Evergy Metro

2025 Annual Update

Integrated Resource Plan

March 2025

Public

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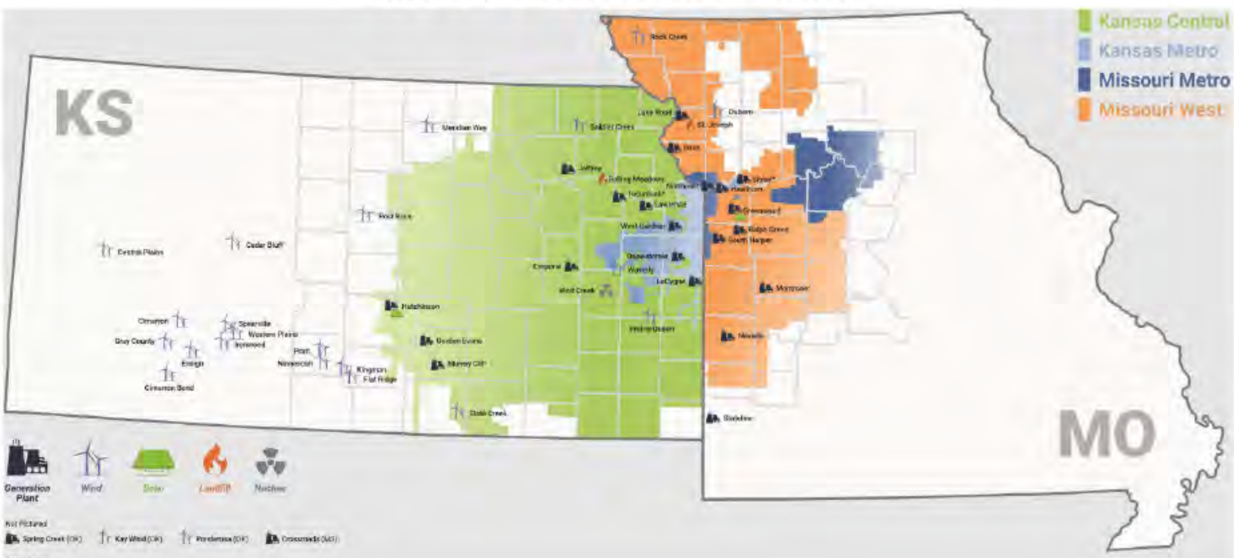
Section 1: Executive Summary

1.1 Utility Introduction

Evergy Metro (or "Company") is an integrated, mid-sized electric utility serving the metropolitan region surrounding the Kansas City, Missouri metropolitan area including customers in Kansas and Missouri. A map of the entire Evergy service territory which includes Evergy Metro is provided in Figure 1: Evergy Service Territory

below.

Figure 1: Evergy Service Territory



Evergy Metro 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 number 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 Missouri Metro	308,319	8,284,560	1,826
Evergy Kansas Metro	276,677	6,316,281	1,700
Total Evergy Metro	**584,896**	**14,600,841**	**3,526**

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

Table 2: Capacity and Energy by Resource Type

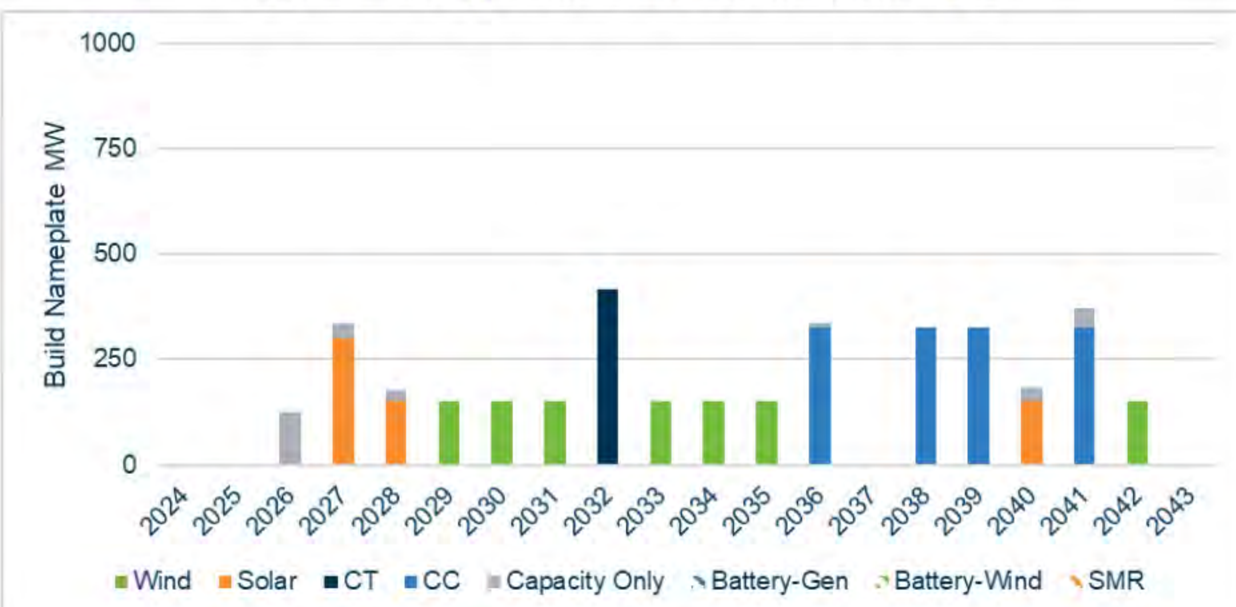
Jurisdiction	Capacity by Fuel Type	Capacity (MW)	Capacity (%)	Energy (MWh)	Energy (%)
Evergy Metro	Coal	2,257	42.3%	7,350,619	44.7%
	Nuclear	553	10.4%	4,326,338	26.3%
	Natural Gas/Oil	1,185	22.2%	1,145,830	7.0%
	Renewable*	1,337	25.1%	3,610,550	22.0%
	Total	**5,332**	**100.0%**	**16,433,337**	**100%**

**Nameplate renewables capacity*

1.2 Preferred Plan Filed in the 2024 Triennial IRP

Evergy Metro submitted its 2024 Triennial IRP filing on April 1, 2024.[1]

Figure 2: Evergy Metro 2024 Preferred Plan CAAB



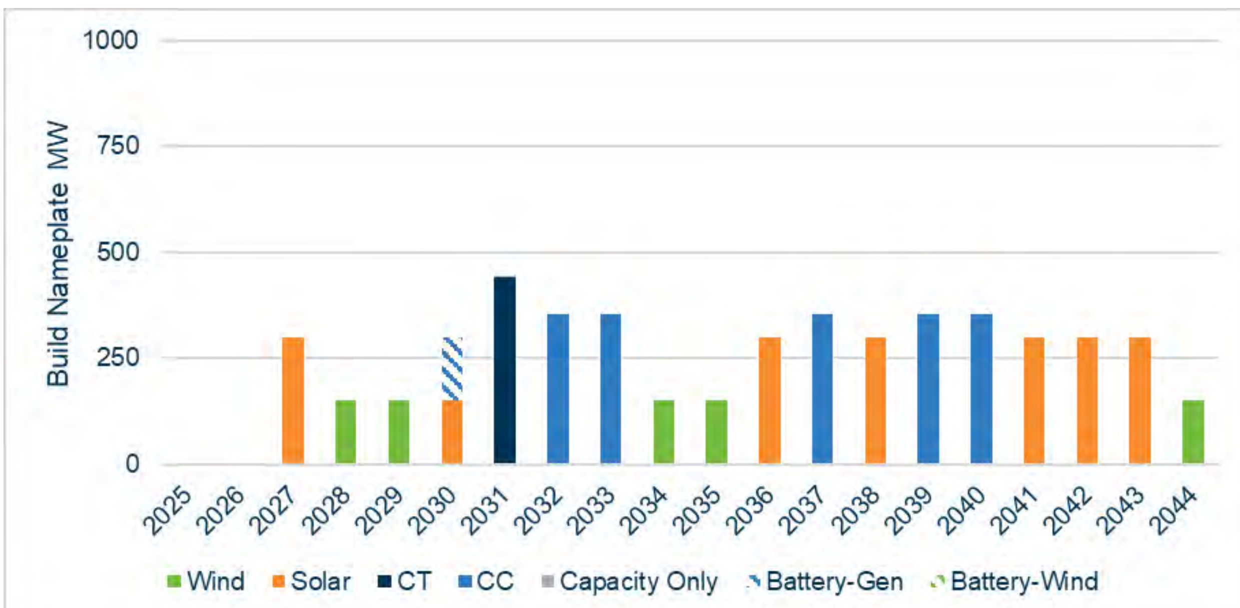
[1] Case No. EO-2024-0153

The Preferred Plan included building or acquiring new resources including 300 MW of solar in 2027, 150 MW of solar in 2028, 150 MW of wind in 2029 and 2030, to meet customer needs through 2030, with the first thermal resource build needed in 2032. Evergy Metro also selected the RAP+ level of future demand-side programs to implement over the planning horizon. Coal generator retirements were anticipated to occur in December 2032 for LaCygne 1, and in December 2039 for Iatan 1 and LaCygne 2.

1.3 Changes to the Preferred Plan for the 2025 Annual Update

This year's 2025 Annual Update shows increasing needs for Metro driven by higher large customer load growth beginning in 2030. The 2025 Preferred Plan AAAA calls for higher levels of resource builds, including storage in 2030 and three thermal resource builds in 2031-2033, compared to the one SCGT addition in 2032 in last year's Preferred Plan.

Figure 3: Evergy Metro 2025 Preferred Plan AAAA



The 2025 Preferred Plan also reflects the demand-side programs consistent with the current MEEIA 4 approved programs.

Table 3: Evergy Metro Preferred Plan 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	LaCygne 1 in 2032 LaCygne 2 in 2039 Iatan 1 in 2039	LaCygne 1 in 2032 LaCygne 2 in 2039 Iatan 1 in 2039
Wind Additions	150 MW in 2029 150 MW in 2030 150 MW in 2031 150 MW in 2033 150 MW in 2034 150 MW in 2035 150 MW in 2042	150 MW in 2028 150 MW in 2029 150 MW in 2034 150 MW in 2035 150 MW in 2044
Solar Additions	300 MW in 2027 150 MW in 2028 150 MW in 2040	300 MW in 2027 150 MW in 2030 300 MW in 2036 300 MW in 2038 300 MW in 2041 300 MW in 2042 300 MW in 2043
Battery Additions	n/a	150 MW in 2030
Thermal Additions	415 MW CT in 2032 325 MW CC in 2036 325 MW CC in 2038 325 MW CC in 2039 325 MW CC in 2041	440 MW CT in 2031 355 MW CC in 2032 355 MW CC in 2033 355 MW CC in 2037 355 MW CC in 2039 355 MW CC in 2040
New DSM Programs	RAP+	MEEIA

In addition to load growth, primary drivers of changes to the needs identified in the resource plan 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 MEEIA Cycle 4 programs compared to RAP Plus levels selected in the 2024 IRP Preferred Plan (more detail is provided in Section 1.6)

Other changes included in the Annual Update:

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

1.4 Managing Risk and Growth Opportunities

Evergy Metro 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 submission of the Triennial IRP.[2] Evergy Metro 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 adding infrastructure to deliver

[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.

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 Plan. 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 Metro, 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's 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 plans 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 Metro's plan 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 Metro to meet increasing requirements driven by higher resource adequacy requirements and load growth from economic development. This resource plan, through the risk analysis performed in compliance with the Chapter 22 IRP rules, 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 plans over time is imperative.

The goal of this Preferred Plan 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 Plan. 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 plan 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

After the 2024 Triennial IRP filing, Evergy Metro filed its proposal for future demand-side programs in its Missouri Energy Efficiency Investment Act (MEEIA) Cycle 4 application on April 29, 2024.[3] The parties to the case reached a joint agreement and the Commission issued its order approving the agreement and tariffs on December 11, 2024, with an effective date of January 1, 2025.

EMM's approved MEEIA Cycle 4 programs will deliver a lower capacity accreditation as compared to the RAP+ (realistic achievable potential plus) demand-side management ("DSM") profile that was selected in EMM's 2024 IRP and subsequently filed in EMM's MEEIA Cycle 4 proposed plan in Case No. EO-2023-0369/0370. Additionally, the approved MEEIA Cycle 4 programs were shorter in duration than the proposed programs in Case No. EO-2023-0369/0370. EMM had filed and proposed a 4-year cycle for its

[3] EO-2023-0369/0370

energy efficiency programs concurrent with a 4-year cycle for its demand response programs. However, the Stipulation and Agreement approved in Case No. EO-2023-0369/0370 included reduced energy efficiency programs for two years (2025-2026) and demand response programs for three years (2025-2027). These changes result in a lower total cost-effective capacity reduction than what could be achieved through the demand-side programs modeled in EMM's 2024 IRP.

As a result, EMM modified its 2025 IRP DSM planning profile to reflect (1) the lower, approved MEEIA Cycle 4 portfolio (budget, energy, demand and cycle duration) and (2) the uncertainty of future MEEIA programs given the tenor of Staff, OPC and Commission comments during the filing, as well as the terms of the Stipulation and Agreement. Therefore, EMM did not model any additional energy efficiency programs after the approved cycle ends in 2026. It also modeled a continuation of the approved MEEIA Cycle 4 level of demand response programs through the end of the IRP planning horizon.

Evergy also includes the estimated impacts of the Commission's time-of-use (TOU) rates from Case No. ER-2022-0129/0130 based on its 2023 DSM potential study by Applied Energy Group (AEG) (see Appendix 8). Following the Commission's order to transition to default TOU rates, the Company modified its potential study TOU impact estimates to better align with the Commission's final order that approved the peak adjustment charge rate as the default TOU rate. Because this rate reflects a much lower price differential than the modeled TOU rates in the potential study, Evergy adjusted the TOU impact downward by 70% (as determined in the potential study for use in its 2024 IRP), which resulted in only 30% of the study's forecasted impact.

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 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 Metro 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 were made 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 COVID19 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 2025 IRP update utilizes end-use forecasts from the 2023 AEO, the same as was used in the 2024 triennial IRP.

- There are some changes in the Moody's Analytics Economic forecasts from 2023 to 2024. Economic forecasts for Population, Households, Employment and Gross Product all show slightly higher growth trajectory in the 2024 forecast compared to the 2023 forecast. The higher growth trajectories in the Economic forecast contributes to a higher growth trajectory in the load forecast.
- The growth trajectory of Evergy Metro Commercial load since the 2024 Triennial IRP forecast partially offsets higher economic forecasts. Additionally, Figures 6 and 7 show how new large customers heavily influences load growth trajectory 2025-2032.

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

[redacted]

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

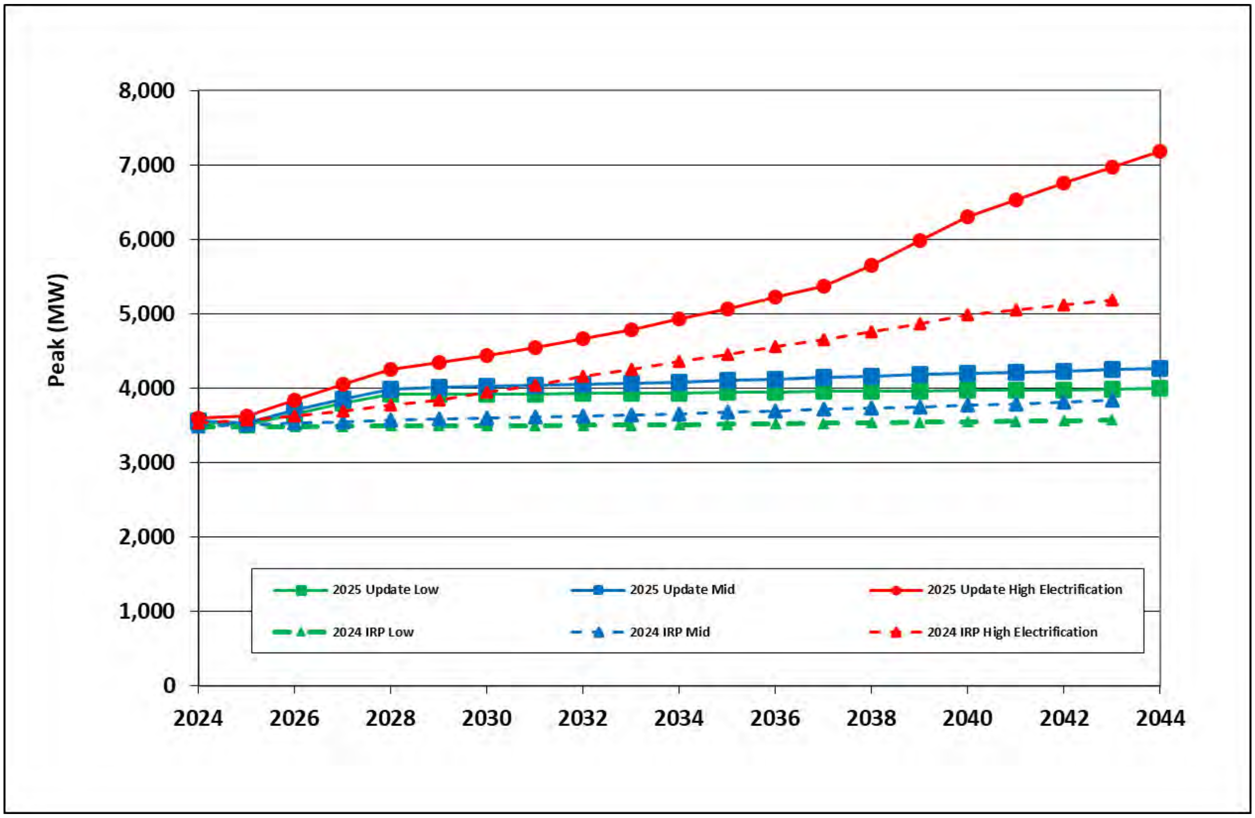
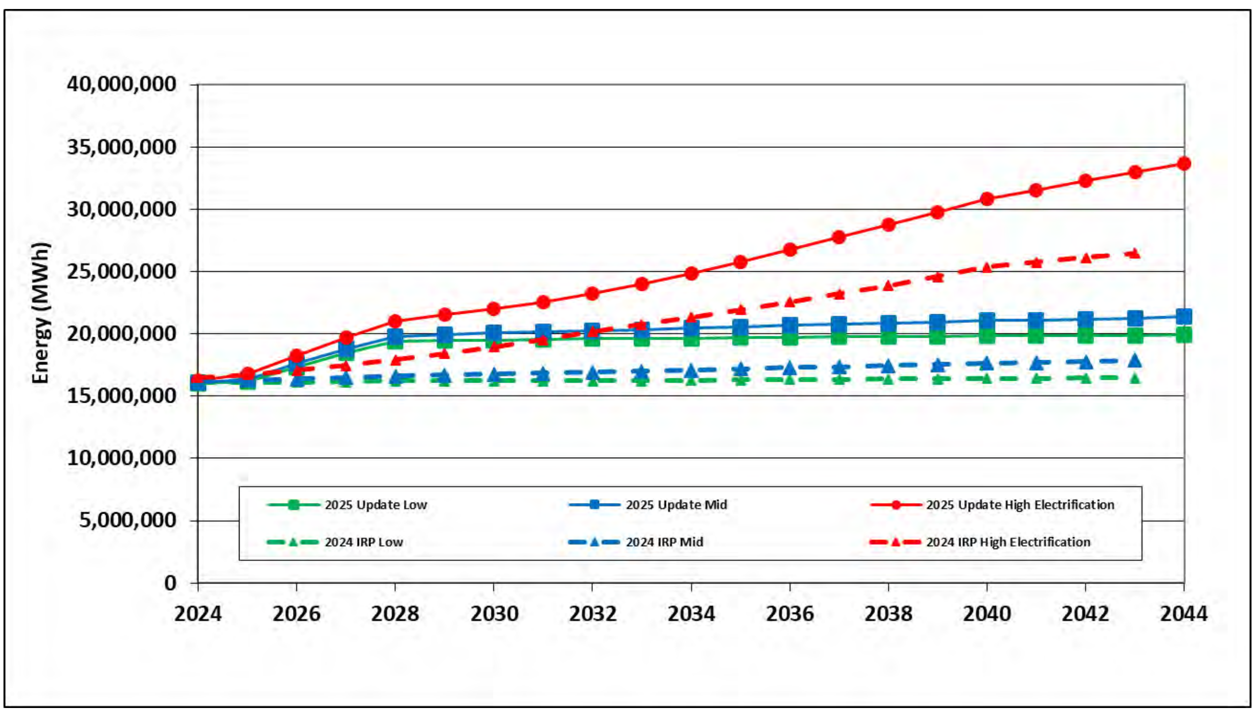


Figure 5: Energy Forecasts – 2025 Annual Update vs. 2024 Triennial IRP



In addition to the higher load forecasts shown in Table 4, Figure 4, and Figure 5 and described above, Evergy Metro has included an updated load ramp for 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 January 2025, Evergy submitted an Attachment AQ study to the SPP to study the transmission upgrade requirements of the incremental new large load. Additionally, Evergy Metro 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 the second half of 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 Plan to unnecessary risks.

A portion of the new large load was included in the typical load forecast data shown in Table 4, Figure 4, and Figure 5. After the 2025 IRP load forecast update process was complete the expected ramp for this customer was increased. In order to fully plan for this customer load profile an adjustment was made to increase the base load. 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.

Figure 6: Evergy Metro Peak MW Load Forecast Including New Large Load

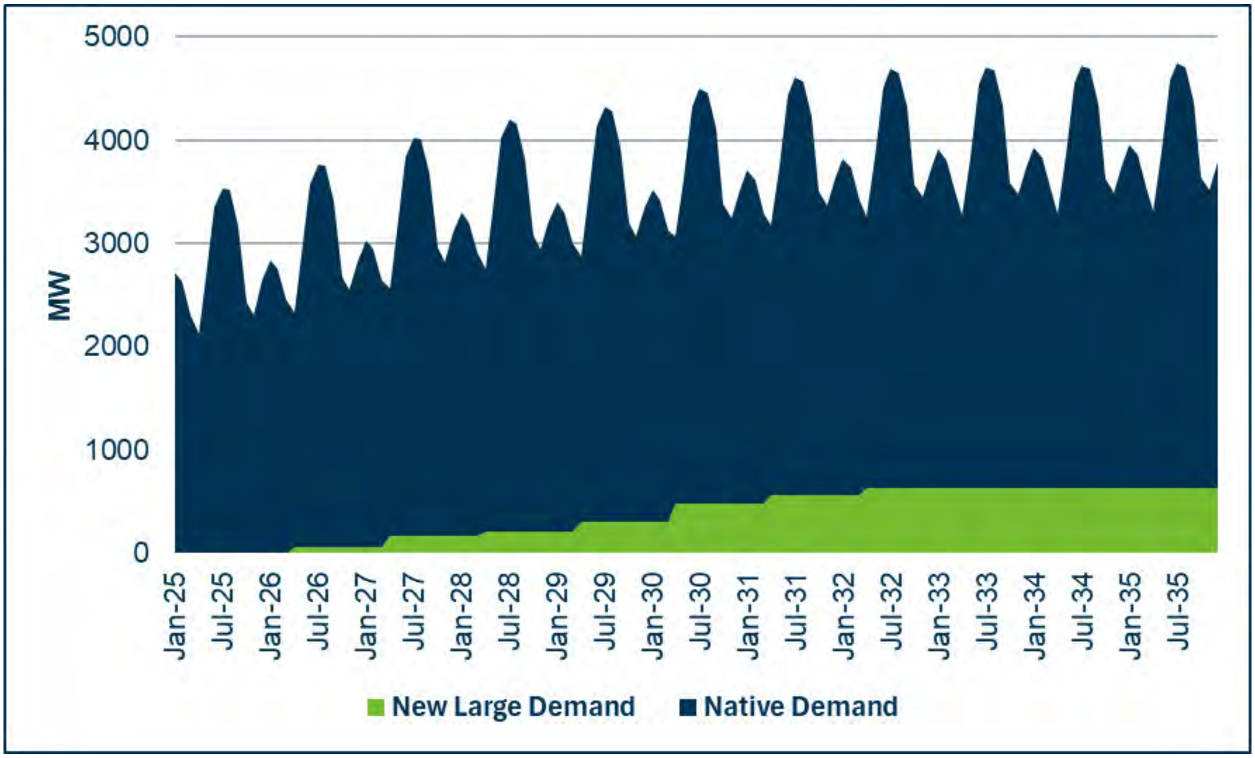
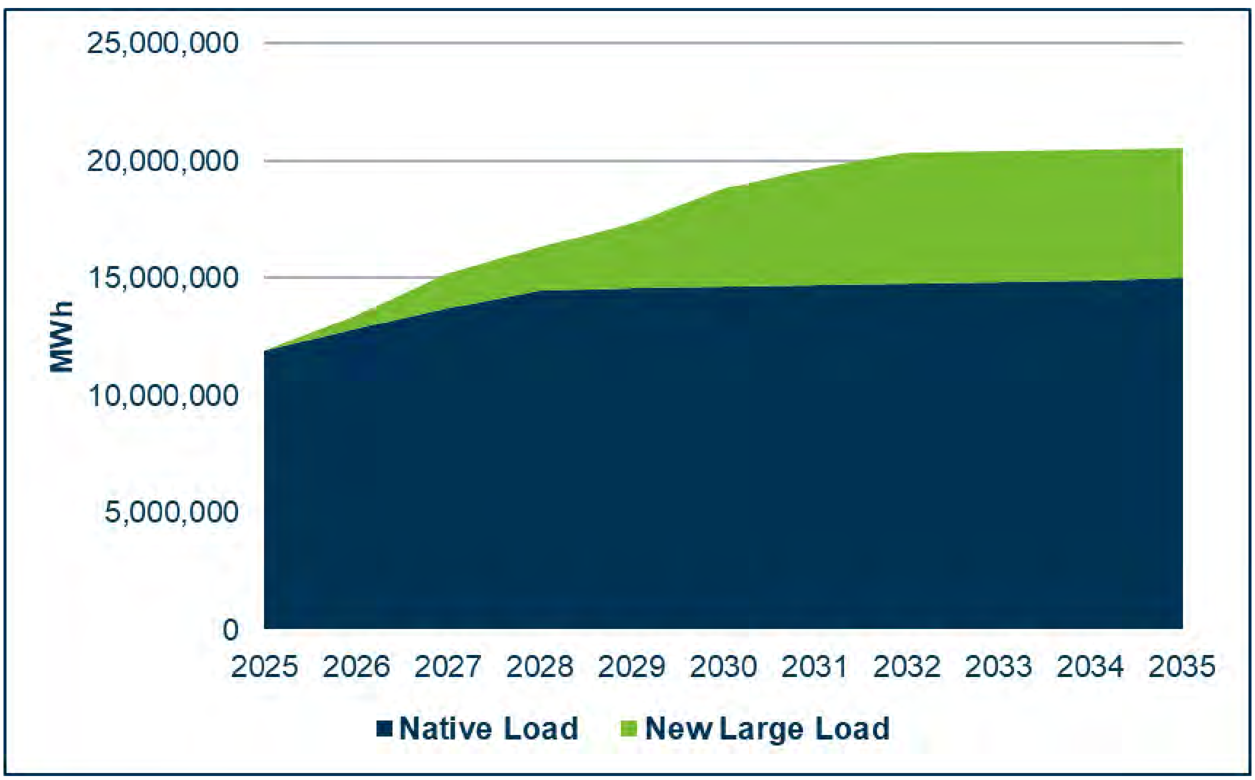


Figure 7: Evergy Metro Peak MWh Load Forecast Including New Large Load



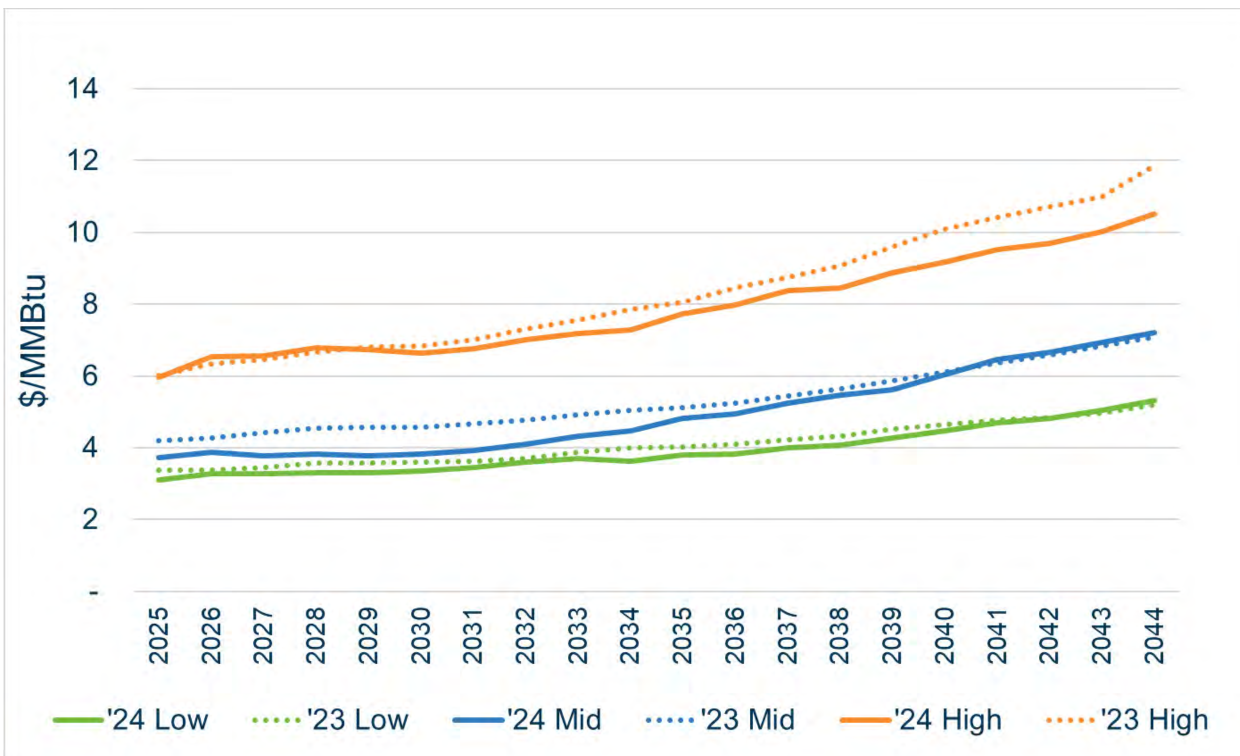
Section 3: Market Fundamentals Update

3.1 Fuel Price Forecasts [4]

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.[5] 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

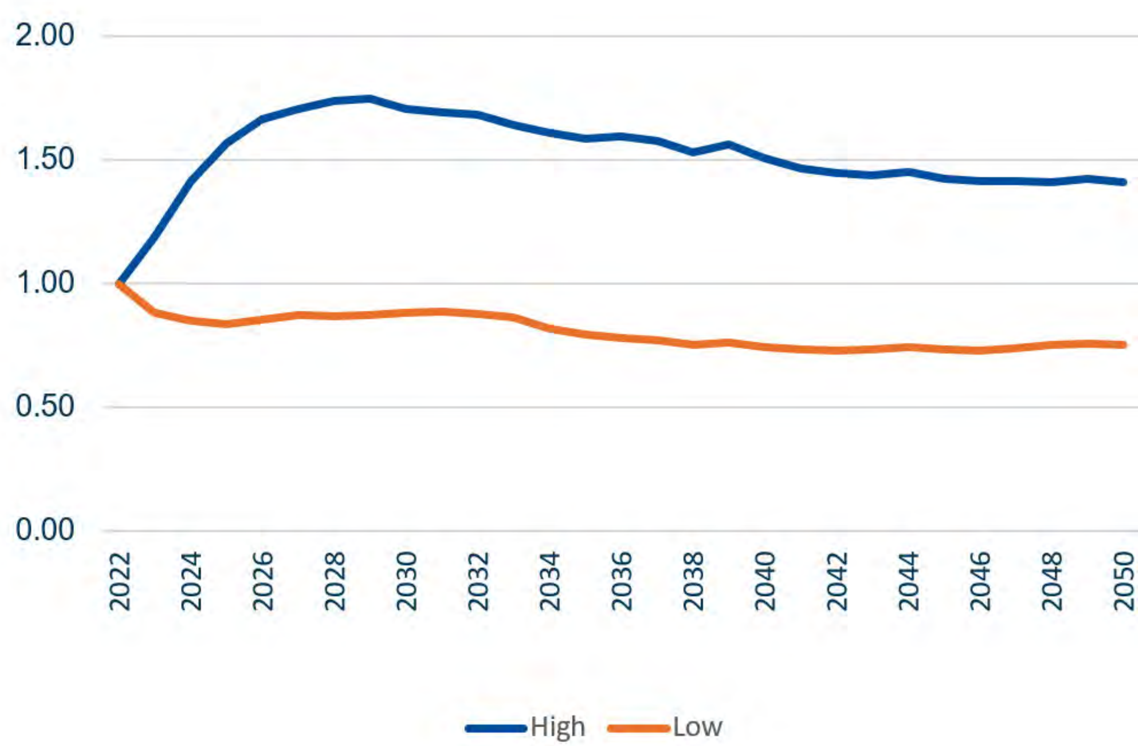


4 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A)

5 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.[6]

Figure 9: Henry Hub Natural Gas Scalar



[6] *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 Metro Coal Price Forecast **<u>Confidential</u>**

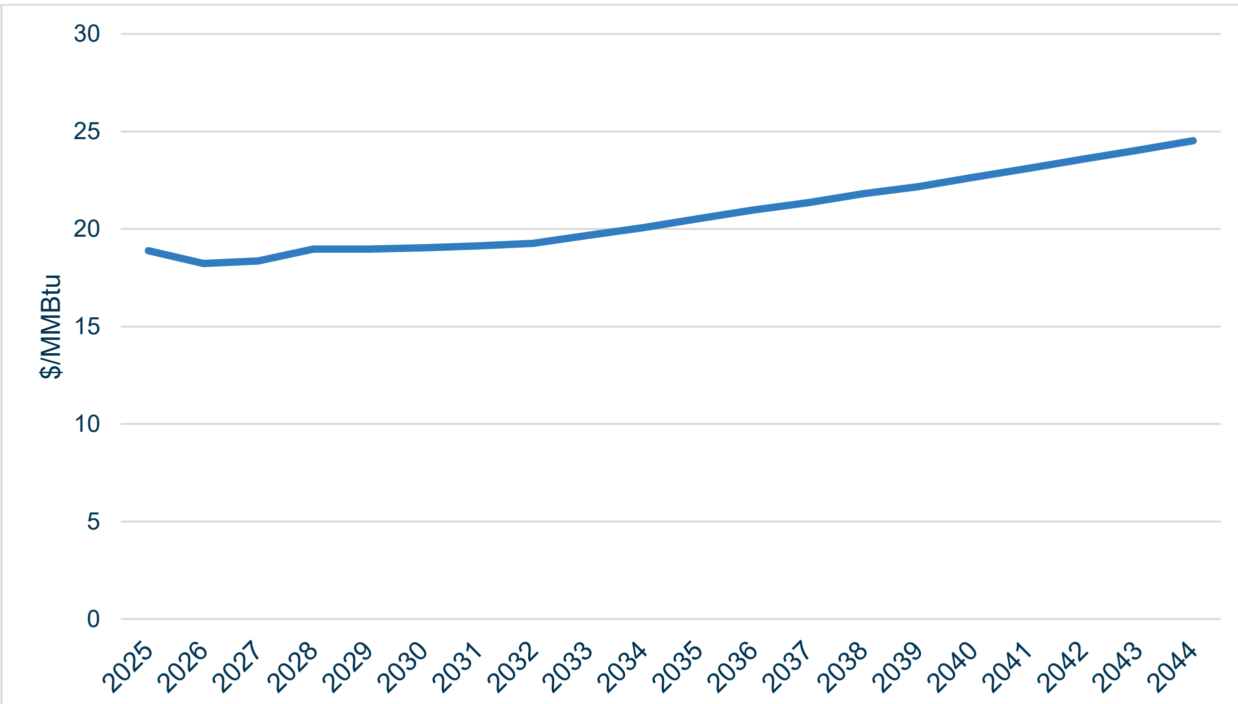
[redacted]

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 IHS 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: Metro CO_2 Emission Constraint

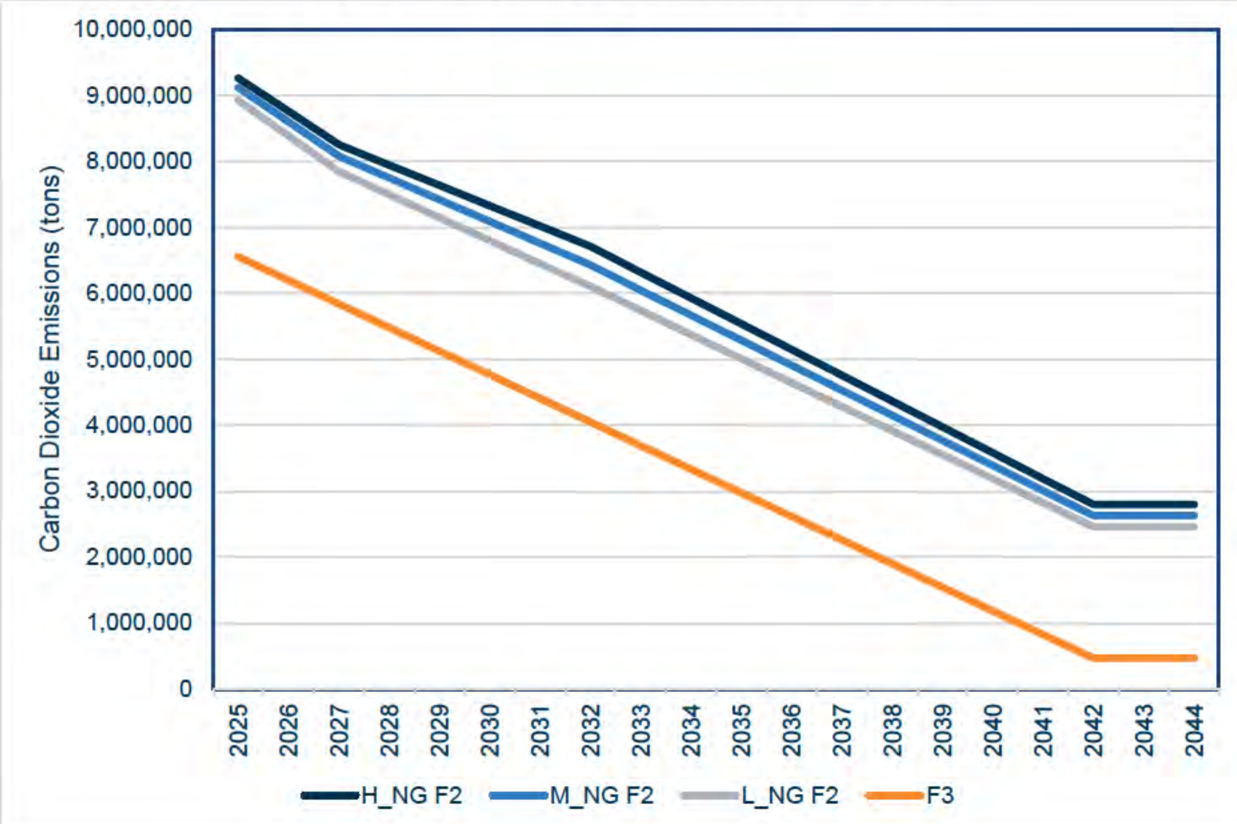


Table 5: Future 3 CO_2 Emission Tax ($/ton)

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.

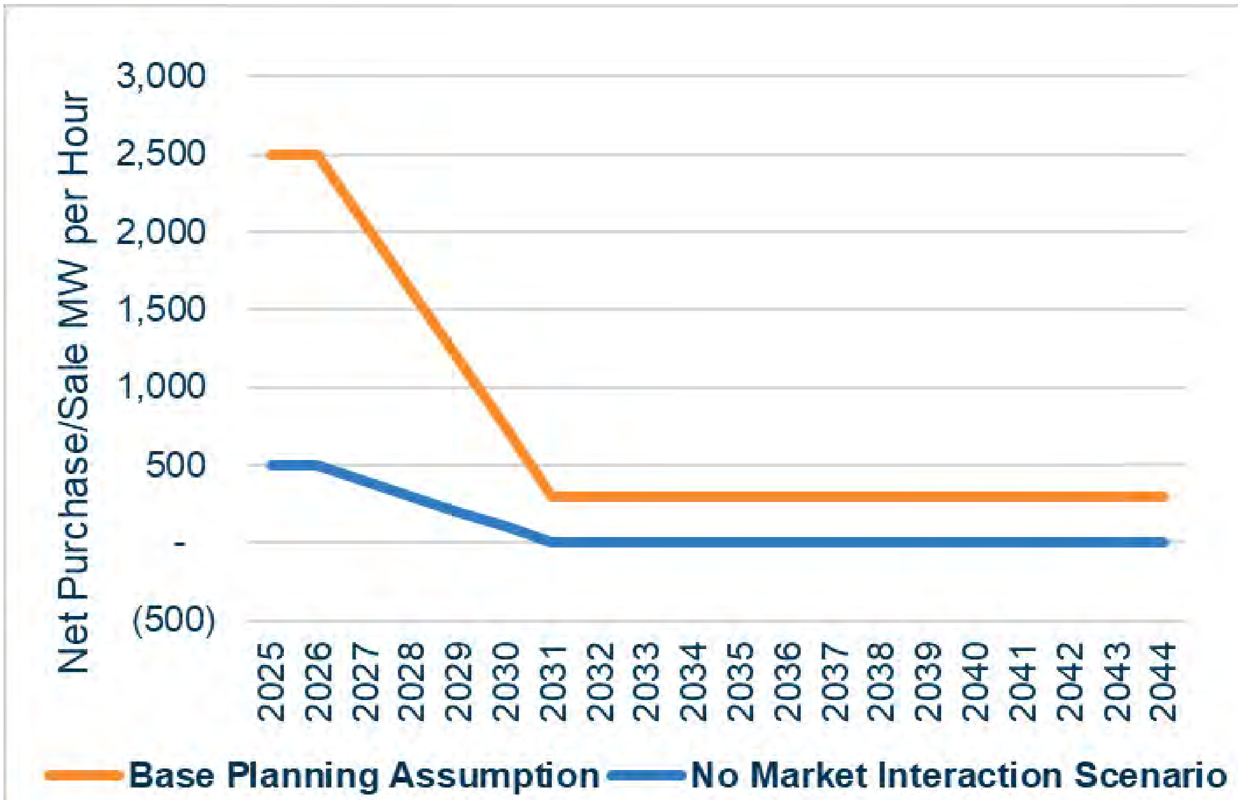
3.4 Market Dependence

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. Evergy Metro is a net seller.

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., Metro) 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 portfolio 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 (Metro)



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 300 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.[7] 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 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.[8]

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[7] SPP OATT Attachment AA, Section 4.0 Planning Reserve Margin
[8] 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 CONE value is based on annual cost, SPP proposed to assess such deficient 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

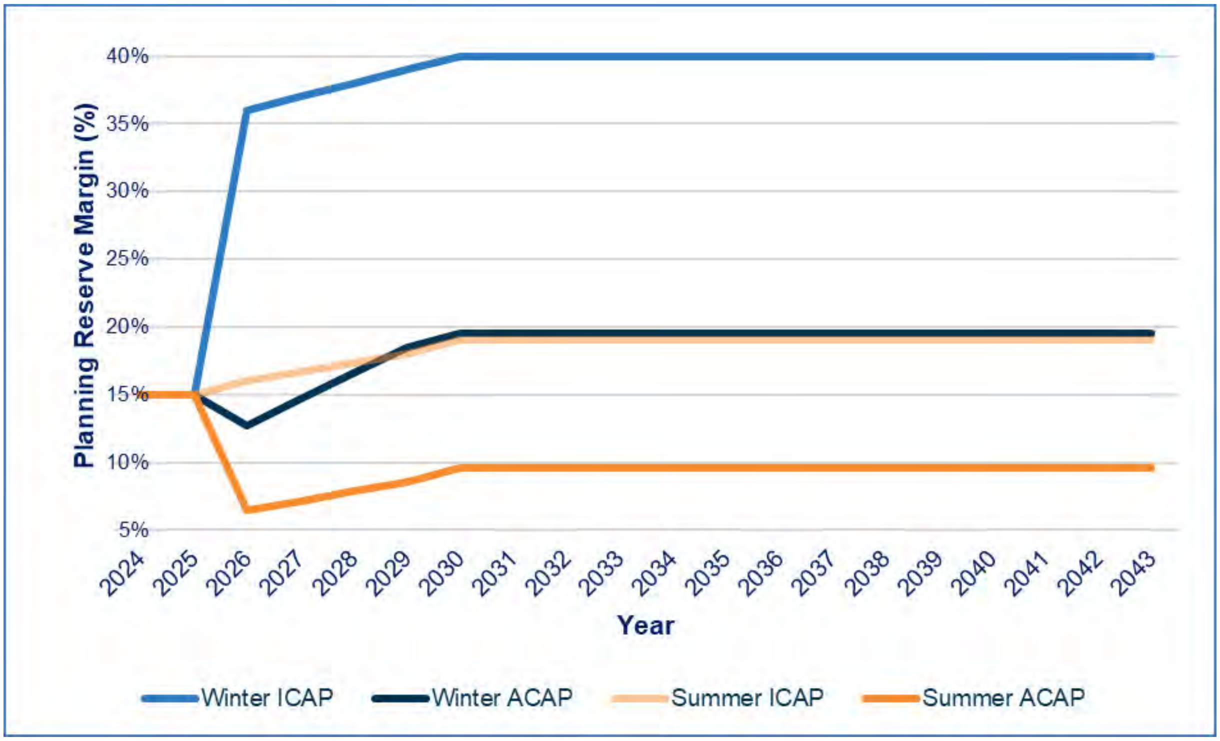
Evergy incorporated a 12% summer reserve margin in its resource plans for the 2021 and 2022 IRPs, consistent with SPP requirements. In July 2022, the SPP board approved an increase in the summer reserve margin to 15% beginning in summer 2023, and Evergy's 2023 IRP met that minimum value for the 20-year 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. All resources lose accreditation under PBA, however the SPP reserve margin will also decrease to reflect the system need for unforced capacity. 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. 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 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 increased 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 continuous 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.

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”.[9] 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 RFP and developers are not pursuing speculative thermal resource projects in SPP. Evergy expects to self-develop these resources.

[9] 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.

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 plan, 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 and 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.[10]

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.

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

[redacted]

[10] Evergy testimony from Kyle Olson and Jason Humphrey in EA-2025-0075 provide more detail on construction cost estimates for planned CCGT and SCGT resources.

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

[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),[11] while the cost of CO_2 transportation and storage was estimated from a 2022 report by the National Energy Technology Laboratory (NETL).[12]

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

****Confidential****

[redacted]

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.

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

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

Table 13: Market Capacity Available Metro

Year	Summer Market Capacity	Winter Market Capacity
2026-2029	250 MW	500 MW
2030	250 MW	250 MW
2031+	30 MW	30 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 Metro 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 Metro 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 the Evergy Metro 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 Metro’s existing emission controls at its La Cygne, Iatan and Hawthorn Generating Stations maintain compliance with these requirements. Future visibility progress goals could result in additional SO_2, NO_x and PM controls or reduction technologies on fossil-fired units.

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.

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 Metro 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: Transmission and Distribution Update

7.1 Changes from the 2024 Triennial IRP

Transmission and Distribution-related changes and updates are provided below:

7.1.1 RTO Expansion Planning

Evergy Metro's assessment of RTO expansion plans is an ongoing process that occurs through the various regional planning processes conducted by SPP. These assessments include review and approval of plan scope documents, review and approval of plan input assumptions, review of plan study analysis and results with feedback from Evergy Metro staff, and review and approval of final plan reports. All transmission projects identified by SPP for the Evergy Metro service territory are included in SPP's annual Transmission Expansion Plan Report and Project List. By meeting the performance standards established for transmission planning, the assessment ensures that adequate transmission is available in the near term and long term to meet the firm load and transmission service requirements included in the SPP Regional Plan for the Company. These documents are attached as Appendix 7A 2024 SPP Transmission Expansion Plan Report.pdf and Appendix 7B 2024 SPP Transmission Expansion Plan Project List.xlsx.

7.1.2 Advanced Distribution Technologies

Evergy's ongoing grid modernization efforts are focused on the need to ensure the grid is reliable and flexible to meet our customers' needs. Out of that initiative, Evergy is focusing on the advanced distribution technologies below to support those needs:

- Advanced Distribution Management Systems (ADMS)
- Communicating Faulted Circuit Indicators (CFCIs)
- Reclosers with communication
- Regulators and Capacitors with Communication
- Load Tap Changers with Communication

Advanced Distribution Management Systems

Evergy has started the process of implementing ADMS functionality beginning with Fault Location, Isolation and Service Restoration (FLISR). When fully deployed, ADMS can provide the following functions for system operators to manage the grid in a safe, intelligent, and efficient manner:

- Fault Location Isolation and Service Restoration (FLISR)
- Advanced Fault Location functionality utilization (FLA)
- Distribution Supervisory Control and Data Acquisition (D-SCADA)
- Power Flow Optimization
- Volt/Var Optimization (VVO)
- State Estimation

Fault Location Isolation and Service Restoration

Evergy is actively deploying FLISR that uses a central application to communicate with and control smart switching with reclosers and communicating fault indicators.

A centralized FLISR engine will be used to drive the primary functions of our Intelligent End Devices (IEDs). These functions include Supervisory Control and Data Acquisition (SCADA) commands, automated FLISR actions, circuit/substation parameters and safety needs such as hold cards. In order to enable a hybrid (partially centralized, partially decentralized) approach, the IED will consume remote data while taking on some of the responsibility to adjust circuit protection settings, trip cycles and switching functions. This allows IEDs to have a subset of safe operational capabilities should communications be interrupted.

Centralized systems require little operator interaction during FLISR events. This allows the FLISR system to run quickly and effectively based on engineered algorithms. Operators will have ultimate authority over the system and will be able to disable and enable FLISR as needed.

Fault Location Analysis Functionality (FLA)

To enable automated fault location prediction, an advanced application is needed which requires accurate and persistently maintained circuit source impedance profiles, primary conductor impedance profiles, and communicating field equipment sensor data. This sensor data allows the application to model and calculate sections of a feeder where a fault is likely or unlikely to be physically located. Further improved fault location accuracy is attainable by installing additional fault sensors (such as communicating faulted circuit indicators or communicating switches) on the circuit to compliment the model with more physical and logical sensor data points in coordination with smart meter integration.

The Company's current fault location solution is an internally engineered application for circuit and data modeling that exists alongside the Company's Outage Management System (OMS), granting capability to leverage system integrations and data which do not necessarily exist or need to exist within the OMS platform itself. This independent application models and calculates fault location using similar methods and equations to an advanced vendor supplied engineering distribution system modeling platform which is leveraged by several engineering departments for various routine system load flow analyses and ad-hoc system studies such as arc-flash. The internally created FLA application has been validated in producing actionable solutions for actual outage events to aid crew and operators in reduction of outage duration.

Benefits anticipated from Fault Location prediction are mainly reduced patrol time for field crews in event location identification during outage events, and the ability to identify and trend momentary faulting events enabling the Company to remedy emergent issues prior to their severity producing a sustained outage event. With a near real-time FLA solution produced for an outage event, dispatchers can immediately direct field crews to focus on specific predicted sections of circuit as opposed to crews needing to patrol an entire circuit to identify the specific location of a system fault.

No specific timeline has been established, but the Company intends to further expand FLA solutions beyond the current state by fully configuring the system impedance model within the OMS application and aggregating in the required field data as a parallel FLA effort, which will enable further validation and model calibration of the two FLA systems in contrast to one another. Success of this planned effort is dependent on OMS system capability plus successful integration and testing of model comparisons and prescribed event solutions.

Communicating Faulted Circuit Indicators (CFCI)

Evergy is perpetually evaluating emerging CFCI technologies and installing where enhancements benefit grid resiliency and reliability.

Dispatchers now have the ability to receive CFCI alarms and activity in OMS. Using the OMS One-line diagram, Operators use CFCIs while troubleshooting an outage. This greatly enhances the "visibility" and usefulness of CFCIs to dispatchers.

CFCIs are also anticipated to be a cost-effective way to enhance the Fault Location functionality discussed previously. Although CFCIs cannot perform switching operations, they can enhance the effectiveness of dispatching and manual switching. To date, over 8,100 CFCIs have been installed in the Evergy service territory.

Reclosers with Communication

Evergy is currently deploying reclosers configured to support FLISR. These devices function like a traditional reclosers with the benefit of being able to communicate with a centralized FLISR application for coordination and action. Additionally, these devices can be used by an operator in our dispatch center.

Regulators and Capacitors with Communication

Evergy is working to upgrade as needed our Regulators and Capacitors with communication to support our VVO planned work. Evergy currently has these assets deployed, however they currently can only react to pre-planned events at the time the asset is deployed. This change will allow us to use automation and intelligence to manage the system to a greater degree.

Load Tap Changers with Communication

Similar to Regulators and Capacitors Evergy is upgrading Load Tap Changers (LTCs) as needed to add communications and controls for these devices. They will support VVO by enabling control of system voltage. Evergy currently has these assets deployed however they currently can only react to pre-planned events at the time the asset is deployed. This change will allow us to use automation and intelligence to manage the system to a greater degree.

7.1.3 Advanced Transmission Technologies Discussion

In the Evergy Metro area, Evergy is using advanced assessment methods to evaluate new technologies to support the transmission system. This effort is focused around maintaining a robust transmission system as customer end-uses and generation resources change, in addition to the continued adoption of behind-the-meter and other distributed energy resources.

Advanced Assessment Methods

Evergy uses end-use load models developed by the North American Electric Reliability Corporation (NERC) in association with the US Department of Energy (DoE) and Electric Power Research Institute (EPRI) to locate areas within the Evergy Metro footprint that may be susceptible to phenomena such as Fault-Induced Delayed Voltage Recovery (FIDVR). FIDVR and other fast-acting phenomena can be mitigated by means of new transmission technologies.

New Transmission Technologies

Static synchronous compensators (STATCOMs), enhanced STATCOMs (E-STATCOMs), and synchronous condensers (SynCons) are advanced transmission technologies currently being evaluated by Evergy.

STATCOM – a sub-division of a group of devices known as Flexible Alternating Current Transmission System (FACTS) devices. A STATCOM uses a voltage source converter

(VSC) to match or produce a voltage wave and can react to large changes nearly instantaneously.

E-STATCOM – a STATCOM with added super-capacitor to enable primary frequency response and enhance grid-support capability.

SynCon – a synchronous generator connected to a motor. SynCons provide nearly identical system support characteristics in terms of voltage and frequency as a traditional synchronous generator. However, since they are connected via a motor to the transmission system, they are unable to produce real-power output (i.e., Megawatts).

Section 8: Demand-Side Resource Analysis Update

8.1 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, Evergy's base case includes impacts of MEEIA Cycle 4 energy efficiency and demand response programs as approved by the Commission in EO-2023-0369/0370.

Evergy also includes estimated impacts of the Commission-ordered time-of-use (TOU) rates from ER-2022-0129/0130 based on its 2023 DSM potential study. However, the estimated impact is adjusted downward because the default TOU rate (i.e., peak adjustment charge rate) that was approved by the Commission reflects a much lower price differential than the modeled TOU rates in the potential study.

8.2 2023 Demand-Side Rate Analysis

The 2023 Demand-Side Management (DSM) Market Potential Study was conducted by Applied Energy Group (AEG). The DSM Market Potential Study included the Evergy Missouri Metro and Evergy Missouri West service territories and was delivered to Evergy in May 2023. The Potential Study included a RAP and a MAP level of DSM, as defined in the IRP Rules. This Potential Study included energy efficiency programs, demand response programs and demand-side rate potential savings analyses.

During the Potential Study and in ER-2022-0129/0130, the Commission ordered default time-of-use (TOU) rates. The Commission ordered that Evergy would transition all residential customers to default TOU rates by October 1, 2023, with the default rate being the two-period TOU rate. AEG analyzed the two-period TOU rate in the Maximum Achievable Potential (MAP) scenario with high, medium and low retention rates. AEG assumed a conservative retention rate of 50% to estimate MAP and then tested the sensitivity of impacts and program costs to changes in the TOU retention rate as shown in Table 14.

Table 14: MAP Sensitivity Analysis

Sensitivity	(1) TOU Standard	(2) TOU for EV Owners	(3) TOU Peak Adjustment Rate	(4) TOU 3-Period
MAP	**50% of all residential customers**	**20% of EV owners who opt out of TOU Standard**	**95% of remaining TOU Standard opt-outs**	**All other TOU Standard opt-outs**
MAP Medium-Retention	70% of all residential customers	50% of EV owners who opt out of TOU Standard	95% of remaining TOU Standard opt-outs	All other TOU Standard opt-outs
MAP High - Retention	85% of all residential customers	100% of EV owners who opt out of TOU standard	95% of remaining TOU Standard opt-outs	All other TOU Standard opt-outs

The expected demand savings in MW for Summer and Winter peak are presented in Table 15 and Table 16.

Table 15: Cumulative Annualized Demand Savings (MW) from TOU – Summer

Year	MAP(High)	MAP(Low)	MAP (Medium)	RAP	RAP (-)	RAP (+)
2025	52	33	44	8	7	8
2026	45	29	38	14	13	14
2027	45	29	38	22	19	22
2028	45	28	38	29	25	29
2029	44	28	38	29	25	29
2030	44	28	37	29	25	29
2031	44	28	37	28	25	28
2032	44	28	37	28	25	28
2033	44	28	37	28	25	28
2034	44	28	37	28	25	28
2035	43	28	37	28	25	28
2036	43	28	37	28	25	28
2037	43	28	37	28	25	28
2038	43	28	37	28	25	28
2039	43	28	37	28	25	28
2040	43	28	37	28	25	28
2041	43	28	37	28	25	28
2042	43	28	37	28	25	28
2043	43	28	37	28	25	28
2044	43	28	37	28	25	28

Table 16: Cumulative Annualized Demand Savings (MW) from TOU – Winter

Year	MAP(High)	MAP(Low)	MAP (Medium)	RAP	RAP (-)	RAP (+)
2025	32	20	27	5	4	5
2026	28	18	23	9	8	9
2027	28	18	24	13	12	13
2028	28	18	24	18	16	18
2029	28	18	24	18	16	18
2030	28	18	24	18	16	18
2031	28	18	24	18	16	18
2032	29	18	24	18	16	18
2033	29	18	24	19	16	19
2034	29	19	25	19	16	19
2035	29	19	25	19	17	19
2036	29	19	25	19	17	19
2037	30	19	25	19	17	19
2038	30	19	25	19	17	19
2039	30	19	25	19	17	19
2040	30	19	26	20	17	20
2041	30	19	26	20	17	20
2042	30	19	26	20	17	20
2043	31	20	26	20	18	20
2044	31	20	26	20	18	20

However, at the end of 2023, the Commission revised its order, changing the default rate for Missouri residential customers to the Peak Adjustment Charge Rate. Because the revised order was received after the DSM Market Potential Study had been completed and because the Peak Adjustment Charge Rate reflects a much lower price differential than the modeled TOU rates in the potential study, it was determined that a lower demand impact would likely result. Therefore, Evergy adjusted the TOU impact downward determined in the potential study for use in its 2024 IRP by 70%, or resulting in 30% of the potential study forecast. The savings modeled in IRP 2025 annual update for TOU are shown in Table 17 and Table 18.

Table 17: IRP Modeled Cumulative Annualized Demand Savings (MW) from TOU – Summer

Year	Time-of-Use (TOU) Rate	Electric Vehicle (EV) TOU Rate	Total
2025	2.46	0.01	2
2026	4.30	0.02	4
2027	6.43	0.03	6
2028	8.55	0.05	9
2029	8.53	0.05	9
2030	8.51	0.05	9
2031	8.48	0.06	9
2032	8.46	0.06	9
2033	8.47	0.06	9
2034	8.44	0.07	9
2035	8.43	0.07	8
2036	8.42	0.08	8
2037	8.44	0.08	9
2038	8.43	0.09	9
2039	8.43	0.09	9
2040	8.43	0.10	9
2041	8.44	0.10	9
2042	8.40	0.11	9
2043	8.42	0.11	9
2044	8.43	0.12	9

Table 18: IRP Modeled Cumulative Annualized Demand Savings (MW) from TOU – Winter

Year	Time-of-Use (TOU) Rate	Electric Vehicle (EV) TOU Rate	Total
2025	1.50	0.00	2
2026	2.65	0.01	3
2027	3.99	0.02	4
2028	5.34	0.03	5
2029	5.38	0.03	5
2030	5.43	0.03	5
2031	5.47	0.04	6
2032	5.50	0.04	6
2033	5.53	0.04	6
2034	5.57	0.04	6
2035	5.61	0.05	6
2036	5.65	0.05	6
2037	5.70	0.05	6
2038	5.73	0.06	6
2039	5.78	0.06	6
2040	5.83	0.07	6
2041	5.86	0.07	6
2042	5.86	0.07	6
2043	5.90	0.08	6
2044	5.94	0.08	6

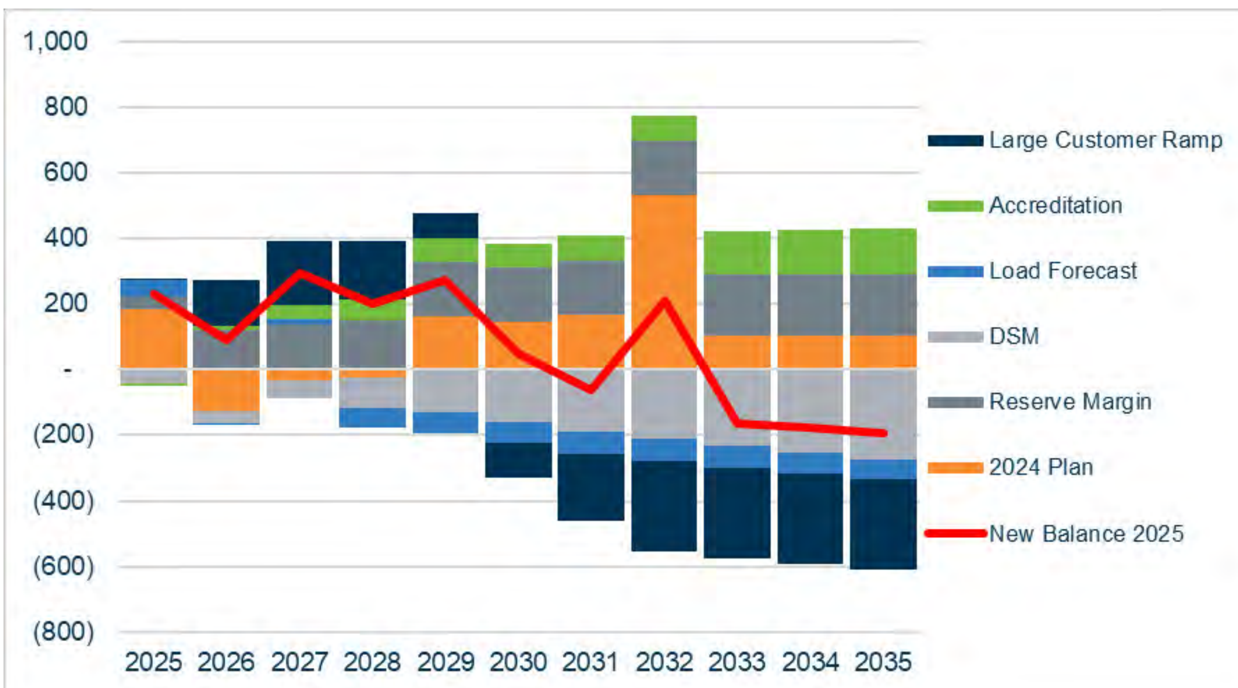
Section 9: Resource Plan Analysis

9.1 Changes to Expected Capacity Needs

Evergy Metro's 2024 Preferred Plan forecasted a summer capacity surplus in 2025, followed by the need to purchase market capacity in 2026-2028. In 2029, after 450 MW of solar additions and the roll-off of a long term capacity contract, the plan was again long summer capacity. The addition of a 415 MW SCGT in 2032 enabled Metro to attain capacity length ahead of the end of year 2032 LaCygne1 retirement.

Evergy Metro's current forecast updates for the 2025 IRP have eliminated the early short position, but the 2024 Preferred Plan builds are insufficient to meet capacity needs beginning in 2031. In 2026-2029 the large customer load ramp decreased from the previous forecast, reducing capacity need. Beginning in 2030, the large customer load ramp increased, increasing capacity need. Changes to reserve margin assumptions and resource accreditation increased the capacity position. Lower levels of demand-side programs and a higher base load forecast beginning in 2028 decreased the capacity balance.

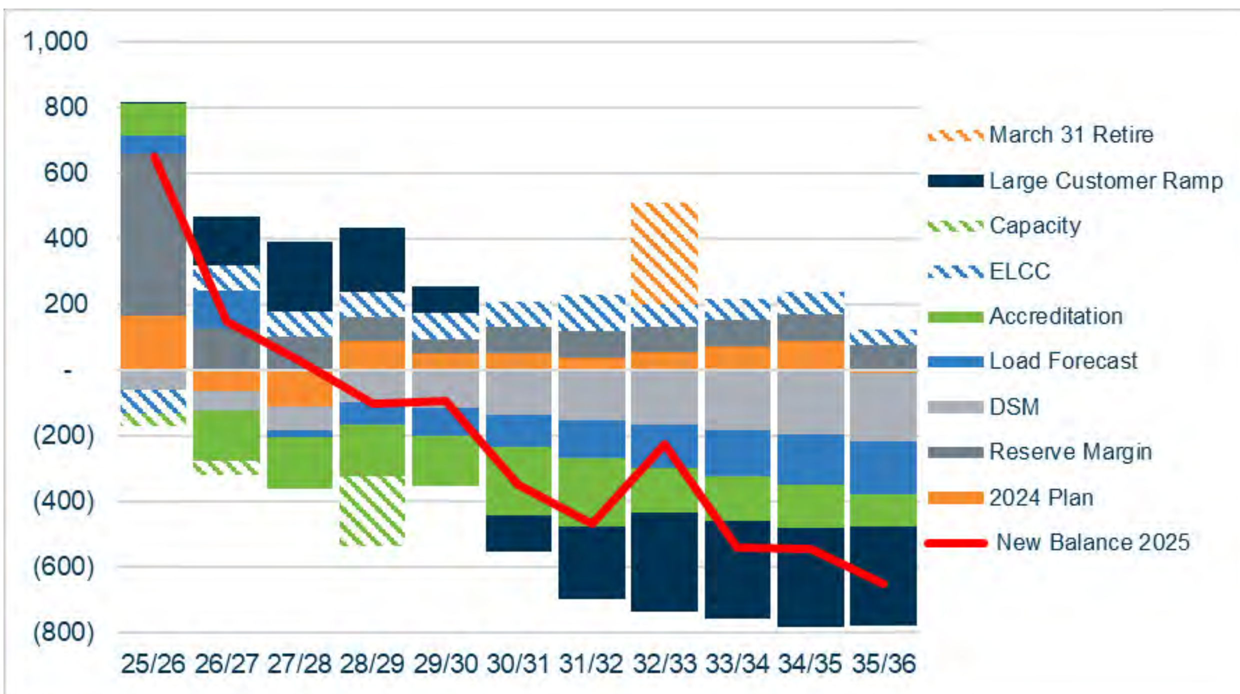
Figure 20: Changes to Summer Capacity Balance



Evergy Metro forecasted a winter capacity short position winter 2026/2027- winter 2027/2028 and then small winter capacity surpluses in future years in its 2024 Preferred Plan.

Updates to forecasts since the 2024 IRP alleviate the early winter short position, but make Every Metro short winter capacity beginning winter 2028/2029 and very short beginning winter 2030/2031. Drivers of increased capacity need include lower demand-side programs forecast, higher base load forecast, large new customer load, and decrease in expected resource accreditation from fuel assurance/ performance-based accreditation provisions. Helping the capacity position were changes to reserve margins, and higher ELCC accreditation. Evergy Metro also better accounted for a capacity contract ending winter 2028/2029, and assumed in this IRP that retirements would be concluded after the winter season to ensure continuity of retirement-new build capacity across seasons.

Figure 21: Changes to Winter Capacity Balance



9.2 Base Planning Options

9.2.1 Resource Availability

All resource plans developed include the 2027 solar, consistent with the 2024 Triennial Preferred Plan. The need for this resource is tested in this 2025 Annual Update by allowing the capacity expansion software to select 300 MW of solar in 2027.

Evergy Metro'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 19: Base Build Limits Assumptions

Year	Solar	Wind	Battery	CC	CT
2027	300 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	355 MW	440 MW

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

Table 20: Higher Wind Build Limits 2035+

Year	Solar	Wind	Battery	CC	CT
2027	300 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	355 MW	440 MW
2035+	300 MW	350 MW	300 MW	355 MW	440 MW

Evergy Metro does not expect to be able to procure or develop additional thermal resources earlier than 2031. A plan was developed to test whether full combined cycles or higher amounts of other resources would be cost-effective if build limits were loosened.

Table 21: Higher Build Limits 2031+

Year	Solar	Wind	Battery	CC	CT
2027	300 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+	600 MW	300 MW	600 MW	710 MW	880 MW

Finally, in order to develop plans that could not select new thermal resources, Evergy Metro tested relaxed build limits equivalent to 10 projects/year each for solar, wind and storage.

Table 22: High Renewables and Storage Build Limits

Year	Solar	Wind	Battery	CC	CT
2027	300 MW	n/a	n/a	n/a	n/a
2028	1500 MW	1500 MW	1500 MW	n/a	n/a
2029	1500 MW	1500 MW	1500 MW	n/a	n/a
2030	1500 MW	1500 MW	1500 MW	n/a	n/a
2031+	1500 MW	1500 MW	1500 MW	n/a	n/a

9.2.2 Retirements

Evergy Metro 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 Plan included the retirement of LaCygne 1 in 2032, LaCygne 2 in 2039, and Iatan 1 in 2039. Continuing to plan for the retirement of LaCygne 1 in 2032 is a balanced approach of responsibly transitioning the fleet, while lowering the overall risk of continuing to operate aged coal generation. The 2025 IRP continues to plan for the retirement in the 2024 Preferred Plan, while testing ARPs with other possible retirement scenarios:

- Iatan 1 retires 2030
- LaCygne 2 retires 2032
- LaCygne 1 retires 2039

9.3 Alternative Resource Plan Testing

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

- Testing the economics of plans without 2031 thermal resources, and with other resources instead
- Testing alternative coal retirement/conversion scenarios
- 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
- Testing a plan that only meets the minimum requirements for Missouri Renewable Energy Standards (RES)

Table 23: Plan Key for Base Plans

DSM	Coal (Changes from PP)	Builds	Load & Contingencies
A - MEEIA Extends	A – 2024 PP Retirements	A - Base capital 2028+	A - Base load
B - MEEIA Ends	B - IAT 1 retires 2030	B - Include 2027 solar 300 MW	P - High NG, High CO_2 Restriction
	C - LaCygne 2 retires 2032	C - Allow higher early solar/storage	Q - Low NG, Low CO_2 Restriction
	D - LaCygne 1 retires 2039	D - Allow higher wind 2035+	R - High NG, Mid CO_2 Restriction
		E - Allow higher builds 2031+	T – Minimum Compliance with RES
		F - Only renewables/storage; No Build Limit	
		G - No 2031 CT	
		H - No 2031 Thermal	
		J – No 2027 Solar	

Table 24: Base Plan Descriptions

Plan Name	Description
AAAA	MEEIA Extends, Base Load, Build Limits, 2024 PP Retirements
AAAP	High NG/High CO_2
AAAQ	Low NG/Low CO_2
AAAR	High NG/Mid CO_2
AAFP	High NG/High CO2, Only renewables/storage relaxed build limit
AAGA	No 2031 CT
AAHA	No 2031 Thermal
AAJA	No 2027 Solar
ABAA	IAT 1 Retires 2030
ACAA	LaCygne 2 Retires 2032
ADAA	LaCygne 1 Retires 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 Missouri IRP process.

Table 25: Critical Uncertain Factor Probabilities

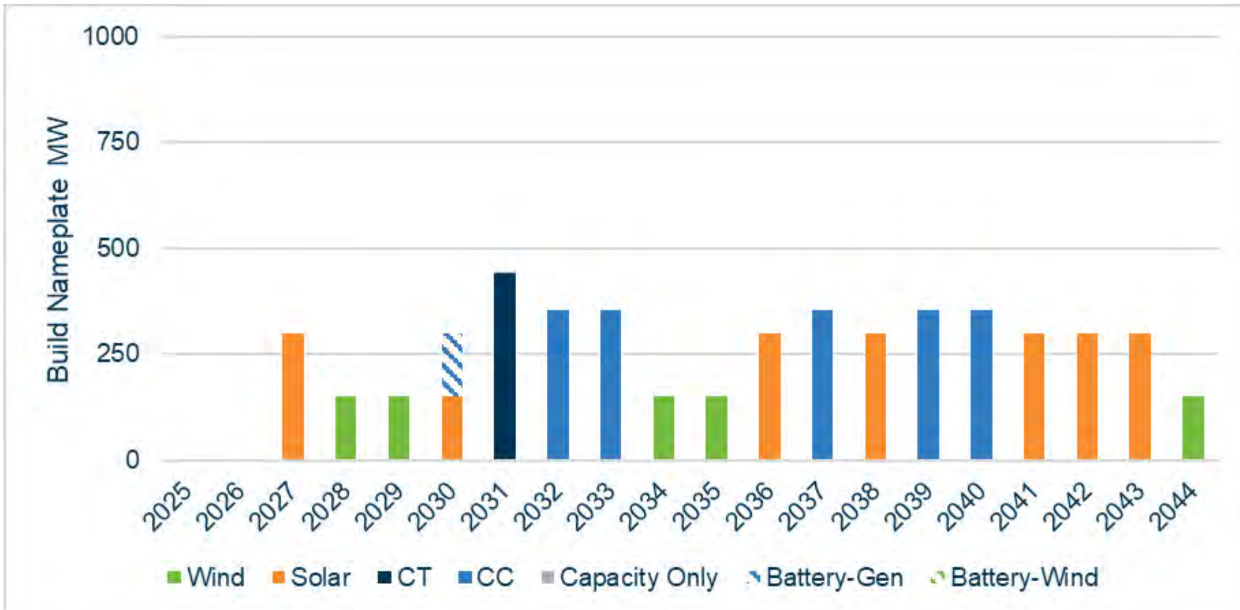
	Natural Gas Price	CO_2 Emissions Restrictions	Construction Cost
Low	35%	25%	25%
Mid	50%	60%	50%
High	15%	15%	25%

9.4 Base Plans

The AAAA plan uses capacity expansion and base planning assumptions, including the updated load and resource adequacy forecasts, retirements identified in the 2024 IRP, and the MEEIA level of demand-side programs.

The AAAA plan selects the 300 MW of solar in the 2024 IRP. The plan also selects wind projects in 2028 and 2029, solar in 2030 and storage in 2030. A full SCGT is selected in 2031 followed by two half CCGTs in 2032 and 2033.

Figure 22: Base Planning Assumptions Plan AAAA



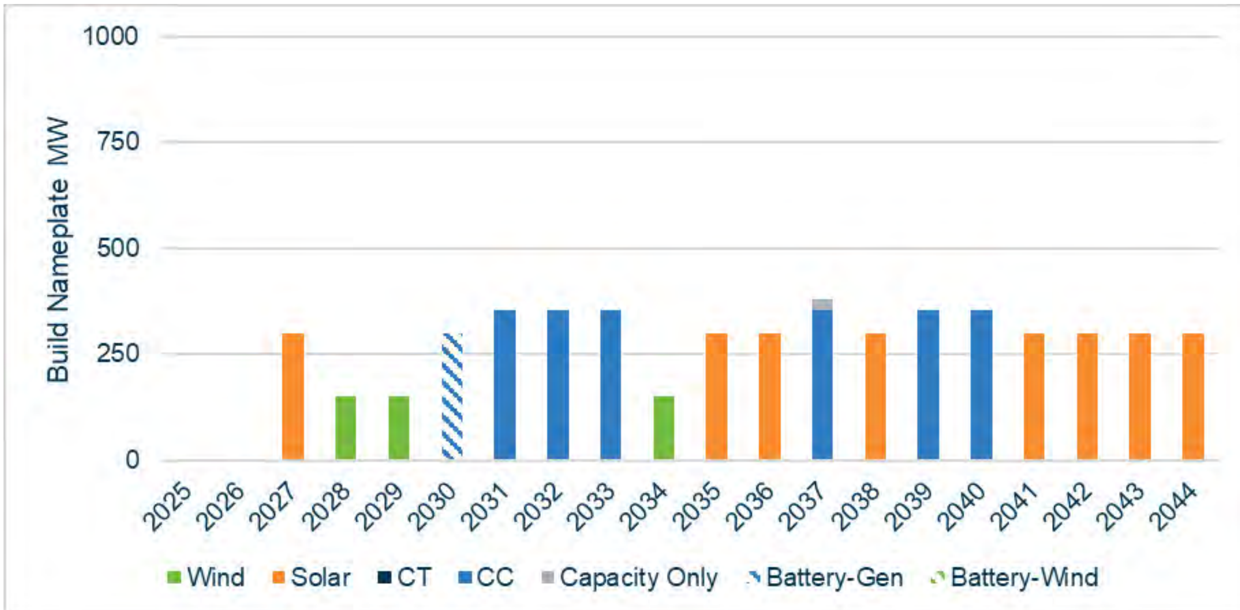
9.5 Plans Testing Near-Term Options

9.5.1 Plans without 2031 Thermal as an Option

Alternative resource plans AAGA and AAHA test what resources would be built if the 2031 SCGT was not a build option.

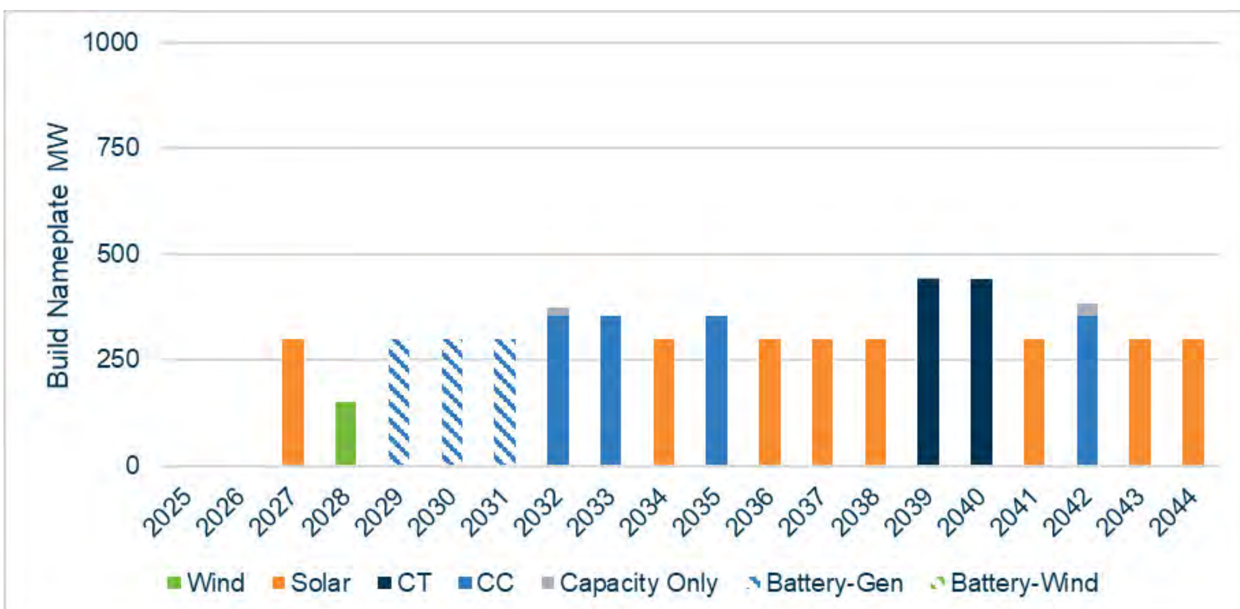
The resource plan AAGA builds 300 MW of storage in 2030 without the 2031 SCGT as a build option. CCGTs are built in 2031, 2032, and 2033.

Figure 23: No 2031 CT Plan AAGA



Plan AAHA does not allow thermal build options through 2031. The resource plan AAHA builds 900 MW of storage from 2029 - 2031. CCGTs are built in 2032, 2033 and 2035.

Figure 24: No 2031 Thermal Plan AAHA



If a 2031 SCGT is not available, the next best resource plan option would include building more storage in 2030, rather than solar and building a 2031 CCGT. This Plan AAGA has a $33 million increase in NPVRR. If no thermal resources can be available by 2031, the alternative resource plan requires 750 MW additional storage in 2029-2031 which is more than $1.2 billion more costly.

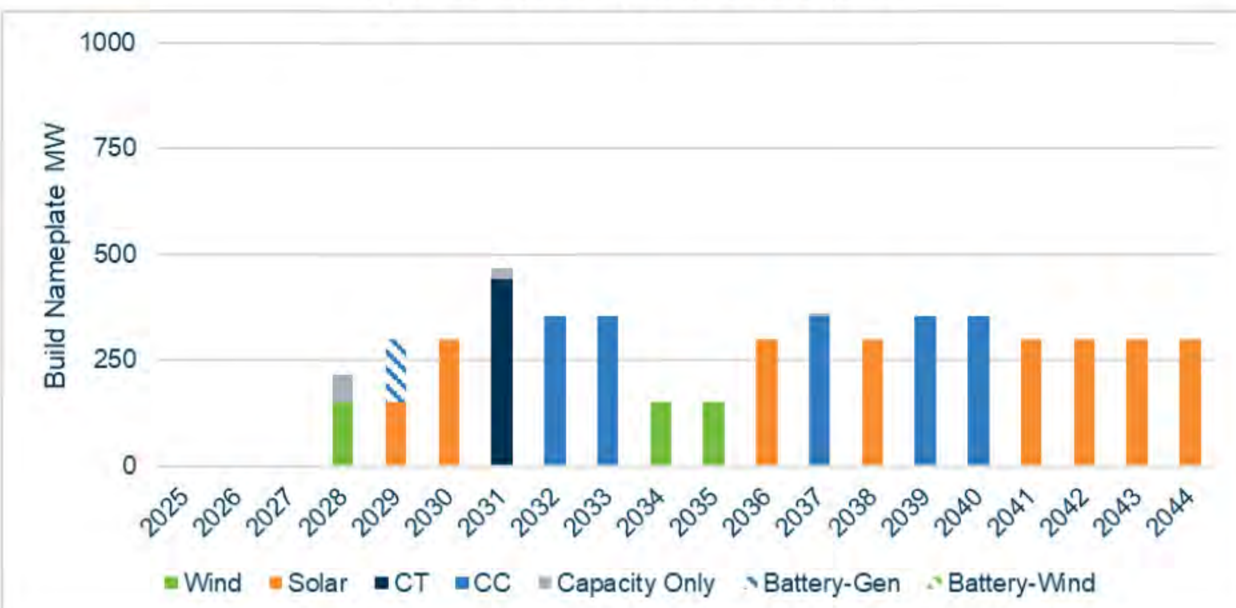
Table 26: Rankings for 2031 Thermal Option Testing

Rank	Plan	NPVRR	Difference	Description
1	AAAA	23,609		Base Load, MEEIA Extends, Build Limits, 2024 PP Retirements
2	AAGA	23,642	33	No 2031 CT
3	AAHA	24,824	1,215	No 2031 Thermal

9.5.2 Plan without 2027 Solar as an Option

Alternative resource plan AAJA tests what resources would be built if the 300 MW 2027 solar is not a build option. The plan adds 150 MW of solar and 150 MW of storage in 2029 instead of 150 MW of wind.

Figure 25: No 2027 Solar Plan AAJA



The alternative resource plan with no 2027 solar increases cost by almost $300 million from the base case Plan AAAA which includes 300 MW of solar in 2027. The Plan AAJA moves solar builds to a later year, but still builds 450 MW of solar before 2031.

Table 27: Rankings for No 2027 Solar

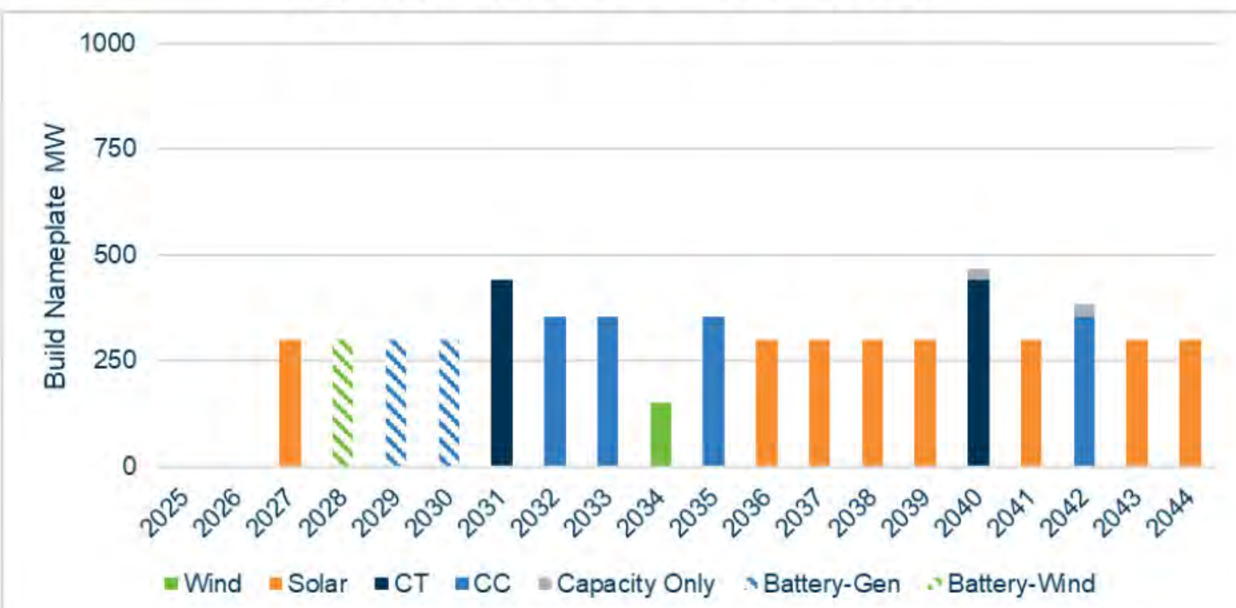
Rank	Plan	NPVRR	Difference	Description
1	AAAA	23,609		Base Load, MEEIA Extends, Build Limits, 2024 PP Retirements
2	AAJA	23,903	294	No 2027 Solar

9.6 Plans Testing Retirements

Alternative resource plans ABAA, ACAA, and ADAA test additional coal plant retirement options. Base build limits are used and the 2027 solar is available as a build option.

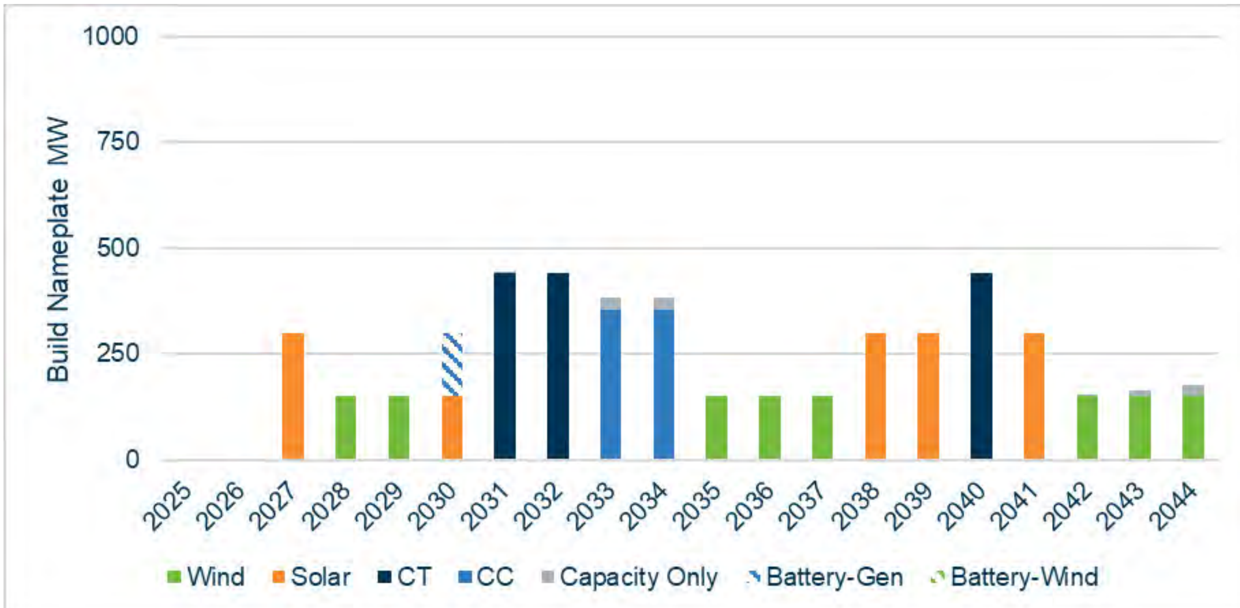
Plan ABAA retires Iatan 1 in 2030. The Iatan 1 retirement reduces summer capacity by about 450 MW beginning in 2031. The resource plan needs more early capacity resources to replace the retirement. It builds 300 MW storage in each year from 2028-2030, in addition to the 2027 solar SCGT in 2031, and ½ CCGTs in 2032, 2033. The next thermal build is pulled forward to 2035.

Figure 26: Retire Iatan 1 in 2030 Plan ABAA



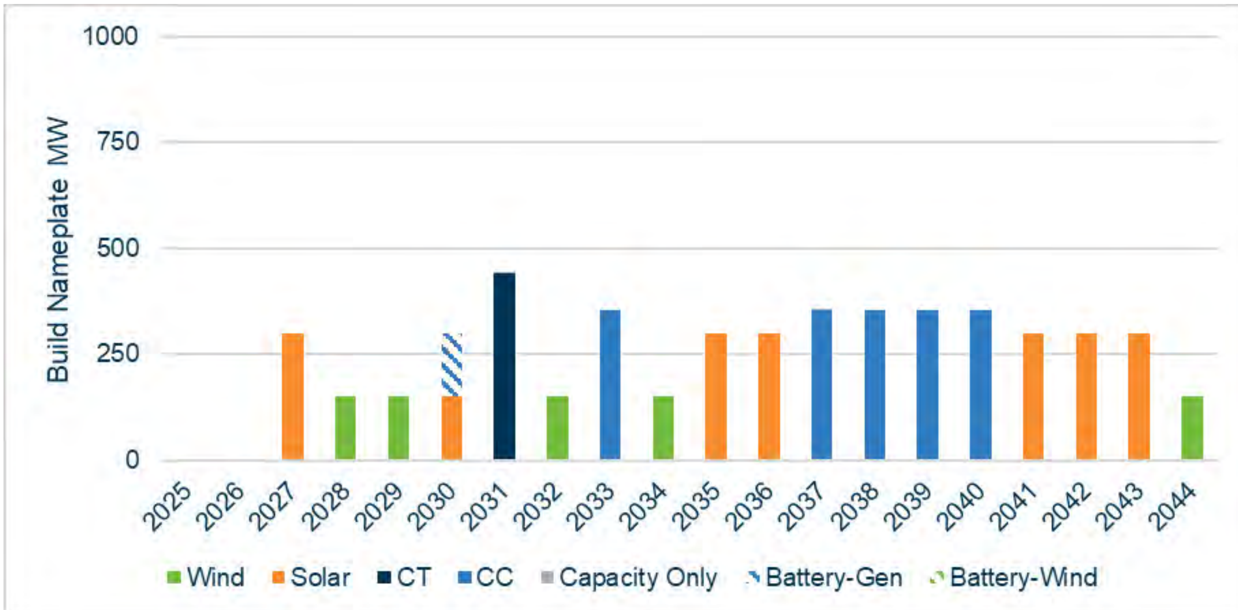
Plan ACAA retires LaCygne 2 in 2032, which results in a loss of about 300 MW of capacity beginning in 2032. Since this capacity loss is later in the planning horizon, the 2027-2031 build plan remains the same. However, an additional SCGT is built in 2032 and the two ½ CCGTs are pushed back one year to 2033 and 2034.

Figure 27: Retire LaCygne 2 in 2032 Plan ACAA



Plan ADAA extends LaCygne 1 to run on coal until 2039. LaCygne 1 retired in 2032 in the Preferred Plan, so this adds about 340 MW of capacity to the resource plan beginning in 2033. The build plan remains the same in 2027-2031. However, the 2032 ½ CCGT is no longer needed and is replaced by 150 MW wind. The plan continues to build a ½ CCGT in 2033. An additional ½ CCGT is built in 2038.

Figure 28: Extend LaCygne 1 Retirement to 2039 Plan ADAA



The plan extending LaCygne 1 to 2039, rather than retiring in 2032 is the least cost plan considered. The Preferred Plan retirements increases NPVRR by $157 million, due to the need for an additional ½ CCGT in 2032. The plan with an early Iatan 1 retirement is the most costly, in part because Evergy Metro does not have many options for replacement capacity before 2031, and must rely heavily on storage builds to meet capacity needs with this retirement in 2030. An earlier retirement of LaCygne 2, to retire in 2032 with LaCygne 1, also increases costs.

While the NPVRR analysis shows benefit in postponing the LaCygne 1 retirement, the NPVRR does not encompass all risks to Evergy Metro's coal fleet. Evergy Metro does not believe it is optimal to plan for no loss of coal resources until 2039. The coal fleet is aging and faces operational risks as well as risks of tightening future environmental regulations. Planning for the LaCygne 1 retirement ensures that Evergy Metro is capable of meeting customer needs considering the risk that at least one coal resource may cease operation.

Table 28: Coal Retirement Plan Rankings

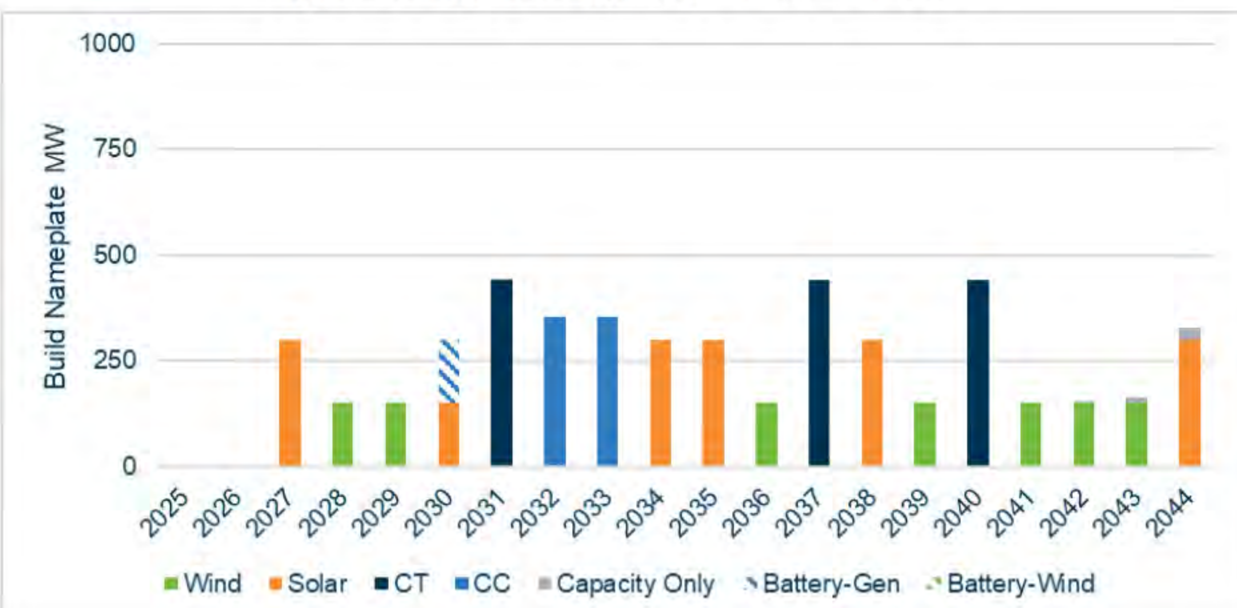
Rank	Plan	NPVRR	Difference	Description
1	ADAA	23,452		LaCygne 1 Retires 2039
2	AAAA	23,609	157	2024 PP Retirements
3	ACAA	24,022	570	LaCygne 2 retires 2032
4	ABAA	25,149	1,697	IAT 1 Retires 2030

9.7 Plans Testing Optimal Builds for Varying Futures

Alternative resource plans AAAP, AAAQ, AAAR, and AAFP test optimal build decisions for varying natural gas and CO_2 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.

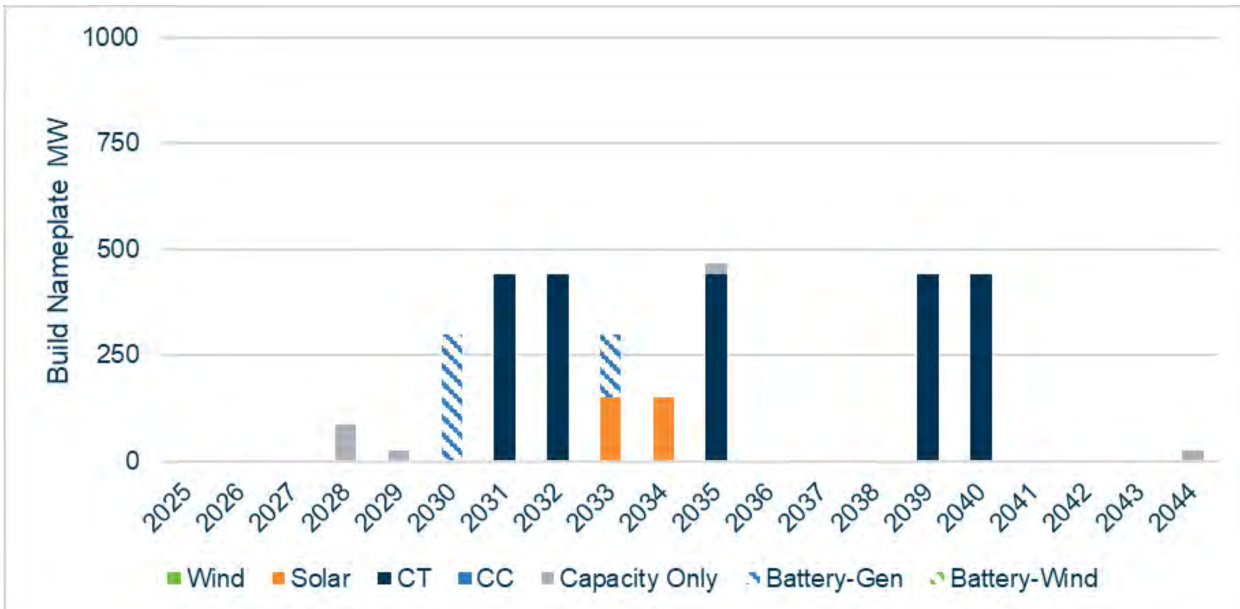
Plan AAAP considers optimal build decisions if a high natural gas price and high carbon dioxide restricted future is expected. This plan has the same early build decisions from 2027-2033 as the base plan AAAA which was optimized at the mid natural gas price and mid carbon dioxide restricted future. Beginning in 2034, the plan has less solar, 1,200 MW rather than 1,500 MW. It has 300 MW more wind, and two SCGTs rather than three ½ CCGTs.

Figure 29: High NG/High CO_2 Future Plan AAAP



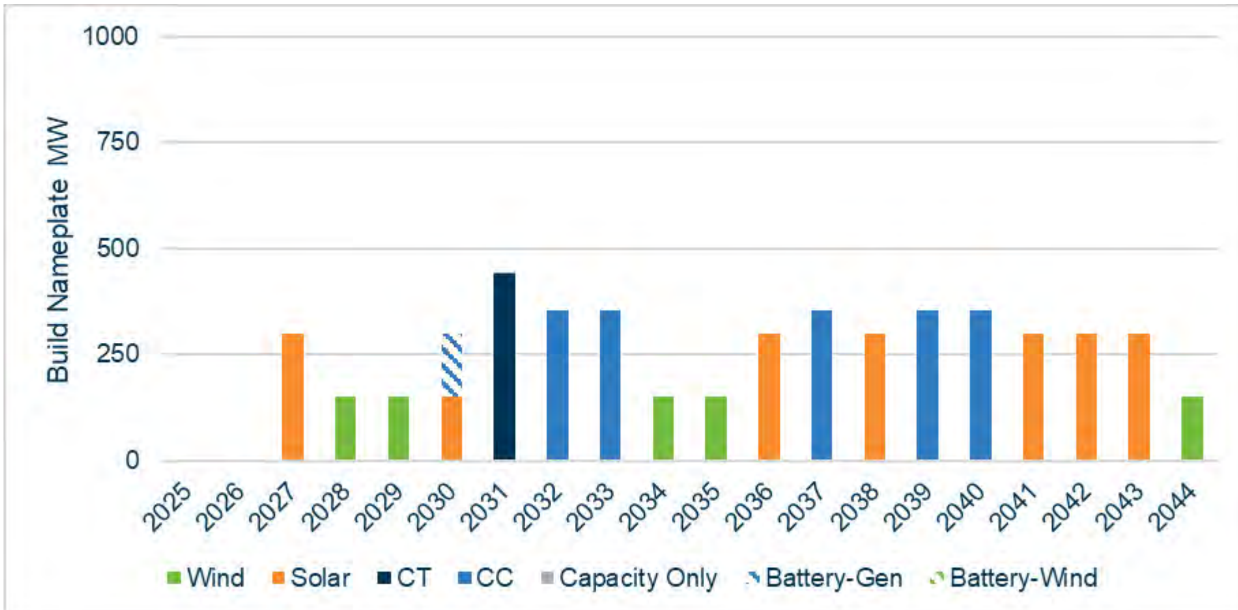
Plan AAAQ considers the optimal build plan with a low natural gas price, and no future carbon dioxide restrictions (low scenario). This plan has fairly large changes from Plan AAAA. The 2027-2030 solar and wind are not selected, and an additional 150 MW of storage is built in 2030. The plan leans more heavily on market capacity in summer and winter in those years. The 2031 SCGT is built, like in Plan AAAA, but the ½ CCGTs in 2032 and 2033 are not selected. The model instead selects another SCGT in 2032 and solar and storage in 2033. The model builds only SCGTs for thermal capacity and builds no wind.

Figure 30: Low NG/Low CO_2 Future Plan AAAQ



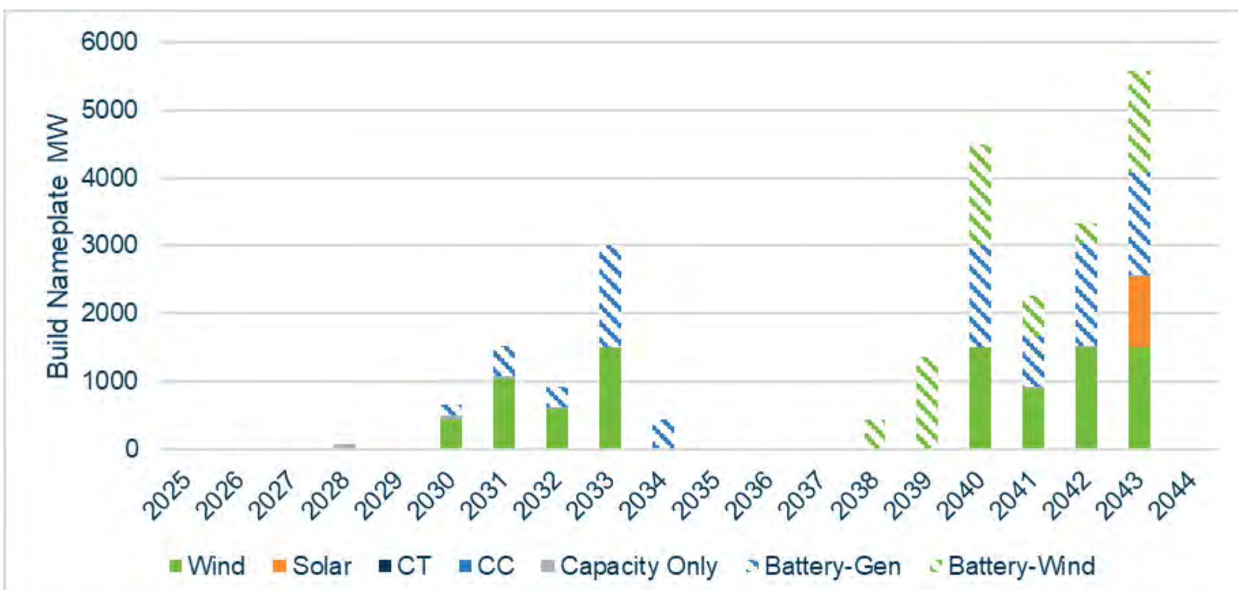
Plan AAAP considers optimal build decisions if a high natural gas price and mid carbon dioxide restricted future is expected. The plan is identical to Plan AAAA.

Figure 31: High NG/Mid CO_2 Future Plan AAAR



Plan AAFP considers optimal build decisions if a high natural gas price and high carbon dioxide restricted future is expected and only renewables and storage added (with relaxed build limits). This plan requires 9 GW wind, over 1 GW solar, and almost 14 GW storage.

Figure 32: High NG/High CO_2 Renewables & Storage Only Plan AAFP



The optimal plan for the High NG/Mid CO_2 future is the same as Plan AAAA which was optimized for the Mid NG/Mid CO_2 future. Plan AAAP which is optimized for the High CO_2 constraint is $262 million more expensive based on the weighted-average NPVRR which considers the risk of each critical uncertain factor future. Plan AAFP which also uses only renewables and storage to meet customer needs is $4 billion more expensive. The Plan AAAQ, optimized for the Low NG/Low CO_2 scenario, is the most expensive due to its poor ability to manage carbon restrictions and still meet energy needs, since no CCGT or wind resources are added.

Table 29: Rankings of Plans Optimized for Different Futures

Rank	Plan	NPVRR	Difference	Description
1	AAAA	23,609		Mid NG/Mid CO_2
2	AAAR	23,609	0	High NG /Mid CO_2
3	AAAP	23,870	262	High NG/High CO_2
4	AAFP	27,788	4,179	High NG/High CO_2, Only renewables/storage no build limit
5	AAAQ	28,393	4,784	Low NG/Low CO_2

9.8 Rankings of Base Plans

9.8.1 Risk-Weighted Rankings

Table 30: Overall Plan Rankings

Rank	Plan	NPVRR	Difference	Description
1	ADAA	23,452		LaCygne 1 Retires 2039
2	AAAA	23,609	157	Base Load, MEEIA Extends, Build Limits, 2024 PP Retirements
3	AAGA	23,642	190	No 2031 CT
4	AAAP	23,870	418	High NG/High CO_2
5	AAJA	23,903	451	No 2027 Solar
6	ACAA	24,022	570	LaCygne 2 Retires 2032
7	AAHA	24,824	1,372	No 2031 Thermal
8	ABAA	25,149	1,697	IAT 1 Retires 2030
9	AAFP	27,788	4,336	High NG/High CO_2, Only renewables/storage no build limit
10	AAFA	27,880	4,427	Only renewables/storage; No Build Limit
11	AAAQ	28,393	4,940	Low NG/Low CO_2

9.8.2 Carbon Restriction Rankings

Table 31: Rankings for High Carbon Restriction Future

Rank	Plan	NPVRR	Difference	Description
1	AAGA	24,901		No 2031 CT
2	AAAA	25,070	169	Base Load, MEEIA Extends, Build Limits, 2024 PP Retirements
3	ADAA	25,179	278	LaCygne 1 Retires 2039
4	AAJA	25,693	791	No 2027 Solar
5	AAAP	26,385	1,484	High NG/High CO_2
6	ACAA	26,725	1,824	LaCygne 2 Retires 2032
7	AAHA	27,621	2,720	No 2031 Thermal
8	ABAA	27,821	2,920	IAT 1 Retires 2030
9	AAFP	28,379	3,477	High NG/High CO_2, Only renewables/storage no build limit
10	AAFA	28,575	3,674	Only renewables/storage; No Build Limit
11	AAAQ	34,803	9,901	Low NG/Low CO_2

Table 32: Rankings for Mid Carbon Restriction Future

Rank	Plan	NPVRR	Difference	Description
1	ADAA	23,633		LaCygne 1 Retires 2039
2	AAAA	23,815	181	Base Load, MEEIA Extends, Build Limits, 2024 PP Retirements
3	AAGA	23,896	263	No 2031 CT
4	AAAP	23,960	327	High NG/High CO_2
5	ACAA	24,087	453	LaCygne 2 Retires 2032
6	AAJA	24,187	554	No 2027 Solar
7	AAHA	25,152	1,519	No 2031 Thermal
8	ABAA	25,497	1,864	IAT 1 Retires 2030
9	AAFP	27,697	4,064	High NG/High CO_2, Only renewables/storage no build limit
10	AAFA	27,774	4,141	Only renewables/storage; No Build Limit
11	AAAQ	29,581	5,947	Low NG/Low CO_2

Table 33: Rankings for Low (No) Carbon Restriction Future

Rank	Plan	NPVRR	Difference	Description
1	AAAQ	21,695		Low NG/Low CO_2
2	ADAA	21,981	286	LaCygne 1 Retires 2039
3	AAAP	22,146	451	High NG/High CO_2
4	AAJA	22,147	452	No 2027 Solar
5	AAAA	22,238	543	Base Load, MEEIA Extends, Build Limits, 2024 PP Retirements
6	ACAA	22,246	551	LaCygne 2 Retires 2032
7	AAGA	22,277	582	No 2031 CT
8	AAHA	22,357	662	No 2031 Thermal
9	ABAA	22,710	1,015	IAT 1 Retires 2030
10	AAFP	27,653	5,958	High NG/High CO_2, Only renewables/storage no build limit
11	AAFA	27,714	6,019	Only renewables/storage; No Build Limit

9.8.3 Natural Gas Price Rankings

Table 34: Rankings for High Natural Gas Price Future

Rank	Plan	NPVRR	Difference	Description
1	ADAA	24,144		LaCygne 1 Retires 2039
2	AAAA	24,322	178	Base Load, MEEIA Extends, Build Limits, 2024 PP Retirements
3	AAGA	24,352	207	No 2031 CT
4	AAAP	24,585	441	High NG/High CO_2
5	AAJA	24,680	536	No 2027 Solar
6	ACAA	24,791	646	LaCygne 2 Retires 2032
7	AAHA	25,581	1,437	No 2031 Thermal
8	ABAA	26,015	1,871	IAT 1 Retires 2030
9	AAFP	27,587	3,443	High NG/High CO_2, Only renewables/storage no build limit
10	AAFA	27,690	3,545	Only renewables/storage; No Build Limit
11	AAAQ	29,414	5,270	Low NG/Low CO_2

Table 35: Rankings for Mid Natural Gas Price Future

Rank	Plan	NPVRR	Difference	Description
1	ADAA	23,408		LaCygne 1 Retires 2039
2	AAAA	23,568	160	Base Load, MEEIA Extends, Build Limits, 2024 PP Retirements
3	AAGA	23,598	190	No 2031 CT
4	AAAP	23,826	418	High NG/High CO_2
5	AAJA	23,846	438	No 2027 Solar
6	ACAA	23,974	566	LaCygne 2 Retires 2032
7	AAHA	24,761	1,353	No 2031 Thermal
8	ABAA	25,078	1,670	IAT 1 Retires 2030
9	AAFP	27,775	4,367	High NG/High CO_2, Only renewables/storage no build limit
10	AAFA	27,864	4,455	Only renewables/storage; No Build Limit
11	AAAQ	28,292	4,884	Low NG/Low CO_2

Table 36: Rankings for Low Natural Gas Price Future

Rank	Plan	NPVRR	Difference	Description
1	ADAA	23,218		LaCygne 1 Retires 2039
2	AAAA	23,362	143	Base Load, MEEIA Extends, Build Limits, 2024 PP Retirements
3	AAGA	23,401	183	No 2031 CT
4	AAAP	23,627	409	High NG/High CO_2
5	AAJA	23,651	433	No 2027 Solar
6	ACAA	23,762	543	LaCygne 2 Retires 2032
7	AAHA	24,589	1,371	No 2031 Thermal
8	ABAA	24,879	1,661	IAT 1 Retires 2030
9	AAFP	27,893	4,675	High NG/High CO_2, Only renewables/storage no build limit
10	AAFA	27,984	4,765	Only renewables/storage; No Build Limit
11	AAAQ	28,098	4,880	Low NG/Low CO_2

9.8.4 Construction Cost Rankings

Table 37: Rankings for High Construction Cost Future

Rank	Plan	NPVRR	Difference	Description
1	ADAA	24,437		LaCygne 1 Retires 2039
2	AAGA	24,614	177	No 2031 CT
3	AAAA	24,617	179	Base Load, MEEIA Extends, Build Limits, 2024 PP Retirements
4	AAJA	24,816	379	No 2027 Solar
5	AAAP	24,900	463	High NG/High CO_2
6	ACAA	25,054	617	LaCygne 2 Retires 2032
7	AAHA	25,746	1,309	No 2031 Thermal
8	ABAA	26,120	1,682	IAT 1 Retires 2030
9	AAAQ	28,953	4,516	Low NG/Low CO_2
10	AAFP	30,849	6,412	High NG/High CO_2, Only renewables/storage no build limit
11	AAFA	30,965	6,527	Only renewables/storage; No Build Limit

Table 38: Rankings for Mid Construction Cost Future

Rank	Plan	NPVRR	Difference	Description
1	ADAA	23,504		LaCygne 1 Retires 2039
2	AAAA	23,665	161	Base Load, MEEIA Extends, Build Limits, 2024 PP Retirements
3	AAGA	23,707	203	No 2031 CT
4	AAAP	23,892	388	High NG/High CO_2
5	AAJA	23,959	455	No 2027 Solar
6	ACAA	24,046	542	LaCygne 2 Retires 2032
7	AAHA	24,836	1,332	No 2031 Thermal
8	ABAA	25,153	1,649	IAT 1 Retires 2030
9	AAFP	27,482	3,978	High NG/High CO_2, Only renewables/storage no build limit
10	AAFA	27,567	4,063	Only renewables/storage; No Build Limit
11	AAAQ	28,374	4,870	Low NG/Low CO_2

Table 39: Rankings for Low Construction Cost Future

Rank	Plan	NPVRR	Difference	Description
1	ADAA	22,363		LaCygne 1 Retires 2039
2	AAAA	22,489	126	Base Load, MEEIA Extends, Build Limits, 2024 PP Retirements
3	AAGA	22,539	176	No 2031 CT
4	AAAP	22,797	435	High NG/High CO_2
5	AAJA	22,878	515	No 2027 Solar
6	ACAA	22,941	579	LaCygne 2 Retires 2032
7	AAHA	23,877	1,514	No 2031 Thermal
8	ABAA	24,170	1,807	IAT 1 Retires 2030
9	AAFP	25,340	2,977	High NG/High CO_2, Only renewables/storage no build limit
10	AAFA	25,419	3,056	Only renewables/storage; No Build Limit
11	AAAQ	27,870	5,507	Low NG/Low CO_2

9.9 Plans Testing Build Limits and Restrictions

9.9.1 Higher Build Limits

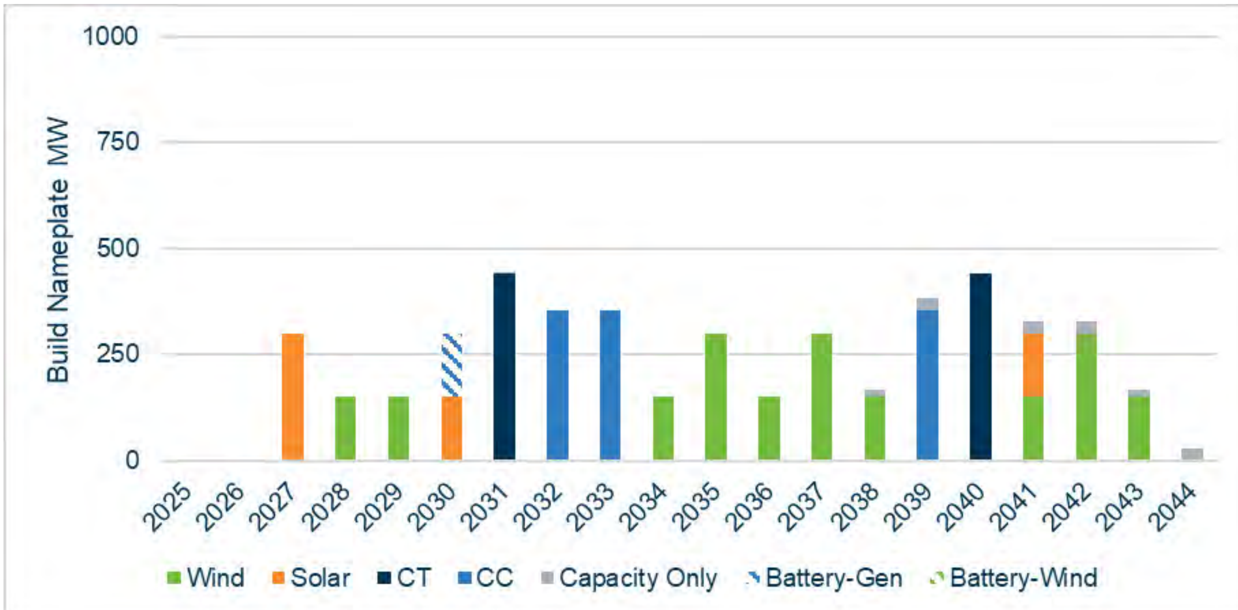
Alternative resource plans AADA, AAEA, and AAFA test different build limits. All plans include base retirements and allow the selection of 300 MW of solar in 2027.

Table 40: Plans Testing Build Limits

Plan Name	Description
AADA	Allow higher wind 2035+
AAEA	Allow higher builds all 2031+
AAFA	Only renewables/storage; relaxed build limit

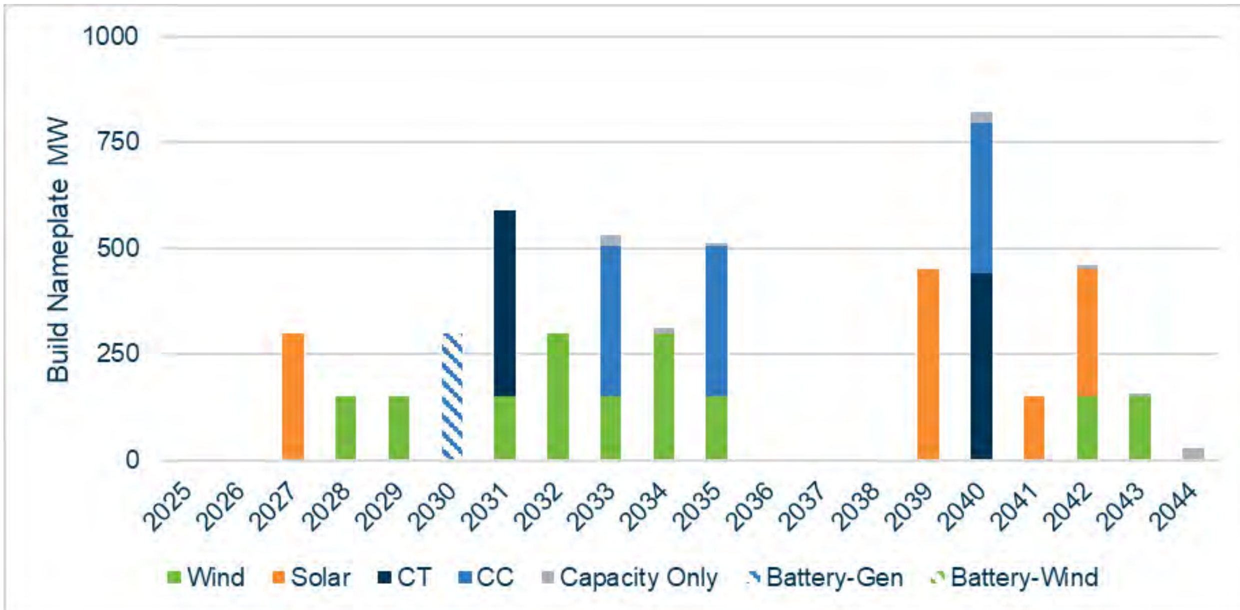
Plan AADA allows a higher amount of wind to be built in the years 2035+. The resource plan is unchanged through 2034 from Plan AAAA. However, 1,200 MW more wind and 1,350 MW less solar is built in later years. A SCGT is also built in 2040 and two ½ CCGTs in 2037 and 2040 are no longer included.

Figure 33: Higher Wind Build Allowed 2035+ Plan AADA



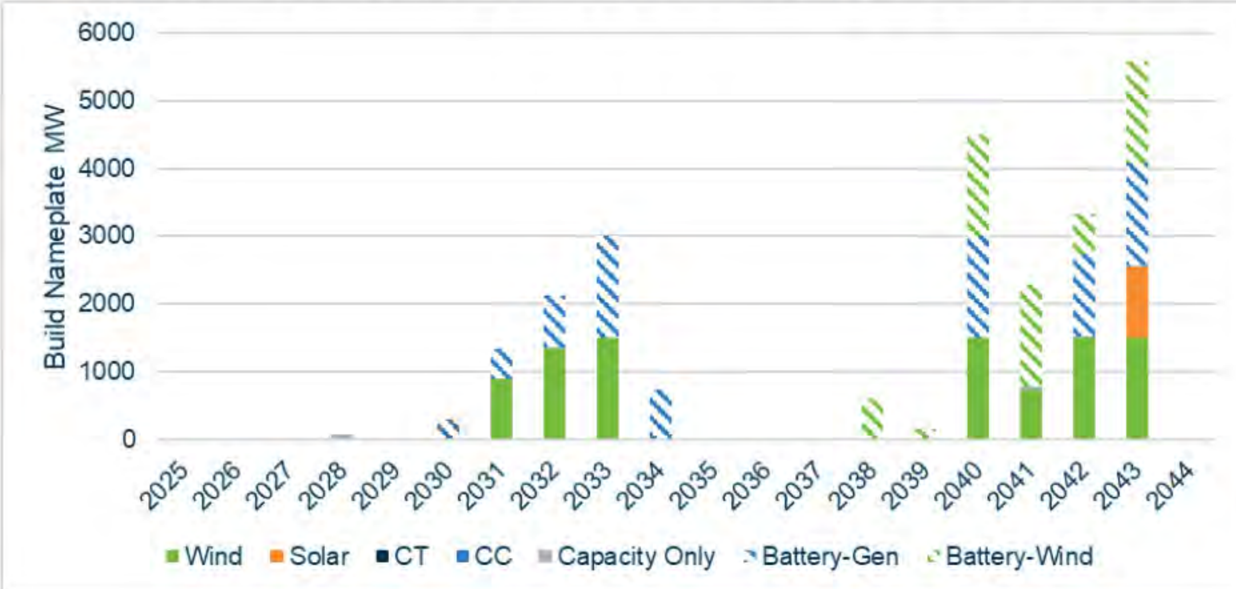
Plan AAEA allows higher amounts of all resource builds beginning in 2031. The same resources are built in 2027-2031 as Plan AAAA, except 150 MW of storage is substituted for the 150 MW of solar in 2030. In 2031-2035 an additional 750 MW of wind is built. The ½ CCGT in 2032 is pushed out to 2035, but the 2033 ½ CCGT is still built. Less solar is built in the later years of the plan and a ½ CCGT and SCGT are both built in 2040 rather than three ½ CCGTs in 2037, 2039, and 2040.

Figure 34: Allow Higher Resource Builds 2031+ Plan AAEA



Plan AAFA allows only renewable and storage builds in the future with a relaxed build limit. This plan is heavily reliant on storage to provide accredited capacity without the ability to add thermal resources. The plan selects 13.8 GW of battery storage, 9 GW of wind, and 1,050 MW of solar.

Figure 35: Only Renewables & Storage with Relaxed Build Limit Plan AAFA



Relaxing build limits allows the resource plan to select more wind resources earlier in the planning horizon. The extra wind resources help with meeting future carbon restrictions and providing low-cost energy. Evergy Metro 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 41: Rankings with Varied Build Limits

Rank	Plan	NPVRR	Difference	Description
1	AAEA	22,652		Allow higher builds all 2031+
2	AADA	23,216	564	Allow higher wind 2035+
3	AAAA	23,609	957	Base build limits
4	AAFA	27,880	5,228	Only renewables/storage; relaxed build limit

9.9.2 Minimally Compliant RES Plan

All Alternative Resource Plans comply with the Missouri renewable energy mandates (Missouri Renewable Energy Standard). The RES requirements include 14.7% of retail sales to be served by non-solar renewables and 0.3% by solar renewables. Evergy Metro's expected compliance need is 5.7 MW of solar in 2032.

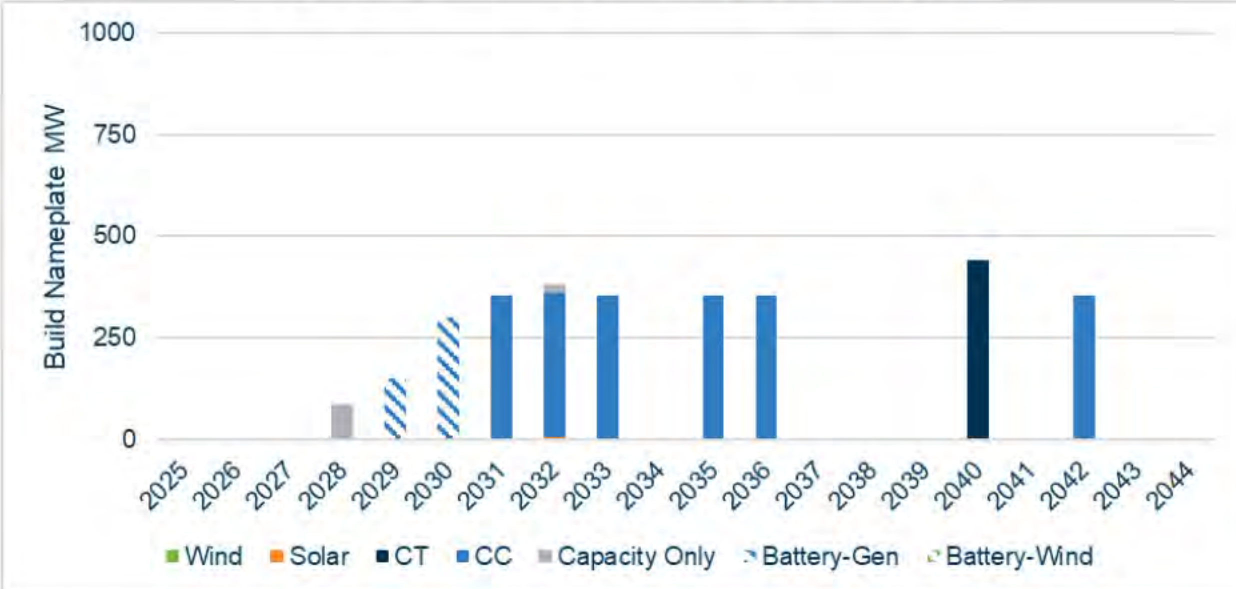
Table 42: Evergy Metro RES Requirements

Year	Evergy Metro Missouri Retail Electric Sales (MWh)	Missouri RES Non-Solar Requirement	Evergy Metro Missouri Non-Solar RES Requirement (MWh)	Missouri RES Solar Requirement	Evergy Metro Missouri Solar RES Requirement (MWh)
2025	8,584,218	14.7%	1,261,880	0.3%	25,753
2026	9,714,636	14.7%	1,428,051	0.3%	29,144
2027	10,799,044	14.7%	1,587,459	0.3%	32,397
2028	11,667,652	14.7%	1,715,145	0.3%	35,003
2029	11,768,982	14.7%	1,730,040	0.3%	35,307
2030	11,821,867	14.7%	1,737,814	0.3%	35,466
2031	11,871,616	14.7%	1,745,128	0.3%	35,615
2032	11,944,370	14.7%	1,755,822	0.3%	35,833
2033	11,982,413	14.7%	1,761,415	0.3%	35,947
2034	12,042,106	14.7%	1,770,190	0.3%	36,126
2035	12,103,658	14.7%	1,779,238	0.3%	36,311
2036	12,184,626	14.7%	1,791,140	0.3%	36,554
2037	12,225,569	14.7%	1,797,159	0.3%	36,677
2038	12,284,719	14.7%	1,805,854	0.3%	36,854
2039	12,340,331	14.7%	1,814,029	0.3%	37,021
2040	12,418,867	14.7%	1,825,573	0.3%	37,257
2041	12,454,816	14.7%	1,830,858	0.3%	37,364
2042	12,505,865	14.7%	1,838,362	0.3%	37,518
2043	12,559,406	14.7%	1,846,233	0.3%	37,678
2044	12,633,533	14.7%	1,857,129	0.3%	37,901

Plan, BAAT limits solar additions to the 5.7 MW of solar capacity in 2032 that is expected to be needed to meet solar RES requirements. Evergy is currently expected to be compliant with non-solar RES requirements through 2044.

Since there is no mandated DSM requirement, the minimally compliant plan assumes no additional DSM beyond what is currently in progress as part of Evergy MEEIA 4 approved programs.

Figure 36: Minimally Compliant RES Plan BAAT



Plan BAAT builds 450 MW of storage in 2029-2030 and then three ½ CCGTs in 2031-2033. The next thermal builds are two ½ CCGTs in 2035 and 2036, followed by an SCGT in 2040 and another ½ CCGT in 2042.

A resource plan that meets customer needs without new renewables is significantly more costly. The NPVRR for the plan that only meets minimum RES requirements is almost $2.8 billion higher than Plan AAAA.

Table 43: RES Plan Ranking

Rank	Plan	NPVRR	Difference	Description
1	AAAA	23,609		Base Load, MEEIA Extends, Build Limits, 2024 PP Retirements
2	BAAT	26,401	2,792	RES Plan

Section 10: Resource Plan Contingency Analysis

Evergy Metro 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
- MEEIA demand-side programs not renewed

Table 44: Plan Key for Contingency Analysis

DSM	Coal	Builds	Load & Contingencies
A. MEEIA Extends	A – 2024 PP Retirements	A - Solar allowed 2027, base capital 2028+	A - Base load
B. MEEIA Ends		E - Allow higher builds 2031+	G - No market energy purchases or sales
			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 growth and electrification
			O - Low load growth
			S – Base load, next large customer

Table 45: Contingency Plan Descriptions

Plan	Description
AAAG	No market energy purchases or sales
AAAH	Additional 50 MW large load early
AAAI	Additional 150 MW large load early
AAAJ	Additional 250 MW large load early
AAAK	Additional 50 MW large load 2031+
AAAL	Additional 150 MW large load 2031+
AAAM	Additional 250 MW large load 2031+
AAAO	Low load growth
AAAS	Next large customer
AAEN	High load growth and electrification
BAAA	MEEIA Ends

10.1 Load Contingencies

10.1.1 Large Customer Growth

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

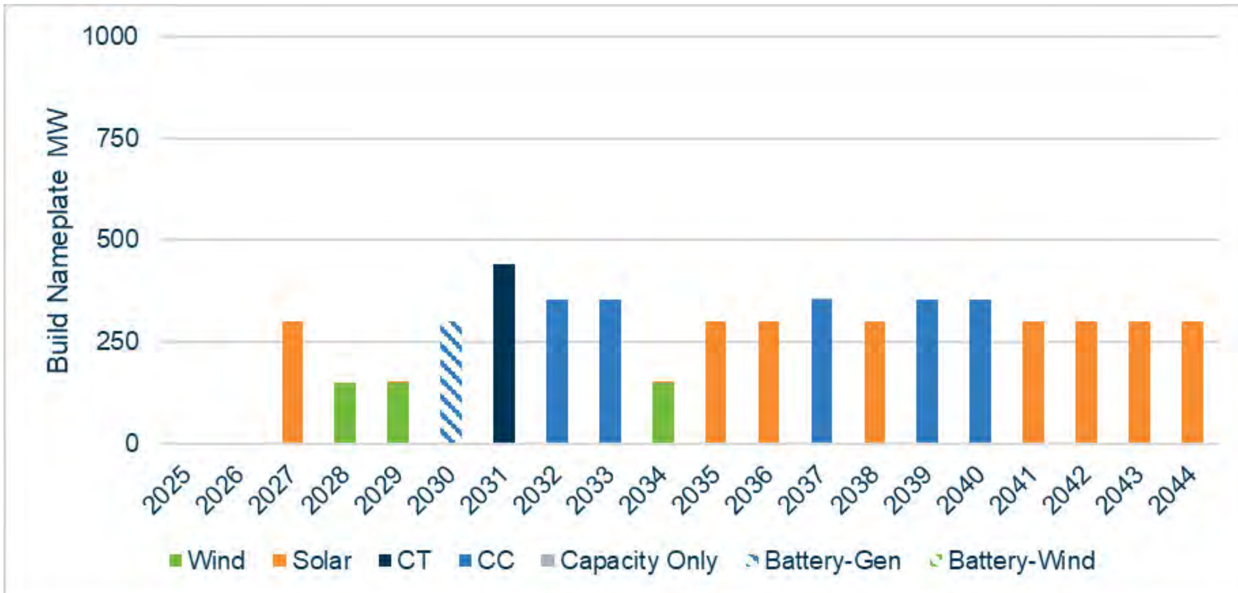
Table 46: Large Customer Growth Scenarios

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
50 MW Late	0	0	0	20	30	50
150 MW Late	0	0	0	50	100	150
250 MW Late	0	0	0	70	150	250
Next Large Customer	150	250	250	250	250	250

Alternative resource plans AAAH, AAAI, and AAAJ evaluate additional early load ramp.

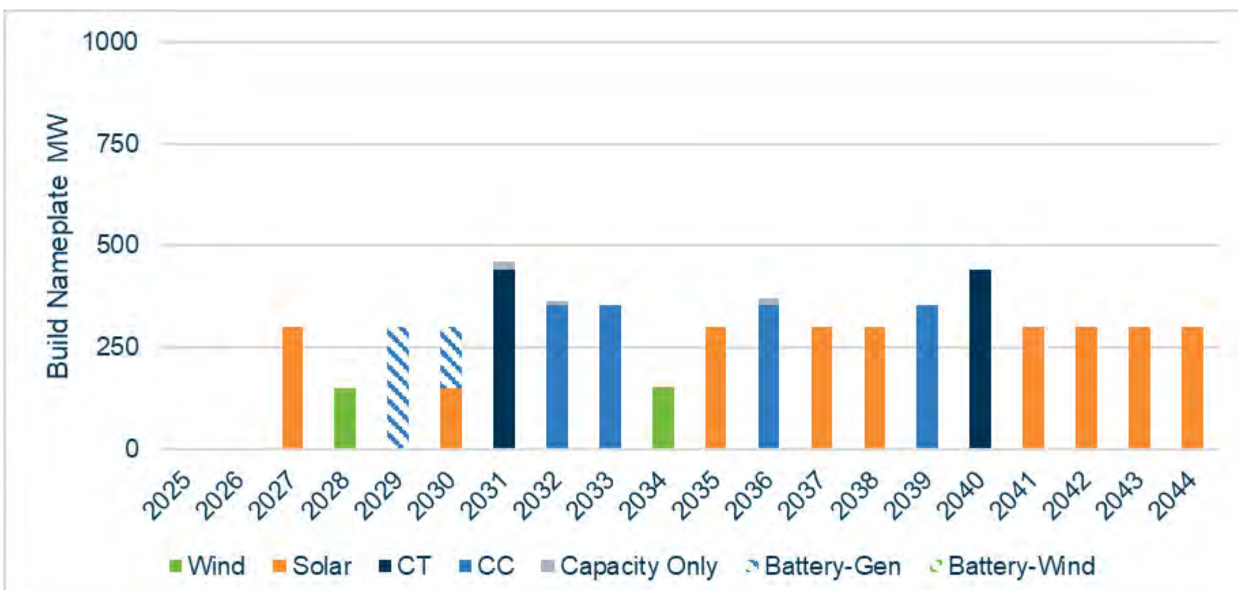
Plan AAAH accommodates an additional 50 MW load by building 300 MW of storage in 2030 instead of 150 MW each of solar and storage. It also substitutes 300 MW solar for 150 MW of wind in 2035 and 2044.

Figure 37: Early 50 MW Load Plan AAAH



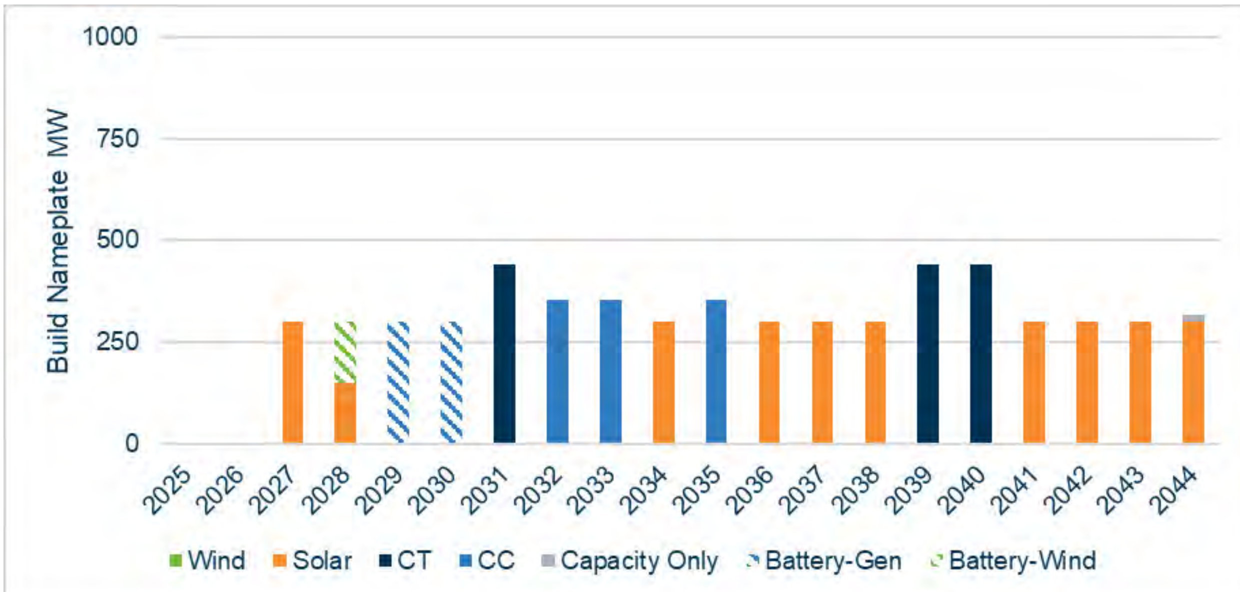
To accommodate an additional 150 MW load, Plan AAAI adds 300 MW of storage in 2029 instead of 150 MW of wind. It also substitutes 300 MW solar for 150 MW of wind in 2035 and 2044, and it brings forward ½ CCGT to 2036 and substitutes an SCGT for ½ CCGT in 2040.

Figure 38: Early 150 MW Load Plan AAAI



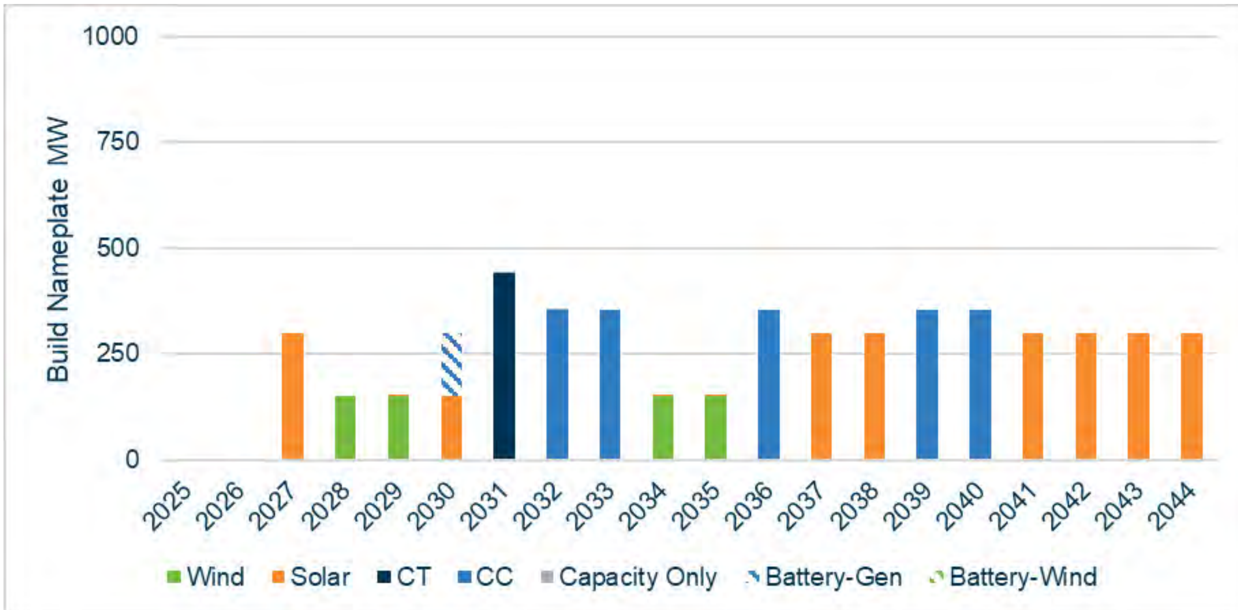
To accommodate an additional 250 MW load, Plan AAAJ adds 150 MW solar and 600 MW of storage to the near-term plan in 2028-2030 and does not select wind. The first thermal resource build after 2033 is pulled forward to 2035 and two SCGTs replace two ½ CCGTs in 2039-2040.

Figure 39: Early 250 MW Load Plan AAAJ



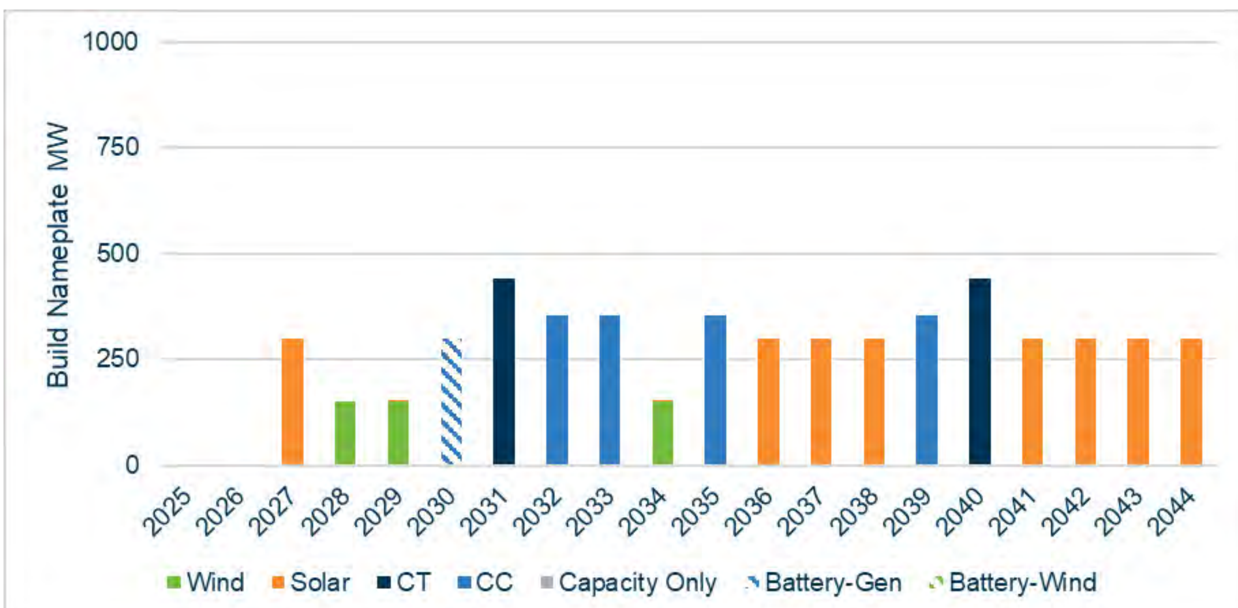
Plan AAAK shows that if Evergy Metro has a 50 MW load beginning its ramp in 2031, it does not require a change from Plan AAAA until 2036 when it brings forward a ½ CCGT one year.

Figure 40: Late 50 MW Load Plan AAAK



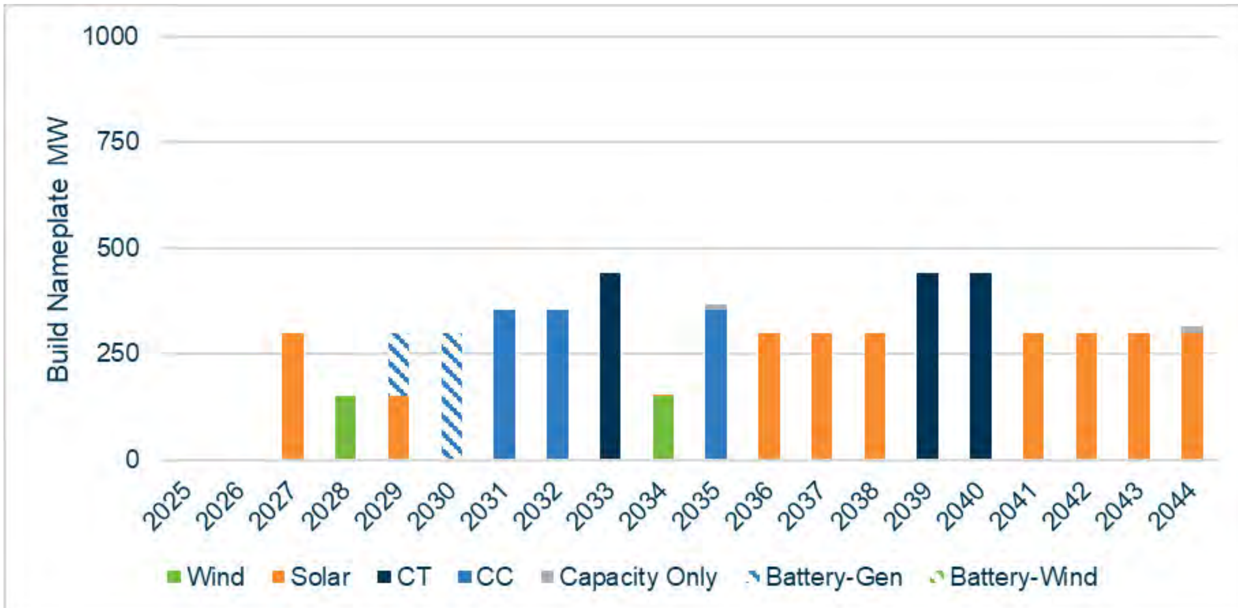
If a 150 MW large customer begins ramping in 2031, Plan AAAL builds an additional 150 MW of storage in 2030, rather than solar. The next thermal resource build after 2033 is pulled up to 2035.

Figure 41: Late 150 MW Load Plan AAAL



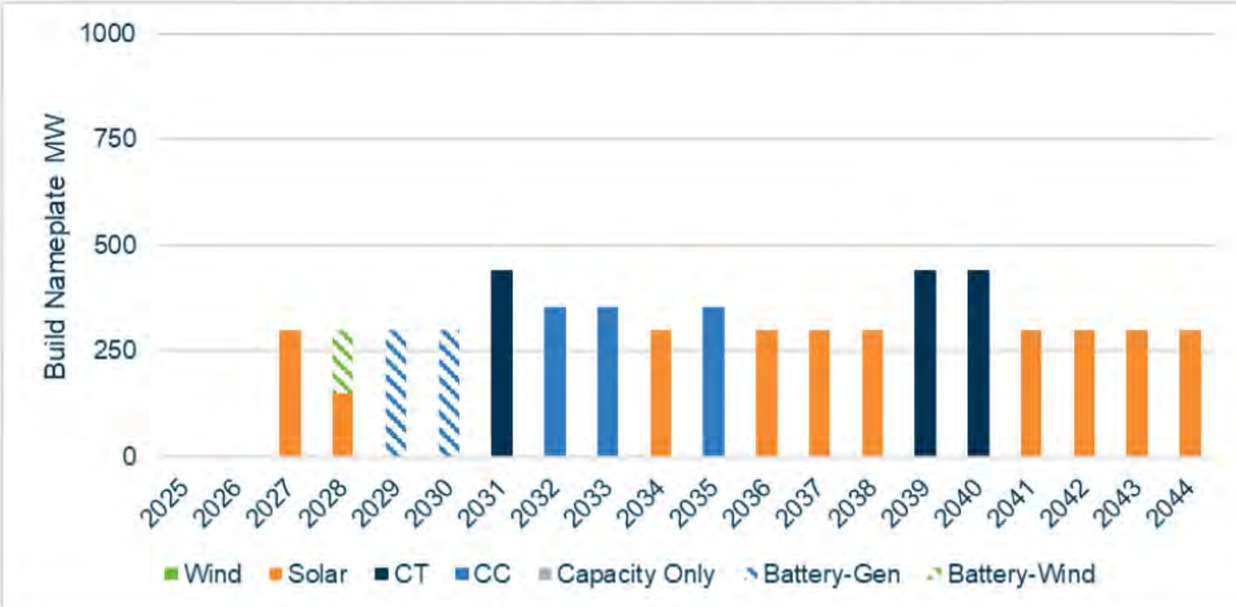
A 250 MW load beginning ramp in 2031 would require an additional 150 MW of storage in 2029 as well as 150 MW of solar instead of wind. The order of ½ CCGTs and the SCGT change between 2031-2033, with the same overall builds, and the next ½ CCGT is built in 2035.

Figure 42: Late 250 MW Load Plan AAAM



Plan AAAS plans for the next large customer in the queue. This customer load begins ramping in 2028 and peaks at 250 MW. To accommodate this customer, more early storage would be needed, replacing the early wind builds. After 2033, the next thermal build is a 2035 ½ CCGT.

Figure 43: Next Large Customer Plan AAAS



10.1.2 High Electrification and Low Load Growth Scenarios

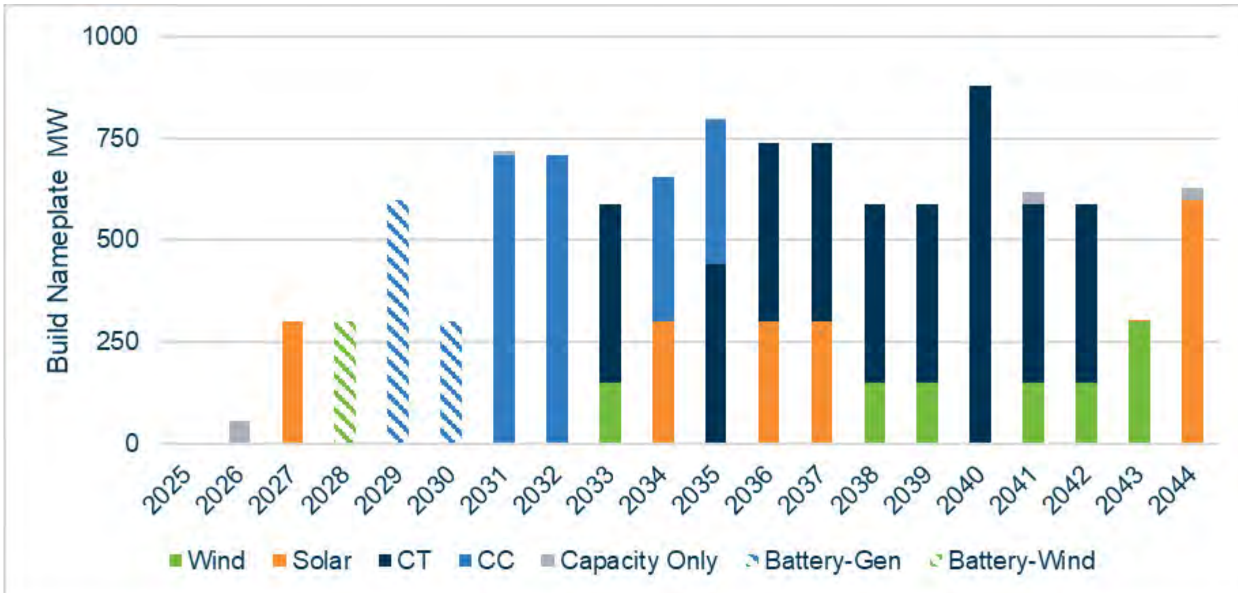
Evergy Metro's high load growth and economy-wide electrification forecast includes the highest load growth over the planning horizon of the scenarios modeled, and a faster ramp than the largest customer scenarios. The low load growth scenario includes more modest reductions in peak load.

Table 47: Evergy Metro Load Growth Scenarios - Difference from Base (MW)

Load Growth	2028	2029	2030	2031	2032	2044
High Electrification	260	340	422	513	612	2917
Low	(75)	(88)	(102)	(114)	(127)	(273)

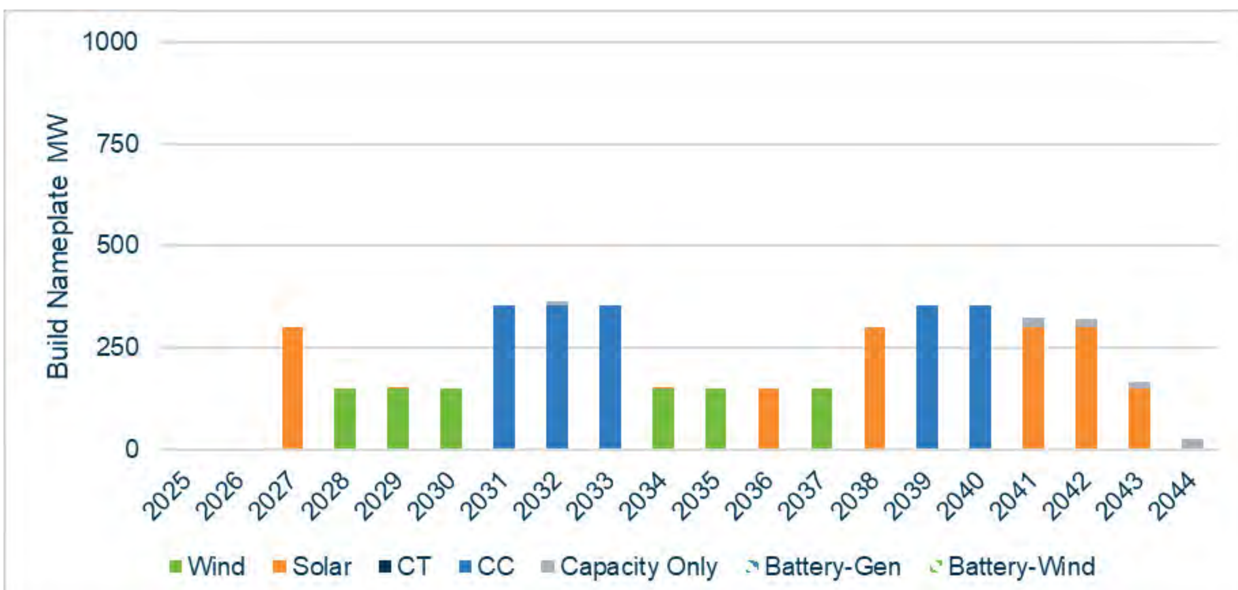
The Plan AAEN shows that to meet high electrification load growth, more storage will be needed before 2031 and much more thermal generation will be needed beginning when it is available in 2031. Much more solar will also be needed. The high electrification scenario increases the Metro peak load by almost 70% over the planning horizon, requiring more than 10 GW nameplate of fleet additions.

Figure 44: High Load Growth and Electrification Plan AAEN



The Plan AAAO shows that with low load growth, Evergy Metro could substitute 150 MW wind in 2030 for 150 MW each of solar and storage. Rather than two ½ CCGTs and an SCGT in 2031-2033, the plan requires three ½ CCGTs in 2031-2033. The ½ CCGT in 2037 is no longer needed, but two ½ CCGTs are still needed in 2039-2040.

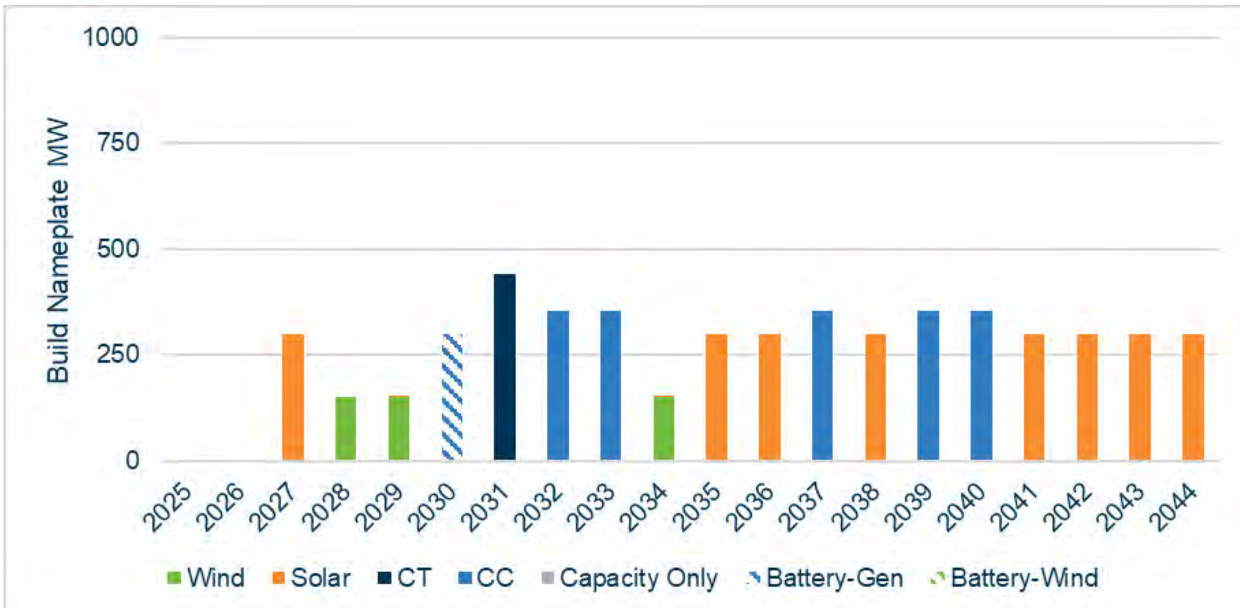
Figure 45: Low Load Growth Plan AAAO



10.2 Demand-Side Contingencies

Evergy Metro's current demand-side programs have been approved through 2027. If programs are not approved going forward the utility will lose the energy and capacity value assumed in the resource plan. Alternative resource Plan BAAA tests MEEIA ending after the current approved time frame. The plan substitutes 150 MW of storage for solar in 2030 and also substitutes solar for wind in 2035 and 2044.

Figure 46: Demand-Side Programs End After MEEIA 4 Plan BAAA

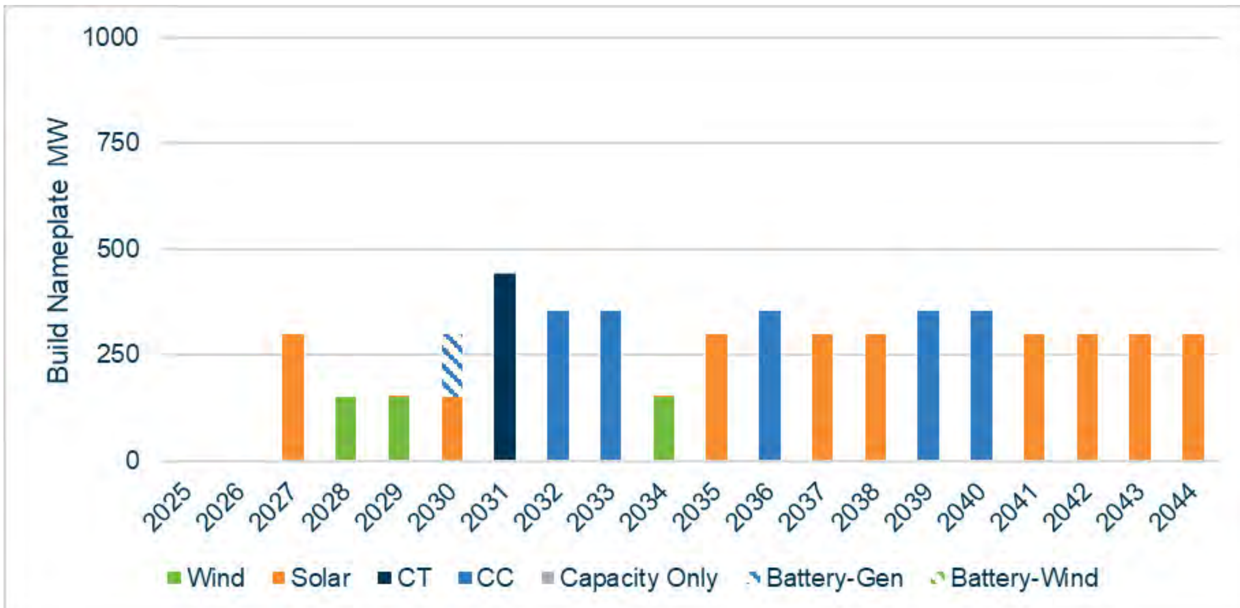


10.3 Capacity Expansion Plan with No Market Energy Purchases or Sales

Evergy Metro is currently a net seller in the SPP market. As discussed in Section 3.4 Evergy Metro 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 Metro's energy and capacity needs at lowest cost. The base planning assumption is that Evergy Metro 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 300 MW per hour beginning in 2031 (approximately 10% of Evergy Metro's peak load, and 15% of average load).

Evergy Metro tested the Preferred Plan 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 AAAG has the Preferred Plan 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 2034, but then substitutes solar for wind in 2035 and 2044 and builds an a ½ CCGT one year earlier in 2036.

Figure 47: No Market Energy Plan AAAG



Section 11: GHG Compliance Plans

11.1 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.

11.2 Evergy Metro 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 Metro, 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 48: 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

11.3 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 49: GHG Rule Cost Estimates[13] **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.

11.4 GHG Rule Compliance vs. Preferred Plan

Using the above assumptions, Evergy modeled a range of compliance scenarios. Table 50 summarizes the scenarios with the estimated cost of GHG compliance relative to the 2025 IRP Preferred Plan AAAA. 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 $3,336 million to $4,486 million.

[13] 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 50: GHG Rule Cost Comparisons

Plan	AAAA	AQAR	ARAR	ASAR
Iatan 1	Ret 2039	Co-Fire	Co-Fire	**Ret 2031**
Iatan 2	No Ret	Conv	**Co-Fire**	Conv
LaCygne 1	Ret 2032	Ret 2031	Ret 2031	Ret 2031
LaCygne 2	Ret 2039	Co-Fire	Co-Fire	Co-Fire
Hawthorn 5	No Ret	Co-Fire	Co-Fire	Co-Fire
H2C NPVRR ($ mil)	**24,532**	**28,072**	**29,018**	**27,868**
GHG vs AAAA ($ mil)	**-**	**3,540**	**4,486**	**3,336**

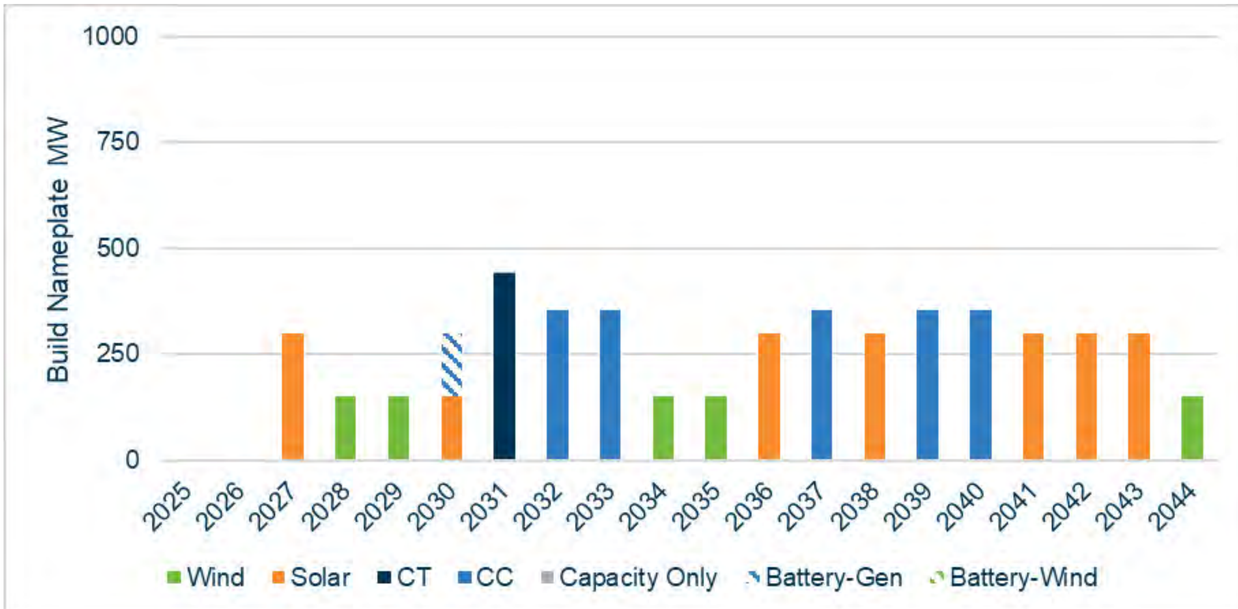
In summary, the GHG compliance plans require significant cost to implement and diverge from the Preferred Plan. Compared to the Preferred Plan, the GHG plans select dispatchable resources in place of renewables. In the near term, 600 MW of storage was selected in place of wind, and in years after 2032 AQAR and ASAR built an additional CCGT and 600 MW less of solar. In contrast, plan ARAR built 300 MW of additional solar, three additional SCGTs, and one less ½ CCGT. In Plans AQAR and ARAR the early storage additions delay the CCGT builds by one year. Plan ASAR, where Iatan 1 retires in 2031, requires a 2032 and 2033 ½ CCGT like the Preferred Plan even with the early storage. Regardless of the compliance path, a minimum of one additional thermal unit and 600 MW of storage would be required. Table 51 summarizes the capacity expansion plans, while Figure 48 presents a comparison of the Preferred Plan with the GHG plans.

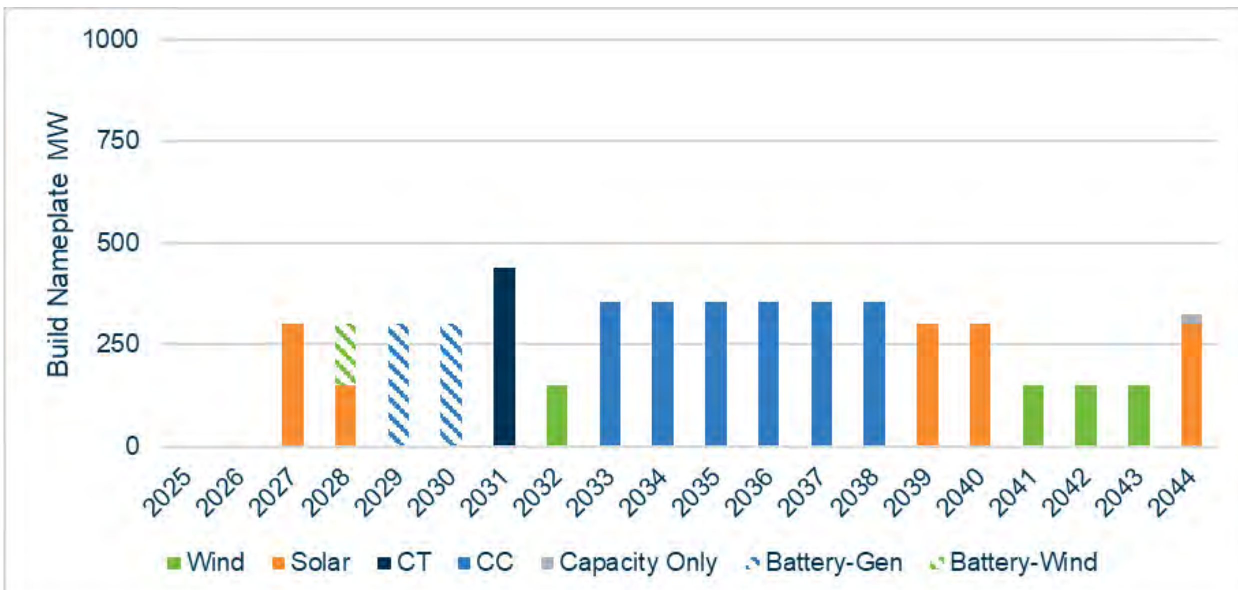
As the GHG Rule progresses through the courts, Evergy will adapt its plans to maintain compliance with the law.

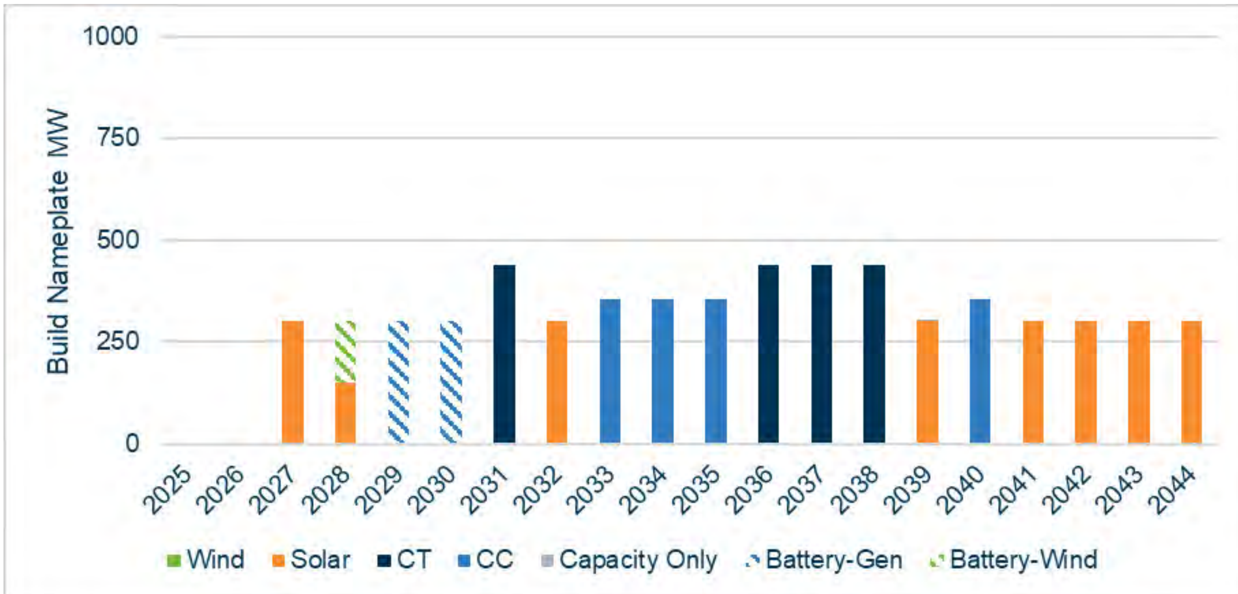
Table 51: GHG Capacity Expansion Summary

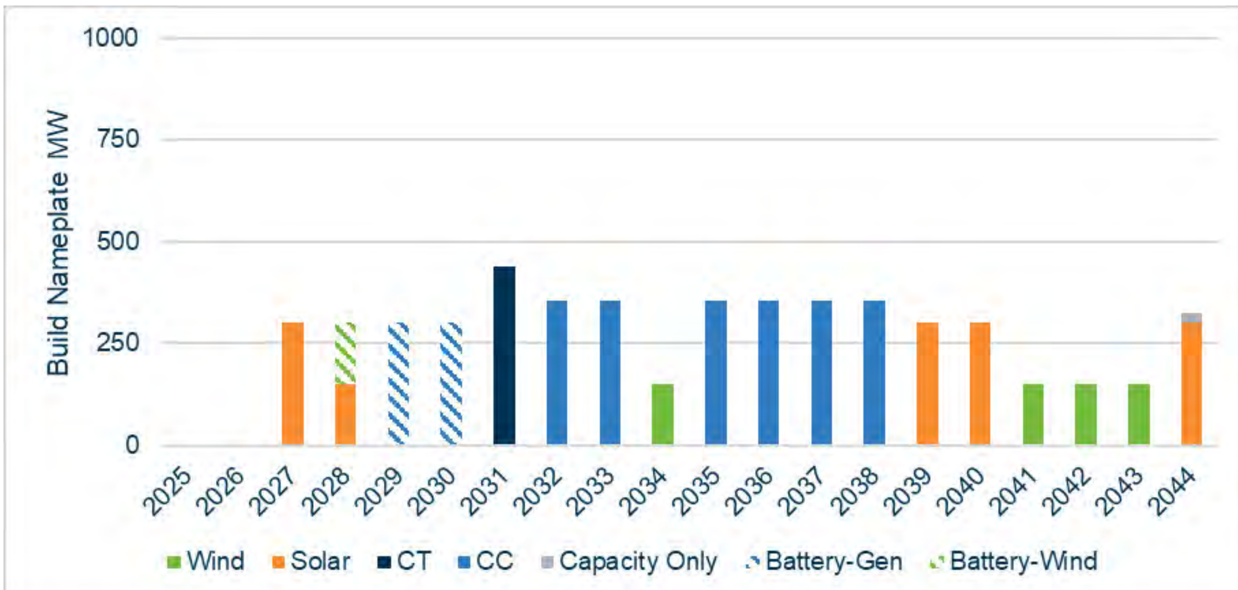
Plan	AAAA	AQAR	ARAR	ASAR
Wind (MW)	750	600	0	600
Solar (MW)	1950	1350	2250	1350
CT (MW)	440	440	1760	440
CC (MW)	1775	2130	1420	2130
Capacity (MW)	5	26	6	26
Storage (MW)	150	750	750	750

Figure 48: Evergy Metro 2025 Preferred Plan AAAA (1st) vs. GHG Compliance Plans AQAR, ARAR, ASAR (2nd, 3rd, 4th)






1000
750
500
250
0
Build Nameplate MW
2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044
Wind Solar CT CC Capacity Only Battery-Gen Battery-Wind


1000
750
500
250
0
Build Nameplate MW
2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044
Wind Solar CT CC Capacity Only Battery-Gen Battery-Wind

Section 12: Resource Acquisition Strategy Update

12.1 2025 Annual Update Preferred Plan

The Alternative Resource Plans (ARP) developed and analyzed under the requirements of 20 CSR 4240-22.060 were designed to meet the objectives of 20 CSR 4240-22.010(2).

Evergy Metro has selected AAAA as its Preferred Plan. This 2025 Preferred Plan called for some revisions to the resources that Evergy Metro had in the early years of the 2024 Preferred Plan. Key items of note are that the 300 MW of solar 2027 remained the same but the 150 MW of solar previously planned for 2028 is now needed in 2030. The 2024 Preferred Plan called for 150 MW of wind in each year 2029 through 2031. That need has been adjusted to equate to 150 MW both 2028 and 2029. Thermal resources were also adjusted. The earliest need identified in the 2024 Preferred Plan was 415 MW in 2032. This need is now 440 MW in 2031.

Evergy Metro 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 Metro is seeing in this update, more resources are included in this plan in the execution window. 150 MW of wind was selected in 2028, along with 150 MW of battery storage in 2030 and 440 MW of thermal resources in 2031, followed by 355 MW of thermal resources in both 2032 and 2033.

The Evergy Metro Preferred Plan AAAA for the 20-year planning period is shown in Table 52.

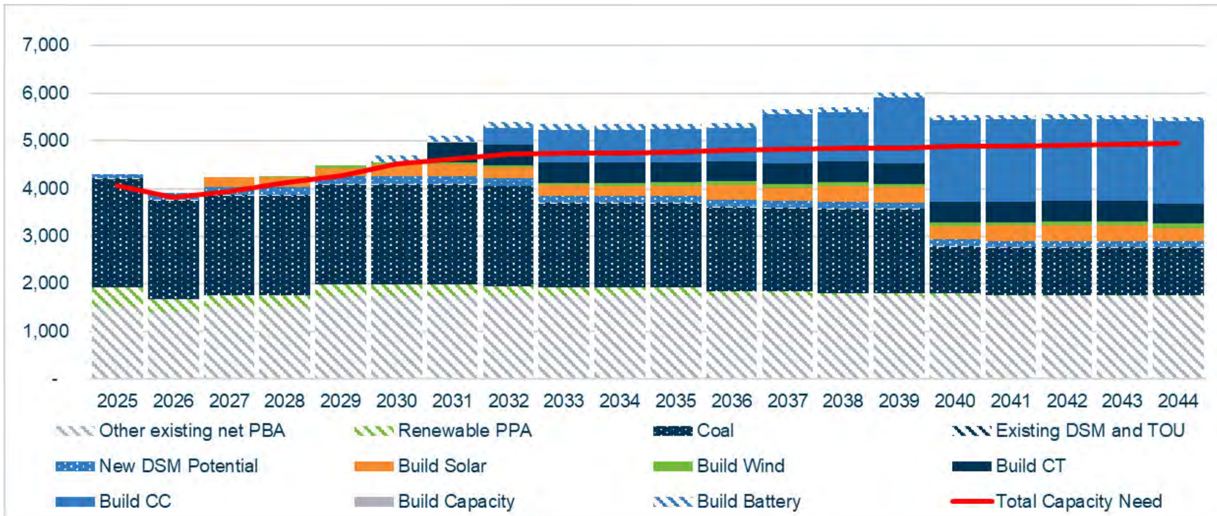
Table 52: Evergy Metro Preferred Plan AAAA

Year	Wind (MW)	Solar (MW)	Battery (MW)	Thermal (MW)	Capacity Only (Summer MW)	DSM (Summer MW)	Retirements (MW)
2025	0	0	0	0	0	90	0
2026	0	0	0	0	0	139	0
2027	0	300	0	0	0	174	0
2028	150	0	0	0	0	175	0
2029	150	0	0	0	0	159	0
2030	0	150	150	0	0	158	0
2031	0	0	0	440	5	157	0
2032	0	0	0	355	0	155	0
2033	0	0	0	355	0	153	375
2034	150	0	0	0	0	152	0
2035	150	0	0	0	0	151	0
2036	0	300	0	0	0	148	0
2037	0	0	0	355	0	144	0
2038	0	300	0	0	0	140	0
2039	0	0	0	355	0	137	0
2040	0	0	0	355	0	136	832
2041	0	300	0	0	0	134	0
2042	0	300	0	0	0	133	0
2043	0	300	0	0	0	132	0
2044	150	0	0	0	0	131	0

As detailed above, resource needs for Evergy Metro include acquiring 150 MW of wind in 2028, 2029, 2034 and 2035, followed by 150 MW in 2044. Solar needs are 300 MW in each year of 2027, 2036, 2038, 2041, 2042, and 2043, while 2030 has a solar need of 150 MW. A need for 150 MW of battery resources was identified for 2030. Thermal resource needs were identified beginning in 2031 with a need of 440 MW SCGT, followed by needs of 355 MW CCGT in each year 2032, 2033, 2037, 2039, and 2040. 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 March 2025, plus Evergy self-developed projects.

12.1.1 Preferred Plan Composition

Figure 49: Evergy Metro Preferred Plan Summer Capacity Composition (MW)



Evergy also invests significant capital on projects to maintain or improve plant efficiency. Table 53 provides examples of these projects.

Table 53: Environmental Retrofit Project Timeline

Project Description	Unit	Year	Performance Impact
Iatan Station			
Cooling Tower Fill Replacement	Iatan 2	2024	Nominal
LP Turbine L-0 Replacement	Iatan 2	2024	Nominal
Major Turbine Overhaul and New IP Rotor	Iatan 1	2025	Moderate
HP Turbine Bucket Repalcement	Iatan 2	2026	Nominal
Air Heater Basket Replacement	Iatan 2	2026	Nominal
LP Turbine L-1 Replacement	Iatan 2	2026	Nominal
Air Heater Basket Replacement	Iatan 1	2028	Nominal
Hawthorn Station			
HP/IP and LP Turbine Overhaul	Hawthorn 9	2027	Nominal
LaCygne Station			
Turbine Overhaul	LaCygne 1	2024	Moderate
Hydrogen Cooler Upgrade	LaCygne 1	2024	Nominal
Air Heater Basket Replacement	LaCygne 1	2024	Nominal
Turbine Overhaul	LaCygne 2	2025	Moderate
IP Turbine Upgrade	LaCygne 1	2025	Significant
Primary AH Baskets Replacement	LaCygne 2	2025	Nominal
22 HP Heater Replacement	LaCygne 2	2026	Nominal
HP Turb Blade Replacement	LaCygne 2	2026	Nominal
LP Turb Blade Replacement	LaCygne 2	2026	Nominal
IP Turb Packing Replacement	LaCygne 2	2026	Nominal
BFP Packing Replacement	LaCygne 1	2027	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 Staff of the Missouri Public Service Commission (MPSC)

13.1.1 Discussions on Modeling, Assumptions, Processes for IRP

Evergy and Staff met on February 10, 2025 to fulfill the agreement to discuss the Company's capacity expansion modeling, assumptions, and processes prior to the Company's 2025 IRP Annual Update filing.

13.1.2 Economic Development Load Modeling

Evergy continued to include economic development load in its alternative resource plans for the 2025 IRP. Evergy Metro is planning for a future resource mix that meets the needs of firmly committed load and has developed several contingency plans to accommodate changes to load growth including additional large customers.

13.2 Missouri Office of the Public Counsel (OPC)

13.2.1 Comparison of Output of Jointly-Owned Resources

The comparison of the energy output of jointly-owned resources is available in the Jointly Owned Generation Output.xlsx file. Please refer to the accompanying workpaper provided with this filing.

There are two constraints in the model which may cause dispatch to differ – the constraint on market reliance which is intended to ensure each utility has a future resource mix that is consistent with meeting its own energy needs at least cost, and the carbon constraint which requires each utility to limit future carbon emissions while meeting energy needs. Differences between the joint owners arise from differences in re-dispatch to optimally comply with carbon policy and serve customers with least-cost energy from their own fleets. Evergy Metro has more baseload generation and a larger coal fleet than Evergy Missouri West, resulting in less need to dispatch more expensive resources to serve its own load, but a greater need to curtail coal generation in favor of lower or non-emitting resources to meet its carbon constraints.

In practice, SPP dispatches the Evergy fleet and there would not be inconsistencies between joint owners. However, each constraint enables the model to plan for a future resource mix that helps the utility manage a planning objective. For Evergy Missouri West, a primary driver is gaining a resource mix that can serve its energy needs cost-effectively and hedge market volatility. Evergy does not know exactly what future carbon policy might look like or how it will be implemented. The GHG Rule was the path taken by the last presidential administration. The carbon constraints in the model appropriately demonstrate that Evergy Metro will be more affected by future carbon rules because of its larger coal fleet. Since the model optimizes to reduce carbon emissions the most cost effectively, it chooses to reduce output from the highest emitting resources, reducing revenue streams from coal resources and incenting lower or non-emitting resources to provide energy.

13.2.2 TOU Rate Impacts

Following the Commission's order to transition to default TOU rates, the Company modified its potential study TOU impact estimates to better align with that order. The Commission approved four TOU rates: a default TOU rate and three optional TOU rates. Because the default TOU rate (i.e. peak adjustment charge rate) that was approved by the Commission reflects a much lower price differential than the modeled TOU rates in the potential study, it was determined that a lower demand impact would likely result. Therefore, Evergy adjusted the TOU impact downward determined in the potential study for use in its 2024 IRP by 70%, or resulting in 30% of the potential study forecast.

13.3 Renew Missouri (RM)

13.3.1 GHG Rules

Evergy developed several compliance plans for the GHG rules in Section 11.

13.3.2 Storage Economics

Evergy continued to model investment tax credits as part of storage economics using the same assumptions as the 2024 IRP. Storage resources were assumed to qualify for 30% investment tax credits and those located in Evergy’s generation area were modeled as qualifying for 40% investment tax credits beginning in 2028. Investment tax credits are still expected to phase out as envisioned by the Inflation Reduction Act.

Storage installed costs were not updated for this IRP because Evergy has not issued another RFP and is not currently developing storage. There is considerable uncertainty regarding how recent tariffs may affect these resource costs. Evergy plans to issue another RFP this year and gain refreshed cost estimates. Subsequent to this filing Evergy will meet with Renew Missouri to discuss assumptions used in this update.

13.3.3 Clean Energy Investment and Production Tax Credits

Evergy continued to assume new wind and solar resources will qualify for production tax credits. Evergy Metro developed several resource plans testing preferences for renewable resources.

13.3.4 Time of Use Pricing and Net Metering Web Content

Evergy's website contains educational content to help customers understand their TOU rate and net metering options. Evergy allows customers with net metering to also participate in TOU rates.

13.4 New Energy Economics (NEE)

13.4.1 Capital Constraints for Wind and Cost Data for Thermal Resources

Evergy agreed to test relaxing capital constraints as wind PPA expire in the 2025 IRP Annual Update. Plan AADA shows three years with higher wind builds and substitution of wind for solar in later years if wind constraints are relaxed beginning in 2035. Other plans relaxing build constraints, such as ACEA also select more wind build. See Section 9.9.1.

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

13.4.2 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.

13.4.3 Coal to Natural Gas Conversions

Evergy Metro 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.

13.4.4 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.

13.4.5 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.

13.4.6 SERVM

SERVM analysis is not included in this IRP, however Evergy is planning to update its models in conjunction with filing the Kansas IRP in April. 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.

Section 14: Special Contemporary Issues

From the Commission Order, EO-2025-0076 & EO-2025-0078, the following Special Contemporary Resource Planning Issues are addressed as follows:

14.1 Resource Adequacy Scenarios

Model and explicitly present future resource adequacy scenarios based on the following assumptions:

- *Incorporation of the utility's Commission-approved and/or anticipated demand-side programs and the utility's Commission-approved demand-side rates;*
- *Only utility's Commission-approved demand-side rates*
- *Alternative demand-side rates options that may be needed to meet near-term resource adequacy;*
- *Indicate whether or not naturally occurring savings and/or federally-sponsored DSM savings are included in the modeling. If yes, these savings should be identified and separated as well*
- *Include an explicit section within the DSM volume and the executive summary where low, medium, and high time-of-use (TOU) differentials are modeled and presented with expected demand savings articulated separate and aside from other demand side management practices.*

Response:

Evergy's base case includes impacts of MEEIA Cycle 4 energy efficiency and demand response programs as approved by the Commission in EO-2023-0369/0370.

Evergy includes estimated impacts of the Commission-ordered time-of-use (TOU) rates from ER-2022-0129/0130 based on its 2023 DSM potential study (see Appendix 8). The 2023 DSM Market Potential Study was conducted by Applied Energy Group (AEG). It included a Realistic Achievable Potential (RAP) reflecting a low retention rate and a Maximum Achievable Potential (MAP) scenario with sensitivity analyses reflecting low, medium and high retention rates. These scenarios are described in detail in Section 8 Demand-Side Resource Analysis Update and the Executive Summary. The expected demand savings in MW are also included in Section 8 Demand-Side Resource Analysis Update.

Federal efficiency standards and the inflation Reduction Act are included in the Energy Information Annual Energy Outlook (AEO). The AEO is the foundation for the end-use projections underlying the Statistically Adjusted End-use forecast models used to produce the energy and peak forecast. Individual efficiency standards or incentives are not individually quantified by EIA therefore cannot be separately quantified for each efficiency standard or incentive contribution in the forecast. Documentation on the assumptions included in the AEO as well as the end-use load estimates is included in the Company’s load forecasting workpapers.

Following the Commission's order to transition to default TOU rates, the Company modified its potential study TOU impact estimates to better align with that order. The Commission approved four TOU rates: a default TOU rate and three optional TOU rates. Because the default TOU rate (i.e. peak adjustment charge rate) that was approved by the Commission reflects a much lower price differential than the modeled TOU rates in the potential study, it was determined that a lower demand impact would likely result. Therefore, Evergy adjusted the TOU impact downward determined in the potential study for use in its 2024 IRP by 70%, or resulting in 30% of the potential study forecast. See Section 8 Demand-Side Resource Analysis Update.

Approximately 12 months have elapsed since Evergy transitioned all eligible residential Missouri customers to default TOU rates. Evergy is evaluating the 2024 TOU summer peak demand impact from the default TOU rates; however, it does not have a final analyses or impact to share to incorporate for this IRP update.

Please refer to Section 8.2 for a description of the demand-side rate scenarios studied in the 2023 DSM Market Potential Study.

14.2 Datacenter Literature Review

Conduct a literature review of best practices on how other utilities are accounting for the addition of data centers in their IRPs and how risks can be minimized.

Response:

The addition of data center load is unprecedented in recent history and has raised questions of how to account for this potential load in utility planning. Given the recency of potential data center demand, industry-wide best practices have yet to be set. However, The Brattle Group prepared a report in May 2024 which analyzes how utilities and RTOs/ISOs have started to think about and incorporate data centers into their load forecasts, and subsequently, IRPs (Appendix 14.2A). This report provides key insights into best practices of other utilities and how to mitigate the risks associated with data center load additions.

Brattle found that demand growth will likely vary depending on the region, as will the ability to moderate this growth through distributed generation, energy efficiency, and demand response. While the report shows some progress in incorporating these new demand drivers, including data centers, into load forecasts, few utilities include a forecast of all new potential demand drivers. Out of the sample of 47 utilities included in the report, only 14 have included data center growth in their public forecasts. Within that group of 14, five entities did not include long-term forecasting of data center growth or did not include data centers in all public load forecasts.

The report also included 3 peer utilities (Ameren Illinois, Black Hills Colorado, Eversource Massachusetts) as well as SPP in its sample. Black Hills and Eversource have included data center growth in public load forecasts but are among the utilities signified as having more limited inclusion of data centers in their forecast, either due to limited long-term forecasting or exclusion of data centers in some load forecasts.

When considering new demand drivers, including data centers, Brattle highlights that risks exist with both over-forecasting and under-forecasting this load. Over-forecasting can lead to excess generation and infrastructure additions. Under-forecasting can ultimately impact reliability, potentially introduce mandatory use of load management measures, and restrict new service connections or expansions. While neither over-forecasting nor under-forecasting is a desired end-result, Brattle suggests under-forecasting is the more challenging of the two in the present circumstances. Demand forecasts have been regularly revised upwards in recent years and the supply chain for many necessary resources has become more constrained and uncertain as well, making it more difficult to respond to new load quickly.

Overall, striking the correct balance for forecasting these loads will be challenging, and no industry best practice has yet emerged. Revisiting how load forecasting should be completed in light of new large loads, like data centers, will likely be necessary. In the interim, Brattle recommends comprehensive inclusion of new demand drivers, including data centers, in load forecasts. Additionally, as highlighted in the Commonwealth of Virginia Industry Document (Appendix 14.2B), load forecasting and resource planning is not the only way to minimize data center risk. Policy and regulation can help lower risk associated with these new large loads, as can investment in other infrastructure such as expanding or enhancing transmission and distribution networks. More best practices will likely emerge in the coming months and years as data center demand comes online.

14.3 Large Load Growth Scenarios

Model large load growth scenarios stemming from: 1) data centers with a demand of 30 megawatts or greater; 2) potential re-shoring of industries, specifically manufacturing or materials refinement; and 3) electrification of buildings and vehicles as a result of federal mandates changes in the marketplace, or evolving consumer preference.

Response:

Evergy Metro modeled various load growth scenarios to determine how its Preferred Plan may need to adapt to customer additions and electrification. Section 10.1.1 discusses modeling results for large customer additions, which could include data centers or industrial facilities. Section 10.1.2 examines resource plan needs for high load growth with economy-wide electrification.

14.4 Technology and Methods Available to Comply with EPA Rules

Provide a review of the technology and methods currently available, as well as the dollar impact for relevant and projected resources, to be compliant with the Environmental Protection Agency's rules targeting reduction of fossil fuel-fired power plant pollution.

Response:

Evergy Metro has conducted an updated analysis of potential options to comply with EPA's final GHG Rule. Please refer to Section 11 GHG Compliance Plans for a discussion of the analysis and presentation of the results.

14.5 Supercritical Carbon Dioxide Power Cycle Plant

Investigate the option of a supercritical carbon dioxide power cycle plant as a resource candidate in future supply-side generation planning and modeling scenarios.

Response:

While not a commercially available technology, research is underway to demonstrate the feasibility of supercritical carbon dioxide (sCO_2) power cycles. Power cycles based on sCO_2 as the working fluid have the potential to yield higher thermal efficiencies at lower capital cost than state-of-the-art steam-based power cycles. Three U.S. Department of Energy (DOE) Offices (Nuclear Energy, Fossil Energy, and Energy Efficiency and Renewable Energy) are working together to reduce the technical hurdles and support foundational research and development of sCO_2 power cycles.

The Supercritical Transformational Electric Power (STEP) Demo project, led by GTI Energy in collaboration with Southwest Research Institute, GE Vernova's Advanced Research, the U.S. DOE's National Energy Technology Laboratory, and several industry partners, is the world's largest and most advanced indirectly fired sCO_2 power plant designed to demonstrate and validate the sCO_2 Brayton power cycle.

As of October 2024, the 10-megawatt STEP Demo pilot plant in San Antonio, Texas, has successfully completed phase 1 testing, demonstrating operability, efficiency, and commercial readiness of the sCO_2 power cycle. During phase 1 testing, the plant achieved full operational speed of its turbine at 27,000 RPM operating at 500°C and generating 4 MW of grid synchronized power. Following this milestone, the STEP Demo project will enter its final phase, which will involve reconfiguring the plant to enhance efficiency and increase energy output. It will operate at 715°C and demonstrate a Recompression Closed Brayton Cycle (RCBC) configuration. Upon completion, the facility is expected to generate 10 MW hourly.

14.6 Interconnection Cost Estimates

Model for low, medium, and high interconnection cost estimates that are supported by historic total interconnection costs by fuel type for Southwest Power Pool (SPP) in its resource planning scenarios.

Response:

Evergy included low, medium, and high interconnection costs scenarios in the 2024 IRP based on analysis of study data from Berkeley Labs. No new data was available before the 2025 IRP filing. However, Evergy continued to incorporate the results from the 2024 IRP, making interconnection costs part of the critical uncertain factor of build costs. Evergy also updated the low, medium, and high estimates of interconnection costs for thermal resources based on its development experience over the past few months with Viola, McNew, and Mullin Creek.

14.7 Estimated Project Length

Articulate the estimated project length for all generation resources given the current MISO backflow, and the overall demand for generation resources across the United States.

Response:

Evergy is located in the Southwest Power Pool (SPP) and any generator interconnection requests would thus be evaluated by SPP, not MISO. Evergy expects that any generator interconnection requests submitted to SPP for inclusion in the 2024-001 cluster, which will close on March 1, 2025, could receive a generator interconnection agreement by the fourth quarter of 2026. Generator interconnection requests submitted after March 1, 2025, will be evaluated in SPP's new Consolidated Planning Process, which is expected to result in generator interconnection agreements in late 2027 or early 2028 contingent upon final design, approval, and implementation of the new process. Table 10 contains the first year in which the resource option was assumed to be available and is indicative of the project duration. These project durations are based RFP results, expected construction timelines and interconnection availability.

14.8 Energy Storage Technologies

Describe any research, investigation, consideration, and/or inclusion of long-duration energy storage (10 or more hours) as well as non-chemical energy storage technologies the Company performed in the development of its IRP update/ triennial analysis. Nonchemical energy storage technologies mainly refer to thermal or mechanical methods of storing energy which could include storing heat in solid materials such as sand, rocks, or concrete blocks or liquids such as molten salts or water and processes utilizing compression, displacement against gravity, rotation, or accumulation of kinetic energy. Include any details or analysis of costs estimates if relied upon.

Explore the design and feasibility of piloting energy storage projects with the specific objective of enhancing system reliability and increasing capacity accreditation of renewable energy resources. Discuss the opportunities and benefits facilitated by inclusion of the explored technology and detail any identified limitations.

Detail any other emerging technologies intended to improve reliability or resource adequacy discovered by the Company or suggested by stakeholders that was considered and describe any pertinent analysis or findings.

Response:

Evergy, in the past has actively monitored long-duration energy storage developments through our participation in the Electric Power Research Institute. Evergy has recently conducted additional reading and research on long-term energy storage technologies to further understand options, performance characteristics and costs. Notes on the findings along with titles from the sources are included as appendix 14.8A.

Evergy is also aware and has been following the ongoing Cambridge Energy Storage Project. A project overview along with highlights and next steps are provided in appendix 14.8B.

In order to facilitate the improved reliability of our critical generating assets, Evergy is partnering with the Electric Power Research Institute and Dimension Software to deploy an Asset Health Management system in 2025. The key objective of the Asset Health system is the enablement of users to view overall fleet health including the ability to drill down to individual sites, units, systems, and assets. The Asset Health system will clearly show any health issues with key assets and systems while also providing the proposed mitigations. (i.e. repairs, enhanced inspections, procurement of critical spares, ...)

In order to facilitate improved resource adequacy during extreme cold weather events, Evergy is partnering with Benetech to implement a new Winter Solid Fuel readiness program for the 2024/2025 winter season. The program involves sectioning off a portion of the coal pile and then proactively applying a metered flow of Glycol spares to ensure that the coal does not freeze and can be effectively transported, crushed, and burned during extreme cold weather events.

14.9 Coal to Natural Gas Conversions

Evaluate the potential for coal to natural gas conversions.

Response:

Evergy has updated estimates for conversion of coal resources to natural gas based on consultation with pipelines and plant engineers. Evergy Metro tested co-firing and natural gas conversion scenarios as part of its GHG Rule compliance plans in Section 11.