

Evergy Missouri West
2026 Annual Update
Integrated Resource Plan

May 2026

Public



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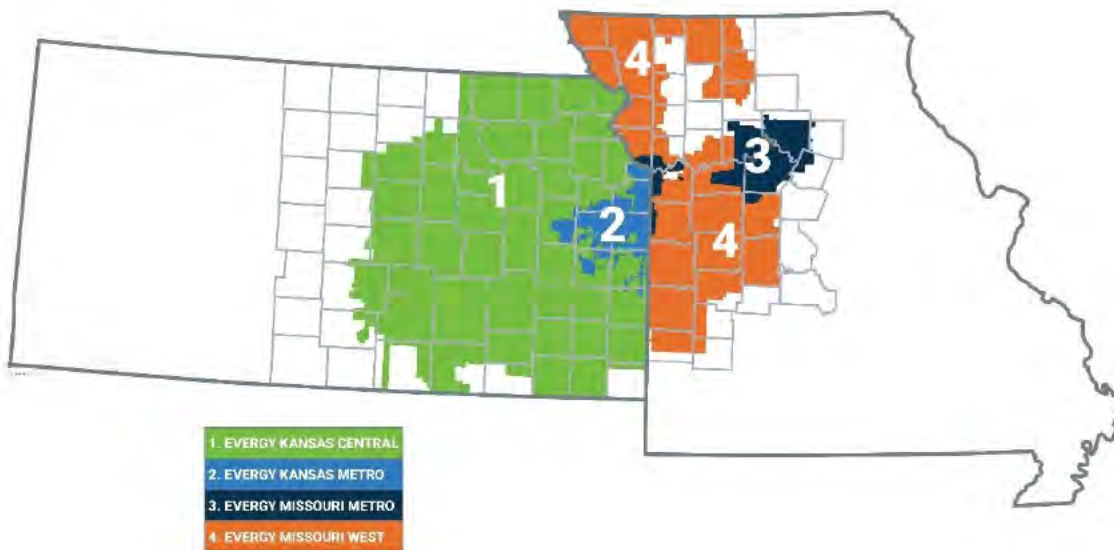
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Section 1: Executive Summary

1.1 Utility Introduction

Evergy Missouri West (or “Company” or “EMW”) is an integrated, mid-sized electric utility serving portions of Northwest Missouri including St. Joseph and several counties south and east of the Kansas City, Missouri metropolitan area. Evergy Missouri West also provides regulated steam service to certain customers in the St. Joseph, Missouri area. A map of the Evergy service territory, which includes Evergy Missouri West, is provided in Figure 1 below.

Figure 1: Evergy Service Territory



Evergy Missouri West 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 2025 data.

Table 1: 2025 Customers, Retail Sales, and Peak Demand

Jurisdiction	Number of Retail Customers	Retail Sales (MWh)	Net Peak Demand (MW)
Evergy Missouri West	349,969	8,766,142	1,965

Evergy Missouri West owns and operates a diverse generating portfolio, including Power Purchase Agreements (“PPAs”), to meet customer energy requirements. The Table below reflects Evergy Missouri West’s generation assets including PPAs.

Table 2: Capacity and Energy by Resource Type

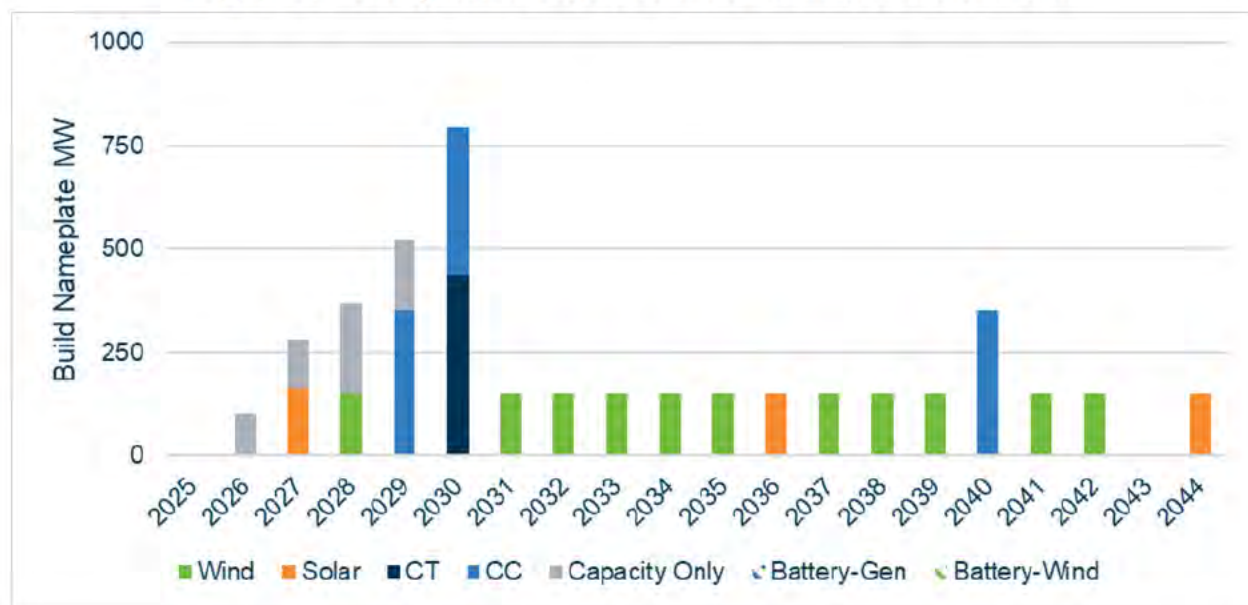
Jurisdiction	Capacity by Fuel Type	Capacity (MW)	Capacity (%)	Energy (MWh)	Energy (%)
Evergy Missouri West	Coal	466	18%	1,699,961	34%
	Nuclear	-	-	-	-
	Natural Gas/Oil	1,330	51%	851,016	17%
	Renewable*	791	31%	2,418,698	49%
Total		2,587	100.0%	4,969,675	100%

*Nameplate renewables capacity

1.2 Preferred Plan Filed in the 2025 Annual Update

Evergy Missouri West submitted its 2025 Annual Update filing on March 13, 2025.¹

Figure 2: Evergy Missouri West 2025 Preferred Plan ACAA



¹ EO-2025-0251

The 2025 Preferred Plan called for EMW to build or acquire new resources including 165 MW of solar in 2027 (build-transfer of the Foxtrot and Sunflower Sky solar projects), 150 MW of wind in 2028, 50% shares (355 MW) of the Viola and McNew Combined-Cycle Gas Turbines (“CCGT”) in 2029 and 2030, respectively, and the Mullin Creek #1 Simple-Cycle Gas Turbine (“SCGT”) (440 MW) in 2030 to meet customer needs in the next 5 years. The Preferred Plan also reflected the demand-side programs consistent with the Missouri Energy Efficiency Investment Act (“MEEIA”) Cycle 4 approved programs, and the Jeffrey 2 coal unit operating on natural gas beginning in 2030. In response to federal environmental rules, coal generator retirements were anticipated to occur in March 2031 for Jeffrey 3, and in March 2040 for Iatan 1 and Jeffrey 1.

1.3 Changes to the Preferred Plan for the 2026 Annual Update

This year’s 2026 Annual Update shows increasing needs for Missouri West inclusive of higher large load customer growth, beginning in 2026 and nearing 350 MW by 2032. The 2026 Preferred Plan ADAA, as shown in Figure 3 below and described in Section 10.3 and 10.4 of this IRP, includes the approved Certificate of Convenience and Necessity (“CCN”) resources, which are under development, postpones planned retirements relative to the 2025 Preferred Plan, and assumes Demand-Side Management (“DSM”) programs continue.

In addition to large-load customer growth, the changes to Missouri West’s resource needs, as identified in the resource plan, were primarily driven by:

- Alignment with the most recent Southwest Power Pool (“SPP”) resource adequacy rules and study results for expected summer and winter reserve margins and capacity accreditation
- Cost and performance characteristics of new thermal resource options consistent with market availability
- Updates to solar, wind, and storage costs based on 2025 all-source Request for Proposal (“RFP”) results
- Changes in policy for renewable and storage tax credits and outlook for carbon regulation

In the near-term, the Preferred Plan meets capacity needs through market capacity purchases until after the CCN resources are in service. The plan adds an additional firm-dispatchable resource in the execution window, a ½ CCGT in 2032. Evergy Missouri West expects to share ownership in the 2032 CCGT with Evergy Metro, which also needs ½ CCGT in its 2026 Preferred Plan.

The 2026 Preferred Plan adds 150 MW of solar in 2035 and an additional ½ CCGT in 2036, which replaces retiring coal and gas capacity with a new firm-dispatchable resource. Retirement planning dates were delayed five years for Jeffrey Energy Center (“JEC”) 3 to March 2036 and seven years for Lake Road 4/6 to March 2038. No other retirement dates are included in the planning horizon through 2045, in contrast to the 2025 Preferred Plan which had JEC 1 and Iatan 1 retiring in March 2040. The 2026 Preferred Plan continues to have JEC 2 undergo conversion to natural gas operation but postpones the conversion from 2030 to 2036. In 2040, another ½ CCGT is needed.

New renewable build and long-term ownership economics have become less favorable compared to prior years due to changes in federal tax policy, carbon policy outlook, and higher fixed costs for wind turbines. The 2025 Preferred Plan had significantly more wind generation additions, with 1.5 GW selected between 2031-2042. The reduction in planned renewable additions in Missouri West’s 2026 IRP Preferred Plan reflects the combined effect of shortened production tax credits (“PTC”) eligibility under the One Big Beautiful Bill Act (“OBBBA”), approximately 30% higher renewable development costs, and local siting and permitting challenges. The Company continues to value resource diversity and will pursue renewable opportunities as economics and permitting conditions allow.

Figure 3: Energy Missouri West 2026 Preferred Plan ADAA

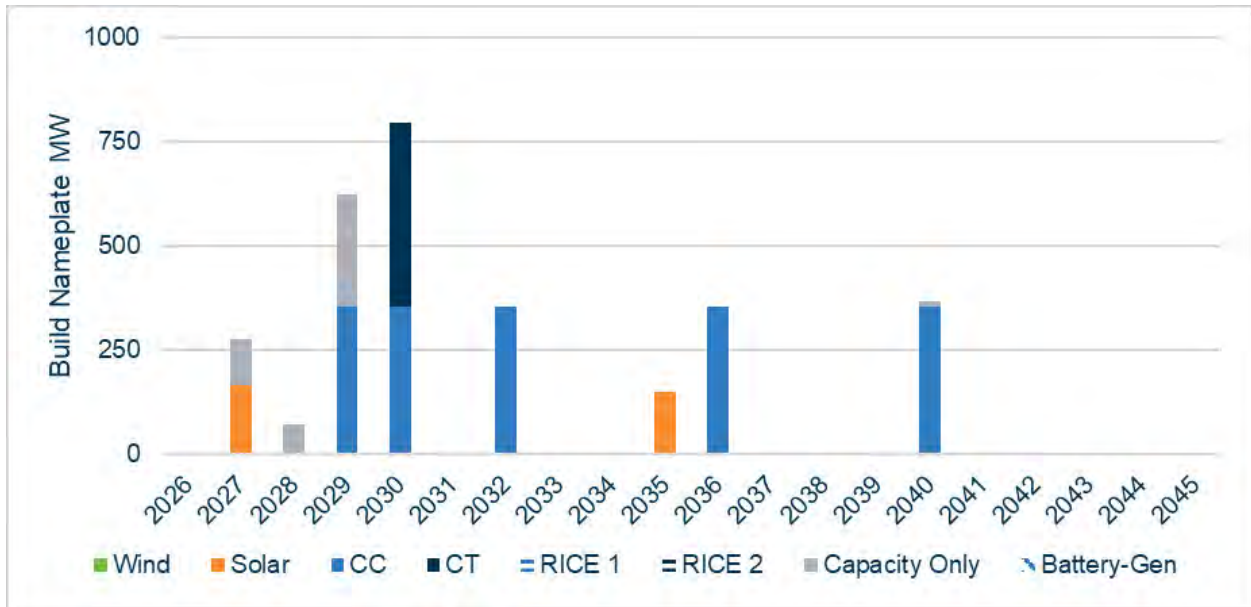


Table 3: Evergy Missouri West Preferred Plan Comparison

	2025 IRP Annual Update	2026 IRP Annual Update
Retirements	Lake Road 4/6 in 2030 Jeffrey 3 in March 2031 Iatan 1 in March 2040 Jeffrey 1 in March 2040 Jeffrey 2 to NG in 2030	Lake Road 4/6 in March 2038 Jeffrey 3 in March 2036 Jeffrey 2 to NG in 2035
Wind Additions	150 MW in 2028 150 MW in 2031 150 MW in 2032 150 MW in 2033 150 MW in 2034 150 MW in 2035 150 MW in 2037 150 MW in 2038 150 MW in 2039 150 MW in 2041 150 MW in 2042	n/a
Solar Additions	165 MW in 2027 150 MW in 2036 150 MW in 2044	165 MW in 2027 150 MW in 2035
Battery Additions	n/a	n/a
Thermal Additions	355 MW CC in 2029 440 MW CT in 2030 355 MW CC in 2030 355 MW CC in 2040	355 MW CC in 2029 440 MW CT in 2030 355 MW CC in 2030 355 MW CC in 2032 355 MW CC in 2036 355 MW CC in 2040
New DSM Programs	MEEIA Cycle 4 Extended Demand Response	Continuation of Demand Response

*CCGT = CC, SCGT = CT, Natural Gas = NG

1.4 Managing Risk and Investing to Support Regional Growth

This IRP plans for Evergy Missouri West to grow from a summer peak of 2.2 GW in 2026 to 2.9 GW in 2032, and 3.2 GW by 2045, approximately 32% and 45% of system peak growth, respectively. The base load forecast has increased this year as Evergy Missouri West has gained commitments from more customers, driven primarily by the datacenter and artificial intelligence (“AI”) economy, and facilitated by the approval of a Large-Load Power Service (“LLPS”) tariff in Missouri.

The increase in committed and prospective load in Evergy Missouri West, Evergy’s other utilities, and SPP will require significant investments in the bulk power system in the next

few years. Eversource Missouri West customers will benefit from expansion and modernization of the transmission system and new sources of supply, including highly efficient, reliable baseload energy resources, to complement the aging fleet.

Eversource Missouri West must keep pace with rapidly growing generation capacity and energy needs to foster economic development in Missouri and support regional prosperity. Eversource Missouri West also prioritizes maintaining affordability and minimizing investment risks for its current customers. The Company has taken a balanced approach in planning to grow its fleet in step with customer commitments while ensuring there is sufficient confidence in the load forecast before adding long-life assets to its infrastructure portfolio. With the LLPS tariff, large customers are committed to long-term minimum offtakes and will pay a premium rate that covers their fair share of existing and new system costs to drive affordability benefits for existing customers and enhance economic growth.

IRPs over the past few years have prompted additions to Eversource Missouri West's generating fleet, including a share of Dogwood Energy Center and new solar (165 MW) and natural gas (1.15 GW) resources in development for operation by 2030. These resources will help meet the increased needs forecasted in this IRP, but Eversource Missouri West will have to add more capacity prior to 2030 to meet its capacity needs.

Building new generation resources commensurate with new committed load growth is challenging in practice, because the supply and demand forces in the generation development sector have led to rising costs each year for the past few years and longer lead times for project completion.

Options are limited for new generation projects that can be developed and placed into commercial operation prior to 2031. Eversource Missouri West has explored the possibilities for meeting near-term needs and chosen a Preferred Plan that includes a mix of short-duration market capacity as a bridge and buildable owned resource additions that comprise the least-cost resource portfolio over the planning horizon. In the medium-term

(5-7 years out), Eversource Missouri West has a wider range of planning options and has selected new natural gas-fired baseload resources to meet capacity and energy needs.

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 and viability 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 both the supply- and demand-side additions outlined in the first 3-6 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 whole IRP 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.

Consistent with EMW's prior two IRPs, future natural gas commodity prices, carbon dioxide emissions policy, and new resource construction costs are assessed as critical uncertain factors ("CUF") which contribute to the economic evaluation of plans. The 2026 Annual Update includes a refresh of planning cost forecasts consistent with current market conditions and a reassessment of risks based on Federal policy changes.

There is strong potential for even greater future load growth than what is laid out in this Preferred Plan, as there is a pipeline of customers interested in locating in Eversource's service territory. This IRP includes alternative resource plans ("ARPs") to determine additional resource additions that can accommodate future committed large load customers in the most cost-effective and reliable manner across the planning horizon.

Section 2: Evolution in the Planning Environment

The planning environment in the United States (“US”) electricity sector has been very dynamic since the 2025 Annual Update to the IRP and in the past few years. The 2026 Annual Update incorporates forecast revisions consistent with the most recent expectations of load growth and changes to policy and economics.

2.1 Higher Expected Load Growth

Eversource is planning for additional load growth above the 2025 Annual Update forecast for all three utilities.

Since the 2025 Annual Update, the pathway to integrate large loads has become more certain. In November 2025, Eversource completed the regulatory processes in both Missouri and Kansas to establish plans for LLPS customers.² These cases resulted in tariffs requiring long-term commitments from customers with over 75 MW of peak load and include rate structures aligned with their incremental costs to the system.

With these Tariff approvals, Eversource has made more progress finalizing agreements with customers. Eversource’s preferred plans reflect a load forecast based on final Energy Service Agreements or near-final negotiations. As Eversource negotiates customer agreements, a primary consideration is ensuring that new load can be supplied with Eversource’s existing and planned resources and a realistic level of future resource development and acquisitions, considering availability, cost, and lead time for new projects.

This IRP also considers ARPs that would accommodate additional large-load customers and demand growth. Eversource has a large pipeline of prospective customers beyond just the customers included in the Preferred Plan.

² The Public Service Commission of the State of Missouri. Report and Order, Case No. EO-2025-0154, November 13, 2025. The State Corporation Commission of the State of Kansas. Order Approving Unanimous Settlement Agreement, Docket No. 25-EKME-315-TAR, November 6, 2025.

From a broader perspective, data centers are driving load growth across the country. S&P Global reports that data center demand was projected to rise by 22% (11.3 GW) year-over-year by the end of 2025.³ There are strong indications that the nationwide boom in Hyperscaler activity will continue to be a big driver of load growth across the country as technology companies compete to dominate the AI sector. In early 2026, Microsoft, Meta, Alphabet (Google), and Amazon announced a combined total of \$650 billion in expected capex spending for 2026, a 60% increase from 2025 (with both Google and Meta further increasing their 2026 capex estimates in late April).⁴ Analysts are tracking AI spending, and some forecast that in the coming years, it will exceed historic infrastructure expansions (telecom, railroads, New Deal projects). President Trump has directed an action plan for the US to achieve global dominance in AI, that includes goals to streamline permitting of datacenters and adapt the power grid to meet supply needs.⁵

Currently, forecasts for US datacenter demand vary widely as there are many unknowns. Some recent projections estimate an increase in peak demand from datacenters of 60 GW to 167 GW in 2030.⁶ Overall, US peak demand forecasts for 2030 have increased 20% between 2022 and 2025 forecast updates, and the SPP forecast has increased almost 42%.⁷

³ Hering, Garrett and Dlin, Susan. S&P Global. "Data Center Grid-Power Demand to Rise 22% in 2025, Nearly Triple by 2030". October 14, 2025.

⁴ Day, Matt and Bang, Annie. Bloomberg. "Big Tech to Spend \$650 Billion This Year as AI Race Intensifies." February 6, 2026. <https://finance.yahoo.com/news/big-tech-spend-650-billion-012716850.html>

⁵ Executive Office of the President of the United States, Office of Science and Technology Policy. Winning the Race America's AI Action Plan. July 2025.

⁶ Grid Strategies deconstructed forecasts submitted to FERC in 2025 from the planning entities and determined 90 GW of the projected 166 MW of load growth by 2030 could be attributed to datacenters. They compared this estimate to the Cleanview database tracking datacenters which estimated 60 GW by 2029, and a TD Cowen projection of 65 GW based on shipments of processing chips. Grid Strategies. Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers. Slide 10. November 2025. High end estimate based on 451 Research. Datacenter Services & Infrastructure Market Monitor & Forecast, December 2025.

⁷ Grid Strategies. Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers. Slide 22. November 2025. It is likely that some of the SPP increase is due to efforts to electrify the Permian Basin and Bakken.

While data center demand presents significant growth opportunities, Eversource recognizes the importance of ensuring that the pace of resource development in the Preferred Plan aligns with customer commitments and that existing customers are not exposed to stranded asset risk from speculative load growth.

2.2 Continued Focus on Reliability

Eversource's preferred and alternative resource plans are developed to meet expected reliability needs in every year of the planning horizon. Eversource follows and participates in resource adequacy policy development at SPP. The IRP reflects the most up-to-date expectations for capacity needs, resource accreditation, and timelines for development and interconnection. SPP and stakeholders acknowledge challenges with resource adequacy and continue to work through policy and process changes. In the past year, SPP finalized the seasonal reserve margin construct, conducted more reserve margin studies, and established a cadence for informational studies. SPP also created a one-time pathway to resolve imminent resource adequacy shortfalls due to interconnection queue delays. Eversource expects continued focus on resource adequacy in SPP with future rules focusing on forecast accuracy of load and demand response. The State of Missouri also passed Senate Bill 4 during the 2025 legislative session to address resource adequacy concerns which also included incentives for new gas generation and requirements for replacing dispatchable resources one-for-one with dispatchable capacity.⁸ Other provisions include a reliability mechanism with annual reporting by utilities and accounting changes to promote construction of natural gas-fired power plants and grid upgrades.

In 2025, the Federal Energy Regulatory Commission ("FERC") accepted SPP's proposed tariff change to establish separate planning reserve margins for winter and summer seasons.⁹ SPP refreshed its Loss of Load Expectation ("LOLE") study with updated

⁸ Mike Kehoe, Missouri Governor. "Governor Kehoe Signs SB 4 Into Law, Securing Missouri's Energy Future and Economic Growth." April 9, 2025. <https://governor.mo.gov/press-releases/archive/governor-kehoe-signs-sb-4-law-securing-missouris-energy-future-and-economic>

⁹ *Sw. Power Pool, Inc.*, 192 FERC ¶ 61,161. August 19, 2025. The Order also approved SPP's proposal to consider length and duration of loss of load events in setting reserve margin requirements.

planning information from load-serving entities and set the 2029 installed capacity planning reserve margins, which increased from 16% in summer 2026 to 17% for summer 2029, and from 36% to 38% in winters 2026/27 to 2029/30. Evergy's 2025 Annual Update and capacity planning had anticipated these changes. SPP has instituted a new process for periodic LOLE studies, including informational studies of future years to better anticipate planning needs. The preliminary results from LOLE studies for 2030 and 2032 indicate that reserve margins will remain stable or increase slightly if the load and resource mix planned by SPP load-serving entities materialize.¹⁰

Recognizing a potential reliability challenge due to rapidly increasing load forecasts, higher reserve margin requirements, and long lead times in the interconnection queue, SPP stakeholders proposed a process to quickly enable generators needed for resource adequacy to connect to the grid by 2030. In July 2025, FERC approved SPP's Expedited Resource Adequacy Study ("ERAS") process.¹¹ ERAS created a one-time interconnection queue process for resources needed to meet capacity needs. Evergy submitted four thermal resources consistent with its 2025 Annual Update to ensure firm-dispatchable capacity is online to meet the needs identified in its resource plan.¹²

The next emerging issue related to SPP's resource adequacy is forecast accuracy. SPP has suggested assessing compliance with reserve margin requirements on an ex-post basis after the season concludes. Load-serving entities would be accountable for actual net peak needs (including load and demand response), rather than pre-season forecasted net peak needs and subject to penalties if accredited capacity is insufficient.¹³ The potential change in the framework illustrates the importance of having sufficient capacity to meet forecasted peak load.

¹⁰ SPP. 2025 LOLE Study Results and PRM Recommendation. January 2026 SAWG.

¹¹ *Sw. Power Pool, Inc.*, 192 FERC ¶ 61,062. July 21, 2025.

¹² Evergy resources in the ERAS queue include Viola and McNew combined-cycle gas turbine projects jointly owned by Evergy Missouri West and Evergy Kansas Central, Mullin Creek #1 simple-cycle gas turbine owned by Evergy Missouri West and Mullin Creek #2 simple cycle gas turbine for Evergy Metro.

¹³ See SPP Revision Request RR703.

2.3 Changes in Environmental Policy and Decarbonization Outlook

In the past year, there have been several changes to policy and market fundamentals that reduce Eversource's expectations for the pace of decarbonization in the US electric sector, including for the Eversource generating fleet and SPP more broadly. Eversource has adjusted its future carbon-reduction-risk CUF values, updated its future SPP resource mix assumptions for market pricing, and reassessed coal plant retirement risks due to the following changes:

- Federal implementation of greenhouse gas emissions ("GHG") rules being postponed and potentially eliminated
- Timeline for required investment in JEC nitrogen-oxide ("NO_x") emissions controls being extended
- PTC eligibility for new renewable resources ending earlier
- Load growth and reliability needs driving resource plans toward retaining and adding new firm-dispatchable resources
- Availability of carbon-free dispatchable options remaining limited

2.3.1 GHG Rule

For the 2025 Annual Update, Eversource included ARPs to comply with the Environmental Protection Agency's ("EPA") GHG Final Rule which was issued in May 2024.¹⁴ Eversource Missouri West 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 natural gas to the sites. A compliance plan was not chosen as the Preferred Plan because of higher expected costs and uncertainty of enforcement of the rule due to the change in presidential administration prior to the IRP.

¹⁴ 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.

In March 2025, the EPA publicly announced reconsideration of the GHG Rule.¹⁵ In June 2025, EPA proposed a rule to repeal all GHG emissions standards for fossil fuel-fired plants, or in the alternative, to repeal the standards created in the GHG Rule.¹⁶ As of the 2026 Annual Update, a final rule has not been issued.

2.3.2 Capital Investment for Regional Haze Rule

Eversource anticipates that JEC 2 and 3 will need to reduce NO_x emissions to comply with the Regional Haze Rule in the future. For the 2025 Annual Update, Eversource expected to comply by retiring JEC 3 and converting JEC 2 to natural gas operation in March 2030 to avoid the need for costly selective catalytic reduction (“SCR”) investment. Recent updates in Regional Haze Rule administration, including the submission of a supplemental state plan by Kansas and the delay of deadlines for the next planning period, have moved back Eversource’s expected investment needs. The 2026 Annual Update forecasts that JEC 3 and JEC 2 can continue coal operation through March 2038 and would need to undertake changes (invest in SCR, convert to natural gas, retire) after that time.

2.3.3 Production Tax Credits and Investment Tax Credits

PTCs and investment tax credits (“ITCs”) provide customer benefit for eligible resources as the tax attributes are flowed back to the customers. Recent federal law changes have shortened the eligibility timeline for PTCs for wind and solar resources, thereby increasing the expected net costs for solar and wind additions beginning operation in 2030 and beyond. There are also stricter project qualification requirements for production or investment tax credits, which may affect the viability and cost of new resource builds.

In August 2022, Congress passed the Inflation Reduction Act (“IRA”), and it was signed into law by President Biden. The IRA increased and extended availability of PTC and ITC.

¹⁵ EPA Press Office. “Trump EPA Announces Reconsideration of Biden-Harris Rule, ‘Clean Power Plan 2.0’, That Prioritized Shutting Down Power Plants While Raising Costs on American Families.” March 12, 2025. <https://www.epa.gov/newsreleases/trump-epa-announces-reconsideration-biden-harris-rule-clean-power-plan-20-prioritized>

¹⁶ Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units. 90 FR 25752.

Eversource's IRPs in 2023, 2024, and 2025 assumed that new wind and solar resources would receive PTC and new battery resources would receive ITC. The IRA included a phase-out of eligibility for tax credits as the US meets its GHG emissions reduction goals. Projects beginning operation before 2034 were forecast to receive 100% of credits, with the credits phasing down to 75% and 50% for projects beginning operation in 2034 and 2035 and ceasing for projects after 2035.

In July 2025, Congress passed the OBBBA and it was signed into law by President Trump. The OBBBA shortened the eligibility window for new projects to qualify for PTC. New wind and solar resources must begin operation before 2028, or begin construction by July 4, 2026, and begin operation before 2030. In addition, resource developers will be subject to stricter criteria to meet the definition of beginning construction¹⁷ and to qualify projects that source parts and components from Foreign Entities of Concern ("FEOC").¹⁸ Storage resources maintain their eligibility for ITC within the same time horizon expected under the IRA rules but will also be subject to FEOC rules.

2.3.4 Pace of Resource Mix Change

For the 2026 Annual Update, Eversource continues to consider carbon policy as a CUF and has updated market pricing based on updated ITP supply and demand forecasts (see Appendix B Eversource Market Prices 2025 Refresh). Eversource is no longer using the 95% carbon reduction resource mix as a scenario because it does not seem plausible, even in a "high" case based on the current fundamental and policy drivers.

For the 2024 and 2025 IRPs, Eversource used two different future resource mix scenarios for market pricing, based on the SPP Integrated Transmission Planning (ITP) process assumptions which project the system supply and demand 2, 5, 10 and 20 years into the

¹⁷ The IRS has issued a notice with guidance on establishing beginning of construction to meet OBBBA requirements. The standard is a Physical Work Test with a Continuity Requirement. See IRS Notice 2025-42, Beginning of Construction Requirements for Purposes of the Termination of Clean Electricity Production Credits and Clean Electricity Investment Credits for Applicable Wind and Solar Facilities. <https://www.irs.gov/pub/irs-drop/n-25-42.pdf>

¹⁸ The US Treasury has not finalized FEOC guidance.

future. The scenario including a moderate level of renewable and storage resource additions was used for the “low” (no) and “mid” carbon policy risk models. The scenario used for Eversource’s “high” carbon policy risk was based on high levels of renewable and storage buildout as well as earlier retirement assumptions for emitting resources to achieve a 95% carbon reduction from 2017 levels by 2040. Eversource analysis found that this reduction was fairly consistent with the EPA GHG rule goals. The resulting market price forecast declined over time, consistent with a high fixed cost, low variable cost supply mix, including negative production costs due to tax credits.

2.3.5 Enabling Technologies

Dispatchable, carbon-free energy sources will be needed to achieve decarbonization while meeting load growth and reliability needs. Commercially viable options are not expected to be available in the near term as AI and datacenter load ramps up. There is some optimism that US government and tech company support may help accelerate nuclear development. Eversource plans to continue monitoring the progress of nuclear generation technology and study it within the IRP when it becomes technologically and economically viable.

In the past few years, some pathways to decarbonization began to gain traction, including using hydrogen as an alternative fuel, carbon emissions capture, and development of Small Modular Reactors (“SMRs”). However, none of these options are economically viable without advances in technology. Hydrogen fuel is created by using other energy sources to break up water molecules. The process uses more energy than can be created and can be cost-prohibitive. Naturally occurring geologic hydrogen has been identified,¹⁹ but mining and extraction methods have not been developed. There are also cost and logistical challenges in storing and transporting hydrogen for power production. Carbon capture technology has been in existence for many years but requires significant and expensive infrastructure to complete chemical processes to separate the carbon. Post separation, the carbon then must be stored in a geologically appropriate location or

¹⁹ See Section 14.4 for discussion of geologic hydrogen in our area.

transported for off-site storage. Evergy considered carbon capture at coal plants to comply with the GHG Rule but found that storage would likely be physically impractical, in addition to being extremely costly. In the past few years, SMR technology appeared to be making gains in viability. However, in late 2023, Utah Associated Municipal Power Systems cancelled its SMR project with NuScale after 8 years of development due to rising costs, exceeding three times the initial estimate.²⁰

Some of the largest datacenter end-users have carbon-free energy goals. Their financial backing, as well as support from US government programs and policies, may help accelerate nuclear development. In mid-2025, Google and Kairos Power announced the development of a 50 MW advanced nuclear reactor that will supply Tennessee Valley Authority beginning in 2030.²¹ Google has a partnership with Kairos Power to financially support the development of the first-of-a-kind technology and enable progress to commercial viability.

Building a new large-scale nuclear resource requires about 10 years of lead time.²² Large-scale nuclear development in the US has been deterred by safety concerns resulting from the Fukushima nuclear accident in Japan, the bankruptcy of Westinghouse, and the long delays and large cost overruns in building the Vogtle units in Georgia. Some electricity suppliers are looking at restarting retired nuclear reactors to serve datacenter customers.²³ The US government has also announced goals, policy reforms, and

²⁰ Day, Paul. Cancelled NuScale Contract Weighs Heavy on New Nuclear. Reuters. January 10, 2024. <https://www.reuters.com/business/energy/cancelled-nuscale-contract-weighs-heavy-new-nuclear-2024-01-10/>. Ramana, M.V. The Collapse of NuScale's Project Should Spell the End for Small Modular Nuclear Reactors (Opinion). Utility Dive. January 31, 2024. <https://www.utilitydive.com/news/nuscale-uamps-project-small-modular-reactor-ramanasmr-705717/>

²¹ Kimball, Spencer. Google, Kairos Power Plan Advanced Nuclear Plant for Tennessee Valley Authority Grid by 2030. CNBC. August 18, 2025. <https://www.cnbc.com/2025/08/18/google-kairos-nuclear-smr-tennessee-valley-authority-tva-data-center-ai.html>

²² See later discussion on nuclear timelines in Section 14.1

²³ In late 2024, Microsoft signed a deal with Constellation to restart Three Mile Island, which closed in 2019. In late 2025, NextEra Energy and Google announced an agreement to restart Duane Arnold which closed in 2020.

financing to boost nuclear power development including improving supply chains for nuclear fuel, advancing reactor technology, and restarting closed reactors.²⁴

2.4 Continued Increase in New Build Costs, Long Lead Times for Development

The 2026 Annual Update includes cost increases for most new resource options and updates to the expected availability and lead times for new resources. Eversource's planning options for the 2026 Annual Update are informed by offers received in the 2025 all-source RFP, continued discussions with RFP project sponsors, and knowledge gained through self-development research.

Costs for new gas turbines have increased since the 2025 Annual Update due to supply and demand forces including supply chain issues, inflation, prices of metals and other components, limited manufacturing capabilities, and expectations for strong demand growth across the country and internationally due to advanced manufacturing, AI, and datacenter investment. In 2025, S&P Global reported long wait times of 5-7 years for gas-turbine orders and cost increases of over 200% compared to a few years ago.²⁵ It also noted high increases in development costs for engineering and construction of all types of projects. Eversource received some offers for gas-fired projects in its 2025 RFP and has continued to advance thermal self-development activity based on needs identified in the 2025 Annual Update. These options allow Eversource to add natural gas resources in the early 2030's. Eversource also forecasts increases in development costs and firm natural gas delivery contracts. Total costs for new natural gas-fired additions are expected to be about 20-25% higher than forecasted in the 2025 Annual Update.

Relative to the 2025 forecast, costs for developing new wind and solar projects have increased by about 30%, while storage project costs have increased by about half as much. Renewable and storage projects have a quicker development timeline than new

²⁴ US Department of Energy. Fact Sheet: The Energy Department is Delivering on Accelerating the Deployment of Nuclear Power. January 19, 2026. <https://www.energy.gov/articles/fact-sheet-energy-department-delivering-accelerating-deployment-nuclear-power>

²⁵ Anderson, Jared. Wait Times for US Gas-Fired Turbines Averaging 5-7 Years, Costs Up Sharply. S&P Capital IQ. May 25, 2025.

natural gas-fired resources and can help accommodate load growth while diversifying Eversgy's energy and capacity mix. Based on RFP offers and self-development options analysis, Eversgy has few options for near-term wind or solar additions, particularly options that would be eligible for PTCs. Solar project viability and timing have been challenged by local opposition in some counties in both Kansas and Missouri, which has stalled or prevented permitting. There is also a threat that solar development could be restricted or delayed on a state-wide basis in Missouri, based on bills introduced in the 2026 legislative session. Eversgy has more viable storage options, including adding surplus to existing sites or executing on RFP projects. Storage costs are affected by sourcing options, which must avoid FEOC restrictions. Development timelines are also impacted by availability of substation and transmission equipment, which can have significant procurement lead times by 2-3 years.

2.5 Delay of Coal Retirements Relative to Prior Forecasts

Eversgy's 2025 and prior IRPs recognized that the coal fleet is aging, and its performance has a significant impact on meeting SPP's resource adequacy requirements ("RARs"). Additionally, the coal fleet has been and continues to be at risk of tightening environmental regulations. Eversgy continues to plan for the measured retirement of the coal fleet over time and the replacement of its capacity and energy. However, the risk balance has shifted due to the fundamental drivers discussed previously, including rapid load growth, need for reliable dispatchable capacity, higher development costs, and slowing of decarbonization and environmental restrictions. Given these broader market dynamic changes and outlook for federal policy, the 2026 Annual Update delays planned retirement dates relative to the 2025 Annual Update.

Section 3: Load Analysis and Load Forecasting Update

3.1 Changes from the 2025 Annual Update

Several inputs to the load forecasting models were updated for this filing compared to the 2025 Annual Update:

- Historical data for customers, kWh and \$/kWh: ending May 2025 vs ending June 2024.
- DOE forecasts of Residential appliance and equipment saturations and kWh/unit are from the Energy Information Administration (“EIA”) 2025 Annual Energy Outlook (“AEO”), while non-Residential equipment saturations and efficiency forecasts are from the 2023 AEO. See below for additional descriptions.
- Economic forecasts from Moody’s Analytics: May 2025 vs June 2024.
- Class models in the 2026 Eversource Missouri West Annual Update filing are the same as the 2025 Annual Update filing: residential, small commercial, big commercial (medium, large, large power) and industrial. However, Nucor Steel was separated from the rest of the Industrial class and forecasted separately.
- The elasticities inherent to the end-use structured variables were evaluated for model fit and minor adjustments were made as necessary. A summary of elasticity values is included in the Load Forecasting workpapers.
- The Company utilized an Electric Power Research Institute (“EPRI”) electric vehicle study within its modeling for the 2026 Annual 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 2026 Annual Update compared to the 2025 Annual Update. Below are the primary reasons for the change in forecast:

- The EIA produced an updated AEO for 2025. Eversource’s 2026 Annual Update utilizes end-use forecasts from the 2025 AEO for the Residential class. However, the 2023

AEO was used to support Commercial and Industrial classes because the data was not available for sufficient review prior to the forecast timeline.

- There are some changes from the Moody's Analytics Economic forecasts from 2024 to 2025. Economic forecasts for Population, Households, Employment and Non-Manufacturing Gross Product show a stronger growth trajectory throughout the forecast period, while Manufacturing Gross Product shows a weaker forecast compared to 2024.
- The growth trajectory of Eversource Missouri West Commercial load since the 2025 Annual Update forecast contributes to a higher forecast trajectory, while Residential and Industrial load since the 2025 Annual Update forecast contribute to a lower forecast trajectory.
- New large load customer forecasts have been incorporated into the Eversource Missouri West energy and peak forecasts for all scenarios. Figures 6 and 7 show how new large load customers influence load growth trajectory of the mid-case forecast during the 2026-2036 timeframe.
- A new electric vehicle forecast in partnership with EPRI results in lower growth in passenger electric vehicle adoption but higher non-passenger electric vehicle growth. Additionally, charging profile estimates result in a MW peak forecast in the High Electrification scenario that is reduced compared to the 2025 Annual Update forecast. Much of this effect is due to the timing of electric vehicle charging occurring outside of typical peak hours.

Table 4: Energy MO West Mid-Case Annual Forecast ****Confidential****

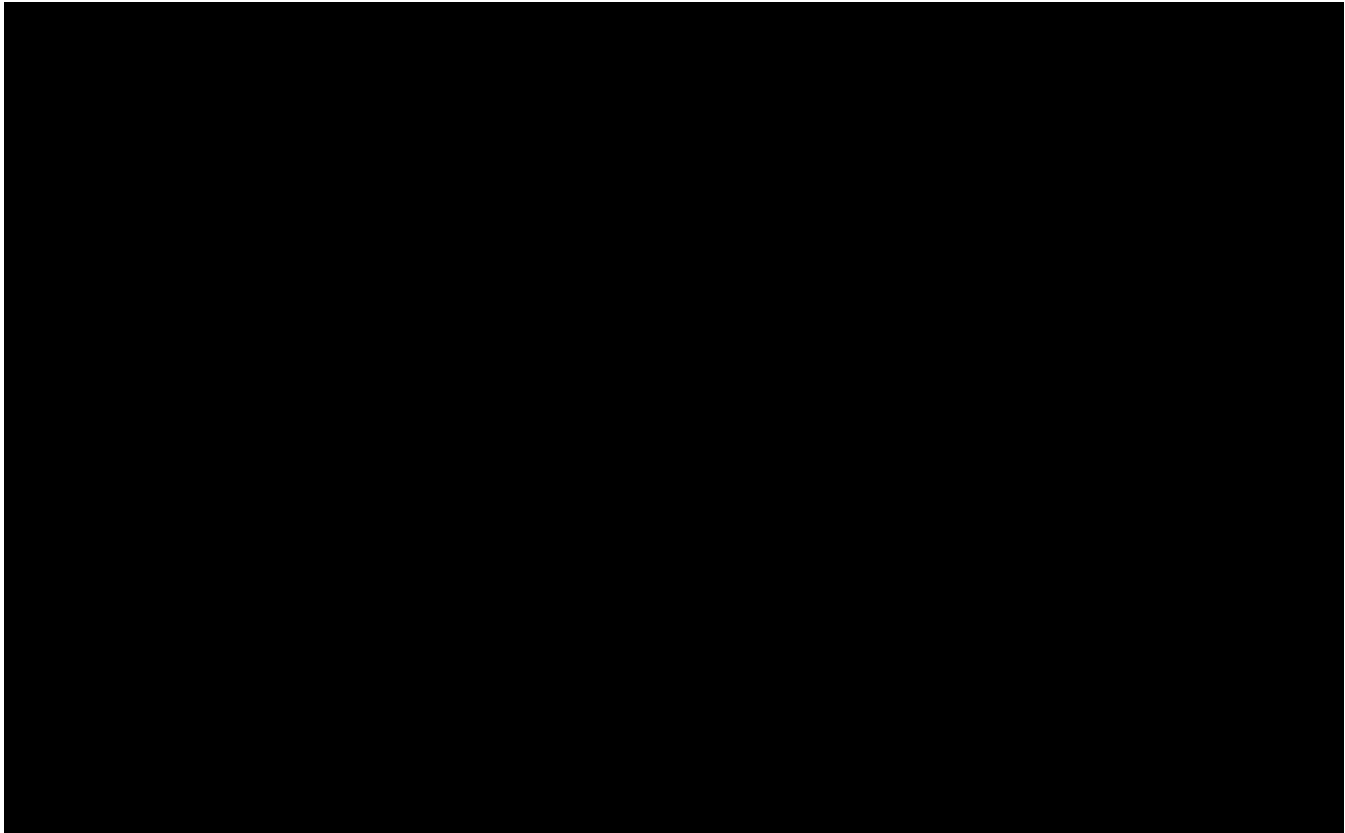


Figure 4: Peak Forecasts - 2026 Annual Update vs. 2025 Annual Update

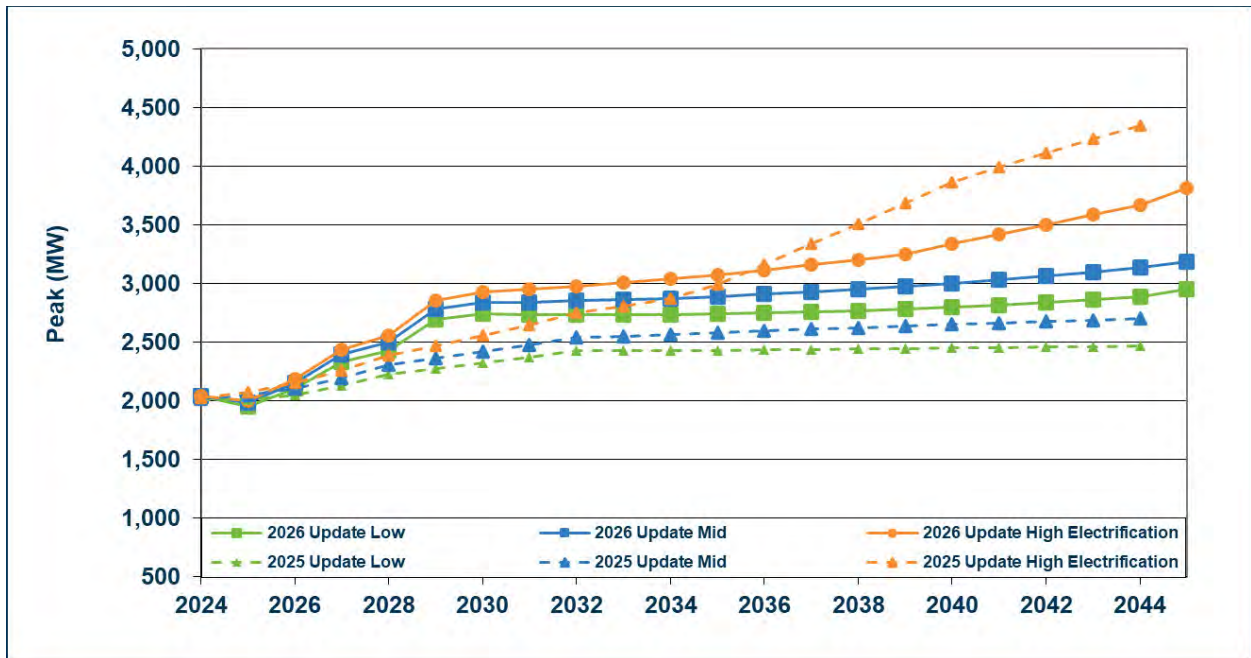
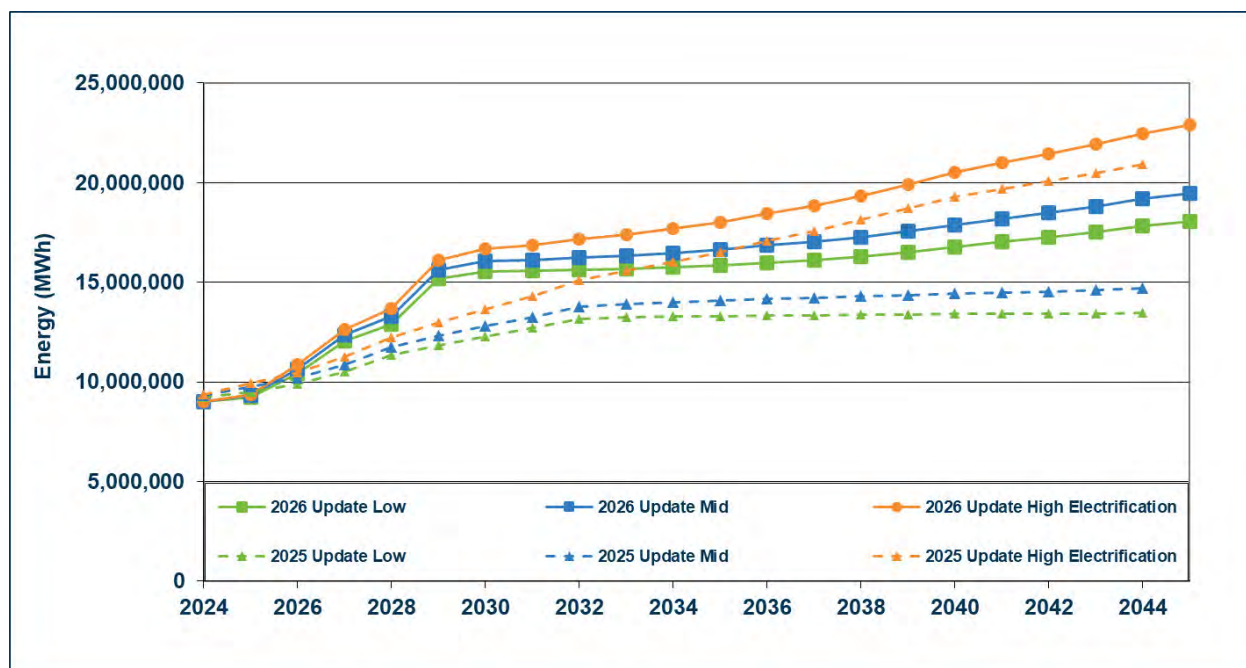


Figure 5: Energy Forecasts - 2026 Annual Update vs. 2025 Annual Update



While Evergy has a robust pipeline of prospective large load customers, only customers who meet critical criteria and milestones within Evergy’s established review process are included in base load planning to avoid exposing our Preferred Plan to unnecessary risks. Generally, for a large load to be included into base load IRP planning, Evergy expects that a large load customer project have met at least one of the following criteria: recently commenced electric service from Evergy, an executed Electric Service Agreement (“ESA”) under the LLPS tariff, or have a finalized SPP load addition study (typically Attachment AQ) and expect to have an executed LLPS ESA within the next 3-6 months. Evergy Missouri West has five specific large load customers that meet the criteria for base load planning and have been incorporated in all load forecast scenarios (low, mid, high) for the 2026 Annual Update.

The total combined peak of these five large load customers is projected to be approximately 800 MW at steady state. Three of these customers have executed ESAs under the LLPS, two of which have been in EMW’s base load planning assumptions in previous IRPs. The other two projects are below the LLPS 75 MW threshold. One customer is online and taking service under an existing Large Power Service tariff and

the other is expected to be online later this year under the same tariff. When and if both projects further develop to exceed the 75 MW threshold, Evergy will work with these customers to transition them to the LLPS tariff.

To explain how the large load drives EMW’s 2026 IRP mid-case load forecast, Figures 6 and 7 show the peak MW and MWh impact over the next decade of adding the new large load profiles to the native demand. Each of the base planning scenarios studied in this 2026 IRP (low, mid, high) includes the new large loads starting to ramp in 2026, reaching peaks by 2032, and continuing at those levels through the end of the 20-year planning period.

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

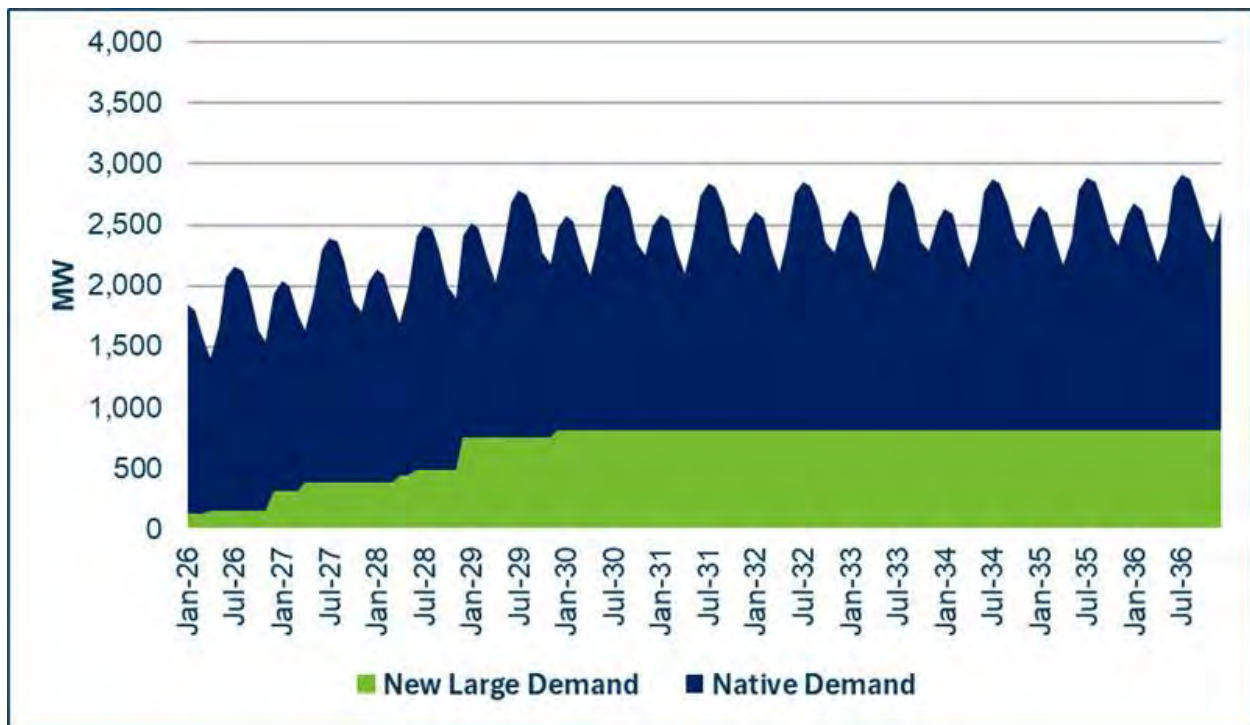
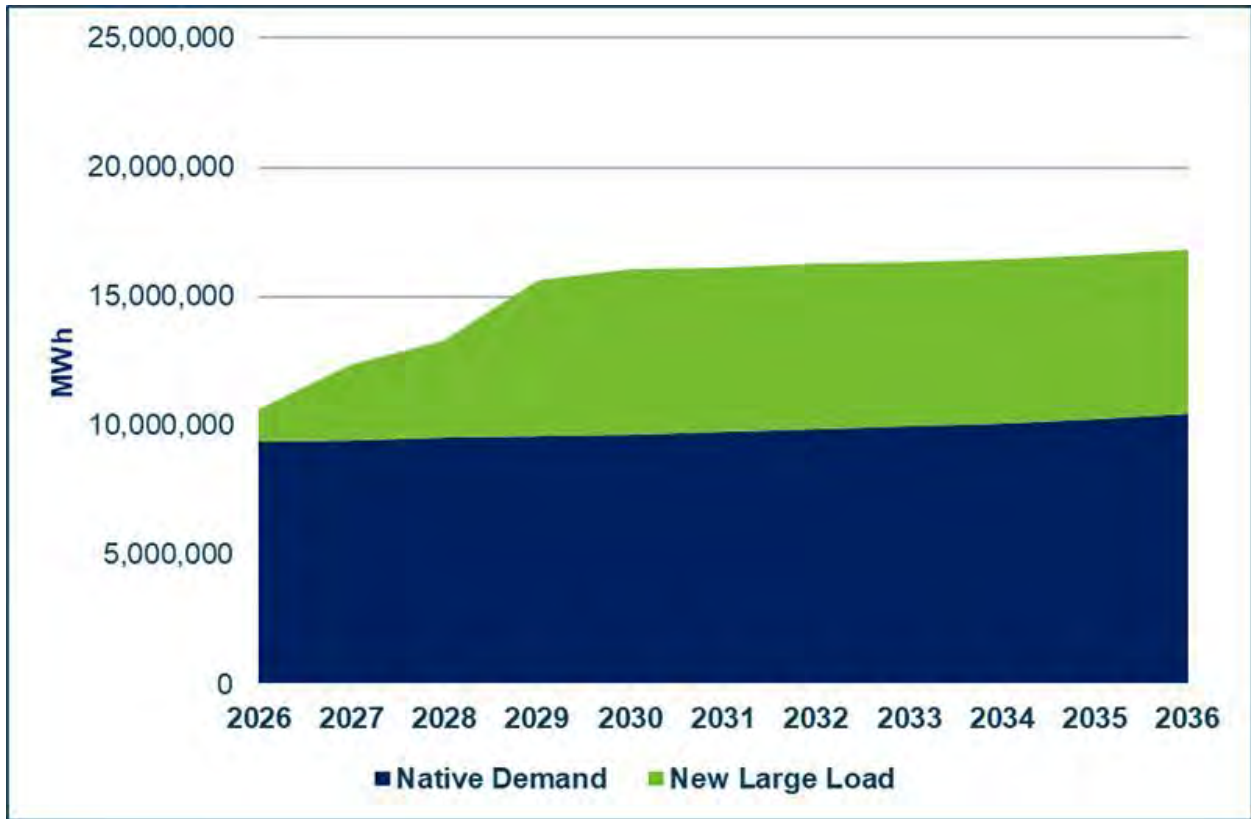


Figure 7: EMW Peak MWh Load Forecast Including New Large Load



Section 4: Market Fundamentals Update

4.1 Fuel Price Forecasts ²⁶

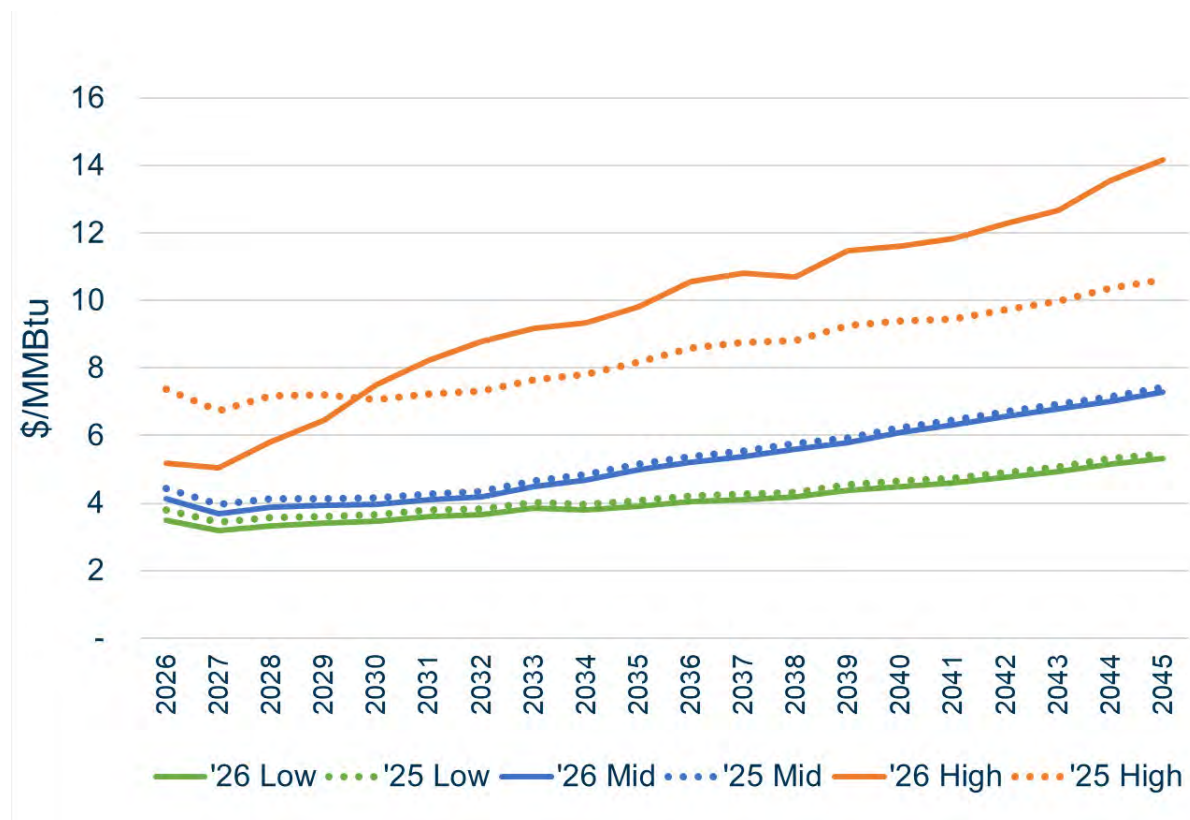
4.1.1 Natural Gas

Eversgy updates the IRP natural gas forecast annually based on the forecast used for internal budgeting, which is developed from vendor forecasts and forward markets.²⁷ The internal forecast is then scaled by EIA's fundamental supply and demand forecasts to produce high and low estimates. EIA released new fundamental forecasts in the 2025 AEO. EIA's low and mid natural gas supply cases were consistent with the previous 2023 forecasts; however, the high case significantly increased from the 2023 outlook. The 2025 high case was incorporated into this year's IRP modeling to better capture natural gas sensitivity with anticipated industry-wide load growth and natural gas build out. Natural gas prices were identified as a CUF, consistent with the 2024 Triennial IRP. High, mid (base), and low forecasts are used in the development of resource plans and evaluation of plan economics.

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

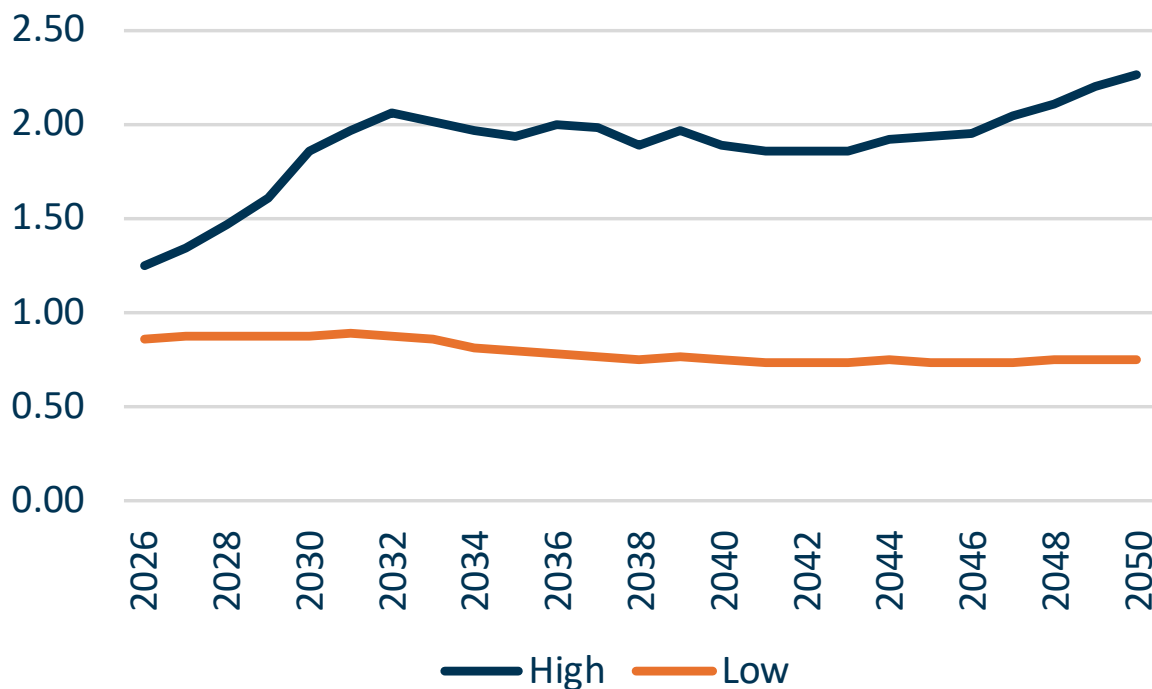
²⁷ Third party sources include IHS Markit, Energy Information Administration, S&P Global Platts, Energy Ventures Analysis, CME Futures, and ICE.

Figure 8: Natural Gas Price Forecasts 2026 IRP vs 2025 IRP



The high and low forecasts were developed by scaling the mid forecast based on the fundamental supply and demand forecasts in the EIA AEO model. 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 Liquefied Natural Gas (“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.

Figure 9: Henry Hub Natural Gas Scalar

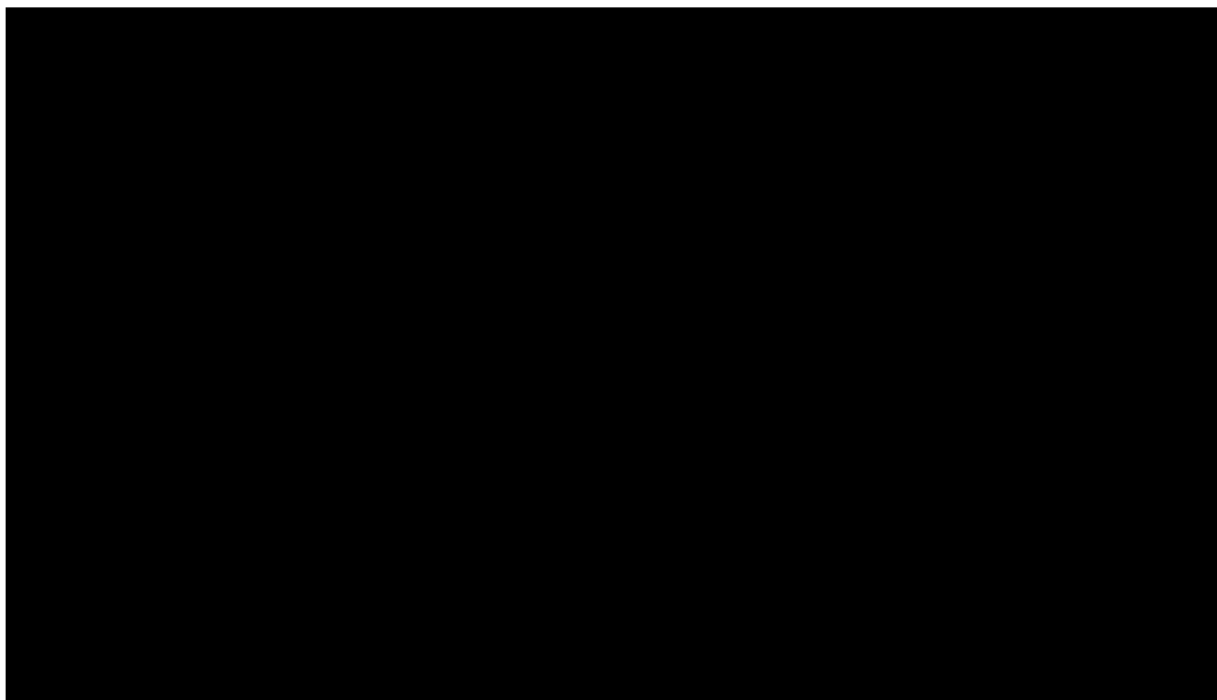


This method was used beginning in the 2022 IRP to derive a wider range of prices based on changes in fundamental assumptions.

4.1.2 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 IHS 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 case consensus of the major forecast sources.

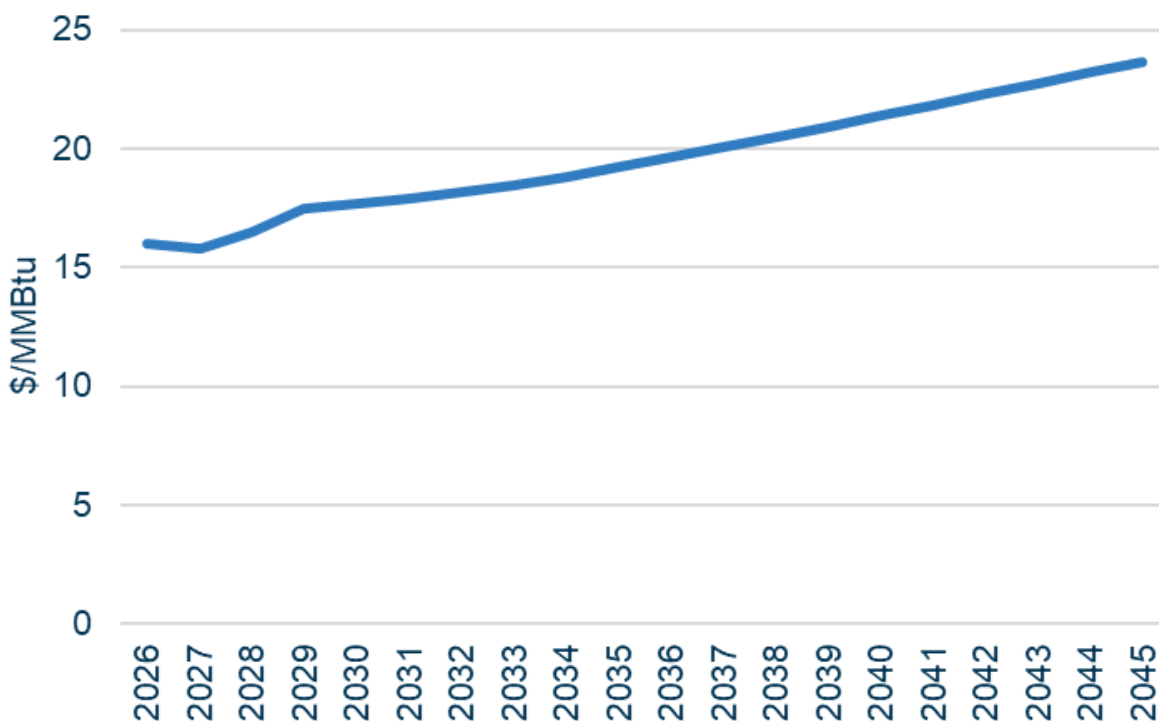
Figure 10: 2026 IRP Missouri West Coal Price Forecast ****Confidential****



4.1.3 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: 2026 IRP Fuel Oil Price Forecast



4.2 Carbon Emissions Policy

Evergy identified carbon emissions policy as a CUF through model scenario analysis in the 2024 Triennial IRP, consistent with the 2021 Triennial IRP, and has included it in the economic analysis of resource plans for at least the past 5 years. It is challenging to accurately forecast the impact of carbon emissions policy on utility financial performance because future market conditions, regulations, and compliance options are highly uncertain.

For the 2021 and 2022 IRPs, Evergy incorporated future carbon taxes, beginning to take effect in 2026 for its “mid” and “high” scenarios. The mid was based on an average of vendor forecasts, while the high was based on one vendor forecast which estimated the expected costs of economy-wide carbon reductions. For the 2023-2025 IRPs, Evergy found that vendor forecasts had been discontinued or were outdated given recent policy changes including the IRA incentives for renewables and expected regulations on GHG emissions. Evergy modeled the impacts of carbon policy through physical emissions

reductions in the mid and high cases and also included a carbon tax in the high case. The mid case for the 2023-2025 IRPs was consistent with an emissions reduction trend seen in the SPP ITP models over the 20-year planning horizon, which included increasing penetration of renewables in the supply mix, retirements of older coal, natural gas, and oil plants, and modest load growth in Evergy's service area. The high case was based on SPP modeling of an explicit carbon reduction goal of an approximately 95% reduction in carbon dioxide ("CO₂") production from 2017 levels, which resembles the expected emissions reductions contemplated in GHG Rule issued in 2024.

Evergy has reassessed its carbon policy risks for the 2026 Annual Update based on announced policy changes including reconsideration of the GHG Rule and curtailment of IRA incentives under the OBBBA, as well as changes in market conditions including expectations of substantial load growth, and rebalancing of the future supply mix towards firm dispatchable resources. The 2026 Annual Update employs a carbon tax (rather than physical reduction) for the mid and high carbon policy risk scenarios. The low scenario, consistent with past IRPs, has no tax.

Evergy researched existing carbon reduction pricing mechanisms and other utility IRPs to determine appropriate economic risk levels for a future carbon tax.

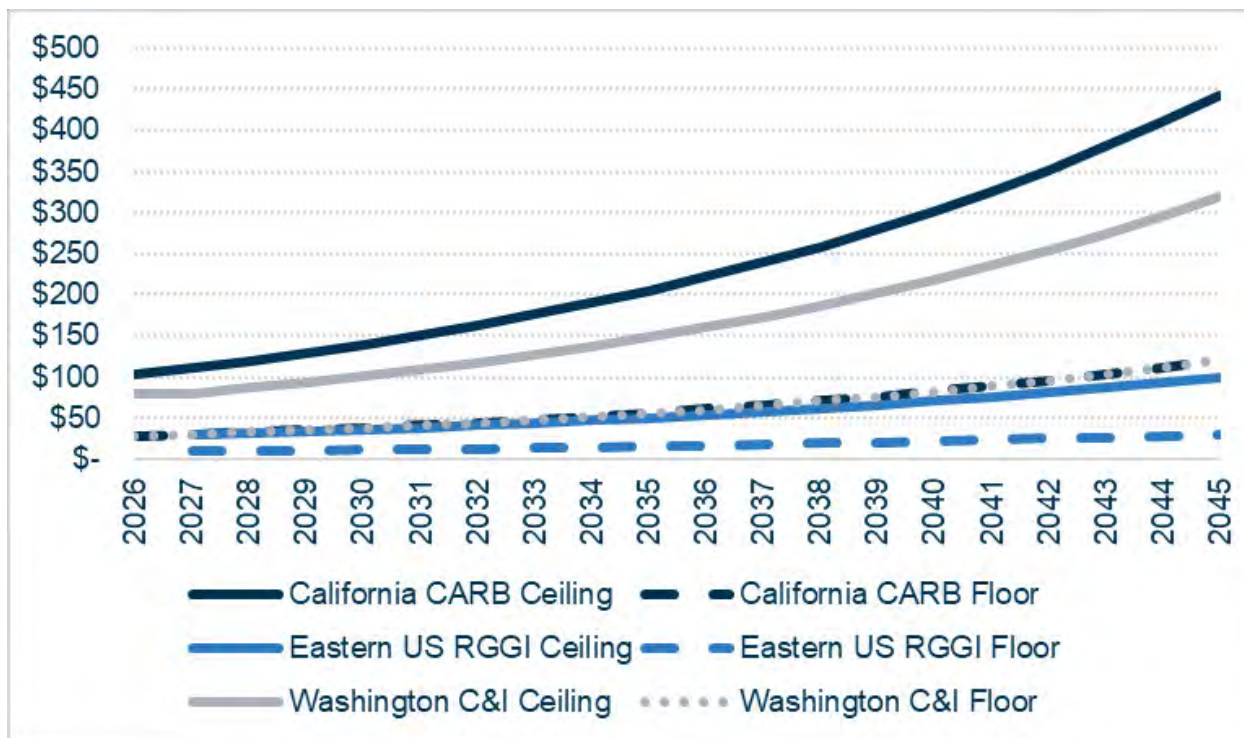
There are three current cap and trade programs in the United States, including state-level programs in California and Washington, and the multi-state²⁸ Regional Greenhouse Gas Initiative ("RGGI") program in the Eastern US.²⁹ All three programs require emitting resources to hold an allowance for each ton of CO₂ emitted. The number of allowances available declines over time to achieve emissions reductions. Each program has a minimum (floor) allowance price and pricing tiers for issuing additional allowances up to

²⁸ Since 2012, RGGI has had 9, 10, or 11 states participating each year.

²⁹ For program information, see <https://ww2.arb.ca.gov/our-work/programs/cap-and-invest-program/about>, <https://ecology.wa.gov/air-climate/climate-commitment-act/cap-and-invest>, <https://www.rggi.org/program-overview-and-design/elements>

a maximum (ceiling price). These prices escalate each year. California and Washington have price ranges approximately three times higher than RGGI.³⁰

Figure 12: US Emissions Cap and Trade Program CO₂ Allowance Prices (\$/ton)



Evergy is using carbon tax assumptions informed by the RGGI Cap and Trade program in the Eastern US. The mid tax is based on the price floor for the program, and the high tax is based on the weighted-average price expected if the ceiling amount of allowances are used. The mid and high taxes are modeled to begin in 2032, which Evergy believes is a plausible start time for regulatory action on carbon emissions. Evergy selected RGGI-based assumptions as the most plausible reference for potential carbon regulation applicable to the SPP region, given that California and Washington programs reflect more aggressive state-level climate policies. However, Evergy's probability-weighted analysis

³⁰ See Workpaper, or [https://ww2.arb.ca.gov/sites/default/files/2025-12/nc-2026 annual reserve price notice joint auction.pdf](https://ww2.arb.ca.gov/sites/default/files/2025-12/nc-2026%20annual%20reserve%20price%20notice%20joint%20auction.pdf), <https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/cost-containment-information>, <https://apps.ecology.wa.gov/publications/documents/2514102.pdf>, <https://apps.ecology.wa.gov/publications/documents/2514103.pdf>, <https://www.rggi.org/program-overview-and-design/program-review>

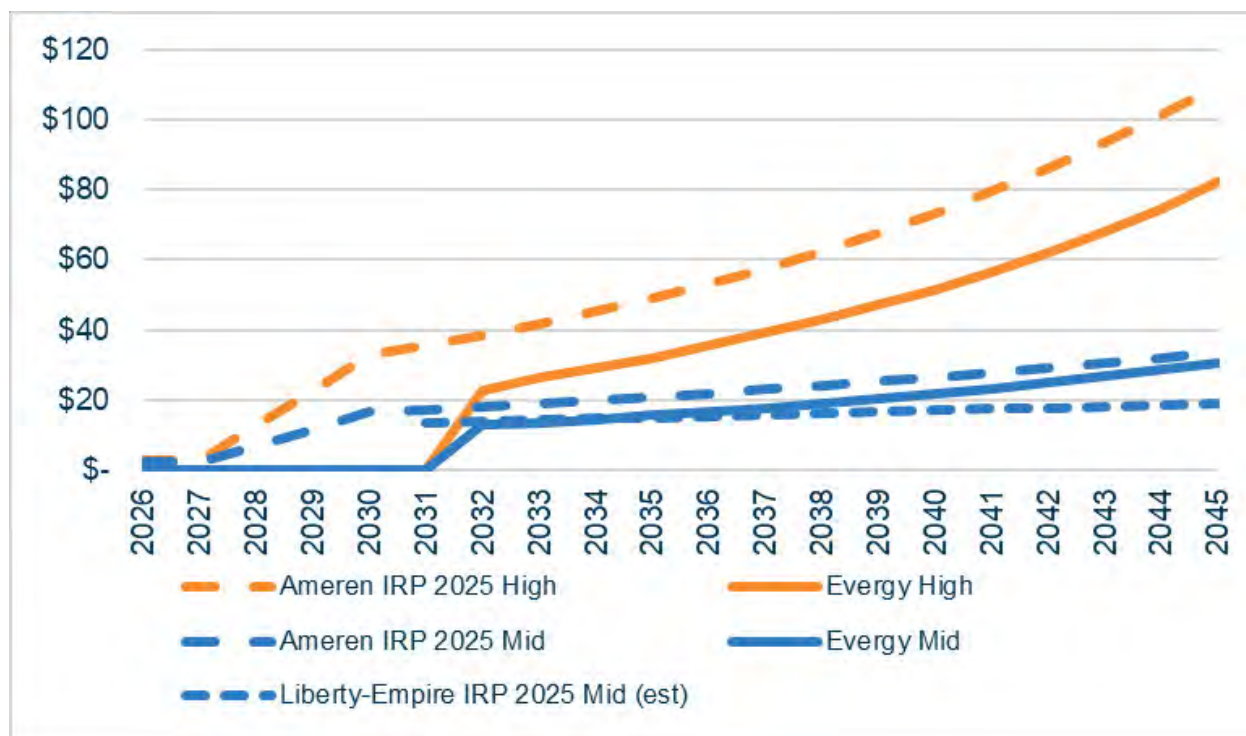
ensures that plans are tested against a range of outcomes, including high carbon restriction futures where renewable-heavy plans outperform. Further strengthening this selection, Evergy’s assumptions appear to be similar to the values used by Ameren and Liberty-Empire in their 2025 IRPs.³¹

Figure 13: CO₂ Emission Tax (\$/ton)



³¹ The Liberty-Empire IRP cites a \$13-\$14/short ton price beginning in 2031. The annual forecast was marked confidential, so Evergy assumes a 2.5% inflation rate in future years.

Figure 14: Eversource and Missouri Utility CO₂ Tax Scenarios



4.3 Market Price Forecasts

Eversource considers current and future market conditions in developing its 20-year forward looking forecasts for the IRP. Starting with the 2022 IRP Annual Update, Eversource contracted with 1898&Co. to produce 20-year market price forecasts using SPP’s transmission planning models as a baseline. As mentioned in Section 2.3.4, Eversource has updated its market price forecast from the 2024 and 2025 IRPs.

The 2026 Annual Update pricing models, based on the finalized 2025 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 2025 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

Market pricing was calculated for three different natural gas price futures, based on the values used for the natural gas CUF forecasts. After the pricing was completed, EIA issued a new AEO for 2025. Eversource updated natural gas price assumptions based on the new data and found that while its new low and mid natural gas price forecasts were substantially unchanged, the new high price forecast was much higher. To align with this higher forecast, Eversource scaled up the high natural gas market price series.

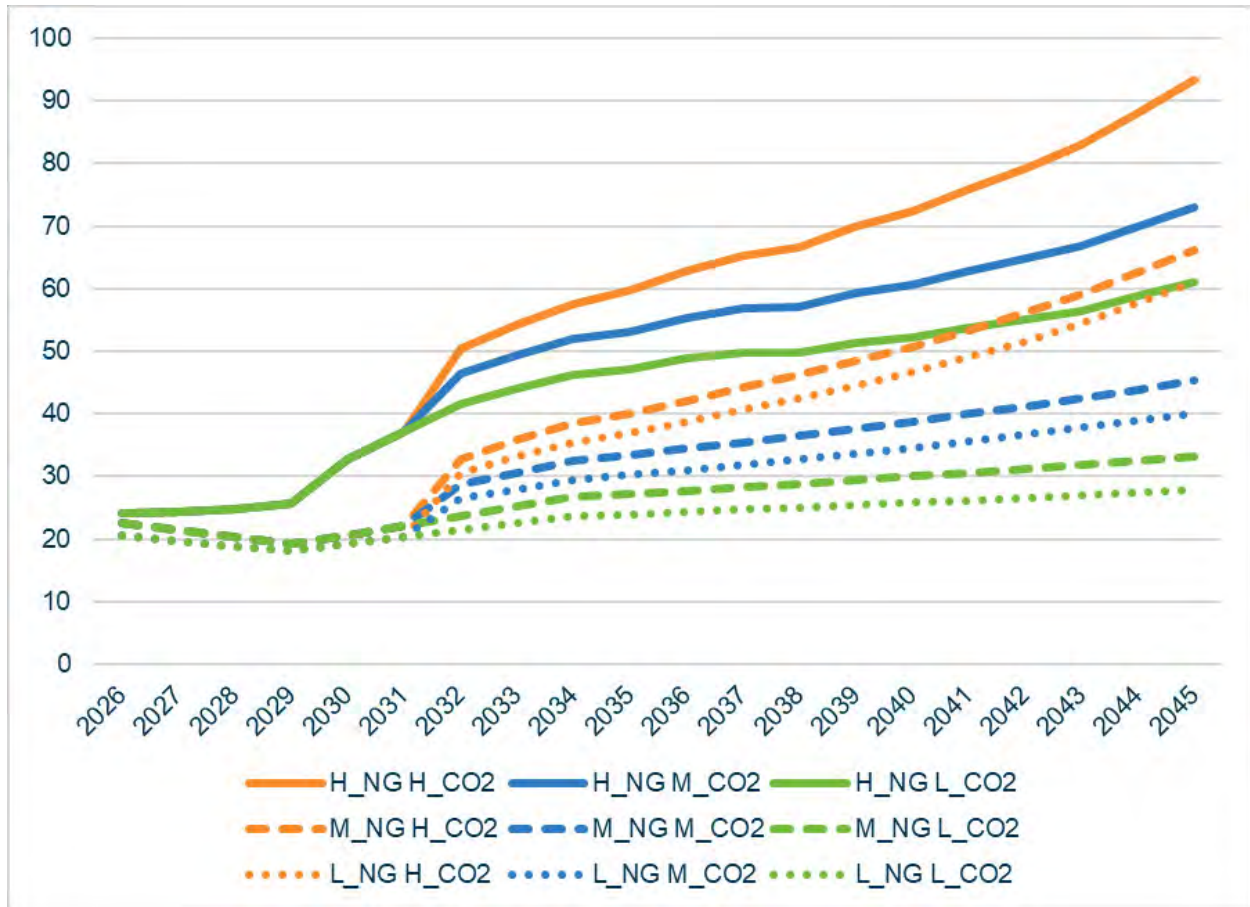
The base market price forecasts did not include carbon taxes. Eversource adjusted market prices to incorporate the expected impact of the taxes for the mid and high CO₂ tax futures, beginning in 2032.³²

Overall, nine price series, incorporating the different values of the high, mid, and low natural gas and CO₂ tax futures, were used to model future production costs and to calculate expected net present value revenue requirements (“NPVRR”) of resource plans.

The “Build Gen” node represents a central generation location in Eversource’s system (Metro Generation Hub) and is used to represent the siting of generic resource additions, other than wind. Price series across the nine endpoints show that the highest prices over the 20-year horizon are seen in the high natural gas price, high CO₂ tax market price series. The high natural gas price with mid CO₂ tax is the second highest. The high natural gas price with low (no) CO₂ tax is the third highest until the last few years of the planning horizon when it is exceeded by the mid natural gas price, high CO₂ tax scenario, and equals the low natural gas, high CO₂ tax scenario in 2045. The rest of the price series from highest to lowest are mid natural gas with mid CO₂ tax, low natural gas with mid CO₂ tax, mid natural gas with low CO₂ tax, low natural gas with mid CO₂ tax, low natural gas with low CO₂ tax.

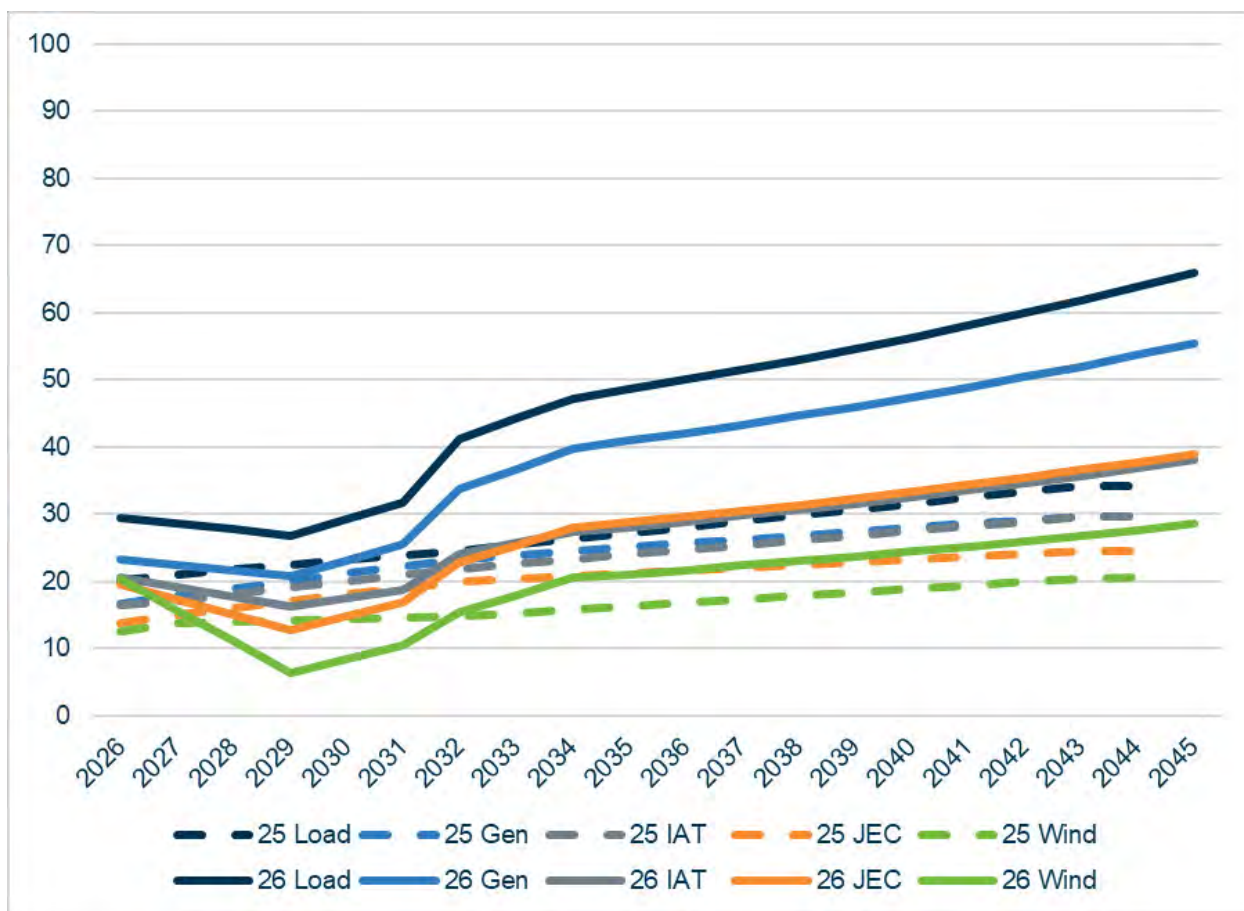
³² See Carbon Tax Workpaper. Taxes were incorporated into future prices based on expectations of the percentage of hours emitting resources are on the margin to set price.

Figure 15: Build Gen Node Market Prices (\$/MWh)



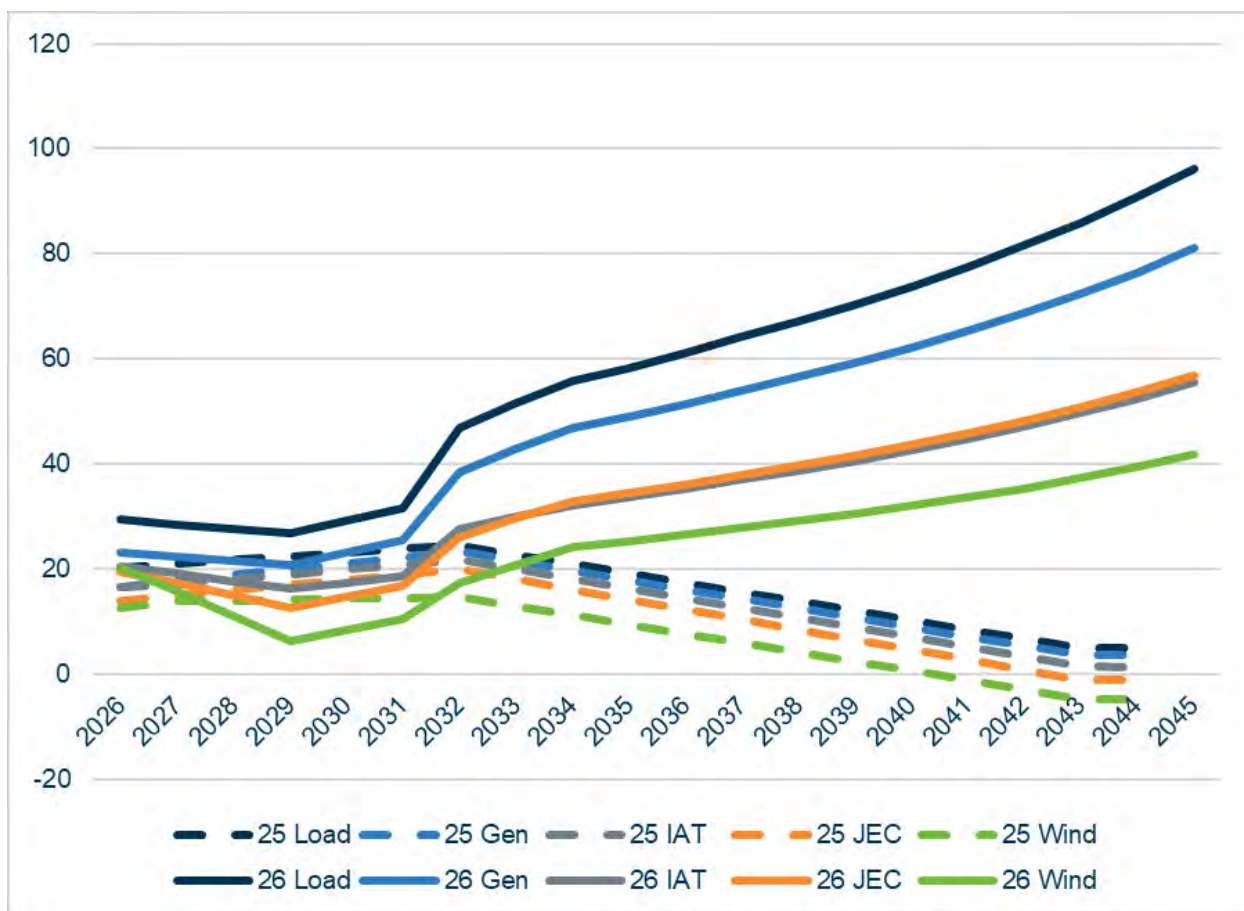
Compared to prices in the 2025 IRP, the 2026 IRP prices are higher in most years for the mid natural gas with mid CO₂ tax price series. For the Missouri West load and generation nodes, 2026 IRP prices are higher throughout the time horizon. For the coal and wind nodes, prices are lower in 2027-2031 before climbing higher for the rest of the planning period.

Figure 16: 2026 IRP vs. 2025 IRP Mid NG Mid CO₂ Market Prices (\$/MWh)



For the mid natural gas high CO₂ tax price series, the increase in prices between the 2026 and 2025 IRPs is more substantial. The 2025 IRP scenario for high CO₂ policy used a high-renewables resource mix and redispatch to achieve carbon reductions. High renewable investment drives a high fixed cost, low variable cost system, with low production costs and market prices. Prices in the 2025 IRP declined over time. Updated assumptions for the 2026 IRP no longer use this future resource mix, and implement carbon policy through a tax on emissions, which raises prices.

Figure 17: 2026 IRP vs. 2025 IRP Mid NG High CO₂ Market Prices (\$/MWh)



4.3.1 Other Emissions Costs or Restrictions

Energy does not expect to incur costs for emissions allowances for sulfur dioxide (“SO₂”) and NO_x, and does not expect future restrictions to be limiting on operations.

4.4 Market Dependence

Energy 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 Energy supply and demand (including Energy Metro, Missouri West, and Kansas Central) are well-matched in SPP. Historically, Missouri West has been a net buyer.

With high load growth expected over the next few years, planned retirements, and expiration of wind PPA contracts, Eversource does not expect other utilities in SPP to build generation to serve the needs of Eversource customers. In addition to meeting SPP RARs, Eversource 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. Beginning in 2030, market purchases and sales are limited to 200 MW per hour.

Allowing market purchases does not mean that a utility (e.g., Missouri West) is physically incapable of meeting 100% of customer energy needs. RARs 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 RARs, but also because it is the lowest-cost way to produce energy which aligns closely with the utility's customers' hourly energy needs. On the market sale side, it also means that an optimal plan will not be developed solely because of the revenues it could generate from selling energy in excess of customer needs. In short, this constraint ensures that a resource plan is developed based on specific customer energy needs and not just forecasted energy market prices.

Section 5: Resource Adequacy Requirements Update

SPP requires all Load Responsible Entities (“LREs”) to maintain sufficient accredited capacity to meet both summer and winter RARs. These requirements are established by combining each LRE’s forecasted seasonal peak load with the applicable Planning Reserve Margin (“PRM”), which is informed by SPP’s biennial LOLE studies. As SPP transitions to performance-based and effective load carrying capability-based accreditation methodologies, Evergy continues to update its planning assumptions to reflect the evolving accreditation rules, PRM levels, and expected resource performance.

5.1 Winter Resource Adequacy Requirement

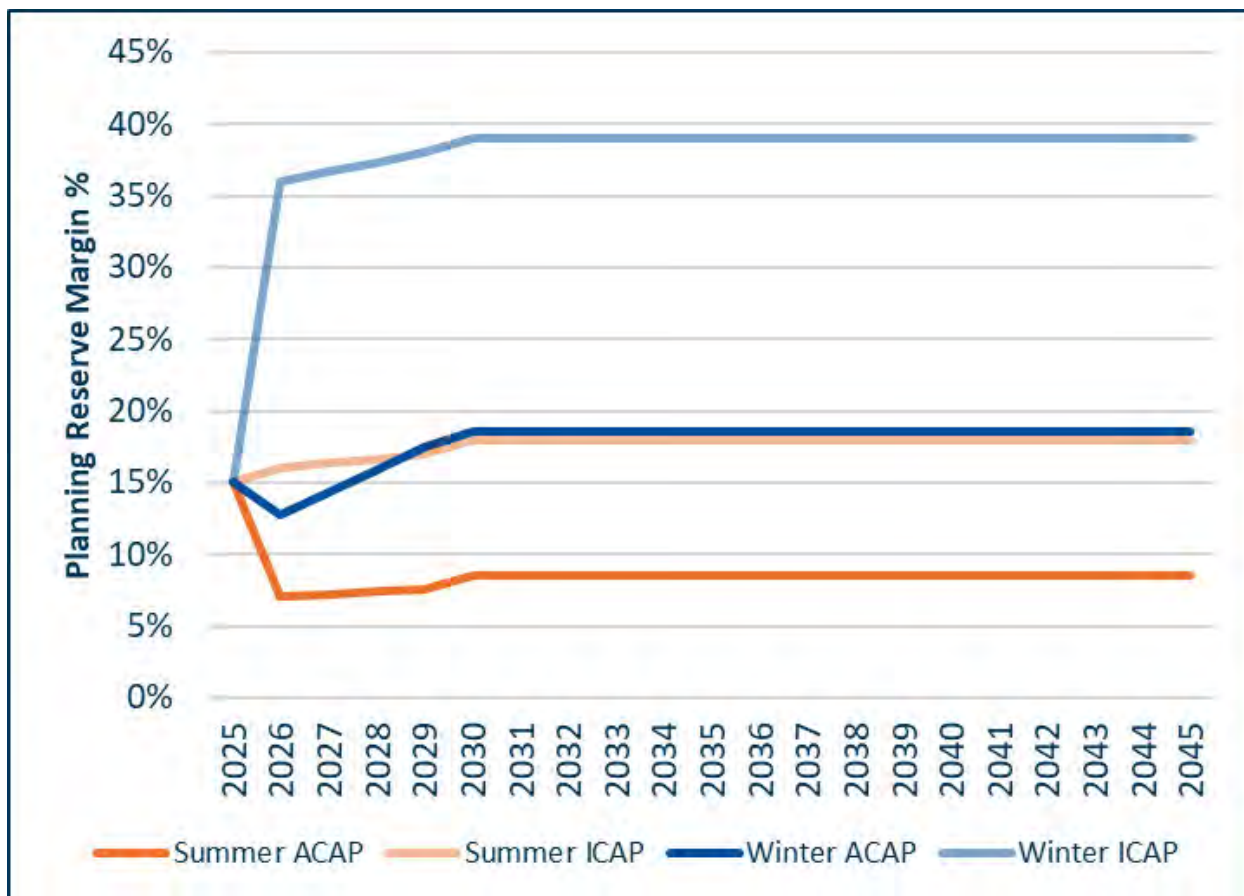
SPP implemented a Winter RAR beginning with the 2025–26 winter season, applying a structure parallel to the summer requirement but reflecting winter-specific risks, outage patterns, and accreditation values. LREs must demonstrate sufficient accredited winter capacity and are subject to deficiency payments if requirements are not met. While the initial winter PRM began at 15%, SPP’s recent LOLE analyses indicate that larger winter reserve margins will be needed in future years due to increased cold-weather outage, winter peak load variability, and planned outage overlaps. Evergy’s IRP modeling reflects these expanding winter needs and ensures the portfolio maintains adequate accredited capacity in both seasons.

5.2 LOLE Study Results and Reserve Margin Expectations

Recent LOLE study results show that SPP’s historical reserve margin levels will not meet future reliability needs without adjustments. Planning years beginning in 2026 require higher summer and significantly higher winter PRMs due to cold-weather correlated outages, changes in the regional resource mix, increased load growth, and the shifting seasonal balance of LOLE events toward winter conditions. Evergy’s IRP incorporates these emerging requirements by adopting higher assumed reserve margins for both summer and winter across the planning horizon. Summer PRMs are modeled to gradually increase, while winter PRMs are modeled to rise sharply beginning in 2026 and remain elevated thereafter, ensuring resource portfolios remain resilient to future LOLE-driven reserve margin requirements. Figure 18 details the IRP assumption for PRM over the next

20 years and the difference between installed capacity based (“ICAP”) PRM and accredited capacity based (“ACAP”) PRM.

Figure 18: 2026 IRP Planning Reserve Margin Assumptions



5.3 Performance-Based Accreditation

SPP’s Performance-Based Accreditation (“PBA”) methodology replaces historic test-based thermal capacity accreditation with performance-driven measures tied to seasonal forced outage behavior. Under PBA, a resource’s accredited capacity reflects its availability during peak-risk hours, based on multi-year seasonal forced outage rates and other performance indicators. As SPP transitions toward PBA beginning in summer 2026, Evergy incorporates these changes into its IRP by applying updated accreditation assumptions for all thermal resources. Winter accreditation also includes a forced outage factor (“EFOF”) representing cold-weather and fuel-assurance risks, consistent with the

methodology applied beginning in Eversource's 2025 Annual Update and continued in the 2026 Annual Update with updated data.

5.4 Effective Load Carrying Capability

SPP is implementing Effective Load Carrying Capability ("ELCC") for wind, solar, and storage resources as part of its unified accreditation framework. ELCC quantifies a resource's contribution to meeting load by accounting for variability, duration limitations, and availability constraints. Beginning in summer 2026, renewable and storage resources' accredited capacity will be determined through ELCC, while thermal resources will be accredited through PBA. Eversource applies expected ELCC values in its IRP to reflect the evolving contribution of renewable and battery resources to meet resource adequacy obligations under SPP's accreditation approach.

5.5 Accredited Capacity Reserve Margin

With the implementation of PBA and ELCC, SPP is transitioning from an ICAP PRM to an ACAP PRM. Under this approach, the reserve margin represents the amount of accredited capacity—already adjusted for ELCC and PBA—needed to satisfy RARs. Eversource adopted ACAP-based planning beginning in summer 2026 in the 2025 IRP and continues applying it in the 2026 IRP to ensure alignment with SPP's accreditation transition.

5.6 Demand Response Accreditation

Demand response resources are currently credited against load based on their tested performance, but SPP stakeholders are evaluating whether future accreditation should account for availability constraints such as event frequency, duration, and seasonal limitations. To avoid overstating the resource adequacy contribution of these resources and to prepare for potential future policy changes, Eversource's 2026 Annual Update continues to assume that demand response receives accredited capacity equal only to its expected tested capability rather than receiving credit as a full net reduction to load. This conservative approach ensures that Eversource's resource plans remain robust and appropriately reflect the evolving accreditation landscape for demand-side resources.

Section 6: Supply-Side Resource Options

Combined cycle (“CC”) and combustion turbine (“CT”) installed costs and resource characteristics were updated for the 2026 Annual Update based on recent Evergy development experience. Updates were made to battery, wind, and solar resource costs based on Evergy’s 2025 RFP and updated EIA and National Renewable Energy Laboratory (“NREL”) future resource cost forecasts. Additionally, two thermal options for RICE were added using developer information from the 2025 RFP. PTCs were updated based on recent published guidance. Resource availability was also updated based on expected lead time.

Table 5: Primary Resource Options **Confidential**

Evergy continues to consider construction costs a CUF in resource planning. Evergy modeled installed cost increases by 25% for the high construction cost scenarios, and cost decreases by 25% for the low construction cost scenarios. Installed costs in Table 5 include estimated interconnection costs.

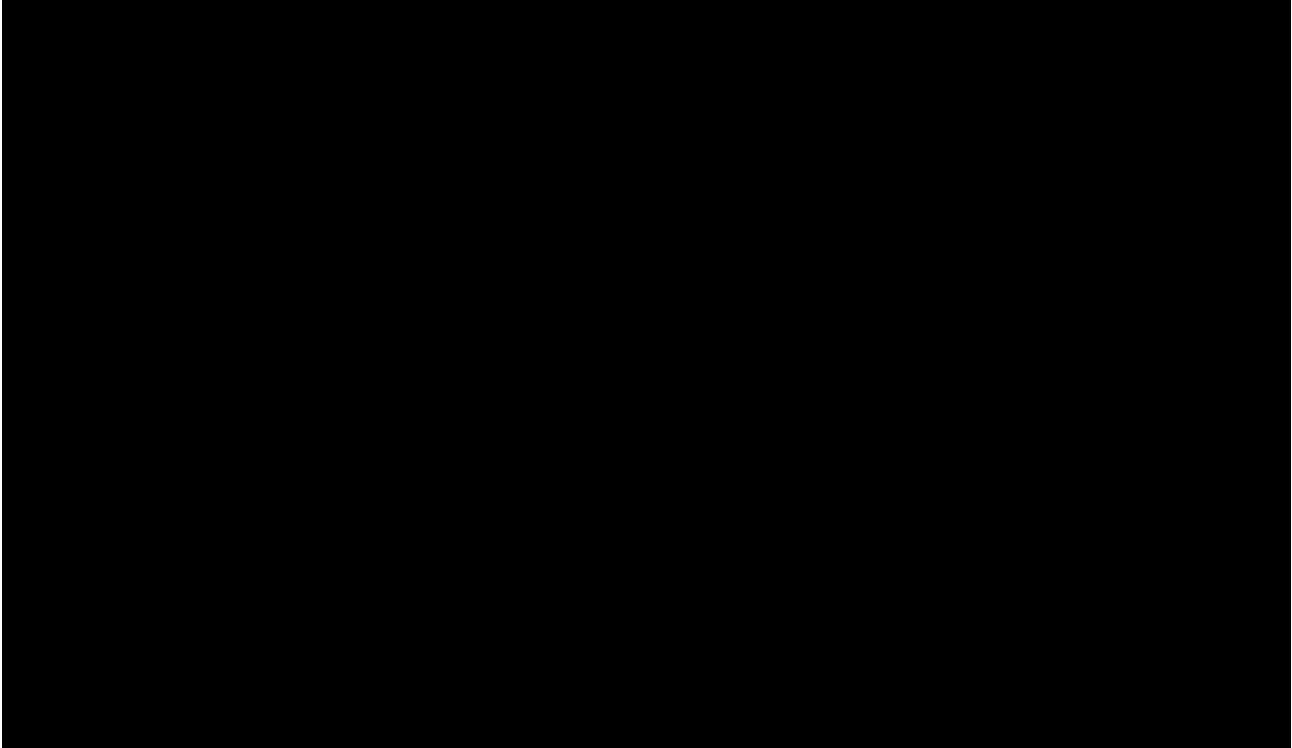
Table 6: Primary Resource Costs in First Year of Operation **Confidential**

Table 7: New Resource Emissions Rates (lb/MWh)

Resource Type	NO _x	SO ₂	CO ₂
Solar	-	-	-
Wind	-	-	-
Battery	-	-	-
Reciprocating Internal Combustion Engine	0.032	0.008	927.9
Combustion Turbine	0.045	0.009	1,064
Combined Cycle	0.026	0.006	754
Half Combined Cycle	0.026	0.006	754

6.1 Renewable and Storage Resources

Renewable and storage resource costs and characteristics have been updated to reflect Evergy’s 2025 RFP. Resource costs have increased compared to Evergy’s 2023 RFP (which helped inform resource costs for the prior two IRPs), as depicted in the next graph. Changes to federal policy have materially changed the economics of renewable and storage resources. Cost increases in the 2026 Annual Update reflect both current marketplace pricing and updated future resource cost forecasts. Cost estimates from Evergy’s 2025 RFP responses reflect marketplace offers made after the passage of the OBBBA. Consistent with prior IRPs, future year cost incorporate inflation and updated resource cost forecasts from the EIA and NREL.

Figure 19: Annual Renewable and Storage Build Costs (\$/kW) **Confidential**

Battery costs depicted above exclude ITCs.

6.2 Tax Incentives

The OBBBA substantially accelerated the phase-out of PTC and ITC eligibility for wind and solar facilities. Under the new law, wind and solar facilities that begin construction on or before July 4, 2026, remain eligible for the full credit and are not subject to the accelerated placed-in-service deadline, provided they satisfy the continuity safe harbor by being placed in service within four calendar years of when construction began. For the 2026 Annual Update, Evergy assumes that the 150 MW solar resource planned for 2028 will qualify for 100% PTC. Evergy's development team has taken steps to establish beginning of construction for this project consistent with the Physical Work Test IRS requirements. The PTC value used in the IRP is based on the most recent IRS annual inflation adjustment. Wind and solar resources planned for operation in 2030 and beyond are not assumed to receive PTC or ITC, as they would not meet the beginning of construction deadline under current law.

Battery energy storage systems are eligible for the clean electricity ITC under Section 48E. Unlike wind and solar, storage resources were not subject to the OBBBA's accelerated phase-out. Storage facilities that begin construction before 2034 remain eligible for the full ITC. The credit phases down to 75% for facilities beginning construction in 2034, 50% in 2035, and is eliminated for projects beginning construction in 2036 or later. Eversource assumes that the 150 MW battery storage resource planned for 2030 will qualify for a 40% ITC, reflecting the base 30% credit plus a 10% bonus for either domestic content or location in an energy community, consistent with IRA provisions. The ITC benefit is received upfront in the first year of operation.

The combined effect of the OBBBA's accelerated PTC phase-out for wind and solar, the tightened beginning of construction requirements, and the new FEOC restrictions has materially changed the economics of renewable and storage resource additions compared to prior IRPs. The loss of PTC eligibility for wind and solar resources beginning operation after 2029–2030 increases the expected levelized cost of these resources by the value of the forgone credits. This change is a driver of the reduction in renewable resource selections in the 2026 Preferred Plan relative to the 2025 Preferred Plan, as discussed in Section 1.3.

6.3 New Renewable and Battery ELCC

Eversource 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. 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.). Eversource's assumptions are based on SPP studies which estimate the relationship between increasing amounts of resources and ELCC value.

Evergy has updated ELCC assumptions from the 2025 Annual Update using reported data from SPP’s 2024 ELCC Study and 2025 LOLE Study. In addition to these studies, Evergy tweaked its previous degradation curves that were based on SPP’s 2022 ELCC Study. This tweak lessened the overall degradation of renewable and storage resources to coincide with more recent market and policy dynamics surrounding the preference for thermal resources to meet the level of load growth seen across the nation (refer to Section 2.3 for more context).

The differences from the 2026 Annual Update and the prior two IRPs, for both summer and winter ELCC, are depicted in the next couple of graphs. Overall, both new renewable and storage resources have better accreditation in the winter compared to previous ELCC degradation curves. In terms of summer accreditation, both new solar and battery resources are seeing worse accreditation in the early years, while the later years are showing more favorable ELCCs.

Figure 20: Renewable and Storage New Build ELCC (Summer)

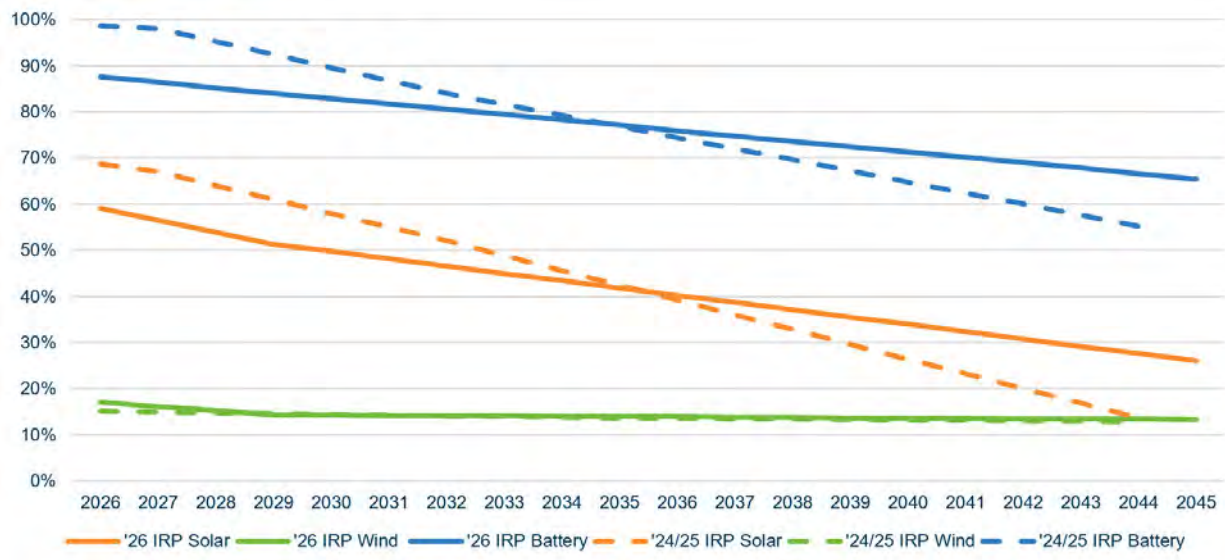
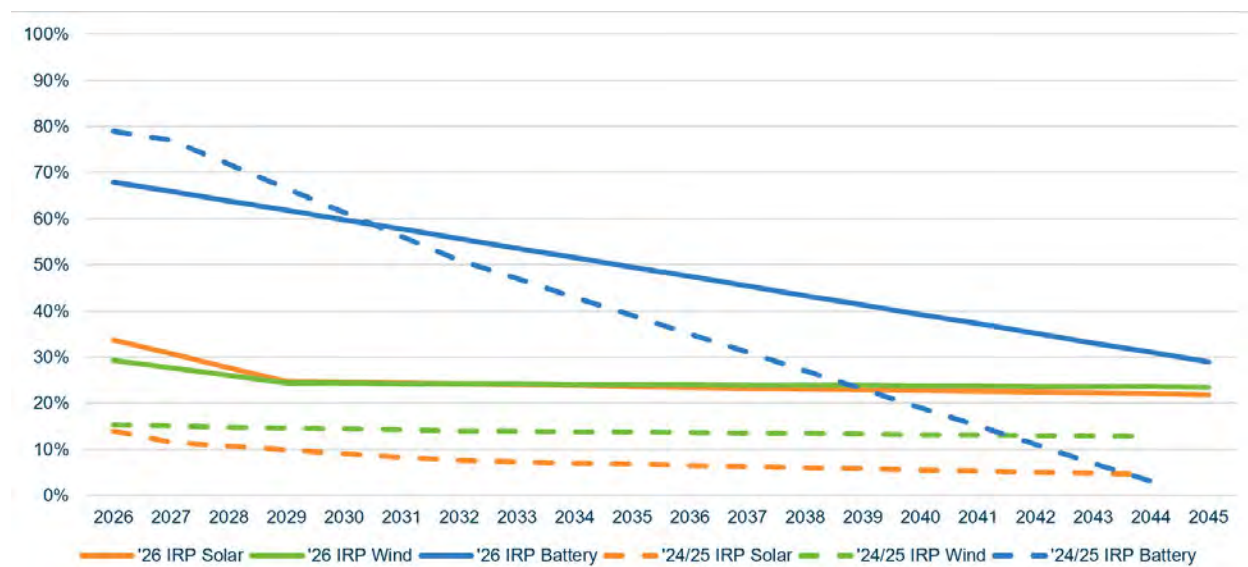


Figure 21: Renewable and Storage New Build ELCC (Winter)



6.4 Thermal Resources

6.4.1 Cost and Availability

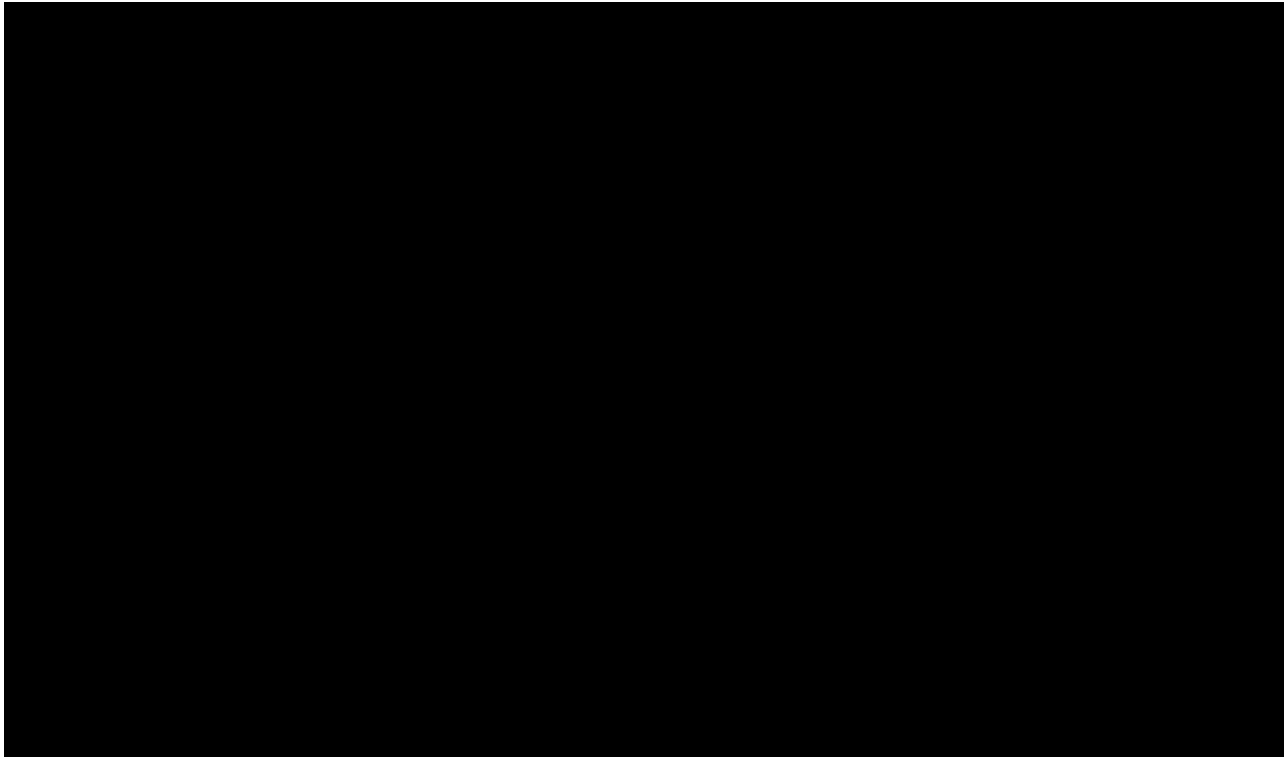
The need for firm dispatchable generation beginning in the late 2020’s to early 2030’s was identified in prior IRPs. Evergy expects to self-develop the majority of these resources, while also evaluating thermal offers from the 2025 RFP. Cost estimates were based on both recent development experience surrounding the approved natural gas CCN resources and manufacturer information from the 2025 RFP.

Evergy’s development team has taken steps to execute on the resource plan and has received updated cost estimates from suppliers. Cost estimates have risen significantly from the 2025 Annual Update. This is partly attributable to broad inflation in the economy, but also likely the result of the strong supply and demand forces for natural gas-fired generation. Utilities across the US are forecasting unprecedented load growth from economic development, datacenters, and other large-load customers. Many utilities have announced intentions to build new natural gas projects to meet their growing needs.

2029 and 2030 thermal costs reflect the approved natural gas CCN resource costs. Costs for future years were estimated by scaling cost estimates for 2031 and 2032 self-

developed combined cycle and combustion turbine projects by inflation and the average of the NREL and EIA technology curves. Inflation exceeds technological innovation, resulting in higher nominal costs each year.

Figure 22: Thermal Installed Costs (\$/kW) **Confidential**



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

6.4.2 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.

6.5 Market Capacity

Evergy has been actively pursuing market capacity purchases to meet short term reliability needs prior to thermal resource construction. This near-term bridge strategy is

necessary due to the lead time required to develop new generation resources. The Company recognizes that market capacity availability beyond current commitments is uncertain and has limited its reliance to conservative levels. 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 RARs, including raising reserve margins, reducing capacity accreditation, and imposing penalties for failing to meet winter requirements, Evergy expects market capacity to be higher-priced and scarce relative to recent history of market capacity in SPP. 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.

Section 7: Environmental Regulation Update

7.1 Air Emission Impacts

7.1.1 Particulate Matter National Ambient Air Quality Standards

In March 2024, the EPA published in the Federal Register a final rule which strengthens the primary annual particulate matter less than 2.5 microns in diameter (“PM_{2.5}”) National Ambient Air Quality Standard (“NAAQS”). The EPA lowered the primary annual PM_{2.5} NAAQS from 12.0 µg/m³ (micrograms per cubic meter) to 9.0 µg/m³. The final rule took effect in May 2024. In March 2024, a coalition of 24 states, including Kansas and Missouri, filed a challenge to the final 2024 PM_{2.5} NAAQS regulation, claiming the final rule exceeded EPA’s statutory authority by failing to conduct a full analysis before revising the NAAQS. In February 2025, with the change in presidential administrations, the D.C. Circuit Court agreed to hold in abeyance all challenges to this final rule pending EPA’s reconsideration of the final 2024 PM_{2.5} NAAQS. In November 2025, EPA filed a motion requesting that the DC Circuit Court vacate the 2024 PM_{2.5} NAAQS, asserting that the Biden Administration’s EPA failed to consider costs during its revision process and therefore did not conduct a thorough review, as required.

Depending on the outcome of these court challenges, future non-attainment designation for this revised standard could require additional emission reduction technologies on existing fossil-fueled units.

7.1.2 Cross-State Air Pollution Rule

Ozone Interstate Transport State Implementation Plans (“ITSIP”)

In 2015, the EPA lowered the Ozone 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 19 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. As described below, in January 2026, EPA proposed to re-evaluate and approve previously disapproved ITSIP submissions for five states including Kansas.

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 26 states including Missouri and Oklahoma. This ITFIP would establish a revised Cross-State Air Pollution Rule (“CSAPR”) ozone season NO_x emissions trading program for electric generating units (“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 Missouri West provided formal comments as part of the rulemaking process. In March 2023, the EPA issued the final ITFIPs for 23 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 CAA 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. 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). In March 2025, EPA announced that they plan to eliminate the requirements of the ITFIP. EPA has not provided details regarding how they plan to rescind the applicable ITFIP. Regardless, EPA never finalized the ITFIP for Kansas. Missouri submitted a supplemental ITSIP to EPA. In January 2026, EPA published in the Federal Register, a proposed "Phase 1" reconsideration rule addressing interstate transport requirements for six states including Kansas. EPA indicated they intend to address additional states, including Missouri in a separate action. The Phase 1 proposal would reevaluate and approve previously disapproved ITSIP submissions for five states including Kansas; thus, Kansas would no longer be subject to the ITFIP if this rule is finalized.

Eversource Missouri West 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, particulate matter ("PM"), or SO₂ standards could result in additional CSAPR updates requiring additional procurement of allowances, emission reduction technologies or reduced generation on fossil-fueled units.

7.1.3 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. In December 2025, EPA issued a final rule extending the SIP revision deadline for the third ten-year implementation period to from July 2028 to July 2031.

The Missouri SIP revision does not require any additional reductions from the Eversource 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 Eversource Missouri West 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. In January 2026, KDHE submitted a supplemental Kansas SIP revision to EPA for approval. The supplement includes a KDHE analysis for two Kansas emissions sources, one of which is Eversource's La Cygne Generating Station, demonstrating both emission sources do not require additional emission reductions. If EPA approves this supplement, no emission reductions will be required for any Kansas emissions sources, including Eversource Missouri West sources, during the second ten-year implementation period.

7.1.4 Greenhouse Gases

In April 2024, EPA finalized the GHG regulations and guidelines that apply to new and existing fossil fuel fired EGUs.

In June 2025, EPA published in the Federal Register a proposed rule to repeal and/or revise the GHG regulation and guidelines. EPA is proposing both a primary and alternative proposal. The primary proposal would repeal all GHG emission standards for the power sector promulgated in both 2015 and 2024. The alternative proposal would repeal specific portions of the 2024 final rule based on revised best system of emission reduction ("BSER") determinations for existing coal-fired units and new combustion turbines. EPA is proposing to repeal the requirement to add carbon capture and sequestration ("CCS") to existing coal-fired units retiring on or after January 1, 2039, and new combustion turbines units. EPA is also proposing to repeal the requirement to conduct natural gas co-firing for existing coal-fired units retiring between 2032 and 2039. This proposal would eliminate all GHG requirements for existing coal-fired units.

In July 2025, EPA proposed a repeal of the GHG 2009 endangerment finding as well as GHG emission standards for motor vehicles. Specifically, EPA proposed to repeal all GHG emissions standards for motor vehicles and repeal the Endangerment finding because EPA had no authority to establish GHG emissions standards. The previous EPA unreasonably analyzed the scientific record and failed to determine that GHG reduction technology poses greater harm to public health and welfare.

Eversource Missouri West awaits EPA's finalization of these regulations to determine the full impact on our operations.

7.1.5 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 lowered the emission limit for PM and required the use of PM continuous emissions monitors ("CEMs") for coal-fired units.

In February 2026, EPA issued a final regulation repealing the April 2024 regulation. This repeal eliminated the proposed reduction in the PM limitation and the requirement for PM CEMs on all coal units. In March 2026, a coalition comprising environmental organizations, states, and cities petitioned the DC Circuit Court to review and challenge the EPA's final rule.

7.2 Water Emission Impacts

7.2.1 Effluent Limitation Guidelines

The Eversource Companies discharge some of the water used in generation and other operations containing substances deemed to be pollutants. In April 2024 and December 2025, the EPA finalized updates to the Effluent Limitation Guidelines ("ELGs") for steam electric power generating facilities to address the vacated limitations, deadlines, 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 2034. The Eversource Companies have reviewed the modifications to limitations on FGD wastewater and bottom ash transport water and the Eversource Companies do not believe the impact to be material. The Eversource 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 and regulatory review by EPA is ongoing that could impact the timing or cost to comply.

7.2.2 Clean Water Act Section 316(A)

Eversource'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 Eversource 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.

7.2.3 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.

7.2.4 Zebra Mussel Infestation

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

7.2.5 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.

7.3 Waste Material Impact

7.3.1 Coal Combustion Residuals (“CCRs”)

In the course of operating their coal generation plants, the Evergy Companies produce 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 and February 2026, the EPA finalized an expansion and deadline 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. Additional litigation and announced reconsiderations from EPA could impact the timing or cost to comply.

Section 8: Transmission and Distribution Update

8.1 Changes from the 2025 Annual Update

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

8.1.1 RTO Expansion Planning

Eversource Missouri West assessment of regional transmission organization (“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 Eversource Missouri West staff, and review and approval of final plan reports. All transmission projects identified by SPP for the Eversource Missouri West service territory are included in SPP’s annual Transmission Expansion Plan Report and Project List, posted publicly on SPP’s website. 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 Eversource Missouri West.

8.1.2 Advanced Distribution Technologies

Eversource’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, Eversource 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
- Private Long-Term Evolution (“PLTE”) Cellular

ADMS

Eversource 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:

- Outage Management System (“OMS”)
- FLISR
- Advanced Fault Location Functionality Utilization
- Distribution Supervisory Control and Data Acquisition (“D-SCADA”)
- Distributed Energy Resource Management System (“DERMS”)
- Power Flow Optimization
- Volt/Var Optimization (“VVO”)
- State Estimation

FLISR

Eversource 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. 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 complement 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 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 FLA 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.

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.

CFCI

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

CFCIs are also anticipated to be a cost-effective way to enhance the FLA 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 Eversource service territory.

Reclosers with Communication

Eversource is currently deploying reclosers configured to support FLISR. These devices function like 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

Eversource is working to upgrade as needed our Regulators and Capacitors with communication to support our VVO by enabling control of system voltage. Eversource 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, Eversource is upgrading Load Tap Changers (“LTCs”) as needed to add communications and controls for these devices. They will support VVO. Eversource 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.

PLTE Cellular

Eversource is deploying a PLTE communications network as a foundational element of grid modernization. This dedicated wireless network provides secure broadband connectivity to field devices, substations, and grid automation equipment, enabling faster data transfer, improved situational awareness, and more reliable remote operations.

This reduces reliance on leased public carrier networks and legacy narrowband systems. In addition, PLTE improves cybersecurity posture, network performance, and long-term cost stability.

8.1.3 Advanced Transmission Technologies Discussion

In the Eversource Missouri West area, Eversource 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

Eversource uses end-use load models developed by the North American Electric Reliability Corporation (“NERC”) in association with the US Department of Energy (“DoE”) and EPRI to locate areas within the Eversource Missouri West 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 9: Demand-Side Resource Analysis Update

After the 2024 Triennial IRP filing, EMW filed its proposal for future demand-side programs in its MEEIA Cycle 4 application on April 29, 2024.³³ 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.

EMW's approved MEEIA Cycle 4 programs will deliver a lower capacity accreditation as compared to the realistic achievable potential plus ("RAP+") DSM portfolio that was selected in EMW's 2024 Triennial IRP and subsequently filed in EMW'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. EMW had filed and proposed a 4-year cycle for its 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 EMW's 2024 Triennial IRP.

As a result, EMW modified its 2026 Annual Update IRP DSM planning profile to reflect:

- the lower, approved MEEIA Cycle 4 portfolio (budget, energy, demand and cycle duration)
- 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, EMW 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.

³³ EO-2023-0369/0370

Eversource 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 C). 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, Eversource adjusted the TOU impact downward by 70% (as determined in the potential study for use in its 2024 Triennial IRP), which resulted in only 30% of the study's forecasted impact.

9.1 Changes from the 2025 Annual Update

Eversource'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 with adjustments for demand response impacts to reflect the actual achievements from the recent year.

Eversource 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 in its base case. 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.

Table 8 shows the total energy and demand savings included in EMW's base case.

Table 8: Base Case DSM Impacts – EMW

Year	MWh	MW-Summer	MW-Winter
2027	10,565	128	35
2028	10,517	139	41
2029	10,324	106	35
2030	10,039	107	38
2031	9,508	107	38
2032	8,538	108	39
2033	7,963	108	39
2034	7,889	108	40
2035	7,727	108	40
2036	7,215	108	41
2037	6,500	108	41
2038	6,083	108	41
2039	5,939	108	41
2040	4,984	107	41
2041	2,337	107	40
2042	568	107	40
2043	371	107	40
2044	228	107	40

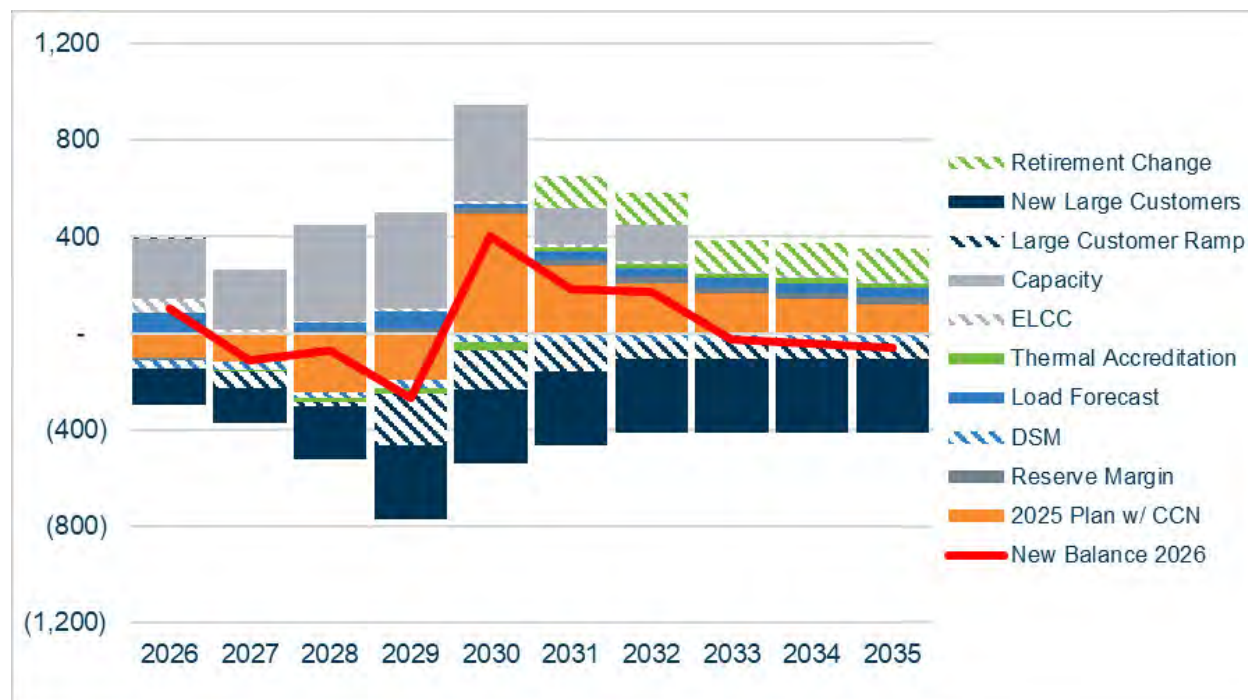
Section 10: Resource Plan Analysis

10.1 Changes to Expected Capacity Needs

Evergy Missouri West’s 2025 Annual Update was filed during the CCN proceedings for five new resources. In summer 2025, Evergy Missouri West received approval for the resources including two solar projects, Foxtrot and Sunflower Sky, totaling 165 MW in 2027, 50% shares of Viola and McNew CCGTs, totaling 710 MW in 2029 and 2030 and Mullin Creek #1 SCGT at 440 MW in 2030.

Evergy Missouri West’s 2025 Preferred Plan showed the need for additional summer capacity, prior to 2030, even with the approved CCN resources. The 2025 Preferred Plan expected to meet summer capacity needs primarily through additional market capacity purchases and a resource addition of 150 MW wind in 2028 (non-CCN capacity is omitted from the capacity balance charts). After the addition of the five CCN resources by 2030, Evergy Missouri West’s summer capacity balance was forecast to be higher than reserve margin needs through 2035. The Preferred Plan included wind and solar additions from 2031-2039 until the next thermal resource was needed in 2040.

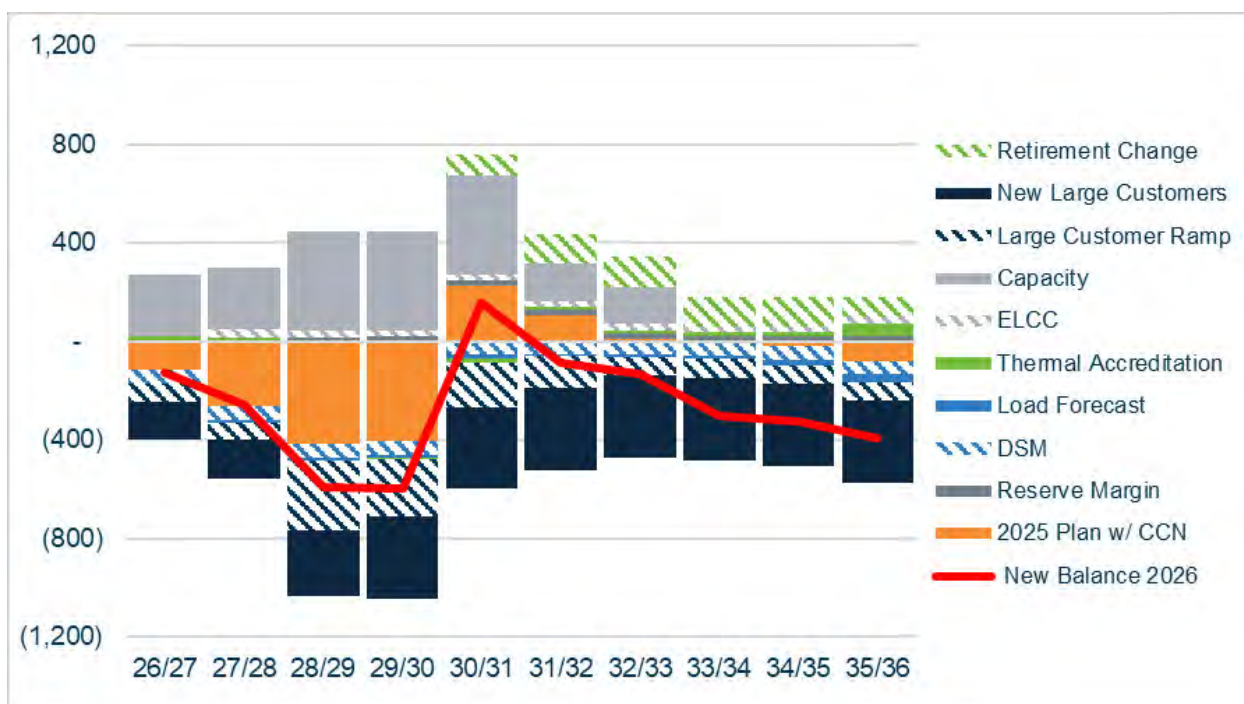
Figure 23: Changes to Evergy Missouri West Summer Capacity Balance



In the past year, Evergy Missouri West has contracted for market capacity to improve its near-term capacity balances. However, for the 2026 Annual Update, capacity needs have increased over the planning horizon primarily due to increases in the load forecast, including increases in expected load for customer projects included in last year’s Preferred Plan, and large load customer projects that are new to the base load forecast.

Evergy Missouri West needs additional summer capacity 2027-2029 with the current resource plan. With thermal additions by 2030, Evergy Missouri West will be in balance in 2030 before going slightly short again in summer 2033 and beyond. The delays of the 2025 Preferred Plan’s Jeffrey 3 retirement from March 2031 to March 2036 and Lake Road 4/6 retirement from December 2030 to March 2038 in the 2026 Preferred Plan provide 131 MW of capacity to offset the load growth needs in that timeframe.

Figure 24: Changes to Evergy Missouri West Winter Capacity Balance



Evergy Missouri West’s 2025 Preferred Plan showed greater needs for winter capacity than summer capacity prior to 2030, even with the approved CCN resources. The market-capacity purchases made prior to the 2026 Annual Update help fill the need identified in

the 2025 Preferred Plan. Eversource Missouri West's winter capacity balance declined slightly due to lower expected winter capacity accreditation for demand response and gained slightly due to higher ELCC for renewables.

The increase in large load forecasts is the most significant change to the winter capacity position from the 2025 Annual Update. Increases in expected load from customers included in the 2025 Annual Update and customers added to the base forecast this year leave Eversource Missouri West with capacity deficits across the planning horizon. Datacenter loads tend to require fairly flat energy consumption across the year and do not peak in summer like Eversource's customer base. Winter reserve margins are greater than summer reserve margins, so the addition of these customers is more impactful to winter needs. The updated forecast for the 2026 Annual Update shows that Eversource Missouri West needs an additional 100 MW in winter 2026/27, rising to almost 600 MW in winter 2028/29. The additions of McNew and Mullin Creek #1 provide a boost in winter 2030/31 before Eversource Missouri West begins to need capacity again in winter 2031/32, rising to 300 MW by winter 2033/34. The planning delay of Jeffrey 3 and Lake Road 4/6 retirements adds 120 MW back to winter capacity in the early 2030s.

10.2 Base Planning Options

10.2.1 Resource Availability

Eversource Missouri West's base planning assumptions consider the availability of viable projects from the RFP and self-development options that can be executed in the near-term window. In future years, the number of project additions is limited each year to ensure the company continues to meet financial metrics and maintain an investment-grade credit rating.

Table 9: Base Build Limit Assumptions

Year	Solar	Wind	Battery	CC	CT	RICE
2027	Foxtrot, Sunflower Sky	n/a	n/a	n/a	n/a	n/a
2028	n/a	n/a	n/a	n/a	n/a	n/a
2029	n/a	n/a	150 MW	Viola	n/a	n/a
2030	150 MW	150 MW	150 MW	McNew	Mullin Creek #1	n/a
2031	150 MW	150 MW	150 MW	710 MW	n/a	373 MW
2032	300 MW	150 MW	300 MW	710 MW	n/a	373 MW
2033+	300 MW	150 MW	300 MW	355 MW	440 MW	373 MW

10.2.2 Retirements

Evergy Missouri West assumes that as 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 2025 Preferred Plan included the retirement of Lake Road 4/6 in December 2030, Jeffrey 3 in March 2031, Jeffrey 1 in March 2040, and Iatan 1 in March 2040. The 2025 Preferred Plan also included Jeffrey 2 converting to natural gas operation in 2030. The 2026 Annual Update tests extending the life of these units with later retirement dates and postponing the natural gas conversion:

- Jeffrey 3 retires March 2036
- Lake Road 4/6 retires March 2038
- Jeffrey 2 converts to NG 2035
- Iatan 1 retires after 2045
- Jeffrey 3 retires after 2045

The 2025 Preferred Plan projected the retirement date for Iatan 2 would be beyond the planning horizon. It is modeled as operating through the whole planning horizon (2026-2045) in all 2026 Annual Update ARPs.

10.3 ARP Testing

Evergy Missouri West 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 with variations in near-term resource build decisions
- Testing plans with different future CUF expectations
- Testing plan variations for meeting the minimum requirements for Missouri Renewable Energy Standards (“RES”)

Table 10: Plan Key for Retirement/Build Options

Load	Retirements	Build Options	Other
A- Base Load	A- 2025 PP Retirement Dates	A- Base	A- Base
	B- Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038	B- No 2032 1/2 CCGT	K- RES Solar Additions
	C- Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035	C- Add 2029 and 2030 Storage	L- RES Wind Additions
	D- Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035, Extend Iatan 1 and Jeffrey 1 Beyond 2045	D- Add 2029 Solar	
		E- Add 2029 Storage	

Table 11: Plan Key for Futures Testing

Load	Retirements	Build Options	Other
A- Base Load	D- Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035, Extend Iatan 1 and Jeffrey 1 Beyond 2045	A- Base	B- High CO ₂ , High NG
			C-Low CO ₂ , Low NG
			D- High CO ₂
			E- Low CO ₂
			G- High Build Cost
			H- Low Build Cost
			I- High NG
			J- Low NG

Table 12: Base Plan Descriptions

Plan Name	Description
AAAA	2025 PP Retirement Dates
ABAA	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038
ACAA	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035
ADAA	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035, Extend Iatan 1 and Jeffrey 1 Beyond 2045
ADBA	No 2032 1/2 CCGT
ADCA	Add 2029 and 2030 Storage
ADDA	Add 2029 Solar
ADEA	Add 2029 Storage
ADAB	High CO ₂ , High NG
ADAC	Low CO ₂ , Low NG
ADAD	High CO ₂
ADAE	Low CO ₂
ADAG	High Build Cost
ADAH	Low Build Cost
ADAI	High NG
ADAJ	Low NG
ADAK	RES Solar Additions
ADAL	RES Wind Additions

The ARPs generated through this process were tested in each endpoint (future with varied CUFs) and rankings were developed based on the probability-weighted average NPVRR, consistent with the 2024 Triennial IRP and the Missouri IRP process.

Table 13: CUF Probabilities

	Natural Gas Price	CO ₂ Emissions Restrictions	Construction Cost
Low	35%	25%	25%
Mid	50%	60%	50%
High	15%	15%	25%

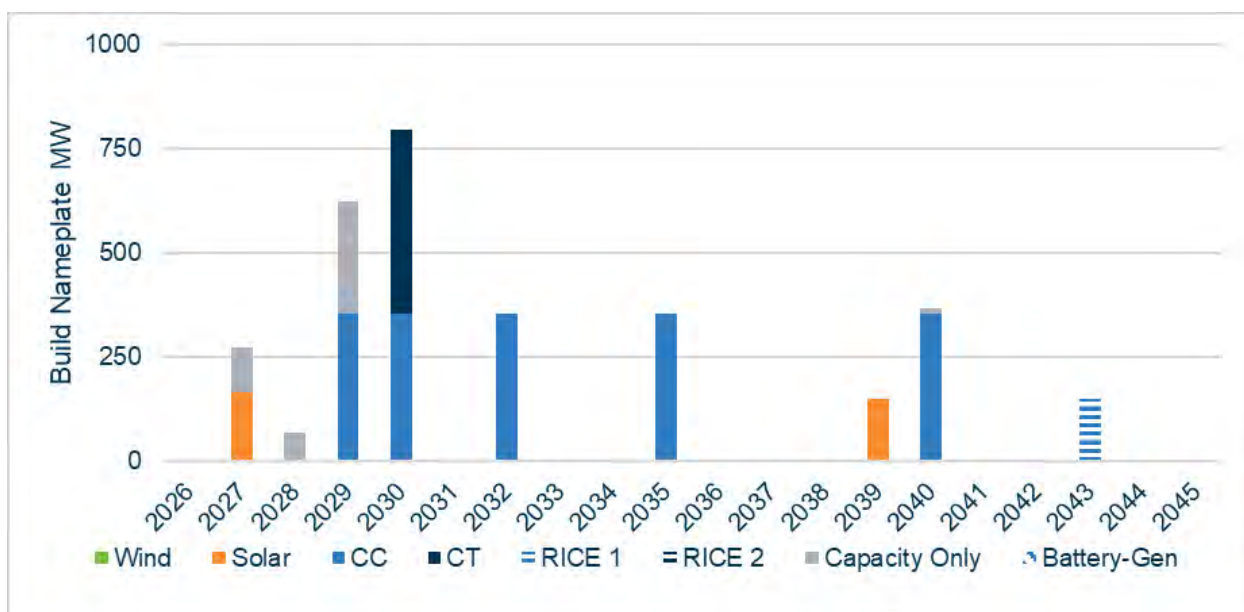
10.4 Plans Testing Retirements

Retirement decisions were tested using capacity expansion and base planning assumptions, including the updated load, demand-side program and resource adequacy forecasts. Resources with CCN are included in all plans. Plan AAAA uses retirement dates identified in the 2025 Annual Update Preferred Plan. Plans ABAA, ACAA and ADAA

use the same base assumptions but vary the retirement dates. Plan ABAA postpones the Jeffrey 3 retirement from March 2031 to March 2036 and Lake Road 4/6 retirement from 2030 to March 2038. Plan ACAA also postpones the Jeffrey 2 conversion to NG from 2030 to 2035. Plan ADAA incorporates the previous date changes and also postpones the latan 1 and Jeffrey 1 retirements from March 2040 to beyond 2045 (the last year in the IRP 20-year window).

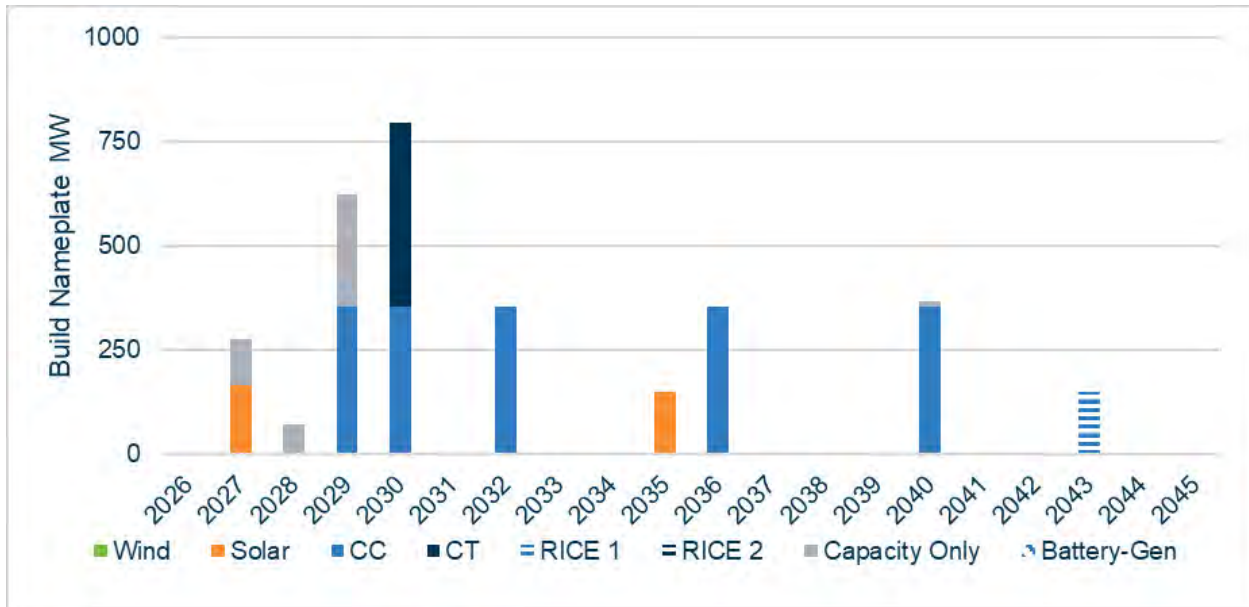
Plan AAAA selects market capacity to meet capacity needs supplementing the CCN resources through 2031. It selects ½ CCGT in 2032, 2035, and 2040, 150 MW of solar in 2039, and a RICE unit in 2043.

Figure 25: Base Planning Assumptions and 2025 PP Retirements Plan AAAA



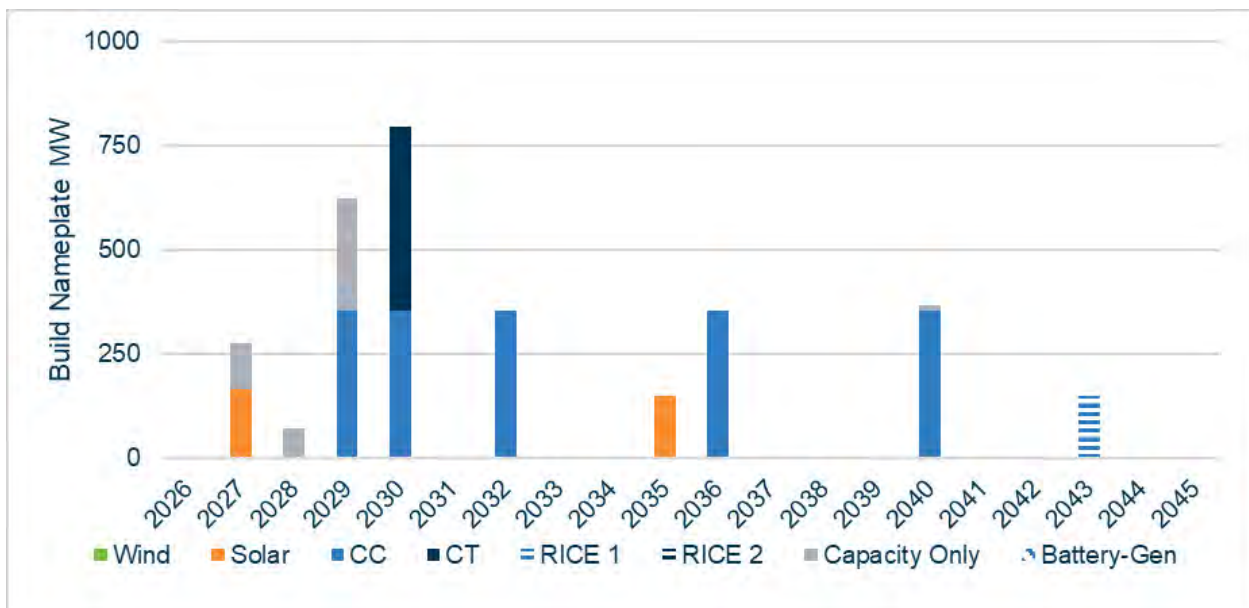
Plan ABAA gains back about 150 MW of capacity between 2031 and 2035 due to the delayed retirements. This causes small changes in the optimal build plan. The ½ CCGT in 2032 remains, the next ½ CCGT is delayed one year to 2036, and the 150 MW of solar moved up to 2035. The plan continues to select ½ CCGT in 2040 and a RICE unit in 2043.

Figure 26: Extend Jeffrey 3, Lake Road 4/6 Plan ABAA



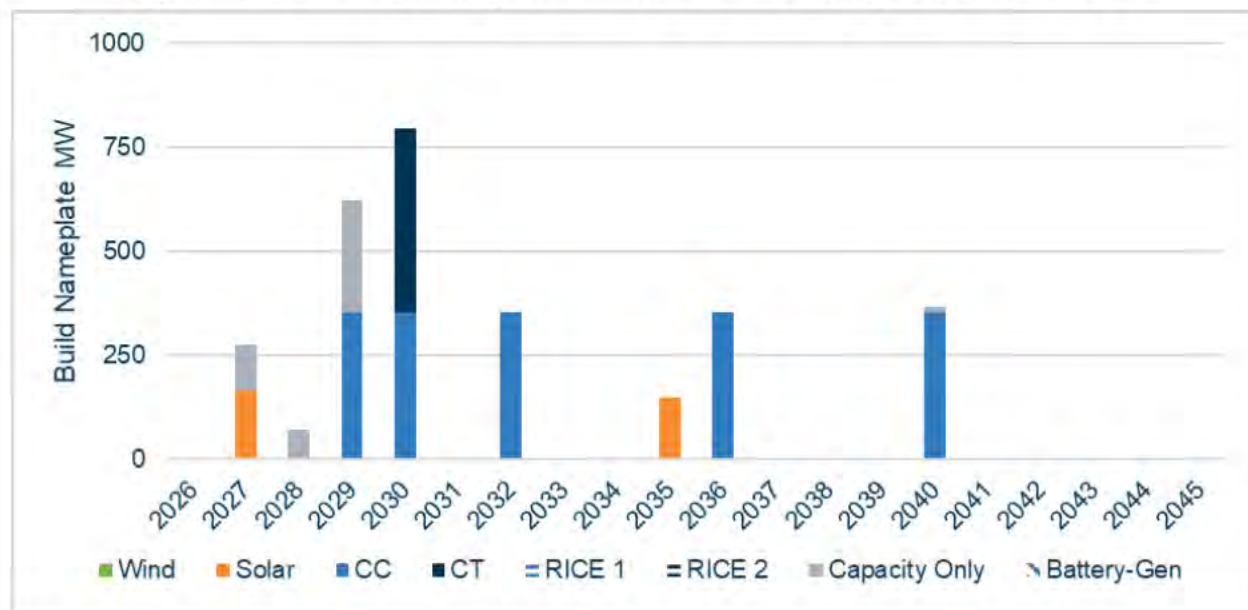
Plan ACAA has the same capacity position as Plan ABAA, but the delayed conversion of Jeffrey 2 to natural gas changes fixed and production costs. The optimal build plan is the same as Plan ABAA.

Figure 27: Extend Jeffrey 3, Lake Road 4/6, Jeffrey 2 NG Plan ACAA



Plan ADAA adds 187 MW to the capacity balance beginning in 2040, as compared to Plans ABAA and ACAA. It has the same optimal build plan as these plans but does not require the RICE unit in 2043.

Figure 28: Extend Jeffrey 3, Lake Road 4/6, Jeffrey 2 NG Plan ADAA



The plan extending all retirement decisions, Plan ADAA, is the least cost plan considered. The 2025 Preferred Plan retirements increase NPVRR by \$128 million, due to the need to replace retiring resources with earlier capacity additions.

Table 14: Coal Retirement Plan Rankings

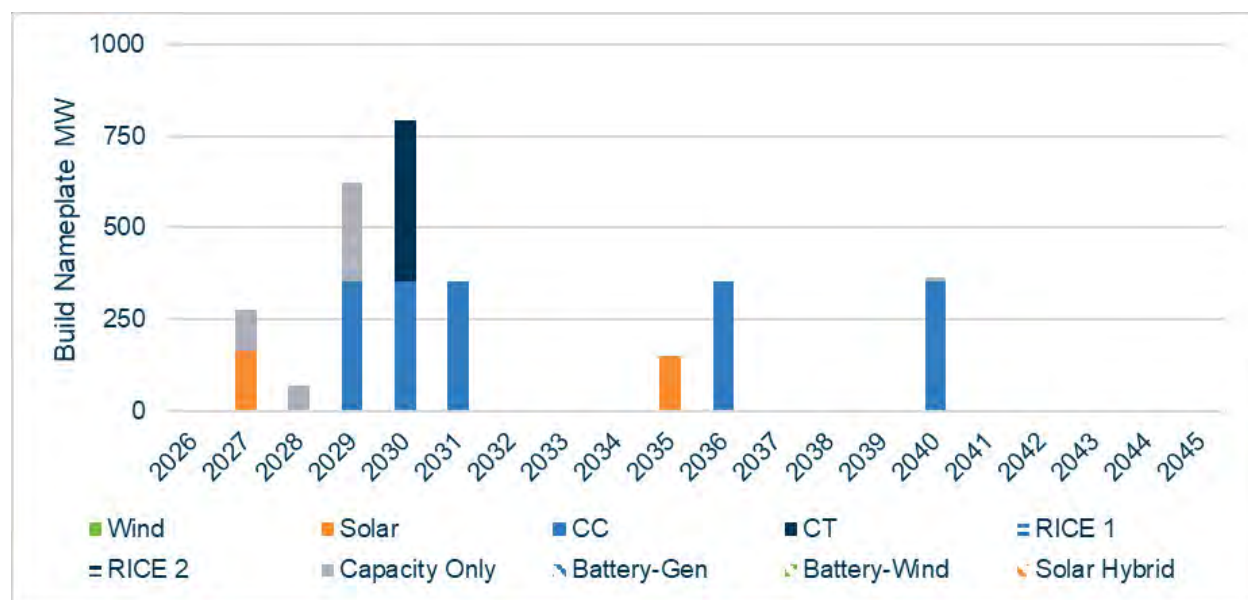
Rank	Plan	NPVRR	Difference	Description
1	ADAA	23,277		Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035, Extend Iatan 1 and Jeffrey 1 Beyond 2045
2	ACAA	23,344	67	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035
3	ABAA	23,383	105	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038
4	AAAA	23,406	128	2025 PP Retirement Dates

10.5 Plans Testing Near-Term Options

All ARPs testing retirement dates did not select any additional builds to supplement the Foxtrot and Sunflower Sky solar resources in 2027, Viola CCGT in 2029, and McNew and Mullin Creek #1 natural gas plants in 2030. All ARPs selected as the first additional resource ½ CCGT in 2032. Plans ADBA, ADCA, ADDA, and ADEA test the tradeoffs of resource plan options in the 2028-2032 horizon. All of these plans include the extended retirement dates.

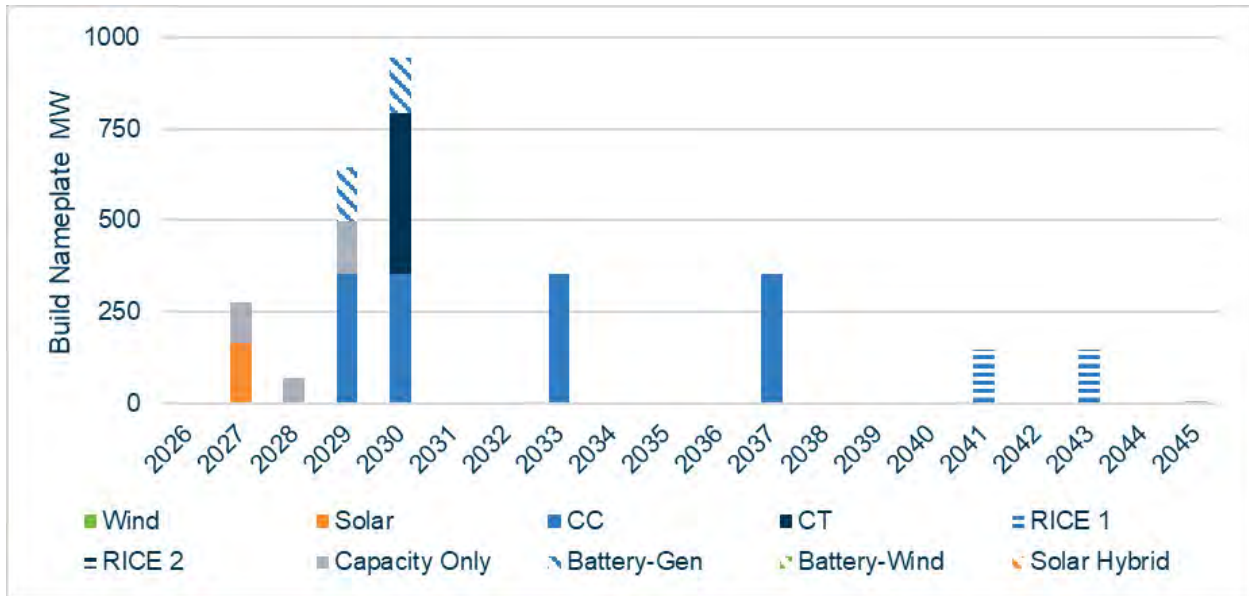
Plan ADBA removes the option for a ½ CCGT in 2032. The ARP selects the same resource in 2031, pulling it forward one year earlier. The rest of the plan is exactly the same as Plan ADAA.

Figure 29: No 2032 ½ CCGT Plan ADBA



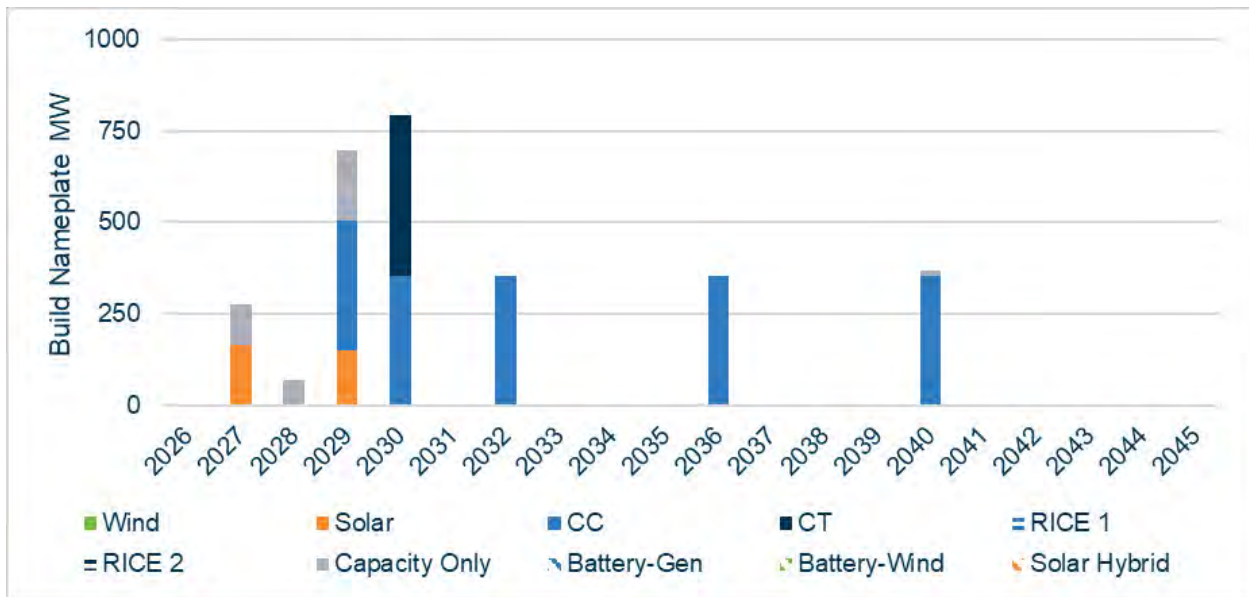
Plan ADCA adds 150 MW of storage each year in 2029 and 2030. The additional storage defers the ½ CCGT from 2032 to 2033. The ARP does not select additional solar (beyond the 2027 projects), and the next ½ CCGT is deferred to 2037. RICE in 2041 and 2043 replace the ½ CCGT in 2040.

Figure 30: Plan Adding 2029 & 2030 Storage ADCA



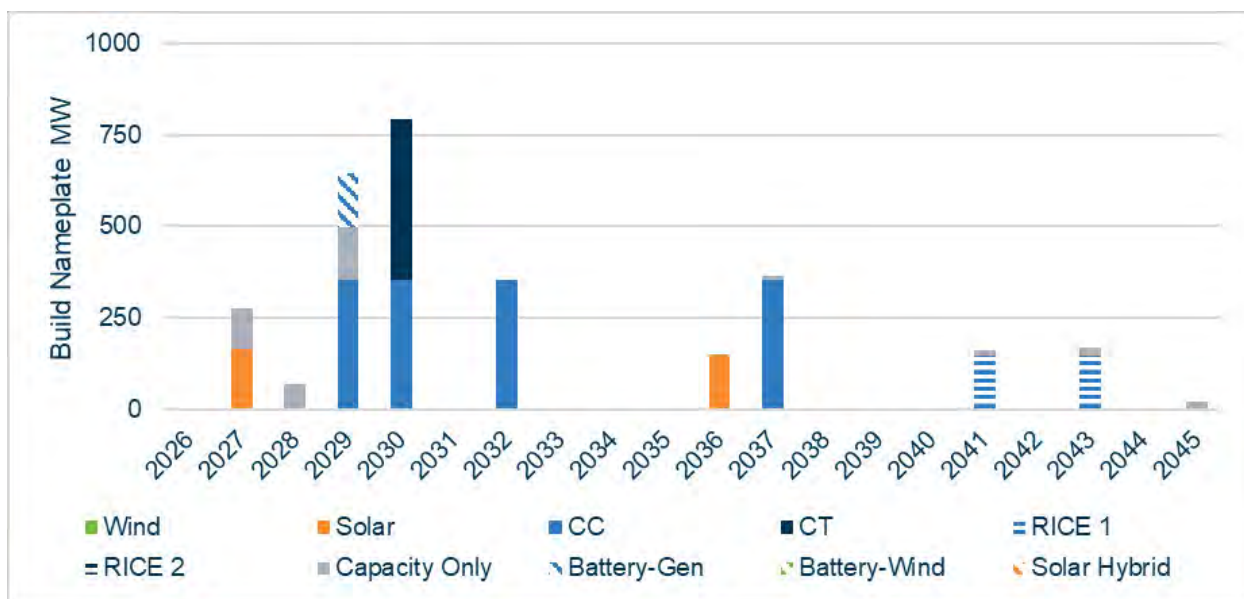
Plan ADDA tests how the resource plan would change with 150 MW of solar added in 2029. Adding a solar resource earlier in the planning horizon eliminates the need for the 2035 solar in Plan ADAA, but the rest of the resource plan is identical.

Figure 31: Plan Adding 2029 Solar ADDA



Plan ADEA tests adding 150 MW of storage in 2029. The ARP continues to select the ½ CCGT in 2032, but defers the next two resources 1 year, selecting 150 MW solar in 2036 and ½ CCGT in 2037. The ARP does not build a ½ CCGT in 2040 and instead builds RICE in 2041 and 2043.

Figure 32: Plan Adding 2029 Storage ADEA



Plan ACBA tested removing the ½ CCGT from 2032 and found that building the ½ CCGT one year earlier was the next best option. That plan is expected to be \$52 million more expensive from an NPVRR perspective.

The addition of 300 MW of storage in 2029 and 2030 in Plan ADCA defers the ½ CCGT need by one year to 2033. However, the NPVRR increases by \$331 million. Adding only 150 MW of storage, does not postpone the ½ CCGT in 2032, but postpones the next additions, and adds \$171 million NPVRR.

Building 150 MW of solar earlier in 2029 eliminates the need for the 2035 solar addition but increases NPVRR by \$73 million.

Table 15: Rankings for Near-Term Build Decisions

Rank	Plan	NPVRR	Difference	Description
1	ADAA	23,277		Base Builds
2	ADBA	23,330	52	No 2032 1/2 CCGT
3	ADDA	23,350	73	Add 2029 Solar
4	ADEA	23,448	171	Add 2029 Storage
5	ADCA	23,608	331	Add 2029 and 2030 Storage

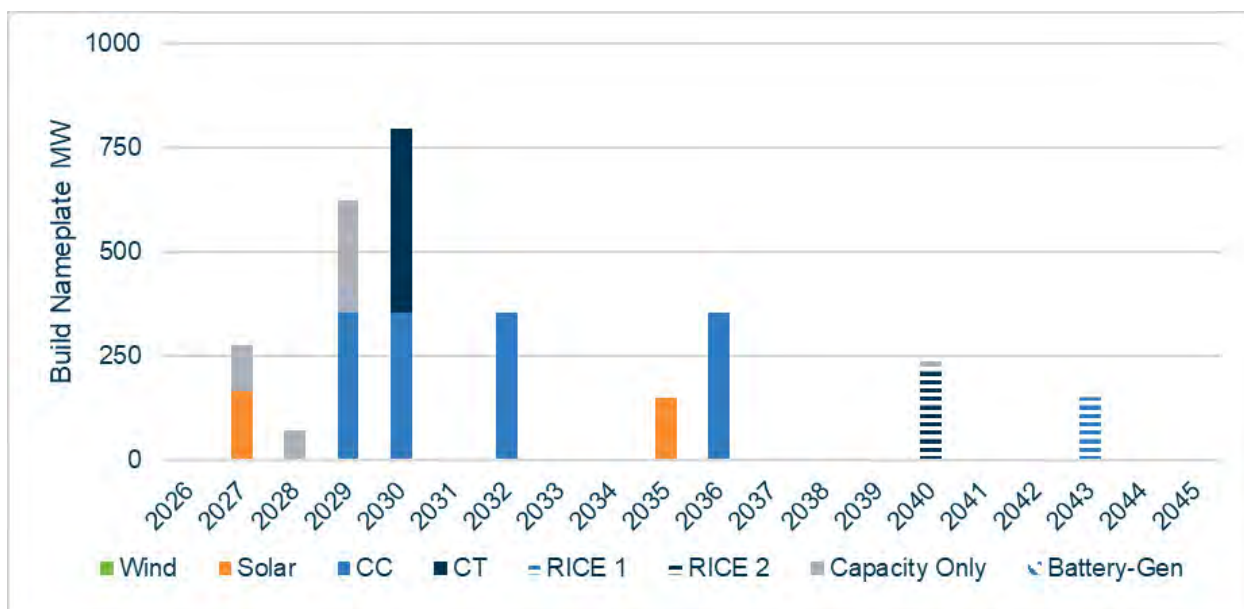
10.6 Plans Testing Optimal Builds for Varying Futures

All ARPs testing retirement dates and early build decisions were based on the optimal build decisions at the “mid” level of each CUF. Additional ARPs were created by varying the CUF level. These plans show the optimal build decisions if future forecasts were expected to be at the “low” or “high” levels.

Capacity expansion plans were developed to test how build decisions would change if the expectation was no future CO₂ regulation/costs in the planning horizon (Low CO₂ scenario), or high CO₂ taxes.

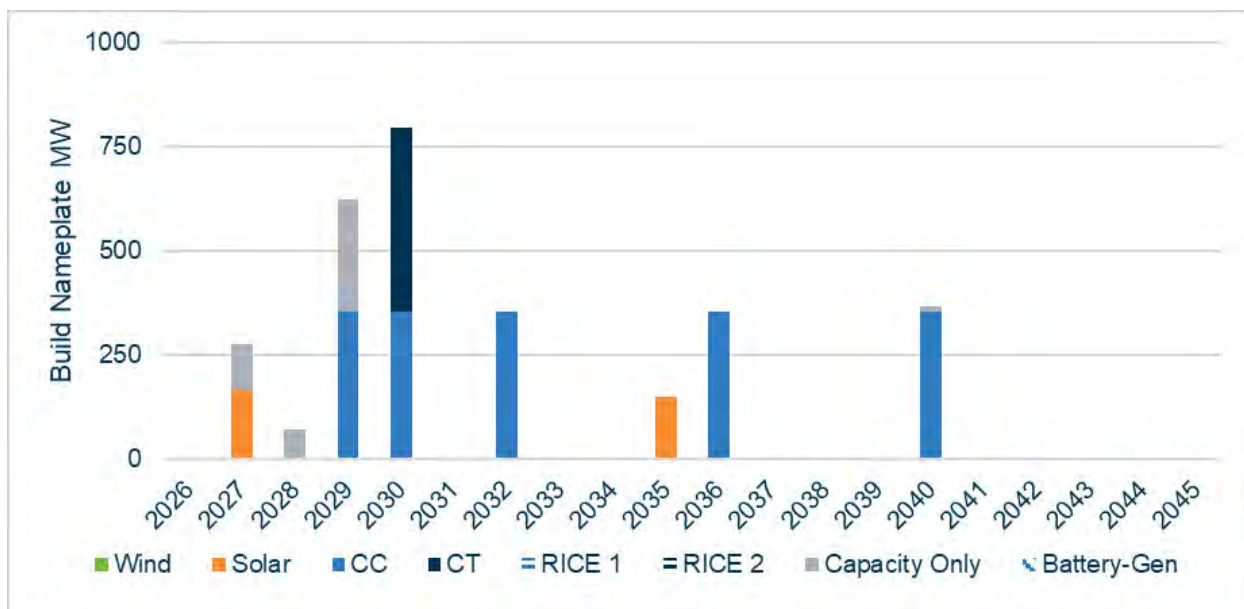
Plan ADAE assumes no future CO₂ taxes. It selects the same resource plan as the Preferred Plan ADAA through 2036. However, it substitutes the 2040 ½ CCGT picked by Plan ADAA for RICE units in 2040 and 2043.

Figure 33: Low CO₂ Future Plan ADAE



Plan ADAD uses the High CO₂ tax future. It has the same optimal build plan as Plan ADAE.

Figure 34: High CO₂ Future Plan ADAD



Two ARPs were to optimize the build decisions with varied future construction cost assumptions. Plan ADAG includes the High Construction Cost forecast, and Plan ADAH includes the Low Construction Cost forecast. Both plans are the same as Plan ADAE.

Variation in construction costs within the high and low ranges does not change the optimal resources selected.

Figure 35: High Construction Cost Future Plan ADAG

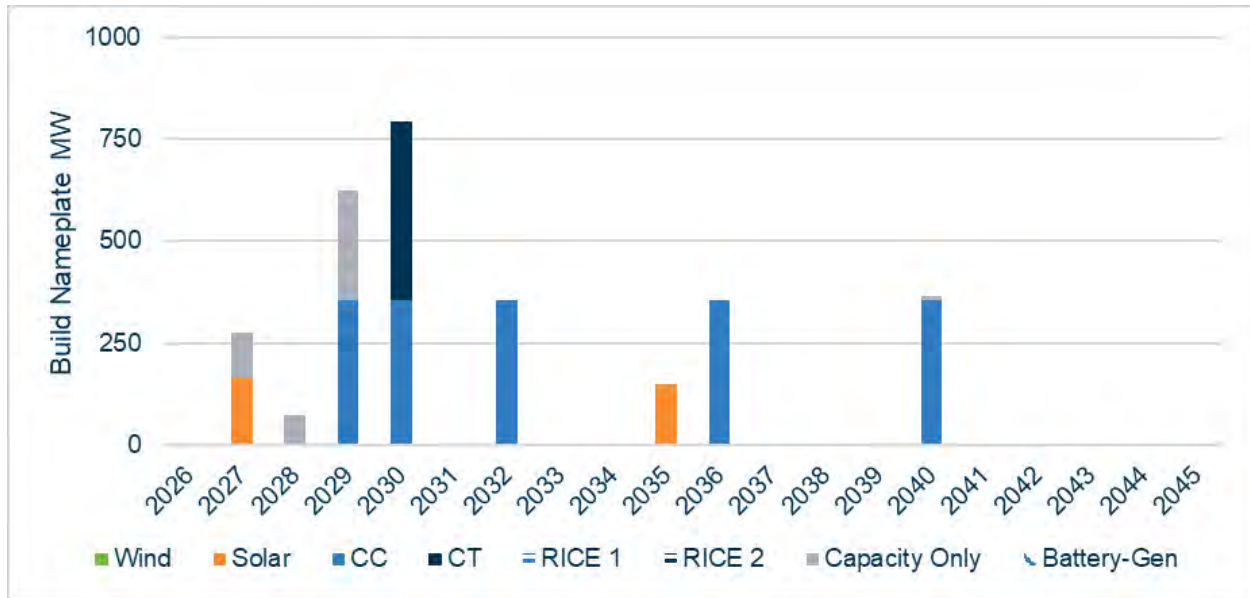
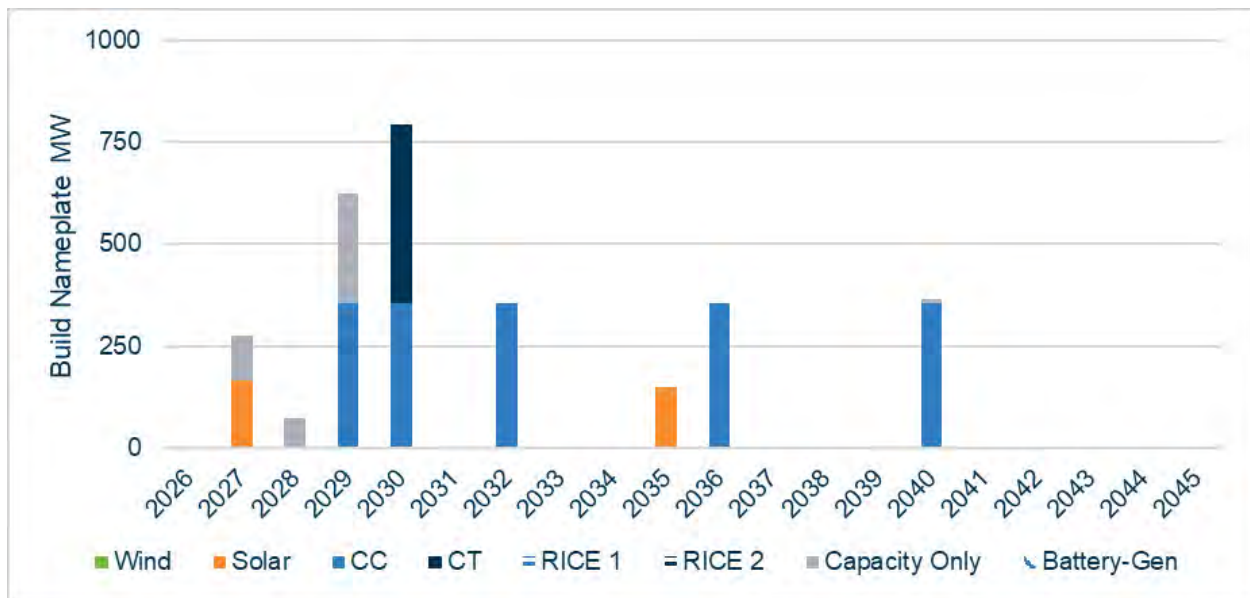


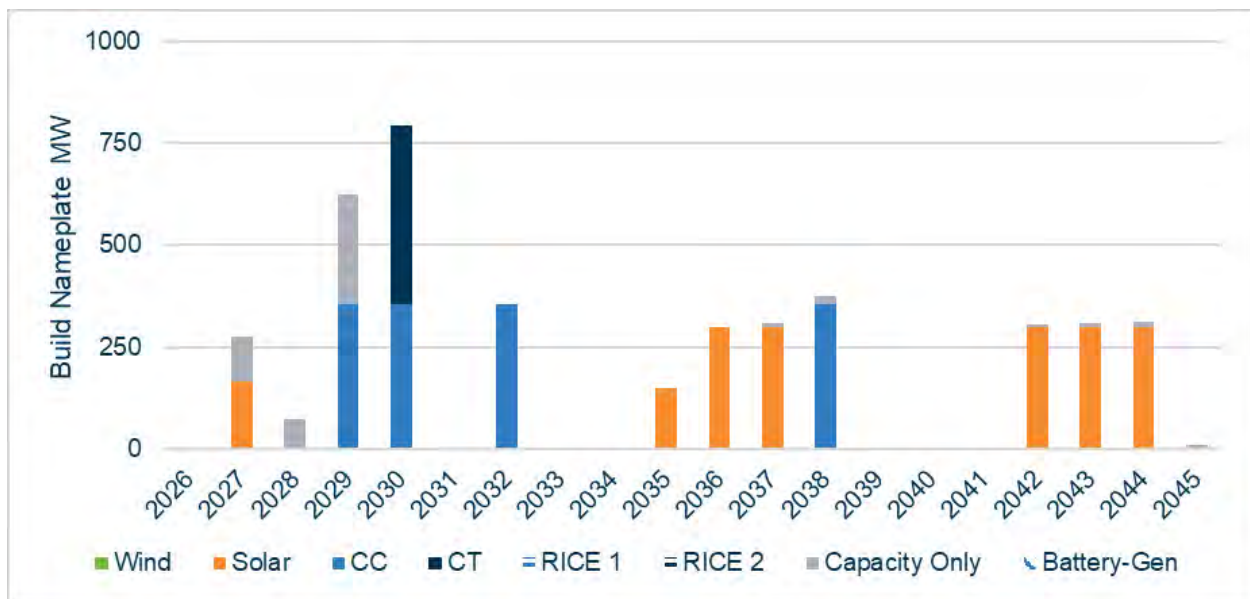
Figure 36: Low Construction Cost Future Plan ADAH



Plans ADAI and ADAJ isolate the effects of the natural gas price forecasts on the optimal build decisions.

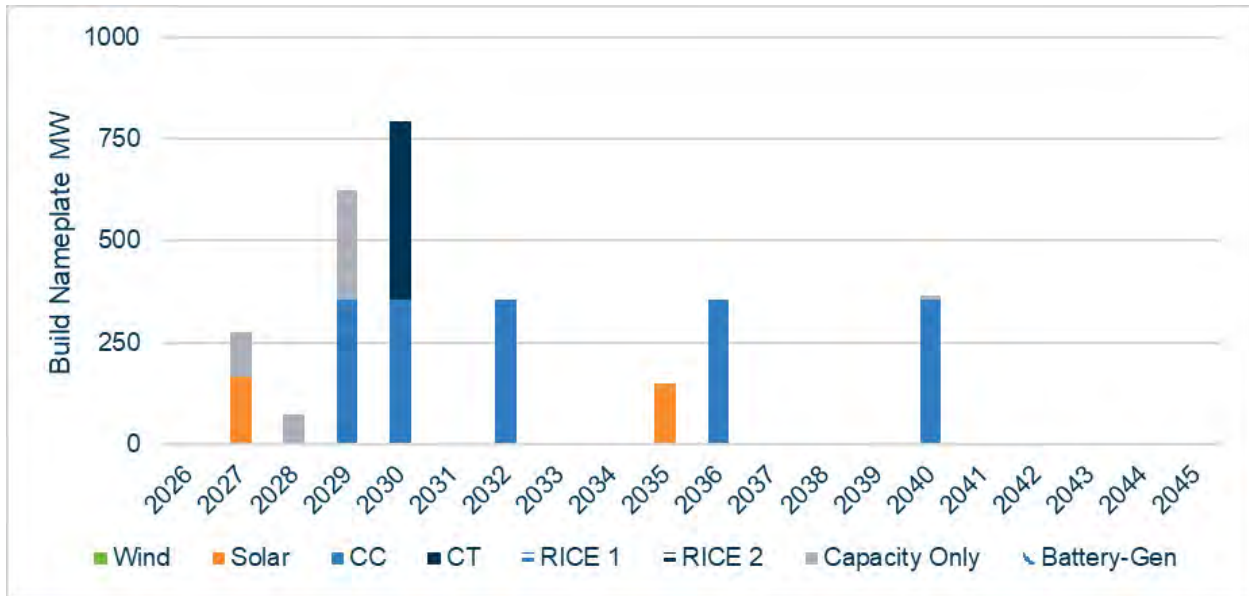
Plan ADAI uses the high NG price forecast. In the near term (through 2032), it selects the same plan as Plan ADAA. It also continues to select 150 MW of solar in 2035 like Plan ADAA. It selects significantly more solar in the balance of the planning horizon, including 300 MW per year in 2036, 2037, 2042, 2043, and 2044. It selects one ½ CCGT after 2032, in 2038, in contrast to Plan ADAA which selects two. The high natural gas price forecast encourages the addition of zero production cost solar resources, and substitution of solar for a natural gas resource.

Figure 37: High NG Future Plan ADAI



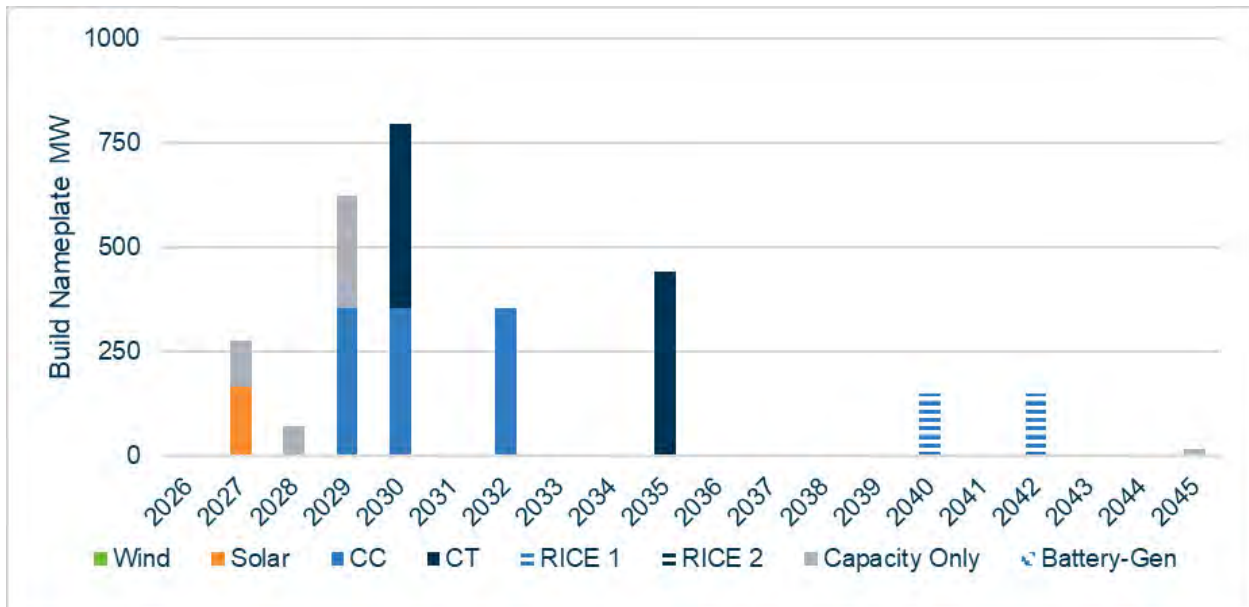
Plan ADAJ uses the Low NG price forecast. It selects the same optimal plan as Plan ADAA.

Figure 38: Low NG Future Plan ADAJ



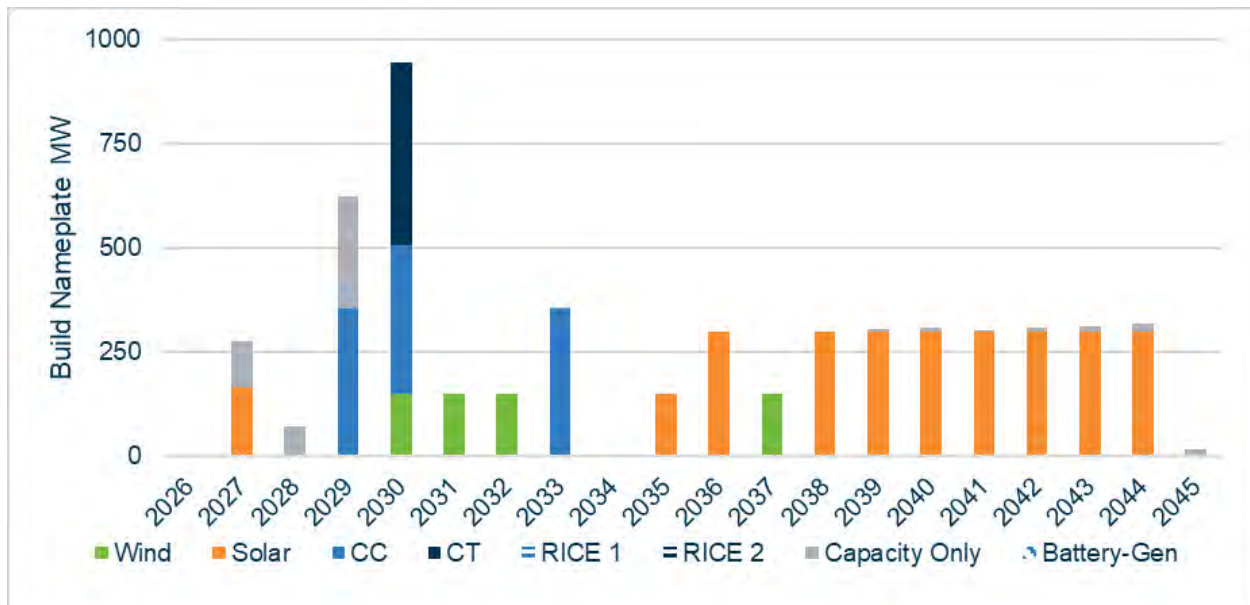
Plan ADAC which couples the Low CO₂ tax with the Low NG forecast selects the ½ CCGT in 2032 consistent with Plan ADAA. However, it substitutes the 2035 solar and 2036 ½ CCGT for a 2035 SCGT. It selects two RICE units in 2040 and 2042 rather than the 2040 ½ CCGT in Plan ADAA.

Figure 39: Low NG/Low CO₂ Future Plan ADAC



Plan ADAB, which couples High NG prices with High CO₂ taxes, changes the near-term execution plan to include 150 MW Wind in 2030, 2031 and 2032. It moves back the ½ CCGT from 2032 to 2033. It does not build additional natural gas fired resources for the rest of the planning period and adds 2,550 MW of solar and 150 MW of wind. This plan shows that with very high natural gas prices and emissions taxes, there are economic benefits to adding a large quantity of zero production cost, non-emitting solar resources, despite the increase in fixed costs.

Figure 40: High NG/High CO₂ Future Plan ADAB



Evergy Missouri West is developing five new resources in the 2027-2031 horizon, which were already approved for CCN. The Preferred Plan ADAA only selects one new resource in the execution period, ½ CCGT in 2032. It selects an additional three resources in the final 13 years of the planning horizon, including 150 MW solar and two ½ CCGTs. Plan ADAA was optimized with mid-level assumptions for each of the CUFs. ARPs created for each low- and high-level future forecast show that many of the future forecast changes do not change any resource decisions – plans with high and low construction cost forecasts, low NG price forecasts, and high CO₂ tax forecasts. The Low CO₂ tax plan produces changes in type of natural gas fired unit selected in the resource plan beginning

in 2040. Similarly, the combined Low CO₂/Low NG plan eliminates a solar resource and produces changes in the types of natural gas fired units selected beginning in 2035.

The High NG price forecast future prompts larger resource plan changes, but those changes do not occur until 2036 in the plan and include significantly more solar and one less ½ CCGT.

The combined High CO₂/High NG plan produces the most impactful changes including additional wind resources in the execution period, one ½ CCGT in 2033, and significant renewable build with no additional natural gas fired resources in the planning horizon.

Table 16: Rankings of Plans Optimized for Different Futures

Rank	Plan	NPVRR	Difference	Description
1	ADAA	23,277		Base
2	ADAG	23,277	0	High Build Cost
3	ADAH	23,277	0	Low Build Cost
4	ADAJ	23,277	0	Low NG
5	ADAD	23,277	0	High CO ₂
6	ADAE	23,296	19	Low CO ₂
7	ADAC	23,377	99	Low CO ₂ , Low NG
8	ADAI	23,364	86	High NG
9	ADAB	24,011	733	High CO ₂ , High NG

10.7 Rankings of Base Plans

10.7.1 Risk-Weighted Rankings

Table 17: Overall Plan Rankings³⁴

Rank	Plan	NPVRR	Difference	Description
1	ADAA	23,277		Base Assumptions, Extended Retirements
2	ADAE	23,296	19	Low CO ₂
3	ADBA	23,330	52	No 2032 1/2 CCGT
4	ACAA	23,344	67	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035
5	ADDA	23,350	73	Add 2029 Solar
6	ADAI	23,364	86	High NG
7	ADAC	23,377	99	Low CO ₂ , Low NG
8	ABAA	23,383	105	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038
9	AAAA	23,406	128	2025 PP Retirement Dates
10	ADEA	23,448	171	Add 2029 Storage
11	ADCA	23,608	331	Add 2029 and 2030 Storage
12	ADAB	24,011	733	High CO ₂ , High NG

³⁴ ADAD (High CO₂), ADAG (High Build Cost), ADAH (Low Build Cost), and ADAJ (Low NG) match ADAA and are not displayed in Rankings Tables.

10.7.2 Carbon Restriction Rankings

Table 18: Rankings for High Carbon Tax

Rank	Plan	NPVRR	Difference	Description
1	ADAI	26,881		High NG
2	ADAA	26,960	79	Base Assumptions, Extended Retirements
3	ADBA	27,008	126	No 2032 1/2 CCGT
4	ADAE	27,011	130	Low CO ₂
5	ADDA	27,012	131	Add 2029 Solar
6	ACAA	27,023	142	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035
7	ABAA	27,071	190	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038
8	ADAB	27,106	224	High CO ₂ , High NG
9	AAAA	27,112	231	2025 PP Retirement Dates
10	ADEA	27,175	294	Add 2029 Storage
11	ADAC	27,228	347	Low CO ₂ , Low NG
12	ADCA	27,386	505	Add 2029 and 2030 Storage

Table 19: Rankings for Mid Carbon Tax Future

Rank	Plan	NPVRR	Difference	Description
1	ADAA	22,991		Base Assumptions, Extended Retirements
2	ADAE	23,009	18	Low CO ₂
3	ADBA	23,044	53	No 2032 1/2 CCGT
4	ACAA	23,050	59	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035
5	ADDA	23,066	76	Add 2029 Solar
6	ADAC	23,080	90	Low CO ₂ , Low NG
7	ABAA	23,085	94	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038
8	ADAI	23,091	101	High NG
9	AAAA	23,104	114	2025 PP Retirement Dates
10	ADEA	23,161	170	Add 2029 Storage
11	ADCA	23,318	327	Add 2029 and 2030 Storage
12	ADAB	23,779	788	High CO ₂ , High NG

Table 20: Rankings for Low (No) Carbon Tax Future

Rank	Plan	NPVRR	Difference	Description
1	ADAA	21,756		Base Assumptions, Extended Retirements
2	ADAE	21,757	1	Low CO ₂
3	ADAC	21,777	21	Low CO ₂ , Low NG
4	ADBA	21,809	53	No 2032 1/2 CCGT
5	ADDA	21,836	80	Add 2029 Solar
6	ACAA	21,844	88	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035
7	ABAA	21,884	128	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038
8	ADEA	21,902	146	Add 2029 Storage
9	AAAA	21,906	150	2025 PP Retirement Dates
10	ADAI	21,907	151	High NG
11	ADCA	22,039	283	Add 2029 and 2030 Storage
12	ADAB	22,711	955	High CO ₂ , High NG

10.7.3 Natural Gas Price Rankings

Table 21: Rankings for High Natural Gas Price Future

Rank	Plan	NPVRR	Difference	Description
1	ADAI	27,232		High NG
2	ADAA	27,328	97	Base Assumptions, Extended Retirements
3	ADAE	27,366	135	Low CO ₂
4	ADDA	27,368	136	Add 2029 Solar
5	ADAB	27,369	137	High CO ₂ , High NG
6	ADBA	27,371	139	No 2032 1/2 CCGT
7	ACAA	27,467	235	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035
8	ADEA	27,526	294	Add 2029 Storage
9	ABAA	27,534	302	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038
10	ADAC	27,581	349	Low CO ₂ , Low NG
11	AAAA	27,596	365	2025 PP Retirement Dates
12	ADCA	27,737	505	Add 2029 and 2030 Storage

Table 22: Rankings for Mid Natural Gas Price Future

Rank	Plan	NPVRR	Difference	Description
1	ADAA	23,296		Base Assumptions, Extended Retirements
2	ADAE	23,312	17	Low CO ₂
3	ADBA	23,349	53	No 2032 1/2 CCGT
4	ACAA	23,360	64	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035
5	ADDA	23,370	74	Add 2029 Solar
6	ADAI	23,376	81	High NG
7	ADAC	23,392	96	Low CO ₂ , Low NG
8	ABAA	23,397	101	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038
9	AAAA	23,419	123	2025 PP Retirement Dates
10	ADEA	23,463	168	Add 2029 Storage
11	ADCA	23,623	327	Add 2029 and 2030 Storage
12	ADAB	24,015	720	High CO ₂ , High NG

Table 23: Rankings for Low Natural Gas Price Future

Rank	Plan	NPVRR	Difference	Description
1	ADAA	21,515		Base Assumptions, Extended Retirements
2	ADAE	21,529	14	Low CO ₂
3	ADAC	21,553	38	Low CO ₂ , Low NG
4	ACAA	21,555	40	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035
5	ADBA	21,571	56	No 2032 1/2 CCGT
6	ABAA	21,583	68	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038
7	AAAA	21,591	76	2025 PP Retirement Dates
8	ADDA	21,601	86	Add 2029 Solar
9	ADEA	21,680	164	Add 2029 Storage
10	ADAI	21,688	173	High NG
11	ADCA	21,819	303	Add 2029 and 2030 Storage
12	ADAB	22,565	1,050	High CO ₂ , High NG

10.7.4 Construction Cost Rankings

Table 24: Rankings for High Construction Cost Future

Rank	Plan	NPVRR	Difference	Description
1	ADAA	23,983		Base Assumptions, Extended Retirements
2	ADAE	23,993	10	Low CO ₂
3	ADAC	24,030	47	Low CO ₂ , Low NG
4	ADBA	24,051	68	No 2032 1/2 CCGT
5	ACAA	24,068	85	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035
6	ADDA	24,090	108	Add 2029 Solar
7	ABAA	24,107	124	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038
8	AAAA	24,128	145	2025 PP Retirement Dates
9	ADEA	24,153	171	Add 2029 Storage
10	ADAI	24,187	205	High NG
11	ADCA	24,300	317	Add 2029 and 2030 Storage
12	ADAB	25,221	1,238	High CO ₂ , High NG

Table 25: Rankings for Mid Construction Cost Future

Rank	Plan	NPVRR	Difference	Description
1	ADAA	23,443		Base Assumptions, Extended Retirements
2	ADAE	23,465	23	Low CO ₂
3	ADBA	23,495	52	No 2032 1/2 CCGT
4	ACAA	23,506	64	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035
5	ADDA	23,514	72	Add 2029 Solar
6	ADAI	23,516	74	High NG
7	ABAA	23,544	101	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038
8	ADAC	23,559	116	Low CO ₂ , Low NG
9	AAAA	23,567	124	2025 PP Retirement Dates
10	ADEA	23,619	177	Add 2029 Storage
11	ADCA	23,784	341	Add 2029 and 2030 Storage
12	ADAB	24,129	686	High CO ₂ , High NG

Table 26: Rankings for Low Construction Cost Future

Rank	Plan	NPVRR	Difference	Description
1	ADAI	22,235		High NG
2	ADAA	22,242	7	Base Assumptions, Extended Retirements
3	ADAE	22,261	27	Low CO ₂
4	ADBA	22,278	43	No 2032 1/2 CCGT
5	ADDA	22,282	47	Add 2029 Solar
6	ACAA	22,296	61	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035
7	ABAA	22,335	100	Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038
8	ADAC	22,359	125	Low CO ₂ , Low NG
9	AAAA	22,362	127	2025 PP Retirement Dates
10	ADEA	22,402	167	Add 2029 Storage
11	ADCA	22,565	330	Add 2029 and 2030 Storage
12	ADAB	22,565	330	High CO ₂ , High NG

10.8 Plans to Comply with RES Requirements

The Missouri RES requirements include 14.7% of retail sales to be served by non-solar renewables and 0.3% by solar renewables.

Table 27: Missouri West RES Requirements

Year	Retail Electric Sales (MWh)	Missouri RES Non-Solar Requirement	Non-Solar RES Requirement (MWh)	Missouri RES Solar Requirement	Solar RES Requirement (MWh)
2026	9,910,676	14.7%	1,456,869	0.30%	29,732
2027	11,600,803	14.7%	1,705,318	0.30%	34,802
2028	12,512,665	14.7%	1,839,362	0.30%	37,538
2029	14,834,356	14.7%	2,180,650	0.30%	44,503
2030	15,262,315	14.7%	2,243,560	0.30%	45,787
2031	15,329,166	14.7%	2,253,387	0.30%	45,987
2032	15,424,467	14.7%	2,267,397	0.30%	46,273
2033	15,502,378	14.7%	2,278,850	0.30%	46,507
2034	15,609,333	14.7%	2,294,572	0.30%	46,828
2035	15,736,033	14.7%	2,313,197	0.30%	47,208
2036	15,901,149	14.7%	2,337,469	0.30%	47,703
2037	16,054,688	14.7%	2,360,039	0.30%	48,164
2038	16,255,479	14.7%	2,389,555	0.30%	48,766
2039	16,478,487	14.7%	2,422,338	0.30%	49,435
2040	16,747,739	14.7%	2,461,918	0.30%	50,243
2041	16,992,271	14.7%	2,497,864	0.30%	50,977
2042	17,253,704	14.7%	2,536,294	0.30%	51,761
2043	17,519,921	14.7%	2,575,428	0.30%	52,560
2044	17,804,176	14.7%	2,617,214	0.30%	53,413
2045	18,048,999	14.7%	2,653,203	0.30%	54,147

Plan ADAA includes 165 MW of solar in 2027, which will supply enough solar energy to meet the solar requirement throughout the planning horizon. However, beginning in 2037, Eversource Missouri West’s planned renewable generation falls short of the total target amount. Eversource Missouri West would need a source of renewable energy by 2037 to continue to meet the standard. Given this runway, Eversource Missouri West has nearly a decade to monitor and reassess the timing and magnitude of RES compliance requirements in future IRPs. The RES compliance gap may narrow or widen depending on retail sales volumes and any future changes to RES compliance requirements. Eversource Missouri West could purchase renewable energy credits (“RECs”) or procure additional renewable resources. Market REC purchases provide a flexible, lower-capital compliance mechanism that does not require Eversource to commit to long-lived generating assets solely for compliance purposes. Eversource has utilized market REC purchases as

part of its compliance strategy in prior years and will continue to evaluate market REC pricing relative to the cost of owned renewable generation.

Plans ADAK and ADAL test meeting the standard with new owned or contracted resources.

Figure 41: Solar Generation Compared to RES Target for Plan ADAA

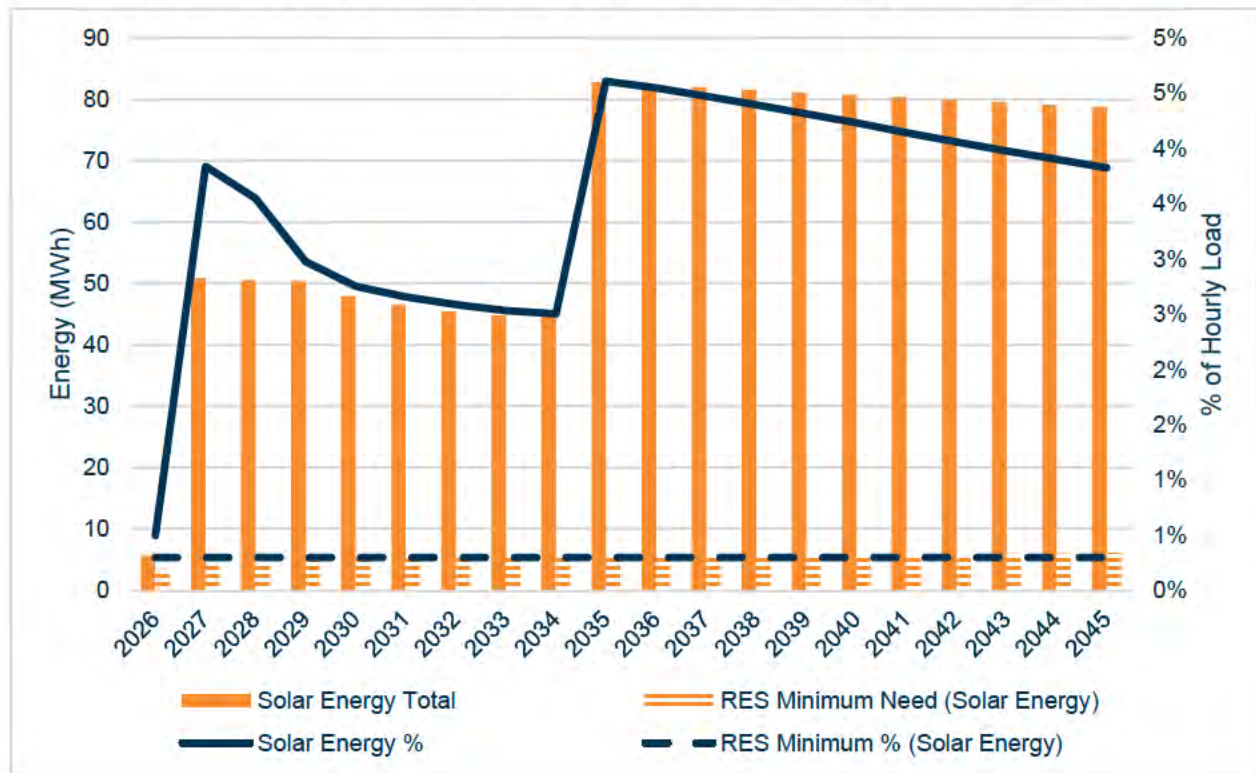
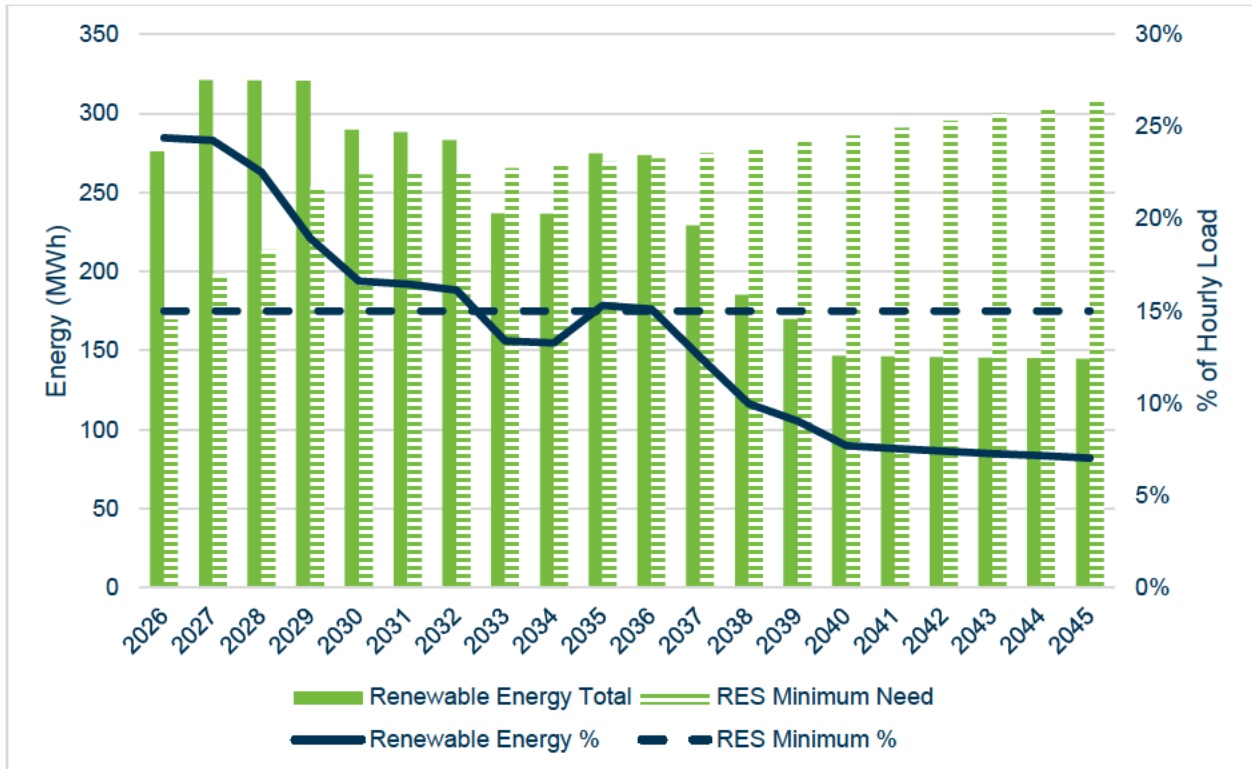
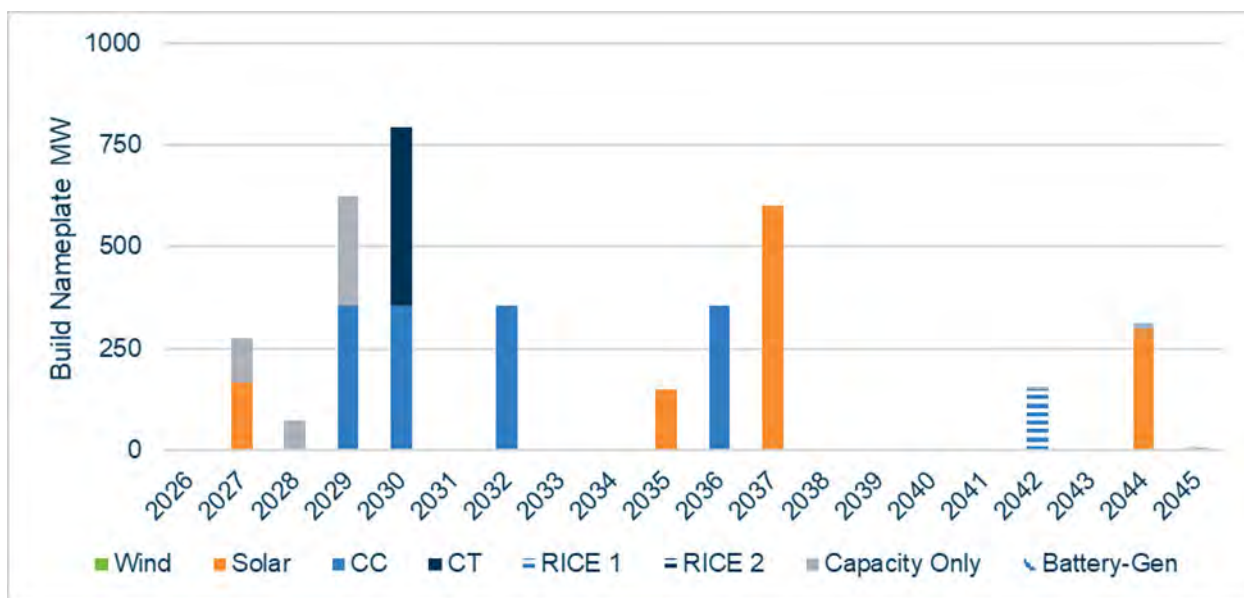


Figure 42: Renewable Generation Compared to RES Target for Plan ADAA



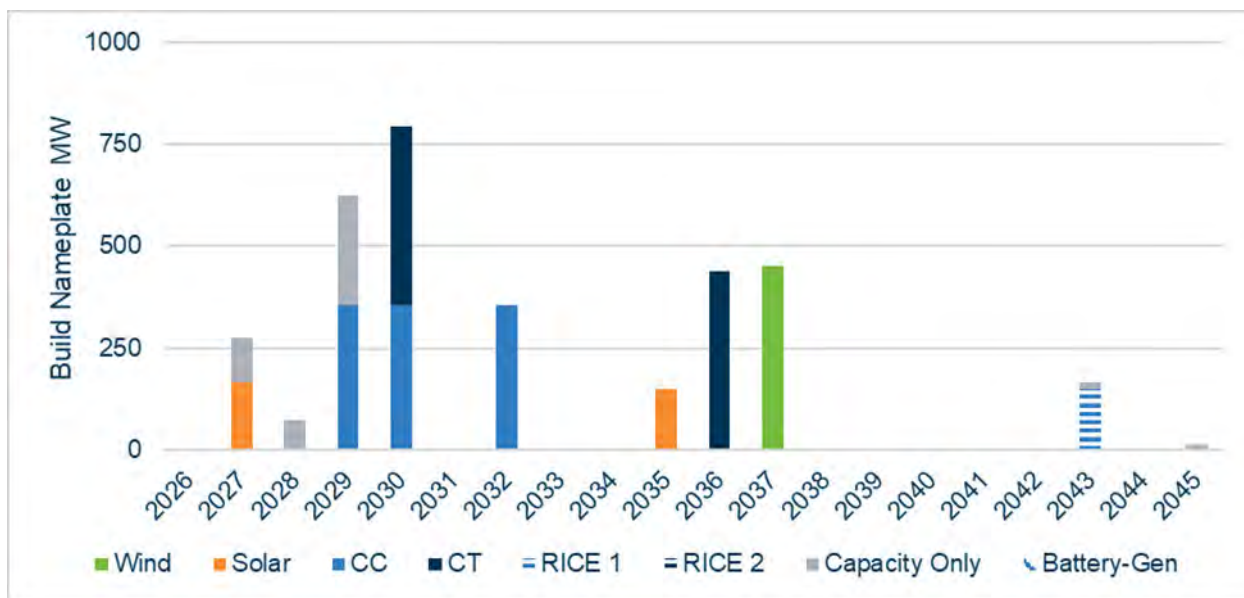
Plan ADAK tests meeting the requirement with 600 MW of solar in 2037. This level of solar additions would produce enough energy through 2045 to meet RES needs each year.

Figure 43: Compliance with RES through Wind Additions Plan ADAK



Plan ADAL tests meeting the requirement with 450 MW of wind in 2037. This level of wind additions would produce enough energy through 2045 to meet RES needs each year.

Figure 44: Compliance with RES through Solar Additions Plan ADAL



The economic analysis of the two options shows that procuring solar additions would be a lower cost option for meeting the RES requirements than wind. Evergy Missouri West

does not plan to execute on 2037 resources this early in the planning process but will continue to monitor the RES compliance needs and sources in future IRPs.

Table 28: RES Plan Compliance Options Comparison

Rank	Plan	NPVRR	Difference	Description
1	ADAA	23,277		Base
2	ADAK	23,892	615	RES Solar Additions
3	ADAL	24,066	789	RES Wind Additions

Section 11: Resource Plan Contingency Analysis

Evergy Missouri West also developed several contingency plans to determine the optimal plans for differing load forecasts:

- Large Load customers
 - Large loads of varying sizes 500 MW – 1,500 MW beginning service in 2031
 - Increased load from existing large load customer
- Other retail forecast drivers
 - High electrification
 - Low load growth

Table 29: Plan Key for Load Contingency Analysis

Load	Retirements	Build Options	Other
A- Base Load	D- Extend Jeffrey 3 to March 2036, Extend Lake Road 4/6 to March 2038, Jeffrey 2 Converts to NG 2035, Extend Iatan 1 and Jeffrey 1 beyond 2045	A- Base	A- Base
B- Large Customer Upsize			
C- Additional 500 MW Load			
D- Additional 750 MW Load			
E- Additional 1,000 MW Load			
F- Additional 1,500 MW Load			
G- High Electrification Load			
H- Low Load			

Table 30: Contingency Plan Descriptions

Plan Name	Description
ADAA	Base Load
BDAA	Large Customer Upsize
CDAA	Additional 500 MW Load
DDAA	Additional 750 MW Load
EDAA	Additional 1,000 MW Load
FDA A	Additional 1,500 MW Load
GDAA	High Electrification Load
HDAA	Low Load

11.1 Large Customer Growth

Eversource Missouri West developed ARPs to determine how additional large customers could be served.

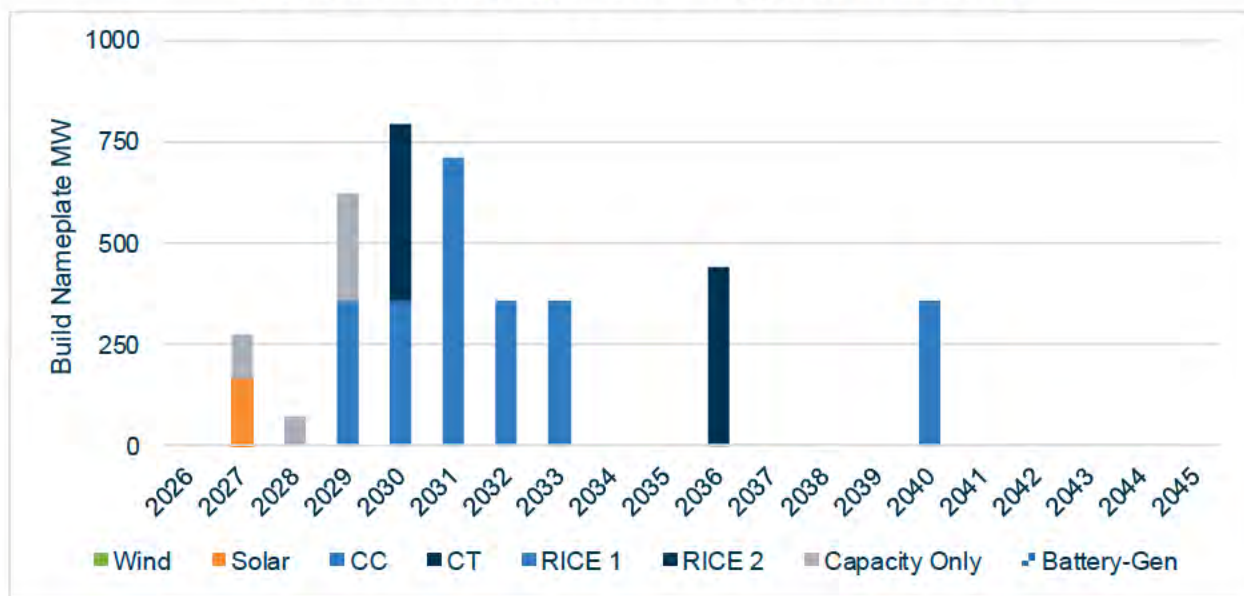
Table 31: New Large Customer Load Ramp Scenarios (MW)

New Load Scenario	2032	2033	2034	2035+
500 MW	500	500	500	500
750 MW	500	750	750	750
1,000 MW	500	750	1,000	1,000
1,500 MW	500	750	1,000	1,500
Large Customer Upsize	725	900	900	900

Plan BDAA evaluates the resource plan needed for the next large customer in the Eversource Missouri West pipeline. Plans CDAA, DDAA, EDAA and FDAA evaluate large customer loads of varying sizes.

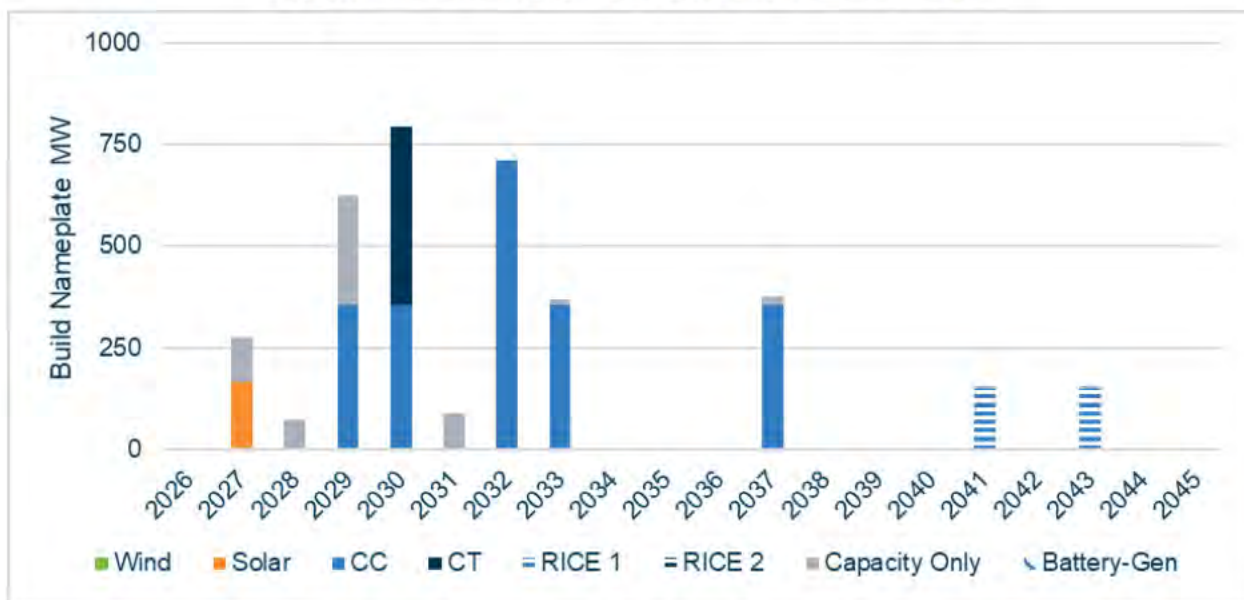
Plan BDAA accommodates additional load requested by an existing large customer. In the near-term, a full CCGT is needed in 2031 in addition to the ½ CCGT added in Plan ADAA. The increased load also prompts the addition of another ½ CCGT in 2033. The plan does not select solar in 2035 and substitutes an SCGT for the ½ CCGT in 2036. It continues to select a ½ CCGT in 2040.

Figure 45: Next Large Load Anticipated Plan BDAA



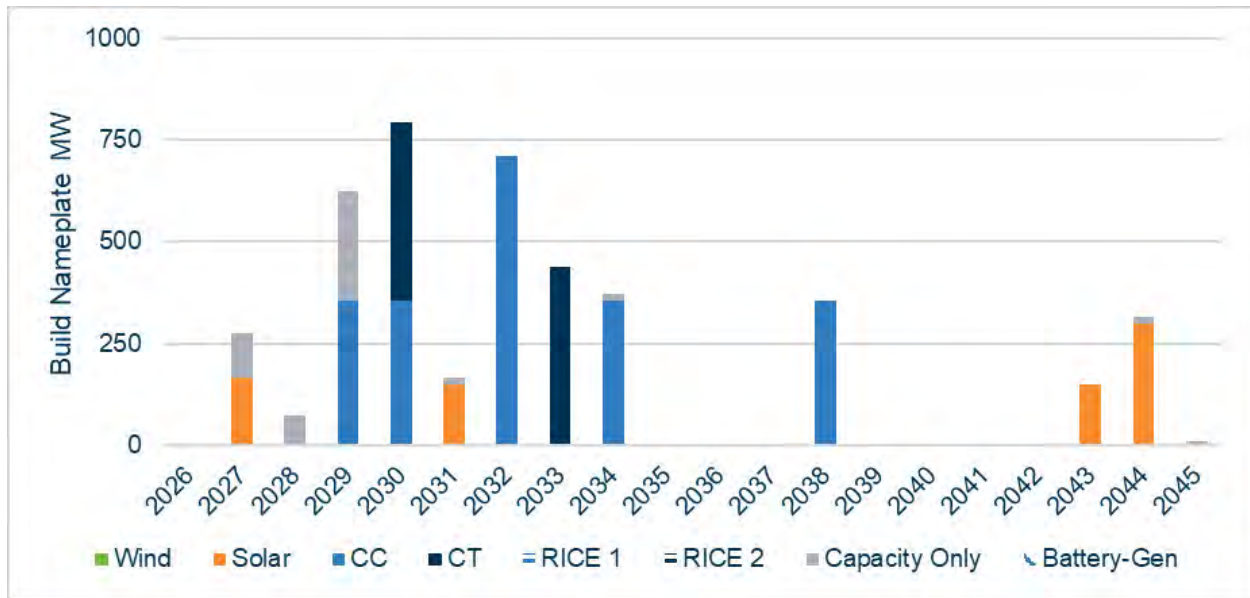
Plan CDAA accommodates an additional 500 MW load in the near term by adding additional ½ CCGTs in 2032 and 2033. With 250 MW of additional load in 2031 and ramping to a peak of 500 MW in 2032, the plan requires additional thermal above the ½ CCGT planned in 2032 in Plan ADAA. The future build plan differs with a ½ CCGT selected in 2037 and two RICE in 2041 and 2043.

Figure 46: Additional 500 MW Load Plan CDAA



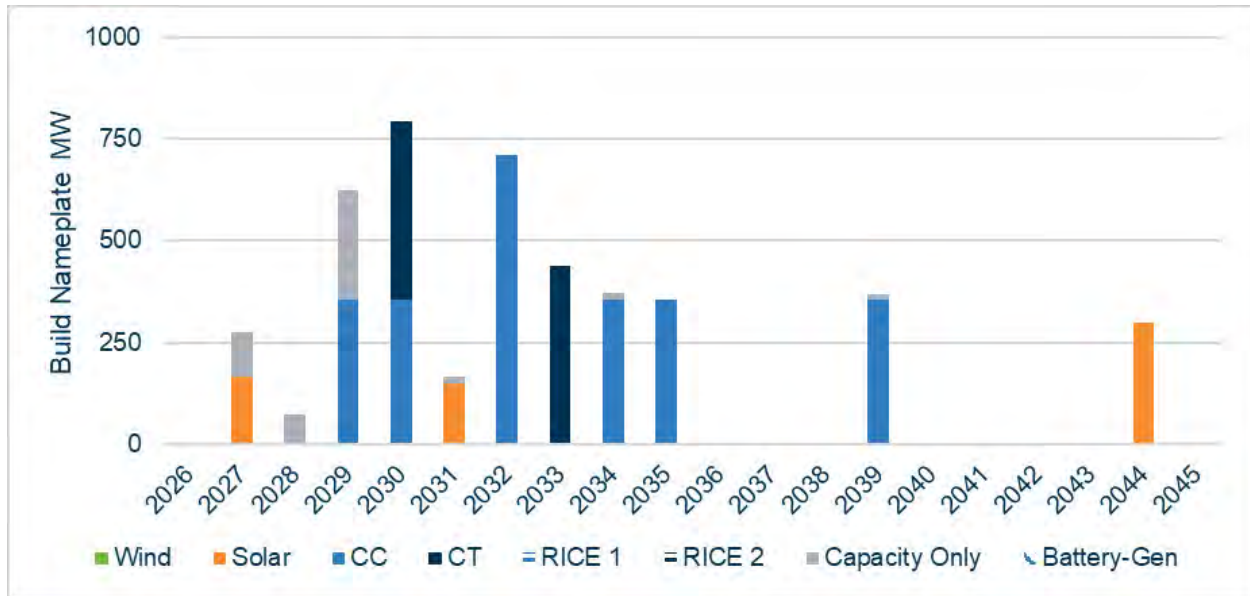
Plan DDAA considers the addition of a customer that has a peak load of 250 MW in 2031, 500 MW in 2032, and 750 MW in 2033 and beyond. Compared to Plan ADAA, in the near term, it selects an additional 150 MW Solar in 2031 and ½ CCGT in 2032. It also selects an SCGT in 2033 and ½ CCGT in 2034. It does not select solar in 2035. It also moves forward the 2040 ½ CCGT to 2038 and adds 450 MW of solar from 2043-2044.

Figure 47: Additional 750 MW Load Plan DDAA



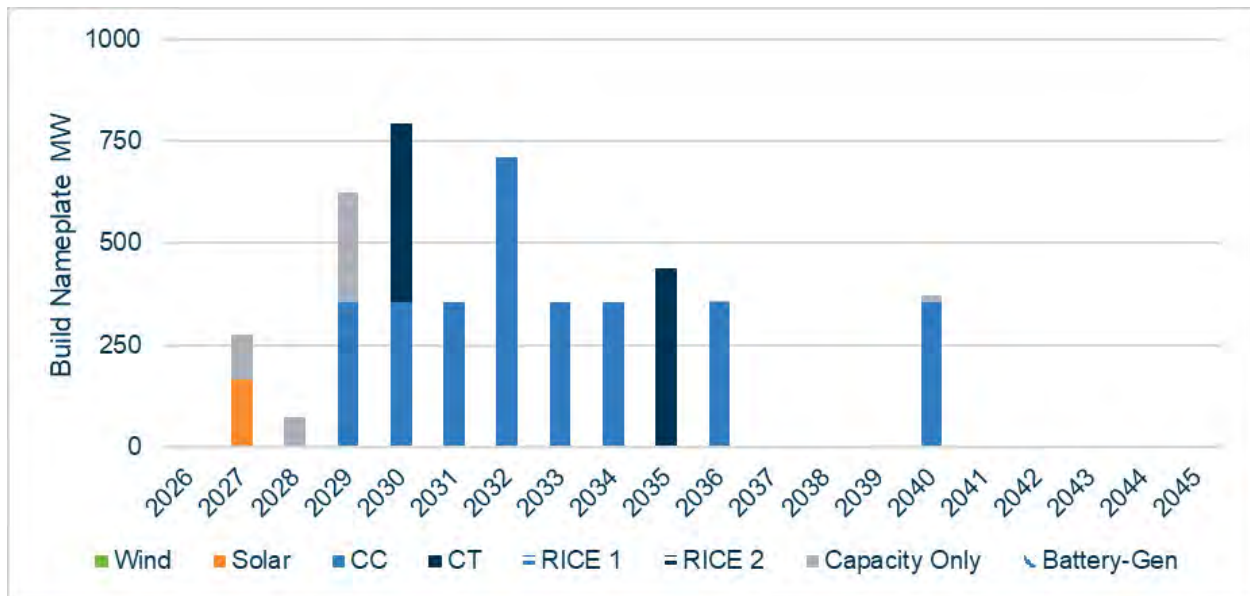
Plan EDAA accommodates a new large load that peaks at 1,000 MW in 4 years. It has the same additional load as Plan DDAA in 2031- 2033, and ramps to its peak of 1 GW in 2034. Along with the ½ CCGT added by Plan ADAA in 2032, it selects a CCGT in 2032, and ½ CCGTs in 2034 and 35. It selects a SCGT in 2033, a ½ CCGT in 2039, and 300 MW solar in 2044.

Figure 48: Additional 1,000 MW Load Plan EDA



Plan FDAA accommodates a new large load that peaks at 1,500 MW in 4 years. It has the same additional load as Plan EDA in 2031-2033, and ramps to its peak of 1.5 GW in 2036. Along with the ½ CCGT added by Plan ADA in 2032, it selects additional ½ CCGTs in 2031, 2032, 2033, 2034, and 2036. It selects an SCGT in 2035, and a ½ CCGT in 2040.

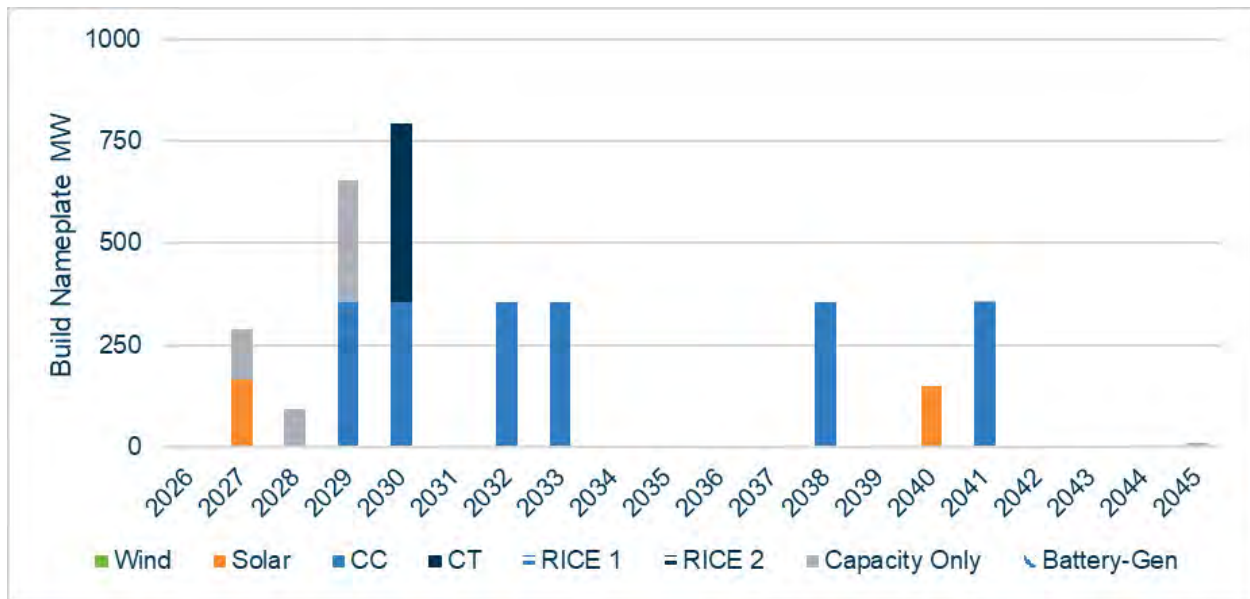
Figure 49: Additional 1,500 MW Load Plan FDAA



11.2 High Electrification and Low Load Growth Scenarios

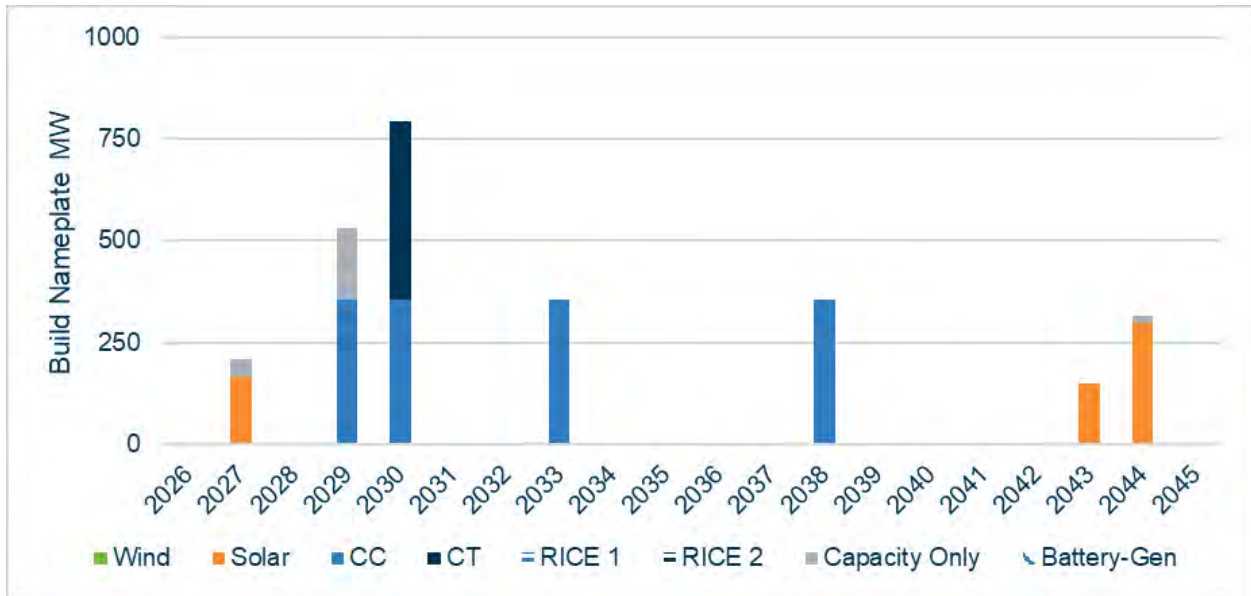
Evergy Missouri West’s high load growth and economy-wide electrification forecast incorporates a higher load than the base planning forecast but has a slower load ramp than the large load customer scenarios. Plan GDAA shows that to meet this growth, an additional ½ CCGT is needed in 2033. The plan selects ½ CCGTs in 2038 and 2041, as well as 150 MW of solar in 2040.

Figure 50: High Electrification Plan GDAA



The low growth scenario, Plan HDAA, delays the ½ CCGT from 2032 to 2033. Additional resources are not needed in this scenario until 2038.

Figure 51: Low Load Growth Plan HDAA



Section 12: Preferred Plan Selection and Resource Acquisition Strategy Update

12.1 2026 Annual Update Preferred Plan

The ARPs 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). A balanced mix of demand- and supply-side resources has been a key component of the Company's resource planning efforts for over a decade and remains a key part of its preferred plan going forward.

Eversource Missouri West has selected Plan ADAA as the Preferred Plan for the 2026 Annual Update. Plan ADAA was chosen based on a comprehensive evaluation of ARPs across multiple CUF endpoints, near-term build option sensitivities, retirement scenario testing, and contingency load analyses. The Preferred Plan represents the resource portfolio that Eversource Missouri West believes best satisfies the planning objectives of providing safe, reliable, and efficient energy services at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies. Table 32 details the supply-side and demand-side requirements for the 20-year planning period.

Table 32: Evergy Missouri West Preferred Plan ADAA

Year	Wind (MW)	Solar (MW)	Battery (MW)	Thermal (MW)	Capacity (Summer MW)	DSM (Summer MW)	Retirements (MW)
2026	0	0	0	0	0	98	0
2027	0	165	0	0	110	113	0
2028	0	0	0	0	71	123	0
2029	0	0	0	355	268	90	0
2030	0	0	0	795	0	90	0
2031	0	0	0	0	0	90	0
2032	0	0	0	355	0	89	0
2033	0	0	0	0	0	89	0
2034	0	0	0	0	0	89	0
2035	0	150	0	0	0	89	0
2036	0	0	0	355	0	89	59
2037	0	0	0	0	0	89	0
2038	0	0	0	0	0	88	89
2039	0	0	0	0	0	88	0
2040	0	0	0	355	0	88	0
2041	0	0	0	0	0	87	0
2042	0	0	0	0	0	87	0
2043	0	0	0	0	0	87	0
2044	0	0	0	0	0	87	0
2045	0	0	0	0	0	124	0

Figure 52: Preferred Plan ADAA Summer Capacity Composition (MW)

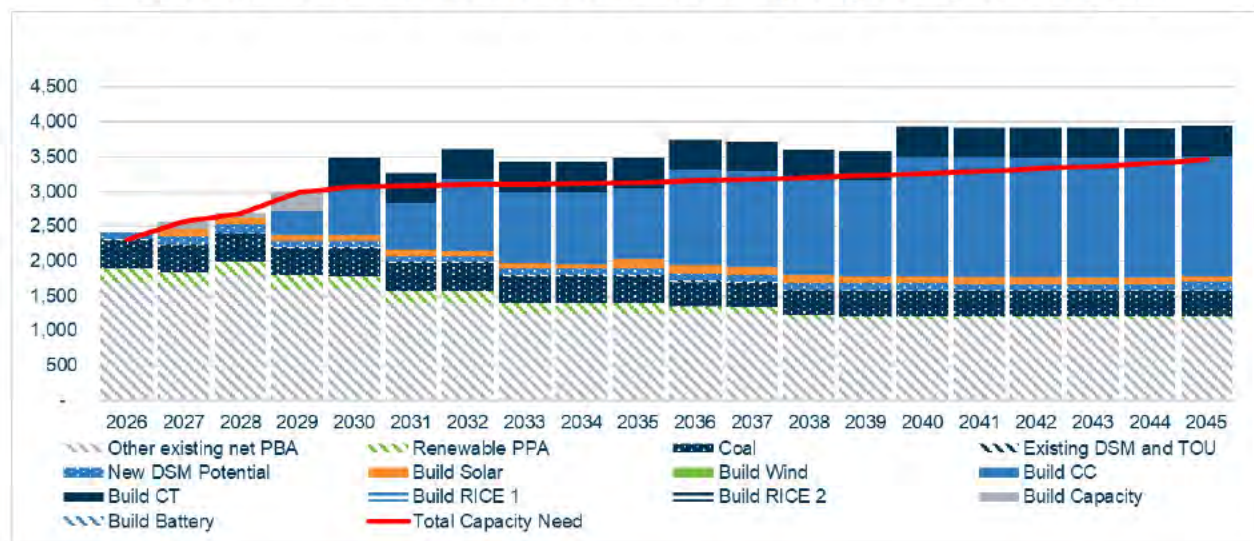
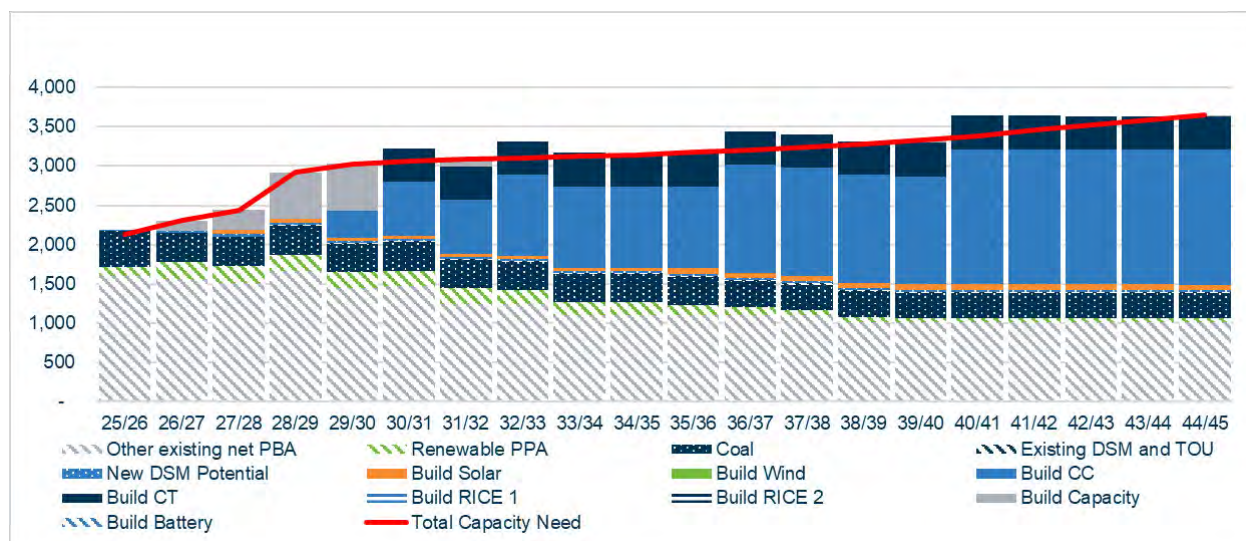


Figure 53: Preferred Plan ADA A Winter Capacity Composition (MW)



12.2 Preferred Plan Selection

Evergy Missouri West selected Plan ADA A as the 2026 Preferred Plan based on a comprehensive evaluation of ARPs across retirement scenarios, near-term build option sensitivities, CUF endpoints, and contingency load analysis. Plan ADA A produces the lowest probability-weighted NPVRR among the retirement plans tested at \$23,277 million — \$128 million less than Plan AAAA (reflecting the 2025 Preferred Plan retirement dates), \$67 million less than Plan ACAA, and \$105 million less than Plan ABAA.

The near-term resource additions in Plan ADA A — the five approved CCN resources (165 MW solar in 2027, 355 MW Viola CCGT in 2029, 355 MW McNew CCGT and 440 MW Mullin Creek #1 SCGT in 2030), followed by a 355 MW half CCGT in 2032 — were consistently selected across the ARPs tested. The 2032 half CCGT is a critical addition that addresses the residual capacity gap emerging as large load customers ramp to steady-state consumption, which approaches 800 MW of peak demand by 2032. Evergy Missouri West expects to share ownership of the 2032 CCGT with Evergy Metro, which has identified a corresponding need for a half CCGT in its 2026 Preferred Plan, enabling cost-sharing and development efficiency across the Evergy system.

Plan ADAA is consistent with Missouri Senate Bill 4's emphasis on maintaining and adding firm, dispatchable generation capacity. The plan retains the existing coal fleet to provide reliable baseload energy during a period of rapid load growth driven by large-load customer expansion and adds highly efficient combined-cycle and simple-cycle gas turbines to meet incremental capacity and energy needs. The plan maintains compliance with Missouri RES requirements through the early 2030s with existing and planned renewable resources, with strategies to address the compliance gap that emerges later in the planning horizon as discussed in Section 10.8. The extended operation of Iatan 1 and JEC 1 beyond 2045 provides a critical reliability backstop, ensuring that Eversource Missouri West does not prematurely commit to replacement resources whose costs and characteristics remain uncertain this far into the planning horizon.

12.3 Preferred Plan Composition

The 2026 Preferred Plan charts Eversource Missouri West's path to meet growing capacity and energy requirements over the 20-year planning horizon, sequenced in three phases that balance near-term urgency with long-term flexibility.

12.3.1 Near-term (2026–2032)

The near-term phase addresses the most pressing capacity deficits driven by the steep ramp in large load customer demand. Eversource Missouri West's summer peak is expected to grow from approximately 2.2 GW in 2026 to 2.9 GW by 2032, approximately 32% growth driven by higher SPP RARs and significant load growth.

Before the CCN resources reach commercial operation, Eversource Missouri West bridges its capacity position through market capacity purchases of up to 250 MW in summer and 500 MW in winter during 2026–2029, supplemented by the continuation of demand response programs approved under MEEIA Cycle 4. Market capacity purchases are expected to be expensive and scarce as SPP tightens RARs, and Eversource Missouri West has limited its reliance to conservative levels based on ongoing counterparty negotiations.

12.3.2 Mid-term (2033–2038)

The mid-term phase manages the transition of the coal fleet and adds targeted resources to sustain reliability through a period of continued, though moderating, load growth. A 150 MW solar resource in 2035 provides energy diversity and extends Eversource Missouri West's runway for Missouri RES compliance. While the 2035 solar resource does not qualify for the PTC under the OBBBA's accelerated phase-out, it was selected by the capacity expansion model on an unsubsidized basis and contributes renewable energy that delays the onset of the RES compliance gap identified in Section 10.8.

A half CCGT (355 MW) in 2036 replaces the capacity lost from the planned retirement of JEC 3 in March 2036 (59 MW accredited capacity) and sustains the capacity balance as the system absorbs the JEC 2 conversion to natural gas operation in 2035. Lake Road 4/6 retires in March 2038 (89 MW accredited capacity), and the existing fleet — including Iatan 1, JEC 1, and Iatan 2, all of which are extended beyond 2045 — provides sufficient capacity to absorb that retirement without additional resource additions in the 2037–2039 timeframe.

No new wind resources are selected in this phase, reflecting the loss of PTC eligibility for wind projects beginning operation after 2029–2030 under the OBBBA, approximately 30% higher wind development costs compared to prior IRPs, and the current carbon policy outlook. The 2025 Preferred Plan included 1.5 GW of wind additions between 2031 and 2042; the elimination of these additions in the 2026 Preferred Plan reflects the combined effect of shortened PTC eligibility, higher fixed costs, and local permitting challenges. Eversource Missouri West continues to value resource diversity and will continue to evaluate renewable economics in future IRP cycles and will pursue additions to the extent they are competitive and buildable.

12.3.3 Long-term (2039–2045)

A half CCGT (355 MW) in 2040 rounds out the portfolio to meet continued load growth and maintain capacity margins as wind PPA contracts begin to expire in the later years of the planning horizon. No additional resource selections are made in the 2041–2045

timeframe under Plan ADAA, as the extended operation of Unit 1, JEC 1, and Unit 2 provides sufficient capacity through the end of the planning period.

Resource selections this far into the planning horizon carry inherent uncertainty and will be refined in future IRP cycles as technology costs, customer commitments, carbon policy, and regional RARs evolve.

Across all three phases it is expected that sourcing resources to cover needs will be achieved through a combination of projects identified through the 2025 all source RFP that was issued in May 2025, potential future all source RFPs, and Eversource self-developed projects.

12.4 Resource Acquisition Strategy — Near-Term Preferred Plan Resources

Eversource Missouri West's acquisition strategy for the 2026 Preferred Plan is designed to secure the resources needed to meet customer energy requirements on a timeline consistent with the capacity needs identified in this IRP, while managing development risk, preserving financial flexibility, and maintaining optionality as market conditions evolve.

12.4.1 Supply-Side Implementation Schedules

Combine Cycle Additions – Viola and McNew Plants

The Preferred Plan includes the construction of two advanced class 710 MW CCGT generating facilities known as the Viola Generating Station and the McNew Generating Station. The configuration and equipment for the two CCGT facilities will be substantially the same. These combined cycle plants are slated to be shared 50/50 between Eversource Missouri West and Eversource Kansas Central. The Viola facility has a planned commercial operation date in the first quarter of 2029. The McNew facility has a planned commercial operation date in the first quarter of 2030. A schedule of the major milestones for the CCGT plants is detailed in Table 33.

Table 33: Combined Cycle Implementation Milestones

Illustrative Milestone Schedule (By Developer or Evergy)	CCGT #1 (Viola) Expected Completion	CCGT#2 (McNew) Expected Completion
Air Permit Approved	Q4 2025	Q4 2025
Construction Begins	Q1 2026	Q1 2027
Gas Turbine Delivery	Q3 2027	Q3 2028
Generator Step Up Delivery	Q4 2027	Q3 2028
Commissioning	Q1 2029	Q3 2029
In Service	Q1 2029	Q1 2030

Simple Cycle Addition – Mullin Creek #1

The Preferred Plan also includes the construction of one advanced class 440 MW SCGT generating facility known as the Mullin Creek #1 Generating Station (Mullin Creek #1). The Mullin Creek #1 facility has a planned commercial operation date of Q1 2030. This plant, along with the two CCGTs, will satisfy the 1,150 MW need for thermal resources identified in the 2026 Preferred Plan. A CCN that authorizes Evergy Missouri West to construct, install, own, operate, and control these plants was received from the Missouri Public Service Commission on August 10, 2025. A schedule of the major milestones for the Mullin Creek #1 plant is detailed in Table 34.

The five resources authorized under the CCN (EA-2025-0075) — Foxtrot Solar, Sunflower Sky Solar, Viola CCGT, McNew CCGT, and Mullin Creek #1 SCGT — are in active development and construction.

Table 34: Mullin Creek #1 Implementation Milestones

Milestone Description	Expected Completion
Receive Baseline Schedule from EPC	Q2 2026
Air Permit Approved	Q3 2026
Construction Begins	Q3 2026
Gas Turbine Delivery	Q3 2028
Generator Step Up Delivery	Q1 2029
Commissioning	Q1 2030
In Service	Q1 2030

2026 Solar Additions

The 2026 solar additions are modeled from responses to Evergy’s 2023 All-Source RFP. Evergy plans to move forward with the acquisition process out of the RFP offered projects. Effective August 9, 2025, Evergy Missouri West received CCNs authorizing it to construct, install, own, operate, manage, maintain, and control two solar generating facilities. These facilities are known as the Sunflower Sky Solar Project, and Foxtrot Solar Energy LLC. Details of the projects are provided below.

Sunflower Sky Solar

Sunflower Sky Solar is an 88 MWdc/65 MWac single axis tracking photovoltaic solar facility located in Wilson County, Kansas. The project is being developed by a third-party developer and is projected to go commercial in the second quarter of 2027. This project is being acquired through a development asset sale, which means the developer will complete the early phase project due diligence and Evergy will be responsible for project construction.

A schedule of the major milestones for the Sunflower Sky project is detailed in Table 35.

Table 35: Sunflower Sky Solar Implementation Milestones

Milestone Description	Expected Completion
Predrilling and Pile Installation	Q2 2026
Module Installation	Q2 2026
Main Power Transformer Installation	Q3 2026
Inverter Installation	Q4 2026
Civil/Site Construction	Q4 2026
In Service	Q2 2027

Foxtrot Solar

Foxtrot Solar is a 130 MWdc/100 MWac single axis tracking photovoltaic solar facility located in Jasper County, Missouri. The project is being developed by a third-party developer and is projected to go commercial in the second quarter of 2027. Evergy is purchasing this project through a build transfer agreement, which has both acquisition agreement and construction contract portions. The developer is responsible for securing land rights, permits, interconnection rights, approval from local jurisdictions, and required engineering, land, and water studies of the site. Once the development work and a contract have been finalized, the project goes into the construction phase. The developer (or its contractor) will then procure all necessary material, design, and build the project. In the case of Foxtrot, the developer will hire a contractor to provide these services. A schedule of the major milestones for the Foxtrot project is detailed in Table 36 below:

Table 36: Foxtrot Solar Implementation Milestones

Milestone Description	Expected Completion
Pile Installation	Q2 2026
Civil/Site Construction	Q3 2026
Module Installation	Q3 2026
Main Power Transformer Installation	Q4 2026
Inverter Installation	Q4 2026
In Service	Q2 2027

In addition to the planned resources detail above, the IRP has identified an additional 150 MWs of solar that is needed in 2035. 355 MW of thermal was identified as a need in 2032, followed by an additional 355 MW in 2036. 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 that was issued in May 2025, potential future all source RFPs, and Evergy self-developed projects.

Section 13: Joint Agreements and MO CCN Stipulations

From the 2024 Triennial Joint Agreement (EO-2024-0154) and CCN Stipulation and Agreement (EA-2025-0075), the following agreements are addressed as follows:

13.1 Ranges of Critical Factors

Evergy Missouri West conducted sensitivity analysis to determine how variations in CUF probabilities would change the expected economics of the resource plans. Evergy Missouri West used seven probability variations to understand how the ranges are most impactful. Variation 1 uses a 75% weighting for the Low forecast and 25% weighting for the Mid forecast, with 0% weighting for the High forecast. Variations 2 and 3 decrease the Low weighting while increasing the Mid weighting, still giving no weight to the High. Variation 4 gives equal weight (1/3) to all three forecasts. Variations 5-7 give no weight to the Low Forecast and vary the weights of the Mid and High forecasts.

Table 37: Variations in Probability of CUF Forecast

	1	2	3	4	5	6	7
Low	75%	50%	25%	33%	0%	0%	0%
Mid	25%	50%	75%	33%	75%	50%	25%
High	0%	0%	0%	33%	25%	50%	75%

Three representative plans were compared with the Preferred Plan ADAA. Plan ADBA accelerates the first resource addition, a ½ CCGT, by one year to 2031.

Table 38: NPVRR Difference Plan ADBA – Plan ADAA

	1	2	3	4	5	6	7
NG	56	55	55	51	52	49	45
CO2	55	55	55	51	52	49	45
ConCost	43	47	51	55	59	63	67

Plan ADBA has a higher weighted-NPVRR than Plan ADAA in all probability distributions. However, as the probability of higher natural gas prices increases or the probability of higher CO₂ tax increases, Plan ADBA becomes slightly more favorable with smaller

differences from Plan ADAA. With probabilities skewing toward Low Construction Cost, Plan ADDB is also more favorable, but is still more expensive than Plan ADAA.

Plan ADCA adds 300 MW of storage to the resource plan, which postpones the ½ CCGT addition to 2033 and reduces future resource needs. This ARP also has a higher weighted-NPVRR than Plan ADAA in all probability distributions. Plan ADCA is relatively less desirable as the probabilities of High NG prices and High CO₂ taxes increase. Construction Cost probabilities have very little effect on the NPVRR difference between the plans.

Table 39: NPVRR Difference Plan ADCA – Plan ADAA

	1	2	3	4	5	6	7
NG	346	336	327	361	340	363	387
CO2	286	296	307	349	352	386	421
ConCost	318	318	318	316	316	315	314

Plan ADAB was optimized for the High CO₂/High NG Forecast scenario. It adds a ½ CCGT in 2033, instead of 2032 as in Plan ADAA. It also selects an additional 3 GW of renewables – 600 MW of wind in the earlier years and 2,400 MW of solar in the later years. It does not require additional thermal resources.

Table 40: NPVRR Difference Plan ADAB – Plan ADAA

	1	2	3	4	5	6	7
NG	838	835	832	566	629	429	229
CO2	955	913	871	536	567	305	43
ConCost	495	607	718	837	947	1,064	1,181

Plan ADAB has a higher weighted-NPVRR than Plan ADAA in all probability distributions, however the distributions show significant NPVRR differences. Plan ADAB is significantly more expensive if it is expected that future NG prices will be lower and CO₂ taxes will be lower. The most cost convergence with Plan ADAA is seen with the highest probability of high CO₂ tax. Plan ADAB also becomes significantly more expensive than Plan ADAA as High Construction Costs become more probable.

13.2 Battery Storage and Surplus Interconnection

Eversource Missouri West considered battery storage as a resource candidate in the 2026 IRP. Consistent with the 2025 IRP, storage was not selected in the Preferred Plan. In its most recent RFP, Eversource received offers for stand-alone and co-located storage. Eversource has also explored options for locating storage at existing resource sites that have surplus interconnection available.

13.3 AQCS, Environmental Mitigation, and Unit Upgrade Costs

It is assumed for this IRP that no significant air quality control equipment is required to be added. Remediation costs, including those associated with coal combustion residual (“CCR”) disposal, are fully dependent on prior operations and do not vary based on electric generating unit retirement decisions. Any remediation required will be dependent on environmental monitoring results taken for that asset and the applicable regulations at time of closure.

13.4 Retirement Cost-Benefit Analysis

As outlined in Section 10.4 Plans Testing Retirements, Eversource Missouri West tested coal resource retirement decisions using capacity expansion and base planning assumptions, including the updated load, DSM program, and resource adequacy forecasts. Resources with CCN are included in all plans.

The baseline Plan AAAA uses retirement dates identified in the 2025 Annual Update Preferred Plan. Plans ABAA, ACAA and ADAA use the same base assumptions but vary the retirement dates. Plan ABAA postpones the Jeffrey 3 retirement from March 2031 to March 2036 and the Lake Road 4/6 retirement from 2030 to March 2038. Plan ACAA also postpones the Jeffrey 2 conversion to NG from 2030 to 2035. Plan ADAA incorporates the previous date changes and also postpones the Iatan 1 and Jeffrey 1 retirements from March 2040 to beyond 2045 (the last year in the IRP 20-year window). These retirement dates are summarized in the following Table.

Table 41: Coal Resource Retirement Dates

Generation Unit	Plan AAAA	Plan ABAA	Plan ACAA	Plan ADAA
Iatan 1	March 2040	March 2040	March 2040	Beyond 2045
Iatan 2	Beyond 2045	Beyond 2045	Beyond 2045	Beyond 2045
Jeffrey 1	March 2040	March 2040	March 2040	Beyond 2045
Jeffrey 2	NG 2030 retire Beyond 2045	NG 2030 retire Beyond 2045	NG 2035 retire Beyond 2045	NG 2035 retire Beyond 2045
Jeffrey 3	March 2031	March 2036	March 2036	March 2036
Lake Road 4/6	December 2030	March 2038	March 2038	March 2038

The 2025 Preferred Plan is the highest cost based on the weighted-average NPVRR of \$23.406 billion across all planning endpoints. Extending the Jeffrey 3 and Lake Road 4/6 retirements in Plan ABAA reduces cost by \$23 million to \$23.383 billion. The incremental postponement of the Jeffrey 2 gas conversion in Plan ACAA reduces cost by an additional \$39 million to \$23.344 billion. The extension of the Iatan 1 and Jeffrey 1 retirements in Plan ADAA further reduces costs by \$67 million to \$23.277 billion for a total benefit of \$128 million versus Plan AAAA.

The cost reductions demonstrate the economic benefit of extending coal resources, which can adjust the nature and timing of new resource additions or eliminate the need altogether. Referring to the build plan figures in Section 10.4, Plans ABAA, ACAA, and ADAA produce the following changes compared to Plan AAAA:

- **Plan ABAA vs. Plan AAAA:** Extending the Jeffrey and Lake Road 4/6 retirements delays by one year 355 MW CC from 2035 to 2036 and advances 150 MW solar from 2039 to 2035.
- **Plan ACAA vs. Plan AAAA:** Postponing to Jeffrey 2 gas conversion produces the same capacity expansion plan as Plan ABAA.
- **Plan ADAA vs. Plan AAAA:** Postponing the Iatan 1 and Jeffrey 1 retirements retains the Plan ABAA changes and additionally eliminates the need for 148 MW RICE in 2043.

While the total NPVRR presents the relative value of the plans, a more detailed review of the NPVRR components can provide a better understanding of what drives the capacity

expansion decisions. The weighted-average NPVRR is composed of 27 distinct endpoints representing various assumptions for electricity prices, natural gas prices, carbon dioxide regulation, and construction costs. Since capacity expansion modeling is conducted using the mid-point for these assumptions, a review of the results for the M2C endpoint can illustrate the relative costs and benefits of the plans. The following results show that the M2C endpoint produces a similar trend in NPVRR values to the overall weighted-average NPVRR, with Plan ADAA yielding the lowest cost by \$98 million for the M2C endpoint and by \$128 million for the weighted-average values.

Table 42: Coal Retirement Plan Midpoint vs. Weighted-Average NPVRR

NPV (\$ million)	Plan AAAA	Plan ABAA	Plan ACAA	Plan ADAA	ADAA vs AAAA
Wtd-Avg	23,406	23,383	23,344	23,277	(128)
M2C	22,745	22,729	22,698	22,646	(98)
M2C vs W-A	(661)	(653)	(646)	(631)	-
% Diff	-2.8%	-2.8%	-2.8%	-2.7%	-

Focusing on the M2C results, the Plan ABAA is \$16 million less than Plan AAAA, Plan ACAA is \$47 million less than Plan AAAA, and Plan ADAA is \$98 million less than Plan AAAA. For brevity, the following detailed review presents a comparison of Plan ADAA to Plan AAAA. Since all the retirement extensions produce a reduction in costs, the findings for Plans ABAA and ACAA are similar to the comparison of Plan ADAA to Plan AAAA.

At the plan level, the \$98 million cost reduction is driven by increased generator revenue, lower generation cost, and decreased generator retirement cost partly offset by higher fixed costs and emissions cost.

Table 43: Coal Retirement Plan NPVRR Detailed Summary

NPVRR (\$ million)	M2C ADAA	M2C AAAA	ADAA vs AAAA
Cost to Load	\$7,751	\$7,751	\$0
Total Fixed Costs	\$4,948	\$4,938	\$11
Generation Cost	\$5,094	\$5,175	(\$81)
Emissions Cost	\$813	\$783	\$30
Generator Pool Revenue	\$5,032	\$5,015	\$17
Penalty Cost	\$6	\$6	\$0
Generator Retirement Cost	\$11	\$52	(\$41)
Model RR (All Costs - Pool Revenue)	\$13,591	\$13,689	(\$98)
Rest of Company RR	\$9,055	\$9,055	\$0
NPVRR	\$22,646	\$22,745	(\$98)

The increase in generator revenue (\$17 million) and decrease in generation cost (\$81 million) combine to improve aggregate generation margin by \$98 million. All generator classes produce higher total margins, with an increase of \$32 million for coal resources, \$39 million for gas resources, and \$27 million for solar.

The \$41 million reduction in generator retirement costs is attributed to the extension of operations for the coal resources.

The \$11 million increase in fixed costs is the net of increases totaling \$138 million for coal (\$72 million) and solar (\$66 million) and decreases totaling \$127 million for gas resources (\$59 million CT, \$66 million RICE) and market capacity purchases (\$2 million).

The \$30 million increase in emissions cost consists of a \$52 million increase for coal generators coupled with a \$22 million decrease for gas resources.

In summary, the cost of extending coal resources produces a benefit for customers based on improved generation margins and lower retirement costs. This benefit is partly offset by increases in fixed costs and emissions cost.

13.5 Virtual Power Plants (“VPPs”)

Eversource engaged with Cadmus to evaluate the VPP as a grid storage resource. This analysis evaluates the costs and operational performance of a proposed 5 MW/20 MWh residential behind the meter (“BTM”) battery fleet, consisting of customer-owned 3.6 kW/14.4 kWh battery systems. The program analysis reflects realistic dispatchable capacity, program administration requirements, and an annual incentive for participants.

13.5.1 Realistic Dispatchable Capacity

A key modeling element is the differentiation between a battery’s available capacity and its achievable capacity for demand-response dispatch. While the LG ESS H8 inverter is capable of short duration output near 6 kW, a 14.4 kWh battery can sustain no more than 3.6 kW over a four-hour event. To account for customer-owned systems and realistic operating constraints, the model applies a 70% availability factor based on state of charge limits (85% maximum, 15% minimum). This adjustment results in an estimated 2.52 kW of achievable dispatch capacity (or 3.5 MW for the total program battery fleet), which is used to calculate incentive payments. Annual battery degradation is estimated at 2%, and incentive payments are reduced to reflect this decline in capacity.

13.5.2 Program Costs

Program costs are categorized into one-time marketing and recruitment costs and ongoing fixed O&M costs. Annual fixed costs include program administration—based on Eversource’s demand response management system (“DRMS”) and overhead assumptions—and performance-based participation incentives.

13.5.3 Performance-Based Participation Incentives

Customer enrollment varies with incentive structure, so this analysis considered 3 potential incentive scenarios:

- **Low Incentive Scenario:** Based on avoided capacity costs (adjusted for losses), representing the most cost-effective approach.

- **High Incentive Scenario:** Reflects the highest performance incentive identified in benchmarking, providing a comparison with leading residential bring your own battery programs.
- **Mid Incentive Scenario:** Calculated as the midpoint between the low and high scenarios.

13.5.4 Cost Modeling

Since the customer participation rate at any given incentive level can't be known without a potential study, Evergy conducted detailed modeling using avoided capacity costs (low incentive) assuming participation at the full 5MW / 20 MWh level. Avoided capacity was valued at the price of market capacity purchases in the IRP model. Program administration costs were included to arrive at total expenses. The net revenues from battery operations were subtracted from the program expenses to produce a net cost estimate.

13.5.5 Total Program Cost

Using the low incentive assumptions, the VPP program was modeled as an addition to the preferred plan. The NPVRR comparison of the plans shows that the VPP adds \$10 million in cost. The following Table presents these results.

Table 44: VPP Program Cost Summary

Rank	Plan	NPVRR	Difference	Description
1	ADAA	23,277		Base
2	ADAM	23,287	10	VPP Plan

Section 14: Special Contemporary Issues

From the Commission Order, EO-2026-0036, the following Special Contemporary Resource Planning Issues are addressed as follows:

14.1 Nuclear Permitting, Construction, Credits, and Policies

The process is generally divided into three main phases: Planning and Licensing, Construction, and Commissioning & Operation. The typical timeline for the permitting and construction of a new commercial nuclear power plant in the US at a greenfield site is 10 to 12 years total, with 4-6 years for the licensing/permitting phase and over 6 years for construction and commissioning. This can be longer or shorter depending on project management, regulatory stability, and whether a certified reactor design is used. In addition, recent executive orders and congressional acts seek to improve these timelines.

14.1.1 Phase 1: Planning and Licensing (Approximately 4-6 Years)

This phase is dominated by extensive studies, design finalization, and approvals from the Nuclear Regulatory Commission (“NRC”). Pre-application licensing correspondence and supporting design analysis and calculations should be completed at early stages prior to studies and permit application requests.

Project Initiation and Feasibility Studies

Initial engineering, design, and site analysis (geological, hydrological, meteorological, environmental).

- Duration: 1-2 years

Early Site Permit (“ESP”) Application and Review

The applicant may apply for an ESP to address site suitability independent of a specific reactor design. This can include a Limited Work Authorization (“LWA”) for non-safety related site preparation.

- Application Development and NRC Review: 2-4 years (NRC review has typically been 24 months).

Design Certification

The NRC certifies a standard reactor design through a separate rulemaking process, which is then valid for 40 years and can be referenced by multiple applicants to streamline their process.

- Duration: ~18 months for the NRC review of the application.

Combined Operating License (“COL”) Application and Review

If an ESP and certified design are used, the process is more streamlined. A COL application need not be preceded by an ESP and a certified design. The NRC review will be longer as site suitability and reactor design will be reviewed as part of the COL review. The NRC conducts safety and environmental reviews, a mandatory public hearing, and a final decision on whether to issue the COL, which authorizes both construction and operation.

- Duration: ~18 months for the NRC review (if a certified design and ESP are used).

14.1.2 Phase 2: Construction (Approximately 6-8 Years)

Once the COL is issued, physical construction of safety-related facilities can begin. Construction of non-nuclear assets such as training facilities, etc. typically are before nuclear construction or in parallel.

Site Preparation and Infrastructure

Clearing, excavation, and grading (some non-safety work may be done earlier with an LWA).

- Duration: ~1 year (overlaps with licensing phase if LWA is used)

Major Construction

Pouring foundation concrete, building primary structures, installing major components (reactor vessel, steam generators, piping, electrical systems).

- Duration: 4-6 years

Inspections and Testing

Throughout construction, the NRC performs inspections, tests, and analyses to verify the plant is built according to the approved design and safety requirements.

14.1.3 Phase 3: Commissioning and Operation (Approximately 1 Year)

This phase involves final testing and transitioning the facility to commercial operation.

Fuel Loading and Pre-operational Testing

Once construction is substantially complete, the NRC conducts final reviews and authorizes the loading of nuclear fuel.

Startup Testing and Commercial Operation

A period of testing to ensure all systems operate correctly, followed by the start of commercial power generation.

- Duration: ~1 year

Past data within the US is provided in the Table below for the existing nuclear fleet build times and recent Vogtle 3 reactor. International data is provided for recent builds of large nuclear reactors as comparison. Some SMRs are partially through Phase 1 but have not completed Phase 2 or 3. For those reactors, estimates are provided based on published schedules.

Table 45: New Nuclear Reactor Timeline Comparison

Technology	Phase 1	Phase 2	Phase 3
Generic Large Nuclear Reactor	4-6 yrs	6-8 yrs	1 yr
Vogtle 3 Reactor (~1000 MWe)	3-4 yrs	9-10 yrs	<1 yr
International Large Nuclear Reactor (>800 MWe)	1-2 yrs	8-9 yrs	<1 yr
Small Modular Reactor (Terrapower 345 MWe)	1-2 yrs	3 yrs	<1 yr

As for existing sites, using Wolf Creek Nuclear Generating Station as an example, here are several considerations:

- Licensing and permitting timelines would be generally shortened as existing analysis and studies can be used versus creating new ones.
- Architectural planning and alternate siting reviews would be roughly the same timeline as a new construction.
- Impacts to the existing station's switchyard and transmission capacity would have to be analyzed to determine needs to additional switchyard buildout and whether another 345kV transmission line would be needed to remove power from new builds and prevent congestion.
- Other impacts requiring analysis and attention would be water rights/needs of a new station including expected impacts to Coffey County cooling lake temperatures.
- Based on existing infrastructure, training staff, and experienced nuclear personnel, it is expected that commissioning timelines would be shortened.

14.1.4 Tax Credit Availability and Achievability

While tax credits for both existing and new nuclear facilities are available under the IRA, new tax credit restrictions and accelerated phaseouts were enacted by the OBBBA in July 2025, which may make achieving milestones for new projects more difficult. The following are influenced by the aforementioned congressional acts:

- **Zero-Emission Nuclear Power Production Credit (Section 45U):** Available for existing nuclear facilities through 2032.
- **Advanced Nuclear Reactor Production Tax Credit (Section 45J):** Applied to facilities in service after August 9, 2005. It provides a tax credit for the first eight years of operation.
- **Clean Electricity Investment/Production Tax Credits ("CEITC/CEPTC"):** Nuclear plants placed in service after 2024 were initially eligible for these technology-neutral credits under the IRA. However, the OBBBA repealed CEITC and CEPTC for nonnuclear facilities built after late 2028, and it introduced a slower phaseout schedule for nuclear facilities starting in 2033. A caveat is that facilities

beginning construction after December 31, 2025, are ineligible for the credit if they receive "Material Assistance" from or are under "effective control" by a "Prohibited Foreign Entity" ("PFE"), including those from China or Russia.

- **Bonus credits:** New and existing reactors may qualify for bonus tax credits for generating clean hydrogen, and the OBBBA added a new bonus for advanced nuclear facilities in specific metropolitan areas.

14.1.5 Nuclear-Based Energy Attributes

Nuclear-based energy attributes are tracked through regional, electronic Energy Attribute Certificate ("EAC") tracking systems. While many of these systems were initially designed for RECs, many now also register and track attributes from non-renewable sources, including nuclear generation. The U.S. does not have a single national tracking system, but rather a number of regional systems, such as PJM-GATS, NEPOOL-GIS, WREGIS, and ERCOT. These systems create a unique, serial-numbered electronic certificate for every megawatt-hour of electricity generated. The certificates contain information about the generation source (fuel type, location, emissions rate, etc.), ensuring transparency and preventing double-counting of claims.

A specific type of EAC often associated with nuclear generation is the Zero-Emissions Credit ("ZEC"), also called an emission-free energy certificate. These credits verify the carbon-free nature of nuclear power. ZECs provide qualifying reactors with a supplemental payment—in addition to what they receive in the wholesale market—for every megawatt-hour of carbon-free electricity sold. While Illinois was one of the first states to enact a ZECs policy, the legislature decided to expand its support for the state's nuclear fleet with the passage of the Climate and Equitable Jobs Act in 2021. The state now supports five nuclear power plants through ZECs-style policies—up from two that were supported under the 2016 legislation. Through the Infrastructure Investment and Jobs Act ("IIJA"), Congress established a federal program that is substantially similar to these state ZECs programs: the Civil Nuclear Credit Program ("CNCP"). The CNCP is available to nuclear power plants across the nation.

14.1.6 State Policies (Renewable or Clean Energy Standards)

State-level policies on energy standards are the primary drivers for the use of these certificates. The key distinction in policies is between a Renewable Portfolio Standard (“RPS”) and a Clean Energy Standard (“CES”).

RPS

These standards typically require electricity suppliers to source a minimum percentage of their electricity Missouri Public Service Commission Order Response Input 8 from renewable resources (e.g., wind, solar, hydro, geothermal). Nuclear energy is generally not considered a renewable source and is therefore often ineligible under traditional RPS policies.

CES

CES policies employ a broader definition of qualifying resources to include any zero-carbon or carbon-neutral energy source. Many states have adopted a CES specifically to include nuclear power, recognizing its carbon-free attributes. The goal of a CES is often to achieve more ambitious overall emissions reductions by allowing a wider range of technologies to count toward the goal.

States with Policies that Include Nuclear Attributes (often via ZECs or a CES)

Several states have adopted policies to support their existing nuclear fleets or promote new nuclear capacity by recognizing its clean energy attributes. Examples include:

- New York (adopted ZEC program in 2016)
- Illinois (adopted ZEC program in 2016)
- New Jersey (adopted ZEC program in 2018)
- Connecticut (established ZEC program in 2022)

These state policies use the regional tracking systems (like PJM-GATS and NYGATS) to verify compliance, ensuring that utilities and power marketers can demonstrate their use and retirement of the appropriate energy attribute certificates.

14.2 Large Load Customers

Evergy is evaluating a pipeline of large load customer requests to connect within the Evergy service territories. In addition to the customers that were discussed in detail in Section 3 and included in the 2026 IRP base load forecast, there are numerous customer projects that are being considered for electric service at Missouri West. Table 46 describes the attributes of four customers in Missouri West’s large load pipeline by detailing the customer type, status of Evergy’s internal transmission interconnection study, status of whether the project has completed SPP’s transmission study for load additions, and the customer’s requested ramp in the years 2028 to 2033. The ability to meet the customer’s desired ramp will be heavily dependent upon transmission infrastructure requirements and timing for delivery of interconnection facilities and transmission network upgrades. Additionally, generation capacity to meet the customer’s ramp may not be available on the timeline requested. The combination of potential transmission and generation capacity constraints may require the customer to ramp their projects online later than originally requested. Evergy expects to continue to work with customers in its pipeline to further understand the requirements, feasibility, and fit for Evergy’s service territory.

Table 46: Missouri West Large Load Customer Pipeline

Customer	Jurisdiction	Customer Type	Interconnection Studies		2028	2029	2030	2031	2032	2033
			Evergy Complete?	SPP Complete?						
Company A	EMW	Data Center	No	No	225	375	500	500	500	500
Company B	EMW	Data Center	No	No	100	150	250	250	250	250
Company C	EMW	Data Center	No	No	200	400	400	400	400	400
Company D	EMW	Data Center	No	No	600	600	600	600	600	600
<i>*Load request information based on most recent customer engagement and subject to change.</i>					1,125	1,525	1,750	1,750	1,750	1,750

14.3 Renewable Energy Standard Requirement

Graphs/metrics are included in the plan workbook workpapers to gauge how much future resource plans meet the RES requirement. However, capacity expansion models were not calibrated to solve for this. With recent policy headwinds favoring dispatchable, base load generation to meet emerging large load growth, the Evergy Missouri West 2026 Preferred Plan falls short in 2037 (the slight dip in 2033 and 2034 would be satisfied by

the prior 3 years’ worth of renewable credits), so minimum RES plans were made in Section 10.8. Analysis shows that complying with the Missouri RES with either only solar or wind resources significantly makes the plan more expensive than the Preferred Plan. Evergy will also explore utilizing renewable energy credits/PPAs in the future to help meet the requirement.

In terms of varying large load scenarios, the already short RES position becomes even shorter as depicted in the following Table. The general rule of thumb was that on an average hourly generation basis, it would take half as many wind units when compared to the number of solar units needed to generate a similar amount of renewable energy for RES compliance (the solar/wind units below have some rounding to them).

Table 47: EMW Large Load Plans RES Compliance Comparison

	ADAA	CDA A	DDAA	BDAA	EDAA	FDA A
RES (Short) by 2045 (Average Hourly MWh)	(164)	(268)	(152)	(322)	(224)	(403)
150 MW Solar Units Needed	4	7	4	8	6	11
150 MW Wind Units Needed	3*	4	2	4	3	5

**One more wind unit needed to be built to satisfy the RES requirement through 2045*

Plan ADAA, as was seen in Section 10.8, needed either 600 MW of solar or 450 MW of wind to satisfy the RES requirement all the way through the time horizon. Plan CDAA not only has a greater load ramp than Plan ADAA, but it also elects to not build a solar unit in 2035 (both plans had the CCN approved solar resources in 2027), which increases the number of solar or wind renewable resources needed by 2045. Although Plan DDAA has a greater load ramp than Plan CDAA, the plan elects to build solar units in 2031, 2043, and 2044 units which helps lessen the RES need by the end of the time horizon. However, prior to the 2043 and 2044 buildouts, the RES called for about 7 solar units or 3/4 wind units to be built by 2042. Plan BDAA is the next largest load ramp, and it does not elect to build any renewable resources apart from the CCN approved resources like Plan CDAA. This makes the RES need 8 solar units or 4 wind units by 2045. Plan EDAA is the second largest large load scenario, and it elects to build solar in 2044. This lessens the RES need by 2045, but peaks at 8 solar units or 4 wind units by 2043. Lastly, Plan FDAA

has the largest load ramp scenario and, like Plans BDAA and CDAA, does not elect to build renewable resources past the CCN solar resources. This makes it have the greatest RES need by 2045.

NPVRR analysis was not done for plans other than Plan ADAA, as they are contingency plans listed in Section 11 of this IRP. However, the NPVRR comparison shown in Section 10.8 makes it evident that fulfilling the RES requirement for the varying large load scenarios would result in much more expensive plans when compared to the Preferred Plan ADAA.

14.4 Geologic Hydrogen Onsite or Near Natural Gas Storage

As recently as September 2022, Eversource has supported the analysis of the presence of geologic hydrogen within our region and the viability of storing it underground (specifically in salt caverns). Appendix D: H-2-SALT Storing Fossil Energy as Hydrogen in Salt Caverns, coordinated by Dr. Franciszek Hasiuk at the University of Kansas and submitted to the U.S. Department of Energy, highlighted that storing hydrogen both below and above ground were viable opportunities within the Company's service territory. The study's authors go as far as indicating, under certain circumstances, the commercial viability of co-locating hydrogen storage with both an electrolyzer and a natural gas combustion cycle plant that is capable of burning fuel with blended hydrogen. While the result seems promising, it is the Company's position to continue monitoring the exploration of geologic hydrogen formations and how it could be utilized to serve customer needs.