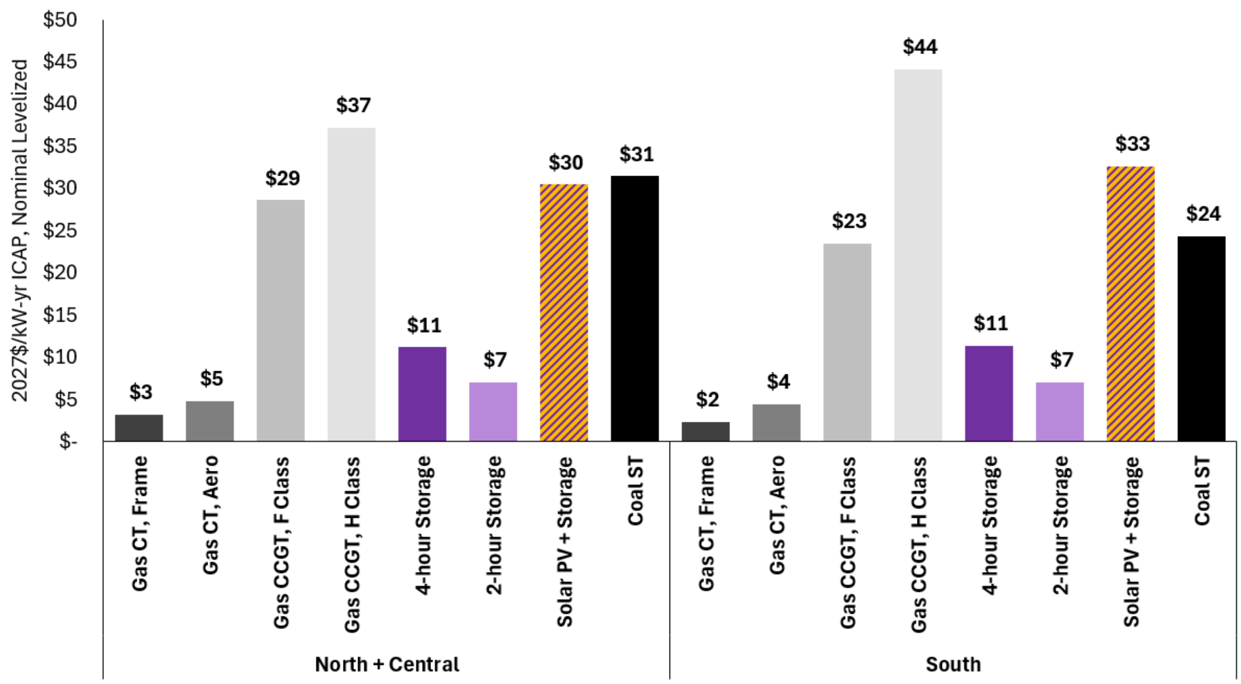
Table 38. 2027 Gross CONE (ICAP Basis) for Coal ST (2027$, Nominal Levelized)

	Gross CONE (ICAP), 2027 COD ($2027, Nom Levelized)		North + Central			South		
	Coal ST		*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
1)	**Capital Costs, excl. IX**	$/kW	$4,265	$4,323	$4,381	$3,966	$4,019	$4,073
2)	**Interconnection Costs**	$/kW	$11	$14	$80	$4	$29	$146
3)	**After-Tax WACC**	%	8.0%	8.0%	8.0%	8.1%	8.1%	8.1%
4)	**Installed Capacity**	MW-ac	650	650	650	650	650	650
5)	**Useful Life**	years	30	30	30	30	30	30
6)	**Total Capital Costs, incl. IX**	$M	$2,780	$2,819	$2,900	$2,581	$2,632	$2,742
7)	**Levelized Capital Costs**	$/kW-yr	$401	$406	$411	$378	$383	$388
8)	**Levelized Interconnection Costs**	$/kW-yr	$1	$1	$8	$0	$3	$14
9)	**Levelized Fixed O&M**	$/kW-yr	$117	$118	$119	$108	$110	$111
10)	**Gross CONE, excl. ITC**	$/kW-yr	$518	$525	$538	$487	$496	$513
11)	**Levelized Investment Tax Credit**	$/kW-yr	$0	$0	$0	$0	$0	$0
12)	**Gross CONE (ICAP)**	$/kW-yr	**$518**	**$525**	**$538**	**$487**	**$496**	**$513**

6.3 Modeled Energy and Ancillary Services Margins (Modeled E+AS Margins), ICAP Basis

This section summarizes the median modeled E+AS margins for each reference technology candidate, expressed in nominal $/kW-year on an ICAP basis, for resources built in 2027. As discussed in prior sections, these margins represent the expected non-capacity net revenues that offset gross CONE and therefore influence each technology's modeled net CONE. As discussed in prior sections, these modeled E+AS margins are derived using a forward-looking, production cost modeling–based methodology and therefore differ from the inframarginal rents used by MISO in its annual CONE process. Figure 10 displays the summary levelized modeled E+AS margins results.

Figure 10. Levelized Modeled E+AS Margins (ICAP Basis) by Candidate Technology and Region, 2027 COD (2027$, Nominal Levelized)



Across both regions, the results show a clear differentiation between technologies whose value is driven primarily by energy market participation versus technologies that rely more heavily on capacity revenues. CCGT plants exhibit the highest modeled E+AS margins, with the H class CCGTs producing the largest margins in both regions. The co-located solar plus storage also received relatively high margins, mainly driven by solar energy value. Finally, coal—generally a baseload energy resource—shows relatively high modeled margins. By contrast, peaking gas CTs have relatively low levelized modeled E+AS margins when at target reliability, consistent with limited runtime expectations. Storage exhibits modest margins, since energy arbitrage is only expected to make part of its total net revenue.

Regional differences are generally modest for most technologies but are more pronounced for certain thermal resources. Specifically, gas CCGTs and Coal STs face the biggest regional margin differences, with newer CCGTs making more margins in South but coal plants making more margins in North + Central. Note that the relative operational characteristics of each plant in MISO's PLEXOS model also impacts these results.

Figure 11 and Figure 12 show the annual median E+AS margin trajectories in MISO North + Central that underlie the levelized modeled E+AS margins summarized in Figure 10. The figure shows modeled annual net operating margins on an ICAP basis, by technology, over the full forecast horizon used for levelization. These trajectories illustrate how the value of different resource types evolves over time as system conditions change. The significant changes in E+AS margin trajectories reinforce the decision to use lifetime values, rather than a single snapshot year, to represent a technology's long-run economics.

Figure 11. Annual Modeled E+AS Margins (ICAP Basis) by Candidate Technology, North + Central (Nominal$)

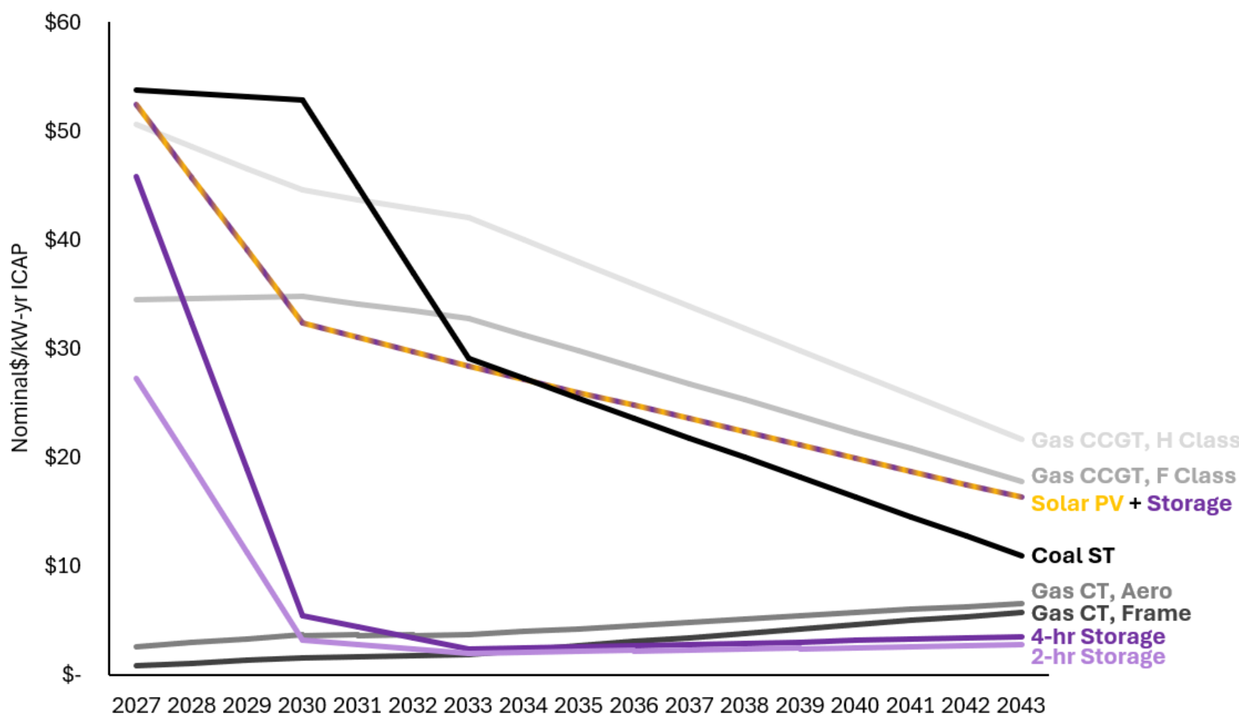
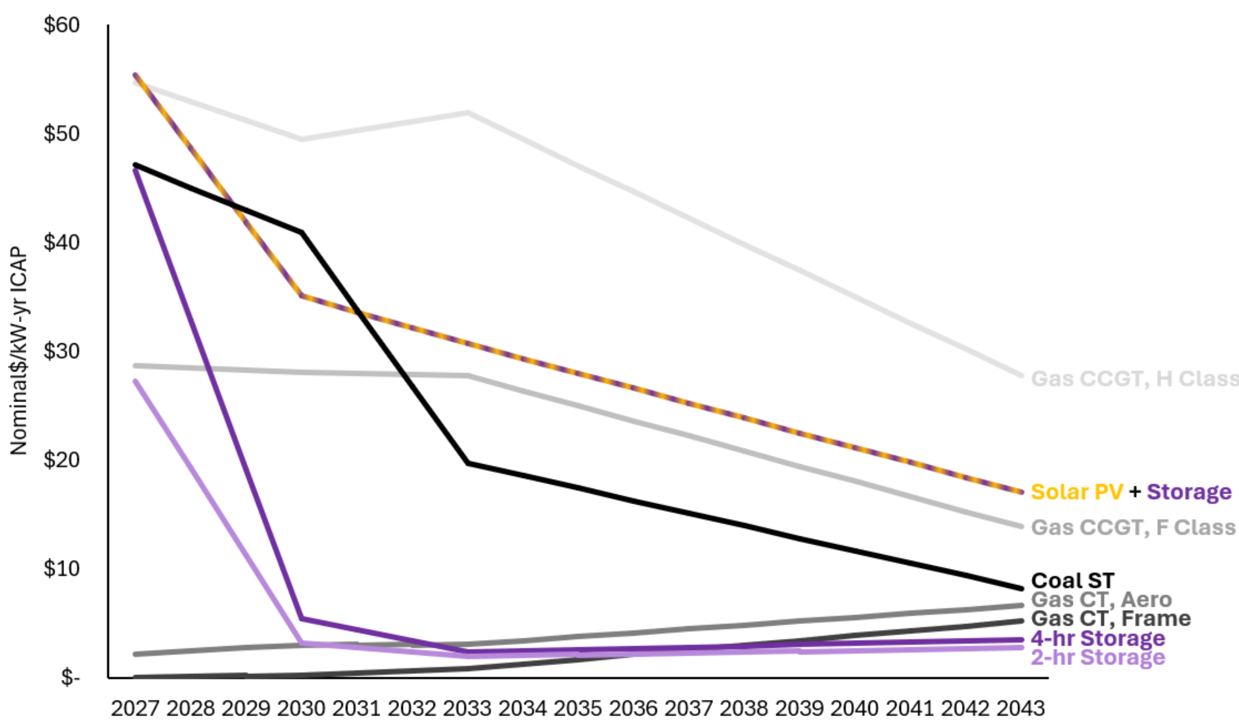


Figure 12. Annual Modeled E+AS Margins (ICAP Basis) by Candidate Technology, South (Nominal$)



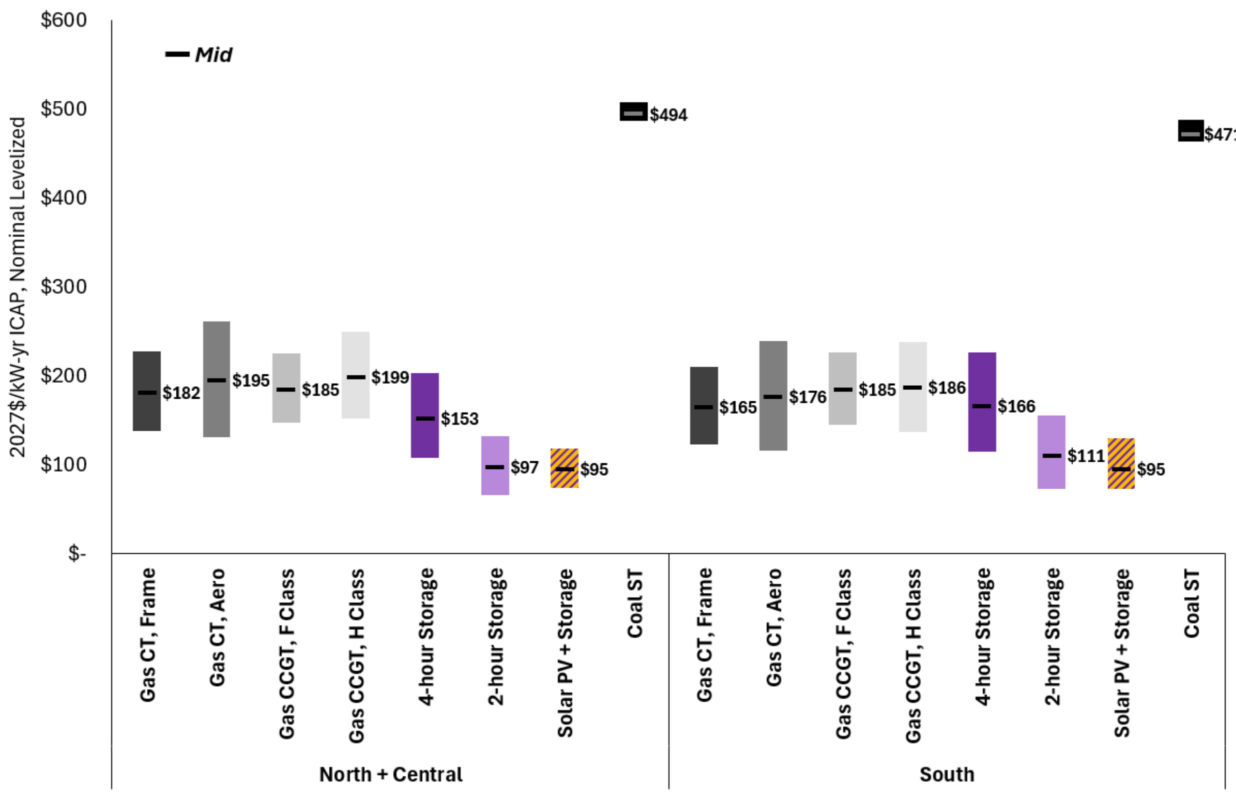
The annual trajectories show a divergence across technologies over time. Modeled E+AS margins for higher-capacity-factor resources, including gas CCGT and coal, start relatively high and then decline through 2043. Storage resources face an even steeper margin decline, dropping significantly from 2027 to 2030. By contrast, peaking-oriented like gas CTs earn lower margins throughout the forecast horizon.

These patterns are consistent with the modeled evolution of system conditions. Rising solar penetration reduces energy prices and dispatch opportunities across a broad set of hours, compressing margins for resources that depend on sustained energy market output, including gas CCGTs, coal, and co-located solar PV + storage. Similarly, increasing storage penetration narrows charging-discharging price spreads and saturates ancillary service opportunities. As more storage competes for the same high-value hours, modeled E+AS margins decline over the forecast horizon.

6.4 Modeled Net Cost of New Entry (Modeled Net CONE), ICAP Basis

This subsection presents the modeled net CONE results on an ICAP basis by candidate technology and region, for resources built in 2027. As discussed in Section *Modeled Net Cost of New Entry (Modeled Net CONE),* ICAP Basis, the Low, Mid, and High scenario values for modeled net CONE are calculated on a technology- and region-specific basis by subtracting a single median modeled E+AS margins value from each of the corresponding gross CONE scenario values (all on an ICAP basis). In other words, for each technology and region, the same median modeled E+AS margins curve is applied to the Low, Mid, and High gross CONE curves to produce the Low, Mid, and High modeled net CONE (ICAP basis) results. Because these modeled E+AS margins are derived from forward-looking production cost modeling rather than MISO's historical inframarginal rent methodology, the resulting modeled net CONE values differ from the net CONE values MISO calculates in its annual CONE process. These results are summarized in Figure 13.

Figure 13. 2027 Modeled Net CONE (ICAP Basis) by Candidate Technology and Region (2027$, Nominal Levelized)



Storage-based candidate resources (2-hour storage, 4-hour storage, and co-located solar PV + storage) exhibit the lowest modeled net CONE values on an ICAP basis, primarily driven by their relatively low fixed costs. Conventional gas technologies (frame CT, aero CT, and F and H class CCGTs) cluster in a relatively higher-cost band, but all with similar modeled net CONEs per ICAP MW. Coal plant modeled net CONE (ICAP basis) are higher than conventional gas technologies, consistent with their relatively higher fixed costs.

Across regions, the relative ordering is largely consistent, but the level of modeled net CONE differs for some technologies. In particular, storage-based technologies tend to show higher modeled net CONE in MISO South than in North + Central, due to the higher costs in that region. Conventional gas technologies are slightly less expensive in South, leading to lower modeled net CONE (ICAP basis) values. Coal modeled net CONE is lower in the South than in North + Central, driven by the expectation of higher modeled E+AS margins in South.

The following subsections summarize the modeled net CONE (ICAP basis) calculations and resulting values for each candidate technology and region evaluated in this study.

6.4.1 Gas Combustion Turbine (CT), Frame

Modeled net CONE (ICAP basis) estimates for frame gas CTs range from $123/kW-yr in MISO South, Low scenario to $228/kW-yr in MISO North + Central, High scenario. Table 39 displays details of the modeled net CONE (ICAP basis) results for this technology.

Table 39. 2027 Modeled Net CONE (ICAP Basis) for Gas CT, Frame (2027$, Nominal Levelized)

	Modeled Net CONE (ICAP), 2027 COD ($2027, Nom Lev.)		North + Central			South		
	Gas CT, Frame		Low	Mid	High	Low	Mid	High
12)	Gross CONE (ICAP)	$/kW-yr	$142	$185	$231	$125	$168	$212
13)	Modeled E+AS Margins (ICAP)	$/kW-yr	$3	$3	$3	$2	$2	$2
14)	Modeled Net CONE (ICAP)	$/kW-yr	$138	$182	$228	$123	$165	$210

6.4.2 Gas Combustion Turbine (CT), Aero

Modeled net CONE (ICAP basis) estimates for aero gas CTs range from $116/kW-yr in MISO South, Low scenario to $261/kW-yr in MISO North + Central, High scenario. Table 40 displays details of the modeled net CONE (ICAP basis) results for this technology.

Table 40. 2027 Modeled Net CONE (ICAP Basis) for Gas CT, Aero (2027$, Nominal Levelized)

	Modeled Net CONE (ICAP), 2027 COD ($2027, Nom Lev.)		North + Central			South		
	Gas CT, Aero		Low	Mid	High	Low	Mid	High
12)	Gross CONE (ICAP)	$/kW-yr	$136	$199	$266	$120	$181	$243
13)	Modeled E+AS Margins (ICAP)	$/kW-yr	$5	$5	$5	$4	$4	$4
14)	Modeled Net CONE (ICAP)	$/kW-yr	$131	$195	$261	$116	$176	$239

6.4.3 Gas Combined Cycle Gas Turbine (CCGT), F Class

Modeled net CONE (ICAP basis) estimates for F class CCGTs range from $145/kW-yr in MISO South, Low scenario to $225/kW-yr in MISO South, High scenario. Table 41 displays details of the modeled net CONE (ICAP basis) results for this technology.

Table 41. 2027 Modeled Net CONE (ICAP Basis) for Gas CCGT, F Class (2027$, Nominal Levelized)

	Modeled Net CONE (ICAP), 2027 COD ($2027, Nom Lev.)		North + Central			South		
	Gas CCGT, F Class		Low	Mid	High	Low	Mid	High
12)	Gross CONE (ICAP)	$/kW-yr	$177	$213	$253	$169	$208	$250
13)	Modeled E+AS Margins (ICAP)	$/kW-yr	$29	$29	$29	$23	$23	$23
14)	Modeled Net CONE (ICAP)	$/kW-yr	$148	$185	$225	$145	$185	$227

6.4.4 Gas Combined Cycle Gas Turbine (CCGT), H Class

Modeled net CONE (ICAP basis) estimates for H class CCGTs range from $137/kW-yr in MISO South, Low scenario to $249/kW-yr in MISO North + Central, High scenario. Table 42 displays details of the modeled net CONE (ICAP basis) results for this technology.

Table 42. 2027 Modeled Net CONE (ICAP Basis) for Gas CCGT, H Class (2027$, Nominal Levelized)

	Modeled Net CONE (ICAP), 2027 COD ($2027, Nom Lev.)		North + Central			South		
	Gas CCGT, H Class		Low	Mid	High	Low	Mid	High
12)	Gross CONE (ICAP)	$/kW-yr	$190	$236	$286	$182	$230	$282
13)	Modeled E+AS Margins (ICAP)	$/kW-yr	$37	$37	$37	$44	$44	$44
14)	Modeled Net CONE (ICAP)	$/kW-yr	$152	$199	$249	$137	$186	$238

6.4.5 4-hour Battery Storage (4-hour Storage)

Modeled net CONE (ICAP basis) estimates for 4-hour storage range from $108/kW-yr in MISO North + Central, Low scenario to $191/kW-yr in MISO South, High scenario. Table 43 displays details of the modeled net CONE (ICAP basis) results for this technology.

Table 43. 2027 Modeled Net CONE (ICAP Basis) for 4-hour Storage (2027$, Nominal Levelized)

	Modeled Net CONE (ICAP), 2027 COD ($2027, Nom Lev.)		North + Central			South		
	4-hour Storage		Low	Mid	High	Low	Mid	High
12)	Gross CONE (ICAP)	$/kW-yr	$119	$164	$214	$126	$177	$237
13)	Modeled E+AS Margins (ICAP)	$/kW-yr	$11	$11	$11	$11	$11	$11
14)	Modeled Net CONE (ICAP)	$/kW-yr	$108	$153	$203	$115	$166	$226

6.4.6 2-hour Battery Storage (2-hour Storage)

Modeled et CONE estimates for 2-hour storage range from $66/kW-yr in MISO North + Central, Low scenario to $135/kW-yr in MISO South, High scenario. Table 44 displays details of the modeled net CONE (ICAP basis) results for this technology.

Table 44. 2027 Modeled Net CONE (ICAP Basis) for 2-hour Storage (2027$, Nominal Levelized)

	Modeled Net CONE (ICAP), 2027 COD ($2027, Nom Lev.)		North + Central			South		
	2-hour Storage		Low	Mid	High	Low	Mid	High
12)	Gross CONE (ICAP)	$/kW-yr	$73	$104	$139	$80	$118	$163
13)	Modeled E+AS Margins (ICAP)	$/kW-yr	$7	$7	$7	$7	$7	$7
14)	Modeled Net CONE (ICAP)	$/kW-yr	$66	$97	$132	$73	$111	$156

6.4.7 Co-located Solar Photovoltaic and 4-Hour Battery Storage (Solar PV + Storage)

Modeled net CONE estimates for co-located solar PV + storage range from $73/kW-yr in MISO South, Low scenario to $130/kW-yr in MISO South, High scenario. Table 45 displays details of the modeled net CONE (ICAP basis) results for this technology.[60]

Table 45. 2027 Modeled Net CONE (ICAP Basis) for Solar PV + Storage (2027$, Nominal Levelized)

	Modeled Net CONE (ICAP), 2027 COD ($2027, Nom Lev.)		MISO North and Central			MISO South		
	Solar PV + Storage		Low	Mid	High	Low	Mid	High
12)	Gross CONE (ICAP)	$/kW-yr	$105	$126	$149	$105	$128	$162
13)	Modeled E+AS Margins (ICAP)	$/kW-yr	$30	$30	$30	$33	$33	$33
14)	**Modeled Net CONE (ICAP)**	$/kW-yr	**$75**	**$95**	**$118**	**$73**	**$95**	**$130**

6.4.8 Coal Steam Turbine (ST)

Modeled net CONE (ICAP basis) estimates for coal ST range from $462/kW-yr in MISO South, Low scenario to $507/kW-yr in MISO North + Central, High scenario. Table 46 displays the details of modeled net CONE (ICAP basis) results for this technology.

Table 46. 2027 Modeled Net CONE (ICAP Basis) for Coal ST (2027$, Nominal Levelized)

	Modeled Net CONE (ICAP), 2027 COD ($2027, Nom Lev.)		North + Central			South		
	Coal ST		Low	Mid	High	Low	Mid	High
12)	Gross CONE (ICAP)	$/kW-yr	$518	$525	$538	$487	$496	$513
13)	Modeled E+AS Margins (ICAP)	$/kW-yr	$31	$31	$31	$24	$24	$24
14)	**Modeled Net CONE (ICAP)**	$/kW-yr	**$487**	**$494**	**$507**	**$462**	**$471**	**$489**

6.5 Capacity Accreditation (DLOL UCAP %)

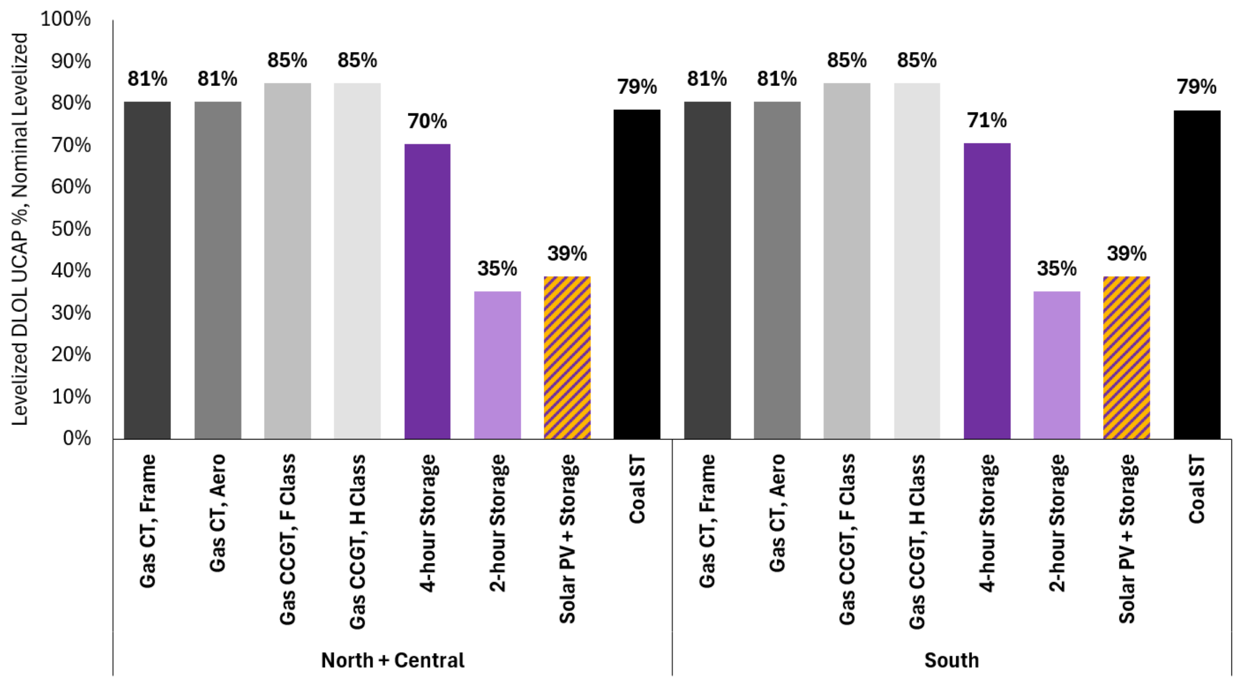
This section summarizes the levelized DLOL UCAP % (MISO's capacity accreditation metric) results used for the reference technology candidates, for resources built in 2027. As described in Section *Capacity Accreditation (DLOL UCAP %)*, these accreditation factors convert ICAP MW into UCAP MW for the cost metrics reported in this study. Under MISO's DLOL framework, the underlying seasonal (and annualized) DLOL UCAP % trajectories are applied consistently across the MISO footprint and therefore do not vary by region or by the Low/Mid/High scenarios. However, because the study reports levelized values, small differences can arise in levelized DLOL UCAP % across regions due

[60] Modeled net CONE (ICAP basis) estimate for co-located solar PV + storage represent the modeled net CONE per kW of installed capacity of the co-located resource's total capacity (20 MW-ac ICAP).

to region-specific levelization parameters (mainly the difference in the WACC used to discount the annual accreditation stream).

Figure 14 presents the levelized DLOL UCAP % for each candidate technology, assuming a 2027 COD year. Dispatchable thermal technologies receive the highest levelized accreditation values, ranging between 79% and 85%. By contrast, storage-based resources receive lower accreditation values, suffering from the duration-limited nature of their dispatch that limits their ability to be available during highest-risk hours.

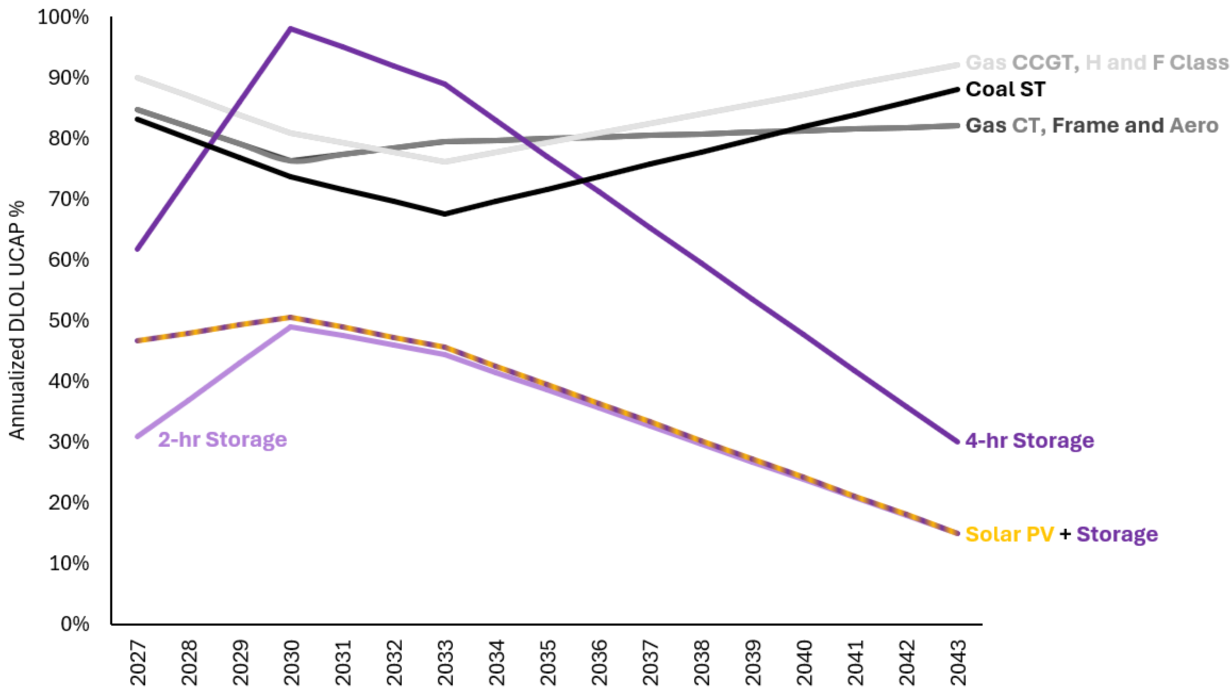
Figure 14. Levelized DLOL UCAP % by Candidate Technology, 2027 COD (Nominal Levelized)[61]



The levelized DLOL UCAP% values are derived from the annual accreditation trajectories shown in Figure 15. Thermal resources exhibit relatively stable accreditation over the forecast horizon, indicating that their reliability contribution during the system's highest-risk hours changes only modestly as conditions evolve. In contrast, storage-based resources (2-hour storage, 4-hour storage, and Solar PV + Storage) show larger shifts over time, reinforcing the importance of evaluating accreditation over multiple years rather than relying on a single snapshot.

[61] MISO's underlying DLOL UCAP % (seasonal and annualized accreditation) is applied consistently across the footprint. The small differences in levelized DLOL UCAP % shown by region reflect region-specific financing assumptions (i.e., ATWACC). Most values appear identical because the levelized differences are minor and rounded to whole percentages, while the visible 4-hour storage difference is also a rounding effect.

Figure 15. Annual DLOL UCAP % by Candidate Technology



Specifically, storage accreditation rises in the latter half of the 2020s as incremental solar shifts reliability risk toward shorter-duration, peakier net-load conditions, which short-duration storage is well positioned to serve. By the mid-2030s, those same storage resources see declining accreditation as (1) the system's highest-risk conditions increasingly reflect longer-duration stress events—driven by a shift toward winter risk and "renewable drought" conditions—and (2) additional storage enters and competes for the same scarcity window, effectively extending the duration of system stress beyond what short-duration output can cover. In contrast, dispatchable thermal resources maintain relatively stable accreditation over time because they can sustain output across a broader range of highest-risk conditions, preserving their reliability contribution even as the timing and duration of system stress evolves.

When comparing the annual forecasts of storage modeled E+AS margins (Figure 11) and DLOL UCAP% (Figure 15), the two trajectories generally move in the same direction over the long run, but they do not track one another closely in the near term, most notably between 2027 and 2030. This short-run divergence reflects two differences in what each metric measures and how it is derived.

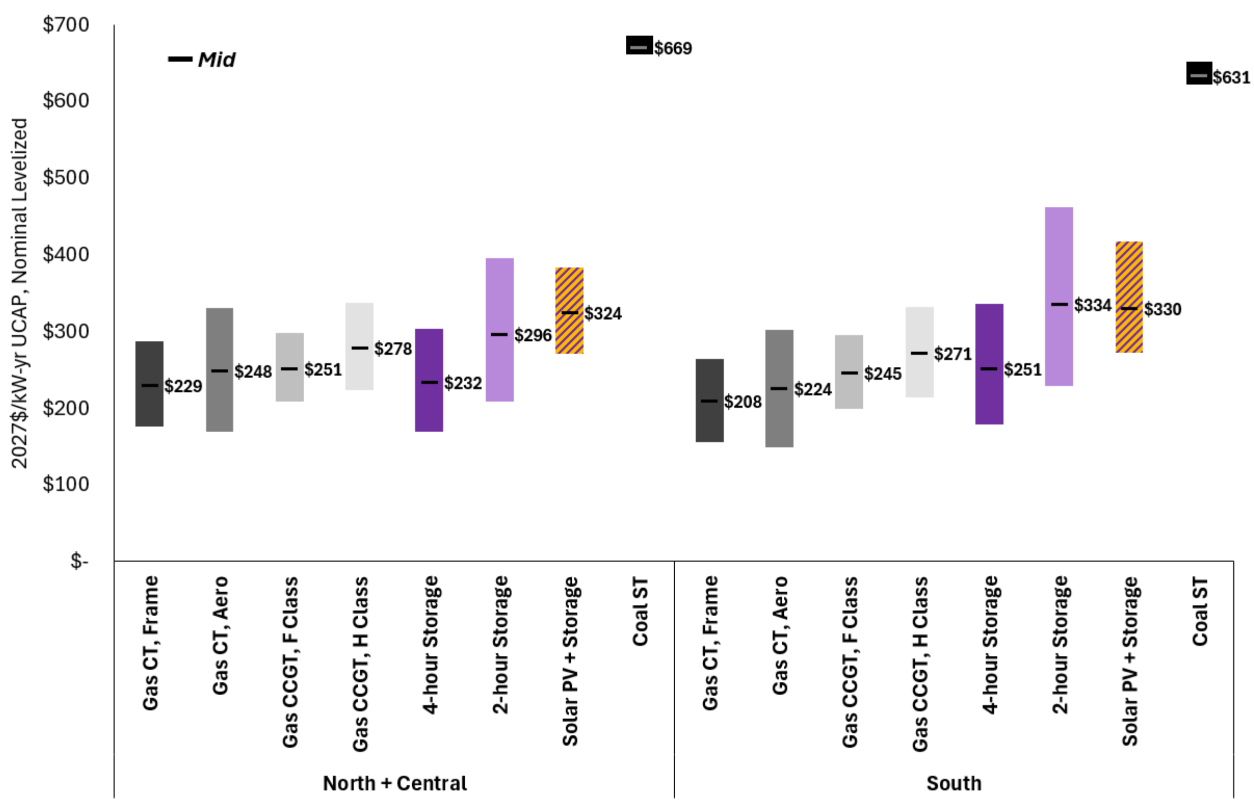
First, modeled E+AS margins reflect operating value across *all* hours of the year, whereas DLOL UCAP% reflects incremental reliability contribution during the relatively small set of the system's highest-risk hours. As a result, modeled E+AS margins are driven primarily by energy price spreads and competition among similar resources; as storage penetration increases, more projects compete for the same charging and discharging opportunities, compressing arbitrage spreads and reducing margins. In contrast, DLOL UCAP% is driven by the timing and duration of the highest-risk periods. In the modeled outlook through 2030, incremental solar additions are expected to shorten peak net-load risk periods, which can temporarily increase the accredited contribution of limited-duration storage, even as storage's market revenues are being compressed by growing storage competition.

Second, the two forecasts come from different modeling frameworks. DLOL UCAP% is based on Monte Carlo loss-of-load probability ("LOLP") simulations across many stochastic draws of weather, outages, and other uncertain conditions, whereas the E+AS margin trajectories are derived from deterministic production cost modeling outputs for a representative (median) set of conditions. Taken together, these differences can produce different near-term trajectories for storage across metrics, even when both are responding to the same underlying evolution of the system.

6.6 Gross Cost of New Entry (CONE), UCAP Basis

To convert ICAP-based gross CONE to an UCAP-based, we scale the Low, Mid, and High scenario gross CONE values by the annualized DLOL UCAP % for the applicable technology, producing gross CONE in $/kW-year of UCAP. This expresses each asset's new entry costs on a capacity-equivalent basis used for resource adequacy, enabling more direct comparison across technologies with different firm capacity contributions. The summary results for gross CONE (UCAP) by technology and region, for resources built in 2027, are shown in Figure 16.

Figure 16. 2027 Gross CONE (UCAP Basis) by Candidate Technology and Region (2027$, Nominal Levelized)



Relative to the ICAP-based results, gross CONE per UCAP MW will be higher technologies for all technologies (assuming UCAP % is not 100%), with lower accreditation resources showing the biggest relative increase. This effect can be seen in storage-based technologies, which were shown to be less expensive per ICAP MW (see Section *Gross Cost of New Entry (CONE), ICAP Basis*) than gas technologies but are in a similar range of costs per UCAP MW. In fact, looking at Mid scenario, gas frame CT becomes the cheapest technology per UCAP MW. This shift in relative ordering of technologies when looking at UCAP-based gross CONE underscores why accreditation-adjusted (UCAP-based) metrics are central to reference technology comparisons.

Across regions, differences in UCAP-based gross CONE largely track the underlying ICAP-based cost differences, because the same UCAP % factors are applied across regions. Consistent with the gross CONE on an ICAP basis results, gross CONE on a UCAP basis is lower for gas technologies but higher for storage-based technologies in MISO South (relative to MISO North + Central).

The following subsections summarize the gross CONE (UCAP basis) calculations and resulting values for each candidate technology and region evaluated in this study.

6.6.1 Gas Combustion Turbine (CT), Frame

Gross CONE (UCAP basis) estimates for frame CTs range from \$155/kW-yr in MISO South Low scenario to \$287/kW-yr in MISO North + Central, High scenario. Table 47 displays details of the gross CONE (UCAP basis) results for this technology.

Table 47. 2027 Gross CONE (UCAP Basis) for Gas CT, Frame (2027\$, Nominal Levelized)

	Gross CONE (UCAP), 2027 COD (\$2027, Nom Levelized)		North + Central			South		
	Gas CT, Frame		*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
12)	**Gross CONE (ICAP)**	\$/kW-yr	\$142	\$185	\$231	\$125	\$168	\$212
15)	**DLOL UCAP %**	%	81%	81%	81%	81%	81%	81%
16)	**Gross CONE (UCAP)**	\$/kW-yr	**\$176**	**\$229**	**\$287**	**\$155**	**\$208**	**\$264**

6.6.2 Gas Combustion Turbine (CT), Aero

Gross CONE (UCAP basis) estimates for aero CTs range from \$149/kW-yr in MISO South Low scenario to \$330/kW-yr in MISO North + Central, High scenario. Table 48 displays details of the gross CONE (UCAP basis) results for this technology.

Table 48. 2027 Gross CONE (UCAP Basis) for Gas CT, Aero (2027$, Nominal Levelized)

	Gross CONE (UCAP), 2027 COD ($2027, Nom Levelized)		North + Central			South		
	Gas CT, Aero		Low	Mid	High	Low	Mid	High
12)	Gross CONE (ICAP)	$/kW-yr	$136	$199	$266	$120	$181	$243
15)	DLOL UCAP %	%	81%	81%	81%	81%	81%	81%
16)	**Gross CONE (UCAP)**	$/kW-yr	**$169**	**$248**	**$330**	**$149**	**$224**	**$302**

6.6.3 Gas Combined Cycle Gas Turbine (CCGT), F Class

Gross CONE (UCAP basis) estimates for F class CCGTs range from $199/kW-yr in MISO South Low scenario to $298/kW-yr in MISO North + Central, High scenario. Table 49 displays details of the gross CONE (UCAP basis) results for this technology.

Table 49. 2027 Gross CONE (UCAP Basis) for Gas CCGT, F Class (2027$, Nominal Levelized)

	Gross CONE (UCAP), 2027 COD ($2027, Nom Levelized)		North + Central			South		
	Gas CCGT, F Class		Low	Mid	High	Low	Mid	High
12)	Gross CONE (ICAP)	$/kW-yr	$177	$213	$253	$169	$208	$250
15)	DLOL UCAP %	%	85%	85%	85%	85%	85%	85%
16)	**Gross CONE (UCAP)**	$/kW-yr	**$208**	**$251**	**$298**	**$199**	**$245**	**$295**

6.6.4 Gas Combined Cycle Gas Turbine (CCGT), H Class

Gross CONE (UCAP basis) estimates for H class CCGTs range from $214/kW-yr in MISO South Low scenario to $337/kW-yr in MISO North + Central, High scenario. Table 50 displays details of the gross CONE (UCAP basis) results for this technology.

Table 50. 2027 Gross CONE (UCAP Basis) for Gas CCGT, H Class (2027$, Nominal Levelized)

	Gross CONE (UCAP), 2027 COD ($2027, Nom Levelized)		North + Central			South		
	Gas CCGT, H Class		Low	Mid	High	Low	Mid	High
12)	Gross CONE (ICAP)	$/kW-yr	$190	$236	$286	$182	$230	$282
15)	DLOL UCAP %	%	85%	85%	85%	85%	85%	85%
16)	**Gross CONE (UCAP)**	$/kW-yr	**$223**	**$278**	**$337**	**$214**	**$271**	**$332**

6.6.5 4-hour Battery Storage (4-hour Storage)

Gross CONE (UCAP basis) estimates 4-hour storage range from $170/kW-yr in MISO North + Central, Low scenario to $336/kW-yr in MISO South, High scenario. Table 51 displays details of the gross CONE (UCAP basis) results for this technology.

Table 51. 2027 Gross CONE (UCAP Basis) for 4-hour Storage (2027$, Nominal Levelized)

	Gross CONE (UCAP), 2027 COD ($2027, Nom Levelized)		North + Central			South		
	4-hour Storage		Low	Mid	High	Low	Mid	High
12)	Gross CONE (ICAP)	$/kW-yr	$119	$164	$214	$126	$177	$237
15)	DLOL UCAP %	%	70%	70%	70%	71%	71%	71%
16)	**Gross CONE (UCAP)**	$/kW-yr	**$170**	**$232**	**$304**	**$179**	**$251**	**$336**

6.6.6 2-hour Battery Storage (2-hour Storage)

Gross CONE (UCAP basis) estimates for 2-hour storage range from $208/kW-yr in MISO North + Central, Low scenario to $461/kW-yr in MISO South, High scenario. Table 52 displays details of the gross CONE (UCAP basis) results for this technology.

Table 52. 2027 Gross CONE (UCAP Basis) for 2-hour Storage (2027$, Nominal Levelized)

	Gross CONE (UCAP), 2027 COD ($2027, Nom Levelized)		North + Central			South		
	2-hour Storage		Low	Mid	High	Low	Mid	High
12)	Gross CONE (ICAP)	$/kW-yr	$73	$104	$139	$80	$118	$163
15)	DLOL UCAP %	%	35%	35%	35%	35%	35%	35%
16)	**Gross CONE (UCAP)**	$/kW-yr	**$208**	**$296**	**$396**	**$228**	**$334**	**$461**

6.6.7 Co-located Solar Photovoltaic and 4-Hour Battery Storage (Solar PV + Storage)

Gross CONE (UCAP basis) estimates for co-located solar PV + storage range from $462/kW-yr in MISO South, Low scenario to $507/kW-yr in MISO North + Central, High scenario. Table 53 displays details of the gross CONE (UCAP basis) results for this technology.[62]

[62] Gross CONE (UCAP basis) estimate for co-located solar PV + storage represents the gross CONE per kW of accredited capacity of the co-located resource's total capacity (20 MW-ac ICAP).

Table 53. 2027 Gross CONE (UCAP Basis) for Solar PV + Storage (2027$, Nominal Levelized)

	Gross CONE (UCAP), 2027 COD (Real $2027)		MISO North and Central			MISO South		
	Solar PV + Storage		Low	Mid	High	Low	Mid	High
12)	Gross CONE (ICAP)	$/kW-yr	$105	$126	$149	$105	$128	$162
15)	DLOL UCAP %	%	39%	39%	39%	39%	39%	39%
16)	**Gross CONE (UCAP)**	$/kW-yr	**$271**	**$324**	**$383**	**$272**	**$330**	**$418**

6.6.8 Coal Steam Turbine (ST)

Gross CONE (UCAP basis) estimates for coal ST range from $620/kW-yr in MISO South, Low scenario to $685/kW-yr in MISO North + Central, High scenario. Table 54 displays details of the gross CONE (UCAP basis) results for this technology.

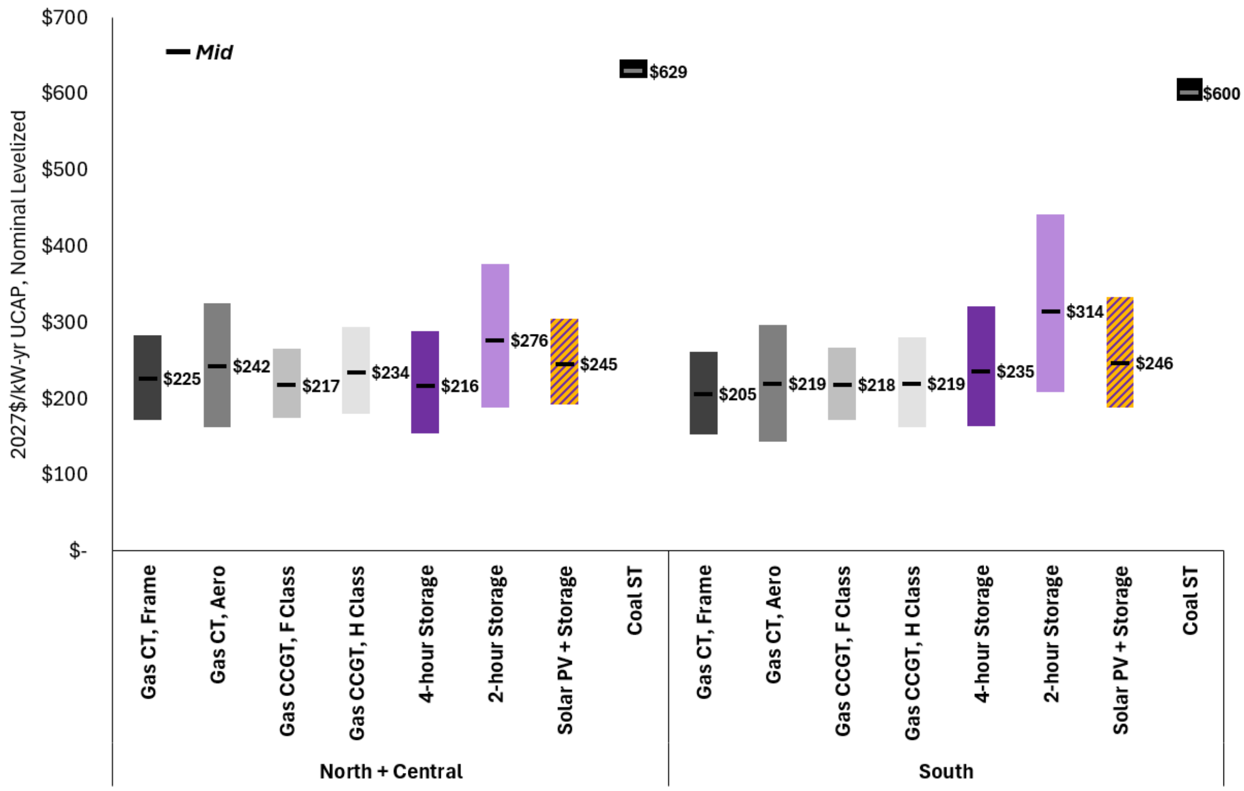
Table 54. 2027 Gross CONE (UCAP Basis) for Coal ST (2027$, Nominal Levelized)

	Gross CONE (UCAP), 2027 COD ($2027, Nom Levelized)		North + Central			South		
	Coal ST		Low	Mid	High	Low	Mid	High
12)	Gross CONE (ICAP)	$/kW-yr	$518	$525	$538	$487	$496	$513
15)	DLOL UCAP %	%	79%	79%	79%	79%	79%	79%
16)	**Gross CONE (UCAP)**	$/kW-yr	**$660**	**$669**	**$685**	**$620**	**$631**	**$653**

6.7 Modeled New Cost of New Entry (Modeled Net CONE), UCAP Basis

Modeled net CONE (UCAP basis) is calculated by dividing the Low, Mid, and High scenario modeled net CONE values (ICAP basis) by the technology's single levelized DLOL UCAP %. Modeled net CONE per UCAP MW is calculated by dividing a technology's modeled net CONE per ICAP MW by its DLOL UCAP %. This conversion places all candidates on a common, capacity-equivalent basis and shows the net capacity cost of providing one MW of UCAP. As with the ICAP results, these UCAP-based values reflect the study's modeled net CONE methodology and therefore should not be interpreted as the net CONE values MISO will ultimately calculate and apply in its annual CONE process. The modeled net CONE (UCAP basis) results for 2027 COD year projects are shown in Figure 17.

Figure 17. 2027 Modeled Net CONE (UCAP Basis) by Candidate Technology and Region (2027$, Nominal Levelized)



Within each region, the UCAP-based modeled net CONE results fall into two clear bands. A broad set of candidates—gas CTs, gas CCGTs, and 4-hour storage—are clustered tightly together; their Mid scenario modeled net CONE (UCAP basis) range between $206/kW-yr and $242/kW-yr in North + Central and $205/kW-yr and $219/kW-yr in South. This tight grouping is consistent with the expectation that, in a system modeled at target reliability with rational market entry, multiple plausible marginal entrants can converge toward a similar effective net cost of accredited capacity. By contrast, the remaining technologies sit in a higher-cost band—most notably 2-hour storage, solar PV + storage, and coal—likely indicating these technologies are either not economic and/or that the entry of these resources is driven by factors other than economics.

Looking at the Mid scenario, the lowest net cost source of accredited capacity is the F class gas CCGT and 4-hour storage in MISO North + Central, and the gas frame CT in MISO South.

Across regions, the same two-band pattern holds, with the clustered "marginal" band remaining intact and the higher-cost technologies remaining separated. The primary regional story is therefore a shift in absolute values rather than a change in the overall structure of the results: North + Central and South exhibit similar relative groupings, but with South showing lower modeled net CONEs in general.

The following subsections summarize the modeled net CONE (UCAP basis) calculations and resulting values for each candidate technology and region evaluated in this study.

6.7.1 Gas Combustion Turbine (CT), Frame

Modeled net CONE (UCAP basis) estimates for frame CTs range from $152/kW-yr in MISO South Low scenario to $283/kW-yr in MISO North + Central, High scenario. Table 55 displays details of the modeled net CONE (UCAP basis) results for this technology.

Table 55. 2027 Modeled Net CONE (UCAP Basis) for Gas CT, Frame (2027$, Nominal Levelized)

	Modeled Net CONE (UCAP), 2027 COD ($2027, Nom Lev.)		North + Central			South		
	Gas CT, Frame		*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
14)	Net CONE (ICAP)	$/kW-yr	$138	$182	$228	$123	$165	$210
15)	DLOL UCAP %	%	81%	81%	81%	81%	81%	81%
17)	**Modeled Net CONE (UCAP)**	$/kW-yr	**$172**	**$225**	**$283**	**$152**	**$205**	**$261**

6.7.2 Gas Combustion Turbine (CT), Aero

Modeled net CONE (UCAP basis) estimates for aero CTs range from $144/kW-yr in MISO South Low scenario to $325/kW-yr in MISO North + Central, High scenario. Table 56 displays details of the modeled net CONE (UCAP basis) results for this technology.

Table 56. 2027 Modeled Net CONE (UCAP Basis) for Gas CT, Aero (2027$, Nominal Levelized)

	Modeled Net CONE (UCAP), 2027 COD ($2027, Nom Lev.)		North + Central			South		
	Gas CT, Aero		*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
14)	Net CONE (ICAP)	$/kW-yr	$131	$195	$261	$116	$176	$239
15)	DLOL UCAP %	%	81%	81%	81%	81%	81%	81%
17)	**Modeled Net CONE (UCAP)**	$/kW-yr	**$163**	**$242**	**$325**	**$144**	**$219**	**$297**

6.7.3 Gas Combined Cycle Gas Turbine (CCGT), F Class

Modeled net CONE (UCAP basis) estimates for F class CCGTs range from $171/kW-yr in MISO South Low scenario to $267/kW-yr in MISO South, High scenario. Table 57 displays details of the modeled net CONE (UCAP basis) results for this technology.

Table 57. 2027 Modeled Net CONE (UCAP Basis) for Gas CCGT, F Class (2027$, Nominal Levelized)

	Modeled Net CONE (UCAP), 2027 COD ($2027, Nom Lev.)		North + Central			South		
	Gas CCGT, F Class		*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
14)	Net CONE (ICAP)	$/kW-yr	$148	$185	$225	$145	$185	$227
15)	DLOL UCAP %	%	85%	85%	85%	85%	85%	85%
17)	**Modeled Net CONE (UCAP)**	$/kW-yr	**$174**	**$217**	**$265**	**$171**	**$218**	**$267**

6.7.4 Gas Combined Cycle Gas Turbine (CCGT), H Class

Modeled net CONE (UCAP basis) estimates for H class CCGTs range from $162/kW-yr in MISO South Low scenario to $294/kW-yr in MISO North + Central, High scenario. Table 58 displays details of the modeled net CONE (UCAP basis) results for this technology.

Table 58. 2027 Modeled Net CONE (UCAP Basis) for Gas CCGT, H Class (2027$, Nominal Levelized)

	Modeled Net CONE (UCAP), 2027 COD ($2027, Nom Lev.)		North + Central			South		
	Gas CCGT, H Class		*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
14)	Net CONE (ICAP)	$/kW-yr	$152	$199	$249	$137	$186	$238
15)	DLOL UCAP %	%	85%	85%	85%	85%	85%	85%
17)	Modeled Net CONE (UCAP)	$/kW-yr	**$180**	**$234**	**$294**	**$162**	**$219**	**$280**

6.7.5 4-hour Battery Storage (4-hour Storage)

Modeled net CONE (UCAP basis) estimates for 4-hour storage range from $154/kW-yr in MISO North + Central, Low scenario to $320/kW-yr in MISO South, High scenario. Table 59 displays details of the modeled net CONE (UCAP basis) results for this technology.

Table 59. 2027 Modeled Net CONE (UCAP Basis) for 4-hour Storage (2027$, Nominal Levelized)

	Modeled Net CONE (UCAP), 2027 COD ($2027, Nom Lev.)		North + Central			South		
	4-hour Storage		*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
14)	Net CONE (ICAP)	$/kW-yr	$108	$153	$203	$115	$166	$226
15)	DLOL UCAP %	%	70%	70%	70%	71%	71%	71%
17)	Modeled Net CONE (UCAP)	$/kW-yr	**$154**	**$216**	**$288**	**$163**	**$235**	**$320**

6.7.6 2-hour Battery Storage (2-hour Storage)

Modeled net CONE (UCAP basis) estimates for 2-hour storage range from $188/kW-yr in MISO North + Central, Low scenario to $441/kW-yr in MISO South, High scenario. Table 60 displays details of the modeled net CONE (UCAP basis) results for this technology.

Table 60. 2027 Modeled Net CONE (UCAP Basis) for 2-hour Storage (2027$, Nominal Levelized)

	Modeled Net CONE (UCAP), 2027 COD ($2027, Nom Lev.)		North + Central			South		
	2-hour Storage		*Low*	*Mid*	*High*	*Low*	*Mid*	*High*
14)	Net CONE (ICAP)	$/kW-yr	$66	$97	$132	$73	$111	$156
15)	DLOL UCAP %	%	35%	35%	35%	35%	35%	35%
17)	Modeled Net CONE (UCAP)	$/kW-yr	**$188**	**$276**	**$376**	**$208**	**$314**	**$441**

6.7.7 Co-located Solar Photovoltaic and 4-Hour Battery Storage (Solar PV + Storage)

Modeled net CONE (UCAP basis) estimates for solar PV + storage range from $462/kW-yr in MISO South Low scenario to $507/kW-yr in MISO North + Central, High scenario. Table 61 displays details of the modeled net CONE (UCAP basis) results for this technology.[63]

Table 61. 2027 Modeled Net CONE (UCAP Basis) for Solar PV + Storage (2027$, Nominal Levelized)

	Modeled Net CONE (UCAP), 2027 COD ($2027, Nom Lev.)		MISO North and Central			MISO South		
	Solar PV + Storage		Low	Mid	High	Low	Mid	High
14)	Net CONE (ICAP)	$/kW-yr	$90	$110	$134	$89	$112	$146
15)	DLOL UCAP %	%	39%	39%	39%	39%	39%	39%
17)	Modeled Net CONE (UCAP)	$/kW-yr	$231	$285	$344	$230	$288	$376

6.7.8 Coal Steam Turbine (ST)

Modeled net CONE (UCAP basis) estimates for coal ST range from $589/kW-yr in MISO South, Low scenario to $645/kW-yr in MISO North + Central, High scenario. Table 62 displays details of the modeled net CONE (UCAP basis) results for this technology.

Table 62. 2027 Modeled Net CONE (UCAP Basis) for Coal ST (2027$, Nominal Levelized)

	Modeled Net CONE (UCAP), 2027 COD ($2027, Nom Lev.)		North + Central			South		
	Coal ST		Low	Mid	High	Low	Mid	High
14)	Net CONE (ICAP)	$/kW-yr	$487	$494	$507	$462	$471	$489
15)	DLOL UCAP %	%	79%	79%	79%	79%	79%	79%
17)	Modeled Net CONE (UCAP)	$/kW-yr	$620	$629	$645	$589	$600	$622

[63] Modeled net CONE (UCAP basis) estimate for co-located solar PV + storage represent the modeled net CONE per kW of accredited capacity of the co-located resource's total capacity (20 MW-ac ICAP).

7 Qualitative Evaluation Results

7.1 Summary of Qualitative Evaluation

This section performs the qualitative evaluation for all technologies across the five qualitative criteria. Overall, the results differentiate between technologies that are both widely deployable and structurally durable over time versus those whose economics and accredited capacity are more sensitive to evolving system conditions. The qualitative evaluation results are summarized in Table 63.

Table 63. Summary of Qualitative Evaluation Results by Technology

Candidate Technology	Feasibility-to-build	Speed-to-build	Market Representation	Forecasts Accuracy	Stability
Gas CT, Frame	High	Mid	High	High	High
Gas CT, Aero	High	Mid	High	High	High
Gas CCGT, F Class	High	Mid	High	High	High
Gas CCGT, H Class	High	Mid	High	High	High
4-hour Storage	High	High	High	Mid	Low
2-hour Storage	High	High	Mid	Mid	Low
Solar PV + Storage	High	Mid	High	Mid	Low
Coal ST	Mid	Low	Low	Mid	Mid

Across the gas technologies (both CT and both CCGT configurations), the qualitative results are consistently strong: these resources are assessed as highly feasible to build, well represented in observed developer behavior, and supported by comparatively high confidence in forecasts and stability over time. Their primary qualitative tradeoff is speed-to-build, where gas technologies generally have longer development and construction timelines than storage technologies.

Storage-based resources (4-hour storage, 2-hour storage, and solar PV + storage) perform well on feasibility-to-build and, in general, market representation (except for 2-hour storage). Storage also scores highest on speed-to-build given its shorter lead times relative to thermal resources. However, these technologies are assessed as relatively lower (Mid rating) on forecasts accuracy and stability, reflecting that both modeled E+AS margins and capacity accreditation for storage is more likely to change as the system evolves since it is more structurally linked to the portfolio mix, storage penetration, and annual and daily load profiles. Within the storage group, 2-hour storage is less aligned with observed MISO development than 4-hour configurations and therefore has a worse performance in this qualitative analysis.

Coal ST stands apart from the rest of the candidate set. While it remains technically feasible and dispatchable, it is assessed as less practical to develop at scale and materially slower to deliver than the other candidates, and it is not reflected in either recent build activity or near-term development pipelines. These factors, alongside greater exposure to evolving permitting, compliance, and financing conditions, result in the lowest qualitative score on aggregate relative to other candidate technologies.

Across the five qualitative criteria, the results point to a clear separation across technology types. **Gas CTs and gas CCGTs score consistently strong—high feasibility, strong market representation, and relatively high forecast accuracy and stability—making them the most "durable" reference technology candidates**, with speed-to-build as the main tradeoff. Storage-based technologies score well on feasibility and speed-to-build (and generally on market representation) but receive lower ratings on forecast accuracy and stability because their revenues and accreditation are more sensitive to evolving portfolio conditions and storage penetration, with 2-hour storage also less aligned with observed development in MISO. Coal ST is qualitatively less competitive overall due to weaker market representation and slower, higher-friction development characteristics.

The remainder of this section provides the supporting basis for each rating in Table 63. The following subsections discuss each criterion—feasibility-to-build, speed-to-build, market representation, forecasts accuracy, and stability—and document the evidence and rationale used to develop the qualitative results for each technology.

7.2 Feasibility-to-build

All candidate technologies in this study were pre-screened by MISO as commercially available options that can, under the right conditions, be sited, permitted, and constructed within the MISO footprint. The feasibility-to-build criterion therefore does not ask whether it is *possible* to build a technology but rather how readily each option can be deployed at scale. This metric highlights technologies that may face greater hurdles in siting, permitting, infrastructure, or financing.

Out of the candidates, coal ST may face additional obstacles to scale. Coal ST power plants are generally feasible to build in concept, but they face materially higher siting and permitting risk than most other candidates because they are large, stationary sources of criteria pollutants, such as sulfur oxides, nitrogen oxides, and particulate matter. In areas that already struggle to meet air-quality standards, permitting a new coal plant is typically much more difficult. Developers may be required to use the most stringent pollution controls and to secure "offsets" by reducing emissions elsewhere to make room for the new source, which can narrow siting options and extend schedules. Even in areas that meet air-quality standards, coal projects still face a detailed air-permitting review and modeling process to demonstrate they will not degrade local air quality, adding development risk. Beyond air emissions, coal projects must also address coal ash and other residuals handling and disposal, which can introduce additional site constraints and local permitting scrutiny. All these developmental hurdles lead this study to categorize coal ST as having a Mid feasibility-to-build rating.

7.3 Speed-to-build

Since a reference technology should be plausibly deployable on timelines that allow developers to respond to reliability needs and market entry signals, this criterion evaluates how quickly each candidate technology can be permitted, procured, constructed, and placed in service. To support a consistent comparison across technologies, this study relies on the "Total Lead Time Before Commercial Operation Date (COD)" reported in the EIA AEO 2025 capital cost study, which reflects representative greenfield project schedules including development, permitting, engineering, and construction.[64] While these lead time estimates are U.S.-wide and not specific to MISO, they provide a consistent, technology-comparable basis for assessing relative build timelines across the candidate set. These values are summarized in Table 64.

Table 64. Lead Time to Commercial Operations by Technology (US-wide, EIA AEO 2025)

Candidate Technology	EIA AEO Case	Total Lead Time to COD (months)	Speed-to-build
Gas CT, Frame	*CT, simple cycle (Case 4)*	40	Mid
Gas CT, Aero	*Aeroderivative CT, simple cycle (Case 3)*	40	Mid
Gas CCGT, F Class	*CC 2x2x1 (Case 5)*	42	Mid
Gas CCGT, H Class	*CC 2x2x1 (Case 5)*	42	Mid
4-hour Storage	*Battery energy storage system (Case 19)*	18	High
2-hour Storage	*Battery energy storage system (Case 19)*	18	High
Solar PV + Storage	*Solar PV (single-axis tracking) with DC-coupled storage (Case 18)*	36	Mid
Coal ST	*Ultra-Supercritical (USC) coal without Carbon Capture and Sequestration (CCS), greenfield (Case 1)*	60	Low

Across the candidate set, storage is the fastest to deliver. The EIA schedules indicate an 18-month total lead time for utility-scale storage, supporting a High speed-to-build rating for both the 2-hour and 4-hour configurations.[65] Co-located solar PV + storage has a longer, but still comparatively moderate, 36-month lead time, reflecting the added scope of the solar facility alongside storage.

Gas technologies generally fall in a similar timeline consistent with a Mid rating. Both frame and aero CT configurations show 40-month lead times, while the CCGT configuration is modestly longer at 42 months, consistent with the additional balance-of-plant and steam cycle scope.

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[64] U.S. Energy Information Administration, *Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies* (Washington, DC: U.S. Energy Information Administration, January 2024), PDF, accessed February 12, 2026, https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

[65] Note: The EIA study does not differentiate lead times of storage by duration.

Coal ST is shown to be the slowest technology to deliver, reflecting substantially longer development and construction schedules for a new greenfield coal facility relative to the other candidates; accordingly, coal is rated Low on speed-to-build.

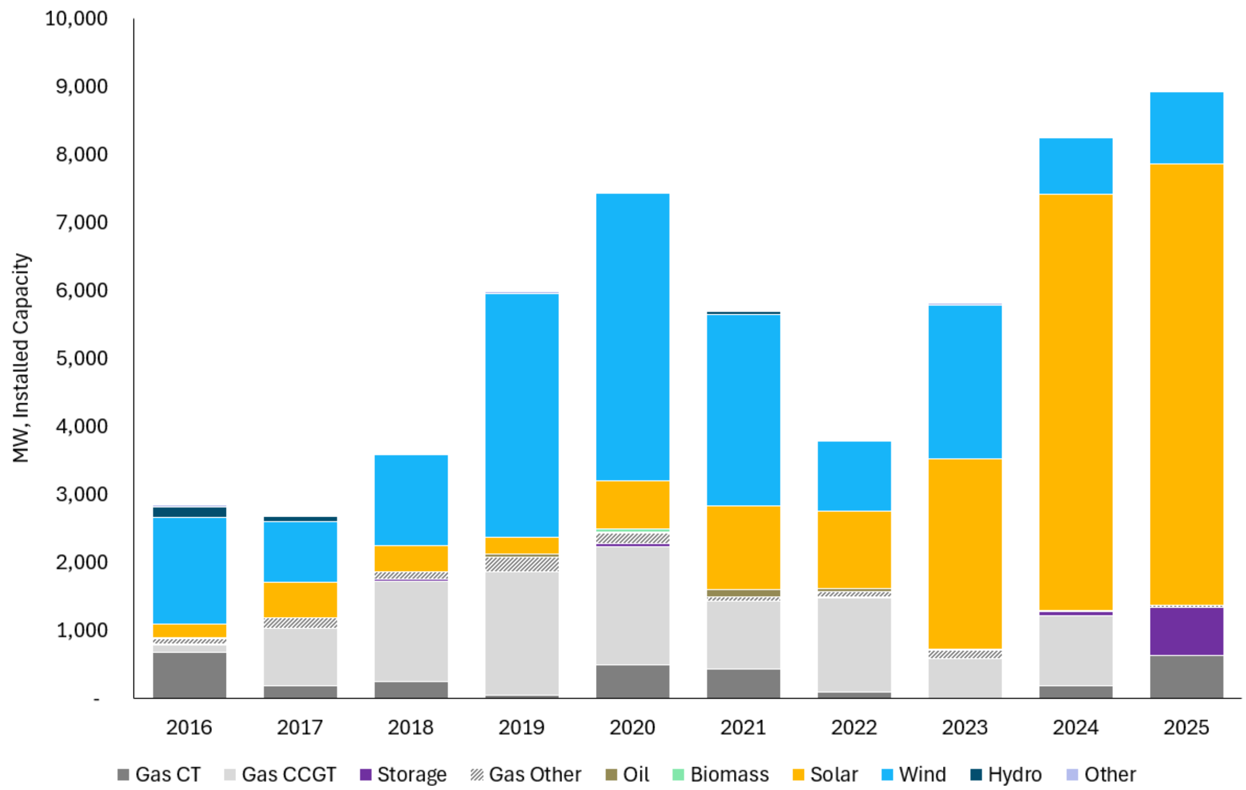
Finally, it is important to interpret these timelines as indicative and comparative, not precise forecasts of project delivery. Realized schedules can vary materially by site-specific permitting and interconnection conditions, as well as by broader factors, such as supply chain constraints or interconnection queue delays (more details in Section *Transient Conditions*). For this qualitative evaluation, the primary use is to distinguish technologies that can plausibly be delivered quickly—notably storage, and gas technologies to a lesser extend—from those with materially longer development horizons—notably coal.

7.4 Market Representation

This criterion confirms whether the candidate technologies evaluated in this study align with what developers are actually developing in MISO. Because resources can be developed for different objectives (e.g., energy value, renewable compliance, flexibility, or capacity value), this screen is not intended to imply that any technology being built is necessarily appropriate as a reference technology. Rather, it serves as a basic check that technologies lacking meaningful near-term development in MISO may be less suitable as reference technology candidates. Two complementary lenses are used to assess market representation: (1) recent historical capacity additions in MISO and (2) the mix of proposed near-term projects in MISO's generator interconnection queue.

Historical capacity additions in MISO between 2016 and 2025 (last 10 years) are shown in Figure 18. Conventional gas technologies (CT and CCGT) have been developed steadily over the decade, consistent with continued developer reliance on dispatchable thermal resources. Storage additions, all of 4-hour duration, increased sharply in 2025, exceeding 500 MW across MISO's footprint. By contrast, no new coal steam turbine capacity and no 2-hour storage additions are observed over this period. The data also shows substantial wind and solar additions; while a fraction of the solar additions may be paired with storage in co-located projects, the data does not distinguish between standalone or co-located solar capacity.

Figure 18. MISO Historical Capacity Additions by Technology and Year (2016-2025)[66]

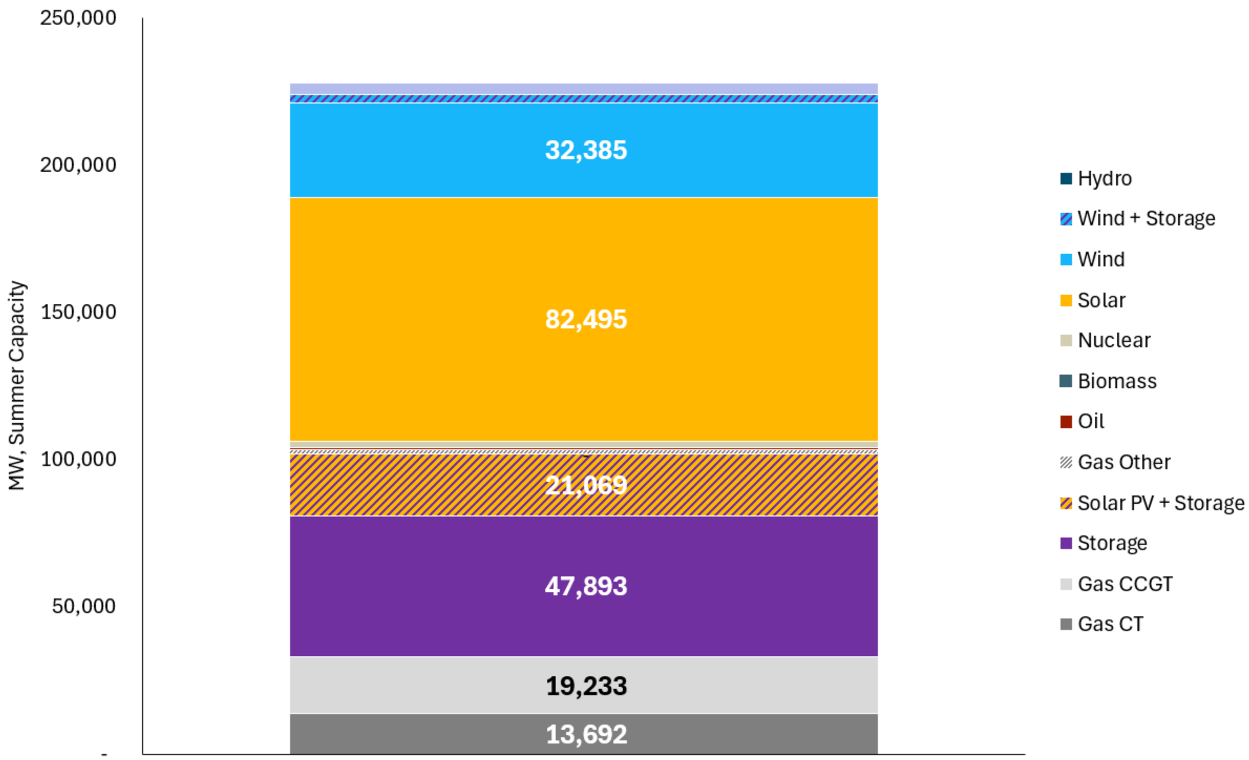


The forward-looking generation interconnection queue, as of February 6, 2026, is shown in Figure 19. The queue is dominated by solar, storage, and wind, gas CCGT, gas CT, and co-located solar PV + storage capacity. While interconnection queues typically overstate realized buildout (i.e., a subset of queued projects ultimately reach commercial operation), the queue remains a useful indicator of the relative mix of technologies the market is pursuing. Consistent with the historical record, the queue does not show any new coal capacity in the pipeline.

While MISO's interconnection queue data does not consistently report storage duration, it is reasonable to expect that most queued storage projects are 4-hour configurations (or longer), consistent with recent build trends. As discussed in Section *Capacity Accreditation (DLOL UCAP %)*, the capacity accreditation of storage is expected to decline over time as storage penetration increases and the system's highest-risk conditions shift toward longer-duration events; dynamics that increase the relative reliability value of longer-duration storage. Given that 4-hour systems represent the prevailing market baseline today, the queue is not expected to shift toward shorter-duration configurations, and the likely development of 2-hour storage projects is likely limited.

[66] S&P Global Market Intelligence, *Power Plant Summary* dashboard, S&P Global Market Intelligence platform [subscription database], accessed February 6, 2026. Figure by author.

Figure 19. MISO Generation Interconnection Queue Capacity (Summer MW) by Technology[67]



Taken together, the historical additions and interconnection queue indicate that gas CTs, gas CCGTs, 4-hour storage, and co-located solar PV + storage align with observed developer activity in MISO, which supports treating these technologies as more representative candidates for a reference technology framework. By contrast, the absence of observable new-build coal suggests this candidate is less representative of near-term marginal entry. Finally, while some 2-hour storage projects may be included in the queue, the lack of historical 2-hour storage additions, alongside the expected decline in capacity accreditation for shorter-duration storage resources, indicates a likely lower market representation for 2-hour storage in MISO.

7.5 Forecasts Accuracy

Forecasts accuracy reflects the ability to project each technology's E+AS margins and capacity accreditation over the study horizon. In particular, forecast accuracy for these metrics is impacted by uncertainty in the future resource portfolio and uncertainty in future costs.

Thermal technologies (both gas CTs, both gas CCGTs, and coal ST) have deep operating history and are widely represented in market and reliability models. While E+AS margins can vary with fuel prices, E+AS margins for these resources generally do not see significant changes due to changes to the

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[67] Midcontinent Independent System Operator, Inc. (MISO), *GI Interactive Queue*, accessed February 6, 2026, https://www.misoenergy.org/planning/resource-utilization/GI_Queue/gi-interactive-queue/. Figure by author.

portfolio mix. Similarly, while capacity accreditation values can vary with the portfolio mix, the interactions between thermal resources and non-firm resources (such as renewables and storage) are relatively limited, meaning these other resources scaling (or not) is likely to have limited impact on the capacity accreditation of thermal technologies.

E+AS margins for any resource—including thermal technologies—can be sensitive to the system's load-resource balance. In a capacity-short system, tighter conditions can materially increase scarcity conditions and E+AS margins, which in turn can push net CONE downward. For example, PJM's gas CCGT net CONE value was set to zero in the 2026/27 Base Residual Auction ("BRA"), driven by high expected E+AS margins. [68] However, this uncertainty is unlikely to be material for this assessment because this study assumes a system at target reliability (see Section *System Representation*).

Storage-based technologies (4-hour storage, 2-hour storage, and co-located solar PV + storage) have growing deployment and improving data availability, but forecasting future E+AS margins and capacity accreditation is more exposed to uncertainty around the future resource portfolio mix. In particular, both E+AS margins and accreditation for storage-forward resources can change materially as additional storage and variable generation enter the system, affecting price spreads, dispatch opportunities, and the duration and timing of critical periods that drive capacity accreditation. This sensitivity to evolving penetration and system conditions supports a Mid forecast-accuracy rating: forecasts are directionally informative, but more contingent on how the broader resource mix evolves than for mature thermal technologies.

7.6 Stability

Stability evaluates whether a technology can be suitable as a durable reference technology over time. That is, whether its quantitative evaluation criteria are likely to suggest that it may be an appropriate reference technology in the future. Technologies are considered more stable when their gross and net CONE on a UCAP basis is expected to maintain the same cardinal ordering relative to other technologies. Stability is lower when changes (e.g., such as penetration-driven saturation effects that depress E+AS margins or capacity accreditation) could alter a technology's costs, revenues, or accreditation relative to other resources.

The gas technologies (both gas CTs and gas CCGTs) are widely deployed in the MISO market. Their resource costs are relatively stable, although recent factors have increased costs along with all other resources (see Section *Transient Conditions*). These resources are less subject to future changes in E+AS margins and capacity accreditation due to the existing saturation of these resources. Additionally, the firm nature of these resources means both E+AS margins and capacity accreditation are less structurally exposed to saturation effects than other resource types (such as

[68] Brattle, *Sixth Review of PJM's Variable Resource Requirement Curve: For Planning Years 2028/29 Through 2031/32* (report prepared for PJM Interconnection, LLC, April 9, 2025), PDF, accessed February 12, 2026, https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250411-special/item-1-03-sixth-review-of-pjm-vrr-curve.pdf.

renewables and storage). This is because these units can sustain output across a broad range of hours and seasons, meaning it matters less when critical scarcity periods occur or the duration of these events. While their E+AS margins can still move with broader market fundamentals (e.g., fuel prices), the impact of these effects is limited (e.g., higher fuel prices increase both fuel costs and market revenues) and do not typically create abrupt, penetration-driven step changes in value. Taken together, these characteristics support a High stability rating for gas technologies.

Storage-based resources (2-hour storage, 4-hour storage, and solar PV + storage) face more pronounced long-term changes to costs, revenues, and capacity accreditation. Costs remain meaningfully influenced by policy and market structure (e.g., changes in tax credit availability under the assumptions applied in this study), which impacts gross CONE. In particular, battery gross CONE is expected to face a step increase in 2035 once ITC fully phases out.

E+AS margins for storage are structurally exposed to penetration effects: as additional storage enters, more projects compete for the same high-value energy arbitrage opportunities, narrowing price spreads and compressing margins over time. Capacity accreditation is also more sensitive to evolving system conditions because storage’s reliability contribution depends on the duration and timing of highest-risk periods. As risk shifts toward longer-duration critical events, driven both by shifting reliability risk into the winter and storage saturation, duration-limited resources are expected to see decreases in their capacity accreditation. Overall, these dynamics support a Low stability rating for storage-based resources.

Coal STs are dispatchable, which helps preserve E+AS and capacity accreditation value across a wide range system condition. However, the durability of these value streams can be more sensitive to operational and regulatory constraints that can limit dispatch over time. Additionally, coal’s long-run cost and operating outlooks are more exposed to structural shifts that can change relative attractiveness over time. Particularly, evolving air compliance expectations and retrofit requirements, siting and permitting friction, and financing constraints can materially affect project costs. These factors introduce greater potential for unexpected changes in costs, E+AS margins, or capacity accreditation and practical viability than for gas technologies, supporting a Mid stability rating for coal ST.

8 Sensitivity Analysis

8.1 Alternative Reference Technology Configurations for Fuel-supply Risk

As discussed in Section *Fuel-supply and Other Operational Risks*, fuel-supply and operational risks can materially affect both a resource's expected economics and its ability to perform when the system is under stress. In MISO's DLOL framework, where accredited capacity is tied to performance during the system's highest-risk conditions, fuel non-delivery can reduce a unit's capacity accreditation and, ultimately, increase its cone per UCAP MW.

While the study's core results model a standard frame natural gas combustion turbine (Gas CT, Frame) configuration, they do not determine which *specific* frame CT configuration is most appropriate, particularly with respect to fuel-supply risk mitigation. For tractability and comparability across candidates, this study's quantitative evaluation models a standard new-build frame CT configuration that does not include incremental upgrades intended specifically to reduce fuel-supply risk. However, because fuel-supply resilience can increase capacity accreditation, but at an incremental cost, it is appropriate to test whether a lower fuel-supply-risk frame CT configuration could be more cost-effective on a UCAP basis than the standard configuration used in the baseline analysis.

Accordingly, this subsection evaluates the modeled net CONE (UCAP basis) of three alternative frame CT configurations to determine which of the three is the least-cost frame CT configuration on a UCAP basis. These three configurations are:

+ **A standard frame CT**, already evaluated in the core part of this study;
+ **A frame CT with a firm fuel arrangement**, which has an annual firm-fuel contract to secure more reliable gas delivery; and
+ **A frame CT with dual-fuel capability (oil)**, including infrastructure to receive, storage, and utilize oil (e.g., on-site oil storage).

8.1.1 Fuel-risk Mitigation Benefit Modeling Approach and Assumptions

In this analysis, the primary value of fuel-supply risk mitigation is reflected through capacity accreditation (DLOL UCAP %). While enhanced fuel arrangements could also increase E+AS margins in certain scarcity conditions by enabling incremental run hours during scarcity, fuel-limited events, that upside is not expected to be fully captured in the modeled E+AS margins in this study. Modeled E+AS margins are derived from a deterministic production cost model under representative (median) conditions, which does not explicitly simulate tail-risk fuel non-delivery events or sustained gas curtailments. As a result, this subsection takes a conservative approach and **evaluates the alternative configurations primarily on the tradeoff between higher fixed costs and higher accredited capacity**, holding modeled E+AS margins constant across the three CT variants.

Additionally, a practical limitation is that MISO's RRA model does not explicitly model a frame CT with firm fuel arrangements or dual-fuel capability as distinct resource types. Therefore, the study applies a proxy approach to estimate the accreditation benefit of reduced fuel-supply risk. However, MISO's "Planning Year 2026-2027: Loss of Load Expectation Study", does model gas CTs and dual-fuel technologies separately.[69, 70] Therefore, this analysis utilized the uplift as a season-specific DLOL UCAP % multiplier to the baseline frame CT accreditation from the RRA report, which are calculated by dividing the "Dual Fuel Oil/Gas" DLOL UCAP % by those of "Gas". These seasonal DLOL UCAP % multipliers are:

- **Summer:** 0.97x
- **Fall:** 1.01x
- **Winter:** 1.06x
- **Spring:** 1.11x

These adjusted seasonal values are then levelized consistent with the methodology in Section *Capacity Accreditation (DLOL UCAP %)* to produce an updated levelized accreditation input for the firmed CT configurations.

This approach is intended to provide a transparent and internally consistent proxy for the reliability benefit of fuel-supply risk mitigation, while acknowledging that actual uplift may vary by site and contractual details and that firm fuel and dual-fuel configurations may not be perfectly equivalent in all stress conditions.

8.1.2 Fuel-risk Mitigation Cost Modeling Approach and Assumptions

The two additional gas frame CT configurations increase gross CONE through either incremental FO&M or capex required to mitigate fuel-supply risk. Specifically:

- **The frame CT with a firm fuel arrangement** is represented as an incremental FO&M cost associated with securing more reliable gas delivery (e.g., firm transportation and associated fixed reservation charges).
- **A frame CT with dual-fuel capability (oil)** is represented through (1) incremental capital costs to enable dual-fuel operation and fuel-handling systems and (2) fixed costs associated with maintaining on-site fuel inventory and associated equipment.

Annual firm natural gas contracting costs vary by pipeline operator and the specific pipeline(s) serving a plant. This study compiled representative firm gas capacity costs by region and by company/pipeline, which are shown in Table 65. The compiled values were averaged within each region to develop a rough regional estimate of firm gas capacity cost: $11.72/Dth-day-month for

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[69] Midcontinent Independent System Operator, Inc., *Planning Year 2026-2027 Loss of Load Expectation Study Initial Report* (PDF, accessed February 6, 2026), https://cdn.misoenergy.org/PY%202026-2027%20LOLE%20Study%20Report728909.pdf.

[70] Midcontinent Independent System Operator, Inc., *Planning Year 2026-2027 Indicative DLOL-Based Unforced Capacity and Planning Reserve Margin Requirement Results* (PDF, accessed February 6, 2026), https://cdn.misoenergy.org/PY26-27%20Indicative%20DLOL-based%20UCAP%20%20PRMR%20Results738545.pdf.

MISO North + Central and $6.77/Dth-day-month for MISO South (both in real 2026$). These costs are assumed to remain constant in real terms (i.e., escalate with inflation) and are levelized in the same manner as other FO&M components used to calculate Gross CONE.

Table 65. Sample of Firm Natural Gas Contract Reservation Charges in MISO

CONE Region	Pipeline / Company	Firm Gas Reservation Cost
		Real 2026$/Dth-day-month
North + Central	DTE Gas Company – Firm Transportation[71]	$14.33
	Natural Gas Pipeline Co. of America (NGPL) – FTS Peak (Iowa-Illinois → Market)[72]	$3.36
	Trunkline Gas Company (Energy Transfer) – Zone 2 Only[73]	$3.44
	Trunkline Gas Company (Energy Transfer) – Zone 1A Only[60]	$3.67
	Northern Natural Gas (NNG) – TF-12 Base (Summer)[74]	$16.26
	Northern Natural Gas (NNG) – TF-12 Base (Winter)[61]	$29.26
South	Enable Gas Transmission (Energy Transfer) – FT / FT-2[75]	$7.43
	Trunkline Gas Company – Field → Zone 1A[60]	$5.35
	Trunkline Gas Company – Field → Zone 1B Reservation[60]	$6.10
	Columbia Gulf Transmission – FTS-1-ELXP[76]	$6.06
	Columbia Gulf Transmission – FTS-1-GXP[64]	$8.91

For the incremental capex and fixed O&M (FO&M) of a dual-fuel (oil backup) gas CT capability, this analysis relies on two U.S. studies (not MISO-specific) that quantify the premium for both installing (capex) and operating (FO&M) dual-fuel plants relative to otherwise comparable gas-only CTs. The first study, published by Electric Power Research Institute ("EPRI"), indicates a 7.5% capex premium and a 4.3% FO&M premium, while the second study, a CONE study in PJM published by Brattle,

[71] DTE Gas Company, *Operating Statement* (November 21, 2024), https://www.dteenergy.com/content/dam/dteenergy/deg/website/common/about-us/company-information/dte-gas-company/DTEGasCoOperatingStatement.pdf.

[72] Natural Gas Pipeline Company of America LLC (NGPL), *FERC Gas Tariff, Eighth Revised Volume No. 1* (effective October 1, 2025), https://pipeline2.kindermorgan.com/Documents/NGPL/NGPL_EntireTariff.pdf.

[73] Trunkline Gas Company, LLC, *FERC NGA Gas Tariff, Fourth Revised Volume No. 1 (Part IV: Currently Effective Rates)* (effective May 10, 2025), https://fgttransfer.energytransfer.com/InfoPost/tariff/tg/TGCTariff.pdf.

[74] Northern Natural Gas Company, *Firm Reservation Interim Rates 01/01/2026–01/31/2026 (Subject to Refund)* (February 24, 2026), https://www.northernnaturalgas.com/Document%20Postings/Other_firm_reservation_202601.pdf.

[75] Enable Gas Transmission, LLC, *FERC NGA Gas Tariff, Tenth Revised Volume No. 1 (Part IV: Currently Effective Rates)* (March 1, 2023), https://pipelines.energytransfer.com/InfoPost/tariff/egt/CEGT-Tariff.pdf.

[76] Columbia Gulf Transmission, LLC, *FERC Tariff, Third Revised Volume No. 1 (Currently Effective Rates)* (effective March 1, 2024), https://hostedtariffs.com/cgt/pdf/tariff.pdf.

indicates a 7.3% CAPEX premium and a 4.8% FO&M premium.[77, 78] This study utilizes the average values for each metric in its analysis:

- **Dual-fuel CAPEX premium:** 7.4%
- **Dual-fuel FO&M premium:** 4.6%

These incremental costs are applied to the baseline frame CT gross CONE (ICAP basis), which is then converted to gross CONE and modeled net CONE (UCAP basis) using the same modeled E+AS margins and the adjusted accreditation described above.

8.1.3 Cost-benefit Results and Takeaways

This subsection evaluates whether configurations intended to mitigate fuel-supply risk, specifically (1) firm gas transportation and (2) dual-fuel capability with on-site oil backup, improve the UCAP-based economics of the standardd frame CT sufficiently to warrant selection as the reference configuration. The relevant comparison metric is modeled net CONE (UCAP basis), since the reference technology is intended to represent the lowest net cost source of accredited capacity. In each case, the analysis compares the incremental accreditation benefit (higher DLOL UCAP %) against the incremental fixed cost required to achieve that benefit.

For the firm gas case, the higher DLOL UCAP % provides a modest accreditation benefit, reducing modeled net CONE (UCAP basis) by $9/kW-yr in MISO North + Central and $8/kW-yr in MISO South. However, the incremental firm gas fixed cost addition increases modeled net CONE (UCAP basis) by $37/kW-yr in North + Central and $24/kW-yr in South. The net effect is an increase in overall UCAP-based modeled net CONE from $225 to $254/kW-yr (+12%) in North + Central and from $205 to $222/kW-yr (+8%) in South. As illustrated in Figure 20, the incremental UCAP accreditation benefit from firm gas is not large enough to offset the incremental fixed cost under the assumptions applied in this study.

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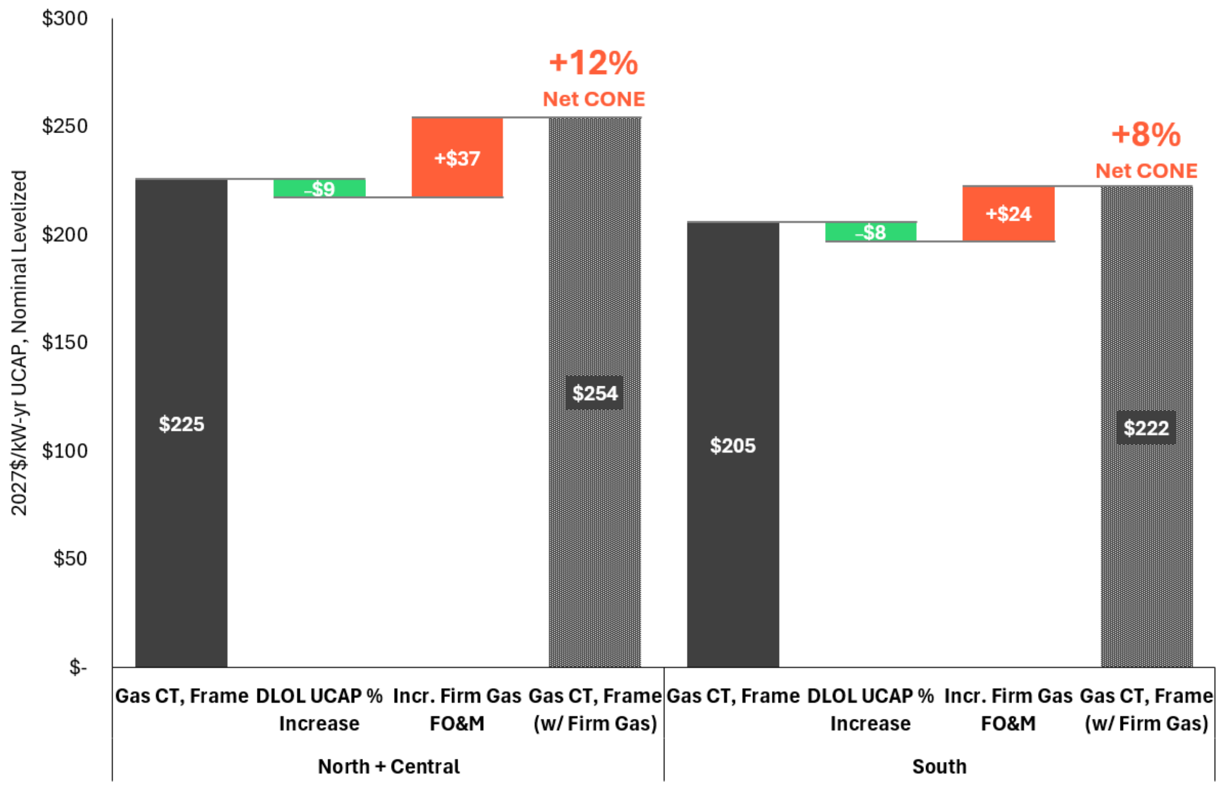
77 Brattle Group, *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM* (October 2017), https://www.brattle.com/wp-content/uploads/2017/10/6068_cost_of_new_entry_estimates_for_combustion_turbine_and_combined_cycle_plants_in_pjm.pdf.

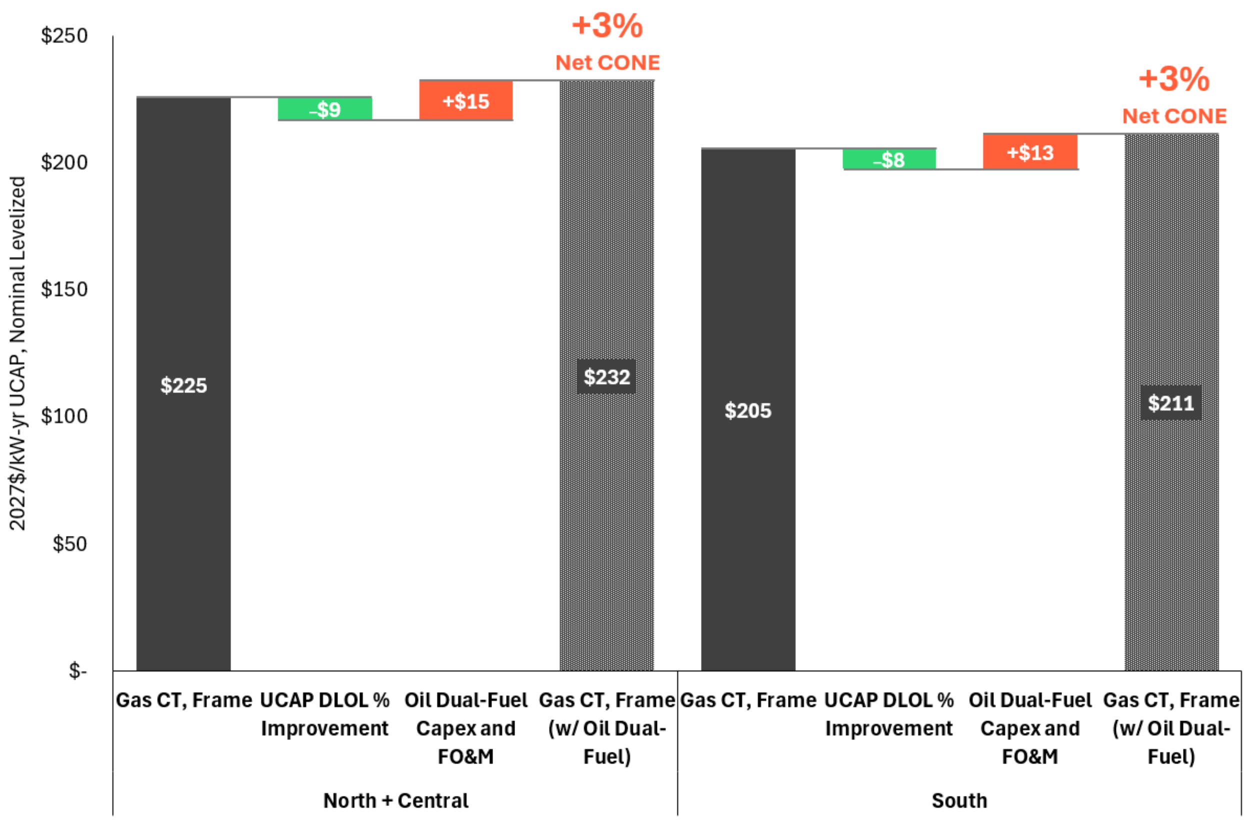
78 Electric Power Research Institute (EPRI), *Conversion to Dual Fuel Capability in Combustion Turbine Plants: Addition of Distillate Oil Firing for Combined Cycles* (September 2001), Report No. 1004599.

Figure 20. Cost-benefit Analysis Comparing Modeled Net CONE Gas CT, Frame with and without Firm Gas Contract



The dual-fuel configuration similarly improves DLOL UCAP %, producing the same order-of-magnitude accreditation benefit as firm gas: a modeled net CONE (UCAP basis) reduction of $9/kW-yr in North + Central and $8/kW-yr in South. The incremental capex and FO&M for oil dual-fuel capability increases modeled net CONE (UCAP basis) by $15/kW-yr in North + Central and $13/kW-yr in South. On net, the dual-fuel configuration increases UCAP-based modeled net CONE from $225 to $232/kW-yr (+3%) in North + Central and from $205 to $211/kW-yr (+3%) in South, as shown in Figure 17. While the UCAP benefit partially offsets the added fixed cost, the dual-fuel option remains incrementally higher cost on a UCAP-adjusted basis.

Figure 21. Cost-benefit Analysis Comparing Modeled Net CONE Gas CT, Frame with and without Oil Dual-Fuel Capability



Taken together, these results show that, in both MISO North + Central and MISO South, the incremental UCAP accreditation benefit associated with fuel-supply risk mitigation does not fully offset the incremental fixed cost required to achieve that benefit. Accordingly, **the standard gas frame CT configuration (without firm gas contract and without backup fuel capability) remains the lowest-cost source of accredited capacity (lowest UCAP-based modeled net CONE) among the frame CT configurations evaluated for both regions**.

Appendix: Overview of E3 RECOST

A.1. Overview of E3 RECOST

Since 2010, E3 has regularly created and released formal public databases and calculations of levelized costs for its clients. In the Western U.S., E3 analysis of resource costs has supported public planning processes of the Western Electricity Coordinating Council (WECC) Transmission Expansion Planning and Policy Committee and the California Public Utilities Commission, for example. This analysis is conducted through E3's in-house analytical tool, known as RECOST.

RECOST is a discounted cash flow model used to calculate the levelized costs of different candidate resources. Given a set of technology- or project-specific assumptions for system performance and operations, upfront and ongoing costs, and financing parameters, RECOST computes levelized cost metrics, such as the gross CONE ($/kW-yr ICAP) and levelized cost of electricity ("LCOE", $/MWh), as well as implied flat nominal PPA prices in $/MWh.

The technologies modeled in RECOST include, but are not limited to:

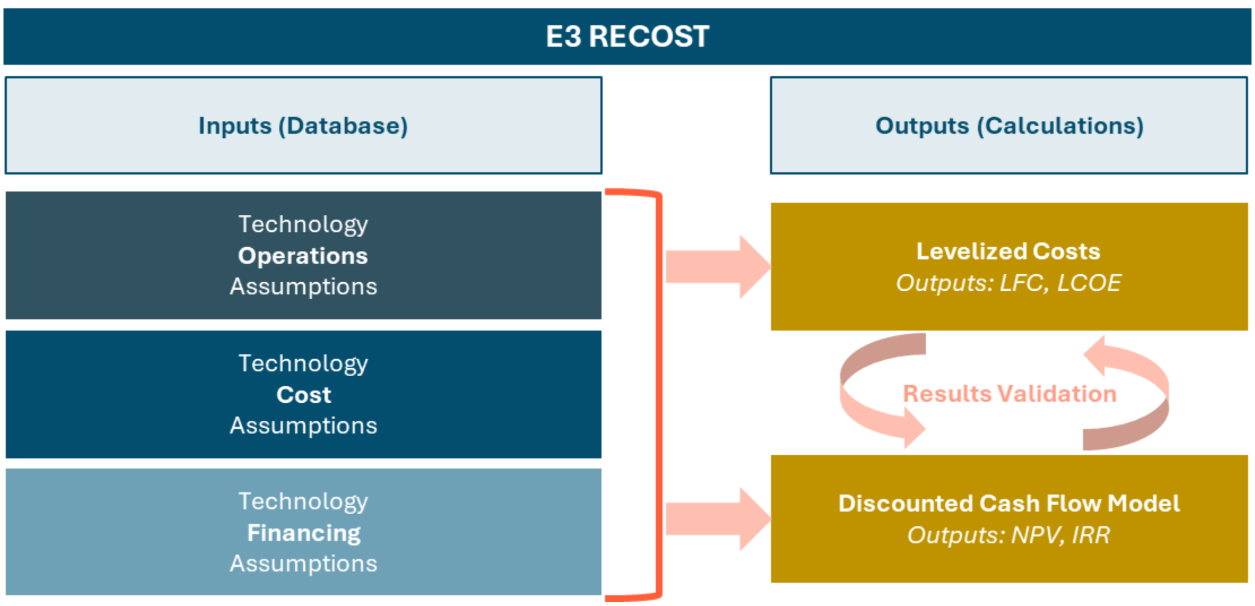
+ Utility-scale solar photovoltaic (PV) systems
+ Commercial and residential behind-the-meter (BTM) solar PV
+ Onshore wind
+ Offshore wind (fixed-bottom and floating)
+ Utility-scale lithium-ion battery storage
+ Behind-the-meter (BTM) lithium-ion battery storage
+ Long-duration energy storage (LDES) technologies
+ Pumped storage hydro
+ Geothermal
+ Biomass
+ Natural gas combustion turbines (CT), combined cycle gas turbines (CCGT), and reciprocating internal combustion engines (RICE)
+ CCGT units equipped with carbon capture and storage (CCS), including new builds and retrofits
+ Hydrogen production, storage, transport, and conversion, including CCGTs, CTs, and fuel cells
+ Nuclear small modular reactor (SMR) and pressurized water reactor (PWR) units

Gross CONE is calculated for each technology and COD vintage, from 2026 through 2050. The components included in Gross CONE capex, including interconnection and interest accrued during construction; FO&M, including site control, property taxes, system warranties, and repowering and augmentation costs; the federal ITC, where applicable; and financing costs (including investor returns on a project). Levelized costs metrics, reported as both real-levelized and nominal-levelized totals, are calculated using a discount rate equal to the cost of equity.

RECOST primarily leverages public data sources such as the National Renewable Energy Laboratory (NLR) Annual Technology Baseline (ATB); U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO); the Pacific Northwest National Laboratory (PNNL) Energy Storage Cost and Performance Database, developed in support of the Department of Energy (DOE) Energy Storage Grand Challenge (ESGC); and the Lazard Levelized Cost of Energy+, all of which provide location-agnostic technology cost data.

E3 performs extensive benchmarking and analysis of these costs to produce custom cost trajectories for utility-scale solar PV, onshore wind, and Li-ion batteries. Financing assumptions are developed by E3 for use in the cash flow analysis and cost levelization calculations. Regional adjustments are also made to reflect state-specific cost conditions for each resource, including labor, site control, and interconnection. RECOST's model structured is shown in Figure 22. Details on E3 cost assumptions are discussed in the following sections.

Figure 22. Model Structure of E3 RECOST

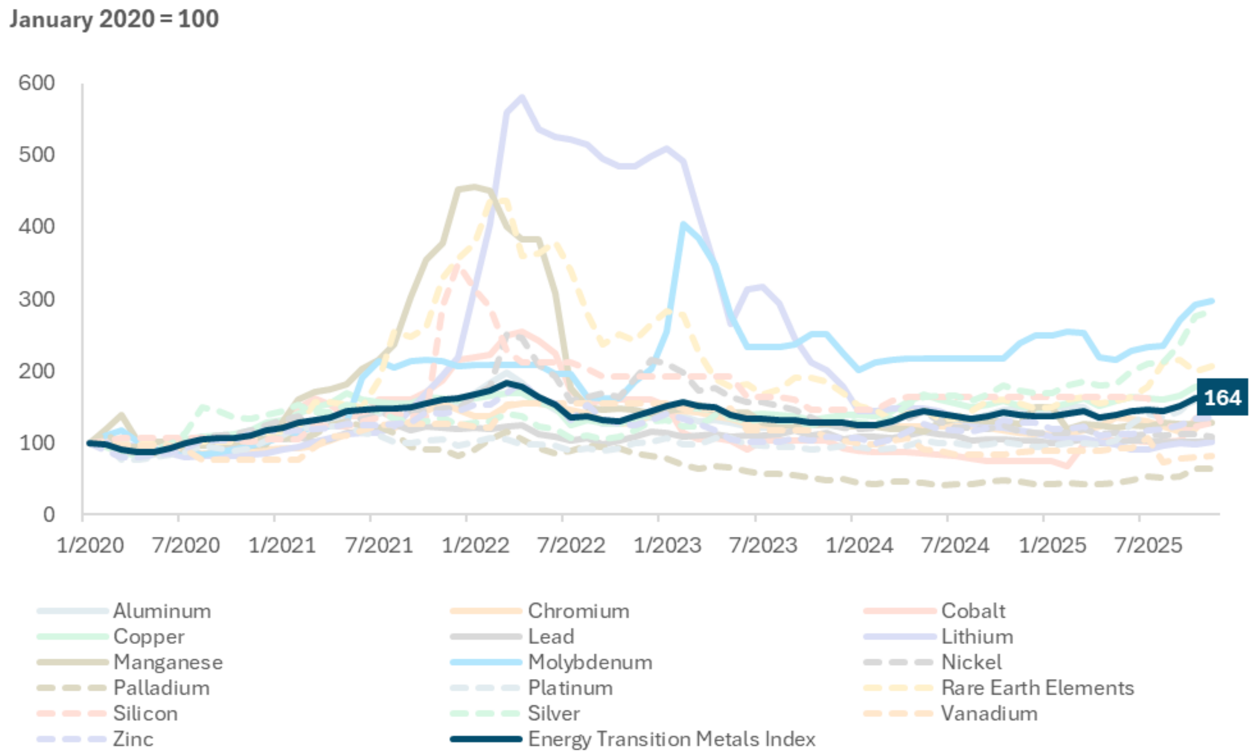


Factors Affecting Resource Costs

Between 2020 and 2024, supply chain issues, higher interest rates, inflationary pressures, and other market impacts attributable to the COVID-19 pandemic resulted in observed cost shocks for certain renewable technologies—most notably onshore wind, offshore wind, solar, and lithium-ion (Li-ion) batteries.

Cost pressures have manifested through multiple vectors. One example is the changes in the primary commodities used for new resources, as shown in Figure 23. The International Monetary Fund's Primary Commodity Price System (PCPS) tracks commodity prices globally, inclusive of "energy transition metals" that include aluminum, copper, lithium, and silicon, among others. Since January 2020, the IMF's energy transition metals index has risen 64%, driven primarily by lithium used in battery storage resources and molybdenum used in new solar, wind, and hydrogen-based electricity generation and storage applications in addition to having general electronics applications.

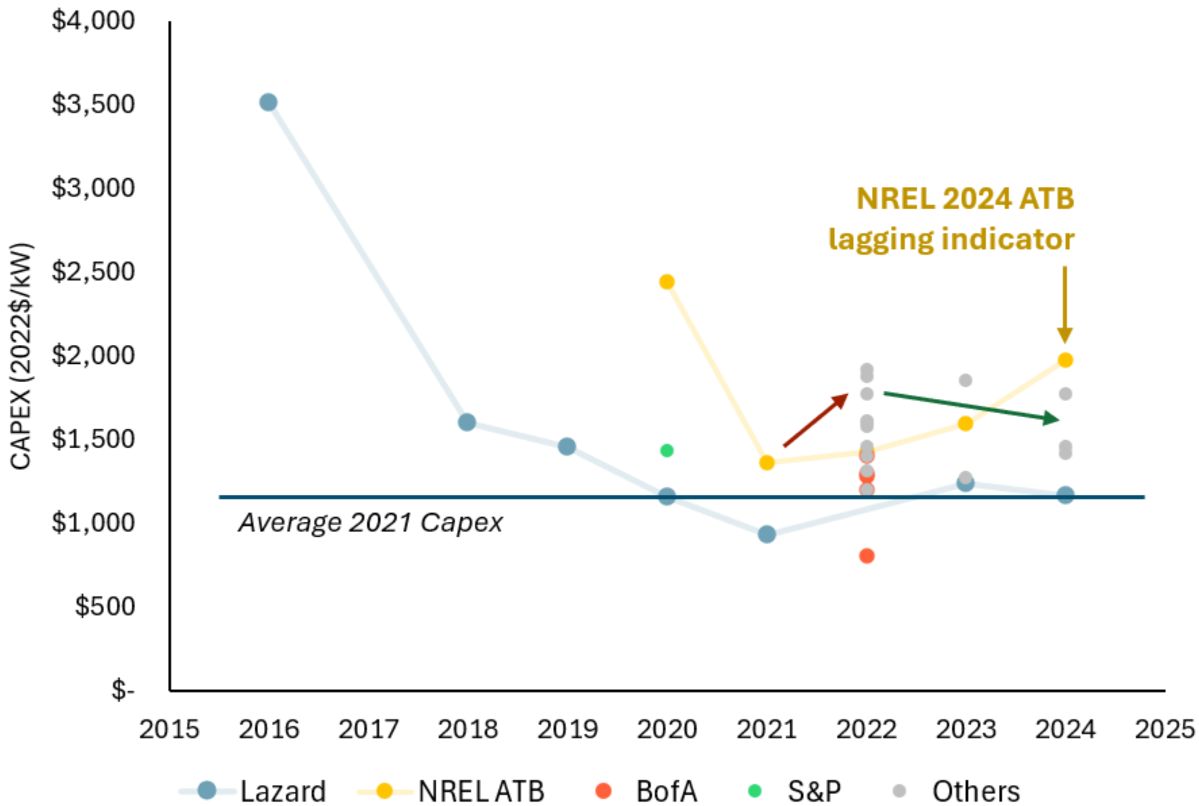
Figure 23. Primary Commodity Prices for Reference Technologies



There has been observable relaxation of supply chain constraints and moderation of inflation trends, but the impact and durability of these developments on longer-term costs is still unclear. Reports from NLR, Lazard, S&P, BofA Securities, and others[79] suggest that estimates for 4-hour battery storage system costs increased at the start of the pandemic and remained elevated through 2023, as shown in Figure 24. NLR ATB and Lazard reported 22% and 35% real cost increases between 2021-2023, respectively. Early market data from 2024, however, suggests that costs did begin to moderate slightly, with Lazard reporting an 8% decrease and other reports showing similar declines. Notably, NLR 2024 ATB continues to rely on cost estimates from 2023, making this data source a lagging indicator of market costs.

[79] Additional sources include Wood Mackenzie, Bloomberg New Energy Finance, and Brattle.

Figure 24. Historical 4-hour Li-ion Capex by Installation Year and Data Source



In RECOST, market data from the most recent available industry reports for solar, onshore wind, and Li-ion batteries are used to benchmark resource costs. The passing of the Inflation Reduction Act (IRA) spurred a short-term increase in demand for clean energy technologies and may underpin long-term deployment and cost declines for technologies like storage, but impacts on resources like photovoltaic solar have been mitigated or reversed by 2025 policy actions.

E3 Approach and Key Assumptions

RECOST reflects E3's latest views on technology costs, including Capex, FO&M, interconnection, tax credit incentives, and financing assumptions. E3 has developed unique cost forecasts to reflect current market conditions and feedback from market participants. E3's adjustments are as follows:

1. Benchmark current-year solar, wind, and Li-ion battery Capex to recent market reports, developing a spread in current-year estimates
2. Develop custom cost trajectories that reflect variability in forecasts
3. Use E3 market-derived financing assumptions for cost of debt, cost of equity, and WACC
4. Assume IRA tax credit phase-out between 2045-2048
5. Implement state-specific cost multipliers for Capex, FO&M, and interconnection

Recent Year Capex Benchmarking

E3 surveyed recent market data and industry reports to develop estimates for current-year resource Capex for solar PV, onshore wind, and Li-ion batteries. The data sources and published years are listed in Table 66.

Table 66. Data Sources Used for Capex Cost Benchmarking Analysis

Publication Name	Publication Year	Benchmarked Technologies
National Renewable Energy Laboratory (NLR) Annual Technology Baseline (ATB)[80]	2024	Utility Solar, Land-Based Wind, Li-ion Battery
U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO)[81]	2023	Utility Solar, Land-Based Wind, Li-ion Battery
Lazard's Levelized Cost of Energy+ (LCOE+)[82]	2024	Utility Solar, Land-Based Wind, Li-ion Battery
Electric Power Research Institute (EPRI) Program on Technology Innovation: Generation Technology Options[83]	2024	Utility Solar, Land-Based Wind, Li-ion Battery
Solar Energy Industries Association (SEIA) Solar Market Insight Report[84]	2024	Utility Solar
Lawrence Berkeley National Lab (LBNL) Land-Based Wind Market Report [85]	2024	Land-Based Wind
Pacific Northwest National Laboratory (PNNL) Energy Storage Cost and Performance Database[86]	2024	Li-ion Battery

An example of the benchmarking analysis results is shown in Figure 25. Additional benchmarking results are available in the public RECOST materials.

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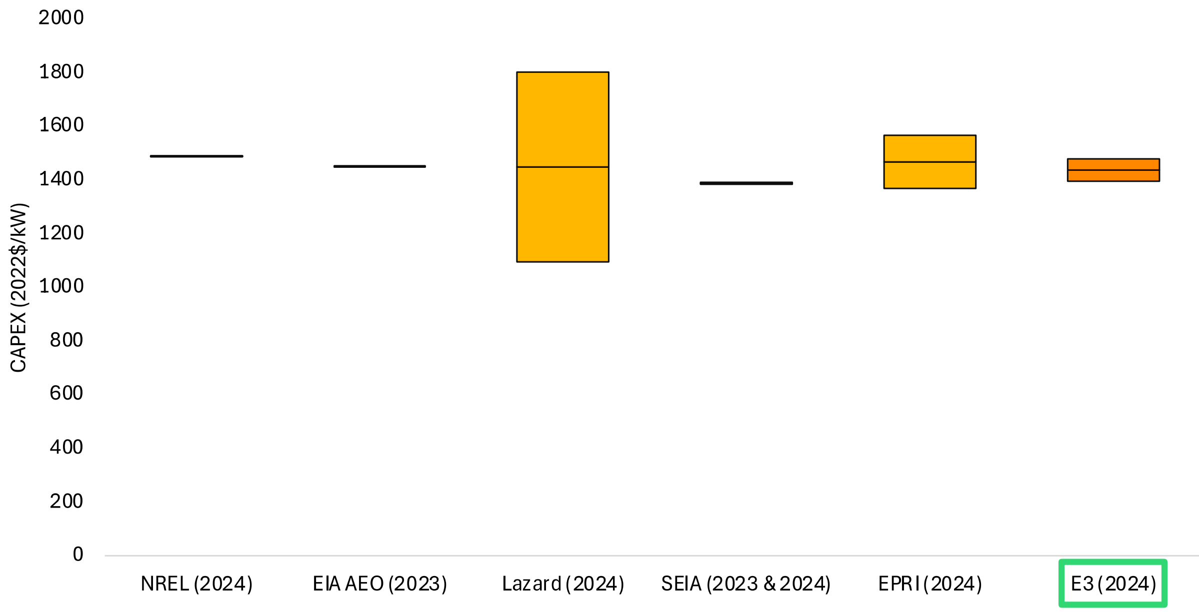
[80] National Renewable Energy Laboratory, *2024 Electricity ATB Technologies* (Annual Technology Baseline), accessed February 6, 2026, https://atb.nrel.gov/electricity/2024/technologies.
[81] U.S. Energy Information Administration, *Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2023*, March 2023, https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf.
[82] Lazard, *Levelized Cost of Energy+*, June 2024, https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf.
[83] Electric Power Research Institute (EPRI), *Program on Technology Innovation: Generation Technology Options: 2024* (Palo Alto, CA: EPRI, July 2024), https://www.epri.com/research/sectors/technology/results/3002029428.
[84] Solar Energy Industries Association (SEIA) and Wood Mackenzie, *Solar Market Insight Report Q2 2024*, June 5, 2024, accessed February 6, 2026, https://seia.org/research-resources/solar-market-insight-report-q2-2024/.
[85] Lawrence Berkeley National Laboratory, *Land-Based Wind Market Report: 2024 Edition*, August 2024, accessed February 6, 2026, https://emp.lbl.gov/publications/land-based-wind-market-report-2024.
[86] Pacific Northwest National Laboratory, *Energy Storage Cost and Performance Database*, accessed February 6, 2026, https://www.pnnl.gov/projects/esgc-cost-performance.

Figure 25. Example of Recent Year Cost Benchmarking for Utility Solar



Cost Trajectory Forecasts

E3's cost trajectories are informed by NLR ATB and E3 input on expected industry learning rates. For most technologies, the trajectories reported by NLR ATB are used. For utility-scale solar PV, onshore wind, and Li-ion batteries, new trajectories were developed. Costs are analyzed in nominal dollars to understand the actual costs that would be paid for resource procurement. High and Low trajectories (forecasts expressed as percentages) are developed and applied to the benchmarked initial-year Capex values to produce a range of expected cost projections. These forecasts reflect a likely range of future costs, but they are not designed to capture all future scenarios with full confidence. A Mid scenario forecast is presented as the average between the High and Low scenarios.

Market-Based Financing Costs

The cost of capital assumption has meaningful impact on levelized cost: a 1% increase in the weighted average cost of capital (WACC) can raise the LCOE for a clean energy technology by more than 10%. Thus, E3 has developed market-based financing assumptions to ensure that the WACC accurately reflects current market conditions and expected ranges of risk. WACC is calculated based on the cost of debt, debt fraction, cost of equity, and effective tax rate for a given state.

E3 developed both near-term and long-term cost of debt forecasts based on market data in the most recent four quarters of trading days. The spread of debt cost rates is approximated using borrowing rates captured by the Bank of America US Corporate Index Effective Yield.[87] The long-term rates were

[87] Federal Reserve Bank of St. Louis, *Federal Reserve Economic Data (FRED), ICE BofA Single-A US Corporate Index Effective Yield*, accessed February 6, 2026, https://fred.stlouisfed.org/series/BAMLC0A3CAEY.

adopted from the U.S. Treasury 10-Year Par Yield Curve, with the spread from current rates maintained. The debt fraction is taken from NLR ATB.

The cost of equity was determined via the Capital Asset Pricing Model (CAPM). Distinct ranges of WACC values were developed for three risk categories (i.e., conventional/low risk, moderate risk, and emerging/higher risk technologies), as shown in Table 67.

Table 67. Risk Levels for Selected technologies

Technology	Type	Risk Category
Wind	**Onshore**	Low
Wind	**Offshore**	High
Solar	**Utility PV**	Low
Geothermal	**Hydro, Binary**	Mid
Gas	**CT, Frame**	Low
Gas	**CCGT**	Low
Biopower	**Dedicated**	Mid
Li-ion Battery	**Utility Standalone**	Mid
Pumped Hydro	**New Reservoir**	High

Tax Credit Phase-Out

The FY2025 Budget Reconciliation Bill (also known as “the One Big Beautiful Bill Act” or OBBBA) modified the investment and production tax credits previously made available to new clean energy resources under the 2022 Inflation Reduction Act (IRA). Under the OBBBA, E3 does not expect any new solar PV resources to be able to claim investment or production tax credits beyond a COD year of 2030, assuming current safe harbor guidelines remain in place. Any storage beginning construction by the end of the calendar year 2032 are eligible to claim the full value of the ITC. After this year, the value of the ITC steps down over a three-year phase-out period. Assuming current safe harbor guidelines remain in place, this may allow storage assets to claim the full value of the ITC through 2036.