EVERGY MISSOURI WEST

INTEGRATED RESOURCE PLAN

2022 ANNUAL UPDATE

JUNE 2022

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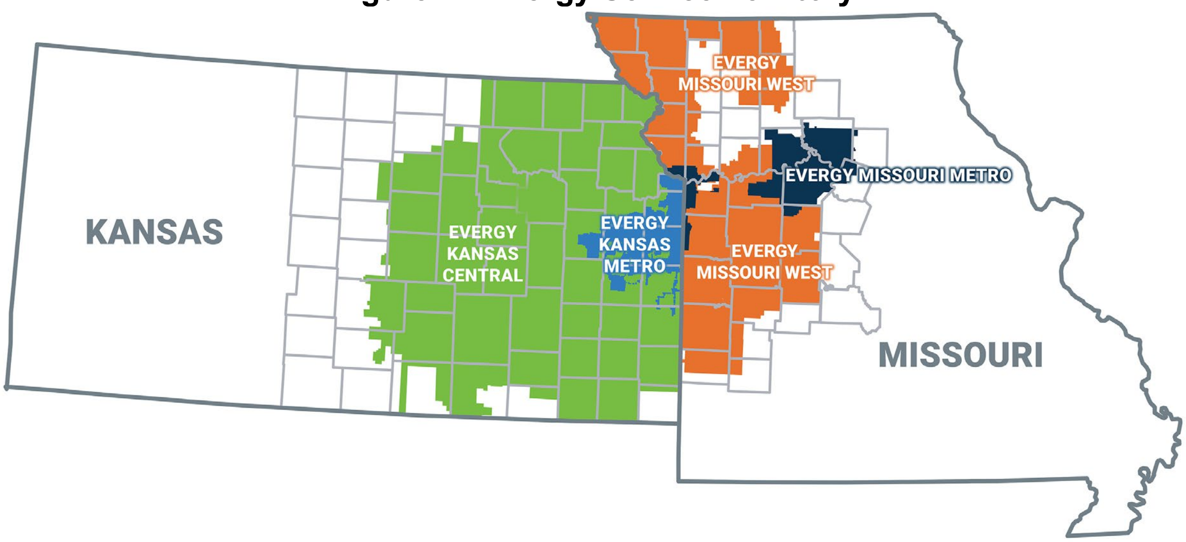
SECTION 1: EXECUTIVE SUMMARY

1.1 UTILITY INTRODUCTION

Evergy Missouri West ("Evergy West" or "Company") 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 West also provides regulated steam service to certain customers in the St. Joseph, Missouri area. A map of the entire Evergy service territory which includes Evergy West is provided in Figure 1 below:

Figure 1: Evergy Service Territory



Evergy West is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Table 1 provides a snapshot of the number of customers served, retail sales and peak demand based upon 2021 data.

Table 1: Evergy West Customers, NSI and Peak Demand

Jurisdiction	Number of Retail Customers	Retail Sales (MWh)	Net Peak Demand (MW)
Evergy Missouri West	**336,644**	**8,320,976**	**1,925**

Evergy West owns and operates a diverse generating portfolio and Power Purchase Agreements (PPA) to meet customer energy requirements. Table 2, Figure 2, and Figure 3 reflect Evergy West's generation assets operating in 2021.

Table 2: Evergy West Capacity and Energy By Resource Type

Capacity By Fuel Type	Capacity (MW)	Capacity (%)	Energy (MWh)	Energy (%)
Coal	460	19.0%	2,084,986	40.9%
Nat. Gas	1,116	46.1%	166,558	3.3%
Oil	57	2.4%	3,686	0.1%
Wind*	783	32.3%	2,832,959	55.5%
LFG	2	0.1%	11,088	0.2%
Solar	3	0.1%	4,498	0.1%
Total	2,421	100.0%	4,306,118	100%

* Wind capacity based upon nameplate

Figure 2: Evergy West Capacity By Resource Type

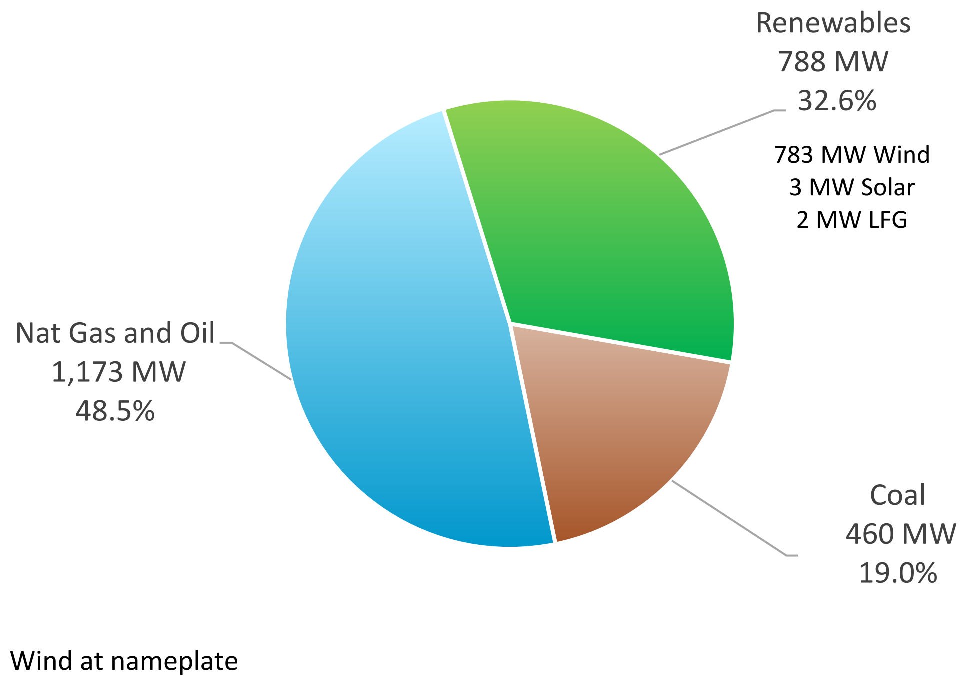
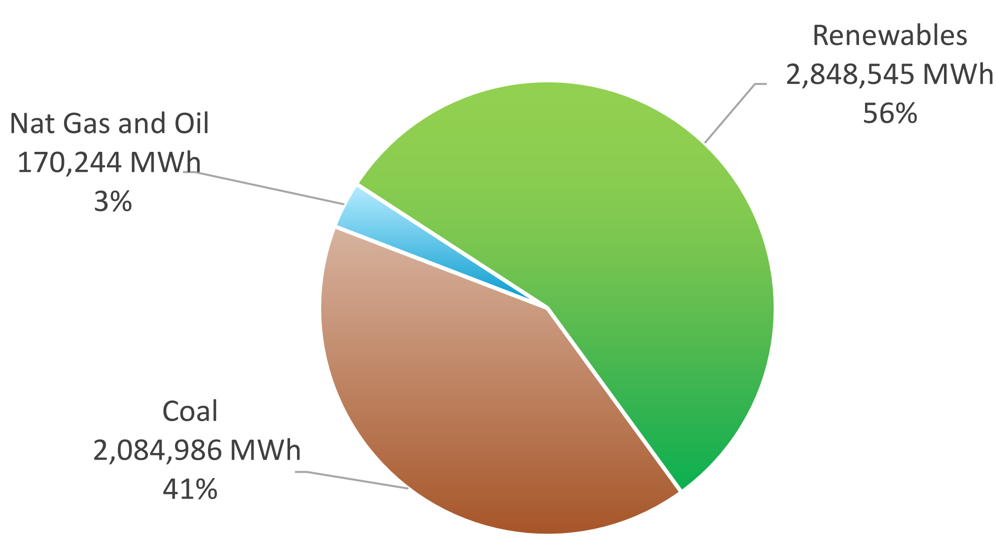


Figure 3: Evergy West Energy By Resource Type



1.2 CHANGES FROM THE 2021 TRIENNIAL IRP

On April 30th, 2021, Evergy Missouri West, Inc. submitted the triennial compliance filing related to Chapter 22 of the Missouri Public Service Commission ("Commission" or "MPSC") regulations concerning Evergy West's Electric Utility Resource Planning. The triennial compliance filing made in Case No. EO-2021-0036 consisted of eight sections of material including the "Evergy Missouri West Preferred Plan" identified in "Volume 7, Resource Acquisition Strategy Selection". The Preferred Plan included 120 MW of solar generation in 2024, and 80 MW of solar generation in each of 2028 – 2032. Additionally, 80 MW of wind generation in 2025 and 2026. The Preferred Plan also included retiring a 97 MW natural gas unit at Lake Road in 2024, Evergy Missouri West's 58 MW share of Jeffrey 3 in 2030, 58 MW share of Jeffrey 1 and 2 in 2039, and Evergy Missouri West's 126 MW share of Iatan 1 in 2039.

Since filing the 2021 Triennial IRP, changing conditions, or major drivers, were refreshed to reflect the latest information and forecasts available to determine if the Preferred Plan and associated Resource Acquisition Strategy identified in 2021 Triennial IRP continue to be the company's path forward. The information and forecasts that have been updated for the 2022 Annual Update include:

- Load forecasts
- Fuel forecasts
- Supply-side costs (both existing and new)
- Proposed and potential environmental regulations

In addition to these input changes, Evergy has also made changes to its modeling software and process in order to expand the capabilities of its planning process. The primary changes are listed below:

- Use of PROMOD for market price forecasts: This tool and process are consistent with the Southwest Power Pool (SPP) economic modeling methodology and produces granular nodal forecasts. In the past, market price forecasts were created using MIDAS.

- Use of Plexos for capacity expansion modeling: Through the implementation of Plexos, Evergy is now able to complete capacity expansion modeling. In capacity expansion modeling, the model (Plexos) is able to generate an "optimized" (lowest cost) resource plan given a certain market scenario and a set of constraints and resource options. This new capability has created additional flexibility in Evergy's modeling processes and was used in this 2022 Annual Update process to supplement individual Alternative Resource Plans which were used to test discrete decisions (similar to past IRPs). Capacity Expansion modeling was not performed using MIDAS in the past.

- Use of Plexos for production cost modeling: While Plexos' production cost modeling capability works similarly to MIDAS, this does represent a change in tool compared to the 2021 Triennial and previous IRPs.

Finally, while working through the procurement process for the near-term renewables from the 2021 IRP Preferred Plan, Evergy has made some shifts in timing for these projects based on relative project maturity within the wind and solar market. In addition, supply chain challenges caused by COVID-19 and federal policy have also resulted in a reduction in near-term (2023/2024) renewables based on available mature, high-value projects. These changes will be discussed in more detail in Section 7:.

1.3 2022 ANNUAL UPDATE PREFERRED PLAN

1.3.1 INTEGRATED RESOURCE PLAN OVERVIEW

Evergy's integrated resource planning experience spans many decades with its most recent Triennial Preferred Plans filed for both Evergy Metro and Evergy Missouri West in 2021 ("2021 IRP"). Between Triennial IRP filings, Commission regulations require annual updates reflect any material changes to the triennial filing and/or confirmation of the continued applicability of the originally filed Preferred Plan. This document includes the annual update filing for 2022 ("2022 Update") that, consistent with Commission regulations, outlines material changes to the 2021 IRP.

The Preferred Plans selected through this 2022 Update for Evergy Metro and for Evergy Joint Planning are materially consistent with the 2021 Preferred Plan, but include the following changes:

- Implementation Period (2022-2025): Changes have been made to the timing and scale of renewable investments in these years based on the responses received as part of Evergy's 2021 Requests for Proposal, including accelerating wind previously identified in 2025 and 2026 into 2024 and 2025 and delaying solar previously identified in 2024 to 2026. In addition, the retirement of coal generation at Lawrence Energy Center in 2024 has been modified to reflect the continued operation of Lawrence 5 on natural gas, as shown in Table 3 below. Finally, the planned retirement of Lake Road 4/6 in 2024 has been delayed to 2030. Note that because the delayed retirement of Lake Road 4/6 has no meaningful impact on Evergy's overall long-term capacity needs, it was not included in the Joint Planning Preferred Plan, but it did reduce costs for Evergy West and is included in the Evergy West Preferred Plan accordingly. The changes to the Evergy West Preferred Plan are described in Table 4 below.

Table 3: Evergy Joint Resource Plan Implementation Period 2022-2025

	2021 Triennial IRP	2022 IRP Annual Update
Retirements	Lawrence 4 & 5 in 2023 Lake Road 4/6 in 2024	Lawrence 4 & 5 (Coal) in 2024 Lake Road 4/6 in 2024
Wind Additions	500 MW in 2025	300 MW in 2024 500 MW in 2025
Solar Additions	350 MW in 2023 350 MW in 2024	190 MW in 2024
Gas Additions		Lawrence 5 NG (338 MW) in 2024
DSM	RAP (Metro and Missouri West), RAP- (Kansas Central)	RAP (Metro and Missouri West), RAP- (Kansas Central)

Note: Lawrence 5 is expected to cease operating on coal and begin operating on natural gas in 2024.

Table 4: Evergy Missouri West Resource Plan Implementation Period 2022-2025

	2021 Triennial IRP	2022 IRP Annual Update
Retirements	Lake Road 4/6 in 2024	
Wind Additions	80 MW in 2025	150 MW in 2024
Solar Additions	120 MW in 2024	
Gas Additions		
DSM	RAP	RAP

- Medium-Term Plan (2026-2031): No changes have been made to the retirements identified in the 2021 IRP Evergy Joint Resource Preferred Plan as shown below in Table 5. The Evergy Missouri West Preferred Plan reflects the delay of the Lake Road 4/6 retirement to 2030 (Table 6). Previously identified solar addition in 2024, which was subsequently delayed to 2026 based on RFP responses, has been replaced with wind based on capacity expansion results, although actual resource selection may vary based on continued procurement activities. Later additions are all reduced slightly to 300-450 MW per year (as opposed to 500 MW) based on capacity expansion results. Evergy West's Preferred Plan includes corresponding changes based on West's share of resource additions.

Table 5: Evergy Joint Resource Plan Medium Term 2026-2031

	2021 Triennial IRP	2022 IRP Annual Update
Retirements	Jeffrey 3 in 2030	Jeffrey 3 in 2030
Wind Additions	500 MW in 2026	450 MW in 2026
Solar Additions	500 MW in 2028 500 MW in 2029 500 MW in 2030 500 MW in 2031	300 MW in 2028 450 MW in 2029 450 MW in 2030 450 MW in 2031
Gas Additions		
DSM	RAP (Metro and Missouri West), RAP- (Kansas Central)	RAP (Metro and Missouri West), RAP- (Kansas Central)

Table 6: Evergy Missouri West Resource Plan Medium Term 2026-2031

	2021 Triennial IRP	2022 IRP Annual Update
Retirements	Jeffrey 3 in 2030	Jeffrey 3 in 2030 Lake Road 4/6 in 2030
Wind Additions	80 MW in 2026	72 MW in 2026
Solar Additions	80 MW in 2028 80 MW in 2029 80 MW in 2030 80 MW in 2031	48 MW in 2028 72 MW in 2029 72 MW in 2030 72 MW in 2031
Gas Additions		
DSM	RAP	RAP

- Long-Term Plan (2032-2041): No changes have been made to the retirements identified in the 2021 IRP Evergy Joint Resource Preferred Plan or 2021 Missouri West Preferred Plan as shown below in Table 7 and Table 8, respectively. 2022 Update Joint Preferred Plan includes reduction in 2032 solar additions to 450 MW per year (as opposed to 500 MW), more planned solar additions in 2033-2035, the addition of 450 MW of wind in 2041, and replacement of some assumed combustion turbines between 2036 and 2041 with combined cycle resources. Evergy continues to assume that these resources currently modeled as natural gas-fired combustion turbines and combined cycle plants will ultimately be replaced by new non-emitting, firm, dispatchable resources. For example, these technologies could include long-term energy storage, hydrogen or ammonia-powered generation, or new nuclear technologies.

Table 7: Evergy Joint Resource Plan Long Term 2032-2041

	2021 Triennial IRP	2022 IRP Annual Update
Retirements	LaCygne 1 in 2032 Iatan 1 in 2039 LaCygne 2 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039	LaCygne 1 in 2032 Iatan 1 in 2039 LaCygne 2 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039
Wind Additions		450 MW in 2041
Solar Additions	500 MW in 2032	450 MW in 2032 450 MW in 2033 450 MW in 2034 450 MW in 2035 150 MW in 2036
Gas Additions	1 CT (233 MW) in 2036 1 CT (233 MW) in 2037 1 CT (233 MW) in 2039 12 CT (2,796 MW) in 2040	1 CT (237 MW) in 2036 1 CC (418 MW) in 2038 2 CC (836 MW) in 2039 4 CT (948 MW) in 2040
DSM	RAP (Metro and Missouri West), RAP- (Kansas Central)	RAP (Metro and Missouri West), RAP- (Kansas Central)

Table 8: Evergy Missouri West Resource Plan Long Term 2032-2041

	2021 Triennial IRP	2022 IRP Annual Update
Retirements	Iatan 1 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039	Iatan 1 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039
Wind Additions		
Solar Additions	80 MW in 2032	72 MW in 2032 72 MW in 2033 72 MW in 2034 72 MW in 2035
Gas Additions	1 CT (233 MW)in 2033 1 CT (233 MW) in 2039 1 CT (233 MW) in 2040	1 CT (237 MW) in 2036 1 CT (237 MW) in 2040
DSM	RAP	RAP

While this 2022 Update does not reflect any changes to plant retirements compared to the 2021 IRP Preferred Plan, Evergy continues to expect pressure on its coal fleet and the need to balance customer affordability, reliability, and sustainability as it continues to transition its fleet. To this end, much of the analysis discussed in Section 6 which was used to develop the Preferred Plan, along with the Risk Analysis prepared in response to the Commission-ordered Special Contemporary Issue related to renewable additions ("Risk Analysis SCI"), includes the potential for accelerated retirements in excess of those identified in Evergy's current Preferred Plans. Given the significant uncertainty around specific drivers which could result in any one (or potentially more than one) of Evergy's six coal units which are currently planned to be in operation until 2039 or later ultimately needing to retire earlier, Evergy has chosen not to identify a specific unit for earlier retirement at this stage. However, the capacity expansion plan included in this Preferred Plan was built based on the assumption that such a retirement would ultimately occur. Evergy believes this approach supports a continued pace of transition, which manages risks as described in the Risk Analysis SCI, but also does not force an overreliance on non-firm fuel sources or new technology too early in the planning period – allowing sufficient time for technology to advance and be incorporated into Evergy's plans.

As discussed with parties following the 2021 IRP, Evergy plans to evaluate energy storage and hybrid options in more detail in its 2023 Annual Update. Evergy is optimistic that these technologies (and their economics) will continue to improve and will ultimately become a key part of the Company's medium- and long-term plans.

In summary, this 2022 Update is consistent with the Commission's integrated resource planning regulations and highlights changes to the Preferred Plan filed in our 2021 IRP. The changes to the Evergy West's Preferred Plan compared to the 2021 IRP are relatively minor and are driven by:

- Timing changes driven by execution in the Implementation Period;
- Delayed retirement of Lake Road 4/6 to maintain low-cost capacity resource for Evergy West;

- Minor changes in overall renewable investment quantity in the Medium-Term; and
- Some changes in capacity additions in long-term between solar and firm, dispatchable resources.

SECTION 2: LOAD ANALYSIS AND LOAD FORECASTING UPDATE

2.1 CHANGES FROM THE 2021 TRIENNIAL IRP

Several inputs to the load forecasting models were updated for this filing compared to the 2021 Triennial IRP.

- Historical data for customers, kwh and $/kwh: ending June 2021 vs ending June 2020
- DOE forecasts of appliance and equipment saturations and kwh/unit: Annual Energy Outlook (AEO) 2021 vs AEO 2020
- Updated Economic forecasts from Moody's Analytics. Historical data ending June 2021
- Class models in the 2022 MO West Update filing are the same as the 2021 Triennial filing: residential, small commercial, big commercial (medium, large, large power) and industrial.
- The Company also re-evaluated the output elasticity used in the commercial and industrial models and the elasticity used in the residential model. Adjustments made were to improve the model fit.
- Company utilized EPRI electric vehicle study within its modeling for 2022 Update filing.
- The Company utilized Google Mobility Reports data to account for load changes resulting from geolocation behaviors induced by the COVID19 pandemic.

Table 9, Table 10, and Table 11 below show a lower forecast for both peak and energy for the 2022 Update compared to the 2021 Triennial IRP. Below are the primary reasons for the change in forecast.

- There are some changes from the Energy Information Administration's (EIA) 2020 Annual Energy Outlook (AEO) to the 2021 AEO resulting from updates to end-use efficiency and saturation estimates. The EIA's updates impact to the 2022 IRP Update short-term (2021-2026) growth rate is slightly lower than the 2021 Triennial IRP forecast due to more efficient Commercial end-uses partially offset by increased Residential Base-use intensity. The long-term growth rate is slightly lower compared to 2021 due to lower Commercial intensity estimates long-term. Below is a summary of the impact by class.

- Residential End-Use: Total residential intensity changed slightly from the 2020 AEO. There is virtually no change in cooling and heating intensity. The difference lies in the base-use intensity. The slope of the base use forecast in the 2021 AEO is slightly less negative in the near term (2021-2026) and the same thereafter after. The difference in base load is explained by updated estimates of miscellaneous intensity.
- Commercial End-Use: Total commercial intensity trajectory declined from the 2020 AEO, with growth being slightly slower throughout the forecast period (2021-2041). The end-uses contributing to the change from the 2021 AEO intensity are primarily Cooling, Heating and Lighting in both the near-term and the long-term.
- Industrial End-Use: Overall intensity and end-use intensity for industrial were largely unchanged.
- There are some changes from the Moody's Analytics Economic forecasts from 2020 to 2021. Economic forecasts for Population, Households, Employment (both Manufacturing and Non-Manufacturing) and Gross Product (both Manufacturing and Non-Manufacturing) all show lower growth trajectory in the 2021 forecast compared to the 2020 forecast. The lower growth trajectory in the Economic forecast contributes to a lower growth trajectory in the load forecast.

- The growth trajectory of Company load since the 2021 Triennial IRP forecast also contributes to a lower forecast for both peak and energy.

Table 9: Evergy MO West Mid-Case Annual Forecast ** Confidential**

Net System Input (NSI) and Peak Forecast												
Date	Gross NSI (MWh)		DSM	Net NSI (MWh)		Gross Peak (MW)		DSM	DVC	Net Peak (MW)		Gross LF
2002	7,472,196			7,472,196		1,680				1,680		0.5077
2003	7,621,565	2.0%		7,621,565	2.0%	1,716	2.1%			1,716	2.1%	0.5070
2004	7,881,521	3.4%		7,881,521	3.4%	1,828	6.5%			1,828	6.5%	0.4922
2005	8,049,913	2.1%		8,049,913	2.1%	1,812	-0.9%			1,812	-0.9%	0.5071
2006	8,271,620	2.8%		8,271,620	2.8%	1,842	1.7%			1,842	1.7%	0.5126
2007	8,552,828	3.4%		8,552,828	3.4%	1,926	4.6%			1,926	4.6%	0.5069
2008	8,708,764	1.8%		8,708,764	1.8%	1,958	1.7%			1,958	1.7%	0.5077
2009	8,650,524	-0.7%		8,650,524	-0.7%	1,896	-3.2%			1,896	-3.2%	0.5208
2010	8,754,972	1.2%		8,754,972	1.2%	1,890	-0.3%			1,890	-0.3%	0.5288
2011	8,732,993	-0.3%		8,732,993	-0.3%	1,914	1.3%			1,914	1.3%	0.5209
2012	8,640,687	-1.1%		8,640,687	-1.1%	1,945	1.6%			1,945	1.6%	0.5072
2013	8,694,450	0.6%		8,694,450	0.6%	1,861	-4.3%			1,861	-4.3%	0.5333
2014	8,737,596	0.5%		8,737,596	0.5%	1,870	0.5%			1,870	0.5%	0.5335
2015	8,717,003	-0.2%		8,717,003	-0.2%	1,869	0.0%			1,869	0.0%	0.5193
2016	8,623,847	-1.1%		8,623,847	-1.1%	1,873	0.2%			1,873	0.2%	0.5257
2017	8,743,444	1.4%		8,743,444	1.4%	1,923	2.7%			1,923	2.7%	0.5190
2018	8,709,034	-0.4%		8,709,034	-0.4%	1,926	0.2%			1,926	0.2%	0.5162
2019	8,718,677	0.1%		8,718,677	0.1%	1,930	0.2%			1,930	0.2%	0.5157
2020	8,854,282	1.6%		8,854,282	1.6%	1,919	-0.6%			1,919	-0.6%	0.5267
2021	8,751,000	-1.2%	(13,600)	8,737,399	-1.3%	1,862	-3.0%	(99)	0	1,763	-8.1%	0.5365
2022	8,911,669	1.8%	(67,198)	8,844,471	1.2%	1,915	2.8%	(118)	0	1,797	1.9%	0.5312
2023	8,963,124	0.6%	(59,579)	8,903,545	0.7%	1,919	0.2%	(62)	0	1,857	3.3%	0.5332
2024	9,026,081	0.7%	(80,378)	8,945,704	0.5%	1,929	0.5%	(60)	0	1,869	0.6%	0.5341
2025	9,064,554	0.4%	(76,144)	8,988,411	0.5%	1,934	0.3%	(56)	0	1,878	0.5%	0.5350
2026	9,105,801	0.5%	(73,090)	9,032,711	0.5%	1,941	0.4%	(52)	0	1,889	0.6%	0.5355
2027	9,142,571	0.4%	(70,661)	9,071,910	0.4%	1,947	0.3%	(47)	0	1,900	0.6%	0.5360
2028	9,191,442	0.5%	(67,063)	9,124,379	0.6%	1,955	0.4%	(41)	0	1,914	0.7%	0.5367
2029	9,219,180	0.3%	(68,541)	9,150,639	0.3%	1,960	0.3%	(38)	0	1,922	0.4%	0.5369
2030	9,246,335	0.3%	(70,286)	9,176,049	0.3%	1,964	0.2%	(35)	0	1,929	0.4%	0.5374
2031	9,276,498	0.3%	(65,624)	9,210,874	0.4%	1,969	0.3%	(27)	0	1,942	0.7%	0.5378
2032	9,322,175	0.5%	(53,717)	9,268,457	0.6%	1,978	0.5%	(16)	0	1,962	1.0%	0.5380
2033	9,351,322	0.3%	(42,219)	9,309,103	0.4%	1,984	0.3%	(10)	0	1,974	0.6%	0.5381
2034	9,390,146	0.4%	(30,260)	9,359,887	0.5%	1,992	0.4%	(8)	0	1,984	0.5%	0.5381
2035	9,428,992	0.4%	(22,869)	9,406,123	0.5%	2,000	0.4%	(7)	0	1,993	0.5%	0.5382
2036	9,479,534	0.5%	(20,261)	9,459,274	0.6%	2,009	0.4%	(7)	0	2,002	0.5%	0.5386
2037	9,509,460	0.3%	(15,043)	9,494,416	0.4%	2,016	0.3%	(6)	0	2,010	0.4%	0.5385
2038	9,551,322	0.4%	(12,117)	9,539,205	0.5%	2,025	0.4%	(6)	0	2,019	0.4%	0.5384
2039	9,592,494	0.4%	(10,162)	9,582,331	0.5%	2,034	0.4%	(5)	0	2,029	0.5%	0.5384
2040	9,634,688	0.4%	(4,444)	9,630,244	0.5%	2,044	0.5%	(2)	0	2,042	0.6%	0.5381
2041	9,650,478	0.2%	(4,696)	9,645,782	0.2%	2,047	0.1%	0	0	2,047	0.2%	0.5382

Historical NSI is Weather Normal, first 6 months of 2021 are weather normal
Historical Peak is Weather Normal, first 6 months of 2021 are weather normal

Gross NSI (MWh) - Forecast		
Forecast Year	2022 Update	2021 IRP
5 Yrs	0.80%	1.13%
10 Yrs	0.58%	0.87%
15 Yrs	0.53%	0.80%
20 Yrs	0.49%	0.79%

Gross Peak (MW) - Forecast		
Forecast Year	2022 Update	2021 IRP
5 Yrs	0.83%	0.83%
10 Yrs	0.56%	0.66%
15 Yrs	0.51%	0.62%
20 Yrs	0.47%	0.62%

Table 10: Peak Forecasts - 2022 Annual Update Vs. 2021 Triennial IRP

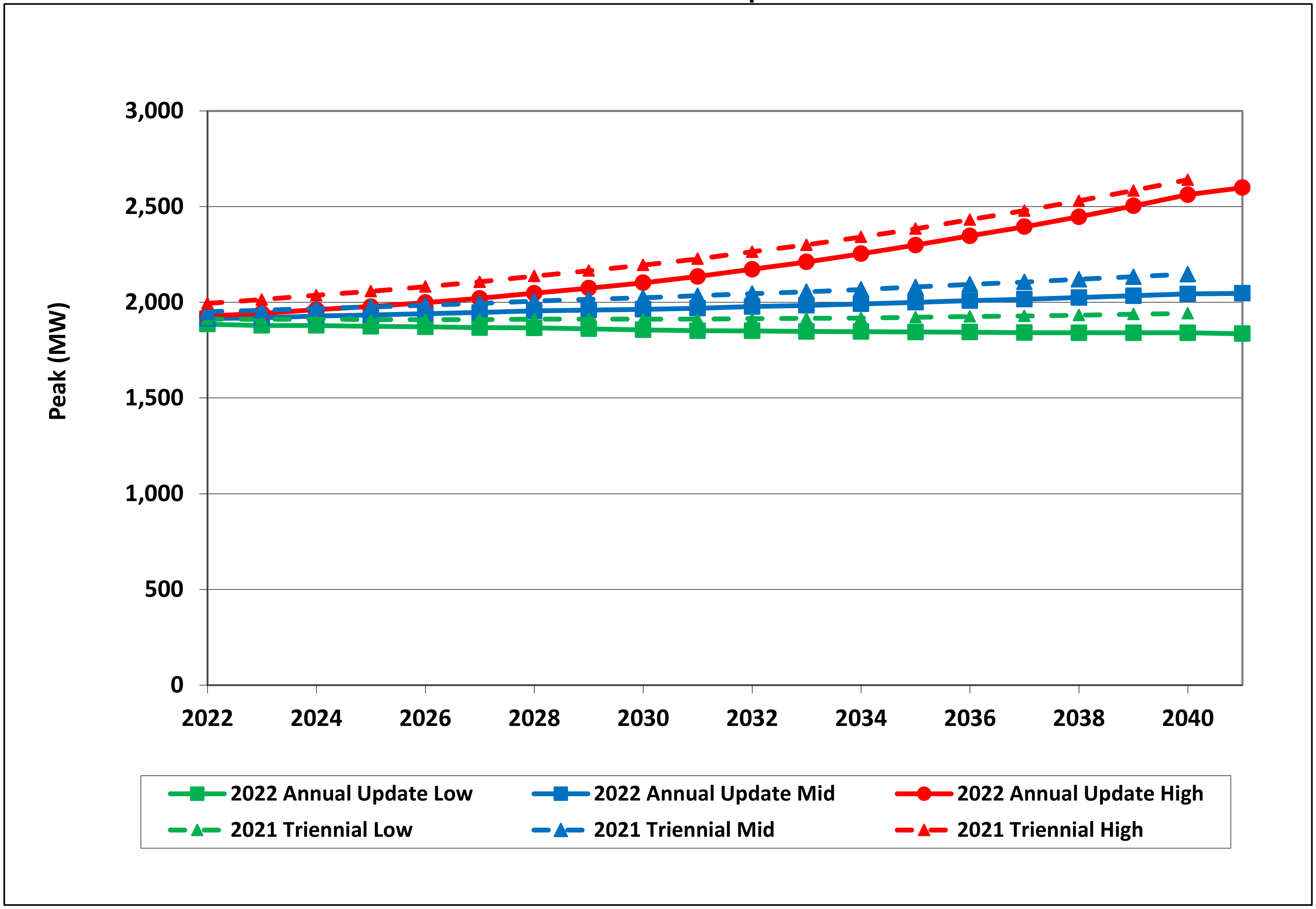
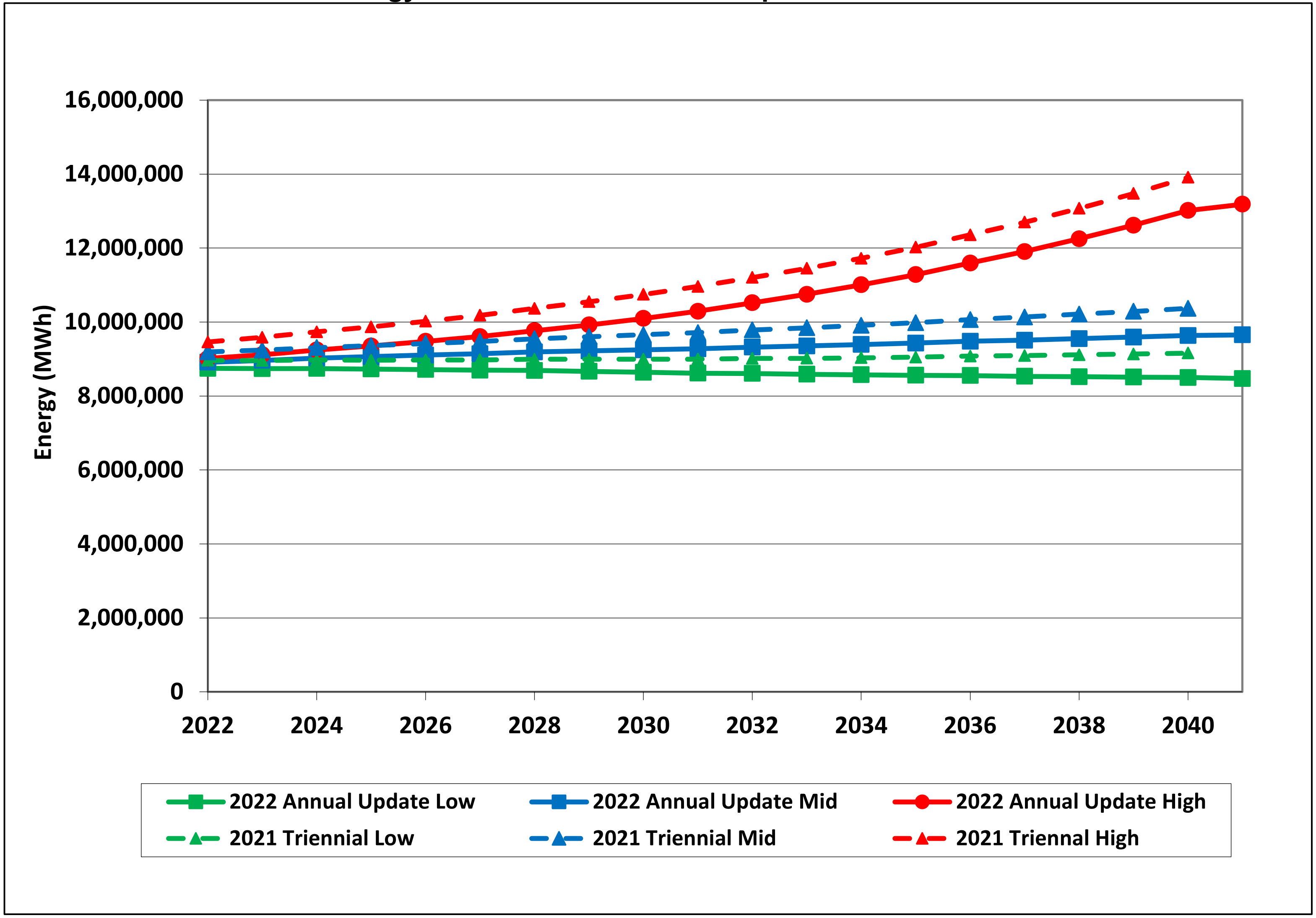


Table 11: Energy Forecasts - 2022 Annual Update Vs. 2021 Triennial IRP



SECTION 3: SUPPLY-SIDE RESOURCE ANALYSIS UPDATE

3.1 FUEL AND EMISSION FORECAST CHANGES FROM THE 2021 TRIENNIAL IRP

The methodology used in determining the forecast range has not changed from the 2021 Triennial IRP. The natural gas and CO_2 forecast data is presented in graphical and tabular form on the next pages. Note that the CO_2 forecast did not change from the 2021 Triennial IRP.

As discussed further in Section 7.2 , Evergy continues to monitor natural gas prices closely given elevated and volatile prices over the last several months. Accordingly, the forecast utilized for this 2022 Annual Update reflects elevated gas prices in the short-term. This forecast was completed in late 2021 and thus does not reflect the latest view of short-term market expectations (which would reflect even higher prices in the near-term), but, because Evergy still expects gas prices to stabilize and decline in the relatively near term (12-24 months), having the latest near-term prices is less critical in testing and developing a long-term (20-year) plan. With that being said, Evergy continues to closely monitor and regularly update its forward natural gas price forecasts. Over the next several months, if the market begins to indicate a more structural shift to long-term higher gas prices, this will be incorporated into Evergy's forecasts accordingly and utilized in the 2023 Annual Update and future IRPs.

Table 12: Natural Gas Forecasts - 2022 Annual Update Vs. 2021 Triennial IRP

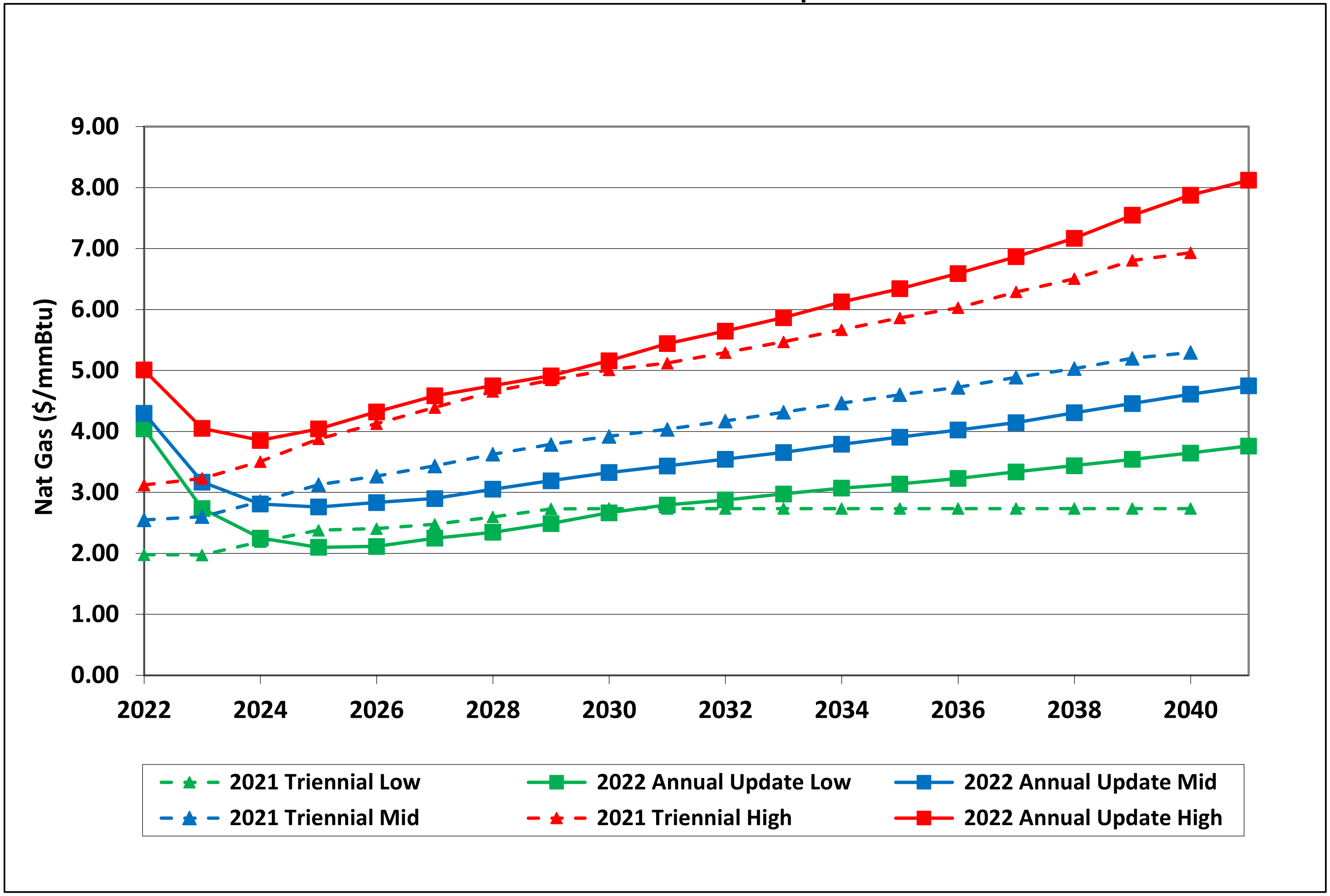


Table 13: Natural Gas Forecasts - 2022 Annual Update Vs. 2021 Triennial IRP

Natural Gas Forecast ($/mmBtu)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
2022 Annual Update Low	4.04	2.74	2.25	2.10	2.12	2.25	2.35	2.49	2.67	2.79
2022 Annual Update Mid	4.30	3.17	2.81	2.76	2.83	2.90	3.05	3.19	3.33	3.43
2022 Annual Update High	5.01	4.05	3.86	4.04	4.32	4.59	4.75	4.91	5.16	5.44
Natural Gas Forecast ($/mmBtu)	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
2022 Annual Update Low	2.88	2.98	3.07	3.14	3.23	3.34	3.44	3.54	3.65	3.76
2022 Annual Update Mid	3.55	3.66	3.79	3.91	4.02	4.15	4.31	4.46	4.61	4.75
2022 Annual Update High	5.65	5.87	6.13	6.34	6.59	6.87	7.17	7.55	7.88	8.12
Natural Gas Forecast ($/mmBtu)	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
2021 Triennial Low	1.98	1.97	2.19	2.38	2.41	2.48	2.60	2.73	2.74	2.74
2021 Triennial Mid	2.55	2.60	2.85	3.13	3.27	3.44	3.63	3.79	3.92	4.03
2021 Triennial High	3.12	3.23	3.51	3.88	4.13	4.39	4.66	4.85	5.01	5.12
Natural Gas Forecast ($/mmBtu)	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
2021 Triennial Low	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	
2021 Triennial Mid	4.17	4.32	4.47	4.60	4.72	4.89	5.03	5.20	5.30	
2021 Triennial High	5.30	5.47	5.67	5.86	6.03	6.29	6.51	6.81	6.93	

Table 14: CO_2 Forecasts - 2022 Annual Update ** Confidential**

[redacted]

Table 15: CO_2 Forecasts - 2022 Annual Update ** Confidential**

CO_2 Forecast ($/ton)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
2022 Annual Update Low	[redacted]									
2022 Annual Update Mid	[redacted]									
2022 Annual Update High	[redacted]									
CO_2 Forecast ($/ton)	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
2022 Annual Update Low	[redacted]									
2022 Annual Update Mid	[redacted]									
2022 Annual Update High	[redacted]									
Carbon Dioxide Forecast ($/ton)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
2021 Triennial Low	[redacted]									
2021 Triennial Mid	[redacted]									
2021 Triennial High	[redacted]									
Carbon Dioxide Forecast ($/ton)	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
2021 Triennial Low	[redacted]									
2021 Triennial Mid	[redacted]									
2021 Triennial High	[redacted]									

The following table provides the sources of the natural gas and CO_2 forecasts reflected in the above charts.

Table 16: Natural Gas and CO_2 Forecast Sources

Forecast Source	Natural Gas	CO_2
IHS Markit	x	x
Energy Information Administration	x	
S&P Global Platts	x	x
Energy Ventures Analysis	x	
JD Energy		x
CME Futures	x	
ICE	x	

3.2 SUPPLY-SIDE TECHNOLOGY CHANGES FROM THE 2021 TRIENNIAL IRP

Supply-side technology candidates were updated for the 2022 Annual Update due to supply-chain issues that have affected capacity costs – especially for solar and wind generation. The comparison of capital cost assumptions between the 2021 Triennial IRPs and the 2022 Annual Update are shown in Table 17 below. Supply-side generation options modeled in the 2022 Annual Update include combustion turbine, combined cycle, wind, and solar generation options. All technologies include an estimate for interconnect costs.

Table 17: Supply-Side Technology Options ** Confidential **

Generation Technology	2021 IRP (2023$/kW)	2022 IRP (2023$/kW)
Combustion Turbine	[redacted]	
Combined Cycle		
Solar		
Wind		

The modeled costs reflect the expectation of continued technology improvements over time, based on publicly available capital cost forecasts from EEI and the NREL ATB. The cost curves available in these forecasts were averaged and applied to the near-term capital costs. In addition to these cost curves, a reduction in solar costs was modeled beginning in the late 2020s to account for an assumed improvement in supply chain pressures, aligning the mid-term and long-term cost estimates more closely with external forecasts.

3.3 CAPITAL PLAN UPDATE FROM THE 2021 TRIENNIAL IRP

Evergy continues to utilize a combination of condition-based planning, operating estimates, and industry expertise when formulating a 20-year capital plan for each unit in the generation fleet. Near term budgeting is based on equipment condition based on advanced pattern recognition (APR) models along with routine predictive maintenance and visual inspections. Long term budgeting is dictated by historical condition of the

C

units along with industry and original equipment manufacturer (OEM) guidance. When possible, individual unit outages are spread out to avoid the risk of a generation capacity deficiency and some maintenance cycles may be altered by up to a year.

3.4 ENVIRONMENTAL REGULATION CHANGES FROM THE 2021 TRIENNIAL IRP

Material changes from 2021 are shown in italics.

3.4.1 AIR EMISSION IMPACTS

3.4.1.1 National Ambient Air Quality Standards

The Clean Air Act (CAA) requires the Environmental Protection Agency (EPA) to set National Ambient Air Quality Standards (NAAQS) for six air pollutants which are considered harmful to public health and the environment. These pollutants include particulate matter (PM), ozone, sulfur dioxides (SO_2), nitrogen dioxide (NO_x), carbon monoxide (CO) and Lead (Pb). Following is a brief description and current state of each NAAQS.

3.4.1.2 Particulate Matter

In 2012, the EPA strengthened the PM standard and maintained the same requirements in a 2020 final action. The Kansas City area is currently in attainment of the PM NAAQS. No additional emission control equipment is currently needed to comply with this standard. It is not known whether the Kansas City area will remain in attainment of a future revision of the standard. *In 2021, the EPA announced their intention to reconsider their 2020 final action retaining the 2012 PM NAAQS.* Future non-attainment of revised standards could require additional reduction technologies, emission limits, or both on fossil-fueled units.

3.4.1.3 Ozone

In 2015, the EPA strengthened the NAAQS for ozone and maintained the same requirement in a 2020 final action. The Kansas City area is currently in attainment of the ozone NAAQS. No additional emission control equipment is currently needed to comply with this standard. *In 2021, the EPA announced their intention* *to reconsider their 2020 final action retaining the 2015 ozone NAAQS.* Future non-attainment of revised standards could result in regulations requiring additional nitrogen oxides (NOx) reduction technologies, emission limits or both on fossil-fueled units. NOx is considered a precursor pollutant for ozone formation.

3.4.1.4 Sulfur Dioxide

In 2010, the EPA strengthened the NAAQS for SO_2 and maintained the same requirement in a 2019 final action. The Kansas City area is currently in attainment of the SO_2 NAAQS. No additional emission control equipment is currently needed to comply with this standard. Future non-attainment of revised standards could result in regulations requiring additional SO_2 reduction technologies, emission limits or both on fossil-fueled units.

3.4.1.5 Carbon Monoxide

In 2011, the EPA maintained the existing 1971 NAAQS for CO. The Kansas City area is currently in attainment of the CO NAAQS. No additional emission control equipment is currently needed to comply with this standard. Future non-attainment of revised standards could result in regulations requiring additional CO reduction technologies, emission limits or both on fossil-fueled units.

3.4.1.6 Lead

In 2016, the EPA maintained the existing 2008 NAAQS for Lead (Pb). The Kansas City area is currently in attainment of the Pb NAAQS. No additional emission control equipment is currently needed to comply with this standard. Future non-attainment of revised standards could result in regulations requiring additional Pb reduction technologies, emission limits or both on fossil-fueled units.

3.4.1.7 Cross-State Air Pollution Rule

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR), requiring eastern and central states to significantly reduce power plant emissions that cross state lines and contribute to ozone and fine particle pollution in downwind states. The CSAPR Update Rule took effect in 2017 with more stringent ozone-season NO_x emission budgets for electric generating units (EGUs) in many states to address significant contribution to modeling nonattainment and maintenance areas in downwind states with respect to the 2008 ozone NAAQS. In 2021 EPA published the final Revised CSAPR Update rule which found that nine states including Kansas, Missouri, and Oklahoma have insignificant impact on downwind states' nonattainment and/or maintenance areas. As a result, no additional reductions in these states' allowances were required.

When EPA lowered the Ozone NAAQS in 2015, impacted states were required to submit Interstate Transport State Implementation Plans (ITSIPs) to address the "Good Neighbor" obligations in the Clean Air Act. These ITSIPs were due to EPA in 2018. The EPA did not act on these submissions and was challenged in a court filing in May 2021 to address them. In February 2022, the EPA published proposed disapprovals of ITSIPs for nineteen states including Missouri while, in April 2022, EPA issued final approval of the Kansas ITSIP.

In April 2022, the EPA published in the Federal Register a proposed Federal Implementation Plan (FIP) to resolve the outstanding "Good Neighbor" obligations with respect to the 2015 Ozone NAAQS for 26 states including Missouri and Oklahoma. This FIP would establish a revised CSAPR ozone season NOx emissions trading program for electric generating units, a new daily backstop NOx limit for applicable coal-fired units larger than 100MW, and unit-specific NOx emission rate limits for certain industrial emissions units. The proposed FIP includes reductions to the state ozone season NOx allowance allocations for Missouri beginning in 2023 with additional reductions each year through 2026. The Company currently complies with the existing CSAPR regulations through a combination of trading allowances within or outside its system in addition to changes in operations as necessary. Future, strengthened ozone, PM, or SO_2 standards could result in additional CSAPR updates requiring additional procurement of allowances, emission reduction technologies or reduced generation on fossil-fueled units.

3.4.1.8 Regional Haze

In June 2005, the EPA finalized amendments to the July 1999 Regional Haze Rule. These amendments apply to the provisions of the Regional Haze Rule that require emission controls for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze. The pollutants that reduce visibility include $PM_{2.5}$, and compounds which contribute to $PM_{2.5}$ formation, such as NO_x, and SO_2.

Under the 1999 Regional Haze Rule, states are required to set periodic goals for improving visibility in natural areas. As states work to reach these goals, they must periodically develop regional haze implementation plans that contain enforceable measures and strategies for reducing visibility-impairing pollution. The Regional Haze Rule directs state air quality agencies to identify whether visibility-reducing emissions from affected sources are below limits set by the state or whether retrofit measures are needed to reduce emissions.

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 31, 2021. Evergy worked with the Kansas Department of Health and Environmental (KDHE) and the Missouri Department of Natural Resources (MDNR) as they worked to draft their SIP revisions. The Missouri SIP revision has been drafted and the public comment period expired in May 2022. The next step is for the Missouri Air Conservation Commission to approve the SIP before it can be submitted to EPA. MDNR has indicated they intend to submit this by the end of July 2022. MDNR shared a draft of this SIP revision in March 2022 which does not require any additional reductions from the Evergy generating units in the state. The Kansas SIP revision was placed on public notice in June 2021 and requested no additional emission reductions by electric utilities based on the significant reductions that were achieved during the first *implementation period. KDHE submitted the Kansas SIP revision in July 2021. EPA is waiting for additional states to submit their SIP revisions before they review and either approve or disapprove these SIP revisions.*

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

3.4.1.9 Greenhouse Gases

In January 2021, a three-judge panel in the D.C. Circuit issued a mandate vacating and remanding the Affordable Clean Energy (ACE) rule back to EPA. *In February 2021, as the result of an unopposed appeal from EPA, the D.C. Circuit issued an order indicating it would withhold the portion of the mandate that would reinstate the Clean Power Plan (CPP). Based on these actions, there are currently no greenhouse gas regulations in effect for existing electric generating units.* Until future rulemakings related to greenhouse gas emissions are proposed, it is difficult to determine the impact but could require the addition of emission reduction technologies, reduced generation, alternate generation, or demand reduction technologies.

3.4.1.10 Mercury and Air Toxics Standards

In 2011, the EPA finalized a rule to reduce emissions of toxic air pollutants from power plants. These mercury and air toxics standards (MATS) for power plants reduced emissions from new and existing coal and oil-fired electric generating units (EGUs). Control equipment was installed to comply with this rule. No additional emission control equipment is currently needed to comply with this standard. There is a potential that this rule will be strengthened in the future to include lower PM limits. Evergy Missouri West has assumed lower limits will be required at the Jeffrey Energy Center in the form of installation of baghouses to replace the electrostatic precipitators. The current capital plans reflect these projects being operational by the end of 2027.

3.4.2 WATER EMISSION IMPACTS

3.4.2.1 Effluent Limitation Guidelines (ELG)

In 2015, EPA established the effluent limitations guidelines (ELG) and standards for wastewater discharges, including limits on the amount of toxic metals and other pollutants that can be discharged. Implementation timelines for this 2015 rule varied from 2018 to 2023. In April 2019, the U.S. Court of Appeals for the 5th Circuit (5th Circuit) issued a ruling that vacated and remanded portions of the original ELG rule.

In October 2020, the EPA published the final ELG Reconsideration Rule. This rule adjusts numeric limits for flue gas desulfurization (FGD) wastewater and adds a 10% volumetric purge limit for bottom ash transport water. The timeline for final FGD wastewater compliance is now as soon as possible on or after one year following publication of the final rule in the federal register but no later than December 31, 2025. *On July 26, 2021, EPA initiated a supplemental rulemaking to strengthen certain discharge limits in the ELG regulation. EPA intends to issue a proposed rule for public comment in the fall of 2022.* Evergy Missouri West is currently in compliance with this regulation, but future strengthening of the rule could require additional reduction technologies, on coal and oil-fired units.

3.4.2.2 Clean Water Act Section 316(A)

Evergy's river plants comply with the calculated limits defined in the current permits. *Iatan Generating Station's water discharge permit issued February 1, 2022 contains future thermal discharge limits that become effective February 1, 2032. The ten-year compliance period will be utilized by Evergy to study both* *discharge conditions and conditions of the receiving river to finalize compliance plans.* Application of these future limitations or future regulations that could be issued that restrict the thermal discharges may require alternative cooling technologies to be installed at coal-fired units using once through cooling, a reduction or shutdown of certain plants during periods of high river water temperature, or application of a thermal variance process.

3.4.2.3 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.

3.4.2.4 Zebra Mussel Infestation

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

3.4.2.5 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.

3.4.3 WASTE MATERIAL IMPACTS

3.4.3.1 Coal Combustion Residuals (CCR's)

In April 2015, the EPA finalized regulations to regulate CCRs under the Resource Conservation and Recovery Act (RCRA) subtitle D to address the risks from the disposal of CCRs generated from the combustion of coal at electric generating facilities. The rule requires periodic assessments; groundwater monitoring;

location restrictions; design and operating requirements; recordkeeping and notifications; and closure, among other requirements, for CCR units.

In March 2019, the D.C. Circuit issued a ruling to grant the EPA's request to remand the Phase I, Part I CCR rule in response to a prior court ruling requiring the EPA to address un-lined surface impoundment closure requirements. In August 2020, the EPA published the Part A CCR Rule. This rule reclassified clay-lined surface impoundments from "lined" to "un-lined" and established a deadline of April 11, 2021 to initiate closure. In November 2020, the EPA published the final Part B CCR Rule. This rule includes a process to allow unlined impoundments to continue to operate if a demonstration is made to prove that the unlined impoundments are not adversely impacting groundwater, human health, or the environment. Evergy Missouri West is in compliance with the Part A CCR rule which included initiating closure of all unlined impoundments by the deadline of April 11, 2021.

In January 2022, EPA published proposed determinations for facilities that filed closure extensions for unlined or clay lined CCR units. These proposed determinations include various interpretations of the CCR regulations and compliance expectations that may impact all owners of CCR units. These interpretations could require modified compliance plans such as different methods of CCR unit closure. Additionally, it includes more stringent remediation requirements for units that are in corrective action or forced to go into corrective action. Future rule modifications could require additional monitoring or remediation of current or closed impoundments and landfills along with additional requirements related to design and construction of future units to more stringent standards.

SECTION 4: TRANSMISSION AND DISTRIBUTION UPDATE

4.1 CHANGES FROM THE 2021 TRIENNIAL IRP

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

4.1.1 RTO EXPANSION PLANNING

Evergy Missouri West assessment of RTO expansion plans is an ongoing process that occurs through the various regional planning processes conducted by SPP. These assessments include review and approval of plan scope documents, review and approval of plan input assumptions, review of plan study analysis and results with feedback from Evergy Missouri West staff, and review and approval of final plan reports. All transmission projects identified by SPP for the Evergy Missouri West service territory are included in SPP's annual Transmission Expansion Plan Report and Project List. By meeting the performance standards established for transmission planning the assessment ensures that adequate transmission is available in the near term and long term to meet the firm load and transmission service requirements included in the SPP Regional Plan for Evergy Missouri West. These documents are attached as Appendix A 2022 SPP Transmission Expansion Plan Report.pdf and Appendix A1 2022 SPP Transmission Expansion Plan Project List.xls.

4.1.2 Advanced Distribution Technologies

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

- Advanced Distribution Management Systems (ADMS)
  - Fault Location Isolation and Supply Restoration (FLISR)
  - Advanced Fault Location Analysis (FLA) Functionality
- Communicating Faulted Circuit Indicators (CFCIs)
- Reclosers with communication

4.1.2.1 Advanced Distribution Management Systems

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

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

4.1.2.2 Fault Location Isolation and Supply Restoration

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

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

Closed-Loop 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.

4.1.2.3 Fault Location Analysis Functionality (FLA)

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

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

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

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

4.1.2.4 <u>Communicating Faulted Circuit Indicators (CFCI)</u>

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

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

CFCIs are also anticipated to be a cost-effective way to enhance the Fault Location functionality discussed previously. Although CFCIs cannot perform switching operations, they can enhance the effectiveness of dispatching and manual switching. To date, over 7,000 CFCIs have been installed in the Evergy service territory.

4.1.2.5 <u>Reclosers with Communication</u>

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

4.1.3 ADVANCED TRANSMISSION TECHNOLOGIES DISCUSSION

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

4.1.3.1 Advanced Assessment Methods

Evergy uses end-use load models developed by the North American Electric Reliability Corporation (NERC) in association with the US Department of Energy (DoE) and Electric Power Research Institute (EPRI) to locate areas within the Evergy 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.

4.1.3.2 New Transmission Technologies

Static Condensers (STATCOMs) and Synchronous Condensers (SynCon) are advanced transmission technologies currently being evaluated by Evergy.

- STATCOM – a sub-division of a group of devices known as Flexible AC 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.

- 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 5: DEMAND-SIDE RESOURCE ANALYSIS UPDATE

5.1 CHANGES FROM THE 2021 TRIENNIAL IRP

There are no changes to the DSM Potential Study results for the IRP Annual Update for any scenario. Beginning Jan 1, 2023, the incremental annual energy and demand impacts are the same as filed in the 2021 Triennial IRP.

5.2 MEEIA CYCLE 3 2020-2022 PROGRAMS

In December 2019, the Commission approved the Company's original MEEIA cycle 3 filing. Table 18 below shows the annual cumulative demand and energy savings of the MEEIA cycle 3 plan which are included in the base plan for each scenario.

Table 18: Evergy Missouri West Cumulative Energy (MWH) and Demand Savings (MW) from MEEIA 3

Year	MEEIA 3 APPROVED - Energy Savings (MWh)	MEEIA 3 APPROVED - Demand Savings (MW)
2022	49,865	72
2023	31,968	18
2024	54,172	21
2025	51,458	21
2026	48,732	21
2027	48,081	21
2028	44,257	19
2029	44,799	20
2030	46,843	21
2031	46,245	21
2032	37,908	13
2033	30,438	7
2034	21,915	5
2035	14,614	4
2036	14,120	4
2037	10,788	4
2038	7,881	4
2039	7,830	4
2040	3,713	2
2041	390	0

Also, effective June 11, 2022, the Commission approved the Company's application to extend its Missouri Energy Efficiency Investment Act (MEEIA) Cycle 3 programs an additional year. The relative impacts of the new targets for the extension will be reflected in the next IRP annual update.

SECTION 6: INTEGRATED RESOURCE PLAN AND RISK ANALYSIS UPDATE

6.1 CHANGES FROM THE 2021 TRIENNIAL IRP

On April 30th, 2021, Evergy Missouri West, Inc. submitted the triennial compliance filing related to Chapter 22 of the Missouri Public Service Commission ("Commission" or "MPSC") regulations concerning Evergy West's Electric Utility Resource Planning. The triennial compliance filing made in Case No. EO-2021-0036 consisted of eight sections of material including the "Evergy Missouri West Preferred Plan" identified in "Volume 7, Resource Acquisition Strategy Selection". The Preferred Plan included 120 MW of solar generation in 2024, and 80 MW of solar generation in each of 2028 – 2032. Additionally, 80 MW of wind generation in 2025 and 2026. The Preferred Plan also included retiring a 97 MW natural gas unit at Lake Road in 2024, Evergy Missouri West's 58 MW share of Jeffrey 3 in 2030, 58 MW share of Jeffrey 1 and 2 in 2039, and Evergy Missouri West's 126 MW share of Iatan 1 in 2039.

Since filing the 2021 Triennial IRP, changing conditions, or major drivers, were refreshed to reflect the latest information and forecasts available to determine if the Preferred Plan and associated Resource Acquisition Strategy identified in 2021 Triennial IRP continue to be the company's path forward. The information and forecasts that have been updated for the 2022 Annual Update include:

- Load forecasts
- Fuel forecasts
- Supply-side costs (Both Existing and New)
- Proposed and potential environmental regulations

In addition to these input changes, Evergy has also made changes to its modeling software and process in order to expand the capabilities of its planning process. The primary changes are listed below:

- Use of PROMOD for market price forecasts: This tool and process are consistent with the Southwest Power Pool (SPP) economic modeling methodology and produces granular nodal forecasts. In the past, market price forecasts were created using MIDAS.

- Use of Plexos for capacity expansion modeling: Through the implementation of Plexos, Evergy is now able to complete capacity expansion modeling. In capacity expansion modeling, the model (Plexos) is able to generate an “optimized” (lowest cost) resource plan given a certain market scenario and a set of constraints. This new capability has created additional flexibility in Evergy’s modeling processes and was used in this 2022 Annual Update process to supplement individual Alternative Resource Plans which were used to test discrete decisions (similar to past IRPs). Capacity Expansion modeling was not performed using MIDAS in the past.

- Use of Plexos for production cost modeling: While Plexos’ production cost modeling capability works similarly to MIDAS, this does represent a change in tool compared to the 2021 Triennial and previous IRPs.

Finally, while working through the procurement process for the near-term renewables from the 2021 IRP Preferred Plan, Evergy has made some shifts in timing for these projects based on relative project maturity within the wind and solar market. In addition, supply chain challenges caused by COVID-19 and federal policy have also resulted in a reduction in near-term (2023/2024) renewables based on available mature, high-value projects. These changes will be discussed in more detail in Section 7:.

6.2 ALTERNATIVE RESOURCE PLAN DEVELOPMENT

Given the implementation of new capacity expansion modeling capabilities, the process of developing Alternative Resource Plans (ARPs) changed slightly in this 2022 Update as compared to prior IRPs. Evergy Missouri West utilized a mix of specific ARPs to demonstrate the impact of specific changes and capacity expansion-driven runs to inform its resource planning process for this 2022 Update.

Due to the significant number of jointly owned units in Evergy's portfolio, joint Network Integration Transmission Service between Evergy Missouri West and Evergy Metro which results in combined resource adequacy requirements, and the potential for jointly owning new capacity or inter-company capacity sales, the initial development of ARPs and all capacity expansion was performed at the Evergy level and then translated into individual utility plans.

The high-level process utilized for the development of ARPs for this 2022 Update is outlined below:

- Plan AAAAA: Began with the 2021 IRP Preferred Plan (ERVFL)
- Plan BBAAA: Made adjustments to Implementation Period additions based on execution to-date (described in Section 7:)
- Plan CBAAA: Reflected operation of Lawrence Unit 5 on natural gas as opposed to retirement
- Plan CCBAA: Performed capacity expansion on medium- and long-term additions given this retirement plan
- Evaluated capacity expansion results given accelerated retirement (2030) of individual coal units (Jeffrey Unit 2 – CCBAB, Hawthorn Unit 5 – CCBAC, La Cygne Unit 2 – CCBAD, Iatan Unit 1 – CCBAE)
- Determined Jeffrey Unit 2 was the most economic accelerated retirement option
- Plan CDAAA: Utilized capacity expansion plan from CCBAB but removed Jeffrey Unit 2 retirement. The reason for modeling a plan without this retirement, but with the capacity expansion plan which accompanied it is:
    - Jeffrey Unit 2 is the most economic option based primarily on the expected need for significant environmental upgrades. If those upgrades are not ultimately needed, it is possible that another unit would become the most economic retirement option.

- Additional factors could ultimately result in another unit becoming more economic for retirement. For example:
    - Evergy Kansas Central currently has a lease for La Cygne 2 which ends in 2029 and the ultimate result of negotiations regarding that lease could impact its economics.
    - While the plan is still in early stages and will require more detailed evaluation, specific plants could be impacted by the Environmental Protection Agency's (EPA) recently published proposed Interstate Transport Federal Implementation Plan for the 2015 ozone National Ambient Air Quality Standards (NAAQS). This plan lowers nitrogen oxide emission allowances starting in 2023.
- In addition to uncertainty around the economics of individual unit requirements, there is significant additional uncertainty around Evergy-level capacity balance which could ultimately change our expected capacity position. This includes changes SPP is evaluating to capacity accreditation and reserve margin requirements, the potential expansion of electrification, and assumptions around the continuing expansion of DSM programs in both Kansas and Missouri.

- Modeled sensitivities agreed to with parties following 2021 IRP
    - Plan CCBAD: La Cygne Unit 2 earlier retirement (2029)
    - Plans CDAAG & CDAAH: Jeffrey Units 1, 2, and 3 with and without environmental upgrades (Kansas agreement, but included in Missouri filings given Missouri West ownership in Jeffrey)
- Development and analysis of individual utility plans which align with each step above
- Plan CDAAF: Modeled delayed retirement of Lake Road 4/6 in 2030 (versus 2024)

- Plan CDABF: Modeled MEEIA Goals sensitivity agreed to with parties following 2021 IRP

6.3 JOINT PLANNING EVERGY RESOURCE PLANS

In total, ten joint-planning Alternative Resource Plans were developed for the 2022 Annual Update. The Evergy Joint Planning Alternative Resource Plan naming convention is provided in Table 19 and an overview of the Alternative Resource Plans is shown in Table 20 below.

Table 19: Evergy Joint Planning Alternative Resource Plan Naming Convention

2023-2025 Execution	Builds 2026-2041	Capacity Expansion	DSM Program	Retirements
A. 2021 Preferred Plan B. Execution Changes C. Execution Changes and Lawrence 5 on Gas	A. 2021 Preferred Plan B. Execution Changes C. Varies (Capacity Expansions) D. Builds from CCBAB	A. Balance as needed B. Full Capacity Expansion	A. RAP (Metro and Missouri West), RAP- (Kansas Central) B. MEEIA Goals (Metro and Missouri West), RAP- (Kansas Central)	A. 2021 Preferred Plan (ERVFL) B. ERVFL + Jeffrey 2 retires in 2030 C. ERVFL + Hawthorn 5 retires in 2029 D. ERVFL + LaCygne 2 retires in 2029 E. ERVFL + Iatan 1 retires in 2029 F. n/a G. ERVFL adjusted for Jeffrey 3 retires in 2039 H. ERVFL adjusted for Jeffrey 3 retires in 2039 and no added environmental cost for Jeffrey units

Table 20: Overview of Joint-Planning Resource Plans

Plan Name	DSM Level	Retire	Renewable Additions		Generation Additions (if needed)
Evergy AAAAA	RAP + DSR (EM) + RAP + DSR (EMW) + RAP- (EKC)	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Lake Road 4/6: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	500 MW Wind 2025 500 MW Wind 2026	350 MW Solar 2023 350 MW Solar 2024 500 MW Solar 2028 500 MW Solar 2029 500 MW Solar 2030 500 MW Solar 2031 500 MW Solar 2032	1 CT (233 MW) in 2036 1 CT (233 MW) in 2037 1 CT (233 MW) in 2039 12 CT (2796 MW) in 2040
Evergy BBAAA	RAP + DSR (EM) + RAP + DSR (EMW) + RAP- (EKC)	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Lake Road 4/6: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	300 MW Wind 2024 500 MW Wind 2025	190 MW Solar 2024 350 MW Solar 2026 500 MW Solar 2028 500 MW Solar 2029 500 MW Solar 2030 500 MW Solar 2031 500 MW Solar 2032	1 CC (418 MW) in 2036 2 CC (836 MW) in 2038 2 CC (836 MW) in 2039 2 CT (474 MW) in 2040 1 CC (418 MW) in 2040 1 CT (237 MW) in 2041
Evergy CBAAA	RAP + DSR (EM) + RAP + DSR (EMW) + RAP- (EKC)	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Lake Road 4/6: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	300 MW Wind 2024 500 MW Wind 2025	190 MW Solar 2024 350 MW Solar 2026 500 MW Solar 2028 500 MW Solar 2029 500 MW Solar 2030 500 MW Solar 2031 500 MW Solar 2032	Lawrence 5 NG (338 MW) 2024 2 CC (836 MW) in 2038 2 CT (474 MW) in 2039 1 CC (418 MW) in 2039 4 CT (948 MW) in 2040 1 CT (237 MW) in 2041
Evergy CBBAB	RAP + DSR (EM) + RAP + DSR (EMW) + RAP- (EKC)	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Lake Road 4/6: Dec 31, 2024 Jeffrey 2&3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	300 MW Wind 2024 500 MW Wind 2025	190 MW Solar 2024 350 MW Solar 2026 500 MW Solar 2028 500 MW Solar 2029 500 MW Solar 2030 500 MW Solar 2031 500 MW Solar 2032 150 MW Solar 2033 450 MW Solar 2034 450 MW Solar 2035 150 MW Solar 2038	Lawrence 5 NG (338 MW) 2024 1 CC (418 MW) in 2036 1 CC (418 MW) in 2038 2 CC (836 MW) in 2039 2 CC (836 MW) in 2040 1 CT (237 MW) in 2041
Evergy CCBAA	RAP + DSR (EM) + RAP + DSR (EMW) + RAP- (EKC)	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Lake Road 4/6: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	300 MW Wind 2024 500 MW Wind 2025 150 MW Wind 2037	190 MW Solar 2024 300 MW Solar 2032 450 MW Solar 2033 450 MW Solar 2034 300 MW Solar 2035 450 MW Solar 2036 300 MW Solar 2037	Lawrence 5 NG (338 MW) 2024 2 CC (836 MW) in 2038 2 CC (836 MW) in 2039 4 CT (948 MW) in 2040 1 CT (237 MW) in 2041

Table 21: Overview of Joint-Planning Resource Plans (continued)

Plan Name	DSM Level	Retire	Renewable Additions		Generation Additions (if needed)
Evergy CCBAB	RAP + DSR (EM) + RAP + DSR (EMW) + RAP- (EKC)	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Lake Road 4/6: Dec 31, 2024 Jeffrey 2&3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	300 MW Wind 2024 500 MW Wind 2025 450 MW Wind 2026 450 MW Wind 2041	190 MW Solar 2024 300 MW Solar 2028 450 MW Solar 2029 450 MW Solar 2030 450 MW Solar 2031 450 MW Solar 2032 450 MW Solar 2033 450 MW Solar 2034 450 MW Solar 2035 150 MW Solar 2036	Lawrence 5 NG (338 MW) 2024 1 CT (237 MW) in 2036 1 CC (418 MW) in 2038 2 CC (836 MW) in 2039 4 CT (948 MW) in 2040
Evergy CCBAC	RAP + DSR (EM) + RAP + DSR (EMW) + RAP- (EKC)	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Lake Road 4/6: Dec 31, 2024 Hawthorn 5: Dec 31, 2029 Jeffrey 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	300 MW Wind 2024 500 MW Wind 2025 150 MW Wind 2026 450 MW Wind 2037 450 MW Wind 2041	190 MW Solar 2024 450 MW Solar 2030 450 MW Solar 2031 450 MW Solar 2032 450 MW Solar 2033 300 MW Solar 2034 450 MW Solar 2035 150 MW Solar 2036	Lawrence 5 NG (338 MW) 2024 1 CC (418 MW) in 2036 2 CC (836 MW) in 2038 2 CC (836 MW) in 2039 4 CT (948 MW) in 2040
Evergy CCBAD	RAP + DSR (EM) + RAP + DSR (EMW) + RAP- (EKC)	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Lake Road 4/6: Dec 31, 2024 LaCygne 2: Dec 31, 2029 Jeffrey 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039	300 MW Wind 2024 500 MW Wind 2025 450 MW Wind 2026 300 MW Wind 2041	190 MW Solar 2024 150 MW Solar 2028 450 MW Solar 2029 450 MW Solar 2030 450 MW Solar 2031 450 MW Solar 2032 450 MW Solar 2033 450 MW Solar 2034 450 MW Solar 2035 150 MW Solar 2041	Lawrence 5 NG (338 MW) 2024 1 CC (418 MW) 2036 1 CC (418 MW) 2038 2 CC (836 MW) 2039 2 CC (836 MW) 2040
Evergy CCBAE	RAP + DSR (EM) + RAP + DSR (EMW) + RAP- (EKC)	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Lake Road 4/6: Dec 31, 2024 Iatan 1: Dec 31, 2029 Jeffrey 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	300 MW Wind 2024 500 MW Wind 2025 450 MW Wind 2026 450 MW Wind 2041	190 MW Solar 2024 150 MW Solar 2029 450 MW Solar 2030 450 MW Solar 2031 450 MW Solar 2032 450 MW Solar 2033 450 MW Solar 2034 450 MW Solar 2035	Lawrence 5 NG (338 MW) 2024 1 CC (418 MW) in 2036 1 CC (418 MW) in 2038 2 CC (836 MW) in 2039 2 CC (836 MW) in 2040
Evergy CDAAA	RAP + DSR (EM) + RAP + DSR (EMW) + RAP- (EKC)	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Lake Road 4/6: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	300 MW Wind 2024 500 MW Wind 2025 450 MW Wind 2026 450 MW Wind 2041	190 MW Solar 2024 300 MW Solar 2028 450 MW Solar 2029 450 MW Solar 2030 450 MW Solar 2031 450 MW Solar 2032 450 MW Solar 2033 450 MW Solar 2034 450 MW Solar 2035 150 MW Solar 2036	Lawrence 5 NG (338 MW) 2024 1 CT (237 MW) in 2036 1 CC (418 MW) in 2038 2 CC (836 MW) in 2039 4 CT (948 MW) in 2040

Additionally, two separate ARPs were modeled – Jeffrey Units 1, 2, and 3 operating until 2039 including and excluding potential future environmental costs.

An overview of these two Alternative Resource Plans is shown in Table 22 below:

Table 22: Jeffrey Station with and without Estimated Environmental Costs Resource Plans

Plan Name	DSM Level		Renewable Additions		Generation Additions (If needed)
Evergy CDAAG	RAP + DSR (EM) + RAP + DSR (EMW) + RAP- (EKC)	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Lake Road 4/6: Dec 31, 2024 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1, 2 & 3: Dec 31, 2039 LaCygne 2:Dec 31, 2039	300 MW Wind 2024 500 MW Wind 2025 450 MW Wind 2026 450 MW Wind 2041	190 MW Solar 2024 300 MW Solar 2028 450 MW Solar 2029 450 MW Solar 2030 450 MW Solar 2031 450 MW Solar 2032 450 MW Solar 2033 450 MW Solar 2034 450 MW Solar 2035 150 MW Solar 2036	Lawrence 5 NG (338 MW) 2024 1 CT (237 MW) in 2036 1 CC (418 MW) in 2038 2 CC (836 MW) in 2039 4 CT (948 MW) in 2040
Evergy CDAAH	RAP + DSR (EM) + RAP + DSR (EMW) + RAP- (EKC)	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Lake Road 4/6: Dec 31, 2024 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1, 2 & 3: Dec 31, 2039 (no environmental cost) LaCygne 2:Dec 31, 2039	300 MW Wind 2024 500 MW Wind 2025 450 MW Wind 2026 450 MW Wind 2041	190 MW Solar 2024 300 MW Solar 2028 450 MW Solar 2029 450 MW Solar 2030 450 MW Solar 2031 450 MW Solar 2032 450 MW Solar 2033 450 MW Solar 2034 450 MW Solar 2035 150 MW Solar 2036	Lawrence 5 NG (338 MW) 2024 1 CT (237 MW) in 2036 1 CC (418 MW) in 2038 2 CC (836 MW) in 2039 4 CT (948 MW) in 2040

6.4 EVERGY MISSOURI WEST RESOURCE PLANS

In total, eleven Evergy West Alternative Resource Plans were developed for the 2022 Annual Update. The Evergy West Alternative Resource Plan naming convention is provided in Table 23 and an overview of the Evergy West ARPs is shown in Table 24

Table 23: Evergy Missouri West Alternative Resource Plan Naming Convention

2023-2025 Execution	Builds 2026-2041	Capacity Expansion	DSM Program	Retirements
A. 2021 Preferred Plan B. Execution Changes C. Execution Changes and Lawrence 5 on Gas	A. 2021 Preferred Plan B. Execution Changes C. 16% of Builds from Evergy Combined Plan through 2035 D. Builds from CCBAB	A. Balance as needed B. Full Capacity Expansion 2036-2041	A. RAP (Metro and Missouri West), RAP- (Kansas Central) B. MEEIA Goals (Metro and Missouri West), RAP- (Kansas Central)	A. 2021 Preferred Plan (ERVFL) B. ERVFL + Jeffrey 2 retires in 2030 C. ERVFL D. ERVFL E. ERVFL + Iatan 1 retires in 2029 F. ERVFL adjusted for Lake Road 4/6 retires in 2030

Table 24: Evergy Missouri West Alternative Resource Plan Overview

Plan Name	DSM Level	Retire	Renewable Additions		Generation Additions (if needed)
West AAAAA	RAP + DSR	Lake Road 4/6: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	80 MW Wind 2025 80 MW Wind 2026	120 MW Solar 2024 80 MW Solar 2028 80 MW Solar 2029 80 MW Solar 2030 80 MW Solar 2031 80 MW Solar 2032	1 CT (237 MW) in 2036 1 CT (237 MW) in 2040
West BBAAA	RAP + DSR	Lake Road 4/6: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2024	120 MW Solar 2026 80 MW Solar 2028 80 MW Solar 2029 80 MW Solar 2030 80 MW Solar 2031 80 MW Solar 2032	1 CT (237 MW) in 2036 1 CT (237 MW) in 2040
West CBAAA	RAP + DSR	Lake Road 4/6: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2024	120 MW Solar 2026 80 MW Solar 2028 80 MW Solar 2029 80 MW Solar 2030 80 MW Solar 2031 80 MW Solar 2032	1 CT (237 MW) in 2036 1 CT (237 MW) in 2040
West CBBAB	RAP + DSR	Lake Road 4/6: Dec 31, 2024 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2024	120 MW Solar 2026 80 MW Solar 2028 80 MW Solar 2029 80 MW Solar 2030 80 MW Solar 2031 80 MW Solar 2032 24 MW Solar 2033 72 MW Solar 2034 72 MW Solar 2035 150 MW Solar 2038	1 CT (237 MW) in 2036 1 CT (237 MW) in 2040
West CCBAA	RAP + DSR	Lake Road 4/6: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2024	48 MW Solar 2032 72 MW Solar 2033 72 MW Solar 2034 48 MW Solar 2035	1 CT (237 MW) in 2036 1 CT (237 MW) in 2040
West CCBAB	RAP + DSR	Lake Road 4/6: Dec 31, 2024 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2024 72 MW Wind 2026	48 MW Solar 2028 72 MW Solar 2029 72 MW Solar 2030 72 MW Solar 2031 72 MW Solar 2032 72 MW Solar 2033 72 MW Solar 2034 72 MW Solar 2035	1 CT (237 MW) in 2036 1 CT (237 MW) in 2040
West CCBAC	RAP + DSR	Lake Road 4/6: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2024 24 MW Wind 2026	72 MW Solar 2030 72 MW Solar 2031 72 MW Solar 2032 72 MW Solar 2033 48 MW Solar 2034 72 MW Solar 2035	1 CT (237 MW) in 2036 1 CT (237 MW) in 2040
West CCBAD	RAP + DSR	Lake Road 4/6: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2024 72 MW Wind 2026	24 MW Solar 2028 72 MW Solar 2029 72 MW Solar 2030 72 MW Solar 2031 72 MW Solar 2032 72 MW Solar 2033 72 MW Solar 2034 72 MW Solar 2035	1 CT (237 MW) in 2036 1 CT (237 MW) in 2040
West CCBAE	RAP + DSR	Lake Road 4/6: Dec 31, 2024 Iatan 1: Dec 31, 2029 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039	150 MW Wind 2024 72 MW Wind 2026	24 MW Solar 2029 72 MW Solar 2030 72 MW Solar 2031 72 MW Solar 2032 72 MW Solar 2033 72 MW Solar 2034 72 MW Solar 2035	1 CT (237 MW) in 2036 1 CT (237 MW) in 2040
West CDAAA	RAP + DSR	Lake Road 4/6: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2024 72 MW Wind 2026	48 MW Solar 2028 72 MW Solar 2029 72 MW Solar 2030 72 MW Solar 2031 72 MW Solar 2032 72 MW Solar 2033 72 MW Solar 2034 72 MW Solar 2035	1 CT (237 MW) in 2036 1 CT (237 MW) in 2040
West CDAAF	RAP + DSR	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2024 72 MW Wind 2026	48 MW Solar 2028 72 MW Solar 2029 72 MW Solar 2030 72 MW Solar 2031 72 MW Solar 2032 72 MW Solar 2033 72 MW Solar 2034 72 MW Solar 2035	1 CT (237 MW) in 2036 1 CT (237 MW) in 2040

Additionally, plan CDABF was modeled utilizing the "MEEIA Goals" level of Demand-Side Management per agreement with parties as part of the 2021 Triennial.

Table 25: Evergy Missouri West MEEIA Resource Plan

Plan Name	DSM Level	Retire	Renewable Additions		Generation Additions (if needed)
West CDABF	MEEIA	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	2024 150 MW Wind 2026 72 MW Wind	48 MW Solar 2028 72 MW Solar 2029 72 MW Solar 2030 72 MW Solar 2031 72 MW Solar 2032 72 MW Solar 2033 72 MW Solar 2034 72 MW Solar 2035	1 CT (237 MW) in 2036 1 CT (237 MW) in 2040

Refer to Appendix B, Capacity Balance Spreadsheets, for tables which provide the Evergy West forecast of capacity balance over the twenty-year planning period for each of the Alternative Resource Plans outlined above. These capacity forecasts include renewable and generation additions. The capacity for existing and new renewable facilities is based on expected accreditation under the Equivalent Load Carrying Capability methodology.

6.5 CRITICAL UNCERTAIN FACTORS

The Critical Uncertain Factors for the 2022 Annual Update are identical to those in the 2021 Triennial IRP. Three risks were determined to be critical uncertain factors that would be used in the risk sensitivities of the integrated analysis: load growth, natural gas prices and CO_2 credit prices. Consistent with the 2021 Triennial IRP, the probabilities for both load growth and natural gas are Low 35%, Mid 50%, and High 15% weighted probabilities while the probabilities for CO_2 are Low 20%, Mid 60%, and High 20% as shown in Figure 4 below:

Figure 4: Critical Uncertain Factor Probability Distribution

	Low	Mid	High
Load Growth	35%	50%	15%
Natural Gas	35%	50%	15%
CO_2 Price	20%	60%	20%

The weighted endpoint probability is the product of these three weighted probabilities as show in Figure 5 below:

Figure 5: Scenario Weighted Endpoint Probabilities

Endpoint	Load Growth	Natural Gas	CO_2	Endpoint Probability
1	High	High	High	0.5%
2	High	High	Mid	1.4%
3	High	High	Low	0.5%
4	High	Mid	High	1.5%
5	High	Mid	Mid	4.5%
6	High	Mid	Low	1.5%
7	High	Low	High	1.1%
8	High	Low	Mid	3.2%
9	High	Low	Low	1.1%
10	Mid	High	High	1.5%
11	Mid	High	Mid	4.5%
12	Mid	High	Low	1.5%
13	Mid	Mid	High	5.0%
14	Mid	Mid	Mid	15.0%
15	Mid	Mid	Low	5.0%
16	Mid	Low	High	3.5%
17	Mid	Low	Mid	10.5%
18	Mid	Low	Low	3.5%
19	Low	High	High	1.1%
20	Low	High	Mid	3.2%
21	Low	High	Low	1.1%
22	Low	Mid	High	3.5%
23	Low	Mid	Mid	10.5%
24	Low	Mid	Low	3.5%
25	Low	Low	High	2.5%
26	Low	Low	Mid	7.4%
27	Low	Low	Low	2.5%

6.6 REVENUE REQUIREMENT – JOINT PLANNING

For each of the Alternative Resource Plans developed, integrated analysis yielded an expected value of the Net Present Value of Revenue Requirement shown in Table 26 below.

Table 26: Joint-Planning Twenty-Year Net Present Value Revenue Requirement
**** Confidential ****

Rank (L-H)	Plan	NPVRR ($mm)	Delta
1	CCBAB	$57,291	$0
2	CCBAE	$57,379	$88
3	[redacted]		
4	CBBAB	$57,451	$161
5	CCBAA	$57,461	$170
6	CDAAA	$57,541	$250
7	CCBAC	$57,565	$274
8	CBAAA	$57,688	$397
9	BBAAA	$57,717	$426
10	AAAAA	$57,808	$517

C

6.7 BY-SCENARIO RESULTS – JOINT PLANNING

Table 27, Table 28, and Table 29 show the expected value of NPVRR for the joint plans assuming high, mid, and low CO_2 restrictions.

Table 27: Joint Plan Results - High CO_2 Restrictions ** Confidential **

Rank (L-H)	Plan	NPVRR ($mm)	Delta	Retirement - Changes from Book Life	Additions	DSM level	DSR
1	CCBAB	$62,957	$0	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J2 & J3 12/30; LaC 2 12/39	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 450 MW Wind 2026 & 2041, 190 MW Solar 2024, 300 MW Solar 2028, 450 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 150 MW Solar 2036, 237 MW CT 2036, 418 MW CC 2038, 836 MW CC 2039, 948 MW CT 2040	RAP	X
[redacted]							
3	CBBAB	$63,224	$267	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J2 & J3 12/30; LaC 2 12/39	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 150 MW Solar 2033 & 2038,190 MW Solar 2024, 350 MW Solar 2026, 450 MW Solar 2034 & 2035, 500 MW Solar 2028, 2029, 2030, 2031, & 2032, 418 MW CC 2036 & 2038, 836 MW CC 2039 & 2040, 237 MW CT 2041	RAP	X
4	CDAAA	$63,248	$291	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J3 12/30	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 450 MW Wind 2026 & 2041, 190 MW Solar 2024, 300 MW Solar 2028, 450 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 150 MW Solar 2036, 237 MW CT 2036, 418 MW CC 2038, 836 MW CC 2039, 948 MW CT 2040	RAP	X
5	CCBAE	$63,330	$373	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; I1 12/29; J3 12/30	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 450 MW Wind 2026 & 2041, 190 MW Solar 2024, 150 MW Solar 2029, 450 MW Solar 2030, 2031, 2032, 2033, 2034 & 2035, 418 MW CC 2036 & 2038, 836 MW CC 2039 & 2040	RAP	X
6	CCBAC	$63,731	$774	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; H5 12/29; J3 12/30; LaC 2 12/39	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 150 MW Wind 2026, 450 MW Wind 2037 & 2041, 190 MW Solar 2024, 450 MW Solar 2030, 2031, 2032, 2033 & 2035, 300 MW Solar 2034, 150 MW Solar 2036, 418 MW CC 2036, 836 MW CC 2038 & 2039, 948 MW CT 2040	RAP	X
7	BBAAA	$63,846	$889	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J3 12/30; LaC 2 12/39	300 MW Wind 2024, 500 MW Wind 2025, 190 MW Solar 2024, 350 MW Solar 2026, 500 MW Solar 2028, 2029, 2030, 2031, & 2032, 418 MW CC 2036, 836 MW CC 2038 & 2039, 474 MW CT 2040, 418 MW CC 2040, 237 MW CT 2041	RAP	X
8	CBAAA	$63,940	$983	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J3 12/30; LaC 2 12/39	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 190 MW Solar 2024, 350 MW Solar 2026, 500 MW Solar 2028, 2029, 2030, 2031, & 2032; 836 MW CC 2038, 474 MW CT 2039, 418 MW CC 2039, 948 MW CT 2040, 237 MW CT 2041	RAP	X
9	AAAAA	$64,006	$1,049	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J3 12/30; LaC 2 12/39	500 MW Wind 2025 & 2026, 350 MW Solar 2023 & 2024, 500 MW Solar 2028, 2029, 2030, 2031, & 2032; 233 MW CT 2036, 2037 & 2039, 2796 MW CT 2040	RAP	X
10	CCBAA	$64,456	$1,499	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J3 12/30; LaC 2 12/39	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 150 MW Wind 2037, 190 MW Solar 2024, 300 MW Solar 2032, 2035 & 2037, 450 MW Solar 2033, 2034 & 2036, 836 MW CC 2038 & 2039, 948 MW CT 2040, 237 MW CT 2041	RAP	X

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Table 28: Joint Plan Results - Mid-CO_2 Restrictions ** Confidential **

Rank (L-H)	Plan	NPVRR ($mm)	Delta	Retirement - Changes from Book Life	Additions	DSM level	DSR
1	CCBAA	$56,386	$0	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J3 12/30; LaC 2 12/39	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 150 MW Wind 2037, 190 MW Solar 2024, 300 MW Solar 2032, 2035 & 2037, 450 MW Solar 2033, 2034 & 2036, 836 MW CC 2038 & 2039, 948 MW CT 2040, 237 MW CT 2041	RAP	X
2	CCBAB	$56,426	$41	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J2 & J3 12/30; LaC 2 12/39	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 450 MW Wind 2026 & 2041, 190 MW Solar 2024, 300 MW Solar 2028, 450 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 150 MW Solar 2036, 237 MW CT 2036, 418 MW CC 2038, 836 MW CC 2039, 948 MW CT 2040	RAP	X
3	CCBAE	$56,469	$83	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; I1 12/29; J3 12/30	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 450 MW Wind 2026 & 2041, 190 MW Solar 2024, 150 MW Solar 2029, 450 MW Solar 2030, 2031, 2032, 2033, 2034 & 2035, 418 MW CC 2036 & 2038, 836 MW CC 2039 & 2040	RAP	X
[redacted]							
5	CBBAB	$56,564	$179	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J2 & J3 12/30; LaC 2 12/39	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 150 MW Solar 2033 & 2038,190 MW Solar 2024, 350 MW Solar 2026, 450 MW Solar 2034 & 2035, 500 MW Solar 2028, 2029, 2030, 2031, & 2032, 418 MW CC 2036 & 2038, 836 MW CC 2039 & 2040, 237 MW CT 2041	RAP	X
6	CCBAC	$56,614	$229	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; H5 12/29; J3 12/30; LaC 2 12/39	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 150 MW Wind 2026, 450 MW Wind 2037 & 2041, 190 MW Solar 2024, 450 MW Solar 2030, 2031, 2032, 2033 & 2035, 300 MW Solar 2034, 150 MW Solar 2036, 418 MW CC 2036, 836 MW CC 2038 & 2039, 948 MW CT 2040	RAP	X
7	CDAAA	$56,677	$291	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J3 12/30	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 450 MW Wind 2026 & 2041, 190 MW Solar 2024, 300 MW Solar 2028, 450 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 150 MW Solar 2036, 237 MW CT 2036, 418 MW CC 2038, 836 MW CC 2039, 948 MW CT 2040	RAP	X
8	CBAAA	$56,745	$359	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J3 12/30; LaC 2 12/39	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 190 MW Solar 2024, 350 MW Solar 2026, 500 MW Solar 2028, 2029, 2030, 2031, & 2032; 836 MW CC 2038, 474 MW CT 2039, 418 MW CC 2039, 948 MW CT 2040, 237 MW CT 2041	RAP	X
9	BBAAA	$56,787	$401	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J3 12/30; LaC 2 12/39	300 MW Wind 2024, 500 MW Wind 2025, 190 MW Solar 2024, 350 MW Solar 2026, 500 MW Solar 2028, 2029, 2030, 2031, & 2032, 418 MW CC 2036, 836 MW CC 2038 & 2039, 474 MW CT 2040, 418 MW CC 2040, 237 MW CT 2041	RAP	X
10	AAAAA	$56,877	$492	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J3 12/30; LaC 2 12/39	500 MW Wind 2025 & 2026, 350 MW Solar 2023 & 2024, 500 MW Solar 2028, 2029, 2030, 2031, & 2032; 233 MW CT 2036, 2037 & 2039, 2796 MW CT 2040	RAP	X

C

Table 29: Joint Plan Results - No CO_2 Restrictions ** Confidential **

Rank (L-H)	Plan	NPVRR ($mm)	Delta	Retirement - Changes from Book Life	Additions	DSM level	DSR
1	CCBAA	$53,690	$0	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J3 12/30; LaC 2 12/39	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 150 MW Wind 2037, 190 MW Solar 2024, 300 MW Solar 2032, 2035 & 2037, 450 MW Solar 2033, 2034 & 2036, 836 MW CC 2038 & 2039, 948 MW CT 2040, 237 MW CT 2041	RAP	X
2	CCBAE	$54,159	$469	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; I1 12/29; J3 12/30	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 450 MW Wind 2026 & 2041, 190 MW Solar 2024, 150 MW Solar 2029, 450 MW Solar 2030, 2031, 2032, 2033, 2034 & 2035, 418 MW CC 2036 & 2038, 836 MW CC 2039 & 2040	RAP	X
3	CCBAB	$54,219	$528	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J2 & J3 12/30; LaC 2 12/39	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 450 MW Wind 2026 & 2041, 190 MW Solar 2024, 300 MW Solar 2028, 450 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 150 MW Solar 2036, 237 MW CT 2036, 418 MW CC 2038, 836 MW CC 2039, 948 MW CT 2040	RAP	X
4	CCBAC	$54,250	$560	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; H5 12/29; J3 12/30; LaC 2 12/39	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 150 MW Wind 2026, 450 MW Wind 2037 & 2041, 190 MW Solar 2024, 450 MW Solar 2030, 2031, 2032, 2033 & 2035, 300 MW Solar 2034, 150 MW Solar 2036, 418 MW CC 2036, 836 MW CC 2038 & 2039, 948 MW CT 2040	RAP	X
5	CBAAA	$54,266	$576	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J3 12/30; LaC 2 12/39	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 190 MW Solar 2024, 350 MW Solar 2026, 500 MW Solar 2028, 2029, 2030, 2031, & 2032; 836 MW CC 2038, 474 MW CT 2039, 418 MW CC 2039, 948 MW CT 2040, 237 MW CT 2041	RAP	X
6	CBBAB	$54,340	$649	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J2 & J3 12/30; LaC 2 12/39	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 150 MW Solar 2033 & 2038,190 MW Solar 2024, 350 MW Solar 2026, 450 MW Solar 2034 & 2035, 500 MW Solar 2028, 2029, 2030, 2031, & 2032, 418 MW CC 2036 & 2038, 836 MW CC 2039 & 2040, 237 MW CT 2041	RAP	X
[redacted]							
8	BBAAA	$54,378	$688	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J3 12/30; LaC 2 12/39	300 MW Wind 2024, 500 MW Wind 2025, 190 MW Solar 2024, 350 MW Solar 2026, 500 MW Solar 2028, 2029, 2030, 2031, & 2032, 418 MW CC 2036, 836 MW CC 2038 & 2039, 474 MW CT 2040, 418 MW CC 2040, 237 MW CT 2041	RAP	X
9	AAAAA	$54,401	$711	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J3 12/30; LaC 2 12/39	500 MW Wind 2025 & 2026, 350 MW Solar 2023 & 2024, 500 MW Solar 2028, 2029, 2030, 2031, & 2032; 233 MW CT 2036, 2037 & 2039, 2796 MW CT 2040	RAP	X
10	CDAAA	$54,427	$736	LEC 5 to NG 12/23; LEC 4 12/24; LR 4/6 12/24; J3 12/30	338 MW LEC 5 to NG 2024, 300 MW Wind 2024, 500 MW Wind 2025, 450 MW Wind 2026 & 2041, 190 MW Solar 2024, 300 MW Solar 2028, 450 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 150 MW Solar 2036, 237 MW CT 2036, 418 MW CC 2038, 836 MW CC 2039, 948 MW CT 2040	RAP	X

C

6.8 JOINT PLANNING ENVIRONMENTAL COST SENSITIVITY

Two alternative resource plans were developed to test NPVRR sensitivity with respect to environmental cost assumptions. CDAAG models the Preferred Plan with the 2030 Jeffrey 3 retirement postponed to 2039. CDAAH models the same plan without the major capital expenses for SCR systems and baghouses forecasted to meet future environmental requirements for Jeffrey Energy Center.

Table 30: Joint Planning - Jeffrey Station Environmental Cost Sensitivity

	NPVRR	Difference
Jeffrey Retires 2039 (CDAAG)	57,931	-
Jeffrey Retires 2039 no environmental costs (CDAAH)	57,417	(514)

6.9 REVENUE REQUIREMENT – EVERGY MISSOURI WEST

Table 31: Evergy Missouri West Twenty-Year Net Present Value Revenue Requirement

Rank (L-H)	Plan	NPVRR ($mm)	Delta
1	CDAAF	$10,013	$0
2	CCBAC	$10,022	$9
3	CCBAB	$10,024	$10
4	CCBAA	$10,027	$14
5	CCBAD	$10,031	$18
6	CDAAA	$10,033	$20
7	CCBAE	$10,036	$23
8	CBBAB	$10,039	$25
9	BBAAA	$10,040	$27
9	CBAAA	$10,040	$27
11	AAAAA	$10,044	$31
12	CDABF	$10,083	$70

6.10 BY-SCENARIO RESULTS – EVERGY MISSOURI WEST

Table 32, Table 33, and Table 34 show the expected value of NPVRR for Evergy West alternative resource plans assuming high, mid, and low CO_2 restrictions.

Table 32: Evergy Missouri West Plan Results – High CO_2 Restrictions

Rank (L-H)	Plan	NPVRR ($mm)	Delta	Retirement - Changes from Book Life	Additions	DSM level	DSR
1	CDAAF	$11,734	$0	LR 4/6 12/30; J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 48 MW Solar 2028, 72 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	RAP	X
2	CBBAB	$11,736	$3	LR 4/6 12/24; J2 & J3 12/30	150 MW Wind 2024, 120 MW Solar 2026, 80 MW Solar 2028, 2029, 2030, 2031, & 2032, 24 MW Solar 2033, 72 MW Solar 2034 & 2035, 150 MW Solar 2038, 237 MW CT 2036 & 2040	RAP	X
3	CCBAB	$11,740	$6	LR 4/6 12/24; J2 & J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 48 MW Solar 2028, 72 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	RAP	X
4	CDABF	$11,753	$19	LR 4/6 12/30; J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 48 MW Solar 2028, 72 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	MEEIA	
5	CDAAA	$11,754	$20	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 48 MW Solar 2028, 72 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	RAP	X
6	CCBAD	$11,765	$31	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 24 MW Solar 2028, 72 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	RAP	X
7	CCBAE	$11,799	$65	LR 4/6 12/24; I1 12/29; J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 24 MW Solar 2029, 72 MW Solar 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	RAP	X
8	BBAAA	$11,801	$68	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 120 MW Solar 2026, 80 MW Solar 2028, 2029, 2030, 2031, & 2032, 237 MW CT 2036 & 2040	RAP	X
8	CBAAA	$11,801	$68	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 120 MW Solar 2026, 80 MW Solar 2028, 2029, 2030, 2031, & 2032; 237 MW CT 2036 & 2040	RAP	X
10	AAAAA	$11,802	$68	LR 4/6 12/24; J3 12/30	80 MW Wind 2025 & 2026, 120 MW Solar 2024, 80 MW Solar 2028, 2029, 2030, 2031, & 2032; 237 MW CT 2036 & 2040	RAP	X
11	CCBAC	$11,846	$112	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 24 MW Wind 2026, 72 MW Solar 2030, 2031, 2032, 2033 & 2035, 48 MW Solar 2034, 237 MW CT 2036 & 2040	RAP	X
12	CCBAA	$11,947	$213	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 48 MW Solar 2032 & 2035, 72 MW Solar 2033 & 2034, 237 MW CT 2036 & 2040	RAP	X

Table 33: Evergy Missouri West Plan Results – Mid CO_2 Restrictions

Rank (L-H)	Plan	NPVRR ($mm)	Delta	Retirement - Changes from Book Life	Additions	DSM level	DSR
1	CCBAA	$9,731	$0	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 48 MW Solar 2032 & 2035, 72 MW Solar 2033 & 2034, 237 MW CT 2036 & 2040	RAP	X
2	CCBAC	$9,740	$9	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 24 MW Wind 2026, 72 MW Solar 2030, 2031, 2032, 2033 & 2035, 48 MW Solar 2034, 237 MW CT 2036 & 2040	RAP	X
3	CDAAF	$9,747	$16	LR 4/6 12/30; J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 48 MW Solar 2028, 72 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	RAP	X
4	CCBAB	$9,758	$27	LR 4/6 12/24; J2 & J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 48 MW Solar 2028, 72 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	RAP	X
5	CCBAD	$9,763	$32	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 24 MW Solar 2028, 72 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	RAP	X
6	CCBAE	$9,764	$33	LR 4/6 12/24; I1 12/29; J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 24 MW Solar 2029, 72 MW Solar 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	RAP	X
7	CDAAA	$9,767	$36	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 48 MW Solar 2028, 72 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	RAP	X
8	BBAAA	$9,769	$38	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 120 MW Solar 2026, 80 MW Solar 2028, 2029, 2030, 2031, & 2032, 237 MW CT 2036 & 2040	RAP	X
8	CBAAA	$9,769	$38	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 120 MW Solar 2026, 80 MW Solar 2028, 2029, 2030, 2031, & 2032; 237 MW CT 2036 & 2040	RAP	X
10	AAAAA	$9,773	$42	LR 4/6 12/24; J3 12/30	80 MW Wind 2025 & 2026, 120 MW Solar 2024, 80 MW Solar 2028, 2029, 2030, 2031, & 2032; 237 MW CT 2036 & 2040	RAP	X
11	CBBAB	$9,774	$43	LR 4/6 12/24; J2 & J3 12/30	150 MW Wind 2024, 120 MW Solar 2026, 80 MW Solar 2028, 2029, 2030, 2031, & 2032, 24 MW Solar 2033, 72 MW Solar 2034 & 2035, 150 MW Solar 2038, 237 MW CT 2036 & 2040	RAP	X
12	CDABF	$9,824	$93	LR 4/6 12/30; J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 48 MW Solar 2028, 72 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	MEEIA	

Table 34: Evergy Missouri West – No CO_2 Restrictions

Rank (L-H)	Plan	NPVRR ($mm)	Delta	Retirement - Changes from Book Life	Additions	DSM level	DSR
1	CCBAA	$8,996	$0	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 48 MW Solar 2032 & 2035, 72 MW Solar 2033 & 2034, 237 MW CT 2036 & 2040	RAP	X
2	CCBAC	$9,042	$47	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 24 MW Wind 2026, 72 MW Solar 2030, 2031, 2032, 2033 & 2035, 48 MW Solar 2034, 237 MW CT 2036 & 2040	RAP	X
3	CDAAF	$9,090	$95	LR 4/6 12/30; J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 48 MW Solar 2028, 72 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	RAP	X
4	CCBAE	$9,092	$96	LR 4/6 12/24; I1 12/29; J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 24 MW Solar 2029, 72 MW Solar 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	RAP	X
5	BBAAA	$9,093	$98	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 120 MW Solar 2026, 80 MW Solar 2028, 2029, 2030, 2031, & 2032, 237 MW CT 2036 & 2040	RAP	X
5	CBAAA	$9,093	$98	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 120 MW Solar 2026, 80 MW Solar 2028, 2029, 2030, 2031, & 2032; 237 MW CT 2036 & 2040	RAP	X
7	AAAAA	$9,098	$103	LR 4/6 12/24; J3 12/30	80 MW Wind 2025 & 2026, 120 MW Solar 2024, 80 MW Solar 2028, 2029, 2030, 2031, & 2032; 237 MW CT 2036 & 2040	RAP	X
8	CCBAD	$9,101	$105	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 24 MW Solar 2028, 72 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	RAP	X
9	CCBAB	$9,104	$109	LR 4/6 12/24; J2 & J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 48 MW Solar 2028, 72 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	RAP	X
10	CDAAA	$9,110	$115	LR 4/6 12/24; J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 48 MW Solar 2028, 72 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	RAP	X
11	CBBAB	$9,133	$138	LR 4/6 12/24; J2 & J3 12/30	150 MW Wind 2024, 120 MW Solar 2026, 80 MW Solar 2028, 2029, 2030, 2031, & 2032, 24 MW Solar 2033, 72 MW Solar 2034 & 2035, 150 MW Solar 2038, 237 MW CT 2036 & 2040	RAP	X
12	CDABF	$9,188	$192	LR 4/6 12/30; J3 12/30	150 MW Wind 2024, 72 MW Wind 2026, 48 MW Solar 2028, 72 MW Solar 2029, 2030, 2031, 2032, 2033, 2034 & 2035, 237 MW CT 2036 & 2040	MEEIA	

6.11 EVERGY MISSOURI WEST DSM SENSITIVITY

The resource plan CDABF was developed to test the NPVRR sensitivity of implementing the MEEIA Goals-level of DSM instead of the RAP-level of DSM selected in the Preferred Plan (CDAAF).

Table 35: Evergy Missouri West - DSM Sensitivity

	NPVRR	Difference
Preferred Plan (CDAAF)	10,013	-
MEEIA Goals Plan (CDABF)	10,083	70

6.12 SUMMARY AND EVALUATION

At the Joint Planning level, the lowest cost plans on an expected value basis are plans which include an additional retirement in the 2030 timeframe compared to the 2021 Triennial Preferred Plan. However, given the significant variability between the potential drivers of *which* additional unit should retire in that timeframe, as well as other uncertainties described previously, Evergy is selecting CDAAA as its Preferred Plan at the joint planning level, which is based on the resource additions needed in the medium-term to support such a retirement, but does not include a specific identified retirement.

Although this Preferred Plan ranks relatively low in the tables shown above, this is because it does not include any savings from an assumed retirement at this point, which is expected to be part of the ultimately executed plan. As an additional factor in the selection of the Preferred Plan, the plan which ranks next lowest cost after accelerated retirement options is CCBAA, which is identical to the Preferred Plan in the Implementation Period and simply has a slower pace of resource additions in the Medium Term because it does not assume an accelerated retirement. Given this, the near-term (Implementation Period) actions of the Preferred Plan are consistent with all of the lowest-cost plans at the Evergy level and the path of continued ratable renewable resource additions to prepare for future retirements in the Medium Term is also consistent with the lowest cost plans while allowing continued flexibility to adjust over the next 10 years.

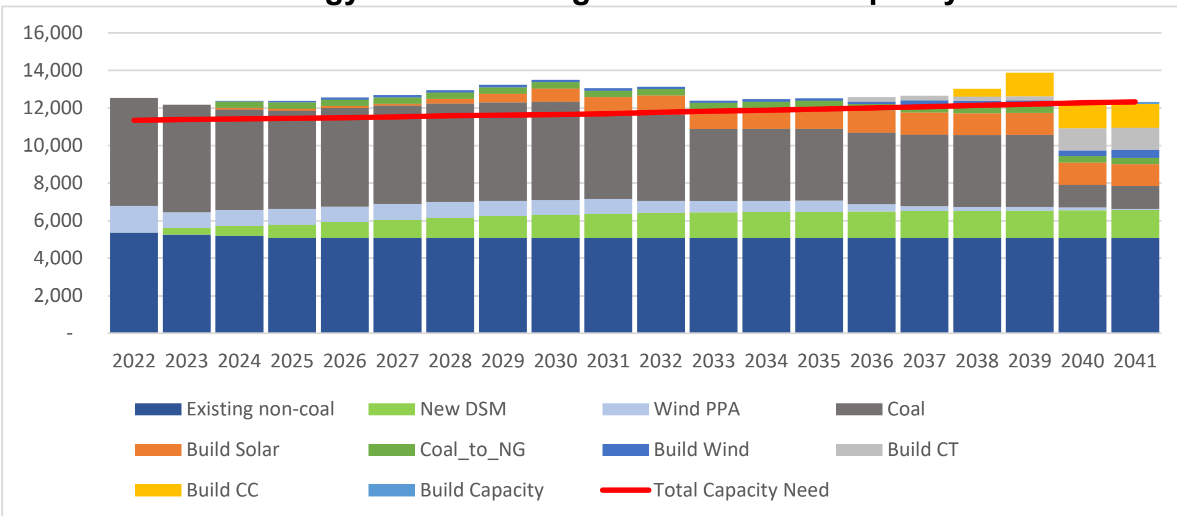
For Evergy West, CDAAF is the lowest cost plan on an expected value basis, followed closely by the early retirement plans and CCBAA mentioned above. CDAAF is consistent with CDAAA but includes the delayed retirement of Lake Road 4/6.

The Joint-Planning Preferred Plan CDAAA for the 20-year planning period is shown in Table 36 below:

Table 36: Evergy Joint Planning Preferred Plan CDAAA

Year	Wind (MW)	Solar (MW)	Thermal (MW)	Capacity Only (Annual MW)	DSM (Annual MW)	Retirements (MW)
2022					404	
2023					643	
2024	300	190	338		799	373
2025	500				926	216
2026	450				1,039	
2027					1,143	
2028		300			1,233	
2029		450			1,308	
2030		450			1,368	
2031		450			1,405	674
2032		450			1,429	
2033		450			1,441	760
2034		450			1,452	
2035		450			1,457	
2036		150	237		1,465	
2037					1,480	
2038			418		1,496	
2039			836		1,509	
2040			948	100	1,517	2,641
2041	450			100	1,521	

Table 37: Evergy Joint Planning Preferred Plan Capacity Balance



The Preferred Plan includes 1,700 MW of total wind additions, including 1,250 MW in 2024-2026 and 3,790 MW of total solar additions, with 190 MW added in 2024 and one to three 150 MW projects per year 2028-2036. Additional thermal resources are modeled to replace retiring coal capacity beginning in 2036, including five combustion turbines and three combined cycles. The Preferred Plan also includes the RAP level of DSM for Evergy Metro and Evergy West and the RAP- level of DSM for Evergy Kansas Central, consistent with the 2021 Preferred Plan.

SECTION 7: RESOURCE ACQUISITION STRATEGY

7.1 <u>2022 ANNUAL UPDATE PREFERRED PLAN</u>

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

The Company has selected CDAAA as its Preferred Plan at the Evergy level and CDAAF as the Preferred plan for Evergy Missouri West. These plans are lower cost than the 2021 IRP Preferred Plan at both the Evergy and Evergy West level. CDAAA was selected despite being higher cost than many of the accelerated retirement plans which were modeled at the Evergy level due to the exclusion of specific additional accelerated retirements because of the significant uncertainty which exists related to such accelerated retirements (Section 6.2). This plan allows Evergy to continue building renewables at a ratable pace, consistent with its 2021 Triennial IRP, while maintaining flexibility to adjust as technology and policy change in the future. Ultimately, it seems likely that an additional retirement may occur in the late-2020s/early 2030s, but there is currently too much uncertainty to commit to a specific unit retirement. Additional discussion is provided in the Customer/Shareholder Risk Analysis Special Contemporary Issue. The Preferred Plan selected for Evergy West – CDAAF – which is consistent with the Evergy-level Preferred Plan but includes the delayed retirement of Lake Road 4/6 to 2030, was the lowest-cost plan on an expected value basis for Evergy West.

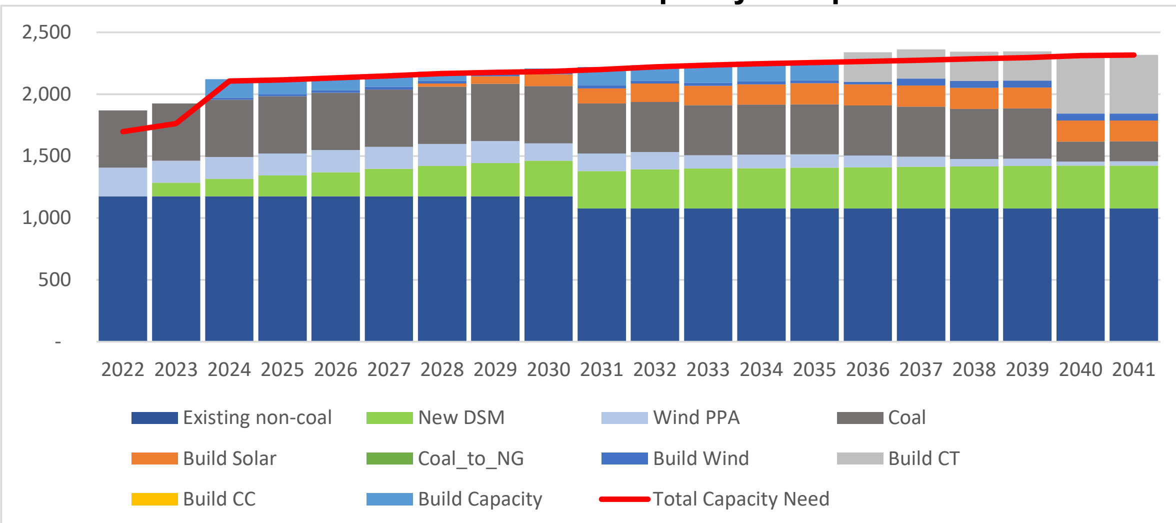
The Evergy Missouri West Preferred Plan CDAAF for the 20-year planning period is shown in Table 38 below:

Table 38: Evergy Missouri West Planning Preferred Plan CDAAF

Year	Wind (MW)	Solar (MW)	Thermal (MW)	Capacity Only (Annual MW)	DSM (Annual MW)	Retirements (MW)
2022					118	
2023					161	
2024	150			150	186	
2025				125	206	
2026	72			100	227	
2027				100	246	
2028		48		75	261	
2029		72		25	278	
2030		72		25	291	
2031		72		150	296	155
2032		72		125	296	
2033		72		150	297	
2034		72		150	299	
2035		72		150	300	
2036			237		302	
2037					306	
2038					309	
2039					311	
2040			237		310	246
2041					309	

7.1.1 PREFERRED PLAN COMPOSITION

Table 39: Preferred Plan Capacity Composition



The Evergy Missouri West Preferred Plan includes the following renewable additions: 150 MW of wind generation in 2024 and 72 MW of wind generation in 2026. Additionally, 48 MW of solar generation in 2028 and 72 MW of solar generation in each of the years 2029 to 2035. Over the 20-year planning period, total renewable additions equal 222 MW of wind generation and 552 MW of solar generation. Also, thermal resources are modeled to replace retiring coal capacity beginning in 2036, including 2 combustion turbines. The Preferred Plan also includes the RAP level of DSM for Evergy Missouri West.

7.2 MONITORING CHANGING CONDITIONS AND MAINTAINING FLEXIBILITY

The primary goals in selecting a Preferred Plan are to evaluate whether near-term actions are robust across various future market scenarios and to maintain as much flexibility as possible to adjust to changing market conditions in the medium- and long-term horizon. The planning environment has continued to evolve and become more dynamic – creating an increased value for maintaining flexibility. Some of the current key sources of uncertainty related to Evergy West's resource plans are described below, as well as a discussion of how this uncertainty has been and will be factored into planning processes and resource planning decision-making.

Commodity Prices: Over the last ~9 months, natural gas prices have increased dramatically and experienced significantly more volatility than in recent years. While Evergy currently expects this to be a relatively short-term (<2 years) dynamic, we continue to monitor market expectations and to incorporate these expectations in our ongoing updates to commodity price forecasts (including the forecast used for this Annual Update). While this recent volatility has certainly impacted Evergy's operations in recent months, it has not resulted in a change to its long-term supply plan at this point.

Supply-Side Resource Costs: Driven by COVID-19 supply chain impacts and uncertainty caused by Department of Justice and Department of Commerce activity involving solar photovoltaic manufacturing, there has been an increase in the cost of materials for renewable generation (as well as many other commodities). Evergy has incorporated this increase into the near-term cost assumptions utilized for this IRP but expects this to be a relatively near-term market dynamic. A third-party cost curve is used to forecast future cost reductions, with an adjustment applied to account for near-term supply chain cost pressures. The impacts of these dynamics have been incorporated into the Implementation Period changes reflected in this 2022 Update. As a result of these dynamics, Evergy has reduced planned near-term renewable investment given supply chain challenges and has pulled forward planned wind investment given availability of more mature projects which are less impacted by supply chain issues (when compared to solar).

SPP Interconnection Queue: The SPP Interconnection Queue is severely backlogged with requests as old as 2016 and 2017 still awaiting finalized Interconnection Agreements. In addition, there is continued uncertainty around upgrade costs which will be assigned to specific projects once they complete the interconnection study process, which can create cost uncertainty depending on the maturity of individual projects. Evergy believes that the ratable approach to renewables included in this Preferred Plan allow it to better manage this risk and make adjustments as needed but will continue to monitor SPP's efforts to mitigate the existing backlog and determine cost allocation methods which will effectively share costs between renewable interconnection customers and the rest of the Pool, as appropriate. In addition to the supply chain impacts described above, these dynamics related to the Interconnection Queue were another driver of some of the re-sequencing of near-term renewables in this 2022 Preferred Plan.

Distributed Energy Resources (DERs): While Evergy has not yet seen significant penetration of distributed energy resources to the point that it impacts our long-term plan, the continued expansion of electrification, DER aggregation driven by FERC Order 2222, and other policy changes which could influence DER adoption will all continue to be monitored and factored into Evergy's long-term plans as needed.

Electrification / Load Growth: Across Evergy's system, the potential for broad electrification (e.g., vehicles, space / water heating) will continue to be an uncertainty in the development of load forecasts and long-term plans. Evergy incorporates forecasts for electric vehicle adoption into its load forecasts used in IRP planning and these forecasts are updated regularly. Evergy also performed a broader electrification potential study for the 2021 Triennial IRP which was included as the "high" case in this 2022 Annual Update as well. Going forward, Evergy will continue to monitor actual electrification activity in its service territory and update load forecasts for IRP filings. This monitoring and forecasting activity will also be informed by the availability of programs and technology which can mitigate the impact of electrification on peak demand (and thus Evergy's capacity requirements).

In addition to Electrification, Evergy continues to see robust economic development activity with large new customer loads evaluating locating in the service territory. The impact of these potential new customers on Evergy's overall planning activities will depend on specific rate structures and tariffs which the customers participate in, but, given the magnitude of some potential new loads, they still represent an uncertainty which needs to be monitored and incorporated into Evergy's load forecasts as they come to fruition.

Reliability and Resource Adequacy: As discussed and agreed with parties following the 2021 IRP, Evergy plans to integrate more detailed reliability risk analysis into its IRP beginning with the 2024 Triennial filing. In the interim, there continues to be significant uncertainty regarding SPP's resource adequacy requirements and, ultimately, how reliability risk should be evaluated and incorporated into planning processes – not just for Evergy or for SPP, but for the entire electric utility industry. Following Winter Storm Uri in 2021, SPP, other Regional Transmission Organizations (RTOs), NERC, and FERC have all initiated efforts to promote changes in resource adequacy processes and requirements so they can be better tailored to a low-carbon resource mix given an increasing dependence of customers on electricity as the economy continues to electrify. It is still uncertain what the ultimate impact of these efforts will be in terms of new Standards and Requirements, but some of the potential impacts are described below. Given the significant amount of uncertainty in these areas and the potential for significant impacts to Evergy's resource planning, Evergy is participating actively in both SPP and NERC activities related to these topics.

> Multi-season adequacy: Across the US, RTOs are modifying their resource adequacy constructs to change how they evaluate adequacy in, at the very least, the winter season and, in many cases, all four seasons. Evergy has historically focused on planning for the summer season given our status as a summer-peaking utility. However, as SPP's requirements change, it is likely that Evergy's planning processes will also need to change. SPP is currently evaluating two-season (winter and summer) performance-based accreditation (discussed below) and reviewing other resource adequacy requirements

related to the winter season. Discussions of spring/fall requirements are fairly nascent in SPP, but are expected to continue developing in the future.

Resource Accreditation: Many regional transmission organizations are currently working to implement or modify accreditation methodologies for thermal generators. Ultimately these changes could take the form of performance-based accreditation where the accreditation of thermal resources is determined not based on their physical capability, but on their historical performance (accounting for forced outages, for example). While resource performance has historically been factored into the calculation of planning reserve margins (i.e., reserve margins are intended to account for the potential for forced outages), these changes in process could ultimately change the overall capacity requirement for the RTO, could change the accredited capacity granted to individual Load Responsible Entities, and could complicate the long-term planning process given it makes thermal accredited capacity – like renewable capacity under the equivalent load-carrying capability (ELCC) methodology – a moving target in planning processes going forward.

Fuel Supply Requirements: Given challenges with natural gas supply during Winter Storm Uri and similar extreme winter events, many RTOs and NERC are evaluating how the firmness of fuel supply should be considered in determining a resource's contribution to meeting Adequacy requirements. Changes in this area could potentially materialize in the form of on-site fuel or firm transport requirements for individual generators or minimum reliability attributes at the overall RTO level in terms of on-site fuel availability.

Reserve Margin: Historically, planning reserve margins have been calculated based on probabilistic studies where the objective is to maintain a loss-of-load-expectation (LOLE) of less than 1 day in 10 years. Beyond this overall construct however, there is significant variability in the input assumptions which can be utilized in these studies. SPP continues to evaluate potential changes to their LOLE study methodologies given learnings from Winter Storm

Uri and continued changes to the resource mix. These evaluations and process changes should, ultimately, result in a more accurate view of potential reliability risk, but are also likely to result in an increase in the 12% reserve margin which is currently in place.

Energy Adequacy (as opposed to Capacity Adequacy): A relatively new concept in this space is the distinction being made between “energy adequacy” and the more traditional view of “resource adequacy” or “capacity adequacy”, with the more traditional view being focused on maintaining sufficient capacity to meet peak hour requirements, plus a level of reserves to mitigate risk (with risk being driven by load uncertainty and resource performance, generally). A key focus of NERC over the last year has been on exploring additional / modified Reliability Standards which expand that traditional focus to a broader view of “Energy Adequacy” which takes into account all hours – not just peaks – and incorporates a greater range of uncertainties given the quickly-changing resource mix (both supply- and demand-side resources). While the outcome of these efforts is still relatively uncertain, it is likely that NERC activities in this space will ultimately impact the types of analysis SPP does to comply with Reliability Standards and to assess reliability risks.

Environmental Regulations: As described elsewhere in this document, Evergy currently assumes that all coal resources will need Best Available Control Technology (“BACT”) before the end of the 20-year planning horizon. For Evergy’s fleet, all units have BACT installed other than Lawrence and Jeffrey Energy Centers. As a result, the capital plan used for the 2022 Annual Update includes a need to install Selective Catalytic Reduction (SCR) and baghouses on all three Jeffrey units (only a baghouse is required for Jeffrey Unit 1 because an SCR has already been installed and no new control equipment is required for Lawrence due to retirement / gas operations) in the middle decade of the planning horizon. This assumption represents Evergy’s current expectation of when this technology may be required given expected tightening of environmental regulations. However, as demonstrated in the modeled sensitivity plans with and without the environmental upgrades included, this expectation represents a large source of uncertainty specifically for the Jeffrey units. Evergy will continue to monitor environmental regulations on an ongoing basis and incorporate any changes in expectations into IRP filings. With that being said, while the timing of regulations which could require BACT is uncertain, the fact that the Jeffrey Units are not fully controlled remains a qualitative decision-making factor when comparing those units to alternative retirement candidates. As an example, if no cost (or a cost very late in the planning period) was assumed to install BACT at a Jeffrey unit and thus a different unit appeared to be a more cost-effective retirement option and was retired, but then a new regulation came about that required BACT after that time, Evergy could then be forced into either making the retrofits or retiring the unit and procuring additional replacement capacity on a reactive basis. As a result, Evergy will continue to assess this uncertainty both quantitatively – through expected capital costs – and qualitatively in future IRPs as we near identified retirement dates for the Jeffrey units.

In addition to monitoring these specific uncertainties, Evergy also monitors all Critical Uncertain Factors on an ongoing basis to identify any significant changes in long-term outlooks for these items.

Critical Uncertain Factor: CO_2

CO_2 credit prices are reviewed on a continual basis. The data sources used are third party views predicting the price of the credits. Most of these third-party studies are sparked by proposed legislation or are updated up to a quarterly basis. This review and update is conducted by the Fuels department with a full review conducted on an annual basis. Given there were no significant changes in policy expectations or available third-party forecasts since the 2021 Triennial, the same forecasts were used for the 2022 Annual Update.

Critical Uncertain Factor: Load

Load forecasts are updated on an annual basis as part of the company's annual budgeting and IRP process. In addition, updated forecasts for economics, end-use efficiency and saturations, electrification and distributed energy resources are incorporated into these load forecasts whenever they become available.

Critical Uncertain Factor: Natural Gas

Natural Gas forecasts are updated weekly with executive updates provided on a monthly basis.

The items described above are considered in ongoing updates to Evergy's IRP on either an annual or triennial basis (depending on the pace of change). In each IRP, Evergy works to take an integrated view of the need for changes to its prior Preferred Plan. Specifically, the IRP process utilizes the latest understanding of the inputs outlined below in order to confirm the prior Preferred Plan or identify a new Preferred Plan through the risk analysis framework outlined in the IRP rules. Note that not all if the detailed items listed below will have updates in or appear specifically in every IRP, but these types of items are monitored on an ongoing basis and changes will be incorporated as they arise.

- Existing resource portfolio:
    - Expected ongoing capital and O&M costs, including the cost of life extension projects, where relevant
    - Potential alternative retirement dates, often based on the potential to avoid significant retrofits or overhaul costs
- Available supply-side resource options:
    - Assessment of current costs and risks associated with new resources
    - Potential for changes (i.e., extensions) to Power Purchase Agreements or Capacity Sales
    - Options for "non-traditional" new resources, including existing facility expansions
- Available demand-side resource options:
    - Latest forecast for DSM adoption and costs, informed by actual adoption data, where available, and program approval
- Alternative resource plans:

- Each IRP which includes the evaluation of changing conditions will include the assessment of alternative resource plans which include Evergy's long-term load forecast and long-term capacity plan designed to meet capacity requirements (factoring in potential retirement dates and replacement resource options)
- These ARPs will be built based on the latest Resource Adequacy Requirements and supplemented by qualitative or quantitative assessments of reliability / resiliency risk where needed

Finally, the Company monitors conditions which could specifically impact its near-term Implementation Plan to determine whether portions of the plan should be reevaluated and/or changed. These near-term actions have varying "points of commitment" which impact when and how they should be monitored by the Company prior to reaching these points.

Plant Retirements: From a system perspective, a plant retirement decision can be changed up until the point when the unit is unregistered from the SPP market. There are interim steps (for example, beginning the SPP retirement study process at least 12 months in advance, regulatory filings, workforce changes) which can complicate changes in retirement plans, but flexibility still exists up until the point the unit is removed from the SPP market. There is generally minimal cost obligation associated with the retirement prior to the retirement of the unit and the beginning of decommissioning / dismantling. Through the process leading up to the retirement, the primary considerations which can impact a final decision are:

Macroeconomic drivers: Significant, structural (long-term) changes in the policy and market environment (e.g., natural gas or CO_2 prices) could trigger a reevaluation of a retirement

Environmental regulations: Specifically, the expectation / certainty around necessary environmental retrofits (and the timing of when these retrofits will be needed)

Conversion options: In some cases (such as Lawrence 5), an option may be available to maintain or convert to natural gas operations at a site as opposed to retiring the unit. These opportunities can be evaluated based on the long-term capacity value they provide and the cost of continued gas operations. Evergy has begun evaluations of the potential cost to maintain gas operations at other sites which are planned for retirement in the future (Jeffrey Energy Center units, for example), but these cost estimates are currently very high-level and need to be refined over the coming years before gas conversion would be evaluated quantitatively as an alternative to the currently planned retirement. However, given the flexibility inherent in planning for a retirement many years in the future, time remains to refine and adjust based on this work prior to any point of commitment related to the retirement.

Long-term seasonal cycling: In some cases, seasonal cycling (i.e., operating only during winter and summer) could be an alternative to retirement which creates significant cost savings while maintaining valuable capacity for when it's needed most. These opportunities can be evaluated based on the long-term capacity value they provide and the cost of continued operations. Evergy has begun evaluation of the potential for seasonal cycling on a short-term basis in order to inform our understanding of future longer-term seasonal cycling options. The decision-making around short-term seasonal cycling is based on near-term market dynamics, and, given recent high prices and gas volatility, seasonal cycling has not yet been broadly utilized.

Other investment needs: As a plant retirement date nears, significant emergent investment needs can impact the ultimate retirement decision (i.e., a large equipment failure can trigger a retirement acceleration)

Maintenance of interconnection rights: Given the uncertainty referenced above in the SPP Interconnection Queue, the maintenance of interconnection rights becomes a very important factor in managing plant retirements in conjunction with new resource additions. SPP's Replacement process allows new resources to utilize the interconnection rights of a retiring unit so, ultimately, a retirement decision could be impacted by the ability to use the unit's interconnection point for a new resource and thus "repower" the site with an alternative generating facility.

Resource Additions: Typically, resource additions include a "notice-to-proceed" (NTP) date which would be the "point of commitment" for that resource. Often these NTPs are conditioned on certain approvals (e.g., tied to regulatory proceedings) which enables flexibility to respond to changing conditions. There is typically minimal cost obligation prior to the NTP point. From that point, costs would be incurred based on the payment and/or construction schedule associated with the project (similar to schedule provided in Section 7.3.1). Primary considerations when making final resource additions decisions are outlined below. All of the items outlined below were factors in the adjustments made, in terms of sequence and scale, to Evergy's near-term resource additions as the company progressed through the procurement process.

Construction costs: Through the negotiation process with developers or suppliers, expected resource costs are often updated multiple times prior to NTP. This allows for continued reevaluation of projects based on up-to-date cost expectations.

Tax credit eligibility: Changes to tax credit eligibility of specific projects or all renewable projects can ultimately impact economics and trigger reevaluation of resource additions.

Project maturity: A key consideration in evaluating near-term resource additions is project maturity because a relatively mature project provides greater certainty in timeline and cost. Key factors which indicate project maturity are site control and equipment (e.g., panels, turbines) availability.

Interconnection queue status: Due to the current backlog of interconnection queue requests, the availability of projects with favorable queue positions is a key consideration in selecting and procuring new resources. For most Generator Interconnect queue clusters, the study process has well-defined milestones that allow visibility into when study results and an Interconnection

Agreement could be expected. Given the current backlog in the Interconnect queue, this timeline is less clear for some clusters, which is why queue status is such a critical consideration in the evaluation of new projects.

Location and Transmission Risk: There can be significant variability in the locational value of different resources (e.g., expected locational marginal price and/or curtailment risk). Additionally, a resource's location on the transmission (or distribution, in some cases) influences the expected cost of incremental system upgrades in order to support the interconnection. As a result, this is assessed in comparing different potential resource additions and determining the ultimate expected attractiveness of the options available.

Demand-Side Management: The implementation of DSM programs is managed through the MEEIA process and thus points of commitment align with MEEIA Cycle approvals. These approval processes, and the potential studies and stakeholder processes which support them, are the primary driver of ultimate DSM implementation.

7.3 IMPLEMENTATION PLAN

7.3.1 SUPPLY-SIDE IMPLEMENTATION SCHEDULES

The Preferred Plan includes acquiring approximately 300 MW of company-owned wind generation reaching commercial operation by December 31, 2024. The 300 MW project would be allocated to both Evergy Metro and Evergy Missouri West, assigning 150 MW to Evergy Metro and 150 MW to Evergy Missouri West. If the wind project ultimately selected is larger or smaller than 300 MW, the allocations to the two utilities will be adjusted accordingly. A draft schedule of the major milestones expected to be undertaken for the construction of a large-scale wind project is provided in Table 40 below:

Table 40: Wind Acquisition Milestones

Milestone Description (By Evergy or Developer)	Expected Completion
Site Control Complete	October 2022
Environmental and Land Permitting Complete	December 2022
BTA and/or EPC Agreement Execution	March 2023
Detailed Design and Engineering	May 2023
Equipment Acquisition and Delivery	September 2023
Construction Complete	April 2024
Testing and Commissioning	June 2024
Commercial Operation	June 2024

There are also environmental retrofit projects continuing or expected to be continued or initiated during the three-year implementation period. Table 41 below provides estimated dates for major projects currently expected.

Table 41: Environmental Retrofit Project Timeline

Milestone Description	2022 IRP Date Range
Iatan 1 - Landfill Phase 1B Cover	2021 - 2022
Iatan 1 - Landfill Phase 2 Cover	2022 - 2023
Iatan 1 - Intake Modification	2021 - 2023
Iatan 2 - Landfill Phase 1B Cover	2021 - 2022
Iatan 2 - Landfill Phase 2 Cover	2022 - 2023
Jeffrey 1 - Fly Ash Landfill Area 1 Permit Modification	2021 - 2024
Jeffrey 1 - Fly Ash Landfill Area 1 Cover	2023 - 2026
Jeffrey 1 - Fly Ash Landfill Area 2 Cover	2021 - 2024
Jeffrey 1 - FGD Landfill Cell 1C Cover	2021 - 2024
Jeffrey 1 - Bottom Ash Settling Area Closure	2021 - 2026
Jeffrey 1 - Bottom Ash Landfill Closure	2021 - 2026
Jeffrey 1 - Effluent Guidelines FGD Wastewater	2021 - 2023
Jeffrey 2 - Fly Ash Landfill Area 1 Permit Modification	2021 - 2024
Jeffrey 2 - Fly Ash Landfill Area 1 Cover	2023 - 2026
Jeffrey 2 - Fly Ash Landfill Area 2 Cover	2021 - 2024
Jeffrey 2 - FGD Landfill Cell 1C Cover	2021 - 2024
Jeffrey 2 - Bottom Ash Settling Area Closure	2021 - 2026
Jeffrey 2 - Bottom Ash Landfill Closure	2021 - 2026
Jeffrey 2 - Effluent Guidelines FGD Wastewater	2021 - 2023
Jeffrey 3 - Fly Ash Landfill Area 1 Permit Modification	2021 - 2024
Jeffrey 3 - Fly Ash Landfill Area 1 Cover	2023 - 2026
Jeffrey 3 - Fly Ash Landfill Area 2 Cover	2021 - 2024
Jeffrey 3 - FGD Landfill Cell 1C Cover	2021 - 2024
Jeffrey 3 - Bottom Ash Settling Area Closure	2021 - 2026
Jeffrey 3 - Bottom Ash Landfill Closure	2021 - 2026
Jeffrey 3 - Effluent Guidelines FGD Wastewater	2021 - 2023
Lake Road 4/6 - 316(b) Study	2021 - 2024

7.3.2 DEMAND-SIDE MANAGEMENT

Effective June 11, 2022, the Commission approved the Company's application to extend its Missouri Energy Efficiency Investment Act (MEEIA) Cycle 3 programs an additional year. The relative impacts of the new targets for the extension will be reflected in the next IRP annual update.

7.3.3 EVALUATION MEASUREMENT AND VERIFICATION

No EM&V changes have occurred since the 2021 Triennial IRP filing.

SECTION 8: 2021 IRP JOINT AGREEMENT RESPONSES

Resolved alleged Concerns and Deficiencies are addressed as follows:

8.1 STAFF OF THE MISSOURI PUBLIC SERVICE COMMISSION (STAFF)

Staff Concern A – Evergy is currently working with Staff to develop an avoided capacity cost curve and if an agreement is not reached by mid-June, Evergy will utilized an avoided capacity cost curve if provided by Staff.

Staff Concern B - Ratepayer risk vs shareholder risk is addressed in Special Contemporary Issues 9.2 below.

Staff Concern C – Ratepayer risk for PPAs - resolved.

8.2 NEW ENERGY ECONOMICS (NEE)

NEE Deficiency 1 – Evergy is utilizing a capacity expansion model beginning with this 2022 Annual Update.

NEE Deficiency 2 - Solar hybrid and battery storage resources will be addressed in the 2023 Annual Update.

NEE Deficiency 4 – Evergy is modeling standalone “MEEIA Goals”-level DSM.

NEE Concern 1 – Evergy continues to utilize various data sources for new generation additions.

NEE Concern 2 - Plan performance summaries as discrete scenarios and develop an alternative approach to evaluating special contemporary issues will be addressed in the 2024 Triennial IRP.

NEE Concern 3 – A description of reliability considerations can be found in Section 7.2. A standalone reliability analysis of extreme weather effects on resources will be in the next Triennial IRP.

8.3 RENEW MISSOURI

Renew Missouri Deficiency 1 – 2021 Value of Solar Study – resolved.

8.4 SIERRA CLUB (SC)

SC Deficiency 1 – 2021 Triennial Preferred Plans were not changed therefore no change of plan filings were required - resolved.

SC Deficiency 2, 3, and 5 - Evergy is utilizing a capacity expansion model beginning with this 2022 Annual Update to develop Alternative Resource Plans. Regarding documenting and describing “the effect of the United States Supreme Court’s 2020 County of Maui v. Hawaii Wildlife Fund decision on its generating fleet”:

The case is centered around the discharge of pollutants from a point source that reaches navigable waters via a conveying medium, specifically groundwater. The Clean Water Act is clear that a discharge from a point source directly into navigable waters requires a permit. In this scenario a National Pollution Discharge Elimination System (NPDES) permit would apply. The question here is if that requirement still applies in the event that the pollutants reach navigable waters by conveyance through groundwater. There were three Circuit Court decisions in 2018 which were not consistent. These three different cases were in the 4th, 6th, and 9th Circuit Courts. The Maui case (Hawai’i Wildlife Fund v. Cty. of Maui) was heard in the 9th Circuit Court. The case was granted certiorari by the Supreme Court, and they issued a decision in April 2020. The Maui case involved a sewage treatment plant which uses wells to dispose of treated waste. These wells discharge into a groundwater aquifer. Environmental groups challenged this back in 2012 and a subsequent dye test indicated that the waste was going into the aquifer and then into the Pacific Ocean. The Supreme Court ruled that a permit is required when the addition of pollutants into navigable waters has the “functional equivalent” of a direct discharge from a point source. The Court identified several factors to consider when determining if a discharge meets this functional equivalence test. This includes factors such as distance traveled, transit time, nature of material through which the pollutant travels, amount of pollutant entering the navigable waters vs the amount that left the point source, etc. In summary, the Supreme Court ruled that this determination is case-specific with several factors that must be considered.

Evergy is in compliance with the Clean Water Act and maintain NPDES permits for any discharges from point sources into navigable waters at our generating facilities and therefore does not expect the Court's ruling to impact Evergy facilities at this time.

Sierra Club Deficiency 4 – Evergy has modeled an earlier La Cygne 2 retirement in this 2022 Annual Update.

Sierra Club Deficiency 6 – Evergy has utilized historical availability data for coal units in this 2022 Annual Update.

Sierra Club Deficiency 7 - Evergy is utilizing various data sources for new generation additions.

Sierra Club Deficiency 8 - Solar hybrid and battery storage resources will be addressed in the 2023 Annual Update.

Sierra Club Deficiency 9 – Securitization is addressed in Special Contemporary Issues below.

SECTION 9: SPECIAL CONTEMPORARY ISSUES

From the Commission Order, EO-2022-0055, the following Special Contemporary Resource Planning Issues are addressed as follows:

9.1 SECURITIZATION

Provide details of its plan, if any, to utilize securitization. Details should include, but not be limited to: 1) type of items to be securitized; 2) explanation for need of securitization for each item; 3) how it plans to utilize securitization for each item; 4) estimated costs of securitized items; and 5) comparison of ratepayer costs and benefits related to its IRP planning.

Response:

Evergy West's only current planned use of securitization is ongoing in docket EF-2022-0155. Relevant details have been provided in that docket.

9.2 COMPARISON OF RATEPAYER AND SHAREHOLDER RISK

Provide detailed analysis in its next annual update filing comparing ratepayer risks and shareholder risks for additional generation resources that are not required to meet federal, state, or RTO requirements.

Response:

BACKGROUND

The Policy Objectives outlined in the Chapter 22 rules for the Integrated Resource Plan ("IRP") specify that a key purpose of the IRP process is for the utility to:

…describe and document the process and rationale used by decision-makers to assess the tradeoffs and determine the appropriate balance between minimization of expected utility costs and these other considerations in selecting the preferred resource plan and developing the resource acquisition strategy. These considerations shall include, but are not necessarily limited to, mitigation of:

1. Risks associated with critical uncertain factors that ***will affect the actual costs*** associated with alternative resource plans;
2. Risks associated with ***new or more stringent legal mandates that may be imposed*** at some point within the planning horizon; and
3. Rate increases associated with alternative resource plans. (20 CSR 4240-22.010(2)(C), emphasis added)

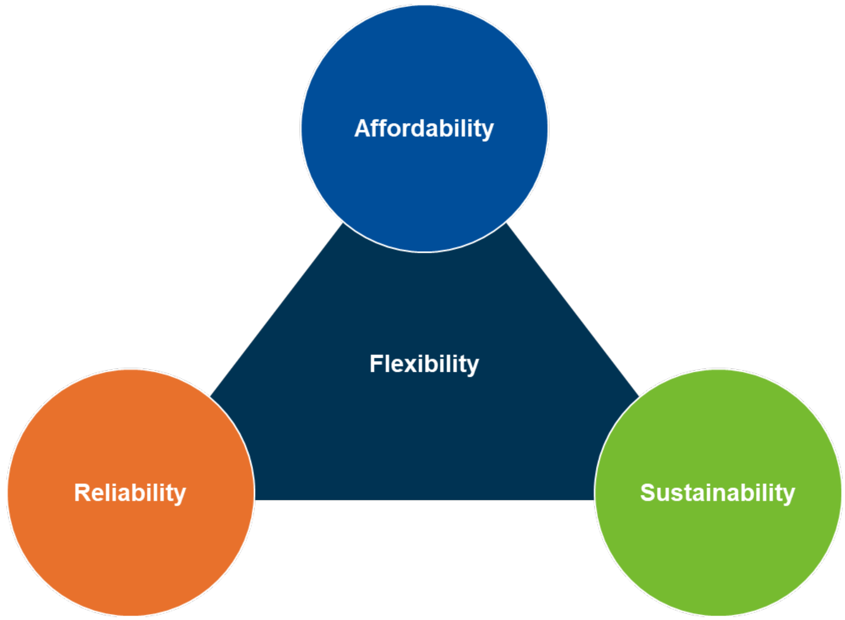
Based on this policy objective, it is clear that the purpose of the IRP is to include an analysis of risks associated with certain alternative resource plans, in addition to the expected costs associated with these resource plans. Balancing and managing risks to customers is a fundamental element of minimizing expected utility costs given an inherently uncertain future. As a result, much of the discussion associated with this Special Contemporary Issue will point to analysis performed within the existing framework of the IRP. Additional detail has been added to the IRP's risk analysis methodology, in particular to focus on shareholder risks, which are not explicitly included in the IRP rules given its focus on minimizing costs to customers. However, as will be discussed in more detail below, the primary reason for a focus on managing shareholder risk – in addition to and alongside managing customer risk – is that perceived or actual risk to shareholders directly or indirectly translates into increased customer costs / risks as these shareholder risks impact the ability of the utility to secure competitively-priced financing and insurance, which in turn influences the cost of service the utility provides to its customers.

In addition, while this Special Contemporary Issue is focused on "ratepayer risks and shareholder risks for additional generation resources which are not required to meet federal, state, or RTO requirements", a key consideration in any risk analysis – as noted by the Chapter 22 IRP rules quoted above – is the risk of <u>new or more stringent</u> legal mandates which could ultimately impact customer costs. For this reason, the risk analysis outlined below will focus on resource additions which are not required to meet *current* federal, state, or RTO requirements, but it will also include discussion of potential future changes to these requirements, which are a key driver of risks to Evergy's customers in the future.

Finally, while this Special Contemporary Issue, as ordered, is focused on generator *additions*, our response – and the IRP more broadly – will focus on an integrated view of both retirements and additions, as key components of an overall resource plan which seeks to manage customer risks and minimize long-term utility costs.

GUIDING PRINCIPLES

In implementing the fundamental objective of the resource planning process (20 CSR 4240-22.010(2)), Evergy's seeks to balance four key guiding principles, depicted below.



- **Affordability:** As outlined in the Chapter 22 rules, minimizing the present worth of long-run utility costs (as measured by the net present value of revenue requirements – NPVRR) is the primary selection criteria in selecting a preferred resource plan. However, this assessment of value and affordability should also include an assessment of other potential risks which could impact the cost of a resource plan or its ability to comply with future legal mandates. This assessment is done through the IRP process – as outlined in detail in Evergy's IRP filing and summarized below – through the use of Critical Uncertain Factors to assess the cost of a resource plan under various future macroeconomic or policy "futures".
- **Reliability:** In parallel with an assessment of risks which may impact the affordability of a given resource plan, it is also critical to assess the ability of the resource plan to continue to provide reliable service throughout the planning period. Evergy's IRP assesses this risk utilizing reliability standards for resource adequacy and resource accreditation which are established by the Southwest Power Pool (SPP); however, as the resource mix continues to change quickly across the SPP and the grid overall, there will continue to need to be refinements of how reliability risk is managed and how reliable service can be maintained as aged fossil plants are retired and replaced with

renewable and other new technologies. Evergy's approach to managing reliability risks for its customers is described in more detail below.

- **Sustainability:** Evergy has been working to transition its generating fleet to more sustainable technologies for many years. Looking forward, continuing this transition is critical not only in order to manage customer and shareholder risks, as described below, but also to continue to enhance our stewardship of the environmental resources impacted by our operations, for the benefit of our customers and communities.
- **Flexibility:** In achieving all of these objectives through the development of a preferred resource plan, maintaining flexibility in the execution and refinement of the plan is also vitally important as the policy, economic, and technology environment that we operate in continues to be more and more dynamic. In the discussion below, we will also describe how maintaining flexibility by conducting a measured and balanced transition is a key part of Evergy's resource plan, for the purpose of managing customer risk created by an ever-changing operating environment.

POLICY REQUIREMENTS

Current:

For the purpose of this analysis, Evergy considered the following current policy requirements:

- **Federal:** Existing Environmental Protection Agency (EPA) regulations are factored into resource cost assumptions in the IRP, but no current federal policy requirements were directly included in this analysis.
- **State:**
  - Missouri Renewable Energy Standard (RES): Evergy Missouri Metro and Evergy Missouri West are required to comply annually with the Missouri Public Service Commission's Renewable Energy Standard Rule 4 CSR 240-20.100 – Electric Utility Renewable Energy Standard Requirements. For 2022 and beyond, each utility must retire qualifying Renewable Energy Credits (RECs) equal to no less than to 15% of retail

sales. Within this, qualifying solar-generated RECs equal to no less than 0.3% of retail sales must be retired.

- **Regional Transmission Organization (RTO):**
    - SPP Resource Adequacy Requirements**:** The current SPP Resource Adequacy requirements include a reserve margin of 12% or greater - requiring that Evergy maintain a level of accredited capacity greater than or equal to 112% of its forecasted peak load for a season. Currently SPP has summer and winter resource adequacy requirements. SPP resource adequacy requirements also include rules for the accreditation of capacity which determines the extent to which a given resource can be counted toward meeting a load-serving entities resource adequacy requirement.

Future:

In addition to the current requirements outlined above, a variety of potential future requirements have also been considered in this analysis given the uncertainty of changes in future policies which is a factor in determining the overall customer or shareholder risk associated with Evergy's plans.

- **Federal:**
    - Future Environmental Protection Agency (EPA) regulations: In the future, it is likely that the EPA will continue to increase the stringency of environmental regulations which impact the viability of Evergy's existing fossil fleet. For example, the EPA has recently published a proposed Interstate Transport Federal Implementation Plan for the 2015 ozone National Ambient Air Quality Standards (NAAQS). This plan lowers nitrogen oxide emission allowances starting in 2023. While this plan is still in early stages, it, or similar changes in regulations, could have future impacts on Evergy's fossil plants which could ultimately require less frequent operations (due to emissions limits), increased capital investment, or, ultimately, retirement prior to Evergy's current planned retirement date for certain units. These changes would impact the economics and operations of Evergy's fleet and could also ultimately

impact its position relative to SPP Resource Adequacy requirements if capacity position is sufficiently changed.

  - Federal Carbon Tax or Similar CO_2 Restriction: One of the critical uncertain factors in Evergy's IRP (described in more detail below) is the imposition of a price on carbon emissions. While this is modeled as a "tax" in the IRP, it could take the form of any federal restriction on carbon emissions (e.g. emission limit or cap and trade). Although this type of policy has not yet been implemented, the ongoing push toward decarbonization among policymakers makes it a continued topic of discussion and a future policy which could have a very large impact on the economics of Evergy's fleet and, in turn, its resource decisions and capacity position.

- **State:**
  - Missouri Renewable Energy Standard: In recent legislative sessions, there have been multiple attempts to increase the RES requirements. The potential for this increase to occur in the future is a consideration in this analysis, although this policy change is perhaps less likely than changes at the Federal and RTO level.
- **Regional Transmission Organization (RTO):**

SPP Resource Adequacy Requirements**:** SPP continues to evaluate changes to resource adequacy requirements given recent extreme events and ongoing changes to the resource mix. These changes could materialize in the form of changes to capacity accreditation for traditional (non-renewable) resources, increases in required reserve margin, or the imposition of four- (or more) season resource adequacy requirements. All of these potential changes would have an impact on Evergy's ability to comply with these requirements and would thus impact its planning decisions related to retirements and additions.

OVERALL CONCLUSIONS AND EVERGY'S PREFERRED RESOURCE PLAN

Figure 6 includes Evergy's combined company capacity position given its current retirement plan, as outlined in the 2022 Preferred Plan. As shown in Figure 6, Evergy has a large capacity need (~4,000 MW) over the twenty-year period and thus all resource additions which were included in Evergy's overall Preferred Plan are ultimately required to meet SPP Resource Adequacy requirements (shown in Figure 7 which includes resource additions from the Preferred Plan). However, for the purpose of this risk analysis, Evergy will compare this Preferred Plan to a new Alternative Resource Plan which adds renewables only when needed to meet Missouri RES requirements (based on renewable forecasts for MO Metro and MO West) and capacity (of any type) only when needed to meet Resource Adequacy requirements as its benchmark for adding resources only when "required" ("RES Requirements Plan", Figure 8).

This comparison will demonstrate the risk-weighted economic benefits of Evergy's current Preferred Plan compared to the "RES Requirements" plan. In addition to this pure financial comparison, Evergy will describe below the way various types of customer and shareholder risks were factored into the decision-making which ultimately resulted in the Preferred Plan.

Figure 6: Capacity Balance based on 2022 Preferred Plan – No Additions

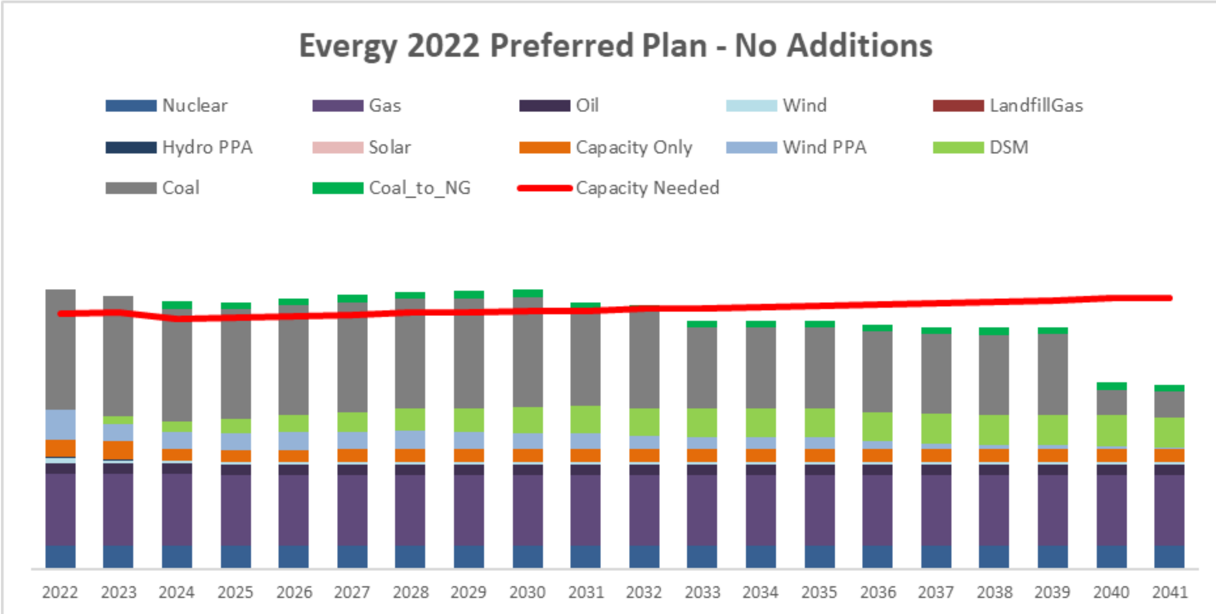


Figure 7: Capacity Balance based on 2022 Preferred Plan – Including Additions

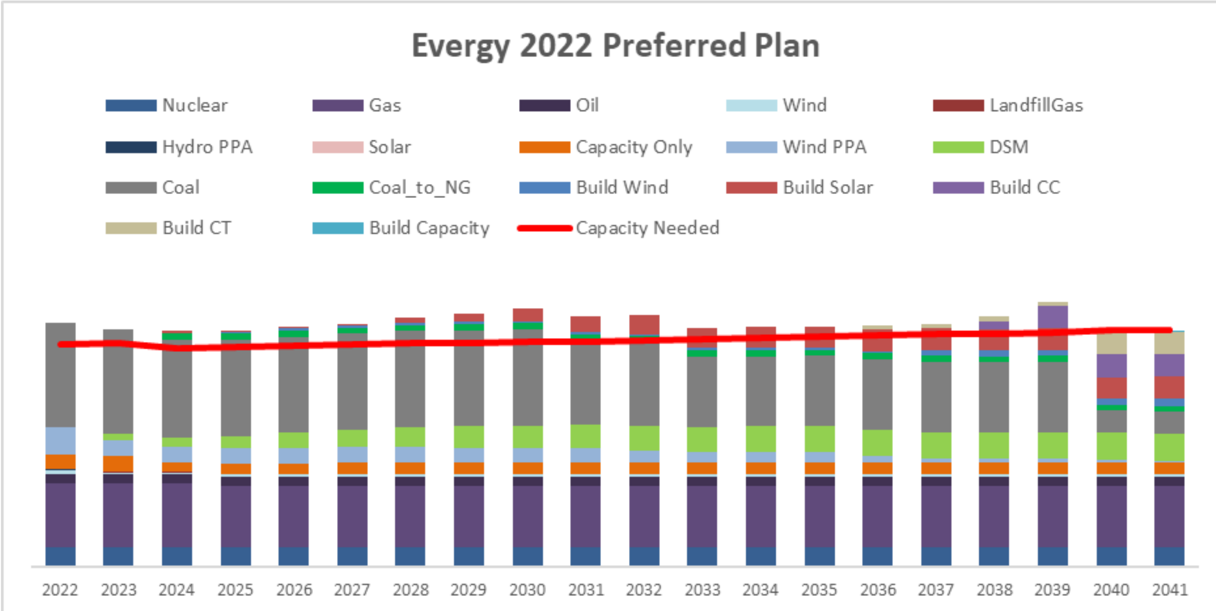
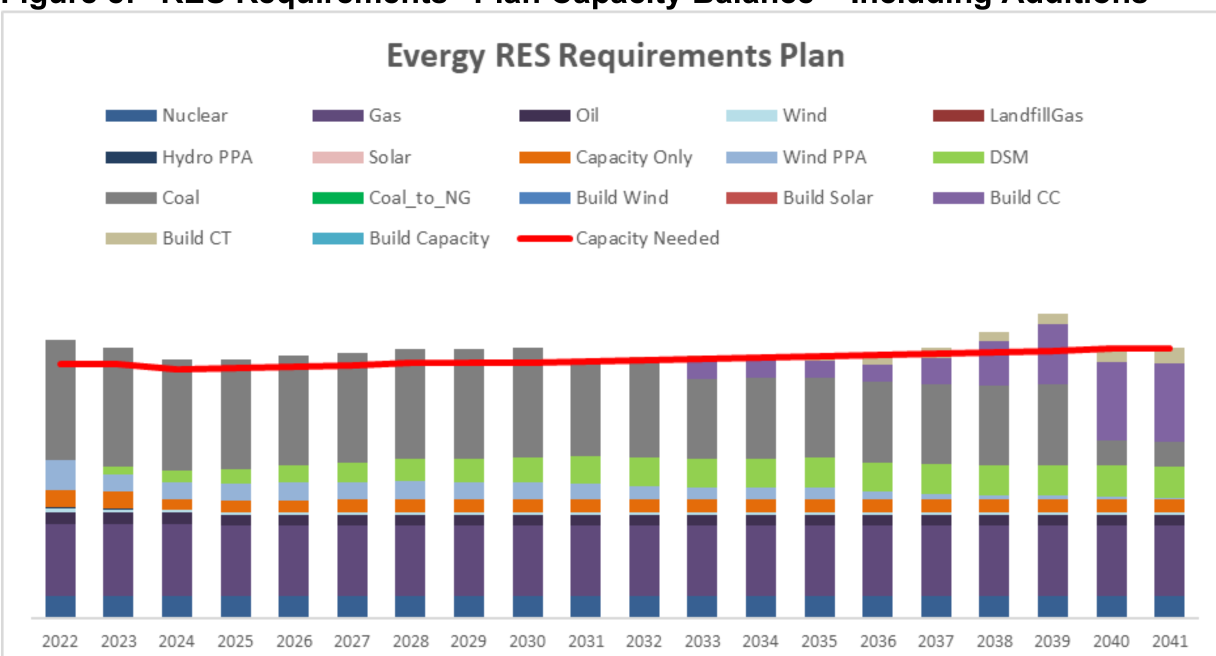


Figure 8: "RES Requirements" Plan Capacity Balance – Including Additions



Ultimately, Evergy's Preferred Plan (and the Preferred Plans of Evergy Missouri West and Evergy Metro which are aligned to Evergy's Preferred Plan), includes a measured pace of plant retirements in order to manage reliability risk and the risk of changes in resource adequacy requirements. The pace of retirements is paired with ratable renewable additions which allow the company to capitalize on current tax credits and the availability of high-quality renewable sites with more favorable locations on the transmission system for the benefit of our customers, while also mitigating the risk of future acceleration of plant retirements, continued pressure on financing and insurance costs, execution risk associated with large just-in-time execution of capacity replacements, and future increases in wholesale market prices due to carbon restrictions.

RISK ANALYSIS APPROACH

In assessing customer and shareholder risks associated with the preferred resource plan, Evergy has identified a variety of types of risks which can be analyzed – either quantitatively or qualitatively. Later sections will contain the results of these analyses.

Customer Risk:

Risk Analysis in the IRP

The IRP Rules include a robust risk analysis framework which has been utilized to conduct much of the Customer Risk Analysis supporting this evaluation. The results of this analysis will include a discussion of the following risk factors:

- Changes to Federal, State or RTO Policy
    - Change in EPA Requirements
    - Carbon Tax / Carbon Restrictions
    - Increase in RES Requirements
    - Changes to Resource Adequacy Requirements
- Commodity / Market Prices
- Resource Costs
    - Capital Costs and Technology Improvements
    - Tax Credits
    - Availability of High-Quality Sites
- Phasing and Executability

Additional Customer Risk Analysis in the IRP

To supplement to those factors explicitly considered in the IRP framework, additional customer risk factors have also been included in this analysis.

- Reliability
- Financing Costs
  - Capital Markets
  - Environmental, Social and Governance ("ESG") / Fossil Exposure
- Insurance Costs
- Customer Preferences

Shareholder Risk

As the IRP is focused primarily on customer risks, an additional shareholder risk analysis has been conducted which factors in the items listed below.

- Execution Risk
- Regulatory Risk

Customer Risk Analysis

RISK ANALYSIS IN THE IRP

The IRP process primarily utilizes scenario analysis to assess the risk of various resource plans in ultimately informing the selection of a Preferred Plan. In addition to this, the input assumptions which are utilized in the IRP can also be informed by risk analysis and can incorporate expectations around certain risks / uncertainties into the analysis, with the goal of selecting a plan which is ultimately robust across a variety of potential customer risks. Both scenario analysis and risk-informed input assumptions will be discussed below.

Scenario Analysis & Input Assumptions

As outlined in the Chapter 22 IRP rules, the IRP utilizes a combination of “Critical Uncertain Factors” to create scenarios across which the economics of various resource plans are subsequently evaluated. In Evergy’s 2022 Annual Update, this included three critical uncertain factors (natural gas prices, CO_2 prices, and load growth), each with three different potential levels (high, mid, low) – ultimately resulting in 27 different scenarios. Evergy then modeled 10 different joint planning (Evergy level) resource plans, with an additional RES Requirements plan modeled for this analysis across these 27 different scenarios, calculated NPVRR for each plan in each of the 27 scenarios, and then calculated an “Expected Value” for NPVRR, which is, essentially, a risk adjusted NPVRR. In the results section below, both the individual scenario results and the expected value will be discussed.

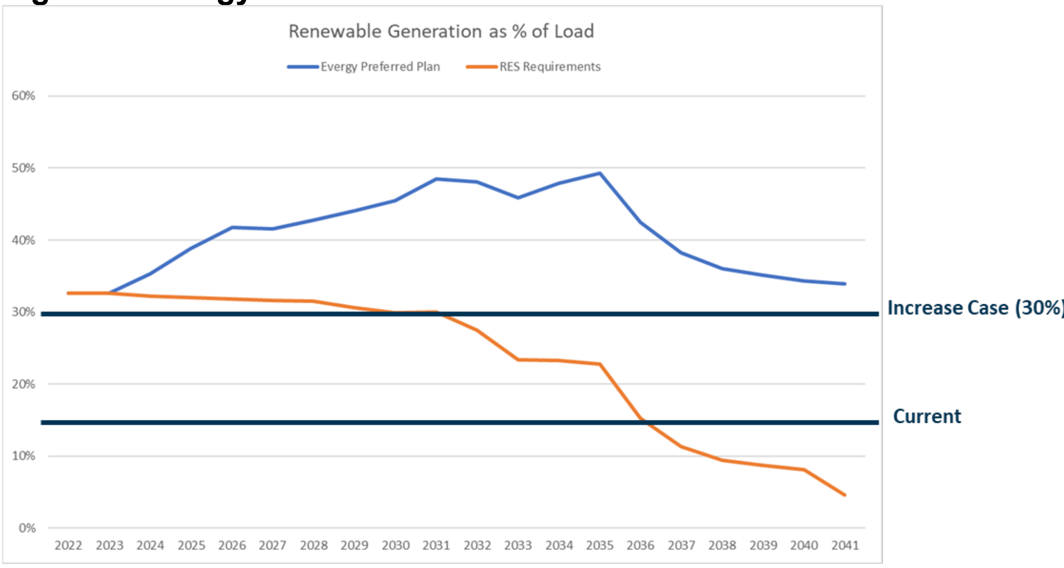
In addition to scenario analysis, risk and uncertainty is also incorporated into many of the input assumptions within Evergy’s IRP.

Through the combination of Critical Uncertain Factors, Alternative Resource Plans (scenario analysis), and Input Assumptions, Evergy has incorporated the customer risk factors discussed below into its analysis:

- Change in Federal Policy
    - Future EPA Regulations: Evergy utilized a mix of resource plans to assess the potential impact of changes to EPA regulations on its resource decisions. The capital plans included in the 2022 Annual Update all assume that Evergy’s resources comply with current EPA regulations. The majority also assume that all units have Best Available Control Technology (including selective catalytic reduction – SCR – and baghouses) before the end of the planning period. This represents an assumption that EPA regulations will continue to become more stringent over the next 10-20 years and, ultimately, these technologies will be required on all coal units. In addition to these base assumptions, two sensitivities were also used to evaluate uncertainty around future EPA regulations.

    - CDDAG and CDDAH: Sensitivity which demonstrates the impact of removing assumed cost of SCRs and baghouses for Jeffrey Energy Center units. This represents a case where relevant EPA regulations do not change in the next twenty years and thus these technologies are not required. Given the small Missouri West ownership percentage in Jeffrey, this sensitivity is included in the IRP filing, but will not be discussed in detail in this analysis.
    - Accelerated (2030) Retirements: Several plans were evaluated which represent accelerated retirement of one of Evergy's large coal units compared to the Preferred Plan from both the 2021 and 2022 IRP. While this retirement could ultimately be accelerated due to economics, assuming suitable replacement technology is available (discussed in more detail in Section 6 and Section 7:), it is perhaps even more likely that this acceleration could be driven by changes in policy requirements. While Jeffrey Unit 2 was identified as the most economic retirement option at the Evergy level, given the focus of this analysis on Missouri West and Metro, the Iatan 1 early retirement plan will be utilized here for illustration purposes.
  - Carbon Tax / Carbon Restrictions: In the 2022 Annual Update, three different levels (high, mid, low) of carbon tax were utilized to assess the impact of a carbon tax / carbon restriction of some sort on the impact of Evergy's resources. The results of this analysis are included in the IRP Results section below.
- Change in State Policy
  - Increase in RES Requirements: While an assessment of different RES Requirements was not directly factored into the 2022 Annual Update, a summary of Evergy's position under various RES Requirements – for both the Preferred Plan and the "RES Requirements" Plan – is included below. This view demonstrates that if, for example, the RES requirement was increased to 30%, it would likely accelerate the need for new renewables into the late 2020s or early 2030s.

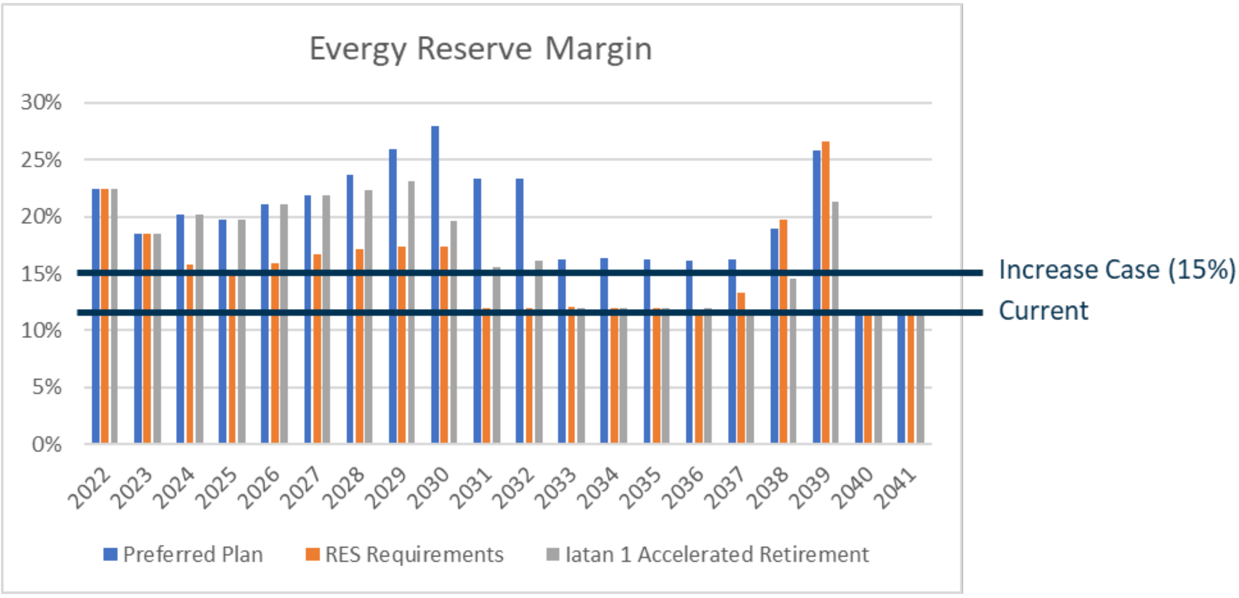
Figure 9: Evergy Renewable Generation as % of Load



Note: Forecast indicates Evergy Missouri West and Evergy Metro would have sufficient banked RECs to comply in later years of period (2037-2041) without additional renewables in RES Requirements plan

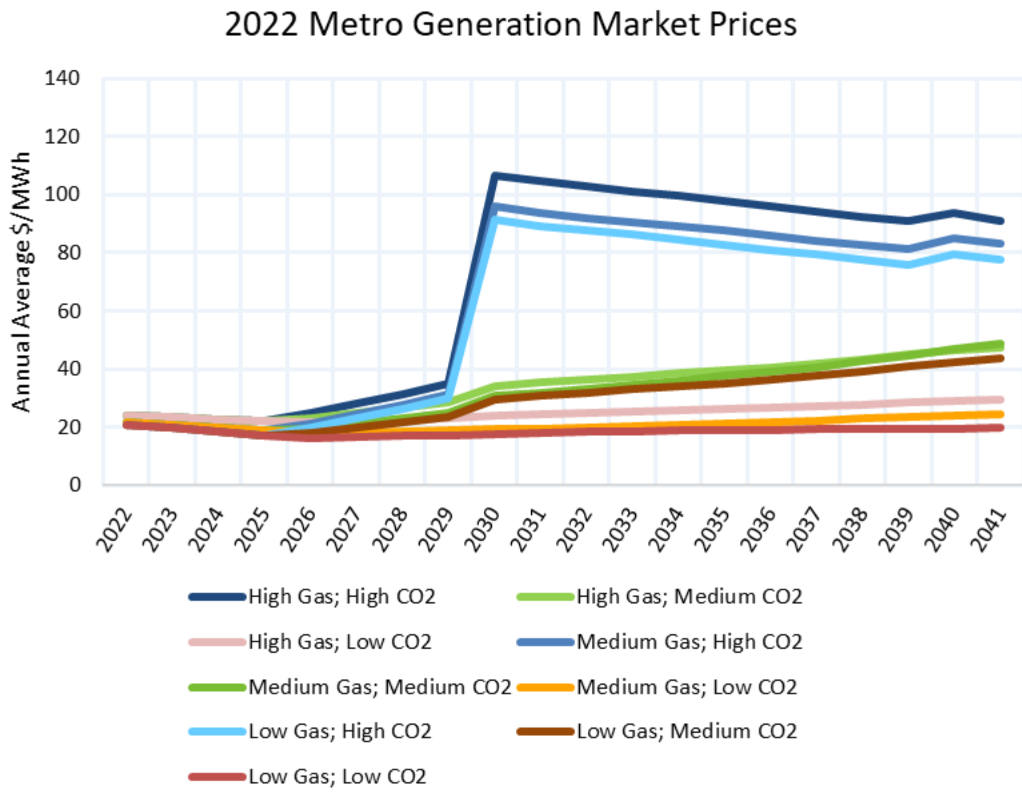
- Change in RTO Policy
  - Changes to Resource Adequacy Requirements: Given the uncertainty around changes to SPP's Resource Adequacy requirements, an assessment of different requirements was not directly factored into the 2022 Annual Update. However, reserve margin results are shown below for the Preferred Plan, the "RES Requirements" Plan, and the "Accelerated Retirement" sensitivity below. These results indicate that under the RES Requirements Plan, if SPP increased its minimum reserve margin requirement to 15%, for example, Evergy (collectively) would be short in the early 2030s after Jeffrey 3 and La Cygne 1 retire. If the retirement of Iatan 1 were accelerated to 2030 ("Accelerated Retirement" case), the combined entity would fall below a 15% reserve margin around the same time (although slightly later), even with consistent renewable additions between now and 2030.

Figure 10: Evergy Combined Reserve Margin



- Commodity / Market Prices: The Critical Uncertain Factors described above incorporate a range of commodity price assumptions into the IRP risk analysis and are, in turn, used to generate a variety of wholesale market price assumptions. This range of wholesale market prices ensures that future variability of commodity and market prices is incorporated into NPVRR calculations for various resource plans. The market prices used in the 2022 Annual Update are shown below.

Figure 11: 2022 Annual Update Market Prices (based on average Metro Generation Node)



- Resource Costs
  - Capital Costs and Technology Improvements: Renewable capital costs have generally declined over time and are expected to continue to decline going forward as technology continues to improve. However, recent supply chain challenges have caused costs to increase in the short-term. In order to incorporate these pricing dynamics into IRP input assumptions, Evergy has utilized recent RFP responses to inform near-term renewable build costs and has applied a third-party cost curve (average of NREL and EEI forecasts) to future builds. This assumption is built into all plans in order to incorporate expected cost changes into the company's risk analysis. While technology-driven cost declines are currently expected to continue, there is an additional risk – which is not included in current IRP assumptions – that future policy regarding renewable supply chains, at either the state or federal level, could increase requirements for domestic manufacturing. This type of policy change could apply upward pricing on supply chains and materials needed for renewable resources in the medium- and long-term depending on when / if these changes are implemented.
  - Tax Credits: Renewable Tax Credits (Investment Tax Credits and Production Tax Credits) can have a large impact on the economics of renewables. Although these tax credits have been extended many times in the past and there are discussions of changes to these credits

which could result in even more favorable economics for renewables, Evergy utilizes tax credit assumptions which are consistent with current Internal Revenue Service (IRS) rules as opposed to speculating about future changes to these rules. This assumption is built into all plans in order to assess the economics of plans under today's tax environment – if changes are made to IRS rules in the future, these changes will be incorporated in future IRPs.
    - Availability of High-Quality Sites: While this is not factored directly into the IRP risk analysis, a key consideration in determining whether to install renewables now or wait until they are absolutely required is the availability of attractive sites for renewable development. There are currently more than 80 GW of wind, solar, battery, and hybrid projects in the SPP interconnection queue. As developers have identified sites for these queue requests, they have first focused on the identification of the most attractive sites in terms of renewable resource, land availability, congestion / curtailment risk, and general executability. If Evergy chose to delay the investment in renewables until they are absolutely required, we would ultimately be limited to the less attractive development sites which would be available at that time.
- Phasing and Executability
    - A key risk to consider when it comes to installing new capacity of any type is executability and ensuring that construction and interconnection can be completed in a timely manner. Particularly given the current backlog in the SPP Interconnection Queue, Evergy believes it is critical to maintain a measured pace of new additions, without requiring sizeable additions all installed within a short one-to-three-year time period, for example. Measured, ratable additions allow Evergy to stay up to date on market conditions, maintain a consistent internal development / procurement organization, and mitigate the risk of delays caused by the Interconnection Queue. In order to capture these risk mitigation benefits, Evergy's capacity expansion model was constrained to allow a maximum number of builds per year, which varied by technology type (Combustion Turbine vs. Combined Cycle vs. Renewable). For renewable resources, this constraint was set at 450 MW per year (3-150 MW projects) based on Evergy's experience executing renewable projects to-date. As conditions change in the renewable supply chain and the SPP Interconnection Queue, it's possible this constraint could be eased, but based on market knowledge today, Evergy believes this constraint is reasonable and allows execution risk to be appropriately considered in the IRP risk analysis.

RESULTS OF IRP CUSTOMER RISK ANALYSIS

As shown below, the RES Requirements plan has a significantly higher expected value NPVRR than the Preferred Plan and was the most costly plan modeled at the Evergy level on an expected value basis. In addition, Figure 12 shows that the RES Requirements plan is also the highest risk plan, as measured by the standard deviation of NPVRR across all 27 endpoints. Standard deviation is used as a statistical measure of risk in this case because it demonstrates variability in resource plan cost across different modeled scenarios. Finally, Figure 13 shows a comparison of the Preferred Plan and the RES Requirements plan in each of the 27 modeled scenarios. This shows that the RES Requirements plan is more expensive than the Preferred Plan in 15 out of 27 modeled endpoints, particularly those which include medium or high carbon prices. In addition, in 6 of the 12 scenarios where the RES plan is lower cost than the Preferred Plan, it is higher cost than plan CCBAA which is identical to the Preferred Plan in the Implementation Period and only varies in the medium- and long-term. The remaining 6 plans where the RES Requirements plan is lower cost than both the Preferred Plan and CCBAA all include no carbon restriction and either low or medium gas prices. Given today's policy and commodity price environment (high gas prices) in particular, selecting the RES Requirements plan as opposed to either CCBAA or Preferred Plan – which include the same near-term actions – would be a poor way to manage future customer risks; particularly given the difference in expected value NPVRR and overall variation in NPVRR across scenarios.

Table 42: Expected Value NPVRR Results

Plan Name	Expected Value NPVRR ($M)	Delta From Preferred Plan ($M)
Preferred Plan (Ratable Renewable Additions)	$57,541	-
RES Requirements	$57,991	$450

Figure 12: Standard Deviation across 27 Endpoints

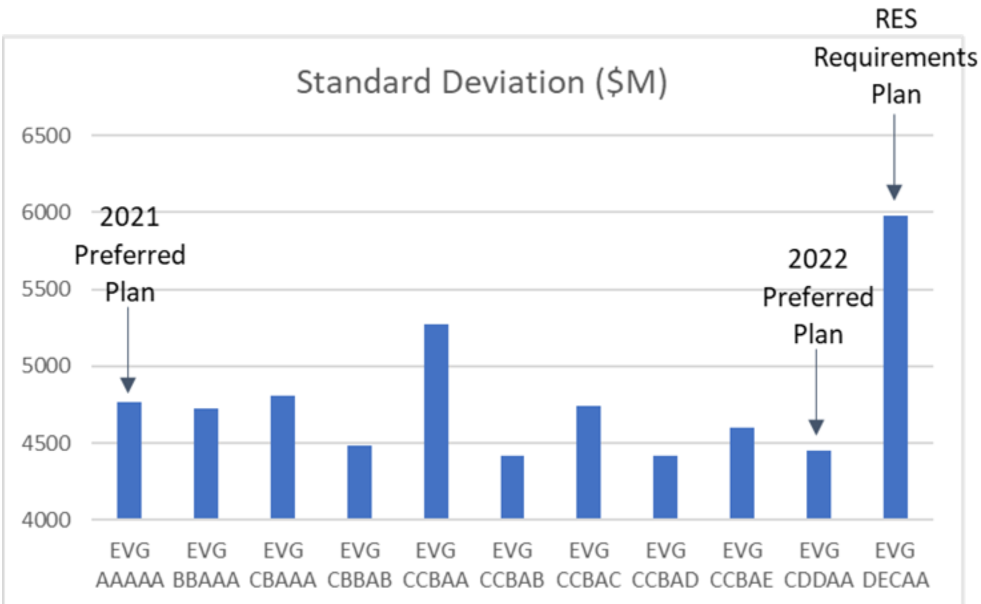
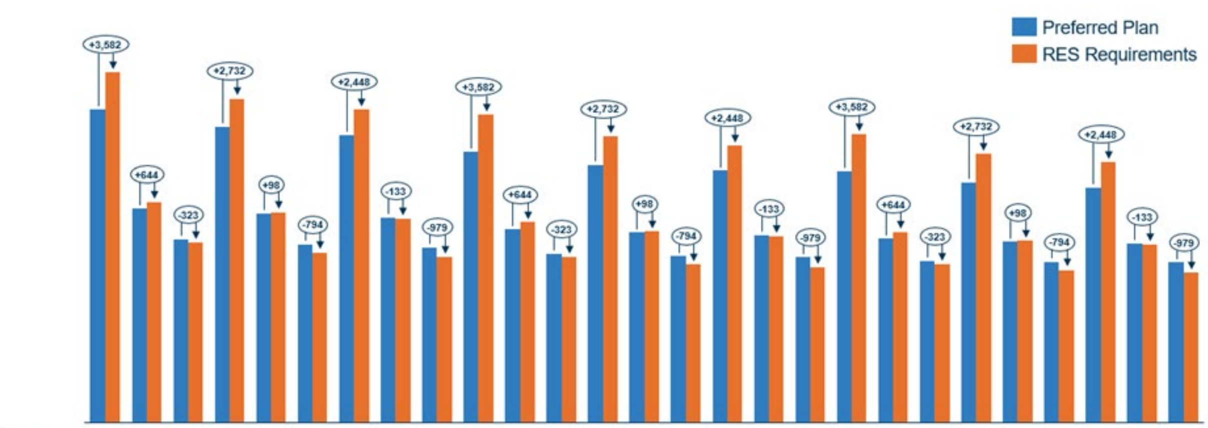


Figure 13: NPVRR Comparison by Endpoint ($M)



Load	H	H	H	H	H	H	H	H	H	M	M	M	M	M	M	M	M	M	L	L	L	L	L	L	L	L	L
Gas	H	H	H	M	M	M	L	L	L	H	H	H	M	M	M	L	L	L	H	H	H	M	M	M	L	L	L
CO_2	H	M	L	H	M	L	H	M	L	H	M	L	H	M	L	H	M	L	H	M	L	H	M	L	H	M	L

ADDITIONAL CUSTOMER RISK ANALYSIS – RELIABILITY

As demonstrated above and in Section 6 of the IRP, if an additional coal retirement is accelerated to the 2030 timeframe, it would reduce costs on an expected value basis compared to the current Preferred Plan and (as shown in Figure 10), the renewable additions included in the Preferred Plan would then be required to meet

SPP Resource Adequacy requirements shortly after the retirement (meaning they would no longer qualify as “additional generation resources that are not required to meet federal, state, or RTO requirements”). However, as outlined in Section 6, Evergy has chosen not to commit to an additional accelerated retirement at this point due to uncertainty in being able to maintain reliability when retiring ~2,500 MW of firm, dispatchable capacity in the next 10 years (through 2032) and relying solely on renewable replacement capacity, even when current SPP Resource Adequacy Requirements can be met using only renewables. The current Preferred Plan includes ratable renewable additions to provide valuable future capacity and energy to Evergy’s customers, managing risk of future policy and market changes, while also maintaining flexibility in coal retirements to allow time for low- or non-emitting technology to develop which can “back up” these renewable resource additions in the medium and long-term.

ADDITIONAL CUSTOMER RISK ANALYSIS – FINANCING COSTS

As part of complying with the Chapter 22 IRP rules, the Company quantitively evaluated financing costs (interest rates, specifically) as a potential critical uncertain factor in the 2021 Triennial IRP and this factor was not identified as critical (i.e., it did not have a material impact on the ranking of plans).

The Company also qualitatively assessed and considered the various levels of financing risk when selecting preferred resource plans. Timing of going to market with a transaction, the size or quantity of capital to be raised, the type of capital to be raised whether debt or equity, the types of projects the capital is going to finance (e.g. renewables, pollution control equipment, or coal generation maintenance), the Company’s regulatory calendar or timing of rate reviews, impacts to credit quality, as well as the current market cost of capital are all factors that need to be considered when assessing financing risk. Customers and shareholders are both subject to financing cost risk due to ever-changing market dynamics, credit risk, management’s track record of plan execution, the Company’s perceived regulatory construct, and world events, to name a few. In addition, investors are becoming more sensitive to environmental, social, and governance issues (“ESG”), also referred to as “sustainable investing.”

Evergy's current owned generating capacity is heavily dependent on fossil fuels, specifically coal. Any resource plan that delays or avoids transitioning the generation fleet to more sustainable sources will be viewed negatively by the growing investor base and investment banks that have ESG investment requirements or coal exposure limiting criteria. The criteria and metrics used by different investors and banks vary when evaluating ESG requirements, but generally, 30% of revenue or 30% of energy generated by coal is a common limit for coal exposure currently seen in the finance space, which most likely will tighten further over time. Currently, about 50% of Evergy's energy, whether generated or from purchased power agreements, comes from fossil fuel sources. Fundamental economic principals would indicate that reduced demand via fewer investors or lower exposure limits will increase the cost to raise future debt and equity capital which is ultimately borne by customers. These increased financing costs, not only impact the financing of maintaining current generation or transitioning the generating fleet but also impact the financing costs of investing in modernizing the transmission and distribution grids.

The possibility of correctly predicting the magnitude of the increase in debt borrowing cost and the future cost of equity returns that is commensurate with companies sharing similar risk is virtually nil. However, the assumption that financing costs will increase due to transitioning the current generating fleet too slowly should be expected. In addition, customers have received the benefit of the Company steadily reducing the weighted cost of its long-term debt portfolio over the last decade by taking advantage of historically low long-term debt rates. Customers have also received the benefit of historically low short-term interest rates, which manifests in the form of lower AFUDC and lower capital project costs. The recent historically low interest rate environment that we've experienced won't last forever, as the Federal Open Market Committee has raised the federal funds interest rates twice this year and has communicated the plan to raise the federal funds interest rate a total of 7 times during 2022 -- another sign that financing costs should be expected to increase in the future. In addition, the 10-year Treasury has moved from 1.63% on Jan 3, 2022 to a high of 3.12% on May 6, 2022 and the 30-year Treasury has moved from 2.01% on Jan 3, 2022 to a high of 3.23% on May 6, 2022. These rates represent a significant upward move in the cost of debt and the federal reserve has indicated continuing monetary policy.

Since the Company can't predict the rise of capital costs directly due to transitioning the generating fleet too slowly, or what is perceived by the investment community as too slowly, we've quantified a sensitivity for both debt and equity costs that would ultimately be paid by customers. A 100-basis point (bps) increase in current debt costs to finance the capital portion of the preferred resource plan (assuming ~50% of the plan is financed with long-term debt) would increase the 20-year NPVRR by $632 million. A 50-bps increase in the cost of equity to finance the capital portion of the preferred resource plan (assuming ~50% of the plan is financed with equity) would increase the 20-year NPVRR $413 million.

ADDITIONAL CUSTOMER RISK ANALYSIS – INSURANCE COSTS

Many commercial insurance markets have announced ESG targets limiting or completely excluding them, now or in the future, from insuring entities that have coal generation. Evergy anticipates that additional commercial insurance markets will announce carbon restrictions in the future. There are two primary results associated with commercial markets carbon restrictions and the Company's continued use of carbon emitting generation sources, these are:

1. Inability to complete our insurance programs and adequately transfer risk due to lack of capacity
2. Higher annual premium expense resulting from reduction of available capacity

Approximately 40% of Evergy's largest insurance lines, excluding nuclear insurance, are exposed to commercial markets. Evergy has already had commercial markets exit our program because of their carbon restrictions; additionally, there are current participants on our program who have announced carbon targets but are able to remain on our program at this time. The Company has qualitatively assessed these risks and determined a delay in transitioning our generating fleet would likely lead to a combination of the two items outlined above.

ADDITIONAL CUSTOMER RISK ANALYSIS – CUSTOMER PREFERENCES

While this has not been assessed quantitatively, a key consideration in Evergy's future fleet transition is customers' and communities' continued preference for more renewable energy and less dependence on fossil fuels. As an example, many of Evergy's commercial / industrial customers and municipalities have very aggressive carbon reduction goals. While Evergy's primary goal in its planning processes is to minimize expected customer costs (NPVRR), it is important to consider the risk – in terms of lost economic development opportunity, for example – of not transitioning away from fossil fuels. Evergy believes its current Preferred Plan contains an appropriate pace of transition that balances affordability, reliability and sustainability effectively given current technology, but a plan similar to the "RES Requirements" plan, by contrast, would severely hamper Evergy's ability to support the ESG goals of its customers and communities.

SHAREHOLDER RISK ANALYSIS

The IRP required risk analysis in selecting a preferred resource plan is centered around minimizing the present worth of long-run utility costs, as measured by the NPVRR. Investor risk, specifically shareholder risk, is a direct input into the cost and affordability of the resource plan for customers, therefore shareholder risks also need to be considered when selecting the preferred resource plan.

Shareholders provide capital to the Company to invest on their behalf with an expectation to be afforded the opportunity to earn a return on their investment that takes into consideration the risks to which their investment is exposed. Shareholders bear risks before customers begin to pay for the use of an asset that shareholders fund, and often, customers receive the benefits of the asset while shareholders continue to bear the entire cost. The risk shareholders are exposed to over the life of their investment can be summarized into the following broad categories:

- **Execution Risk:**
  Execution risk is the risk that management fails to deliver results consistent with operational and financial plans, or in other words, the Company's business plans are not successful when put into action.

The executability of the preferred resource plan and the flexibility the plan affords is a consideration in the selection. The Company considers and weighs the probability of successfully executing on the Preferred Plan to deliver operational and financial results consistent with shareholder expectations, while leaving enough room to adapt to the changing environment we operate within. This is the primary reason why the preferred resource plan must take a measured approach to transitioning the fossil-fuel generating fleet as opposed to making single large-scale changes that put shareholders at greater risk than necessary, which ultimately customers pay for when new rates are established. If the Company were to wait until the last moment to retire and replace the fossil-fuel generating fleet, optimal project site selection could be limited, the ability to negotiate the best terms for those projects is severely limited, and if the market knows the Company needs to raise significant capital at a given point in time, the expectation would be paying a premium to issue bonds and additional equity being issued at potentially steep discounts, all which increase the cost of capital.

Mitigating execution risk includes effectively managing individual project execution as it relates to the Preferred Plan, since relatively large sums of capital are tied to individual generation projects. Project execution involves mitigating pricing exposure to unknowns such as transmission interconnection and network upgrades, navigating supply chain interruptions, mitigating contractor risk, ensuring construction quality, and keeping entire project costs within budget and completed on time to avoid any questions or concerns surrounding prudency issues.

- **Regulatory Risk:**

  Regulatory risk is the risk shareholders are disallowed a return on or of their investment or lose out on opportunities to earn the Company's authorized return due to regulatory lag, or the time between investors deploying their capital and the time that capital is reflected in customer rates. Regulatory risk that shareholders also consider is the overall regulatory construct that an electric utility operates within, with a focus around authorized return on equity, capital structure, and mechanisms to mitigate regulatory lag. As electric utilities continue to transition their generation fleets to more sustainable forms of generation, investors will also consider the availability (or unavailability) of regulatory mechanisms which can facilitate the transition of the generation fleet. Predetermination, accelerated depreciation, and securitization are all examples of these types of mechanisms.

Managing execution and regulatory risk is vital in keeping the cost of equity capital competitive with our peer utilities that we compete with for capital. Managing these same risks is equally important to maintaining credit quality. If shareholders determine they are not being compensated or afforded the opportunity to be compensated for the level of risk they undertook, they will sell their investment, which will drive up the cost of equity capital. In the same vein, if the Company isn't managing execution and regulatory risk, credit rating agencies would view this negatively, which would increase the cost to raise debt capital. Ultimately, the higher cost of equity and debt capital will increase customer costs.

An estimate of the risk shareholders are exposed to over the life of their investment can be quantified by computing what a 100 – 200 bps under-earning of the allowed ROE would be over the 20-year preferred resource plan. Shareholders are exposed to additional risks that are outside just the capital investment of the resource plan. Shareholders are not compensated until all other parties exposed to the Company are paid, but in order to keep the relative risk comparable to the customer risk, the 100 – 200 bps under-earning range is only computed on the capital investment in the preferred resource plan. The present value of the generation related capital investment of the Preferred Plan is $6.2 billion. Assuming the investment is funded with 50% equity, a 100 – 200 bps under-earning of ROE is $31 million - $62 million.

CONCLUSION

The assessment of risk included in this document represents a point-in-time summary of the current understanding of the risk mitigation benefits associated with completing the fleet transition identified in Evergy's Preferred Plan as opposed to waiting to invest in renewables when they are required under the current regulatory and policy framework. The planning environment which Evergy operates within is continuing to become more dynamic so it is likely that our understanding of the drivers outlined in this document will evolve over time, as will the regulatory and policy framework. To that end, the key in selecting a Preferred Plan is ensuring that the near-term actions (Implementation Period) associated with the Preferred Plan are robust across a variety of future scenarios and that the Preferred Plan in total gives the Company sufficient flexibility to adjust over time as technology, market, and policy dynamics change – allowing it to manage risk for customers and shareholders effectively on an ongoing basis. Evergy's current Preferred Plan maintains a measured pace of fossil retirements, which continues to reduce our dependence on fossil fuels over time, but also maintains firm, dispatchable capacity from coal units until later in the planning horizon when it is expected that new / improved technologies will be available which can provide non-emitting, firm, dispatchable capacity to provide the same reliability benefits which coal plants have provided for the last century. In parallel with this pace of retirements, the Preferred Plan includes ratable, consistent renewable additions throughout the first 15 years of the planning horizon. This consistency of investment allows Evergy to manage execution risk for both customers and shareholders, capitalize on the highest-value renewable sites available, and continue to transition to a more renewable energy mix even as coal capacity is retained for reliability purposes. Additionally, this consistent investment in new capacity allows Evergy to be prepared if policy drivers of the fleet transition (e.g., carbon restrictions or EPA regulations) accelerate and force earlier retirement of more of its coal fleet. Through years 5-15 of the Preferred Plan, Evergy is hopeful to see the implementation of economic energy storage capacity as well to supplement / replace some of the planned renewable investments (as well as potentially delay the need for new firm, dispatchable technology). This potential will be evaluated in more detail in Evergy's 2023 Annual Update.

In summary, Evergy believes that the current Preferred Plan represents an effective balance of both customer and shareholder risks as they are understood at this time, while maintaining flexibility for future adjustments as conditions change.

Note: This SCI responds to the 2021 Evergy Missouri West 2021 Triennial Joint Filing "Staff's Concern B".

9.3 FUTURE EMERGENCY EVENT PLANNING

Given the recent COVID pandemic and the Winter Storm Uri weather event, provide details of its plan for handling future emergency events such as these. The details provided should give a clear plan for maintaining supply-side resource generation and public welfare during emergency events.

Response:

Evergy maintains emergency event plans of several types in order to be able to respond to and maintain reliable service and public welfare during a large variety of emergency events. The key categories of emergency preparedness plans are outlined and described below.

Business Continuity Plans

Evergy utilizes an enterprise-wide Crisis Management and Business Continuity Plan (CMP). Because there are many different events that can occur to invoke the Plan that represent a threat to employees, facilities, information, systems, or operations; the Evergy plan is considered an "All Hazards" plan. The Plan is updated annually or when a major change has occurred and is exercised annually as part of the Evergy Annual Exercise Campaign. The Annual Exercise Campaign also supports compliance to the NERC CIP Standards CIP-008 and CIP-009.

There are 3 components or tiers that make up the Evergy CMP model, with linkages to other Plans:

First, the Company adopted an overarching enterprise-wide Crisis Management Plan. The Crisis Management Plan establishes procedures and guidelines for the Crisis Management Team. The Team is composed of senior Officers with decision-making authority to implement policy, notify stakeholders, and bring in additional resources as needed. The Plan establishes a Crisis Management Center or a virtual Emergency Operations Center for incident management, recovery strategy and communications. The Plan also sets procedures for Department-level Recovery Teams.

Secondly, each department has or is covered by a Department-level Business Continuity Plan. This Plan is to include an Information Technology Data Recovery Plan.

Thirdly, there is the Cybersecurity Incident Response Plan/Team (CIRP), which will specifically manage cybersecurity incidents and is foundational across all areas.

Finally, there is linkage between the enterprise-wide and department-level Business Continuity Plans and other major recovery plans in the company such as Pandemic Response Plan, Storm Emergency Restoration Plan, Wolf Creek Emergency Response Plans, and the CIRP Plan.

The Crisis Management Plan purpose at a high level to is to provide a structure and process for reporting, classification, and overall management of a situation. The Plan structure and information flow are designed to ensure cohesion between External / Internal Stakeholders, Board of Directors, the CMP Team, and Recovery Teams.

When an incident occurs, the departments' Recovery Teams may also be activated. With the goal of returning its operations to normal as quickly as possible, the Recovery Team Leader directs the team members and communicates with the Crisis Management Team. Information flows back and forth to inform the Crisis Management Team and direct the actions of the Recovery Team.

Pandemic Response Plans

The Evergy Pandemic Plan follows the Crisis Management and Business Continuity Plan model described above in that there is an overriding enterprise-wide Pandemic Plan and the different Operating Units modified / implemented further, specific Plans to fit their unique operating environment. The key part of each Operating Unit plan consists of a prioritization of job classifications, and ultimately employees within those classifications, based on criticality, specifically as it relates to the necessity of performing work on-site in order to maintain safe and reliable operations. This allows a focus on maintaining the labor workforce needed for critical functions.

Supply-Side Resource Emergency Preparedness

All Supply-Side Resources

As required by NERC Standard EOP-005, Evergy maintains black start resources to support the transmission system restoration plan and has documented procedures for starting each black start resource and energizing a bus. Each black start site performs black start resource tests and maintains records of such testing in accordance with NERC Standard EOP-005.

Evergy Generating Facilities maintain site level Emergency Action Plans in accordance with OSHA Standard 1910.38; Emergency Action Plans cover reporting and response actions to be followed for the following conditions:

- Fire
- Tornado/Severe weather
- Flood
- Earthquake
- Anhydrous Ammonia release (if applicable)
- Oil or chemical spill
- On-the-job injury or illness
- Sabotage
- Bomb threat
- Emergency evacuation

Evergy Generation Facilities that store over 10,000lbs of anhydrous ammonia on site maintain an OSHA Process Safety Management and an EPA Risk Management Plan which includes details on required operation, training, maintenance, and documentation as well as emergency response procedures in the event of a release.

Evergy carries conservative target volumes of fuel oil at units with onsite storage tanks to be prepared for emergency situations that require significant run times (multiple days) of fuel oil resources. Additionally, proactive communication with coal (mine and rail), natural gas (pipelines) and fuel oil suppliers occurs ahead of potentially emergency events.

Evergy's dual fuel (natural gas & fuel oil) fleet is valuable in maintaining reliability for customers during extreme events that result in the loss of primary fuel access (i.e., natural gas). Evergy has 15 units capable of switching from natural gas to fuel oil.

Nuclear

The Wolf Creek Generating Station (WCGS) Radiological Emergency Response Plan (RERP) has been developed in accordance with 10CFR Part 50, Paragraph 50.47 and Appendix E, Regulatory Guide 1.101 and complies with the guidelines of NUREG 0696 and 0654. The RERP is sensitive to a broad spectrum of emergency conditions which have been postulated for a commercial pressurized water reactor. Although the probability of an accident is low, the RERP is maintained to assure the safety and well-being of plant personnel and members of the public in the vicinity of WCGS.

Winter-Specific

Evergy has Cold Weather Checklists for each of its units that it completes prior to each Winter Season. These checklists are reviewed by our Operations Compliance team. In addition, Evergy has unit-specific cold weather training. Finally, Evergy is heavily involved in the drafting of the new Extreme Cold Weather NERC Standard which incorporates key recommendations from the joint FERC / NERC Winter Storm Uri Report (published November 2021). Kenny Luebbert, Director of Operations Support, is currently chairing this NERC Drafting Team.

Evergy maintains a cold weather self-commit policy for its coal-fired generation fleet. The policy differentiates between extreme cold conditions and extended coal conditions and outlines the commitment status for each coal-fired generator for those conditions. This policy addresses the fact that each of these generators has specific challenges and operational risks associated with cycling off-line in below-freezing weather. Evergy believes this conservative operations approach helps maintain reliability.

Other Emergency Preparedness / Response Plans

As required by NERC Standard EOP-011, Evergy has and maintains a plan for operator controlled manual load shedding (Evergy Manual Load Shed Plan). This plan contains multiple improvements from the post Uri Storm lessons learned review. Examples of the implemented improvements include an updated policy for identifying critical customers for exclusion, an improved communication plan and targeting 30-minute outage durations and rotation (rather than the prior target of 120 minutes).

As required by NERC Standard EOP-005, Evergy has and maintains a transmission system restoration plan from black start resources (Evergy Black Start and System Restoration Plan). This plan identifies the black start resources to be used, the cranking paths and the initial switching requirements.

As required by NERC Standard EOP-008, Evergy has and maintains an operating plan to maintain reliable transmission system operation if the primary control center functionality is lost. The plan includes a backup control center location and procedures for implementation.

9.4 URBAN HEAT ISLAND ANALYSIS

Explore the feasibility, impacts, and potential mitigation of a potentially more pronounced urban heat island over the greater Kansas City urban area over a twenty-year IRP cycle.

Response:

Urban Heat Island (UHI) has been supported and studied by key entities, such as the University of Missouri-Kansas City ("UMKC"), Mid-America Regional Council ("MARC") and others, with shared interest in Kansas City for several years.

Evergy has been involved at different levels in multiple initiatives, to include support and participation in:

Dr. Sun's UHI Mapping Campaign (Heat Watch Kansas City) conducted during the summer of 2021.

An Evergy led UHI cohort to assemble organizations and stakeholders, including the Missouri Office of Public Counsel ("OPC"). Evergy supported the effort through its leadership, meeting orchestration and providing high-level data, where appropriate.

Additional internal research with MEEIA implementer to identify energy efficient and demand reducing measures that would most impact UHI effects along with the identification of the most cost effective and positively impacted customer types.

Partnership with the Arbor Day Foundation and Bridging the Gap for the past four years, providing Energy Saving Trees to our customers with a focus on high UHI areas since trees are a primary way to impact UHI. Through 2021 Evergy, in partnership with Bridging the Gap and the Arbor Day Foundation, provided 1,761 - two to six-foot - trees to customers. This results in approximately 32,000 pounds of air pollutants 20 absorbed and nearly 3 million MWh of energy saved over 20-years [1].

[1] Numeric values provided by the Arbor Day Foundation

Also, through a stakeholder engagement process, Evergy will develop a Feasibility and Vulnerability Study for MEEIA Cycle 4 related to Urban Heat Island Research and Development as described in the non-unanimous stipulation and agreement approved by the Commission.

In addition, in the next DSM Potential Study, Evergy will explore various UHI measures for inclusion in the 20-year estimate of impacts.

9.5 SECURITIZATION TO SUPPORT ACCELERATED RETIREMENT OF COAL ASSETS

Analyze and document the prospects for using securitization to support cost-effective accelerated retirement of coal generation assets and to channel the savings into cost-effective investments such as demand-side management, wind and solar generation, and storage. Evergy does not need to repeat the analysis of securitization it performed in its 2021 Triennial IRP filing but must provide an update regarding its securitization plans.

Response:

Evergy West provided an analysis of securitization in its 2021 Triennial filing. As noted previously, Evergy West's only current planned use of securitization is ongoing in docket EF-2022-0155.

9.6 TRANSMISSION GRID UPGRADES

Analyze and document the projected interconnection costs when evaluating additional supply-side options.

Response:

Evergy Missouri West's cost assumptions for new supply-side resources include an assumed cost of transmission interconnection costs. Table 43 below provides the estimated costs assumed for technologies modeled.

Table 43: Interconnect Cost Estimates

Generation Technology	Transmission Interconnect Estimate (2021 $/kW)
Combustion Turbine	$66
Combined Cycle	$66
Solar	$40
Wind	$65