May 1, 2025

Kansas Corporation Commission
1500 SW Arrowhead Rd.
Topeka Kansas 66615

Re: 24-EKCE-387- CPL - In the Matter of the Triennial Compliance Docket for the Integrated Resource Plan of Evergy Kansas Central, Inc. & Evergy Kansas Metro, Inc. Pursuant to the Commission's Order in Docket No. 19-KCPE-096-CPL

To Whom it Concerns:

Evergy Kansas Central Inc., Evergy Kansas South, Inc. (together, "Evergy Kansas Central") and Evergy Kansas Metro, Inc. (Collectively, "Evergy") respectfully submit with this letter information in compliance with the Commission's Order pertaining to the 2025 Annual Update Integrated Resource Plan (IRP) filing.

Evergy's respective IRP contains information that has been designated "Confidential" and should be treated accordingly.

In addition to undersigned counsel, please direct communications regarding these dockets to:

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If you have any questions or concerns, please do not hesitate to contact me.

Respectfully submitted,

Cathryn Dinges

Cathryn Dinges
Sr Director & Regulatory Affairs Counsel

Evergy Kansas Central

2025 Annual Update

Integrated Resource Plan

May 2025

Public

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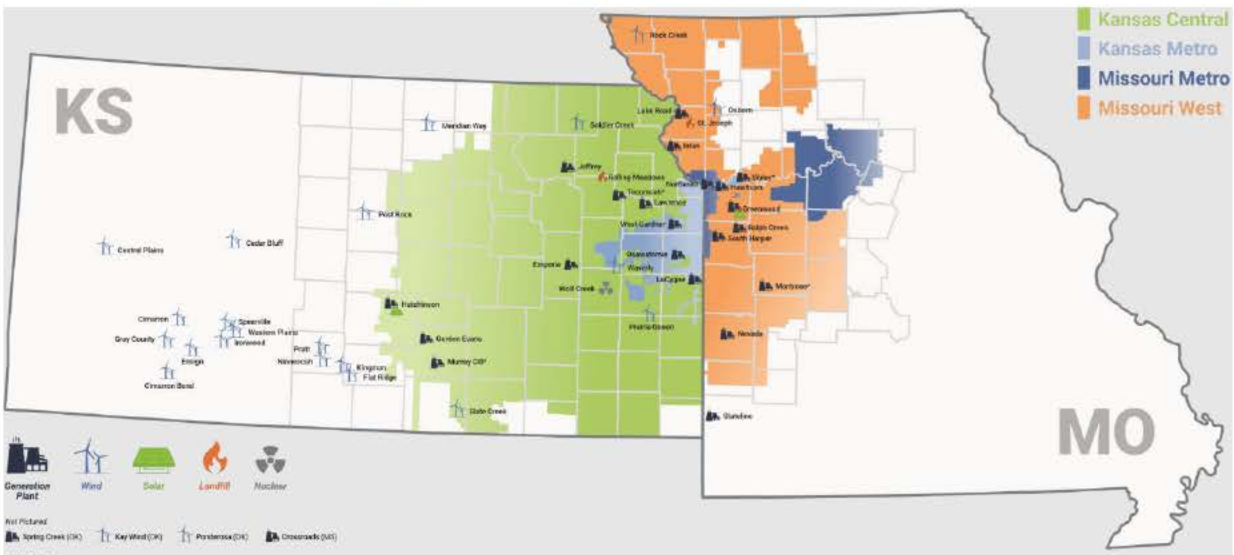
Section 1: Executive Summary

1.1 Utility Introduction

Evergy Kansas Central (or "Company") is an integrated, mid-sized electric utility serving customers in the eastern third of Kansas including the cities of Wichita, Topeka, and portions of the Kansas City metropolitan area. A map of the Evergy service territory which includes Evergy Kansas Central and Evergy Metro is provided in Figure 1 below.

Figure 1: Evergy Service Territory



Evergy Kansas Central is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. The Table below provides a snapshot of the numbers of customers served, retail sales, and peak demand based upon 2024 data.

Table 1: 2024 Customers, Retail Sales, and Peak Demand

Jurisdiction	Number of Retail Customers	Retail Sales (MWh)	Net Peak Demand (MW)
Evergy Kansas Central	743,720	19,362,562	5,319

Evergy Kansas Central (EKC) owns and operates a diverse generating portfolio and Power Purchase Agreements (PPA) to meet customer energy requirements. The Table below reflects Evergy Kansas Central's generation assets including PPAs.

Table 2: Capacity and Energy by Resource Type

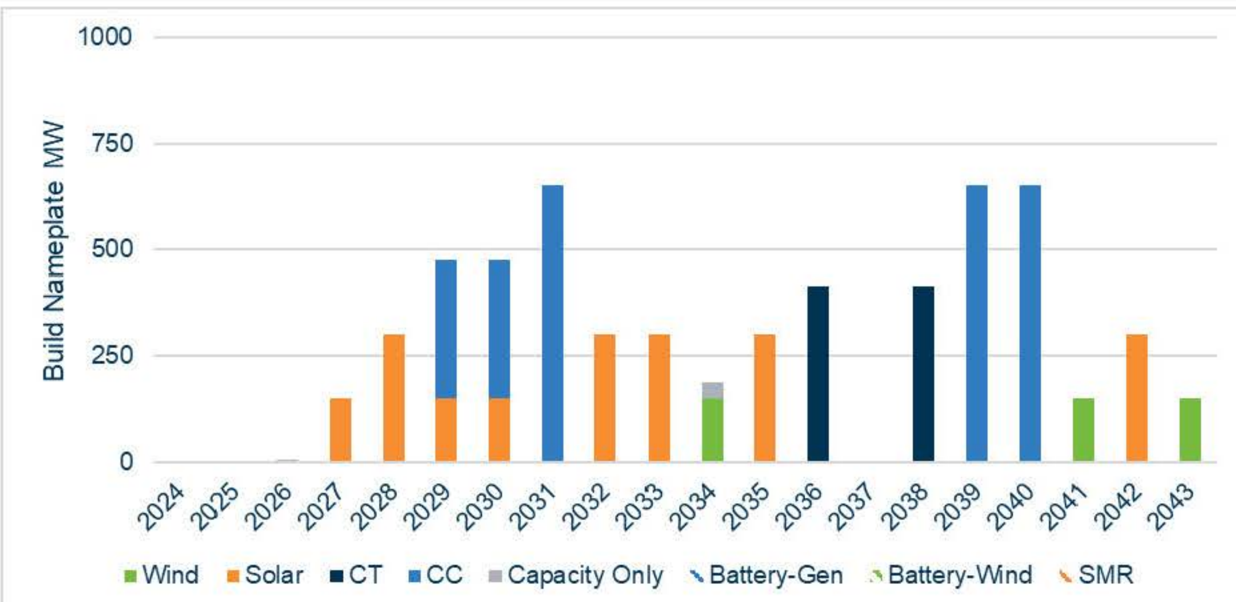
Jurisdiction	Capacity by Fuel Type	Capacity (MW)	Capacity (%)	Energy (MWh)	Energy (%)
Evergy Kansas Central	Coal	3,206	40.8%	8,761,927	39.3%
	Nuclear	553	7.0%	4,324,604	19.4%
	Natural Gas/Oil	1,690	21.5%	2,996,397	13.4%
	Renewable*	2,416	30.7%	6,226,472	27.9%
	Total	**7,865**	**100.0%**	**22,309,400**	**100%**

**Nameplate renewables capacity*

1.2 Preferred Portfolio Filed in the 2024Triennial IRP

Evergy Kansas Central submitted its 2024 Triennial IRP filing on May 17, 2024.[1]

Figure 2: Evergy Kansas Central 2024 Preferred Portfolio AAAB



[1] 24-EKCE-387-CPL

The Preferred Portfolio included building or acquiring new resources including 150 MW of solar in 2027, 300 MW of solar in 2028, 150 MW of solar and 325 MW of combined cycle builds in both 2029 and 2030, and 650 MW of combined cycle build in 2031. Coal generator retirements were anticipated to occur in December 2028 for Lawrence 4, and December 2030 for Jeffrey 2 & 3. Lawrence 5, although not shown in the Figure above, was expected to cease coal operation and fully operate on natural gas beginning in 2029.

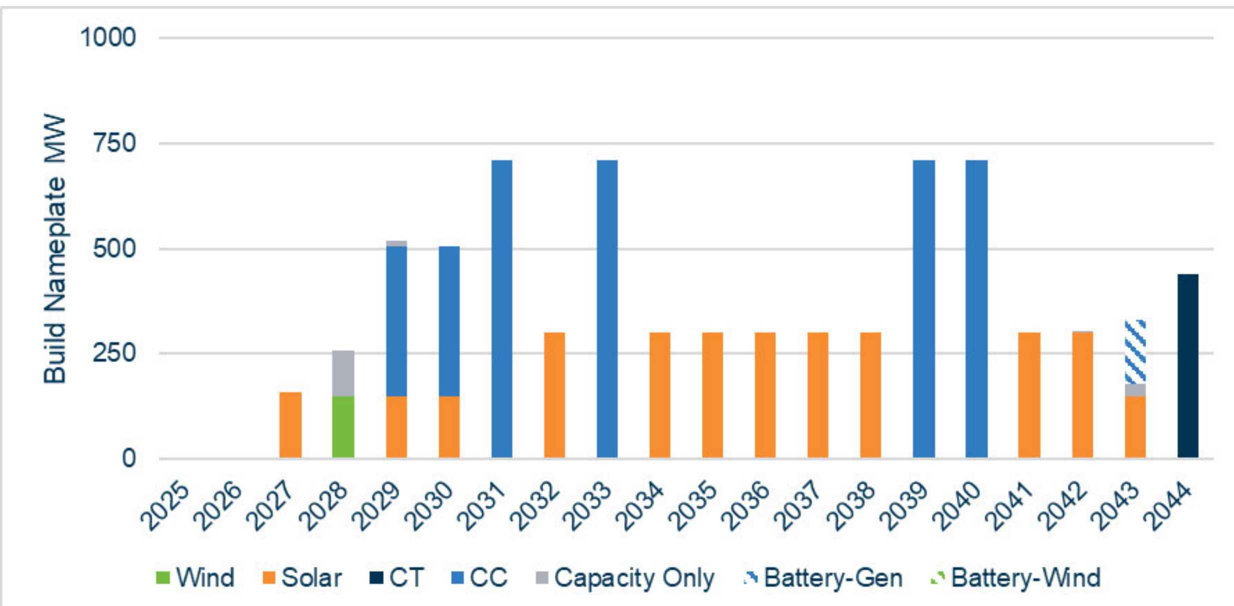
1.3 Changes to the Preferred Portfolio for the 2025 Annual Update

This year's 2025 Annual Update shows increasing needs for Evergy Kansas Central driven by higher large customer load growth expectations. The 2025 Preferred Portfolio ACAA calls for similar resource build through 2031 – including solar in 2027, solar and ½ share of combined-cycle gas turbine resources in 2029 and 2030, and a full CCGT in 2031. The 300 MW of solar in 2028 in the 2024 Preferred Portfolio is substituted for 150 MW of wind and market capacity in the 2025 Preferred Portfolio. Higher customer needs pulled forward the next thermal resource build to 2033 (from 2036 in the 2024 Preferred Portfolio).

As part of a long-term strategy and planning assumption for the Jeffrey Energy Center site, Evergy Kansas Central is planning to fully convert Jeffrey 2 to natural gas operation in 2030 rather than retiring the resource, as was planned in the 2024 IRP. By 2030, the Jeffrey units will be an average age of approximately 50 years. Given the age and condition of the Jeffrey units, increasing importance of reliability for future performance accreditation, broader headwinds to the fuel supply and coal industry supply chain, and future environmental regulation risk, Evergy feels it's important to have a pragmatic long-term plan that balances customer risks and trade-offs of retirement. While the retirement planning assumptions in Evergy's IRP will remain flexible, delaying the Jeffrey 2 retirement and fully converting to natural gas operations will help Evergy to balance the on-going operational risk, while preserving capacity to meet increased customer demand and reliability requirements of the Southwest Power Pool. Additionally, converting to a natural gas fuel source avoids the potential need for future selective catalytic reduction (SCR) investment and natural gas is a is a viable solution to meeting potential future federal carbon reduction compliance requirements. Evergy expects the Jeffrey site will be a prime location for future new natural gas assets as the existing coal facilities are retired. Therefore, building the gas infrastructure will not only enable the conversion for Jeffrey 2, but also deliver valuable flexibility and optionality for customers over the long-term.

Additionally, Evergy Kansas Central expects to postpone the Lawrence 4 retirement from 2028 to 2032 and operate the resource on natural gas from 2029-2032. Evergy Kansas Central continues to plan for natural gas operation at Lawrence 5 beginning in 2029, however, due to the age and condition of the resource, it is expected to retire at the end of 2032 with Lawrence 4.

Figure 3: Evergy Kansas Central 2025 Preferred Portfolio ACAA



The 2025 Preferred Portfolio also reflects the demand-side programs consistent with the current KEEIA approved programs.

Table 3: Evergy Kansas Central Preferred Portfolio Comparison

Note: All retirement dates were assumed to be end of year for 2024 Triennial, but end of winter season for 2025 Annual Update.

	2024 Triennial IRP	2025 IRP Annual Update
Retirements	Lawrence 4 in 2028 Lawrence 5 to NG in 2029 Jeffrey 2 in 2030 Jeffrey 3 in 2030 La Cygne 1 in 2032 La Cygne 2 in 2039 Jeffrey 1 in 2039	Jeffrey 2 to NG in 2030 Jeffrey 3 in 2030 Lawrence 4 in 2032 Lawrence 5 in 2032 La Cygne 1 in 2032 La Cygne 2 in 2039 Jeffrey 1 in 2039
Wind Additions	150 MW in 2034 150 MW in 2041 150 MW in 2043	150 MW in 2028
Solar Additions	150 MW in 2027 300 MW in 2028 150 MW in 2029 150 MW in 2030 300 MW in 2032 300 MW in 2033 300 MW in 2035 300 MW in 2042	150 MW in 2027 150 MW in 2029 150 MW in 2030 300 MW in 2032 300 MW in 2034 300 MW in 2035 300 MW in 2036 300 MW in 2037 300 MW in 2038 300 MW in 2041 300 MW in 2042 150 MW in 2043
Battery Additions	n/a	150 MW in 2043
Thermal Additions	325 MW CC in 2029 325 MW CC in 2030 650 MW CC in 2031 415 MW CT in 2036 415 MW CT in 2038 650 MW CC in 2039 650 MW CC in 2040	355 MW CC in 2029 355 MW CC in 2030 710 MW CC in 2031 710 MW CC in 2033 710 MW CC in 2039 710 MW CC in 2040 440 MW CT in 2044
New DSM Programs	KEEIA	KEEIA

In addition to load growth, primary drivers of changes to the needs identified in the resource portfolio were:

- Alignment with the most recent SPP resource adequacy rules and study results for expected summer and winter reserve margins and capacity accreditation
- Lower demand-side management contributions to capacity needs based on the approved KEEIA programs compared to higher growth expectations forecasted in the 2024 IRP Preferred Portfolio

Other changes included in the Annual Update:

- Cost and performance characteristics of new thermal resource options consistent with current market price and availability
- Minor updates to solar, wind, and storage costs based on technology curve updates

1.4 Managing Risk and Growth Opportunities

Evergy Kansas Central sees opportunities for high load growth from economic development in the region while it faces the challenges of meeting increasing reliability needs driven by extreme weather and an aging fleet, as well as long lead times and rising costs to build new generation.

Recognizing the uncertainty of future load growth and the need to make commitments to ensure energy and capacity supply at least 3-5 years before it is needed, this Annual Update examines different load addition scenarios and existing fleet contingencies to determine least-cost alternative plans and to understand the tradeoffs of new resource decisions.

Consistent with the Triennial IRP, future natural gas commodity prices, carbon dioxide emissions policy, and new resource construction costs are assessed as critical uncertain factors which contribute to the economic evaluation of plans.

The Environmental Protection Agency's (EPA) Greenhouse Gas (GHG) Final Rule was issued in May 2024, after the analysis had been completed for the 2024 Triennial.[2] Evergy Kansas Central developed GHG Rule compliance options for its coal fleet, including high-level cost estimates for retrofitting coal resources to co-fire or fully operate with natural gas. The Company also engaged with natural gas pipelines to estimate the costs of

[2] New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule. 2024-09233 (89 FR 39798). May 5, 2024.

adding infrastructure to deliver natural gas to the sites. An analysis of compliance plans is included in the Annual Update. All compliance plans are expected to be more costly than the Preferred Portfolio. Evergy is not planning to execute a compliance plan until it gets more certainty around enforcement of the rule considering the change in presidential administration.

1.5 Ongoing Commitment to a Responsible Fleet Transition

Evergy Kansas Central, along with the rest of the Evergy Companies, is committed to a long-term strategy to reduce CO_2 emissions in a cost-effective and reliable manner. Evergy's coal fleet is aging, and its performance has significant impact on meeting SPP's new resource adequacy requirements. Additionally, the coal fleet is increasingly at risk due to tightening environmental regulations. As a result, each Evergy utility Integrated Resource Plan (IRP) is built with a goal of responsibly transitioning its fleet away from coal over time, while maintaining a diverse fuel mix and sufficient flexibility to adjust portfolios as policy and technology change. A responsible transition means one that focuses on maintaining reliability and affordability while also reducing environmental impact over time.

Evergy Kansas Central's portfolio continues to include the measured retirement of coal plants over time and the replacement of this capacity and energy with a mix of new dispatchable resources, renewable resources, and demand-side management programs. In addition to replacing capacity, these additions also allow Kansas Central to meet increasing requirements driven by higher resource adequacy requirements and load growth from economic development. This resource portfolio, developed through risk analysis, is designed to be robust across a variety of uncertainties and to include a diverse mix of resources that reduce the risk to both system reliability and customer affordability which can result from "putting all of your eggs in one basket." Despite the robustness of the risk analysis performed, however, the future remains inherently uncertain and, as a result, maintaining flexibility and continuing to adjust portfolios over time is imperative.

The goal of this Preferred Portfolio is to outline the Company's current long-term strategy to meet customer energy needs, but also to focus particularly on the robustness of near-term decisions which must be made to begin executing on that strategy. Given the increasing capacity and energy requirements described throughout this filing, there is significant urgency to continue to execute on both the supply- and demand-side additions outlined in the first three to five years of this Preferred Portfolio. The analysis performed in this IRP will be used to support separate regulatory filings related to these resource additions. These filings must be supported by the IRP, as a whole and not only by resource-specific evaluations because the evaluation of resource decisions cannot be performed in a vacuum. The integrated analysis of risks and resource options, along with customer needs for energy and capacity, is required to reflect the trade-offs inherent in any resource decision. Any resource added (or not added) today has an impact on future resource decisions in the same way that past resource decisions impact future decisions. An integrated analysis of these trade-offs is performed in triennial IRP filings and updated annually in order to make necessary adjustments to the Company's long-term resource portfolio when conditions change. The latest analysis performed through this IRP is summarized below and outlined in detail throughout this filing.

1.6 Demand-Side Management

Evergy has not conducted a new DSM Market Potential Study since 2023. Therefore, no new DSM potential forecast is included in this 2025 IRP Annual Update. However, Application (22-EKME-254-TAR) for demand-side management programs in Kansas under the KEEIA Cycle 1 framework has been approved by the Kansas Corporation Commission. Evergy's base case includes impacts of KEEIA Cycle 1 energy efficiency and demand response programs as approved by the Commission.

Section 2: Load Analysis and Load Forecasting Update

2.1 Changes from the 2024 Triennial IRP

Several inputs to the load forecasting models were updated for this filing compared to the 2024 Triennial IRP:

- Historical data for customers, kWh and $/kWh: ending June 2024 vs ending June 2023
- DOE forecasts of appliance and equipment saturations and kWh/unit are unchanged. Both the 2024 IRP and the 2025 IRP utilize the 2023 Annual Energy Outlook. See below for additional description.
- Economic forecasts from Moody's Analytics: June 2024 vs June 2023
- Class models in the 2025 Evergy Kansas Central's update filing are the same as the 2024 Triennial filing: residential, small commercial, big commercial (medium, large, large power) and industrial.
- The Company also re-evaluated the output elasticity used in the commercial and industrial models and the elasticity used in the residential model. Adjustments made were to improve the model fit.
- The Company utilized an EPRI (Electric Power Research Institute) electric vehicle study within its modeling for 2025 Update filing.
- The Company utilized Google Mobility Reports data through October of 2022, (Google stopped reporting the mobility data publicly October 15, 2022) to account for load pattern changes resulting from geolocation behaviors induced by the COVID-19 pandemic.

Table 4, Figure 4, and Figure 5 below show a higher forecast for both peak and energy for the 2025 Update compared to the 2024 Triennial IRP. Below are the primary reasons for the change in forecast:

- The Energy Information Administration (EIA) did not produce an Annual Energy Outlook (AEO) for 2024 and recommended stakeholders to continue using the 2023 AEO. The EIA chose to invest in making updates to their modeling process during 2024. Evergy's IRP update 2025 utilizes end-use forecasts from the 2023 AEO, the same as was used in the 2024 Triennial IRP.

- There are some changes from the Moody's Analytics Economic forecasts from 2023 to 2024. Economic forecasts for Population, Households, Employment and Gross Product all show similar growth trajectories in the 2024 forecast compared to the 2023 forecast.
- The growth trajectory of Evergy KS Central Residential load since the 2024 Triennial IRP forecast contributes to a higher load growth trajectory. Figures 6 and 7 further below show how an additional large load customer that was not included in the base forecast heavily influences load growth trajectory through 2025-2031.

Table 4: Evergy Kansas Central Mid-Case Annual Forecast **<u>Confidential</u>**

[redacted]

[redacted]

Figure 4: Peak Forecasts – 2025 Annual Update vs. 2024 Triennial IRP

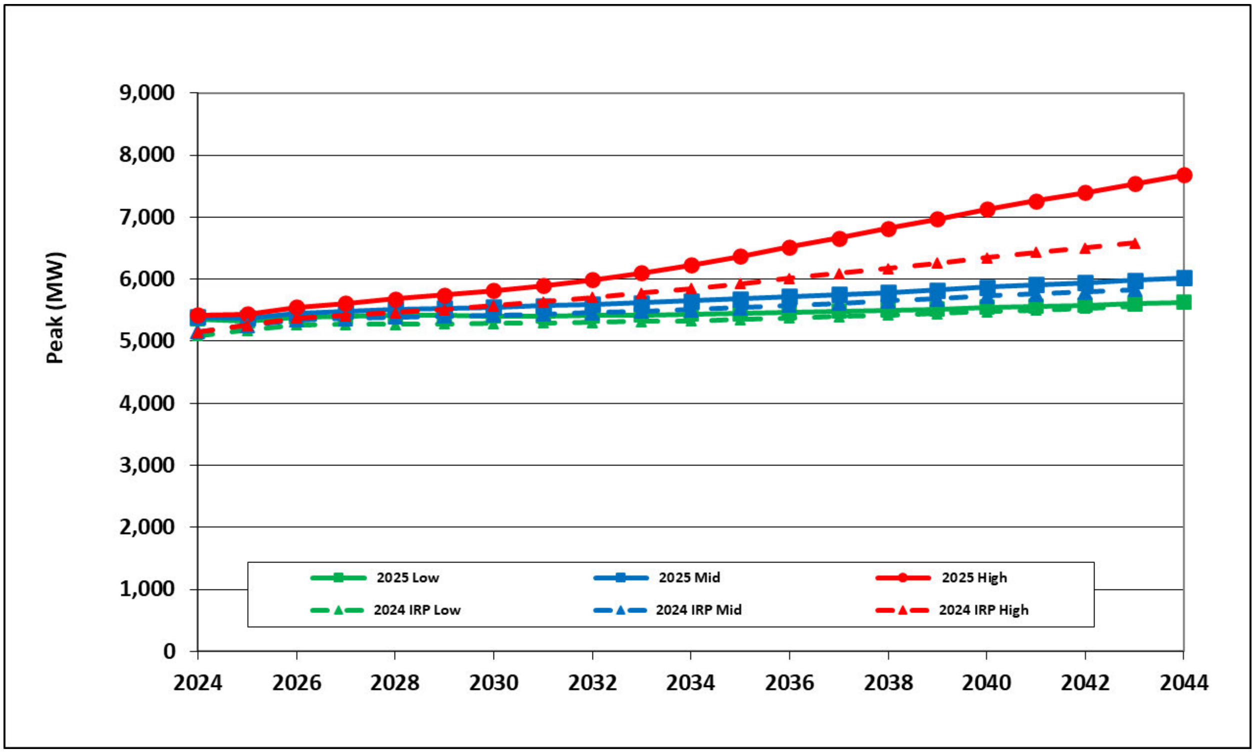
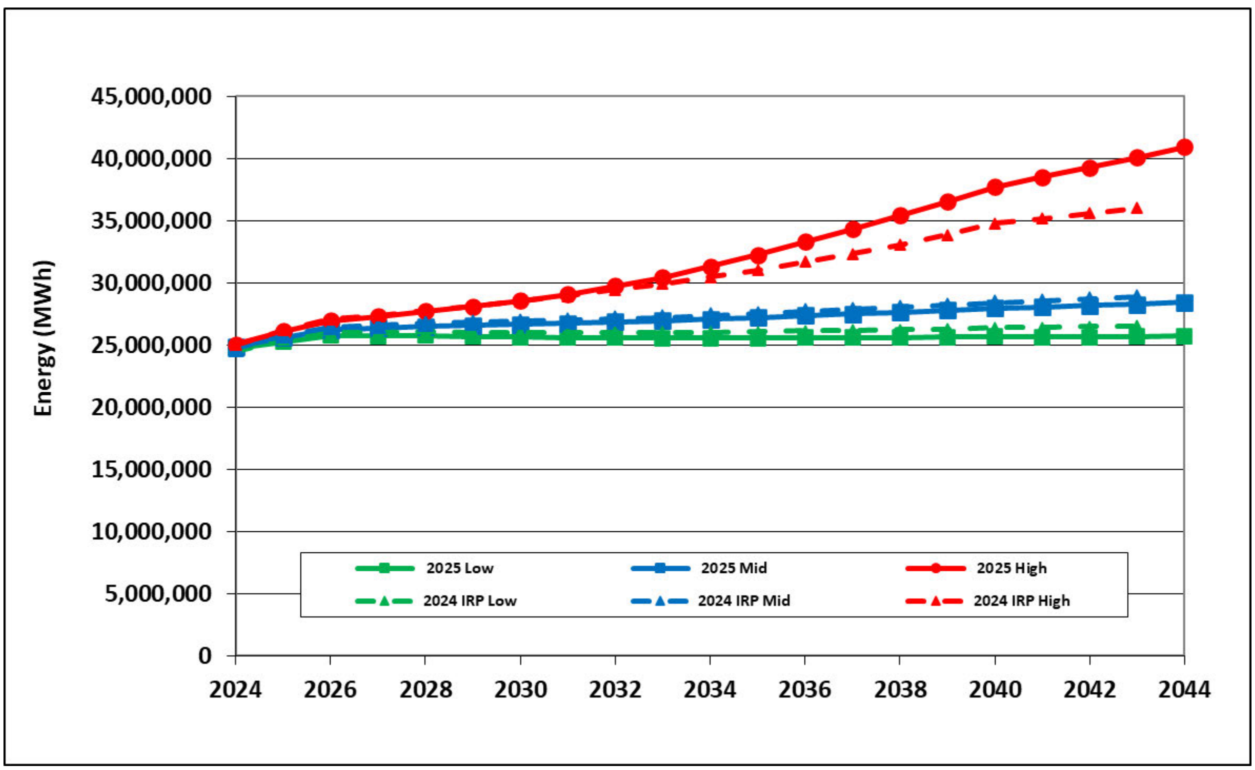


Figure 5: Energy Forecasts – 2025 Annual Update vs. 2024 Triennial IRP



In addition to the higher native load forecasts shown in Table 4, Figure 4, and Figure 5 and described above, Evergy Kansas Central has included a new large load customer profile in its base load forecast for this IRP.

In recent months, the customer completed Evergy's internal review process that allows the Company to complete due diligence on large load customer requests, sets forth numerous data points to vet the feasibility of the customer locating in Evergy's service territory, and requires a sizeable deposit to support analysis to study the viability of the customer's project. In the second quarter of 2025, Evergy expects to submit an Attachment AQ study to the SPP to analyze the transmission upgrade requirements of the incremental new large load. Additionally, Evergy Kansas Central and the new large load customer continue to progress with negotiations and expect to have Construction and Service Agreements fully executed in the second quarter of 2025 with an expected project announcement in 2025.

Evergy has a large pipeline of prospective new large load customers, but not all are included in base load planning until certain progress on Evergy's internal review process has been met to avoid exposing our Preferred Portfolio to unnecessary risks.

The new large load was not included in the typical native load forecast data shown in Table 4, Figure 4, and Figure 5 due to the timing of when Evergy completed its annual load forecast update and the subsequent timing of gaining more certainty of the new large load customer locating in Evergy Kansas Central's service territory. In order to fully plan for this new customer load profile, the incremental new load was added to the native load base forecast. Figures 6 and 7 show the peak MW and MWh impact over the next decade of adding the new large load to the native demand in the 2025 IRP Mid forecast. Each of the base planning scenarios studied in this 2025 IRP include the new large load starting its ramp in 2026 and continuing at the MW peak load in the early-2030s through the end of the 20-year planning period.

Additionally, Evergy Kansas Central has existing wholesale contracts with a Kansas Electric Cooperative that was included through 2030 in the 2024 IRP. After recent discussions, Evergy and the counterparty have agreed to continue to plan on extension of this long-term relationship and as such, EKC's 2025 IRP plans for the extension of wholesale contracts starting in 2031 and through the end of the twenty-year planning period. Similarly, Figure 6 and 7 show the MW and MWh impact over the next decade of increasing the planning obligation to accommodate the in-state wholesale contract extension.

Figure 6: EKC Peak MW Load Forecast Including New Large Load

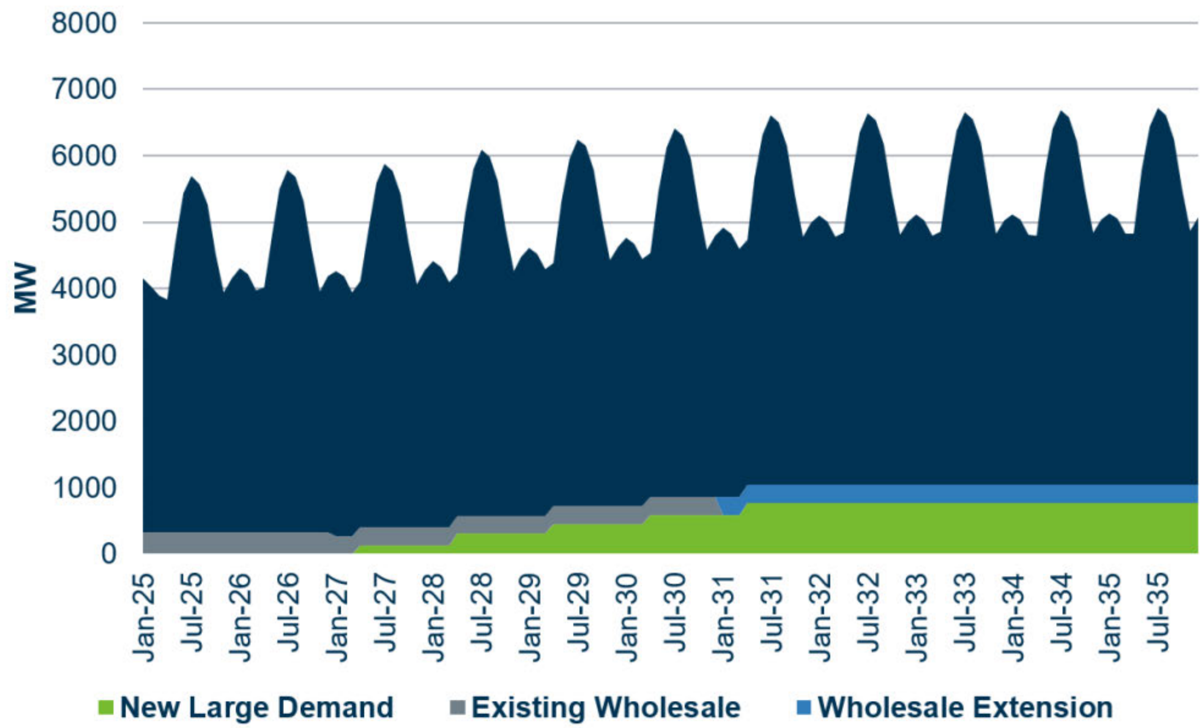
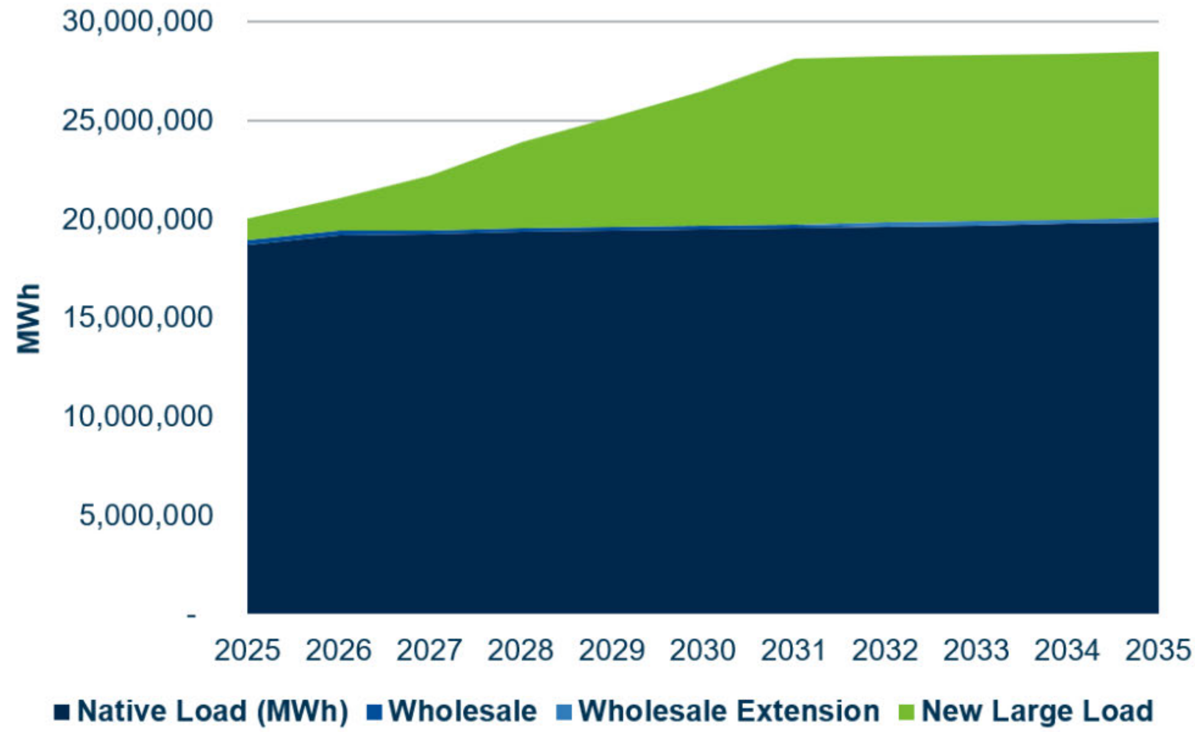


Figure 7: EKC Peak MWh Load Forecast Including New Large Load



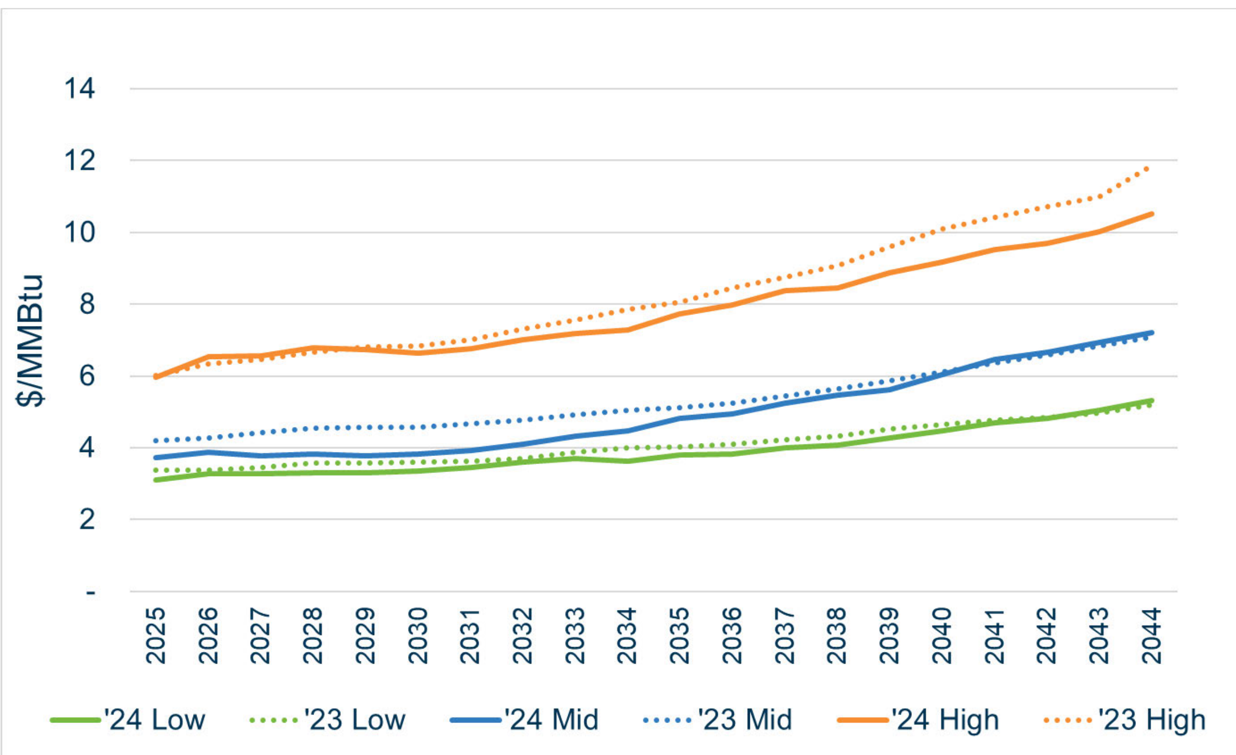
Section 3: Market Fundamentals Update

3.1 Fuel Price Forecasts

3.1.1 Natural Gas

Evergy updates the IRP natural gas forecast annually based on the forecast used for internal budgeting, which is developed from vendor forecasts and forward markets.[3] The internal forecast is then scaled by EIA's fundamental supply and demand forecasts to produce high and low estimates. However, EIA did not release new fundamental forecasts for 2024. Without updated fundamentals there was no significant change in the fuels forecast so the 2025 IRP used the 2024 forecast. Natural Gas prices were identified as a critical uncertain factor, consistent with the 2024 Triennial. High, mid (base) and low forecasts are used in the development of resource plans and evaluation of plan economics.

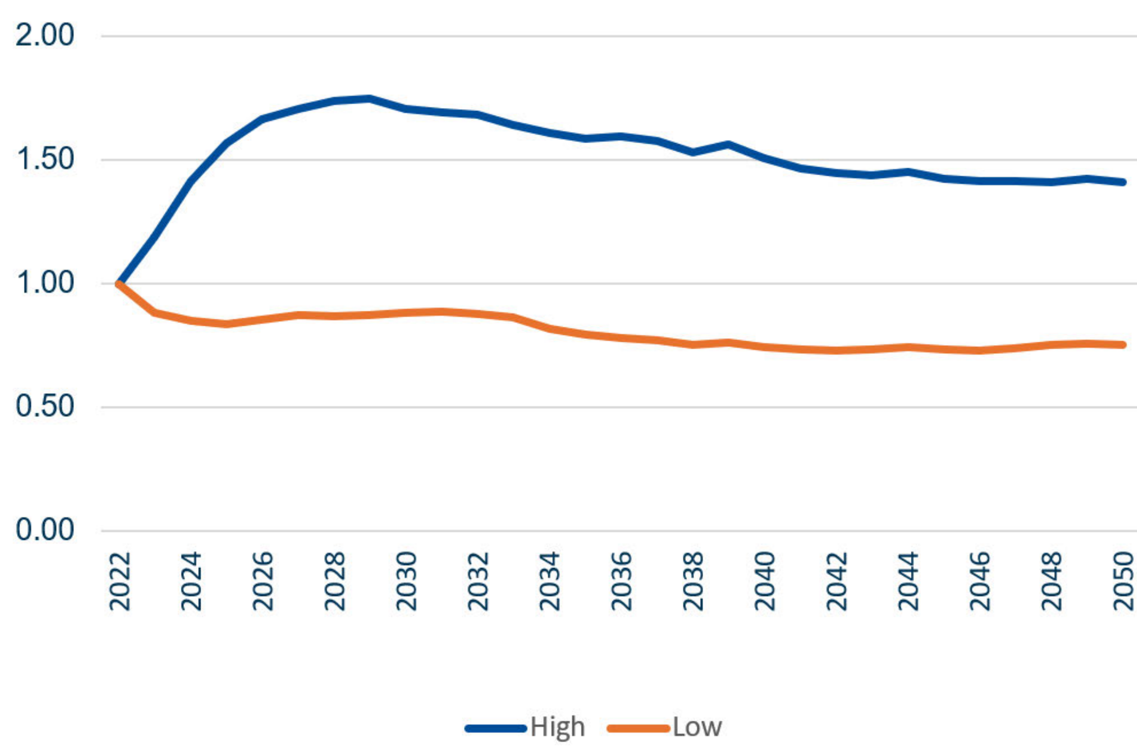
Figure 8: Natural Gas Price Forecasts 2024 IRP and 2023 IRP



[3] Third party sources include IHS Markit, Energy Information Administration, S&P Global Platts, Energy Ventures Analysis, CME Futures, and ICE.

The high and low forecasts were developed by scaling the mid forecast based on the fundamental supply and demand forecasts in the EIA Annual Energy Outlook model. The EIA did not release a 2024 update as they prepare a more exhaustive 2025 update, so data from the 2023 Outlook was used. The EIA builds its forecasts considering a variety of factors, including current laws and regulations, current assessments of economic and demographic trends, technology improvements, compounded annual economic growth, oil and natural gas supply and demand, and renewable energy cost cases. Key drivers for US natural gas production volumes include EIA's outlook on international prices and US LNG exports, as well as technology assumptions. Evergy used the "High Oil and Gas Supply" to calculate the low natural gas price forecast, and the "Low Oil and Gas Supply" for the high natural gas price forecast.[4]

Figure 9: Henry Hub Natural Gas Scalar



[4] *See* 2023 EIA Annual Energy Outlook, Table 13. Natural Gas Supply, Disposition, and Prices.

This method was used beginning in the 2022 IRP to derive a wider range of prices based on changes in fundamental assumptions.

3.1.2 Coal

Evergy negotiates coal and rail delivery contracts with suppliers. The coal price forecast was developed using contract prices for the duration that they are in place. Prices for contracted coal volumes were supplemented with prices from Coaldesk's latest available forward market valuation for all uncontracted coal volumes in that timeframe. For forecasted prices beyond contract terms, a composite coal price forecast was created by combining the forecasts from HIS Markit, S&P Global Platts, Energy Ventures Analysis, and JD Energy. The forecasts are combined and weighted equally to create a composite price forecast that represents the base consensus of the major forecasted sources.

Figure 10: IRP 2025 Kansas Central Coal Price Forecast **Confidential**

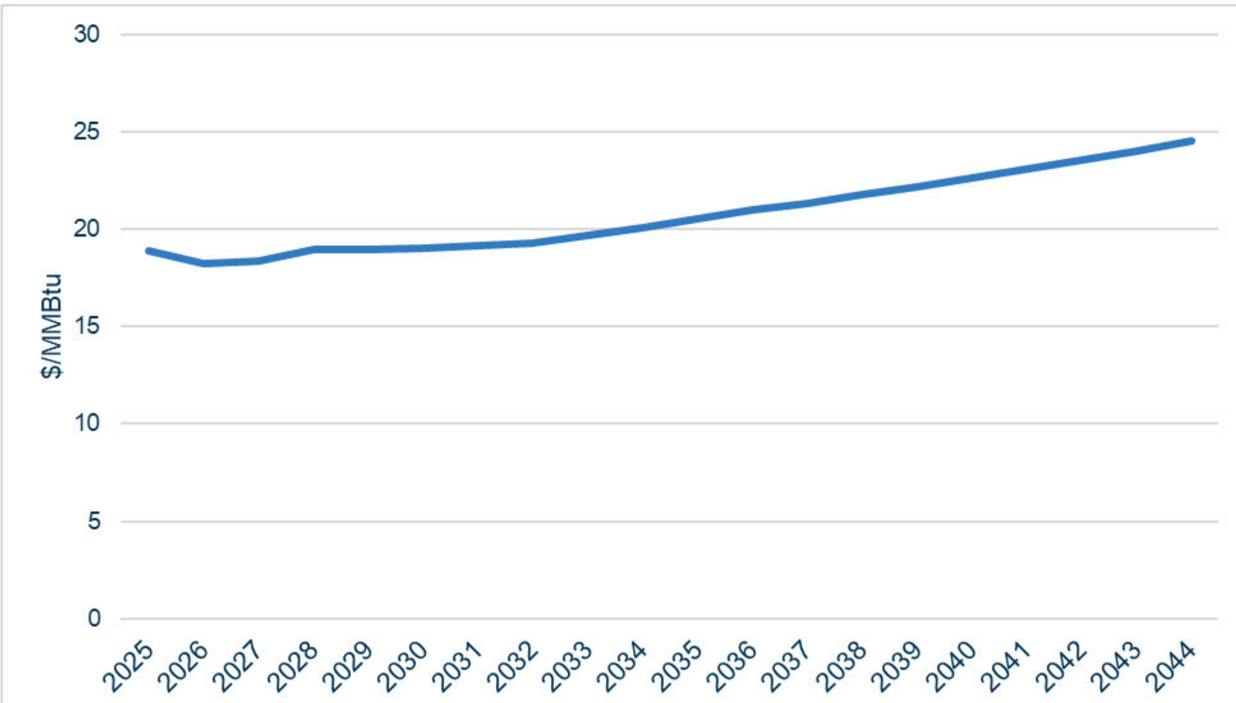
[redacted]

Evergy sources coal from the Powder River Basin. Historically there has been low price volatility in coal commodity prices for Powder River Basin coal because it is not exported, and thus is not subject to the international supply and demand pressures that other coal types, natural gas, and oil experience.

3.1.3 Fuel Oil

A composite crude oil price forecast was created by combining forecasts from HIS Markit, Energy Information Administration, S&P Global Platts, and Energy Ventures Analysis.

Figure 11: IRP 2025 Fuel Oil Price Forecast



3.2 Market Price Forecasts

Evergy considers current and future market conditions in developing its 20-year forward looking forecasts for the IRP. Starting with the 2022 IRP Annual Update, Evergy contracted with 1898&Co. to produce 20-year market price forecasts using SPP's transmission planning models as a baseline. Evergy has not changed its market price forecast from the 2024 IRP.

The 2024 IRP pricing models, based on the finalized 2023 SPP ITP models, reflect current transmission topology and near-term transmission upgrades, including those approved by the SPP Board of Directors to resolve new constraints identified in the 2023 ITP process. The models use economic dispatch, considering transmission limits, to calculate nodal pricing. Pricing was reported at the following locations:

- Load zones for each utility: used for load and DSM
- Coal resource locations for each coal site
- Wind location: used for all new and existing wind and wind PPAs
- Generation zones for each utility: used for existing generators; Metro location used for all non-wind new resources

The market price forecasts reflect the negative pricing that has been observed in SPP and predict that the number of negative-priced hours in SPP will continue to grow. Please see the 2024 Triennial IRP for a more holistic discussion of market price forecasts.

3.3 Carbon Restrictions

Carbon emissions policy was identified as a critical uncertain factor, consistent with the 2024 Triennial IRP. Evergy has modeled three levels of potential future carbon emissions policies. Evergy has not changed its assumptions from the 2024 Triennial IRP.

The low forecast has no emissions restrictions. The mid forecast employs a carbon emissions restriction consistent with the dispatch solution of the pricing model. The CO_2 production constraint mirrors Evergy's anticipated emission levels within the SPP market (e.g., if the dispatch in the pricing model produced a 70% reduction in Evergy's carbon emissions in 2042, the carbon restriction applied in the IRP dispatch model for 2042 is 70%). The high forecast is consistent with the assumptions in the SPP Future 3 model which was engineered with an explicit carbon reduction goal of an approximately 95% reduction in CO_2 production from 2017 levels. Evergy used the same logic to ratably restrict emissions from historic 2017 CO_2 production levels to culminate 2042 with a 95% reduction. The high forecast also incorporates a carbon tax which ramps to $25/ton by the end of the twenty-year horizon, consistent with Future 3.

Figure 12: Kansas Central CO_2 Emission Constraint

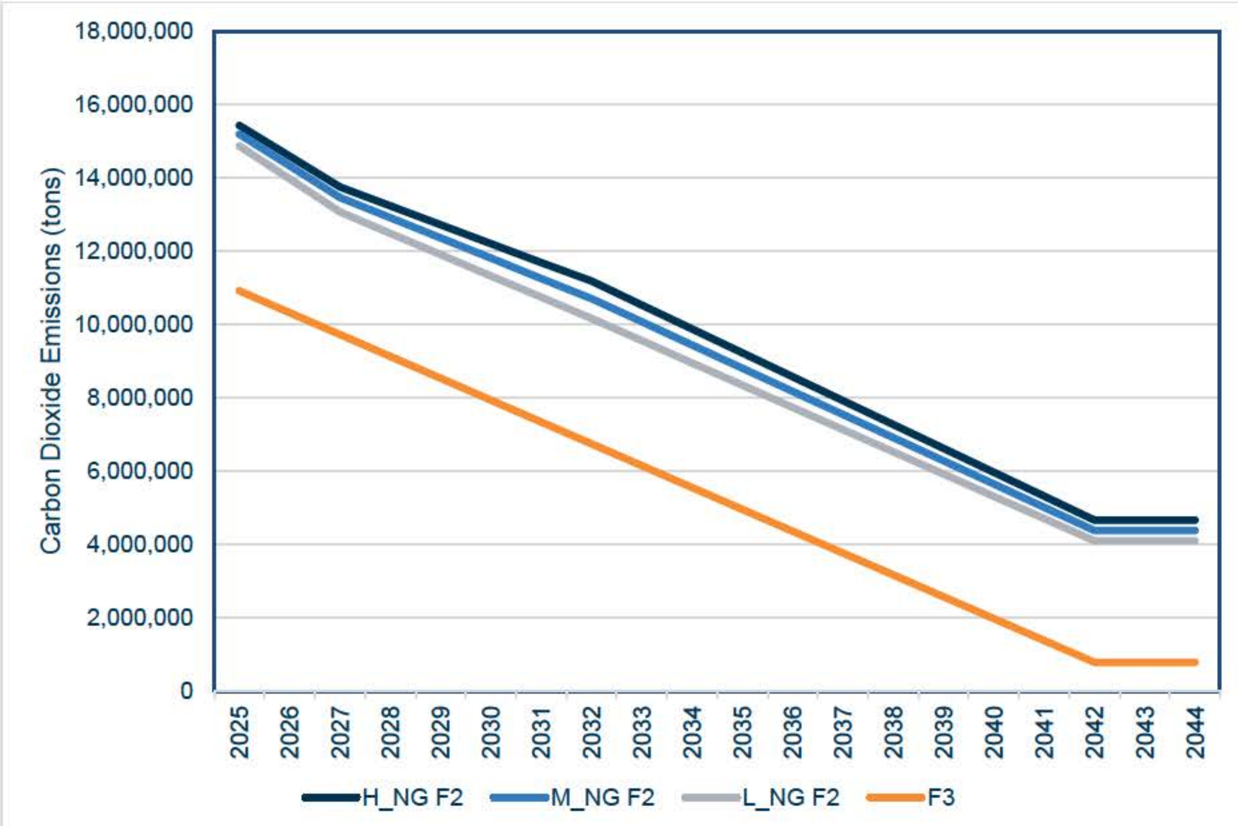


Table 5: Future 3 CO_2 Emission Tax ($/ton)

Year(s)	Price
2025-2032	0
2033	2.5
2034	5
2035	7.5
2036	10
2037	12.5
2038	15
2039	17.5
2040	20
2041	22.5
2042-2044	25

In order to achieve SPP Future 3 emissions goals, breakthroughs would be needed in dispatchable carbon-emissions-free technology. Newer combined cycles and combustion turbines are engineered to burn cleaner fuels including hydrogen or ammonia blends. However, production and transport of these fuels is still cost prohibitive. Improvements in carbon capture and sequestration technologies are another option for reducing or eliminating emissions. US government subsidies are encouraging innovation in these areas. Consistent with the 2024 IRP, costs associated with carbon capture and storage were applied to new combined cycles beginning in 2035 in Future 3, reflecting an assumed cost associated with mitigating carbon emissions from these new resources. Additionally, carbon-free energy was assumed to be available in all models for $300/MWh in case the fleet was unable to generate enough energy, or carbon-free energy to serve load. This price point is based on the current typical price of fuel oil-fired peaking units which, although clearly not representative of actual carbon-free energy, provides a "scarcity price" proxy for the cases when Evergy is unable to meet its own load.

3.3.1 Other Emissions Costs or Restrictions

Evergy does not expect to incur costs for emissions allowances for SO_2 and NO_x, and does not expect future restrictions to be limiting on operations.

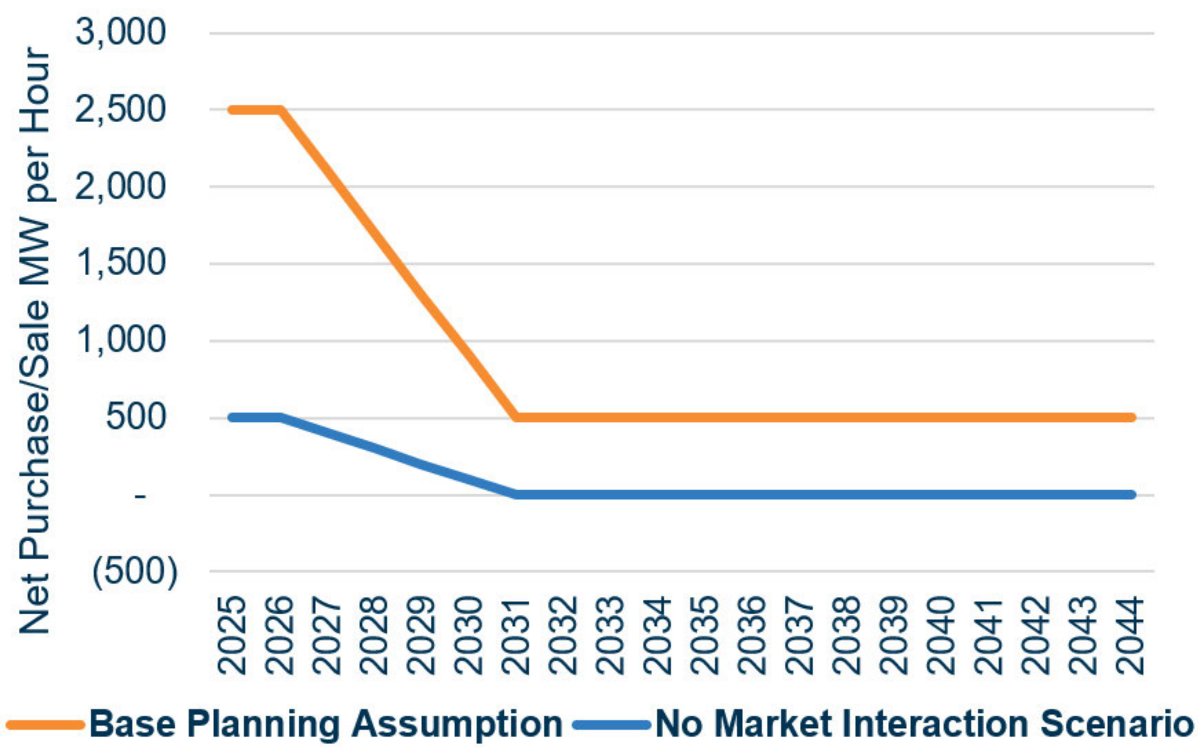
3.4 Market Dependence

Evergy benefits from participation in the SPP energy markets because it can sell energy when prices are higher than production costs and buy energy when prices are lower than production costs. Currently, aggregated Evergy supply and demand (including Evergy Metro, Missouri West, and Kansas Central) is well-matched in SPP.

With high load growth expected over the next few years, planned retirements, and expiration of wind PPA contracts, Evergy does not expect other utilities in SPP to build generation to serve the needs of Evergy customers. In addition to meeting SPP Resource Adequacy Requirements, Evergy aligns its future plans with meeting hourly customer energy needs in the lowest cost manner, by limiting net sales and purchases from the market to design a future portfolio that provides an economic and reliability hedge.

Consistent with the 2024 Triennial IRP, beginning in 2031, the allowed level of market purchases/sales is set at approximately 10% of each utility's peak load and 15% of its average load. Allowing market purchases does not mean that a utility (e.g., Kansas Central) is physically incapable of meeting 100% of customer energy needs. Resource Adequacy Requirements are established to outline the amount of physical capability (i.e., accredited capacity) necessary to meet customer energy needs. These market purchase constraints simply mean that, when an optimal resource mix is selected, it is selected not only because it is the lowest-cost way to meet these Resource Adequacy Requirements, but also because it is the lowest-cost way to produce energy which aligns closely (within 10-15%) with the utility's customers' hourly energy needs. On the market sale side, it also means that an optimal plan will not be developed solely because of the revenues it could generate from selling energy in excess of customer needs. In short, this constraint ensures that a resource plan is developed based on specific customer energy needs and not just forecasted energy market prices. This constraint is phased in over time because it is most relevant in the second decade of the planning horizon when expected fossil retirements across the SPP and within Evergy's fleet, combined with the expiration of Evergy's wind PPAs, are expected to significantly change Evergy's net position in the SPP energy market.

Figure 13: Limit on Market Dependence in Resource Planning (Kansas Central)



Based on stakeholder feedback, Evergy also developed an alternative resource plan assuming (for modeling purposes) no market energy purchases or sales, to understand how SPP energy market assumptions affect the new resource build decisions. This plan assumes market dependence is reduced to zero in 2031, rather than 500 MW.

Section 4: Resource Adequacy Requirements Update

SPP requires all load-serving entities to meet Resource Adequacy Requirements based on forecasted peak load plus planning reserve margins. SPP conducts a LOLE (loss of load expectation) study at least every two years, setting the planning reserve margin based on a LOLE of less than one day in ten years.[5] Evergy plans to have sufficient capacity to meet SPP requirements in every planning year. Evergy submits planning data, including load forecasts and resource accreditation to SPP annually to confirm it has met the requirements prior to the summer and winter seasons respectively.

Significant changes to Resource Adequacy Requirements have occurred over the last year. SPP has filed tariff changes to implement Winter Resource Adequacy Requirements, Performance-Based Accreditation (PBA), and effective Load Carrying Capability (ELCC), all of which have been provisionally approved by FERC effective January 1, 2025. However, there are many interrelated issues to work through which could influence future requirements – including LOLE study assumptions and variations on accreditation calculations.

4.1 Winter Reserve Margin Requirement

The Federal Energy Regulatory Commission (FERC) accepted SPP's tariff change to implement a Winter Resource Adequacy Requirement effective January 1, 2025. The Winter Resource Adequacy Requirement will be identical to the Summer Season Resource Adequacy Requirement, only with the dates being six months apart. SPP also proposed to add language stating that a resource can only be used to meet the Resource Adequacy Requirement if the load responsible entity (LRE) "expects [it] will be available for the duration of the [season]" and has "no knowledge [that the resource] will become unavailable," with an exception for Authorized Outages.[6]

[5] SPP OATT Attachment AA, Section 4.0 Planning Reserve Margin
[6] Sw. Power Pool, Inc., 189 FERC ¶ 61,094, at P 4 (2024).

In addition to the Winter Season Resource Adequacy Requirement, the deficiency payment structure will now account for potential LRE deficiencies in both Summer and Winter. Since the Cost of New Entry calculation used to assess penalties is based on annual cost, SPP will charge LREs with an annual deficiency payment equal to the higher of the deficiency payment amounts the LRE has for either the Summer Season or Winter Season. The annual charge for a capacity deficiency in either season would avoid being punitive to LREs by ensuring that an LRE will not be double charged for the same deficient capacity and ensure LREs proactively procure and maintain sufficient capacity for the Winter Season.

The initial winter reserve margin for winter 25/26 is expected to be 15%, however SPP studies have indicated potential dramatic increases in future winter requirements. There is still uncertainty in predicting what the winter reserve margins will be as stakeholders need to work through LOLE study assumptions that may show greater risks in winter such as higher forced outage rates in extreme cold weather, balance of when loss-of-load events occur between summer and winter in modeling, and planned outages scheduled in winter months.

4.2 LOLE Study Results and Reserve Margin Expectations

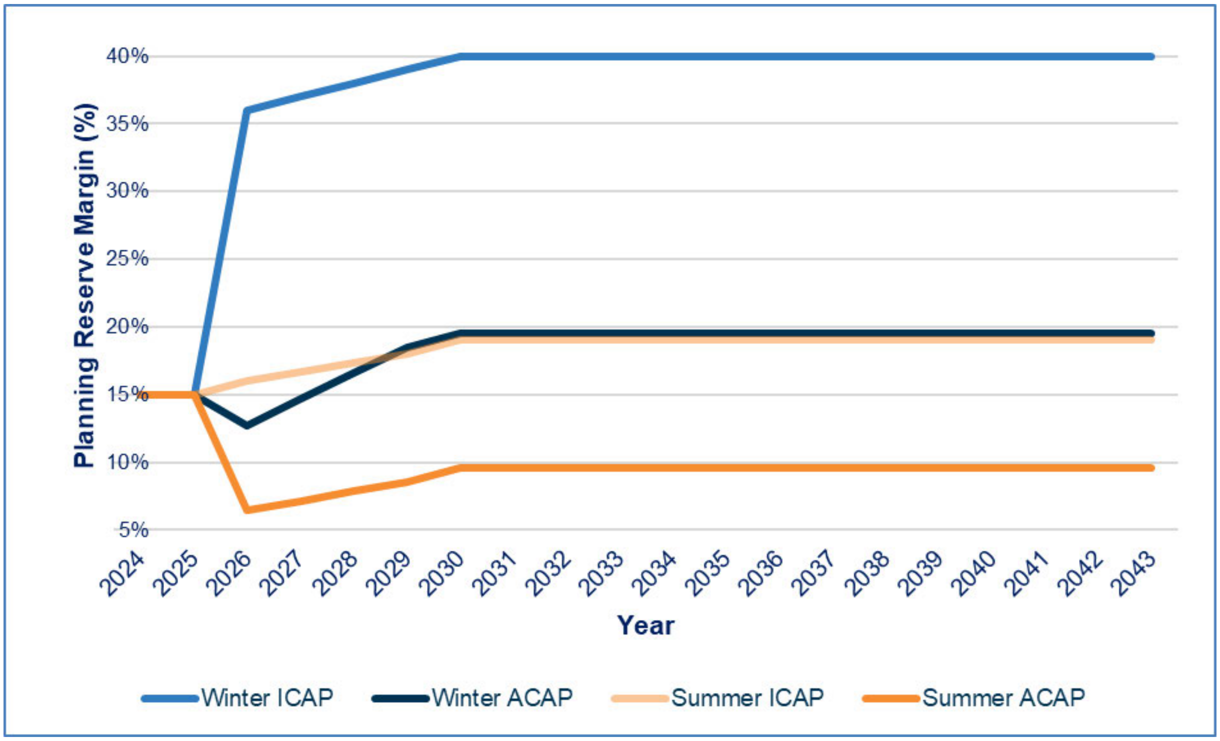
Evergy incorporated a 12% summer reserve margin in its resource plans for the 2021 and 2022 IRPs, consistent with SPP requirements. In July 2022, the SPP board approved an increase in the summer reserve margin to 15% beginning in summer 2023, and Evergy's 2023 IRP met that minimum value for the 20-year planning horizon. The required reserve margin for summers 2024 and 2025 have been set at 15%, and a winter requirement of 15% is in effect for winter 2025/2026. However, SPP's draft LOLE study results anticipate higher reserve margins in future years.

Based on the 2024 submitted forecast for the Resource and Load mix using the 2023 LOLE study assumptions, the 2026 planning year shows a 16% summer reserve margin and a 36% winter reserve margin. For planning year 2029, the summer reserve margin rises to 17%, and the winter reserve margin rises to 38% which includes 50% of cold weather correlated outages assumed. The rise in reserve margins from 2026 to 2029 in the study results is attributed to changes in the resource mix, planned outage scheduling overlaps with high need hours in winter, increase in load, and shift in risk hours, with additional allocation of LOLE risk to winter.

Based on these results, Evergy has revised its planning assumptions to anticipate a higher initial winter reserve margin and higher reserve margins for both summer and winter over the planned horizon. The summer base assumption is that the reserve margin of 15% in 2025 will increase by approximately 1% per year through 2030 and then remain the same for the remainder of the horizon. The winter base assumption is that the same amount of capacity is needed in both seasons, despite the lower winter load. The winter reserve margin is 15% in 2025, steeply increasing to 36% beginning in 2026 and increasing by 1% every year until hitting 40% in 2030 and remaining stable for the rest of the horizon. Evergy believes the assumed levels of reserve margins adequately plan for SPP’s future planning reserve margin requirement while also including an appropriate buffer to account for annual fluctuations in unit performance which impact the fleet’s overall accredited capacity to meet load obligation (see Section 4.3 Performance Based Accreditation).

SPP is transitioning its Planning Reserve Margin (PRM) calculation from Installed Capacity (ICAP) to Accredited Capacity (ACAP) starting in 2026 with the implementation of Performance Based Accreditation (PBA). Under the ICAP PRM approach, the reserve margin is based on the total installed capacity of all generating units, assuming they are available at maximum capacity, without accounting for potential outages or performance variations and the overall PRM includes buffer to cover the risk of outages. In contrast, the ACAP PRM method calculates the reserve margin based on each unit's accredited capacity, reflecting actual performance and reliability. This approach uses historical performance data, including forced outages and deratings, to determine reliable capacity during peak demand. By shifting to an ACAP PRM, performance risk moves from the overall system to individual units, accrediting them based on demonstrated performance. Units with higher reliability receive higher accreditation, while those with frequent outages receive lower accreditation. Consequently, the overall PRM is reduced, because the buffer that was previously included in the ICAP PRM to cover outages and performance variation is now distributed across individual units.

Figure 14: SPP Reserve Margin Assumptions IRP 2025



The 2023 SPP LOLE report results and future LOLE study assumptions are still being vetted in the stakeholder process. Some of the primary focus areas for refinement may be:

- **Future Weather Expectations:** The 2023 LOLE study uses 43 years of historical weather data to model load, wind, and solar patterns. The Monte Carlo approach runs thousands of models with these weather-patterned loads, and varying resource availability based on historical outage distributions. The summer 2026 LOLE events occurred in 10 different weather years, with the most events, 33%, in the 1980 models. The winter 2026 LOLE events occurred in only four different weather years, with 72% of events in the 2021 model which had the winter storm Uri. Stakeholders may consider whether a Uri-type event is likely to occur again and how much weight it should carry in the modeling.

- **Cold-Weather Correlated Outages:** Historical analysis shows a large increase in forced outages when temperatures are below zero in SPP. When the LOLE study considers historical cold-weather outage correlation, more LOLE events occur in winter, increasing the reserve margin needed to lower the number of events back to the 1-in-10 years standard. Stakeholders may consider whether cold weather issues are expected to persist in the future or may have been remedied by better practices in the natural gas industry, winterization, and incorporation of lessons learned.
- **Seasonal Balance of Risk:** The allocation of events to summer and winter changes the reserve margin for each season. For example, allowing more events to occur in winter raises the summer reserve margin and lowers the winter reserve margin. This may affect utilities that are summer and winter peaking differently.
- **Scheduling of Maintenance Outages:** The modeling accounts for some scheduled outages in winter, consistent with historical scheduling practices. The presence of scheduled outages in winter increases the need for other resources to be available, raising the winter reserve margin.

4.3 Performance-Based Accreditation

Performance-based accreditation is a metric to redistribute accreditation based on historical availability at peak times. SPP currently accredits thermal resources based on their tested summer capacity, through 1-hour capability tests every five years, supplemented by 1-hour operational tests annually. The new method that has been provisionally accepted by FERC reduces accreditation based on each resource's seasonal (winter or summer) forced outage rate and forced outage factor (winter only). Seven-year average seasonal forced outage rates will be used. However, until SPP collects seven years of data, class average outage rates will substitute for resource-specific forced outage rates as part of the calculation. Under performance-based accreditation (PBA), all resources will lose some accreditation due to performance. Therefore, resource portfolios with higher outages than average, will get less relative accreditation and will need more capacity to meet requirements and portfolios with lower outages than average, will get more relative accreditation and will need less capacity.

However, as we transition to PBA, the SPP reserve margin will shift from an Installed Capacity Planning Reserve Margin (ICAP PRM) to an Accredited Capacity Planning Reserve Margin (ACAP PRM). This adjustment ensures that the planning reserve margin remains reasonable and not unduly burdensome, reflecting the system's need for unforced capacity and maintaining reliability standards. For the 2025 IRP, Evergy has incorporated the expected change in accreditation in its resource planning beginning summer 2026. Key differences in PBA calculation methodology in the 2025 IRP include a forced outage factor (EFOF) applied in winter to account for Fuel Assurance and Cold Weather Outage Impacts, which was recently finalized in the SPP stakeholder process this year and has made a large impact on Evergy's winter capacity position for the 2025 IRP as compared to the 2024 IRP assumption. In addition, PBA was estimated on a fleetwide basis in the 2024 IRP but has been refined with more data and is estimated at the unit level for the 2025 IRP.

4.4 Effective Load Carrying Capability (ELCC)

ELCC is a method to measure the contribution a resource makes to meeting load, taking into account fuel supply and duration limitations (for example, solar resources cannot serve load at night). SPP is working toward implementing ELCC for renewable and storage resources, recently coupling ELCC with performance-based accreditation, and fuel assurance for thermal resources in a filing to address stakeholder concerns regarding whether renewables and storage would be unfairly accredited more stringently than thermal resources. The filing has been provisionally accepted. For the 2025 IRP, Evergy is factoring in expected ELCC values for renewable and battery resources in its resource planning beginning in summer 2026.

4.5 Accredited Capacity (ACAP) Reserve Margin

As SPP moves to performance-based accreditation and ELCC, it will be measuring the unforced capacity of resources rather than the installed capacity. ACAP reserve margins will reflect the need for resource capacity that has already been adjusted for ELCC and performance-based accreditation. In the 2025 IRP, Evergy includes this beginning in summer 2026 as part of the adjustment to the capacity need for performance-based accreditation.

4.6 Demand Response Accreditation

Demand response resources are currently netted against peak load based on their tested capabilities. Stakeholders have discussed whether these resources should be accredited using an ELCC construct to reflect their availability limitations – such as number and duration of events. The 2025 IRP incorporates an assumption that demand response receives accreditation up to its expected tested capacity. This is lower than the past IRP assumption that demand response would continue to be treated as a net to load, which gave it a capacity value equivalent to its tested capacity plus the reserve margin. Updated policy related to Demand Resource is still in very early stages of development, but this change in assumption allows for a slightly more conservative assessment of accreditation in expectation of potential future changes.

4.7 Resource Adequacy Requirement Uncertainty

Evergy is not specifically treating Resource Adequacy Requirements as a Critical Uncertain Factor in the 2025 IRP. While uncertainty in Resource Adequacy Requirements can certainly impact the amount of capacity Evergy must procure to meet requirements, it does not specifically impact the relative performance of different resource plans (i.e., because if requirements increase, more capacity is necessary; if requirements decrease, less capacity is necessary). In this way, Resource Adequacy Requirements are very similar to Load because they both define the amount of capacity each Evergy utility must maintain to meet customer needs. As a result, for the 2025 IRP, Evergy is considering the load and contingency alternative resource plans sufficient to capture both Load and Resource Adequacy Requirement uncertainty. The High Electrification Load scenario includes a very large amount of load growth based on an assumption of policy changes that support economy-wide electrification. Multiple economic development contingency scenarios capture the impact of a more moderate level of load growth combined with even larger increase in Resource Adequacy Requirements. These various higher load scenarios, along with the Low Load and No Market Energy scenarios, have been assessed to develop contingency plans which would reflect either higher or lower Load/Resource Adequacy Requirements for each utility compared to its base.

Section 5: Supply-Side Resource Options Update

In the 2025 IRP, Evergy updated costs and resource characteristics for combined cycles and combustion turbines based on its recent development experience. Slight modifications were made to battery, wind, and solar resource costs based on updated technology curves. Production tax credits were also updated based on recent published guidance. Resource availability was also updated based on expected lead time.

Table 6: Primary Resource Options **Confidential**

[redacted]

Evergy continues to consider construction costs a critical uncertain factor in resource planning. Evergy modeled installed cost increases of 25% for the high construction cost scenarios, and cost decreases of 25% for the low construction cost scenarios.

Table 7: Primary Resource Costs in First Year of Operation **Confidential**

[redacted]

Table 8: New Resource Emissions Rates (lb/MWh)

Resource Type	NO_x	SO_2	CO_2
Solar	-	-	-
Wind	-	-	-
Battery	-	-	-
Combustion Turbine	0.045	0.009	1,064
Combined Cycle	0.026	0.006	754
Half Combined Cycle	0.026	0.006	754

Evergy also considered Combined Cycles with Carbon Capture as a resource that could be deployed to enable future emissions reductions. While the technology is not currently operating, and cost data is more speculative, it may assist in the analysis of tradeoffs in a low-carbon future.

Table 9: Future Low Emissions Option **Confidential**

[redacted]

Table 10: Future Low Emissions Costs in First Year of Operation **Confidential**

[redacted]

Table 11: Future Low Emissions Resource Emissions Rates (lb/MWh)

Resource Type	NO_x	SO_2	CO_2
Combined Cycle CCS	0.0267	0.0073	42.7

5.1 Renewable and Storage Resources

Renewable and storage resource costs and characteristics continue to be informed by the results of Evergy's 2023 Request for Proposals. Evergy has found solar costs to be similar to 2024 IRP estimates through experience negotiating solar agreements with developers and self-developing a solar project in the months after the 2024 IRP was filed. While the near-term solar construction costs are generally aligned with the 2024 IRP solar costs, changes in the technology curve resulted in lower expected solar costs starting in 2030. Evergy is also not revising expectations for wind and battery costs and characteristics. The updated technology curves for wind shifted costs slightly higher, while the updated technology curve for battery had minimal impact. Evergy does not have refreshed wind project offer prices. Although it has been reported that battery costs have decreased over the past year, there is considerable uncertainty around how US tariffs may affect the market which relies heavily on Chinese imports. Evergy expects to issue another Request for Proposals in 2025.

[redacted]

Figure 15: Annual Solar Build Costs ($/kW) **Confidential**

[redacted]

Figure 16: Annual Wind Build Costs ($/kW) **Confidential**

[redacted]

Figure 17: Battery Build Costs (Excluding ITC) ($/kW) **Confidential**

[redacted]

5.2 Tax Incentives

Consistent with the 2024 IRP, Evergy assumes that new wind and solar will receive PTC and new battery resources will receive ITC. Evergy updated the PTC values per the most recent annual IRS guidance, and used the same assumptions about PTC and ITC eligibility and election as used in the 2024 IRP.

New wind and solar resources can select either the PTC or ITC. New wind resources are expected to have high capacity factors, making the PTC advantageous. Solar resources have lower capacity factors, however the PTC is still expected to be the most economic option for Evergy customers because of the expected capacity factor and the requirement for utilities to amortize the ITC over the life of the asset. New battery resources are only able to use the ITC and utilities are able to take the credit upfront (rather than amortizing it) as part of the IRA guidelines.

Evergy expects new wind and solar projects to meet the eligibility criteria for 100% PTC, with a PTC earned for every MWh of production for the first 10-years of operation. Consistent with IRA provisions, production tax credit eligibility for new projects phases out as the US meets its GHG emissions reduction goals. Projects beginning operation in

2034 and 2035 are eligible for 75% PTC and 50% PTC, respectively, before the credit ceases for projects after 2035.

Evergy expects new battery projects to meet the eligibility criteria for 30% ITC, with the benefit received upfront in the first year of operation. The IRA allows additional bonus credit eligibility for projects located in “energy communities”.[7] Evergy is modeling additional bonus credit eligibility for a total of 40% ITC beginning in 2029. As the credit phases out, projects beginning operation in 2034 and 2035 are eligible for 75% and 50% of the expected credits, respectively, before the credit ceases for projects after 2035.

5.3 ELCC

Evergy expects new renewable and battery resources to be subject to SPP’s ELCC capacity accreditation rules beginning in summer 2026. ELCC measures the effectiveness of the resource to produce energy at times needed to meet load. Generally, as the saturation of the resource type increases in the market, each resource is less effective at meeting load requirements. Evergy has not changed ELCC assumptions from the 2024 IRP. ELCC accreditation is not fixed because it is based on outputs from SPP’s LOLE models. ELCC can change based on changes to other modeling assumptions (load, addition and retirement of other resources, etc.). Evergy’s assumptions are based on SPP studies which estimate the relationship between increasing amounts of resources and ELCC value.

5.4 Thermal Resources

5.4.1 Cost and Availability

The need for firm dispatchable generation beginning in the late 2020’s to early 2030’s was identified in the 2023 and 2024 IRPs. Evergy did not receive any offers for thermal resources in its 2023 Request for Proposal (RFP) and developers are not pursuing

[7] IRS. Energy Community Bonus Credit Amounts under the Inflation Reduction Act of 2022 Notice 2023-29. https://www.irs.gov/irb/2023-29_IRB#NOT-2023-29.

speculative thermal resource projects in SPP. Evergy expects to self-develop these resources.

Cost estimates used in the 2024 IRP were based on engineering studies and publicly available information. In the past year, Evergy's development team has taken steps to execute on the resource portfolio, and has received updated cost estimates from suppliers. Costs have risen significantly from 2024 IRP estimates. This is partly attributable to broad inflation in the economy, but also likely the result of the strong supply and demand forces for natural gas-fired generation. Utilities across the US are forecasting unprecedented load growth from economic development, datacenters, and other large-load customers. Many utilities have announced intentions to build new natural gas projects to meet their growing needs. The high demand for project development is also resulting in higher contracting costs as these firms have limited capacity.[8]

Costs for future years were estimated by scaling the 2029 and 2030 cost estimates by inflation and the average of the NREL and EIA technology curves. Inflation exceeds technological innovation, resulting in higher nominal costs each year.

[8] Evergy testimony from Kyle Olson and Jason Humphrey in 25-EKCE-207-PRE provide more detail on construction cost estimates for planned CCGT and SCGT resources.

Figure 18: Combined Cycle Build Costs ($/kW) **Confidential**

[redacted]

Figure 19: Combustion Turbine Build Costs ($/kW) **Confidential**

[redacted]

Evergy estimates that the earliest available natural gas-fired generation not currently in development would be ready for commercial operation by summer 2031.

5.4.2 PBA Assumptions

New thermal generation will be subject to performance-based accreditation like the rest of the Evergy thermal fleet. The expectation is that initial PBA would be calculated based on design specifications. Since these resources are designed to be highly available and will have firm fuel supply, a 3% outage rate was applied for accreditation purposes.

5.5 Low-Emission Future Resources

5.5.1 Combined Cycle with CCS

Evergy modeled retrofitting new combined cycle builds with CCS beginning in 2035 as an option for compliance with the strict (high) CO_2 emissions reductions scenarios. Carbon capture facilities have high capital costs similar to the costs of building the generator. The operation of carbon capture increases fixed and variable costs, and decreases the efficiency (i.e., increases the heat rate) and the net output of the underlying resource. However, the net CO_2 emissions are also reduced by 95%. Plant capital and operating costs were modeled using NREL estimates from the 2023 Annual Technology Baseline (ATB),[9] while the cost of CO_2 transportation and storage was estimated from a 2022 report by the National Energy Technology Laboratory (NETL).[10]

Table 12: Unit Characteristics of Combined Cycle with and without CCS

****Confidential****

[redacted]

[9] https://atb.nrel.gov/electricity/2023/data

[10] https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf

5.6 Market Capacity

Evergy has been actively pursuing market capacity purchases to meet short term reliability needs and enable large customer load ramp prior to thermal resource construction. Based on ongoing negotiations with counterparties, Evergy believes it can secure some market capacity in the 2026 – 2031 time horizon.

Because SPP is in the process of significantly tightening resource adequacy requirements, including raising reserve margins, reducing capacity accreditation, and imposing penalties for failing to meet winter requirements, Evergy expects that some utilities will be short capacity beginning in 2026 when new rules are forecasted to be in effect. Evergy expects market capacity to be expensive and scarce relative to recent history of market capacity in SPP, limiting potential purchases beyond its current assumptions. Evergy will continue to look for offers in the market to mitigate the risks associated with the lead time in bringing new resources to commercial operation and changes to capacity needs.

Table 13: Market Capacity Available (Kansas Central)

Year	Summer Market Capacity	Winter Market Capacity
2026-2029	250 MW	500 MW
2030	250 MW	250 MW
2031+	50 MW	50 MW

Section 6: Environmental Regulations Update

6.1 Air Emission Impacts

6.1.1 Particulate Matter National Ambient Air Quality Standards

In March 2024, the EPA published in the Federal Register the final rule which strengthens the primary annual PM2.5 (particulate matter less than 2.5 microns in diameter) NAAQS. The EPA lowered the primary annual PM2.5 NAAQS from 12.0 µg/m3 (micrograms per cubic meter) to 9.0 µg/m3. The final rule took effect in May 2024. In August 2024, the EPA released the PM2.5 ambient monitor design values for calendar years 2021 through 2023. These design values will be used by each state governor for recommending to the EPA attainment designations for their states. The EPA will issue final designations for all states, including Kansas and Missouri, by February 2026. Future non-attainment designation for these revised standards could require additional reduction technologies on existing fossil-fueled units.

6.1.2 Cross-State Air Pollution Rule

Ozone Interstate Transport State Implementation Plans (ITSIP)

In 2015, the EPA lowered the Ozone National Ambient Air Quality Standards (NAAQS) from 75 ppb to 70 ppb. States were required to submit ITSIPs in 2018 to comply with the "Good Neighbor Provision" of the Clean Air Act (CAA) as it applies to the revised NAAQS. The EPA did not act on these ITSIP submissions by the deadline established in the CAA and entered consent decrees establishing deadlines to take final action on various ITSIPs. In February 2022, the EPA published a proposed rule to disapprove the ITSIPs submitted by nineteen states including Missouri and Oklahoma. In April 2022, the EPA published an approval of the Kansas ITSIP in the Federal Register. The Missouri Department of Natural Resources (MDNR) submitted a supplemental ITSIP to the EPA in November 2022. In February 2023, the EPA published a final rule disapproving the ITSIPs submitted by nineteen states, including the final disapproval of the Missouri and Oklahoma ITSIPs. In April 2023, the Attorneys General of Missouri and Oklahoma filed Petitions for Review in the U.S. Court of Appeals for the Eighth Circuit (Eighth Circuit) and the U.S. Court of Appeals for the Tenth Circuit (Tenth Circuit), respectively, challenging the EPA's disapproval. In May 2023, the Eighth Circuit granted a stay of the EPA's disapproval of the Missouri ITSIP. Similarly, in July 2023, the Tenth Circuit granted a stay of the EPA's disapproval of the Oklahoma ITSIP. In August 2024, the EPA published in the Federal Register a proposed rule to disapprove the supplemental ITSIP that Missouri submitted in November 2022. In January 2024, the EPA proposed to disapprove the ITSIP for Kansas and four other states. The Kansas ITSIP was previously approved in April 2022.

Ozone Interstate Transport Federal Implementation Plans (ITFIP)

In April 2022, the EPA published in the Federal Register the proposed ITFIP to resolve outstanding "Good Neighbor" obligations with respect to the 2015 Ozone NAAQS for twenty-six states including Missouri and Oklahoma. This ITFIP would establish a revised Cross-State Air Pollution Rule (CSAPR) ozone season nitrogen oxide (NO_x) emissions trading program for EGUs beginning in 2023 and would limit ozone season NO_x emissions from certain industrial stationary sources beginning in 2026. The proposed rule would also establish a new daily backstop NO_x emissions rate limit for applicable coal-fired units larger than 100 MW, as well as unit-specific NO_x emission rate limits for certain industrial emission units and would feature "dynamic" adjustments of emission budgets for EGUs beginning with ozone season 2025. The proposed ITFIP included reductions to the state ozone season NO_x budgets for Missouri and Oklahoma beginning in 2023 with additional reductions in future years. Evergy Kansas Central provided formal comments as part of the rulemaking process. In March 2023, the EPA issued the final ITFIPs for twenty-three states, including Missouri and Oklahoma, which included reduced ozone season NO_x budgets for EGUs in Missouri, Oklahoma and other states, and included other features and requirements that were in the proposed version of the rule. Because the EPA's authority to impose an ITFIP for a state is triggered by the state's failure to submit an ITSIP addressing NAAQS by the statutory deadline or disapproval of an ITSIP, the EPA lacks authority under the Clean Air Act to impose an ITFIP on a state for which state implementation plan (SIP) disapprovals have been stayed by the courts. Accordingly, the EPA issued interim final rules staying the effectiveness of the ITFIP in both Missouri and Oklahoma while the stays issued by the Eighth and Tenth Circuits in the ITSIP disapproval cases remain in place. During this time, both states will continue to operate under the existing CSAPR program. While Kansas was not originally included in the ITFIP, in January 2024, the EPA issued a proposal to include Kansas in the ITFIP. If finalized, the ITFIP for Kansas would become effective for the 2025 ozone season beginning in May 2025. In June 2024, the U.S. Supreme Court issued an order granting emergency motions for stay filed by state and industry petitioners of the final ITFIP pending further review of the ITFIP by the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit).

Evergy Kansas Central currently complies with the existing CSAPR rule through a combination of trading allowances within or outside its system in addition to changes in operations as necessary. Future, strengthened ozone, PM, or SO_2 standards could result in additional CSAPR updates requiring additional procurement of allowances, emission reduction technologies or reduced generation on fossil-fueled units.

6.1.3 Regional Haze

In 1999, the EPA finalized the Regional Haze Rule which aims to restore national parks and wilderness areas to pristine conditions. The rule requires states in coordination with the EPA, the National Park Service, the U.S. Fish and Wildlife Service, the U.S. Forest Service, and other interested parties to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment. There are 156 "Class I" areas across the U.S. that must be restored to pristine conditions by the year 2064. There are no Class I areas in Kansas, whereas Missouri has two: the Hercules-Glades Wilderness Area and the Mingo Wilderness Area. States must submit revisions to their Regional Haze Rule SIPs every ten years and the first round was due in 2007. For the second ten-year implementation period, the EPA issued a final rule revision in 2017 that allowed states to submit their SIP revisions by July 2021.

The Missouri SIP revision does not require any additional reductions from the Evergy Companies' generating units in the state. MDNR submitted the Missouri SIP revision to the EPA in August 2022, however, they failed to do so by the EPA's revised submittal deadline in August 2022. As a result, in August 2022, the EPA published "finding of failure" with respect to Missouri and fourteen other states for failing to submit their Regional Haze

SIP revisions by the applicable deadline. This finding of failure established a two-year deadline for the EPA to issue a Regional Haze federal implementation plan (FIP) for each state unless the state submits, and the EPA approves a revised SIP that meets all applicable requirements before the EPA issues the FIP. In July 2024, the EPA published in the Federal Register a proposal to partially approve and partially disapprove Missouri's Regional Haze SIP revision.

The Kansas SIP revision did not include any additional emission reductions by electric utilities based on the significant reductions that were achieved during the first implementation period. The Kansas Department of Health and Environment (KDHE) submitted the Kansas SIP revision in July 2021. In August 2024, the EPA issued the final disapproval of the Kansas SIP revision for failing to conduct a four-factor analysis for at least two emission sources in Kansas. If a Kansas generating unit of Evergy Kansas Central is selected for analysis, the possibility exists that the state or the EPA, through a revised SIP or a FIP, could determine that additional operational or physical modifications are required on the generating unit to further reduce emissions.

Evergy Kansas Central’s existing emission controls at its Jeffrey Generating Stations maintain compliance with these requirements. Future visibility progress goals will likely result in additional SO_2, NO_x and PM controls or reduction technologies on fossil-fired units. This assumption led to the inclusion of selective catalytic reduction (SCR) systems in the future capital plan for Jeffrey unit 2 and unit 3. Jeffrey unit 1 already has an SCR installed and in service. The timeline selected for these projects is based on EPA’s next Regional Haze planning period which will occur in 2028. It is assumed that a compliance timeline would be agreed upon at that time which would allow the SCRs to be online by the end of 2032 for one unit and 2033 for the other.

6.1.4 Greenhouse Gases

In April 2024, the EPA finalized the Greenhouse Gas (GHG) regulations and GHG guidelines that apply to new and existing fossil fuel fired EGUs. The final GHG regulation establishes CO_2 limitations on emissions from new and reconstructed stationary combustion turbines. The GHG guidelines set CO_2 emission limitations for existing coal, oil and gas-fired steam generating units. For new and reconstructed stationary combustion turbines, the emission limitations were developed by applying the Best System of Emission Reduction (BSER) to three distinct subcategories (low load, intermediate load and base load) taking into consideration the annual capacity factor of the stationary combustion turbine. For intermediate and base load stationary combustion turbines, BSER is assumed to be the utilization of highly efficient combustion turbine technology. Base load stationary combustion turbines are also required to consider the emissions reduction associated with the application of carbon capture and sequestration (CCS) beginning in 2032. For existing coal-fired EGUs, the emission limitations were established by applying the BSER to two subcategories (medium and long-term). For medium-term existing coal-fired units, which are units retiring between 2032 and 2038, the BSER established emission limitation is based on co-firing natural gas beginning in 2030. For units operating in 2039 and after, BSER is the application of CCS starting in 2032. In July 2024, the D.C. Circuit denied motions of stay filed by various states, industry and trade organizations; however, the D.C. Circuit has ordered expedited review of the challenges to the final regulations and guidelines. In December 2024, a three-judge panel of the D.C. Circuit heard oral arguments on challenges to the merits of the rule. In February 2025, EPA filed an unopposed motion to ask the D.C. Circuit to hold the case in abeyance while the new Administration determines their next steps regarding the future of these regulations.

6.1.5 Mercury and Air Toxics Standards

In April 2024, the EPA finalized a rule to tighten certain aspects of the Mercury and Air Toxics Standards (MATS) rule. The EPA is lowering the emission limit for particulate matter (PM) and requiring the use of PM continuous emissions monitors (CEMS). It is anticipated that Evergy Metro will be able to comply with the current PM standard on rule effective date of July 2027. However, further strengthening of the PM emission limitation could require Evergy Kansas Central to consider additional PM controls at the Jeffrey Energy Center.

6.2 Water Emission Impacts

6.2.1 Effluent Limitation Guidelines (ELG)

The Evergy Companies discharge some of the water used in generation and other operations containing substances deemed to be pollutants. In April 2024, the EPA finalized an update to the Effluent Limitation Guidelines (ELG) for steam electric power generating facilities to address the vacated limitations and prior reviews of the existing rule. Flue Gas Desulfurization (FGD) wastewater, bottom ash transport wastewater (BATW), coal residual leachate (CRL), and legacy wastewater are addressed in the rulemaking. FGD, BATW and CRL at operating facilities are required to achieve zero liquid discharge as soon as feasible and no later than December 2029. The Evergy Companies have reviewed the modifications to limitations on FGD wastewater and bottom ash transport water and the Evergy Companies do not believe the impact to be material. The Evergy Companies are reviewing the limitations on CRL, its impact on their operations and financial results and believe the cost to comply will not be material. In June 2024, multiple legal challenges to the ELG were consolidated in the Eighth Circuit. In October 2024, the Eighth Circuit denied a motion to stay the ELG. Additional litigation is ongoing that could impact the timing or cost to comply.

6.2.2 Clean Water Act Section 316(A)

Evergy's river plants comply with the calculated limits defined in the current permits. Hawthorn and Iatan Generating Stations' water discharge permits issued February 1, 2022, and April 1, 2023, respectively, contain future thermal discharge limits that become effective no later than February 1, 2032. The compliance period will be utilized by Evergy to study both discharge conditions and conditions of the receiving river to finalize compliance plans. Application of these future limitations or future regulations that could be issued that restrict the thermal discharges may require alternative cooling technologies to be installed at coal-fired units using once through cooling, a reduction or shutdown of certain plants during periods of high river water temperature, or application of a thermal variance process.

6.2.3 Clean Water Act Section 316(B)

In May 2014, the EPA finalized standards to reduce the injury and death of fish and other aquatic life caused by cooling water intake structures at power plants and factories. The rule could require modifications to cooling water inlet screens and fish return systems. Intake structures at applicable facilities are evaluated and any modifications permitted through site specific wastewater discharge permits with state agencies.

6.2.4 Zebra Mussel Infestation

Evergy monitors for zebra mussels at generation facilities, and a significant infestation could cause operational changes to the stations.

6.2.5 Total Maximum Daily Loads

A Total Maximum Daily Load (TMDL) is a calculation of the maximum amount of a given pollutant that a body of water can absorb before its quality is impacted. A stream is considered impaired if it fails to meet Water Quality Standards established by the Clean Water Commission. Future TMDL standards could restrict discharges and require equipment to be installed to minimize or control the discharge.

6.3 Waste Material Impact

6.3.1 Coal Combustion Residuals (CCR's)

In the course of operating their coal generation plants, Evergy Kansas Central produces CCRs, including fly ash, gypsum and bottom ash. The EPA published a rule to regulate CCRs in April 2015 that required additional CCR handling, processing and storage equipment and closure of certain ash disposal units.

In April 2024, the EPA finalized an expansion to the CCR regulations focused on legacy surface impoundments and historic placements of CCR. This regulation expands the applicability of the 2015 CCR regulation to inactive landfills and beneficial use sites not previously regulated. On August 2, 2024, East Kentucky Power Cooperative (EKPC) filed a petition for review of the Legacy/CCRMU Rule in the D.C. Circuit, which was subsequently consolidated with other petitions for review filed by industry groups and members, a coalition of states, and City Utilities of Springfield. On November 1, 2024, the D.C. Circuit denied EKPC's motion to stay the Legacy/CCRMU Rule and EPKC subsequently filed an application for immediate stay with the United States Supreme Court. In December 2024, the Supreme Court denied the stay application. Additional litigation could impact the timing or cost to comply.

Section 7: Demand-Side Resource Analysis Update

7.1 Changes from the 2024 Triennial IRP

Evergy has not conducted a new DSM Market Potential Study since 2023. Therefore, no new DSM potential forecast is included in this 2025 IRP Annual Update. However, Application (22-EKME-254-TAR) for demand-side management programs in Kansas under the KEEIA Cycle 1 framework has been approved by the Kanas Corporate Commission. Evergy's base case includes impacts of KEEIA Cycle 1 energy efficiency and demand response programs as approved by the Commission.

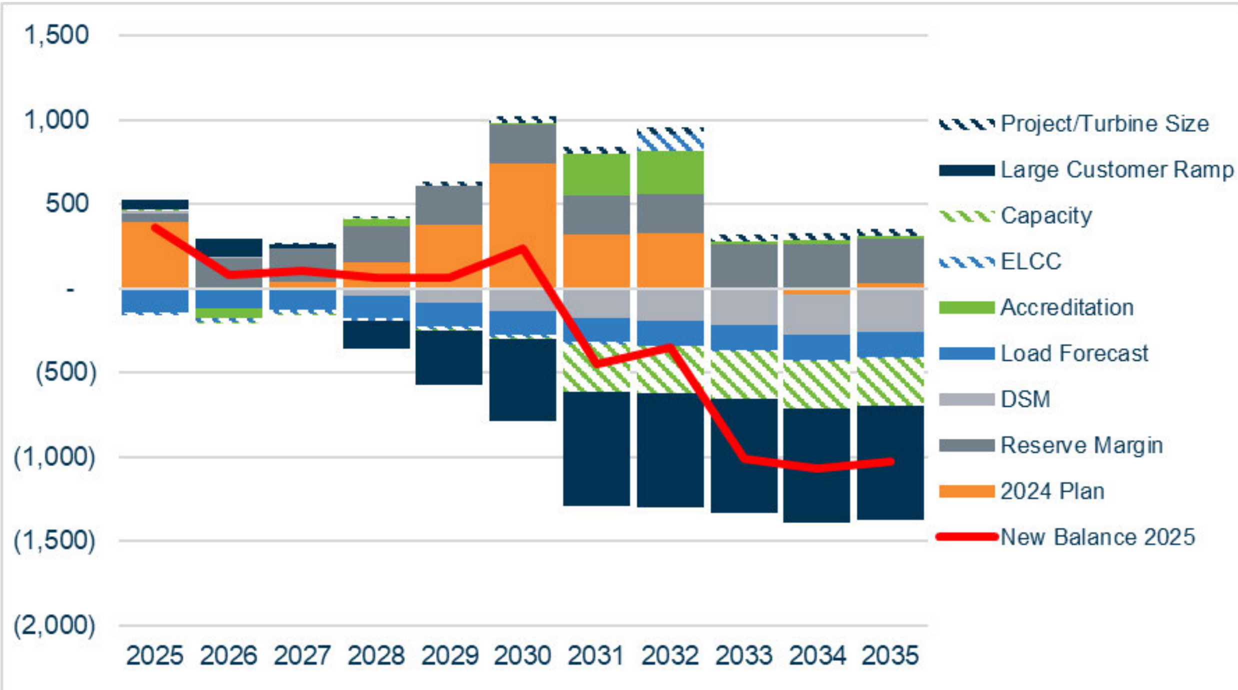
Section 8: Resource Plan Analysis

8.1 Changes to Expected Capacity Needs

Evergy Kansas Central's 2024 Preferred Portfolio forecasted a summer capacity surplus in 2025, followed by a small deficit in 2026, and increasing surpluses from 2027-2030 with the addition of new solar each year, and ½ CCGT shares in 2029 and 2030. The summer capacity position decreased in 2031-2032 with the retirements of Jeffrey 2 & 3 offset partly by addition of a CCGT and more solar and demand-side program growth. After the 2032 retirement of La Cygne 1, Kansas Central was relatively flat summer capacity.

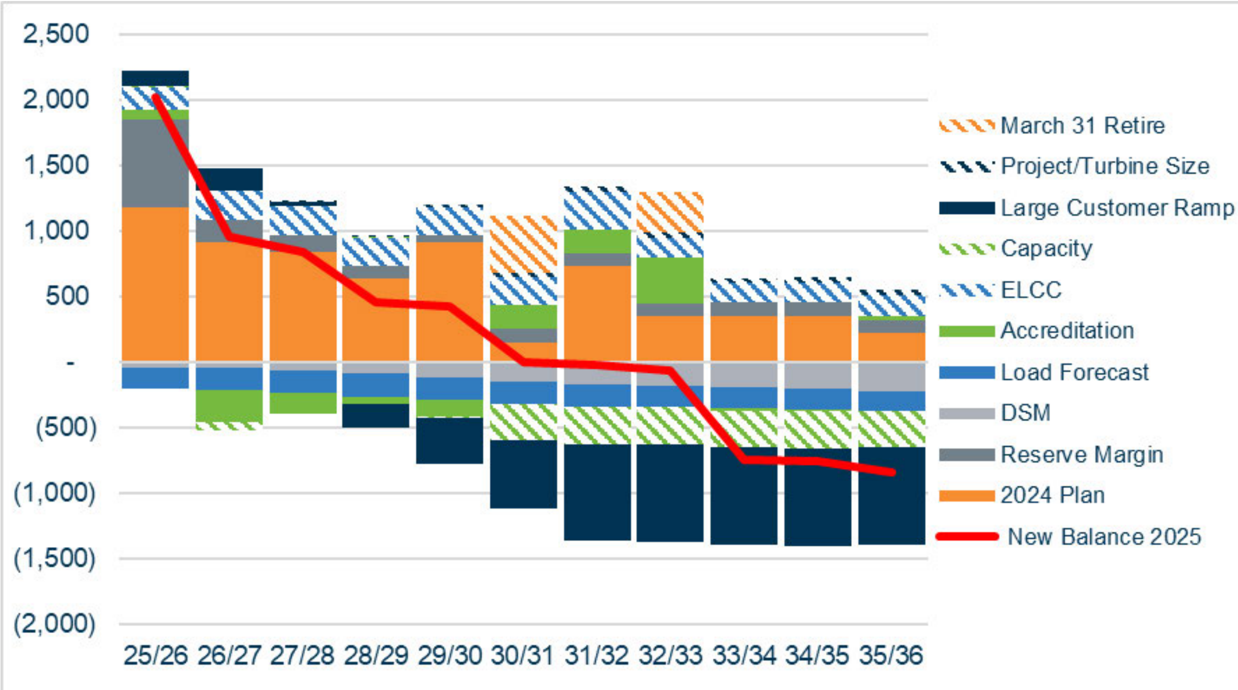
Evergy Kansas Central's current forecast updates for the 2025 IRP have reduced expected capacity length through 2030, and the 2024 Preferred Portfolio builds are insufficient to meet capacity needs beginning in 2031. In 2025-2027 the large customer load ramp forecast is lower than the placeholder in the 2024 IRP, however beginning in 2028, the forecast is higher and grows substantially from last year's IRP assumptions. A higher base load forecast, lower levels of future demand-side programs, and renewal of a wholesale contract also caused reductions to the capacity position from the previous IRP projections. Changes to reserve margin assumptions and resource accreditation increased the capacity position.

Figure 20: Changes to Evergy Kansas Central Summer Capacity Position



Evergy Kansas Central's 2024 Preferred Portfolio resulted in a winter capacity surplus throughout the planning horizon. Changes for the 2025 IRP still result in a surplus through winter 2029/30. In winters 2030/31 – 2032/33 Evergy Kansas Central is balanced with the 2024 IRP Preferred Portfolio resource additions and retirements, but beginning in 2033/34 winter, the portfolio becomes short by almost 750 MW. Reductions to the capacity position were driven by a higher base load forecast, large customer load additions, lower levels of future demand-side programs assumed, and renewal of a wholesale contract. Changes to ELCC accreditation assumptions increased the capacity position, while thermal resource accreditation reduced net capacity in winters 2026/27-2029/30, but increased net capacity in winters 2030/31-2032/33. Moving the coal plant retirement dates to end of winter, rather than end of year also helped the capacity position in winter 2030/31 and winter 2032/33.

Figure 21: Changes to Evergy Kansas Central Winter Capacity Position



8.2 Base Planning Options

8.2.1 Resource Availability

All resource plans include the development projects that are currently undergoing predetermination in Kansas, including Kansas Sky solar in 2027 and ½ share of Viola and ½ share of McNew CCGTs in 2029 and 2030.

Evergy Kansas Central's base planning assumptions include limiting the number of project additions each year to ensure the company continues to meet financial metrics and maintain an investment-grade credit rating. The project limit assumption is two solar or storage resources or one other type of new resource per year.

Table 14: Base Build Limit Assumptions

Year	Solar	Wind	Battery	CC	CT
2027	159 MW	n/a	n/a	n/a	n/a
2028	300 MW	150 MW	300 MW	n/a	n/a
2029	300 MW	150 MW	300 MW	n/a	n/a
2030	300 MW	150 MW	300 MW	n/a	n/a
2031+	300 MW	150 MW	300 MW	710 MW	440 MW

Consistent with stakeholder feedback, alternative resource plans were developed to determine other options to meet customer needs. Because most of Evergy Kansas Central's wind generation is sourced from PPAs which will expire over the planning horizon, allowing more wind build beginning in 2035 was explored.

Table 15: Higher Wind Build Limits 2035+

Year	Solar	Wind	Battery	CC	CT
2027	159 MW	n/a	n/a	n/a	n/a
2028	300 MW	150 MW	300 MW	n/a	n/a
2029	300 MW	150 MW	300 MW	n/a	n/a
2030	300 MW	150 MW	300 MW	n/a	n/a
2031-2034	300 MW	150 MW	300 MW	710 MW	440 MW
2035+	300 MW	300 MW	300 MW	710 MW	440 MW

8.2.2 Retirements

Evergy Kansas Central assumes that if it continues to operate coal resources, it will comply with all environmental and other regulations to keep the plants maintained. These costs are included in the expected value of the resource plan.

The 2024 Preferred Portfolio included the retirements of Lawrence 4 in 2028, Jeffrey 2 & 3 in 2030, La Cygne 1 in 2032, La Cygne 2 in 2039, and Jeffrey 1 in 2039. Lawrence 5 was expected to cease coal operation in 2028 and operate only on natural gas in the future.

Based on the age and condition of the Lawrence resources, Evergy Kansas Central is assuming that the longest life extension of these resources would enable operation through 2032. As a base assumption, Lawrence 5 is expected to transition to natural gas operation in 2029, consistent with past IRP preferred portfolios, but cease operation after winter 2032. In this Annual Update, Evergy Kansas Central considered extending Lawrence 4 on natural gas, similarly to Lawrence 5 with the operational transition occurring in 2029 and retirement after winter 2032. Since Lawrence 4 is also connected to a natural gas pipeline, this is a low-cost way to extend the resource operation for a few years to bridge capacity needs. Evergy Kansas Central also considered conversion of the Jeffrey 2 coal plant to natural gas. Conversion of the resource would allow retention of the capacity to meet reliability needs and avoid the need for costly capital investment in selective-catalytic-reduction upgrades that are needed to comply with environmental rules if the unit continues to burn coal. Evergy expects that when Jeffrey 2 retires, it will be replaced by a natural gas-fired resource which will continue to use the natural gas infrastructure investment.

The 2025 IRP coal retirement and conversion scenarios include:

- Preferred Portfolio 2024 (with LEC 5 2032 retirement)
- Extension of Lawrence 4 on natural gas 2029-2032
- Extension of Jeffrey 2 on natural gas 2030+
- Extension of Jeffrey 2 to 2039
- Retirement of La Cygne 2 in 2032
- Extension of La Cygne 1 to 2039

In this Annual Update, Evergy Kansas Central tested retirement dates for the end of the winter season in the retirement year. For example, a 2030 retirement was modeled as 12/31/2030 in the 2024 Triennial, but is modeled as 3/31/2031 in the 2025 Annual Update. Due to the winter capacity requirements in SPP going forward, Evergy is modeling the loss of accredited capacity through retirement to occur after the winter season, and the gain of accredited capacity through new build to begin in the summer season. It is not clear with current SPP rules whether a winter requirement could be partly met by a retiring resource (through December) and then met by a new resource (beginning in January). Evergy Kansas Central may have some flexibility in retirement dates depending on how

SPP policy evolves, however, it would coordinate the retirement timing with new resources coming online to assure continuity of capacity, if needed.

8.3 Alternative Resource Plan Testing

Evergy Kansas Central developed various scenarios to test the most cost-effective future resource mix to meet customer needs, using capacity expansion modeling:

- Testing alternative coal retirement/conversion scenarios
- Testing the economics of plans without 2031 thermal resources, and with other resources instead
- Testing plans with different future critical uncertain factor expectations
- Testing how varying capital spend/number of projects per year would influence the resource plan decisions and economics

Table 16: Plan Key for Base Plans

DSM	Coal (Changes from 2024 PP)	Builds	Load & Contingencies
A - KEEIA Extends	A – 2024 PP Retirements (LEC 4 ret 2028, LEC 5 NG 2028 ret 2032, ret JEC 2 2030)	A – Base capital + predetermination builds	A - Base load
	B - Extend LEC 4 NG 2028 ret 2032	D - Allow higher wind 2035+	P - High NG, High CO_2 Restriction
	C- Extend LEC 4 NG 2028 ret 2032, Extend JEC 2 NG 2030	F - Only renewables/storage; relaxed build limit	Q - Low NG, Low CO_2 Restriction
	D- Extend LEC 4 NG 2028 ret 2032, Extend JEC 2 2039	G - No 2031 CT	R - High NG, Mid CO_2 Restriction
	E- Extend LEC 4 NG 2028 ret 2032, Extend JEC 2 NG 2030, Ret La Cygne 2 2032	H - No 2031 Thermal	
	F- Extend LEC 4 NG 2028 ret 2032, Extend JEC 2 NG 2030, Extend La Cygne 1 2039	J - No Kansas Sky	

Table 17: Base Plan Descriptions

Plan Name	Description
AAAA	Base Planning Assumptions, 2024 PP Retirements
ABAA	Extend LEC 4 NG 2028-2032
ACAA	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030
ACAP	High NG/High CO_2
ACAQ	Low NG/Low CO_2
ACAR	High NG/Mid CO_2
ACFP	High NG/High CO_2, Only renewables/storage relaxed build limit
ACGA	No 2031 CCGT
ACHA	No 2031 Thermal
ACJA	No Kansas Sky
ADAA	Extend LEC 4 NG 2028-2032, Extend JEC 2 2039
AEAA	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Earlier Retire La Cygne 2 2032
AFAA	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Extend La Cygne 1 Retire 2039

The alternative resource plans generated through this process were tested in each endpoint (future with varied critical uncertain factors) and rankings were developed based on the probability-weighted average net present value revenue requirement (NPVRR), consistent with the 2024 Triennial IRP and the Kansas IRP process.

Table 18: Critical Uncertain Factor Probabilities

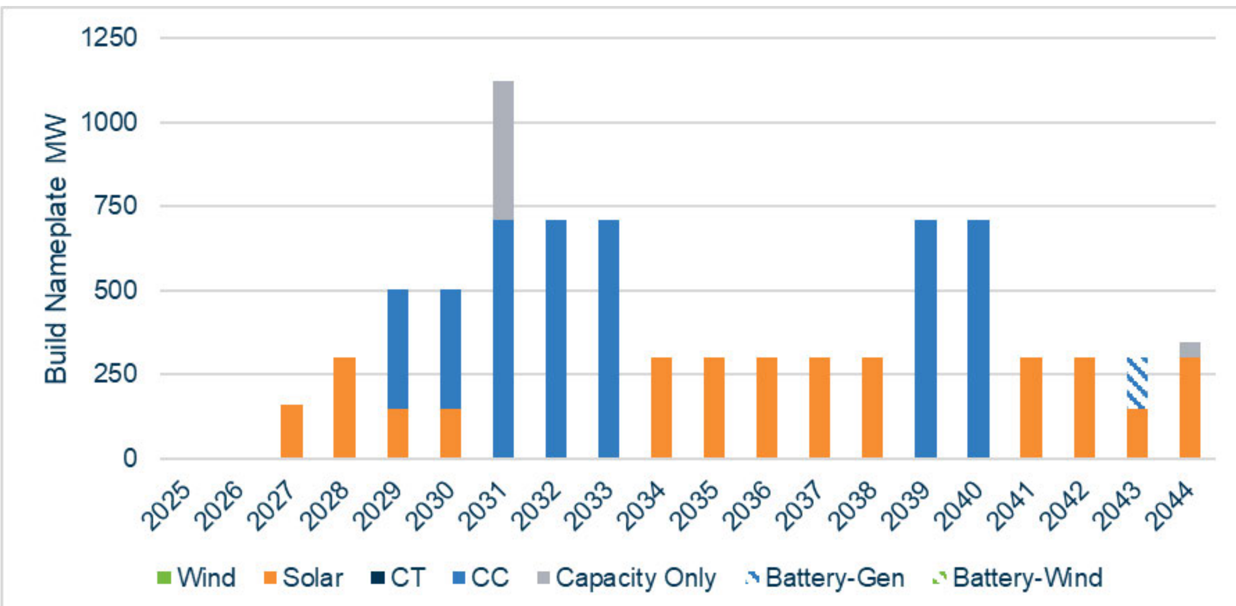
	Natural Gas Price	CO_2 Emissions Restrictions	Construction Cost
Low	35%	25%	25%
Mid	50%	60%	50%
High	15%	15%	25%

8.4 Base Plan

Plan AAAA uses capacity expansion and base planning assumptions, including the updated load and resource adequacy forecasts, retirements identified in the 2024 IRP (with Lawrence 5 operating on natural gas beginning in 2029 and retiring after 2032 winter), and the assumption that KEEIA demand-side programs are maintained at current levels after program expiration. It also includes Kansas Sky solar in 2027, and the ½ shares of Viola and McNew CCGT resources that are in development by Kansas Central and in a predetermination filing.

In addition to the development resources, Plan AAAA includes 300 MW solar in 2028 and 150 MW solar in 2029 and 2030. Due to the increased customer and reliability needs forecasted, the plan requires additional capacity in 2031, exceeding Evergy Kansas Central's preferred build limits. The plan relies on market capacity as a bridge to the next build. Two CCGTs are needed in 2032 and 2033. The plan also requires substantial solar build throughout the planning horizon and additional thermal resources beginning in 2039 as the remaining coal fleet retires.

Figure 22: Base Planning Assumptions Plan AAAA

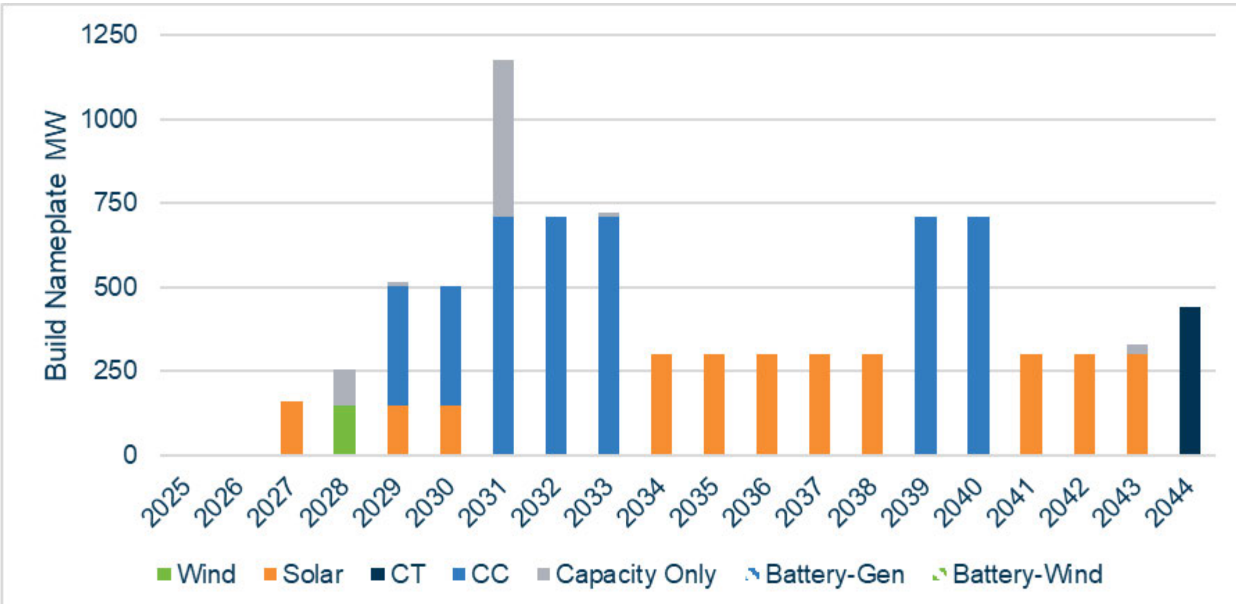


8.5 Plans Testing Coal Retirement and Conversion Options

Alternative resource plans ABAA, ACAA, ADAA, AEAA, and AFAA test additional coal plant planning options. Base build limits are used and the development projects (Kansas Sky, Viola, McNew) are included in the build plan.

Plan ABAA tests the extension of Lawrence 4 (LEC 4) to 2032, with natural gas operation 2029-2032. LEC 4 provides about 100 MW of capacity to the plan for the additional four years. The plan continues to include the 2027-2030 development projects and a full CCGT in 2031. The capacity need in 2031 cannot be met with preferred build limits in 2031 and market capacity is used as a bridge until the next resource addition comes online. Two CCGTs are added in 2032 and 2033. Solar builds total 2,400 MW from 2034-2043, CCGTs are added in 2039 and 2040, and an SCGT is added in 2044.

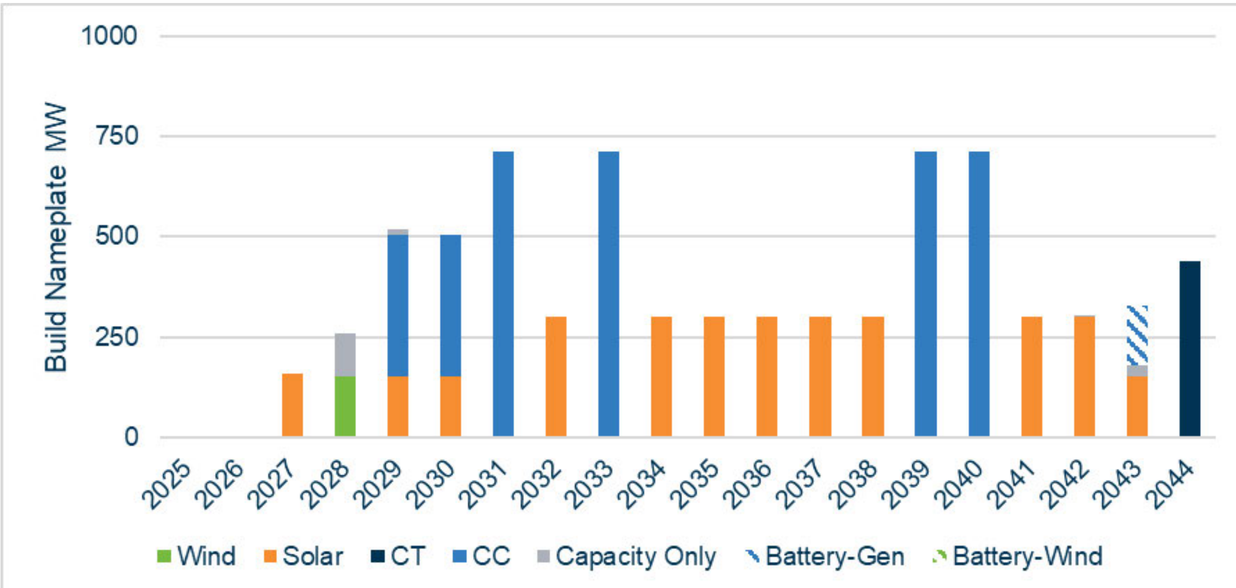
Figure 23: Lawrence 4 on Natural Gas 2029-2032; Retires 2032 Plan ABAA



Plan ACAA continues to operate LEC 4 through 2032 winter, and tests ceasing coal operation at Jeffrey 2 in 2030 and converting the resource to natural gas operation. This plan includes the cost of adding natural gas infrastructure and firm natural gas transportation contracts, but removes the need for SCR investment which is assumed if Jeffrey 2 operates on coal after 2030. The Jeffrey 2 resource provides about 580 MW of summer capacity and 550 MW of winter capacity if it continues operation, however it continues to have the same operational characteristics of a coal resource (heat rate, start up time, etc.) with a more expensive, but lower-emitting fuel (natural gas vs. coal).

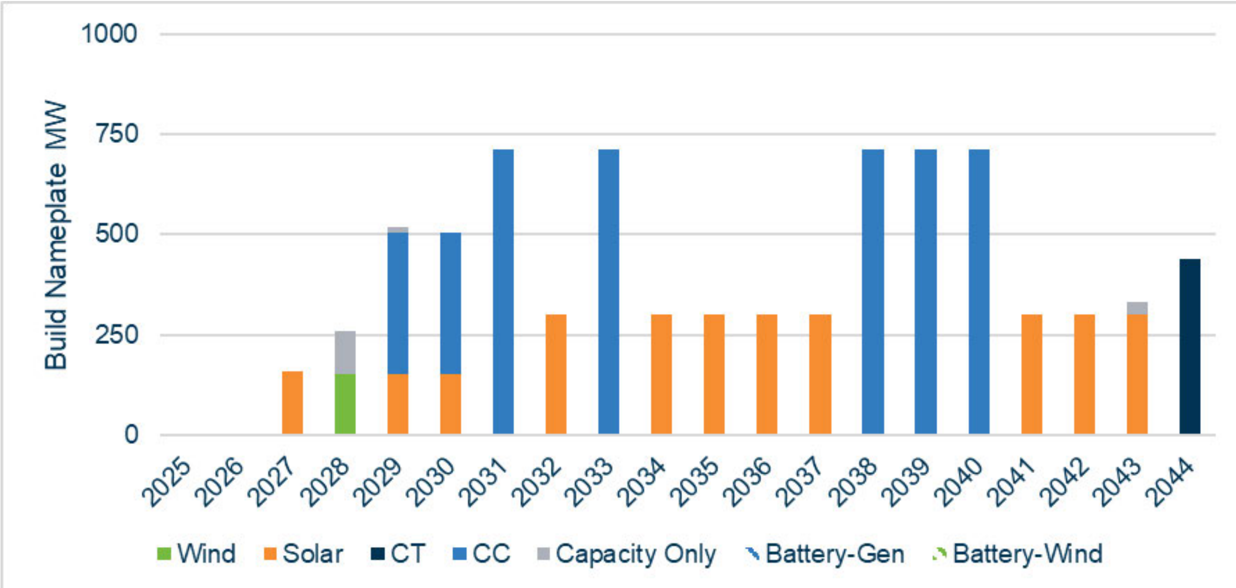
Maintaining operation of Jeffrey 2 enables Kansas Central to meet customer needs within preferred build limits. The resource plan through 2031 includes the 2027-2030 development projects, 150 MW of wind and about 100 MW of market capacity in 2028, 150 MW of solar in 2029 and 2030, and a CCGT in 2031. The plan calls for 2,550 MW of solar, 150 MW of storage, 2,130 MW of CCGT and 440 MW of SCGT in 2032-2044, with the next thermal build in 2033.

Figure 24: Jeffrey 2 Converts to NG 2030, LEC 4 NG 2029-2032 Plan ACAA



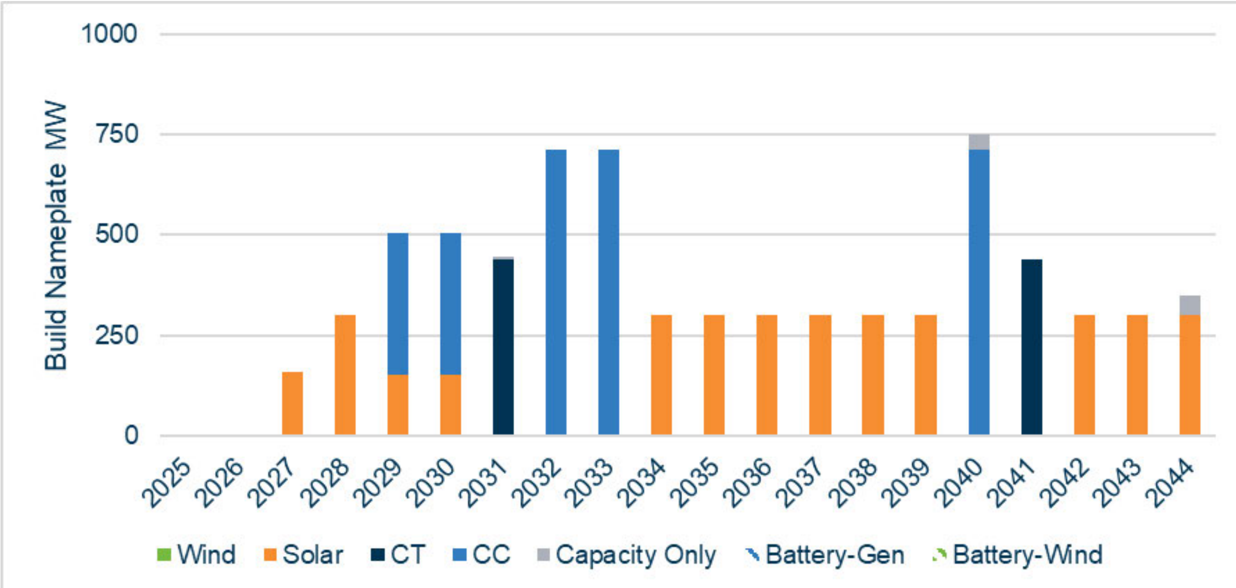
Plan ADAA continues to operate LEC 4 through 2032 winter, and tests extending Jeffrey 2 through 2039 winter. This plan includes the cost of SCR investment and also preserves about 580 MW of summer capacity and 550 MW of winter capacity with continued coal operation. The resource plan is very similar to Plan ACAA, but requires an additional CCGT in 2038 in lieu of solar to replace the Jeffrey 2 retirement, and substitutes solar for storage in 2043.

Figure 25: Jeffrey 2 Extends to 2039, LEC 4 NG 2029-2032 Plan ADAA



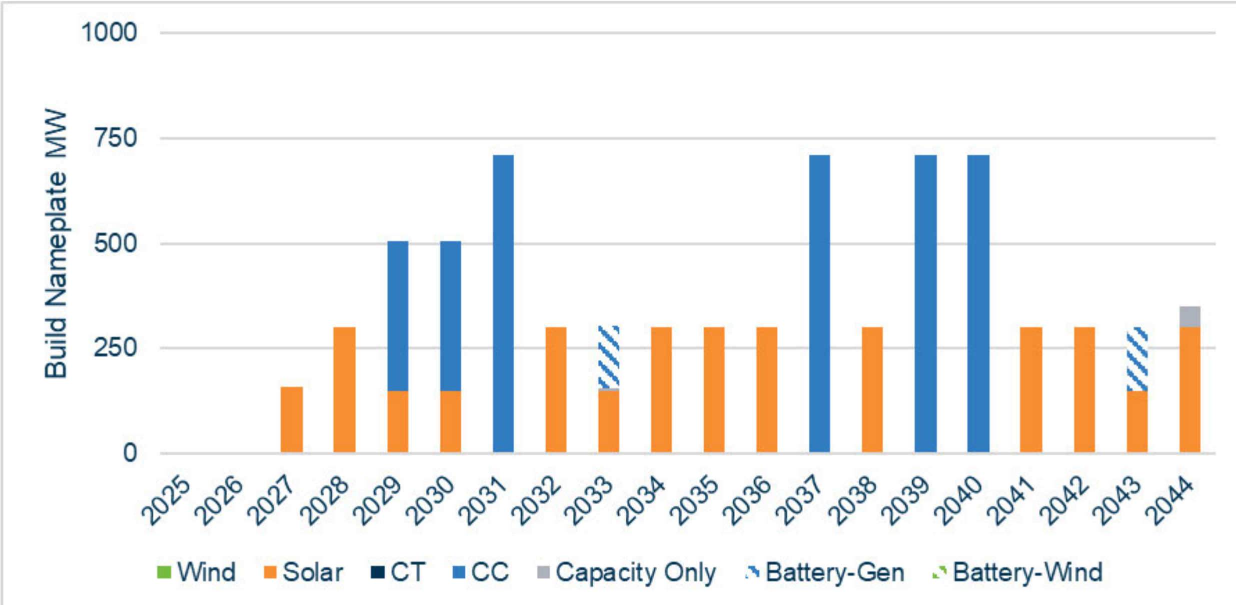
Plan AEAA continues to operate LEC 4 through 2032 winter on NG, converts JEC 2 to NG in 2030, and tests moving forward the retirement date of La Cygne 2 to 2032 (from 2039). La Cygne 2 provides Evergy Kansas Central with about 300 MW of capacity. Retiring La Cygne 2 earlier changes the optimal build needs relative to Plan ACAA to replace wind and market capacity in 2028 with 300 MW of solar, and add an additional thermal build in 2032. Plan AEAA includes an additional SCGT in the 2031-2033 time frame and continues to need the two CCGTs. One fewer thermal resource is needed at the end of the planning horizon.

Figure 26: La Cygne 2 Retires 2032, LEC 4 NG 2029-2032, JEC 2 NG 2030 Plan AEAA



Plan AFAA continues to operate LEC 4 through 2032 winter on NG, converts JEC 2 to NG in 2030, and tests postponing the retirement date of La Cygne 1 to 2039 (from 2032). La Cygne 1 provides Evergy Kansas Central with over 300 MW of capacity. Retiring La Cygne 1 later changes the optimal build needs relative to Plan ACAA to replace wind and market capacity in 2028 with 300 MW of solar, and substitute 150 MW solar and 150 storage for the 2033 CCGT. Plan AFAA pushes back the next thermal resource need (after 2031) to 2037.

Figure 27: La Cygne 1 Retires 2039, LEC 4 NG 2029-2032, JEC 2 NG 2030 Plan AFAA



The 2024 Preferred Portfolio included retiring Lawrence 4 in 2028. Extending the operation of the resource through 2032 on natural gas results in a resource plan that substitutes 300 MW of solar in 2028 with 150 MW of wind, and is almost identical in expected value. Extending Lawrence 4 for a few more years gives Evergy Kansas Central about 100 MW of capacity that may be helpful to mitigate risks around load forecasting, reliability needs, and development timing. This extension is selected as part of the 2025 Preferred Portfolio.

With the large change in capacity needs to meet load and reliability requirements, the plan with the Lawrence 4 extension is still insufficient to meet customer needs in 2031. Plans that push back the Jeffrey 2 retirement from the 2024 Preferred Portfolio date of 2030 enable Evergy Kansas Central to meet customer needs and attain cost savings. Plan ADAA, which tests continuing operation of Jeffrey 2 through 2039 on coal and installing SCR, decreases NPVRR by $85 million. Converting Jeffrey 2 to natural gas in 2030 and continuing to operate it through the time horizon decreases NPVRR by $350 million with Plan ACAA. Both plans substitute a 2032 thermal resource need for 300 MW of solar, and are identical through 2037, until the Jeffrey 2 2039 retirement plan requires an additional CCGT build. Evergy Kansas Central expects that when Jeffrey 2 is retired it will be replaced by a natural gas resource in the same location, due to favorable site characteristics (interconnection, water, etc.). Therefore, adding natural gas capability to the site will be beneficial when the transition occurs. Due to the favorable economics and risk reductions, Plan ACAA is the Preferred Portfolio for 2025.

Evergy Kansas Central is a joint owner of La Cygne 1 & 2 with Evergy Metro. The retirement date testing shows that retiring La Cygne 2 earlier in 2032 significantly increases costs, even with the extension of Jeffrey 2. It also requires an additional thermal resource in 2032. The postponement of the La Cygne 1 retirement date from 2032 to 2039 shows $107 million of economic benefits as it postpones the need for a 2033 CCGT to 2037 and substitutes it with solar and storage in 2033. Evergy Kansas Central is still planning for the resource retirement in 2032 due to the age and condition of the resource and consistent with the Evergy Metro Preferred Portfolio. Due to the lead time, Evergy Kansas Central will have better information in the next couple of years prior to the need to replace the resource.

Table 19: Coal Resource Options Rankings

Rank	Plan	NPVRR	Difference	Description
1	AFAA	38,907		LEC 4 NG 2029-2032, JEC 2 NG 2030, LAC 1 Retires 2039
2	ACAA	39,014	107	LEC 4 NG 2029-2032, JEC 2 NG 2030
3	ADAA	39,278	372	LEC 4 NG 2029-2032, JEC 2 Retires 2039
4	AAAA	39,358	452	2024 PP Retirements
5	ABAA	39,364	457	LEC 4 NG 2029-2032
6	AEAA	39,373	467	LEC 4 NG 2029-2032, JEC 2 NG 2030, LAC 2 Retires 2032

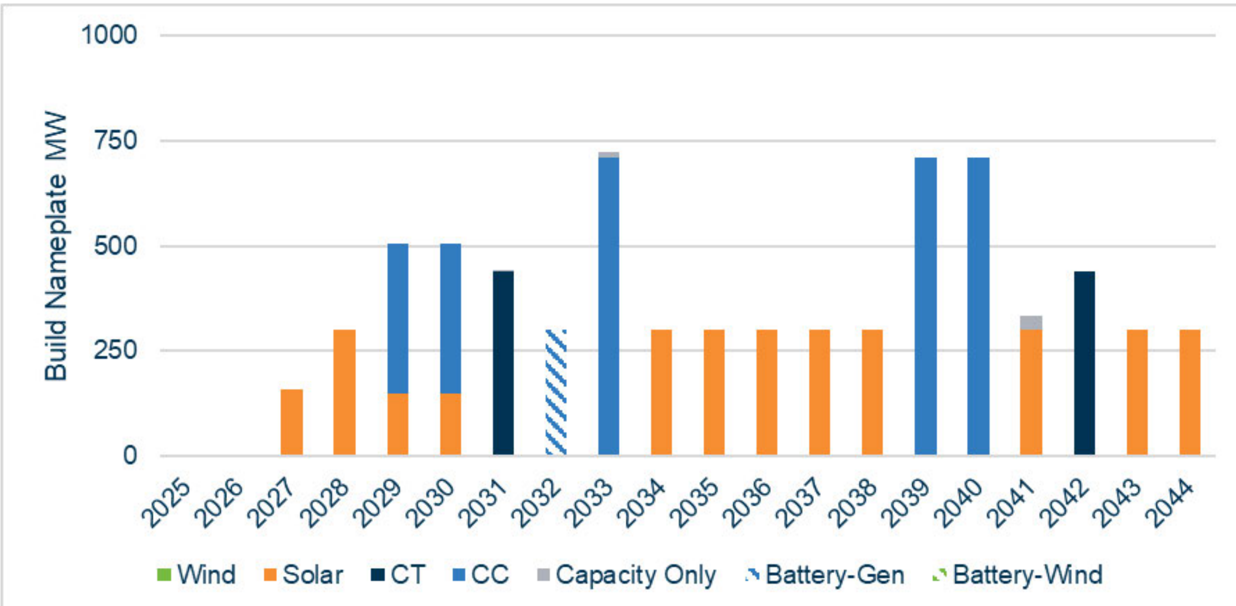
8.6 Plans Testing Near-Term Options

8.6.1 Plans Testing Execution of 2031 CCGT

Evergy Kansas Central is currently developing the Viola and McNew CCGT resources for 2029 and 2030 commercial operation, and is working through predetermination. The next thermal resource in the 2025 Preferred Portfolio is a full CCGT resource in 2031. Plans ACGA and ACHA test other options to understand the tradeoffs of including the 2031 CCGT in the resource plan.

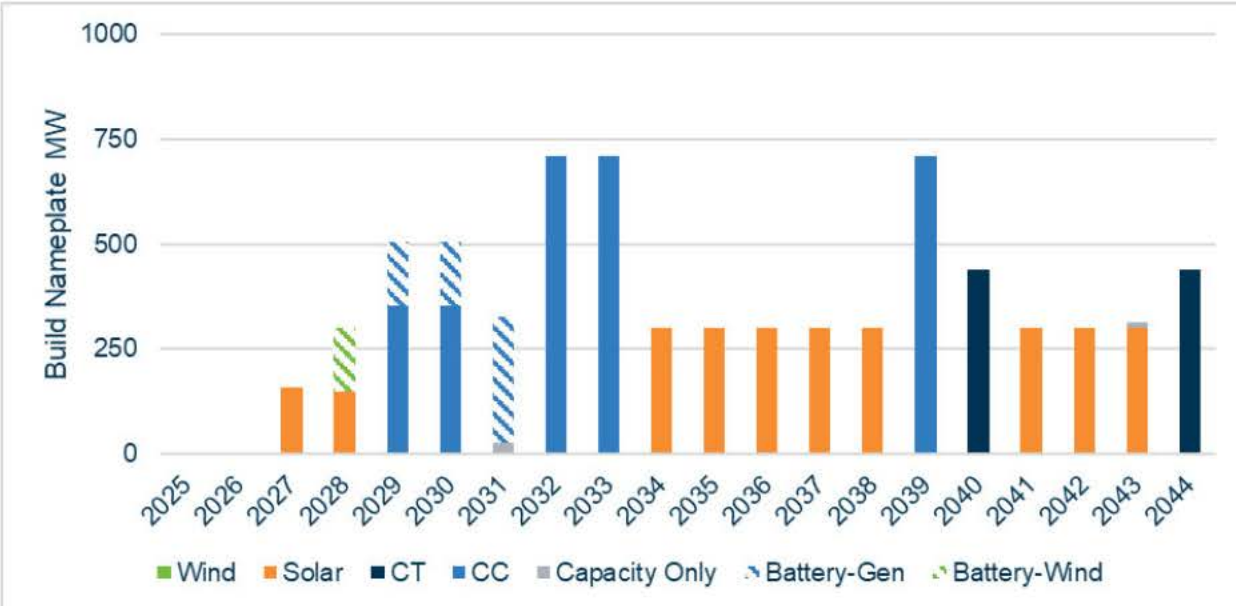
Plan ACGA does not allow a 2031 CCGT build. The optimal plan with this restriction substitutes the 150 MW of wind in 2028 with 300 MW solar, replaces the 2031 CCGT with an SCGT, builds 300 MW storage instead of solar in 2032, and continues to build a CCGT in 2033 followed by solar for the next five years.

Figure 28: No 2031 CCGT Available Plan ACGA



Plan ACHA does not allow any thermal build (CCGT or SCGT) in 2031. The optimal plan with this restriction substitutes the 150 MW of wind in 2028 with 150 MW solar and 150 MW storage, replaces the 2029 and 2030 150 MW solar with 150 MW storage, and the 2031 CCGT with 300 MW storage, and builds a CCGT the next year in 2032, rather than 300 MW of solar. It continues to build a CCGT in 2033 followed by solar for the next five years.

Figure 29: No Thermal Resource in 2031 Plan ACHA



If a 2031 CCGT is not available, the next best option includes an SCGT in the same year, followed by storage. This plan ACGA increases NPVRR by $379 million. If no thermal builds are available in 2031, the optimal plan is to build the CCGT in the next available year, 2032. In order to meet capacity needs, the plan includes 750 MW of storage ahead of that build, increasing NPVRR by almost $1 billion.

Table 20: Rankings for 2031 Build Options

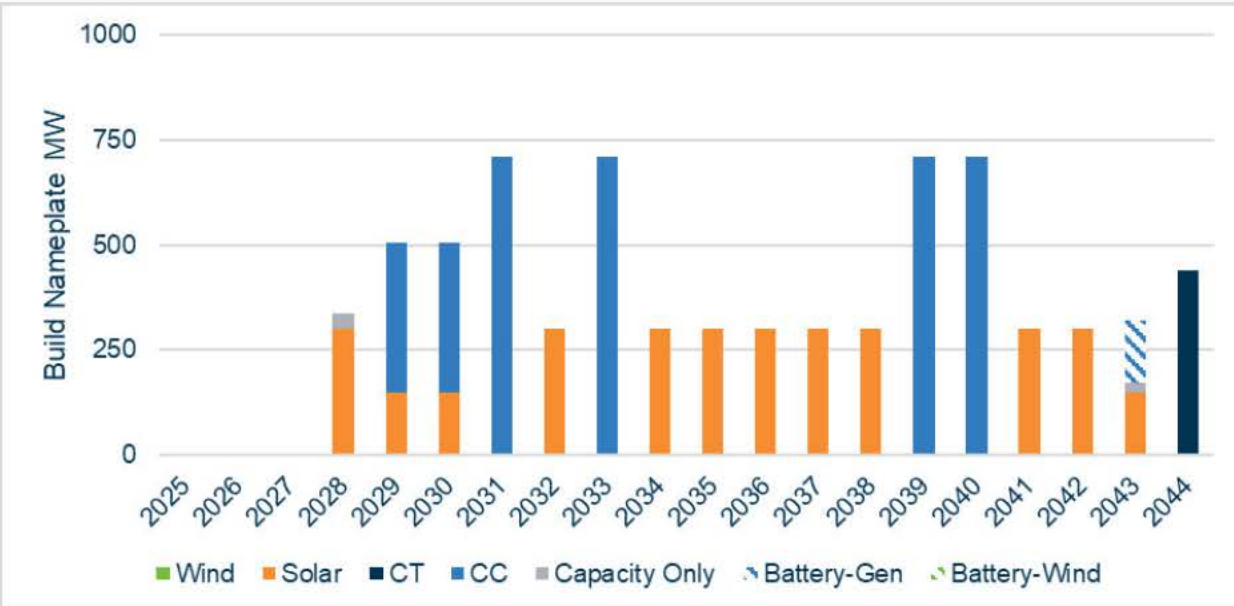
Rank	Plan	NPVRR	Difference	Description
1	ACAA	39,014		2031 CCGT
2	ACGA	39,394	379	No 2031 CCGT
3	ACHA	40,013	999	No 2031 Thermal Resource

8.6.2 Plan without 2027 Solar as an Option

The first renewable resource in the 2025 Preferred Portfolio is solar in 2027. The Kansas Sky project is expected to meet this need, is currently under development, and is included in Evergy Kansas Central's predetermination filing. If the Kansas Sky project is not approved, Evergy Kansas Central does not expect to have other development options that would be available for commercial operation in 2027. Plan ACJA tests the optimal resource plan without Kansas Sky.

Plan ACJA substitutes 300 MW of solar in 2028 for 150 MW of wind. The resource plan includes the same build decisions for the balance of the planning horizon.

Figure 30: No Kansas Sky Plan ACJA



Removing the Kansas Sky project increases NPVRR by $150 million and still requires solar development by the next year, 2028.

Table 21: Rankings for 2027 Solar Options

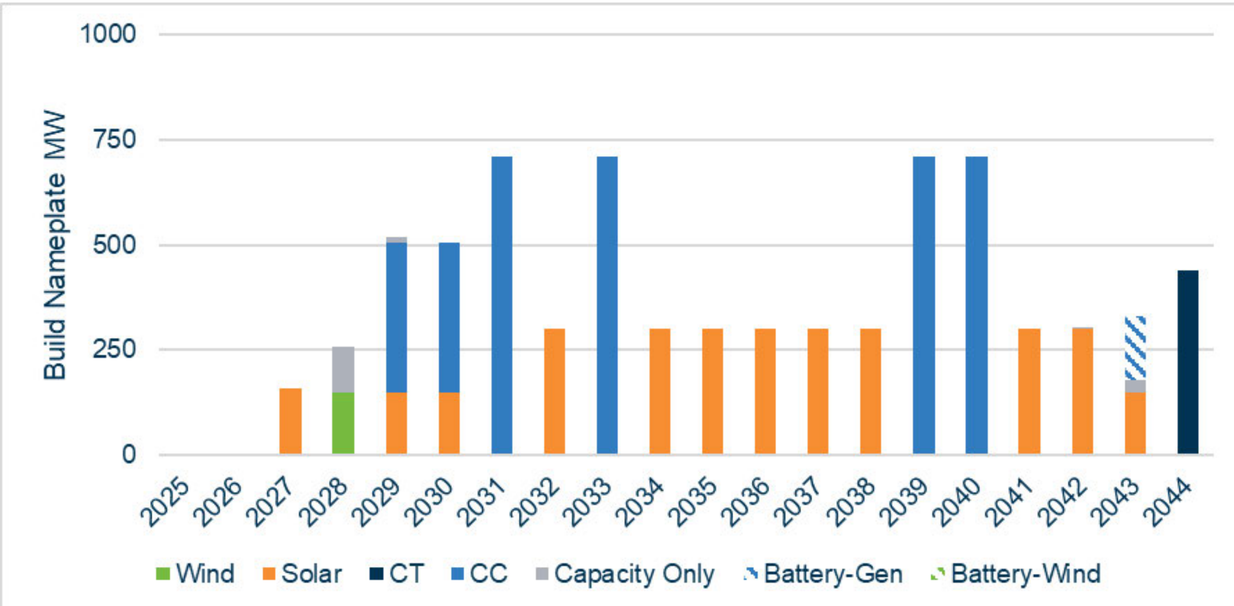
Rank	Plan	NPVRR	Difference	Description
1	ACAA	39,014		Kansas Sky
2	ACJA	39,164	150	No Kansas Sky

8.7 Plans Testing Optimal Builds for Varying Futures

Alternative resource plans ACAP, ACAQ, ACAR, and ACFP test optimal build decisions for varying natural gas and CO2 futures. Base build assumptions and retirements with the option of the 2027 solar are used in all but ACFP, which allows higher renewable and storage builds.

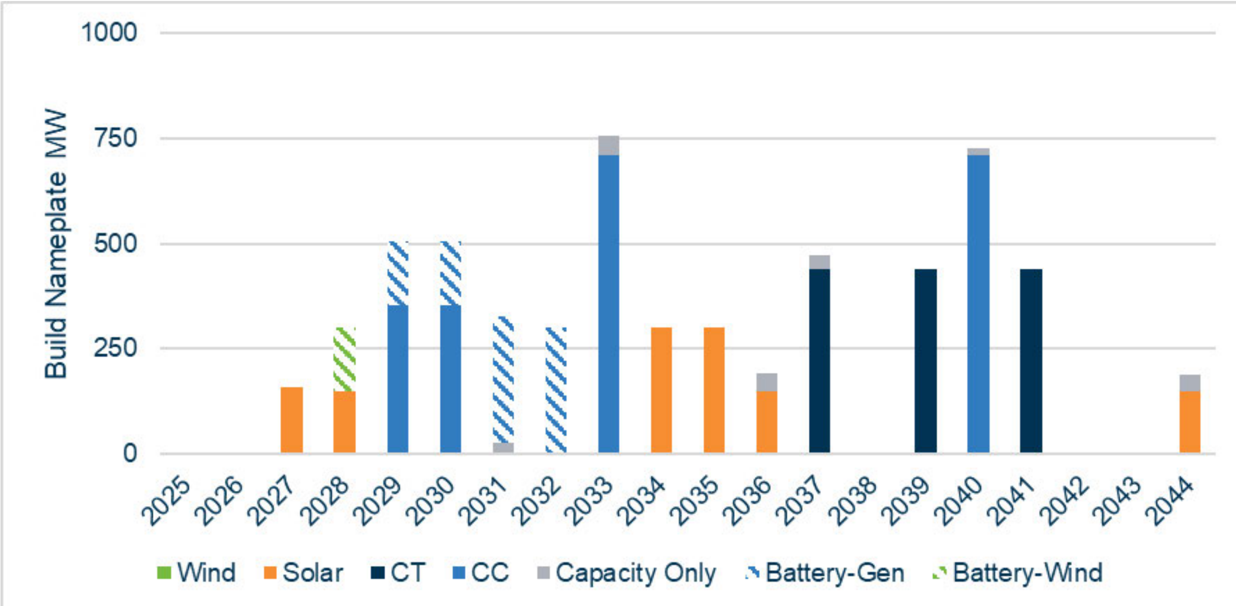
Plan ACAP considers optimal build decisions if a high natural gas price and high carbon dioxide restricted future is expected. The same resource plan is selected as Plan ACAA which uses the mid natural gas price and mid carbon dioxide restriction as the basis for the capacity expansion plan.

Figure 31: High Natural Gas Price, High Carbon Dioxide Restriction Plan ACAP



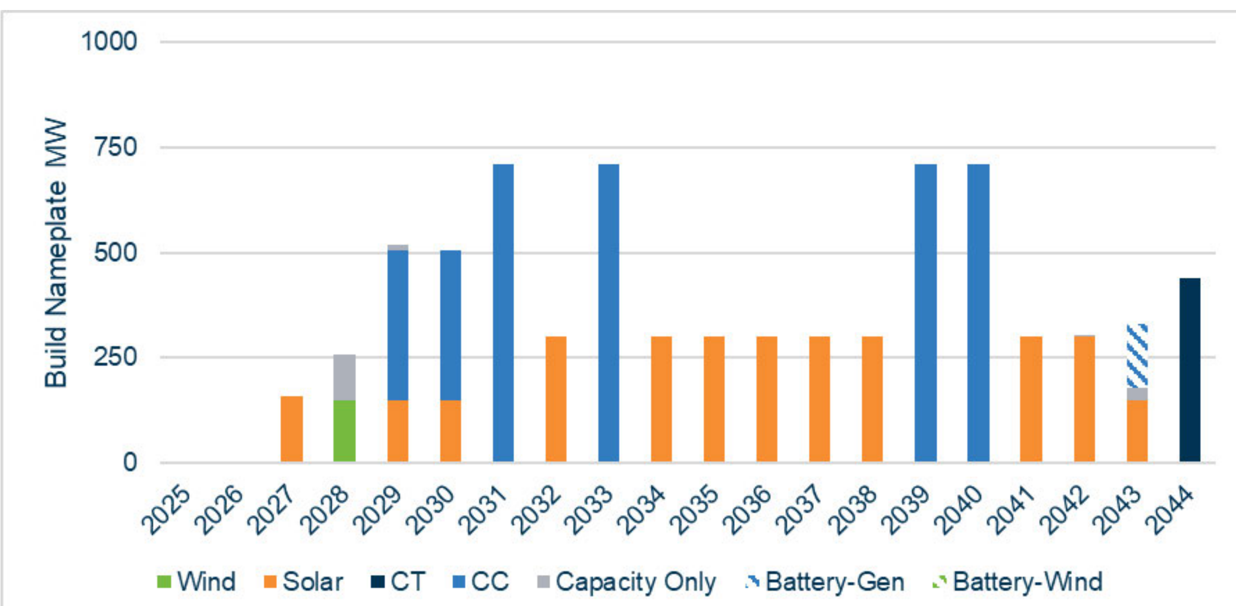
Plan ACAQ considers optimal build decisions if a low natural gas price and low carbon dioxide restricted future is expected. The plan selects 150 MW each of solar and storage instead of wind in 2028. It builds another 900 MW of storage rather than 600 MW of solar and a CCGT in 2029-2032. It continues to build a CCGT in 2033 and pulls the next thermal resource forward to 2037. Overall, less solar, less CCGT and more SCGT capacity is included in the plan.

Figure 32: Low Natural Gas Price, Low Carbon Dioxide Restriction Plan ACAQ



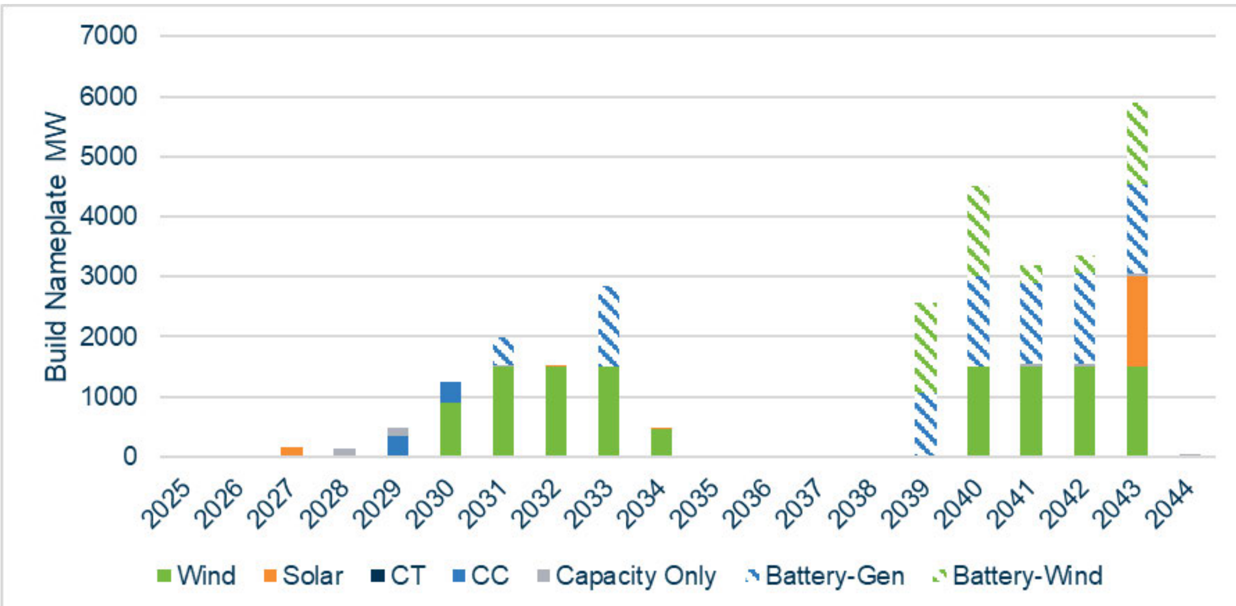
Plan ACAR considers optimal build decisions if a high natural gas price and mid carbon dioxide restricted future is expected. The same resource plan is selected as Plan ACAA which uses the mid natural gas price and mid carbon dioxide restriction as the basis for the capacity expansion plan.

Figure 33: High Natural Gas Price, Mid Carbon Dioxide Restriction Plan ACAR



Plan ACFP considers meeting energy and capacity needs in the future with only renewable and storage builds using the high natural gas and high carbon dioxide restriction future. The resource plan includes the resources under development (Kansas Sky, Viola, McNew) but only allows additional solar, wind and storage and significantly relaxes annual build limits. The plan leans heavily on wind and storage, with almost 12 GW of wind additions and over 13 GW of storage.

Figure 34: High/High Only Renewables and Storage Additions Plan ACFP



Plans ACAA, ACAR, and ACAP which varied the natural gas and carbon dioxide restrictions at the high and mid-levels all chose the same resource plans and have the same expected NPVRR. However, the plan selected with low natural gas prices and no carbon dioxide restrictions was more skewed toward capacity resources (over energy) and had less total builds. This plan, Plan ACAQ, was over $2 billion more expensive when considering the weighted average future expectations. Plan ACFP which only used renewables and storage to meet a high natural gas, high carbon restricted future was the most expensive when considering the weighted average future expectations, adding over $4 billion.

Table 22: Rankings of Plans Optimized for Different Futures

Rank	Plan	NPVRR	Difference	Description
1	ACAA	39,014		Mid NG/Mid CO_2
2	ACAR	39,014	0	High NG/Mid CO_2
3	ACAP	39,014	0	High NG/High CO_2
4	ACAQ	41,351	2,337	Low NG/Low CO_2
5	ACFP	43,179	4,165	High NG/High CO_2, Only renewables/storage relaxed build limits

8.8 Rankings of Base Plans

8.8.1 Risk-Weighted Rankings

Table 23: Overall Plan Rankings

Rank	Plan	NPVRR	Difference	Description
1	AFAA	38,907		Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Extend La Cygne 1 Retire 2039
2	ACAA	39,014	107	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030
3	ACJA	39,164	257	No Kansas Sky
4	ADAA	39,278	372	Extend LEC 4 NG 2028-2032, Extend JEC 2 2039
5	AAAA	39,358	452	Base Planning Assumptions, 2024 PP Retirements
6	ABAA	39,364	457	Extend LEC 4 NG 2028-2032
7	AEAA	39,373	467	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Earlier Retire La Cygne 2 2032
8	ACGA	39,394	487	No 2031 CCGT
9	ACHA	40,013	1,106	No 2031 Thermal
10	ACAQ	41,351	2,444	Low NG/Low CO_2
11	ACFP	43,179	4,272	High NG/High CO_2, Only renewables/storage relaxed build limit
12	ACFA	45,801	6,894	Only renewables/storage relaxed build limit

8.8.2 Carbon Restriction Rankings

Table 24: Rankings for High Carbon Dioxide Restriction Future

Rank	Plan	NPVRR	Difference	Description
1	ACAA	40,513		Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030
2	AFAA	40,671	158	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Extend La Cygne 1 Retire 2039
3	ACJA	40,702	189	No Kansas Sky
4	AAAA	40,789	276	Base Planning Assumptions, 2024 PP Retirements
5	ABAA	40,804	292	Extend LEC 4 NG 2028-2032
6	ADAA	40,833	321	Extend LEC 4 NG 2028-2032, Extend JEC 2 2039
7	AEAA	41,073	560	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Earlier Retire La Cygne 2 2032
8	ACGA	41,746	1,234	No 2031 CCGT
9	ACHA	42,074	1,562	No 2031 Thermal
10	ACFP	44,027	3,514	High NG/High CO_2, Only renewables/storage relaxed build limit
11	ACAQ	45,334	4,821	Low NG/Low CO_2
12	ACFA	46,630	6,117	Only renewables/storage relaxed build limit

Table 25: Rankings for Mid Carbon Dioxide Restriction Future

Rank	Plan	NPVRR	Difference	Description
1	AFAA	39,071		Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Extend La Cygne 1 Retire 2039
2	ACAA	39,158	87	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030
3	ACJA	39,344	273	No Kansas Sky
4	AEAA	39,506	435	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Earlier Retire La Cygne 2 2032
5	ADAA	39,539	468	Extend LEC 4 NG 2028-2032, Extend JEC 2 2039
6	ACGA	39,552	481	No 2031 CCGT
7	AAAA	39,577	506	Base Planning Assumptions, 2024 PP Retirements
8	ABAA	39,579	508	Extend LEC 4 NG 2028-2032
9	ACHA	40,293	1,221	No 2031 Thermal
10	ACAQ	41,928	2,856	Low NG/Low CO_2
11	ACFP	43,035	3,964	High NG/High CO_2, Only renewables/storage relaxed build limit
12	ACFA	45,661	6,590	Only renewables/storage relaxed build limit

Table 26: Rankings for Low (No) Carbon Dioxide Restriction Future

Rank	Plan	NPVRR	Difference	Description
1	AFAA	37,454		Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Extend La Cygne 1 Retire 2039
2	ACAQ	37,577	123	Low NG/Low CO_2
3	ACGA	37,601	147	No 2031 CCGT
4	ADAA	37,719	265	Extend LEC 4 NG 2028-2032, Extend JEC 2 2039
5	ACAA	37,771	317	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030
6	ACJA	37,809	355	No Kansas Sky
7	AAAA	37,975	521	Base Planning Assumptions, 2024 PP Retirements
8	ABAA	37,982	528	Extend LEC 4 NG 2028-2032
9	AEAA	38,035	581	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Earlier Retire La Cygne 2 2032
10	ACHA	38,107	653	No 2031 Thermal
11	ACFP	43,016	5,562	High NG/High CO_2, Only renewables/storage relaxed build limit
12	ACFA	45,639	8,185	Only renewables/storage relaxed build limit

8.8.3 Natural Gas Price Rankings

Table 27: Rankings for High Natural Gas Price Future

Rank	Plan	NPVRR	Difference	Description
1	AFAA	40,505		Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Extend La Cygne 1 Retire 2039
2	ACAA	40,661	156	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030
3	ADAA	40,790	285	Extend LEC 4 NG 2028-2032, Extend JEC 2 2039
4	ACJA	40,837	332	No Kansas Sky
5	AAAA	40,993	488	Base Planning Assumptions, 2024 PP Retirements
6	ABAA	41,011	506	Extend LEC 4 NG 2028-2032
7	ACGA	41,134	629	No 2031 CCGT
8	AEAA	41,140	635	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Earlier Retire La Cygne 2 2032
9	ACHA	41,790	1,285	No 2031 Thermal
10	ACAQ	43,237	2,732	Low NG/Low CO_2
11	ACFP	43,250	2,746	High NG/High CO_2, Only renewables/storage relaxed build limit
12	ACFA	45,699	5,195	Only renewables/storage relaxed build limit

Table 28: Rankings for Mid Natural Gas Price Future

Rank	Plan	NPVRR	Difference	Description
1	AFAA	38,833		Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Extend La Cygne 1 Retire 2039
2	ACAA	38,943	110	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030
3	ACJA	39,088	254	No Kansas Sky
4	ADAA	39,208	374	Extend LEC 4 NG 2028-2032, Extend JEC 2 2039
5	AAAA	39,287	454	Base Planning Assumptions, 2024 PP Retirements
6	ABAA	39,292	458	Extend LEC 4 NG 2028-2032
7	AEAA	39,295	461	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Earlier Retire La Cygne 2 2032
8	ACGA	39,297	464	No 2031 CCGT
9	ACHA	39,918	1,085	No 2031 Thermal
10	ACAQ	41,233	2,400	Low NG/Low CO_2
11	ACFP	43,157	4,323	High NG/High CO_2, Only renewables/storage relaxed build limit
12	ACFA	45,771	6,938	Only renewables/storage relaxed build limit

Table 29: Rankings for Low Natural Gas Price Future

Rank	Plan	NPVRR	Difference	Description
1	AFAA	38,327		Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Extend La Cygne 1 Retire 2039
2	ACAA	38,410	83	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030
3	ACJA	38,555	228	No Kansas Sky
4	AEAA	38,729	402	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Earlier Retire La Cygne 2 2032
5	ADAA	38,732	405	Extend LEC 4 NG 2028-2032, Extend JEC 2 2039
6	AAAA	38,759	432	Base Planning Assumptions, 2024 PP Retirements
7	ABAA	38,761	434	Extend LEC 4 NG 2028-2032
8	ACGA	38,786	459	No 2031 CCGT
9	ACHA	39,388	1,061	No 2031 Thermal
10	ACAQ	40,711	2,384	Low NG/Low CO_2
11	ACFP	43,181	4,854	High NG/High CO_2, Only renewables/storage relaxed build limit
12	ACFA	45,888	7,560	Only renewables/storage relaxed build limit

8.8.4 Construction Cost Rankings

Table 30: Rankings for High Construction Cost Future

Rank	Plan	NPVRR	Difference	Description
1	AFAA	40,191		Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Extend La Cygne 1 Retire 2039
2	ACAA	40,333	141	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030
3	ACJA	40,514	322	No Kansas Sky
4	ACGA	40,624	432	No 2031 CCGT
5	ADAA	40,653	462	Extend LEC 4 NG 2028-2032, Extend JEC 2 2039
6	AEAA	40,721	529	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Earlier Retire La Cygne 2 2032
7	ABAA	40,806	615	Extend LEC 4 NG 2028-2032
8	AAAA	40,829	638	Base Planning Assumptions, 2024 PP Retirements
9	ACHA	41,219	1,027	No 2031 Thermal
10	ACAQ	42,346	2,155	Low NG/Low CO_2
11	ACFP	47,415	7,223	High NG/High CO_2, Only renewables/storage relaxed build limit
12	ACFA	50,700	10,508	Only renewables/storage relaxed build limit

Table 31: Rankings for Mid Construction Cost Future

Rank	Plan	NPVRR	Difference	Description
1	AFAA	39,034		Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Extend La Cygne 1 Retire 2039
2	ACAA	39,152	118	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030
3	ACJA	39,300	267	No Kansas Sky
4	ADAA	39,444	410	Extend LEC 4 NG 2028-2032, Extend JEC 2 2039
5	ACGA	39,491	457	No 2031 CCGT
6	AEAA	39,492	459	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Earlier Retire La Cygne 2 2032
7	AAAA	39,529	496	Base Planning Assumptions, 2024 PP Retirements
8	ABAA	39,537	504	Extend LEC 4 NG 2028-2032
9	ACHA	40,102	1,069	No 2031 Thermal
10	ACAQ	41,395	2,361	Low NG/Low CO_2
11	ACFP	42,924	3,890	High NG/High CO_2, Only renewables/storage relaxed build limit
12	ACFA	45,376	6,342	Only renewables/storage relaxed build limit

Table 32: Rankings for Low Construction Cost Future

Rank	Plan	NPVRR	Difference	Description
1	AFAA	37,369		Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Extend La Cygne 1 Retire 2039
2	ACAA	37,420	51	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030
3	ACJA	37,541	172	No Kansas Sky
4	AAAA	37,546	178	Base Planning Assumptions, 2024 PP Retirements
5	ADAA	37,574	205	Extend LEC 4 NG 2028-2032, Extend JEC 2 2039
6	ABAA	37,575	206	Extend LEC 4 NG 2028-2032
7	AEAA	37,788	419	Extend LEC 4 NG 2028-2032, Extend JEC 2 NG 2030, Earlier Retire La Cygne 2 2032
8	ACGA	37,969	600	No 2031 CCGT
9	ACHA	38,630	1,261	No 2031 Thermal
10	ACFP	39,454	2,086	High NG/High CO_2, Only renewables/storage relaxed build limit
11	ACAQ	40,268	2,899	Low NG/Low CO_2
12	ACFA	41,753	4,384	Only renewables/storage relaxed build limit

8.9 Plans Testing Build Limits and Restrictions

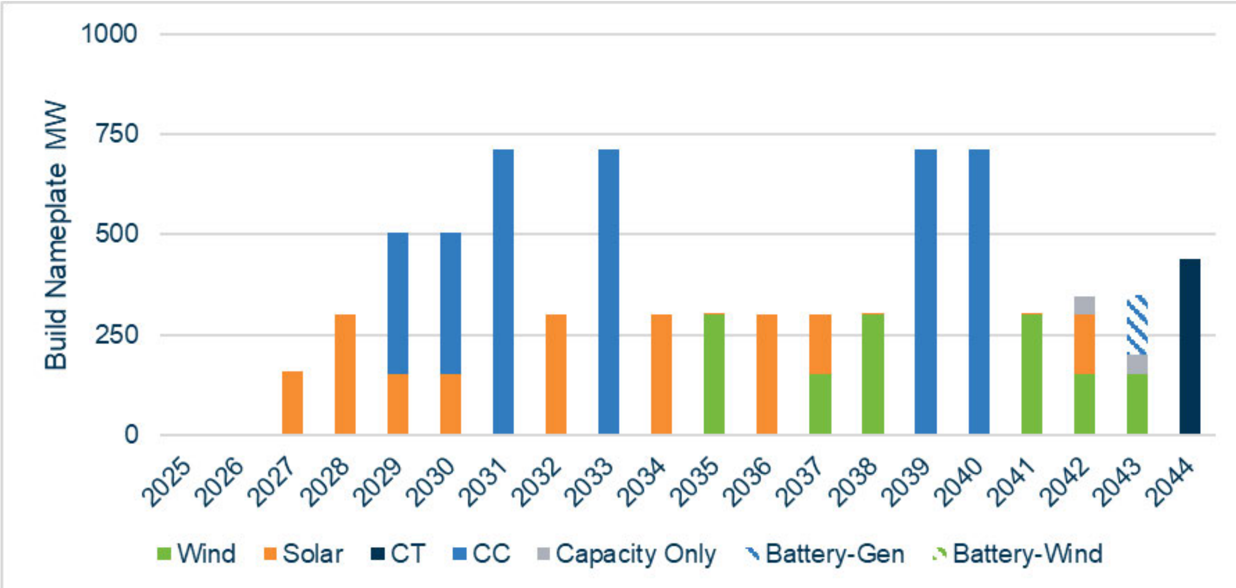
Resource plans ACDA and ACFA test increasing build limits. Both plans assume extension of LEC 4 2029-2032 and JEC 2 conversion to natural gas in 2030.

Table 33: Plans Testing Build Limits

Plan Name	Description
ACDA	Allow higher wind 2035+
ACFA	Only renewables/storage, relaxed build limit

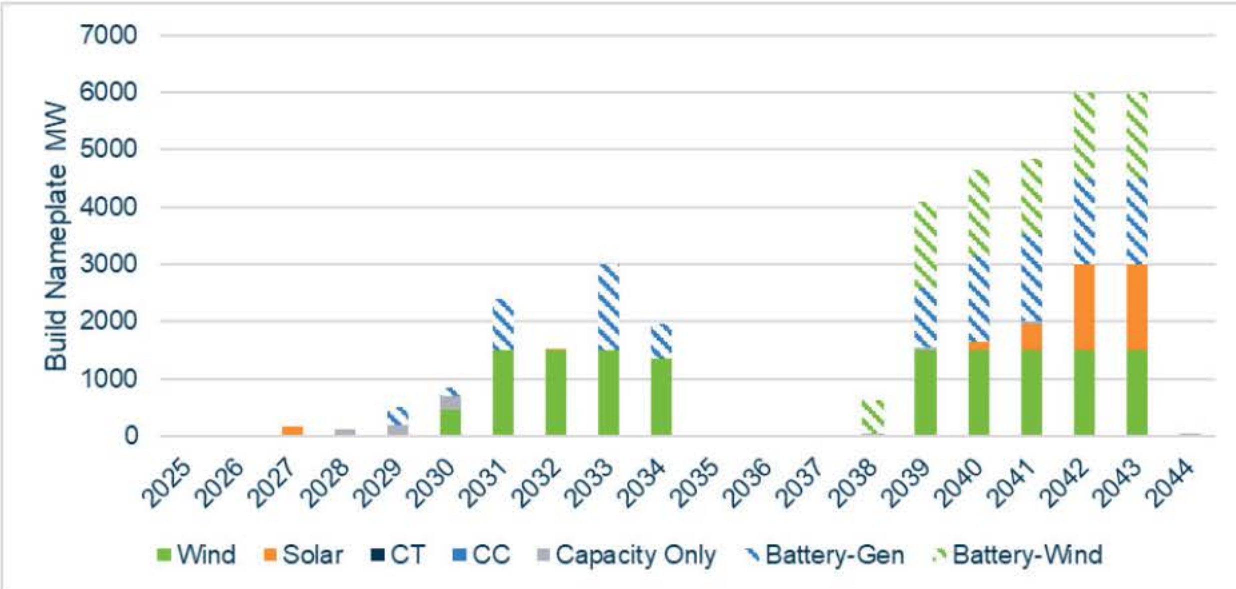
Plan ACDA allows a higher amount of wind to be built in years 2035+. The higher allowed wind builds toward the end of the time horizon remove the 2028 wind and replace it with 300 MW of solar. Beginning in 2035, 1,350 MW of wind is added to the plan and less solar is built.

Figure 35: Allow Higher Wind 2035+ Plan ACDA



Plan ACFA does not allow the selection of thermal resources beyond the predetermination resources, Viola and McNew in 2029 and 2030. The renewables build limits are relaxed to allow up to 1,500 MW of each resource type per year. The plan includes significant additions of storage, wind, and solar. In 2029-2031, 1,350 MW of storage is added, with market capacity supplementing to meet the customer need in 2028-2030. In 2030-2034, 6.3 GW of wind are added and another 2.1 GW of storage is added in 2033-2034. There are a few years when no builds are needed and then beginning in 2038, an additional 7.5 GW wind, 3.6 GW solar, and 15 GW storage are added through the end of the planning horizon.

Figure 36: Only Renewables/Storage, Relaxed Build Limit Plan ACFA



Allowing higher wind builds as PPAs expire in the last 10 years of the planning horizon may be beneficial for customers, enabling low-cost non-emitting energy supply. Evergy Kansas Central will continue to monitor the availability of wind projects and congestion in SPP to determine if owning/contracting more deliverable wind energy can reduce costs as part of the future resource plan.

Table 34: Rankings with Varied Build Limit Plans

Rank	Plan	NPVRR	Difference	Description
1	ACDA	38,805		Allow higher wind 2035+
2	ACAA	39,014	209	Base build limits
3	ACFA	45,801	6,996	Only renewables/storage relaxed build limit

Section 9: Resource Plan Contingency Analysis

Evergy Kansas Central also developed several contingency plans given the uncertainties in the planning process. These include:

- Load variances
  - More load growth early in the plan representing potential new customers of different sizes
  - More load growth later (2031+) in the plan representing potential new customers of different sizes
  - Addition of a next large customer in the queue
- KEEIA demand-side programs not renewed

Table 35: Plan Key for Contingency Analysis

DSM	Coal (Changes from 2024 PP)	Builds	Load & Contingencies
A - KEEIA Extends	C - Extend LEC 4 NG 2028 ret 2032, Extend JEC 2 NG 2030	A – Base capital + predetermination builds	A - Base load
B - KEEIA Ends		E - Allow higher builds 2031+	G- No Market Energy
		I – Allow higher early solar/storage and higher builds 2031+	H - Base load, 50 MW Eco Devo Early
			I - Base load, 150 MW Eco Devo Early
			J - Base load, 250 MW Eco Devo Early
			K - Base load, 50 MW Eco Devo Late
			L - Base load, 150 MW Eco Devo Late
			M - Base load, 250 MW Eco Devo Late
			N - High load (electrification)
			O - Low load
			S - Base load, next large customer

Table 36: Contingency Plan Descriptions

Plan Name	Description
ACAK	Additional 150 MW large load 2031+
ACAL	Additional 250 MW large load 2031+
ACAM	Additional 500 MW large load 2031+
ACAH	Additional 50 MW large load early
ACAI	Additional 150 MW large load early
ACAJ	Additional 250 MW large load early
ACAG	No market energy
ACAO	Low Load
ACEN	High Load and Electrification, Allow higher builds all 2031+
ACIS	Next large customer, Allow higher early solar/storage and higher build 2031+
BCAA	KEEIA Ends

9.1 Load Contingencies

9.1.1 Large Customer Growth

Evergy Kansas Central developed alternative resource plans to determine how additional large customers could be served.

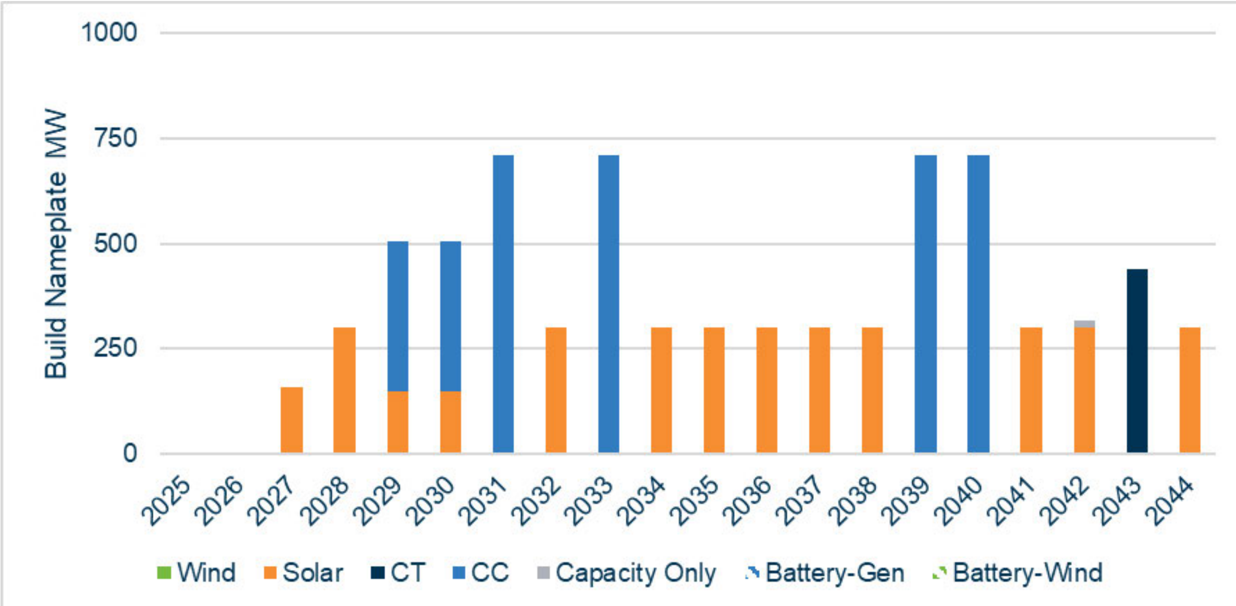
Table 37: Large Customer Growth Scenarios

New Load Scenario	2028	2029	2030	2031	2032	2033+
50 MW Early	20	30	50	50	50	50
150 MW Early	50	100	150	150	150	150
250 MW Early	70	150	250	250	250	250
150 MW Late	0	0	0	50	100	150
250 MW Late	0	0	0	70	150	250
500 MW Late	0	0	0	150	350	500
Next Large Customer	130	230	330	430	530	530

Alternative resource plans ACAH, ACAI, and ACAJ evaluate additional early load ramp.

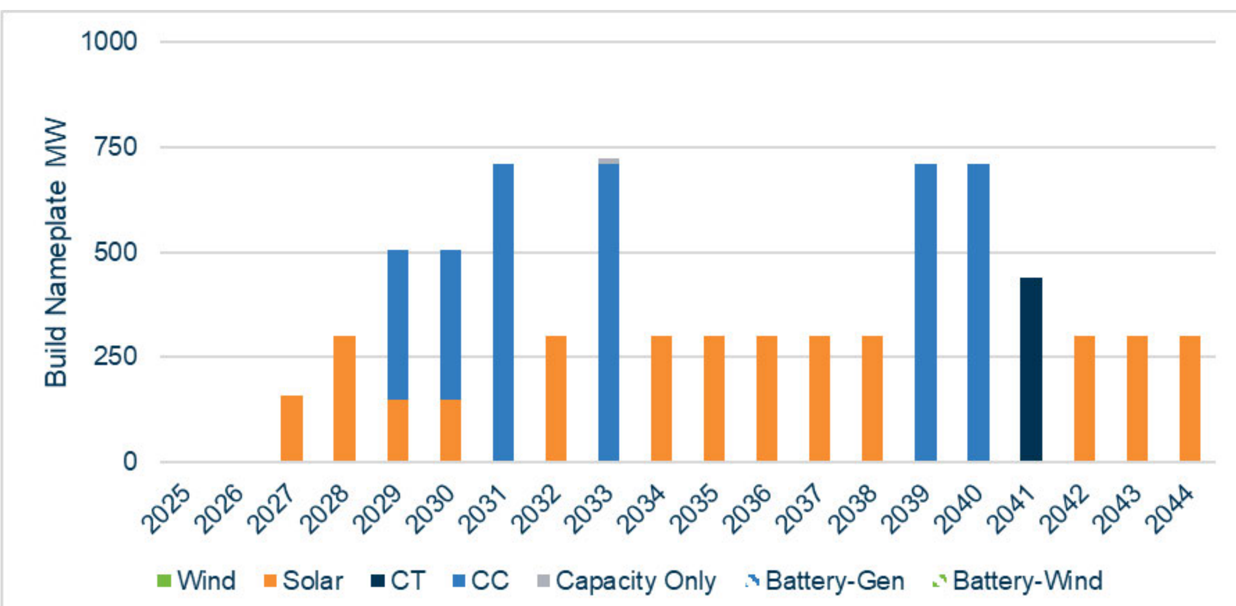
All three resource plans build 300 MW of solar in 2028 rather than 150 MW of wind, but otherwise have the same resource plan as Plan ACAA through 2031. Plan ACAH accommodates an additional 50 MW load with the same resource plan in 2032-2041, adding some market capacity in 2042, moving up the SCGT to 2043, and adding 300 MW of solar in 2044 rather than 150 MW of solar and 150 MW of storage in 2043.

Figure 37: Early 50 MW Load Plan ACAH



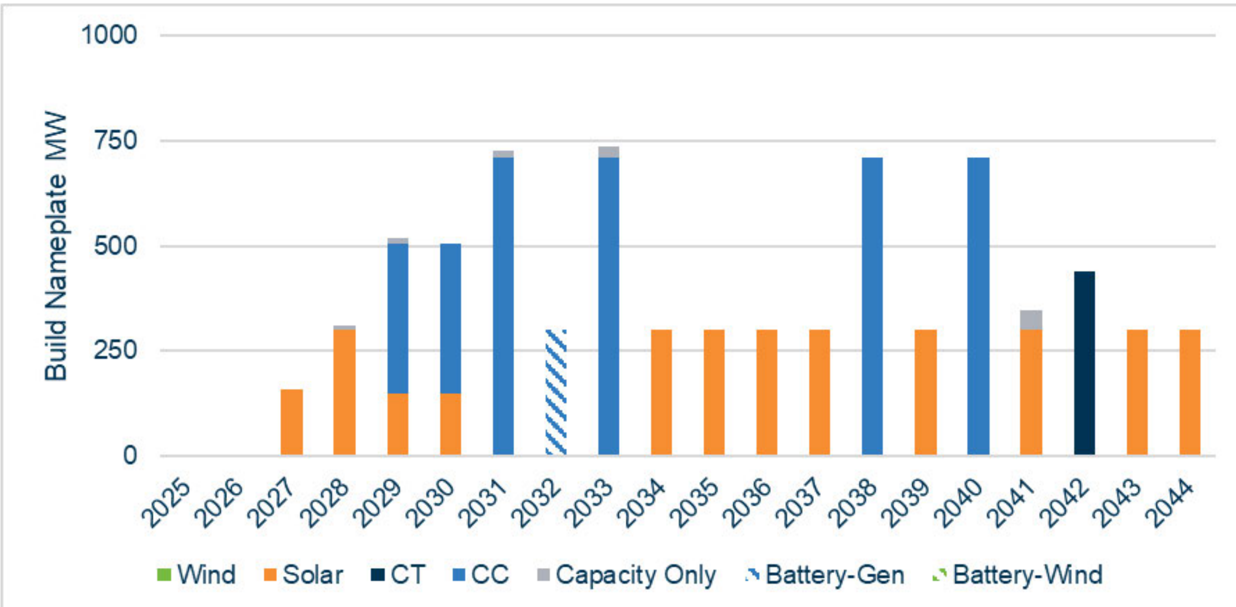
Plan ACAI accommodates an additional 150 MW load with the same resource plan in 2032-2040, but moves the CCGT forward to 2041, and adds 300 MW of solar in each year 2042-2044.

Figure 38: Early 150 MW Load Plan ACAI



Plan ACAJ accommodates an additional 250 MW load by adding some additional market capacity in 2028, 2029, 2031 and 2033. It also replaces 300 MW of solar in 2032 with 300 MW of storage, moves forward the 2039 CCGT to 2038, moves forward the 2044 SCGT to 2042, and replaces 150 MW of storage in 2043 with 150 MW of solar.

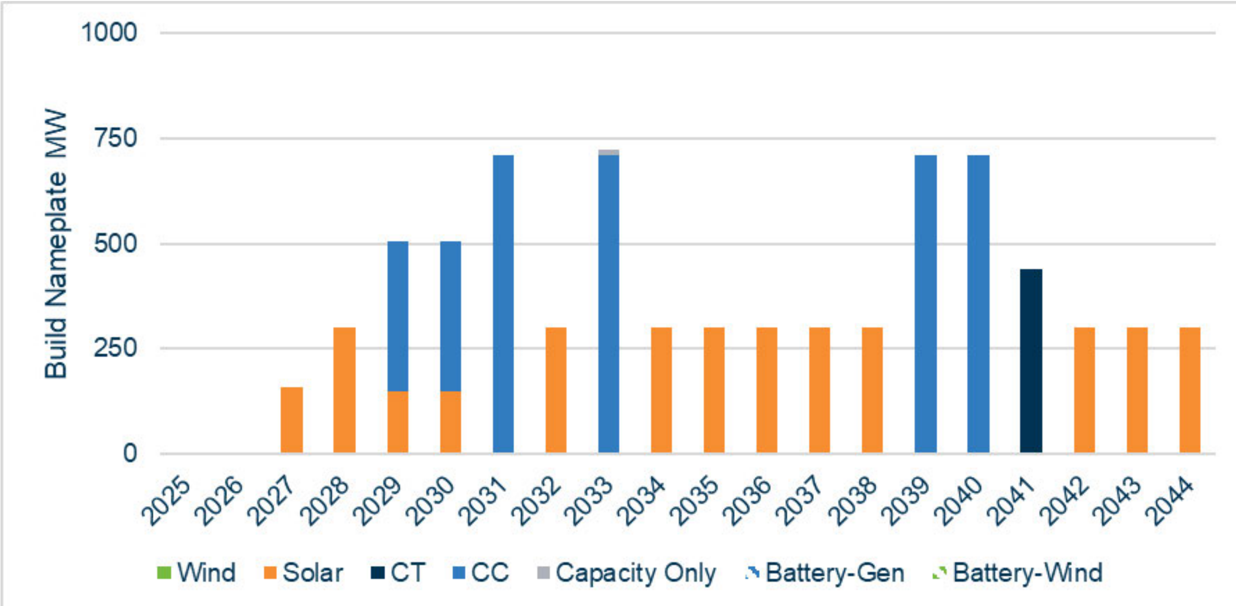
Figure 39: Early 250 MW Load Plan ACAJ



Alternative resource plans ACAH, ACAI, and ACAJ evaluate additional load ramp beginning in 2031.

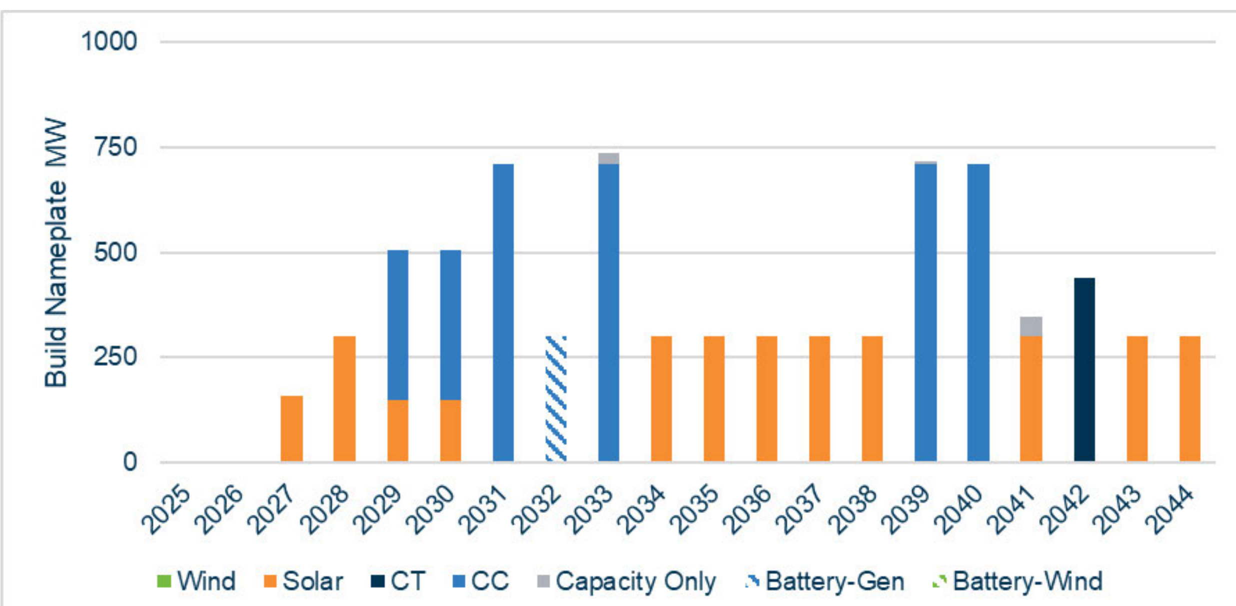
Plan ACAK accommodates a 150 MW load ramp by substituting 300 MW of solar in 2028 for 150 MW of wind and market capacity. An SCGT is moved forward to 2041 and 300 MW of solar is included each year from 2042-2044.

Figure 40: Late 150 MW Load Plan ACAK



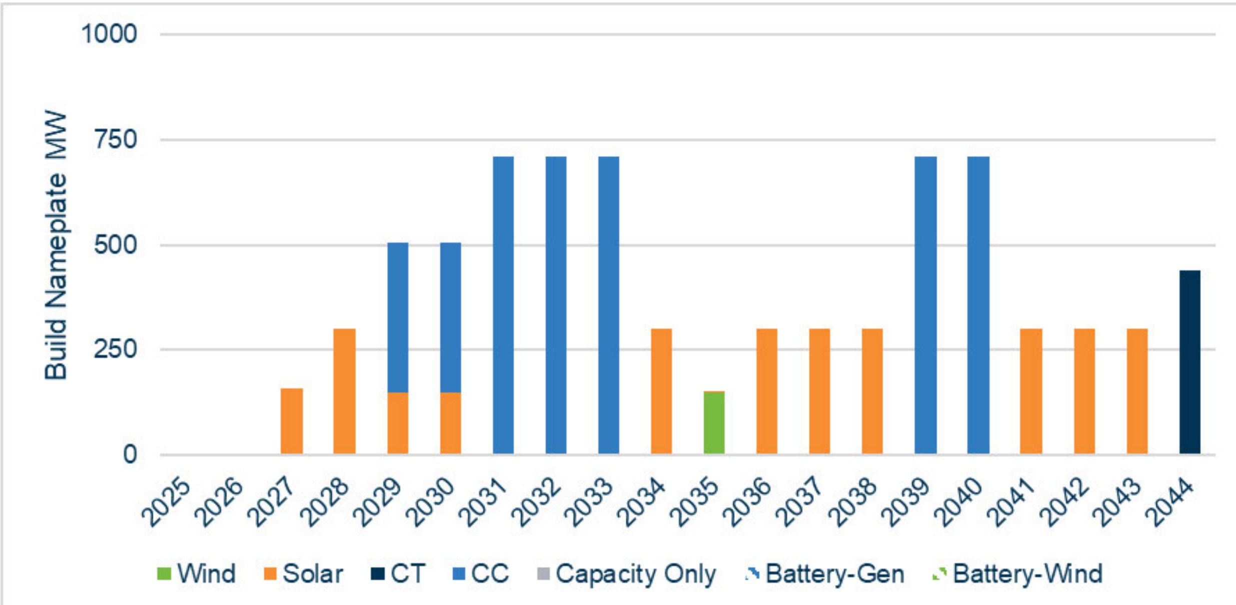
Plan ACAL accommodates a 250 MW load ramp by substituting 300 MW of solar in 2028 for 150 MW of wind and market capacity, and 300 MW of storage in 2032 for 300 MW of solar. An SCGT is moved forward to 2042 and 300 MW of solar is included in 2043 and 2044. Additional market capacity is also needed in 2033 and 2041.

Figure 41: Late 250 MW Load Plan ACAL



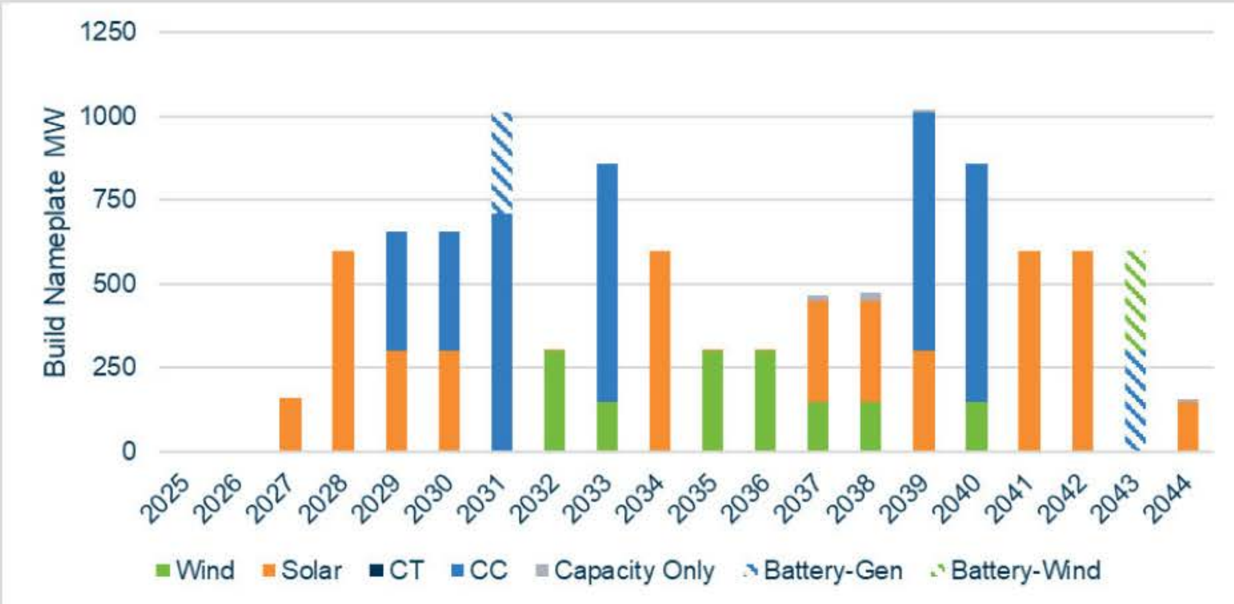
Plan ACAM accommodates a 500 MW load ramp by substituting 300 MW of solar in 2028 for 150 MW of wind and market capacity, and a CCGT in 2032 for 300 MW of solar. 150 MW of wind replaces 300 MW solar in 2035 and 150 MW solar replaces 150 MW of storage in 2043.

Figure 42: Late 500 MW Load Plan ACAM



Evergy Kansas Central's next large customer in the queue has an early load ramp beginning in 2028 and reaches a peak of 530 MW in 2032. Plan ACIS analyzes using higher build limits for solar and storage until a new thermal resource can come online and higher build limits for all resources beginning in 2031 to meet this customer need. In order to meet the early load ramp, the plan chooses 600 MW of solar in 2028, increases solar to 300 MW in 2029 and 2030 and adds 300 MW of storage in addition to the CCGT in 2031. Evergy Kansas Central would need to increase its capital spend to build these resources, or it could bridge the need with market capacity or resources/capacity supplied by the customer. In later years, due to the early additions and higher energy needs, the plan adds more wind and solar than the preferred plan and substitutes storage for an SCGT at the end of the planning horizon.

Figure 43: Next Large Customer Plan ACIS



9.1.2 High Electrification and Low Load Growth Scenarios

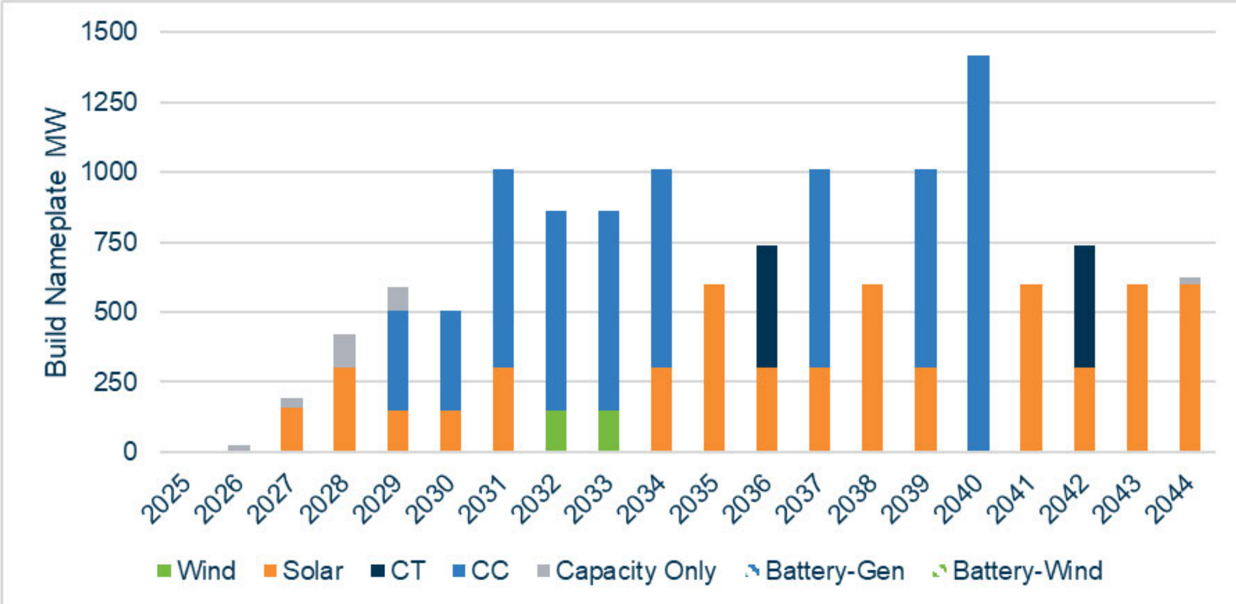
Evergy Kansas Central's high load growth and economy-wide electrification forecast includes the highest load growth over the planning horizon of the scenarios modeled, with an additional 1 GW of load by 2038 and over 1.6 GW more by 2044, compared to the base forecast. The low load growth scenario includes more modest reductions in peak load.

Table 38: Evergy Kansas Central Load Growth - Difference from Base (MW)

Load Growth	2028	2029	2030	2031	2032	2044
High Electrification	169	216	269	329	400	1655
Low	(104)	(122)	(140)	(159)	(178)	(395)

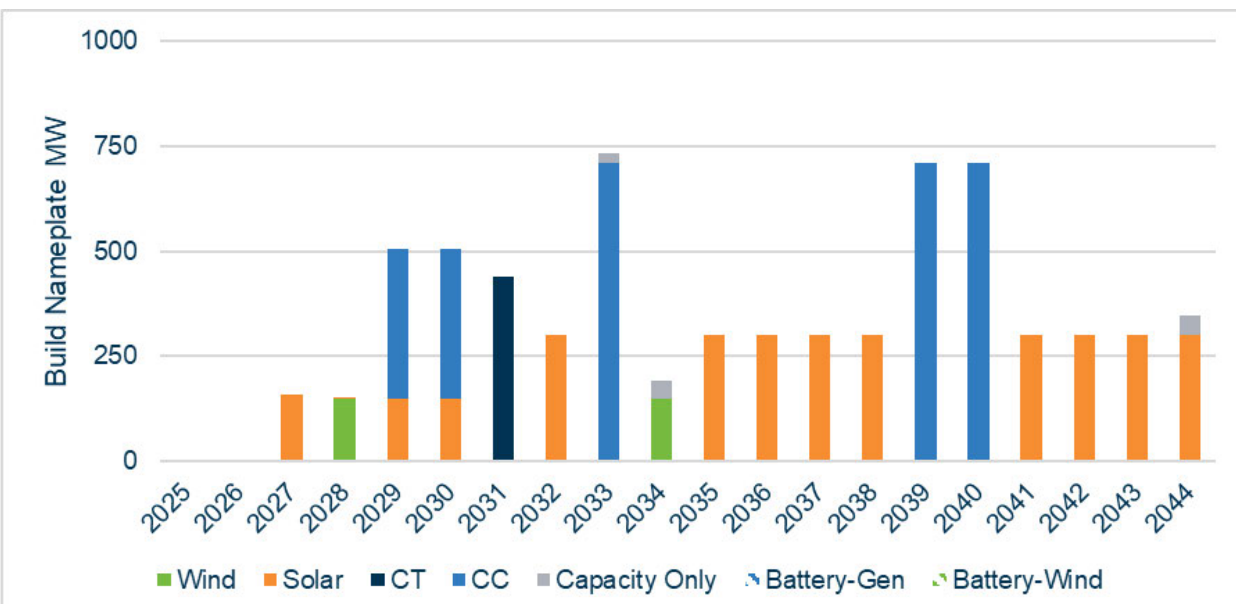
The high load growth Plan ACEN requires significantly more energy and capacity than other scenarios tested. Build limits were relaxed beyond 2031 to accommodate the load ramp. The resource plan includes additional CCGTs in 2032, 2034, 2037 and 2040 as well as an SCGT in 2036 and an earlier SCGT in 2042. It also has 5.5 GW of solar and 300 MW of wind.

Figure 44: High Electrification Load Growth Plan ACEN



The Plan AAAO shows that with low load growth, Evergy Kansas Central could substitute a SCGT for the CCGT in 2031, 150 MW of wind for 300 MW of storage in 2034, and 150 MW of solar for storage in 2043.

Figure 45: Low Load Growth Plan ACAO

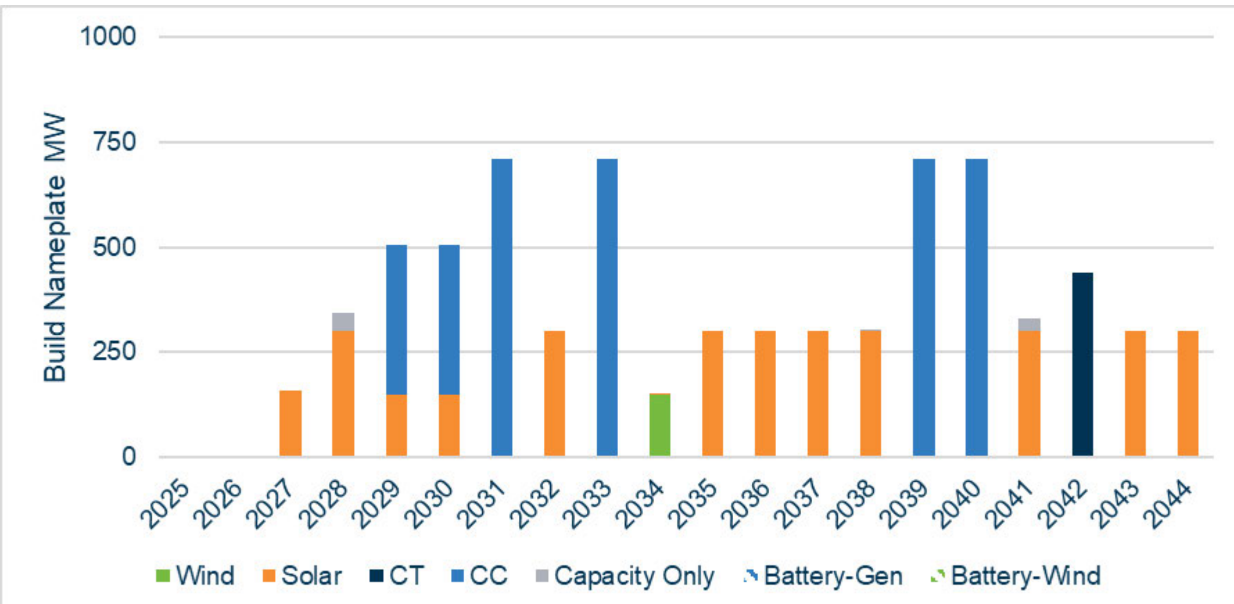


9.2 Demand-Side Contingencies

The base planning assumption for Evergy Kansas Central is that demand-side programs will continue throughout the planning horizon at levels similar to those approved in KEEIA. If programs are not approved going forward, the utility will lose the energy and capacity value assumed in the resource plan.

Plan BCAA tests ending demand-side programs after the current approved time frame. The plan swaps the 150 MW of wind in 2028 for the 300 MW of solar in 2032. It also moves the SCGT build forward from 2044 to 2042, and substitutes the 150 MW storage in 2043 for solar.

Figure 46: KEEIA DSM Programs Discontinued Plan BCAA



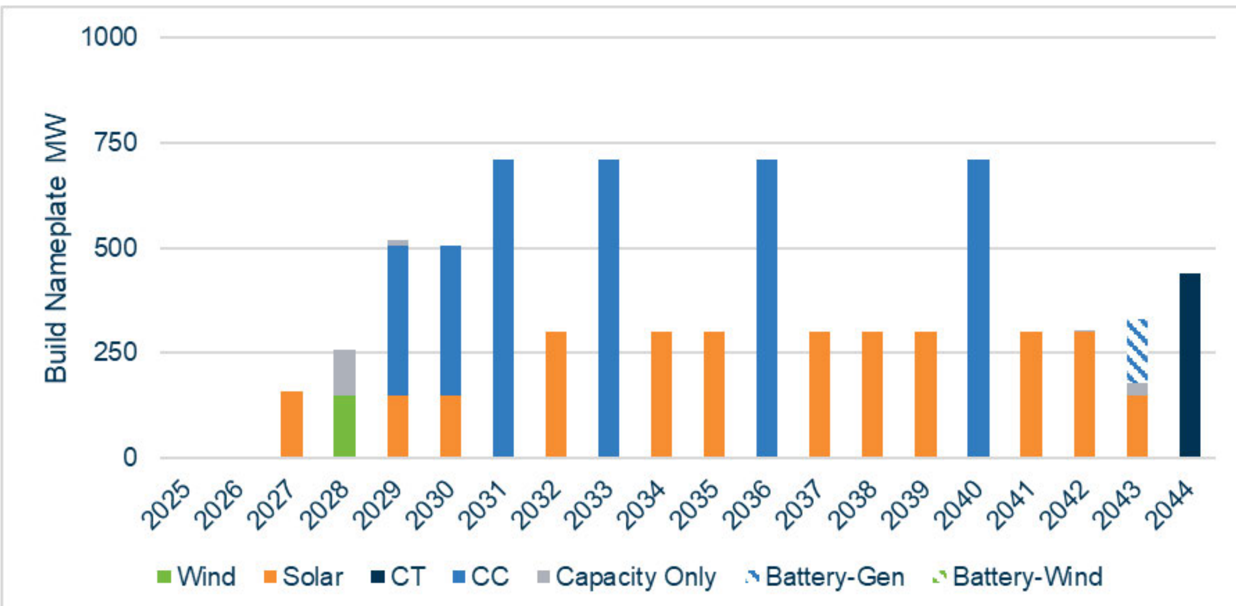
9.3 Capacity Expansion Plan with No Market Energy Purchases or Sales

Evergy Kansas Central does not expect other utilities to build for its customer needs in a time of rapid load growth, increasing reliability needs, and rising costs. The resource planning process is aligned to develop a future resource mix that meets Evergy Kansas Central's energy and capacity needs at lowest cost. The base planning assumption is that Evergy Kansas Central will have a future fleet that hedges its production costs to serve load. This is modeled with a parameter that limits future market purchases and sales to

500 MW per hour beginning in 2031 (approximately 10% of Evergy Kansas Central's peak load, and 15% of average load).

Evergy Kansas Central tested the Preferred Portfolio with a lower limit on market purchases and sales that tapered to zero beginning in 2031 to understand whether the optimal build decisions would differ. Plan ACAG has the Preferred Portfolio assumptions (load, demand-side programs, retirements) but incorporates the restriction of no market purchases and sales beginning in 2031. It builds an identical resource plan through 2035, but then moves forward the 2039 CCGT to 2036 and moves back 300 MW of solar to 2039.

Figure 47: Reduced Market Energy Reliance Plan ACAG



Section 10: GHG Compliance Plans

10.1 GHG Rule Background

On April 25, 2024, the U.S. Environmental Protection Agency (EPA) announced final Clean Air Act performance standards for carbon dioxide (CO_2) emissions from existing coal-fired power plants and new gas power plants. These rules, referred to collectively herein as the GHG Rule, aim to significantly reduce greenhouse gas (GHG) emissions from existing coal-fired power plants and from new natural gas turbines.

According to the GHG Rule, the new source performance standards (NSPS) and emission guidelines reflect what is achievable through implementation of the best system of emission reduction (BSER) that, taking into account costs, energy requirements, and other statutory factors, is adequately demonstrated for the purpose of improving the emissions performance of covered electric generating units (EGUs).

EPA has determined that the BSER for the longest-running existing coal units and for new base load combustion turbines is carbon capture and sequestration/storage (CCS) that can be applied directly to power plants that use fossil fuels to generate electricity. For other types of new gas-fired combustion turbines and existing fossil fuel-fired steam generating units, these rules prescribe standards based on other technologies, including co-firing with natural gas and efficient generating practices.

For existing steam electric generating units, compliance deadlines range from 2030 to 2032 depending upon the type of unit and the applicable standard. For new combustion turbines, efficiency-based requirements apply as soon as the unit starts operation. New base load combustion turbines will have until January 1, 2032, to meet an emission standard based on 90% capture of CO_2 emissions.

For existing coal-fired EGUs, the final rule establishes subcategories based on how far into the future the plant intends to operate.

- Units that demonstrate that they plan to permanently cease operation prior to January 1, 2032, will have no emission reduction obligations under the rule.

- Units that have committed to cease operations by January 1, 2039 (i.e., “medium-term” units) will have a numeric emission rate limit based on 40% natural gas co-firing that they must meet on January 1, 2030.
- Units that intend to operate on or after January 1, 2039 (i.e., “long-term” units) will have a numeric emission rate limit based on application of CCS with 90% capture, which they must meet on January 1, 2032.

For new combustion turbines, the final rule establishes three subcategories based on how intensively they are operated.

- New base load turbines (defined as units that are generating at least 40% of their maximum annual capacity, i.e., greater than 40% capacity factor) are subject to an initial "phase one" standard based on efficient design and operation of combined cycle turbines; and a "phase two" standard based on 90% capture of CO_2 with a compliance deadline of Jan. 1, 2032.
- New intermediate load turbines (defined as units that are generating between 20 and 40% of their maximum annual capacity, i.e., 20-40% capacity factor) are subject to a standard based on efficient design and operation of simple cycle turbines.
- New low load turbines (defined as units that are generating less than 20% of their maximum annual capacity, i.e., less than 20% capacity factor) are subject to a standard based on low-emitting fuel.

10.2 Evergy Kansas Central GHG Rule Compliance

The electric industry has challenged CCS as BSER for a host of reasons delineated in the Edison Electric Institute’s August 2023 comments on the proposed rule. While the final rule includes CCS as BSER, Evergy remains concerned about the ability to implement the technology. In summary, the concerns with CCS center on the current limited deployment and adequate demonstration of the technologies, the unlikely availability at the required scale according to the proposed compliance date, and the lack of documented integration of the individual components (capture, transportation, and storage).

Further, on February 5, 2025, EPA submitted an unopposed motion asking the U.S. Circuit Court for the District of Columbia (DC Circuit Court) to hold in abeyance for 60 days the current case challenging the GHG Rule. This delay will give the new presidential administration time to review the GHG Rule and determine their next steps regarding the future of the Rule. On February 19, 2025, the DC Circuit Court granted EPA's motion. The Court ordered EPA to file motions governing further proceedings by April 21, 2025.

In light of these ongoing concerns regarding CCS deployment, the change in presidential administration, and favorable judicial challenges, Evergy conducted an analysis to comply with the GHG Rule without employing CCS. For Evergy Kansas Central, the evaluation included natural gas (NG) conversion and co-firing options for existing coal units and a capacity factor limitation on new combustion turbines. The effective date for compliance is January 1, 2030 for coal units and January 1, 2032 for combustion turbines (including combined cycle).

Table 39: GHG Rule Compliance Options

Generating Unit	GHG Compliance Pathway	Retirement Date
Coal	Retirement	Prior to January 1, 2032
Coal	40% NG Co-Firing (2030)	By January 1, 2039
Coal	100% NG Conversion (2030)	None
New Combined Cycle	40% Capacity Factor Limit (2032)	None
New Combustion Turbine	40% Capacity Factor Limit (2032)	None

10.3 GHG Rule Cost Estimates and Planning Assumptions

For existing coal units, the natural gas co-firing and conversion compliance options require significant capital investment and ongoing operating expense. In 2030, the cost estimates include the following for plant modifications to burn natural gas, gas pipeline extensions, and annual firm gas transport cost.

Table 40: GHG Rule Cost Estimates[11] **Confidential**

[redacted]

For capacity expansion and production cost modeling, Evergy used high natural gas prices with a mid-point carbon dioxide restriction. The Company assumed that the GHG Rule would increase demand for natural gas and exert upward pressure on prices, and while the GHG Rule is intended to address carbon dioxide limits, Evergy chose to place a restriction on emissions to account for uncertainty in the long-term modeling forecasts.

10.4 GHG Rule Compliance vs. Preferred Portfolio

Using the above assumptions, Evergy modeled a range of compliance scenarios. Table 41 summarizes the scenarios with the estimated cost of GHG compliance relative to the 2025 IRP Preferred Portfolio ACAA. The comparison is based on the H2C modeling endpoint, which was used to develop the GHG estimates. As measured by NPVRR, the GHG compliance cost ranges from $1.146 billion to $1.719 billion.

[11] These cost estimates, which are based on preliminary engagement with the pipeline companies, are classified as Class V construction estimates which have a tolerance of -50% to +100%.

Table 41: GHG Rule Cost Comparisons

Plan	ACAA	AQAR	ARAR	ASAR	AUAR
Jeffrey 1	Ret 2039	**Co-Fire**	Co-Fire	**Conv No Ret**	Co-Fire
Jeffrey 2	Conv No Ret	Conv No Ret	**Co-Fire**	Conv No Ret	**Co-Fire**
Jeffrey 3	Ret 2030	Ret 2030	Ret 2030	Ret 2030	Ret 2030
La Cygne 1	Ret 2032	**Ret 2031**	Ret 2031	Ret 2031	Ret 2031
La Cygne 2	Ret 2039	**Co-Fire**	Ret 2039	Co-Fire	**Ret 2031**
Lawrence 4	Conv	Conv	Conv	Conv	Conv
Lawrence 5	Conv	Conv	Conv	Conv	Conv
H2C NPVRR ($ million)	**40,598**	**41,744**	**42,140**	**42,257**	**42,317**
GHG vs ACAA ($ million)	**-**	**1,146**	**1,543**	**1,659**	**1,719**

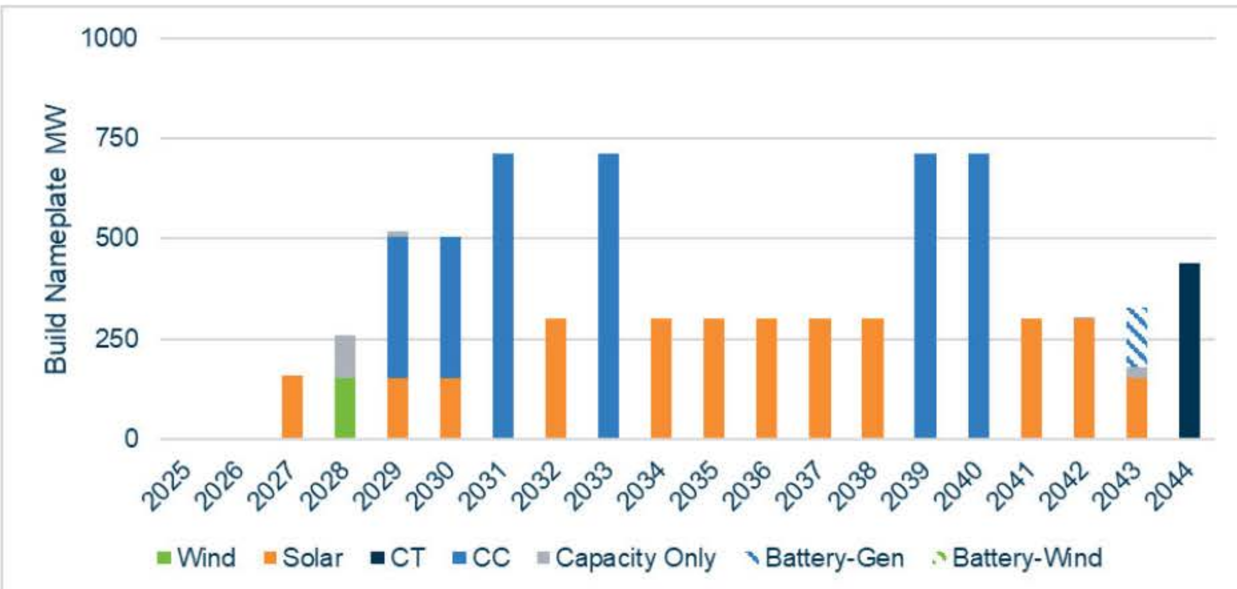
In summary, the GHG compliance plans require significant cost to implement and diverge from the Preferred Portfolio. The near term GHG thermal builds, through 2033, align with the Preferred Portfolio, but the GHG plans select a 2028 solar in place of wind. The exception to this is Plan AUAR (LAC 2 Ret 2031) which selects the 2028 wind and an additional 2032 CCGT. Beyond 2033, the majority of the GHG plans' next thermal build is a 2038 CCGT a year earlier than the Preferred Portfolio's 2039 CCGT. The outlier is Plan ARAR (JEC 2 Co-fire) which selects a 2037 CCGT. The compliance paths that include a Jeffrey full conversion, plans AQAR and ASAR, build 91 MW and 141 MW less capacity, respectively, than the Preferred Portfolio. In contrast, the compliance paths that co-fire both Jeffrey units, plans ARAR and AUAR, build 314 MW and 411 MW more capacity, respectively, than the Preferred Portfolio. Table 42 summarizes the capacity expansion plans, while Figure 48 presents a comparison of the Preferred Portfolio with the GHG plans.

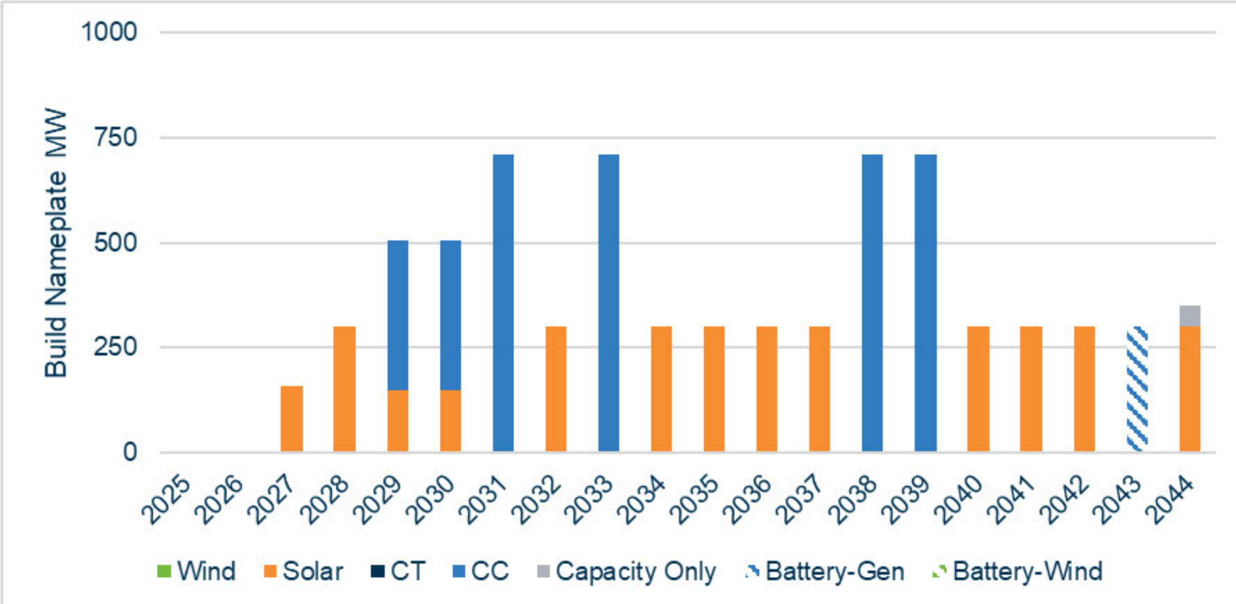
As the GHG Rule progresses through the courts, Evergy will adapt its plans to maintain compliance with the law.

Table 42: GHG Capacity Expansion Summary

Plan	ACAA	AQAR	ARAR	ASAR	AUAR
Wind (MW)	150	0	0	0	150
Solar (MW)	3010	3460	3310	3760	2860
CT (MW)	440	0	0	0	440
CC (MW)	3550	3550	4260	3550	4260
Capacity (MW)	151	50	45	0	152
Storage (MW)	150	300	150	0	0

Figure 48: Evergy Kansas Central 2025 Preferred Portfolio ACAA (1st) vs GHG Compliance Plans AQAR, ARAR, ASAR, AUAR (2nd, 3rd, 4th, 5th)

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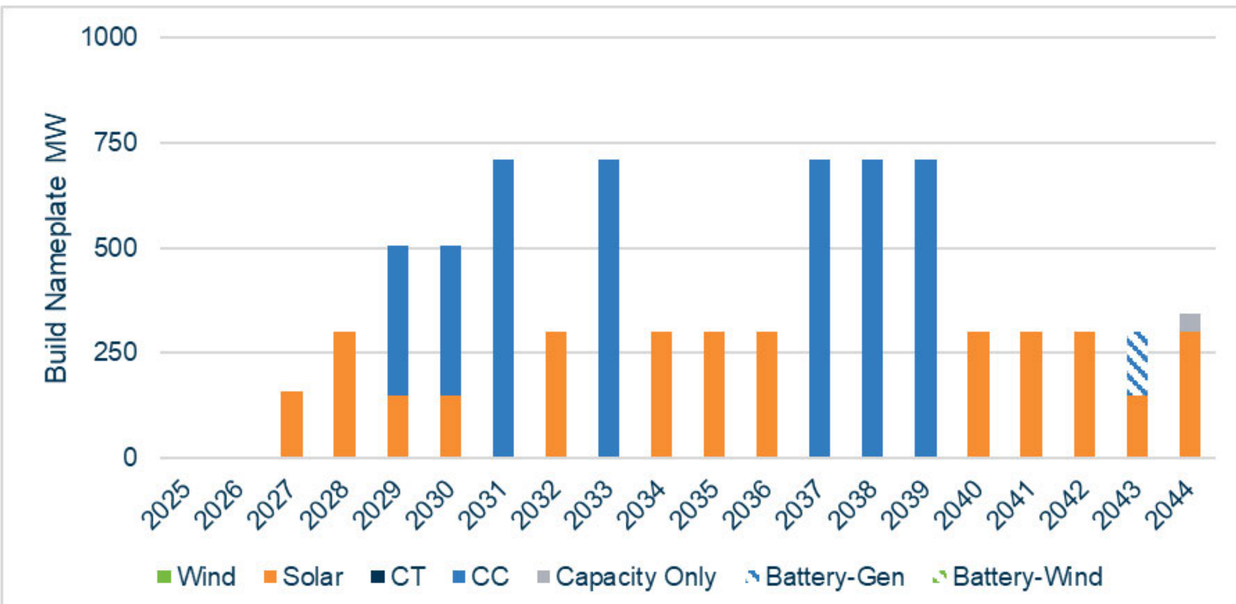
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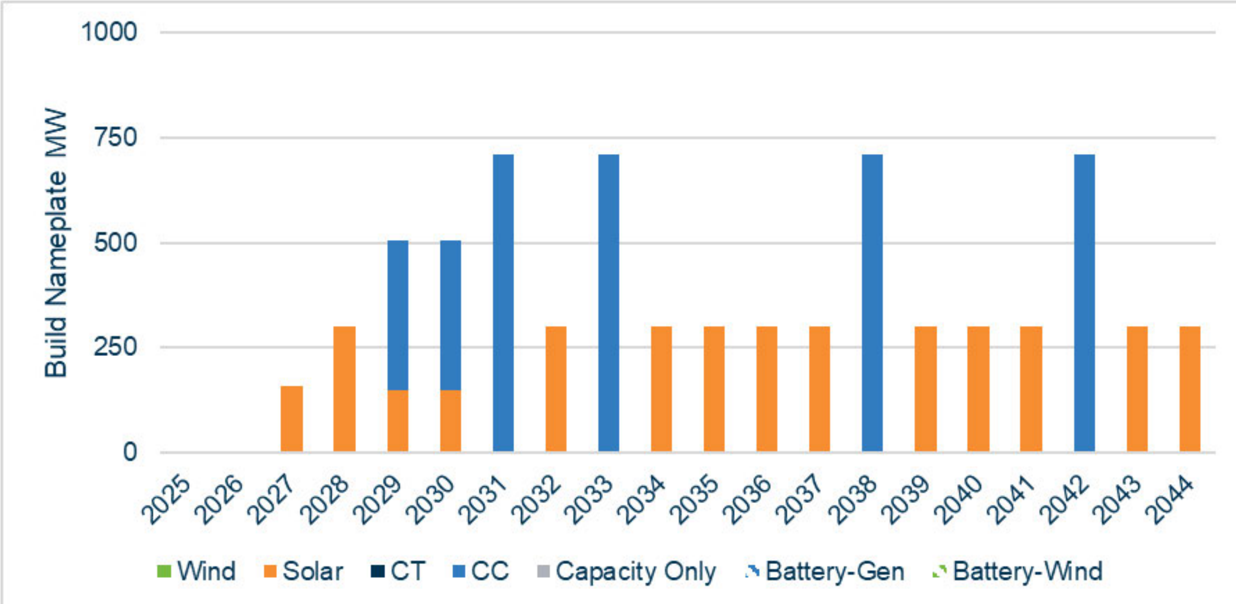
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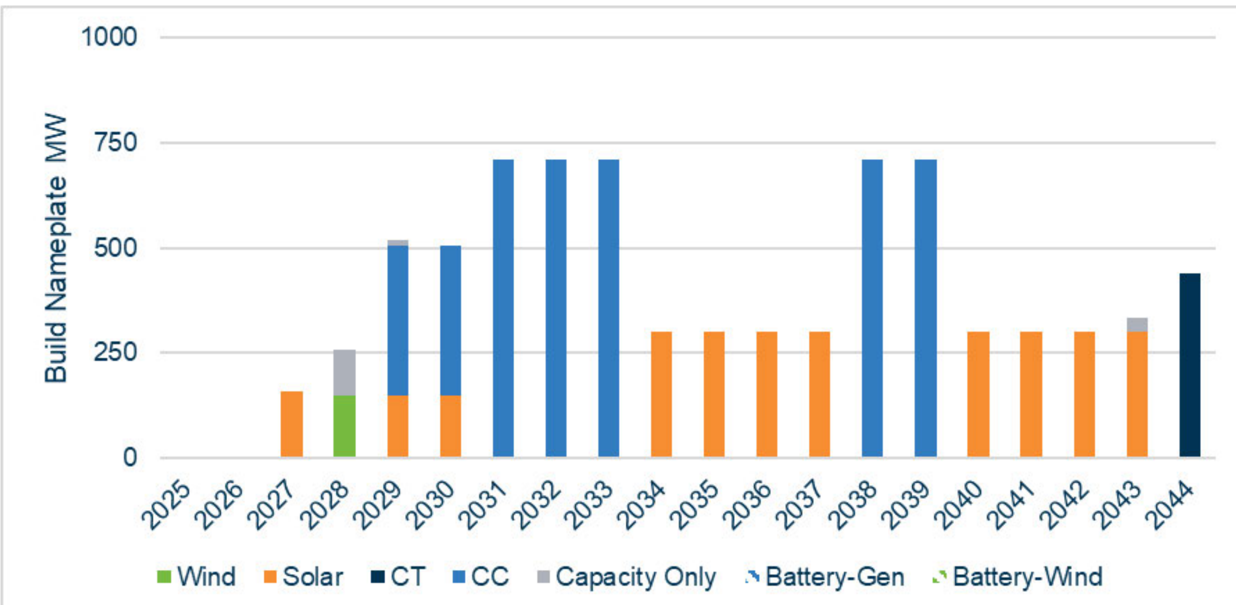
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Section 11: SERVM Analysis

11.1 Background and Purpose

The preferred portfolios and all alternative resource plans were developed to meet SPP Resource Adequacy Requirements as well as hourly customer energy needs. As discussed in prior sections, Evergy incorporated expected SPP requirements and study results to forecast reserve margins and resource accreditation. SPP Resource Adequacy Requirements are designed to maintain a loss of load expectation (LOLE) of less than one day in ten years. The analysis to develop these requirements, particularly the planning reserve margin and ELCC, uses probabilistic modeling to incorporate factors such as extreme weather, generator unavailability, and renewable output (among many other factors).

Evergy is developing its own capability to conduct generation reliability modeling using the Strategic Energy and Risk Valuation Model (SERVM) software used by SPP, primarily to better understand SPP's modeling and provide feedback in the SPP stakeholder process.

For this IRP, Evergy conducted its own probabilistic reliability analysis to assess the reliability of select resource plans. Evergy utilized the SERVM software to assess the performance of future resource portfolios under varying load, weather (including extreme weather), renewable output, and outage conditions. This analysis offers relative comparisons of reliability metrics across different future resource portfolios. Since Evergy does not have access to the confidential data used in SPP models, it is unable to duplicate SPP studies related to future planning reserve margins. However, the general methodology and modeling software used is consistent with SPP and, in subsequent IRPs, efforts will be made to even more closely align Evergy's reliability studies with those conducted by SPP.

The SERVM software evaluates how specific plans align with the industry-standard LOLE metric of 1 day in 10 years (0.1 days per year). According to this metric, a system would experience one day with one or more hours of firm load shedding every 10 years due to a shortage of generating capacity. Significantly higher LOLE values indicate a system that is less reliable in meeting hourly load requirements, and vice versa.

In addition to the LOLE metric, Evergy also monitored the Expected Unserved Energy (EUE) metric, which quantifies the amount of energy (in MWh) a generating system is unable to supply during loss of load events. Specifically, it represents the energy deficit when demand exceeds supply due to system limitations. Although there is no industry-standard for EUE, this metric illustrates the severity of the loss of load events.

11.2 Updates from the 2024 Triennial IRP

In preparation for the 2025 Annual Update, Evergy collaborated with Astrapé Consulting (part of PowerGEM) to update the SERVM database with the latest market data. The updates include:

- Load forecasts
- Additional historical load, renewable, and weather profile years
- Cold weather outage adders
- Effective Forced Outage Rates (EFORs) derived from GADS data*
- Resource portfolio assumptions and characteristics
- Revamped system topology*
- Transmission capabilities and limits based on the 2024 SPP ITP Study*
- Recalibration to ensure that Evergy's neighboring regions maintained an average LOLE of approximately 0.1 to meet their capacity and energy requirements

*Outlined in Appendix 11.2 Evergy GADS Data Processing and Neighbor Database Setup CONFIDENTIAL.pdf.

11.3 LOLE and EUE Analysis and Results

Evergy selected 2033 as the future study year because it includes load growth and resource mix changes. By then, several coal units plan to cease operation and new natural gas, solar, and storage resources will be online.

The following sets of resource plans were selected to assess their reliability in meeting load on an hourly basis throughout 2033:

- 2025 Preferred Portfolios (KSC ACAA, MET AAAA, and MOW ACAA)
- Low Renewables Plans (KSC ACAQ, MET BAAT, and MOW BCAT)
- High Renewables Plans (KSC ACFP, MET AAFP, and MOW ACFP)
- No 2031 Thermal Plans (KSC ACHA, MET AAHA, and MOW ACKA)

All tested plans above maintained Evergy's neighbors' resource portfolios to meet the 0.1 LOLE standard. The results of this analysis are summarized in the following Table.

Table 43: Selected Plans Comparison – LOLE, EUE, NPVRR, Surplus Capacity

	2025 Preferred Portfolios	Low Renewables Plans	High Renewables Plans	No 2031 Thermal Plans
LOLE (Days/Yr)	0.082	0.075	0.037	0.007
EUE (MWh)	101	186	207	17
Evergy-Level NPVRR ($ million)	76,747	85,932	85,416	79,623
NPVRR Difference from PP ($ million)	0	9,185	8,669	2,876
Surplus Summer Capacity (MW)	941	1,033	2,773	2,137

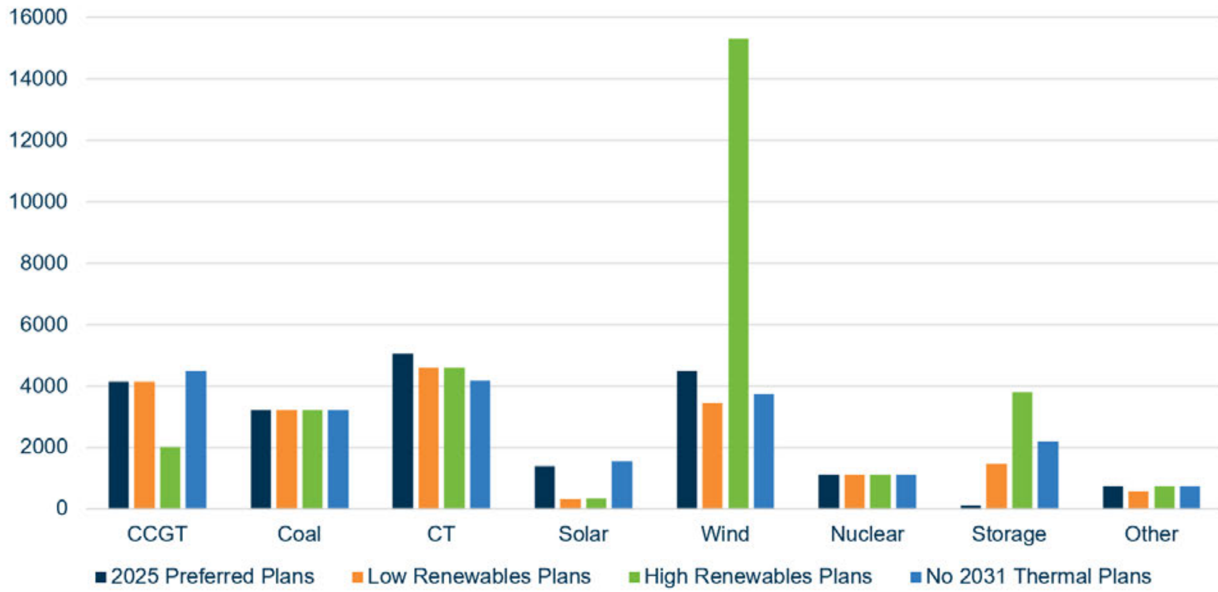
2025 Preferred Portfolios

SERVM results reveal that Evergy's preferred portfolios have a LOLE metric of 0.082. This indicates that the Evergy region is experiencing a loss of load expectation averaging 0.082 days per year. Additionally, Evergy's preferred portfolios exhibit an EUE metric of 101 MWh, implying that these portfolios result in the Evergy region being unable to supply an average of 101 MWh during the 0.082 days of loss of load events.

Alternative Resource Plans vs. 2025 Preferred Portfolios

The driving factors behind the lower LOLEs in the alternative sets of resource plans are the higher amounts of storage, variations in renewables, and differences in combined cycle and combustion turbines built to meet customer needs compared to the preferred portfolios.

Figure 49: Selected Plans Comparison - Installed Capacity (MW) Study Year 2033



Low Renewables Plans

These plans prioritize building higher amounts of storage over new renewable and thermal resources, compared to the preferred portfolios. By 2033, there will be over 1.3 GW more storage resources, over 2 GW fewer renewable resources, and 440 MW fewer thermal resources online, compared to the preferred portfolios. This resulted in a lower LOLE averaging 0.075 days per year, with higher EUE averaging 186 MWh during loss of load events.

High Renewables Plans

Considering a high natural gas price and high carbon dioxide restricted future, these plans focus on building higher amounts of wind and storage resources instead of new combined cycle and combustion turbines, compared to the preferred portfolios. By 2033, there will be over 9.7 GW more renewable resources, over 3.6 GW more storage resources, and over 2.5 GW fewer thermal resources online, compared to the preferred portfolios. This resulted in a lower LOLE averaging 0.037 days per year, with higher EUE averaging 207 MWh during the loss of load events.

No 2031 Thermal Plans

By not allowing thermal build options in 2031, these plans focus on building higher amounts of storage from 2029 to 2031, as well as combined cycle generating units in 2032 and 2033. By 2033, there will be over 2 GW more storage resources, 525 MW fewer thermal resources, and 600 MW fewer renewable resources online, compared to the preferred portfolios. Factoring in all these new builds, these plans provide a very reliable system for 2033, with a very low LOLE averaging 0.007 days per year and an EUE averaging 17 MWh during the loss of load events.

Other Takeaways

While the SERVM studies indicate that the preferred portfolios and selected resource plans meet the 0.1 LOLE reliability metric standard, the IRP process also considers other factors, such as the NPVRR, as explained in Section 8 of this IRP. Table 43 presents the NPVRR for each set of plans studied in SERVM. The results show that although other alternative plans are more reliable than the preferred portfolios, they would incur higher costs to build: an additional $9.2 billion for the Low Renewables Plans, $8.7 billion for the High Renewables Plans, and $2.9 billion for the No 2031 Thermal Plans. Additionally, Table 43 highlights the surplus summer capacity for each studied set of plans. This comparison reveals that the alternative plans would produce higher amounts of surplus accredited summer capacity: 1,003 MW for the Low Renewables Plans, 2,773 MW for the High Renewables Plans, and 2,137 MW for the No 2031 Thermal Plans, compared to 941 MW for the preferred portfolios. The higher surplus capacity suggests that the alternative plans have more generation resources to meet customer needs in 2033, which is consistent with the lower LOLE results.

11.4 Expected Unserved Energy (EUE) Percent Occurrence

The following tables illustrate the percent occurrence of EUE events for the specific month and hour of day in the 2033 study year for each set of resource plans. While LOLE modeling is often used in the development of peak capacity requirements (i.e., planning reserve margin as a percentage of peak load), this modeling is performed for 8,760 hours per year and the risk of loss of load is assessed across all hours. As seen in the hourly analysis below, across each of the EUE percent occurrence tables, most of the risk seen in Evergy's territory is in the winter season.

Table 44: Evergy 2033 Preferred Portfolios 12x24 EUE Percent Occurrence

	Month of Year											
Hour of Day	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0000%	0.2541%	0.1981%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3232%
2	0.0000%	0.4079%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.7272%
3	0.0000%	0.5965%	0.0704%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.9931%
4	0.0000%	0.0195%	0.0005%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3545%
5	0.0000%	0.5548%	0.0495%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.2394%
6	0.0000%	0.9149%	0.0026%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	2.9402%
7	0.0000%	2.5101%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	5.1883%
8	0.0000%	4.6327%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	5.1262%
9	0.1238%	4.0736%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	4.5615%
10	0.0000%	4.0823%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.7308%
11	0.0000%	1.9666%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.5274%
12	0.0000%	1.0674%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.7924%
13	0.0000%	0.4405%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.2320%	0.0000%	0.0000%	0.0000%	0.1429%
14	0.0000%	0.2346%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.4965%	0.0000%	0.0000%	0.0000%	0.0000%
15	0.0000%	0.2268%	0.0000%	0.0000%	0.0404%	0.0000%	0.0000%	1.0126%	0.0000%	0.0000%	0.0000%	0.0000%
16	0.0000%	0.3558%	0.0000%	0.0000%	0.0808%	0.0000%	0.0000%	2.0188%	0.0000%	0.0000%	0.0000%	0.0000%
17	0.0000%	0.6021%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	3.8264%	0.0691%	0.0000%	0.0000%	0.0000%
18	0.0000%	1.8233%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	5.4894%	0.3532%	0.2020%	0.0000%	0.0000%
19	0.0000%	3.2465%	0.2646%	0.0000%	0.0000%	0.0000%	0.1577%	8.1429%	0.4615%	0.0000%	0.0000%	0.0235%
20	0.1199%	3.3929%	0.5982%	0.0000%	0.0000%	0.0000%	0.0795%	7.3646%	0.2919%	0.0000%	0.0000%	0.1720%
21	0.0456%	2.9715%	0.3362%	0.0000%	0.0000%	0.0000%	0.0000%	2.3667%	0.0000%	0.0000%	0.0000%	0.0222%
22	0.1329%	2.0162%	0.2268%	0.0000%	0.0000%	0.0000%	0.0000%	0.6295%	0.0000%	0.0000%	0.0000%	0.0521%
23	0.0000%	0.9397%	0.1851%	0.0000%	0.0000%	0.0000%	0.0000%	0.0990%	0.0000%	0.0000%	0.0000%	0.0821%
24	0.0000%	0.9019%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Table 45: Evergy 2033 Low Renewables Plans 12x24 EUE Percent Occurrence

	Month of Year											
Hour of Day	1	2	3	4	5	6	7	8	9	10	11	12
1	0.2166%	0.0291%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2	0.2142%	0.1646%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
3	0.1777%	0.0748%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
4	0.1053%	0.1107%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0933%
5	0.2890%	0.3961%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.2489%
6	0.1281%	1.2716%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.1029%
7	0.3560%	2.6377%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.1915%
8	0.4177%	3.4006%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.1345%
9	0.6672%	4.3149%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.7175%
10	0.3530%	5.1006%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.9178%
11	0.3411%	3.2618%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	2.5545%
12	0.1412%	2.2110%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0886%	0.0000%	0.0000%	0.0000%	1.5516%
13	0.1819%	1.6850%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3399%	0.0000%	0.0000%	0.0000%	1.0173%
14	0.1131%	1.0974%	0.0000%	0.0000%	0.0000%	0.0000%	0.0760%	0.8282%	0.0000%	0.0000%	0.0000%	0.4661%
15	0.0682%	0.6780%	0.0000%	0.0000%	0.0000%	0.0000%	0.2459%	1.3135%	0.0000%	0.0000%	0.0000%	0.0437%
16	0.2824%	0.6666%	0.0000%	0.0000%	0.0000%	0.0000%	0.5338%	2.7687%	0.0455%	0.0000%	0.0000%	0.0024%
17	0.3734%	0.6618%	0.0000%	0.0000%	0.0000%	0.0000%	0.8162%	5.3220%	0.1328%	0.0000%	0.0000%	0.0000%
18	0.5104%	0.9903%	0.0000%	0.0000%	0.0000%	0.0000%	1.2722%	7.0448%	0.2525%	0.0000%	0.0000%	0.0245%
19	1.5037%	1.0484%	0.0000%	0.0000%	0.0000%	0.0000%	1.5438%	7.8430%	0.4290%	0.0000%	0.0000%	0.3237%
20	1.2943%	1.1938%	0.0233%	0.0000%	0.0000%	0.0000%	1.3131%	7.3793%	0.2429%	0.0000%	0.0000%	0.1598%
21	1.3523%	1.1836%	0.0000%	0.0000%	0.0000%	0.0000%	0.6911%	2.6185%	0.0000%	0.0000%	0.0000%	0.1298%
22	0.9508%	0.8030%	0.0000%	0.0000%	0.0000%	0.0000%	0.0042%	0.3770%	0.0000%	0.0000%	0.0000%	0.0000%
23	0.7815%	0.9227%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0646%	0.0000%	0.0000%	0.0000%	0.0000%
24	0.5697%	0.4165%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Table 46: Evergy 2033 High Renewables Plans 12x24 EUE Percent Occurrence

	Month of Year											
Hour of Day	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0000%	1.6982%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2	0.0000%	1.2585%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
3	0.0000%	1.0475%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
4	0.0000%	1.1256%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
5	0.0000%	0.9124%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
6	0.0000%	1.7369%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
7	0.0000%	2.5909%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
8	0.0000%	3.5329%	0.1041%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0190%
9	0.0000%	4.7394%	0.2722%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0535%
10	0.0000%	6.5804%	0.0098%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.1034%
11	0.0000%	7.7264%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
12	0.0000%	7.0595%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
13	0.0000%	5.4626%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
14	0.0000%	4.0028%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0106%
15	0.0000%	3.4605%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.4115%
16	0.0000%	3.2262%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.4151%
17	0.0000%	3.3620%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
18	0.0000%	4.0844%	0.0000%	0.0000%	0.0000%	0.0000%	0.0577%	1.1277%	0.0000%	0.0000%	0.0000%	0.0000%
19	0.0000%	3.9388%	0.0000%	0.0000%	0.0000%	0.0000%	0.1477%	3.7285%	0.0000%	0.0000%	0.0000%	0.0000%
20	0.0000%	4.6571%	0.0000%	0.0000%	0.0000%	0.0992%	0.1400%	5.4506%	0.0000%	0.0000%	0.0000%	0.0000%
21	0.0000%	4.0676%	0.0000%	0.0000%	0.0000%	0.2722%	0.0000%	0.1512%	0.0000%	0.0000%	0.0000%	0.0000%
22	0.0000%	4.1499%	0.0000%	0.0000%	0.0000%	0.0134%	0.0000%	0.0359%	0.0000%	0.0000%	0.0000%	0.0000%
23	0.0000%	4.2019%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
24	0.0000%	2.7542%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Table 47: Evergy 2033 No 2031 Thermal Plans 12x24 EUE Percent Occurrence

Hour of Day	Month of Year											
	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0000%	0.3240%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2	0.0000%	0.2160%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
3	0.0000%	0.4005%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.6245%
4	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.4275%
5	0.0000%	0.4680%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.2340%
6	0.0000%	1.6785%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.5435%
7	0.0000%	4.3200%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.7145%
8	0.0000%	8.3881%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	3.6450%
9	0.0000%	7.6546%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.8270%
10	0.0000%	5.5936%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	4.7520%
11	0.0000%	3.7665%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	2.2635%
12	0.0000%	0.9225%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	2.5875%
13	0.0000%	0.1395%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
14	0.0000%	0.2025%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
15	0.0000%	0.0630%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
16	0.0000%	0.1575%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
17	0.0000%	0.5805%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
18	0.0000%	0.8145%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.5400%	0.0000%	0.0000%	0.0000%	0.0000%
19	0.0000%	1.2015%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	8.3341%	0.0000%	0.0000%	0.0000%	0.0000%
20	0.0000%	1.3995%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	8.7391%	1.9440%	0.0000%	0.0000%	0.0000%
21	0.0000%	2.3220%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	6.5206%	1.4940%	0.0000%	0.0000%	0.0000%
22	0.0000%	1.4130%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.6830%	0.3825%	0.0000%	0.0000%	1.0170%
23	0.0000%	2.8260%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3420%	0.0000%	0.0000%	0.0000%	0.0000%
24	0.0000%	3.5325%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

11.5 Summary

As seen across the LOLE metrics, all selected sets of resource plans meet the 0.1 LOLE industry-standard utilized by SPP in developing Resource Adequacy Requirements. These portfolios also show an average EUE of around 1% of Evergy's peak load during the expected loss of load events. While the alternative sets of resource plans resulted in a lower LOLE, indicating a more reliable system to meet customer needs compared to the preferred portfolios, the IRP process also considers the NPVRR of each plan to determine the most optimal future resource portfolio.

In conclusion, the preferred portfolios not only meet the industry-standard for reliability, but also offer the most cost-effective solution when considering the overall NPVRR. This comprehensive approach ensures that Evergy can reliably meet customer needs while optimizing costs.

Section 12: Resource Acquisition Strategy Update

12.1 2025 Annual Update Preferred Portfolio

Evergy Kansas Central has selected Plan ACAA as its Preferred Portfolio. This 2025 Preferred Portfolio called for some revisions to the resources that Evergy Kansas Central had in the early years of the 2024 Preferred Portfolio. Key items of note are that the 150 MW of solar in 2027 remained the same but the 300 MW of solar previously planned for 2028 has been replaced by 150 MW of wind with some market capacity purchases.

Evergy Kansas Central has identified the need for additional resources throughout the following 20 years based on changes to the forecasts for load growth, reliability needs and expected accreditation, and demand-side programs.

Due to the increased needs Evergy Kansas Central is seeing in this update, more resources are included in this portfolio in the execution window. 150 MW of wind was selected in 2028. In addition to the Viola and McNew CCGT plants, 710 MW of thermal resources were selected in both 2031 and 2033. Additionally, market capacity is needed to meet summer and winter SPP reserve margin requirements before the thermal buildout in 2029-2030 is complete. Evergy Kansas Central has also changed its expected retirement schedule, with the expected conversion of Jeffrey 2 to natural gas in 2030, rather than retiring. Lawrence 4 and 5 have also been slated to retire in 2032. Evergy Kansas Central continues to expect retirements of Jeffrey 3 in 2030 and Jeffrey 1 in 2039. Evergy Kansas Central is the majority owner in each of these units. La Cygne 1 and 2 are still slated to retire in 2032 and 2039, respectively.

The Evergy Kansas Central Preferred Portfolio ACAA for the 20-year planning period is shown in Table 48.

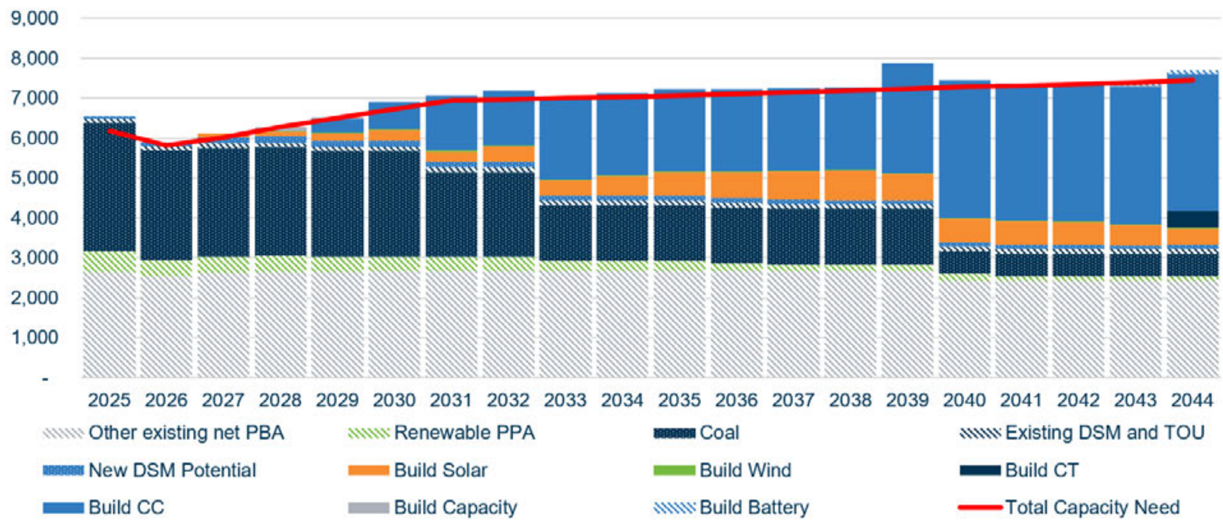
Table 48: Evergy Kansas Central Preferred Portfolio ACAA

Year	Wind (MW)	Solar (MW)	Battery (MW)	Thermal (MW)	Capacity Only (Summer MW)	DSM (Summer MW)	Retirements (MW)
2025	0	0	0	0	0	169	0
2026	0	0	0	0	0	204	0
2027	0	159	0	0	0	255	0
2028	150	0	0	0	107	279	0
2029	0	150	0	355	13	258	0
2030	0	150	0	355	0	257	0
2031	0	0	0	710	0	254	674
2032	0	300	0	0	0	250	0
2033	0	0	0	710	0	244	855
2034	0	300	0	0	0	242	0
2035	0	300	0	0	0	240	0
2036	0	300	0	0	0	236	0
2037	0	300	0	0	0	228	0
2038	0	300	0	0	0	220	0
2039	0	0	0	710	0	214	0
2040	0	0	0	710	0	212	1007
2041	0	300	0	0	0	211	0
2042	0	300	0	0	2	208	0
2043	0	150	150	0	29	205	0
2044	0	0	0	440	0	206	0

As detailed above, resource needs for Evergy Kansas Central include acquiring 150 MW of wind in 2028. Solar needs, apart from the Kansas Sky Solar facility in 2027, are 150 MW in 2029, 2030, and 2043, as well as 300 MW in each year of 2032, 2034, 2035, 2036, 2037, 2038, 2041, and 2042. A need for 150 MW of battery resources was identified for 2043. Aside from the Viola and McNew CCGT additions in 2029 and 2030, respectively, thermal resource needs were identified beginning in 2031 with a need of 710 MW CCGT, then again in 2033, 2039, and 2040. 2044 shows a need of 440 MW SCGT. It is expected that sourcing of resources to cover these needs will be achieved through a combination of projects identified through the 2025 all source RFP, planned for issue in May 2025, potential future all source RFPs, and Evergy self-developed projects.

12.1.1 Preferred Portfolio Composition

Figure 50: Evergy Kansas Central Preferred Portfolio Summer Capacity Composition (MW)



12.2 Implementation Plan

12.2.1 Supply-Side Implementation Schedules

Combined Cycle Additions – Viola and McNew Plants

The Preferred Portfolio includes the construction of two advanced class 710 MW combined cycle gas turbine ("CCGT") generating facilities known as the Viola Generating Station and the McNew Generating Station. The configuration and equipment for the two CCGT facilities will be substantially the same. These combined cycle plants are slated to be shared 50/50 between Evergy Kansas Central and Evergy Missouri West. The Viola facility has a planned commercial operation date of Summer 2029. The McNew facility has a planned commercial operation date of Summer 2030. A schedule of the major milestones for the CCGT plants is detailed in Table 49.

Table 49: Combined Cycle Implementation Milestones

Illustrative Milestone Schedule (By Developer or Evergy)	CCGT #1 (Viola) Expected Completion	CCGT#2 (McNew) Expected Completion
Site Control Complete	December 2023	October 2024
SPP Large Generator Interconnection Application	October 2024	October 2024
Environmental and Land Permitting Complete	2026	2026
Design Spec & Engineering, Procurement, and Construction Award	First Half 2025	First Half 2025
State Utility Regulatory Approvals	Q3 2025	Q3 2025
Detailed Design and Engineering	Second Half 2025	Second Half 2025
On-site Mobilization	2026	2027
Major Equipment Delivery	2026	2027
Construction Complete	2028	2029
Testing and Commissioning Complete	2028	2029
Commercial Operation	Summer 2029	Summer 2030

Renewables Additions – Kansas Sky

The Kansas Sky Solar facility, a 200 MWdc/159 MWac single-axis tracking photovoltaic solar project in Douglas County, Kansas, will be developed by a third-party developer and is planned for commercial operation in Q2 2027. This project will be wholly owned by Evergy Kansas Central. Early development activities will be handled by an outside developer, while Evergy will hire an Engineering, Procurement and Construction ("EPC") contractor for construction. Structured as a Development Asset Sale ("DAS"), Kansas Sky was identified through Evergy's IRP process to address the 150 MW solar need for EKC by Summer 2027, confirmed in the 2024 Triennial IRP. Investor presentations and IRP updates since 2021 have emphasized the growing demand for solar resources, making Kansas Sky an ideal solution for this requirement. A schedule of the major milestones for the Kansas Sky project is detailed in Table 50 below.

Table 50: Kansas Sky Solar Implementation Milestones

Milestone Description	Expected Completion
Term Sheet Executed	May 2022
Purchase Sale Agreement Signed	February 2023
Main Power Transformer on Order	December 2024
EPC Limited Notice to Proceed	December 2024
State Utility Regulatory Approvals	July 2025
Local Permitting Approvals	December 2025
Closing on Development Assets	Q1 2026
EPC Full Notice to Proceed	Q1 2026
Mechanical Completion	Q1 2027
Substantial Completion/Commercial Operation	Q2 2027

Evergy also invests significant capital on projects to maintain or improve plant efficiency. Table 51 provides examples of these projects.

Table 51: Power Plant Efficiency Projects

Project Description	Unit	Year	Performance Impact
Lawrence Energy Center			
LEC 4 HP (2nd) LP (L-0) Turbine Bucket Replacement	Lawrence 4	2026	Significant
LEC 4 RAH Cold End Basket Replacement	Lawrence 4	2026	Significant
LEC 5 LP Turbine L-0 Blade Replacement	Lawrence 5	2027	Significant
LEC 5 RAH Basket Replacement	Lawrence 5	2027	Significant
Jeffrey Energy Center			
JEC 1 HP and IP Turbine Rotor and Case Replacements	Jeffrey 1	2025	Moderate
JEC 1 Cooling Tower Replacement	Jeffrey 1	2025	Nominal
JEC 3 Air Heater Basket Replacement	Jeffrey 3	2026	Nominal
JEC 2 HP and IP Turbine Rotor and Case Replacements	Jeffrey 2	2027	Moderate
JEC 2 Feedwater Heater Replacement	Jeffrey 2	2027	Nominal
JEC 1 Air Heater Basket Replacement	Jeffrey 1	2029	Nominal
Estimated Performance Impact: Nominal - Less than 0.1% efficiency improvement; Moderate - 0.1 - 0.5% improvement; Significant - Greater than 0.5% improvement			

Section 13: 2024 IRP Joint Agreement Responses

13.1 New Energy Economics (NEE)

13.1.1 Capital Constraints for Wind and Cost Data for Thermal Resources

Evergy agreed to test relaxing capital constraints as wind PPAs expire in the 2025 IRP Annual Update. Plan ACDA shows higher wind builds and substitution of wind for solar in later years if wind constraints are relaxed beginning in 2035.

Evergy updated cost data for CC and CT resources consistent with its development experience. See Section 5.4.

13.1.2 Performance-Based Accreditation Modeling

Evergy modeled the effects of expected SPP rules for performance-based accreditation and fuel assurance on each individual thermal resource for this IRP.

13.1.3 Coal to Natural Gas Conversions

Evergy Kansas Central included analysis of natural gas conversion at Jeffrey 2 and natural gas operation at Lawrence 4 & 5. It also considered the cost and options for coal/natural gas co-firing and natural gas conversion to analyze GHG Rule compliance scenarios and determine optimal compliance options.

13.1.4 Production Cost Modeling

Evergy continued to use the modeling process it used in the 2024 Triennial due to time constraints and confidence in the modeling results. However, Evergy has been testing more granular modeling to provide more detail to stakeholders in future IRPs.

13.1.5 Natural Gas Price Volatility

Evergy continued to use natural gas prices as a critical uncertain factor in IRP modeling. The 2024 IRP natural gas price forecast was used for the 2025 IRP due to lack of updated data from EIA. Evergy is willing to continue to collaborate with stakeholders on how to incorporate fuel volatility and uncertainty into the Company's modeling.

13.1.6 SERVM

Refer to Section 11 for a complete explanation of how Evergy is using SERVM as part of its IRP. Currently, Evergy's primary objective for SERVM analysis is to better understand SPP's modeling and provide feedback in the SPP stakeholder process. SPP is the reliability coordinator and it determines the reserve margins and resource accreditation, based on tariff provisions and modeling results. Evergy's resource planning uses expected SPP requirements. SPP's calculations have financial and planning implications for Evergy, so the Company intends to monitor the modeling inputs and results used by SPP to make sure they are aligned with Evergy's data and operational experience.