EVERGY KANSAS CENTRAL

AND

EVERGY METRO

2022 ANNUAL UPDATE

JUNE 2022

PUBIC

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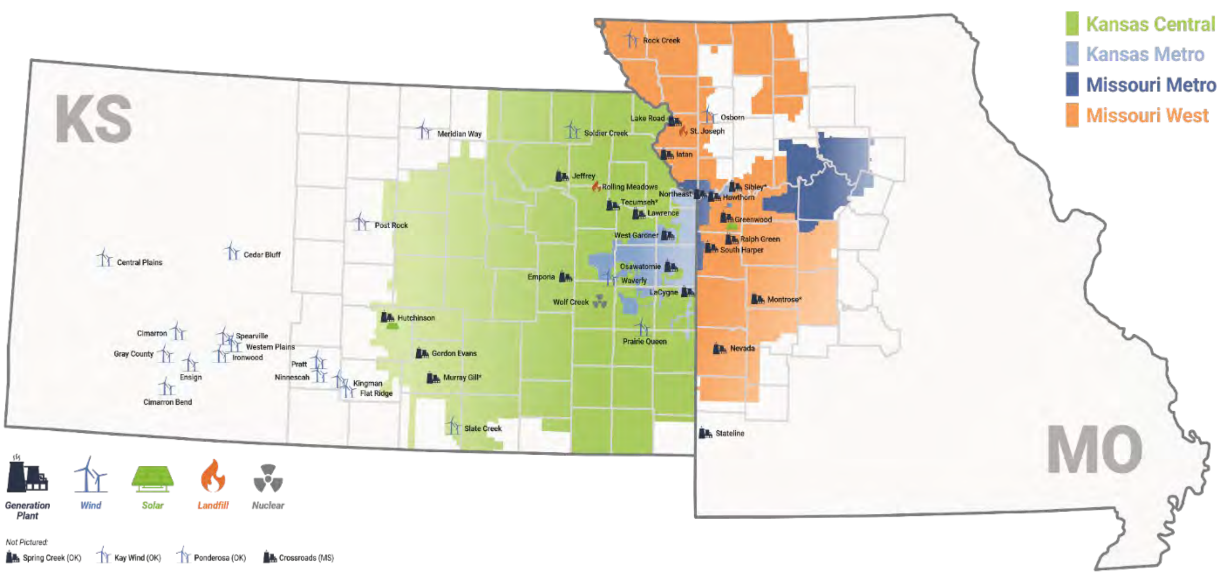
1.1 UTILITY INTRODUCTION - EVERGY KANSAS CENTRAL

Evergy Kansas Central (or "Company") is an integrated, mid-sized electric utility serving customers in the eastern third of Kansas including the cities of Wichita, Topeka, and portions of the Kansas City metropolitan area.

A map of the Evergy service territory which includes Evergy Kansas Central and Evergy Metro is provided in Figure 1 below:

Figure 1: Evergy Service Territory



Evergy Kansas Central is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Table 1 provides a snapshot of the number of customers served, retail sales and peak demand based upon 2022 data.

Table 1: Evergy Kansas Central Customers, Retail Sales and Peak Demand

Jurisdiction	Number of Retail Customers	Retail Sales (MWh)	Net Peak Demand (MW)
Evergy Kansas Central	733,971	19,947,509	5,223

Evergy Kansas Central (EKC) owns and operates a diverse generating portfolio and Power Purchase Agreements (PPA) to meet customer energy requirements. Table 2 reflects Evergy Kansas Central's generation assets operating in 2022.

Table 2: Evergy Kansas Central Capacity and Energy by Resource Type

Jurisdiction	Capacity by Fuel Type	Capacity (MW)	Capacity (%)	Energy (MWh)	Energy (%)
Evergy Kansas Central	Coal	3,032	40.6%	12,797,134	47.4%
	Nuclear	553	7.4%	4,220,251	15.6%
	Nat. Gas	1,600	21.4%	1,559,325	5.8%
	Oil	70	0.9%	1,631	0.0%
	Wind*	2,211	29.6%	8,387,724	31.0%
	LFG	6	0.1%	45,596	0.2%
	Solar	1	0.0%	2,479	0.0%
	Total	7,472	100.0%	27,014,139	100.0%

* Wind capacity is based upon nameplate

1.2 UTILITY INTRODUCTION - EVERGY METRO

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

Evergy Metro is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Table 3 provides a snapshot of the number of customers served, retail sales and peak demand based upon 2022 data.

Table 3: Evergy Metro Customers, Retail Sales and Peak Demand

Jurisdiction	Number of Retail Customers	Retail Sales (MWh)	Net Peak Demand (MW)
Evergy Kansas Metro	271,766	6,488,514	1,651
Evergy Missouri Metro	303,535	8,480,173	1,827
Evergy Metro	575,301	14,968,687	

Evergy Metro owns and operates a diverse generating portfolio and Power Purchase Agreements (PPA) to meet customer energy requirements. Table 4 reflects Evergy Metro’s generation assets operating in 2022.

Table 4: Evergy Metro Capacity and Energy by Resource Type

Jurisdiction	Capacity by Fuel Type	Capacity (MW)	Capacity (%)	Energy (MWh)	Energy (%)
Evergy Metro	Coal	2,248	42.0%	9,902,374	50.5%
	Nat. Gas	553	10.3%	553,540	2.8%
	Oil	773	14.4%	12,938	0.1%
	Nuclear	382	7.1%	4,221,631	21.5%
	Wind*	1,330	24.9%	4,766,642	24.3%
	Hydro	66	1.2%	163,180	0.8%
	Total	5,351	100.0%	19,620,305	100.0%

* Wind capacity is based upon nameplate

1.3 CHANGES FROM THE 2021 TRIENNIAL IRP AND 2022 ANNUAL IRP UPDATE

Evergy submitted its 2021 Triennial IRP filing on June 3, 2021, and updated its resource plan on June 10, 2022, with its 2022 IRP Annual Update filing. This year's 2023 IRP Annual Update reflects updated information and forecasts based on market and policy changes and additional studies that have occurred in the past year.

Changes from the 2021 Triennial IRP and 2022 Annual Update include:

- Updated market pricing reflecting latest SPP transmission planning model assumptions of future resource mix and potential transmission congestion
- Updated fuel price forecasts, including high, mid, and low natural gas price scenarios
- Carbon Dioxide emissions limitations scenarios reflecting future environmental risks, including high, mid, and low (no) restrictions
- Updated cost estimates and timing assumptions for resource additions based on Evergy's First Quarter 2023 Request for Proposal (RFP) results
- Modeling of battery storage and hybrid resources as supply-side options
- Inclusion of incentives for new renewable and storage resources based on Inflation Reduction Act

- Updated load forecasts including large new customers in both Missouri and Kansas, and considerations for future large customer growth based on existing economic development pipeline
- Updated demand response potential study, including four Missouri program options
- Included possible reductions in peak demand from Missouri Commission-ordered mandatory time of use rates
- Refreshed demand response options for Kansas customers based on KEEIA filings pending before the Kansas Commission
- Updated planning reserve margin consistent with SPP rule changes enacted in 2022
- Increased focus on planning for utility-level (as opposed to Evergy-level) resource needs to better identify each utility's specific energy and capacity needs in the future, reduced level of assumed market availability (for both capacity and energy) and reliance on other Evergy affiliates to meet long-term customer needs
- Expanded use of PLEXOS software for production cost modeling and capacity expansion, which was first implemented for 2022 IRP
- Annual refresh of data for existing generators (Capital and Operations & Maintenance costs)

1.4 2023 ANNUAL UPDATE PREFERRED PORTFOLIO

1.4.1 INTEGRATED RESOURCE PLAN OVERVIEW

Between Triennial IRP filings, Commission regulations require annual updates to the triennial filing. This document includes the annual update filing for 2023 ("2023 Update") that, consistent with Commission regulations, outlines material changes to the 2021 IRP and the 2022 Annual Update.

Due to the many changes in planning considerations over the past year, the Preferred Portfolios selected for Kansas Central and Evergy Metro in this 2023 IRP Annual Update differ from the 2021 Triennial and 2022 IRP Preferred Portfolios.

Kansas Central: The 2023 Preferred Portfolio continues to include a series of investments in new wind and solar resources over the planning horizon. The 2023 Preferred Portfolio also includes the addition of approximately 1,000 MW of hydrogen-capable natural gas-fired combined cycle capacity in the late 2020s in order to meet increasing capacity requirements, serve new customer demand, and prepare for future coal retirements. The addition of this capacity along with the expected addition of new hydrogen-capable natural-gas fired combustion turbine capacity in the 2030s is in tandem with a more modest increase in new solar resources relative to the 2022 Annual Update.

Additionally, the Company modeled the two settlements currently before the Commission related to implementation of Demand Side Management (DSM) programs under the Kansas Energy Efficiency Investment Act (KEEIA). The lowest-cost option identified through IRP modeling is the settlement which includes a broader set of programs, with an assumption of continued implementation over time to reach a "full" level of implementation in the long-term. Due to uncertainty around the pending case, and to avoid delaying new capacity builds on the basis of "full" implementation which may not be realized, the Commission Staff settlement for a more targeted set of programs, with only short-term implementation over three years, was selected as part of the Preferred Portfolio. The fact that this is a higher cost option demonstrates the long-term value of DSM programs and their ability to delay capacity needs over time, but the Company believes that selecting this "Low" DSM implementation is the most prudent path to plan around at this time.

Finally, in the 2022 Annual Update, Evergy identified the potential for an additional accelerated retirement which could be economically replaced, but at that time chose not to identify a specific unit for retirement as part of the Preferred

Portfolio due to the uncertainty around which specific unit would ultimately be the best candidate for retirement. In this Annual Update, Jeffrey Unit 2 has been identified for 2030 retirement as part of the Preferred Portfolio. There is still significant uncertainty around different environmental regulations which could drive the retirement of Jeffrey Unit 2 or a different Evergy coal unit and thus Jeffrey Unit 2 still remains a “placeholder” for an accelerated retirement. However, given recent regulation released by the Environmental Protection Agency (EPA), it seems more probable that all units would need to install Best Available Control Technology in order to continue operating beyond the early 2030s. Given Jeffrey Units 2 and 3 are the only large units in Evergy’s fleet without Selective Catalytic Reduction (SCR) systems, the capital forecasts used in this IRP (and prior IRPs) assume that SCRs would need to be added if the units do not retire by 2031. This large capital cost to continue operations make these units the most attractive options for early retirement. Evergy will continue to monitor environmental regulations and make adjustments to retirement plans as needed if conditions change, but at this time believes it is prudent to plan around a medium-term retirement of both Jeffrey Units 2 and 3 in order to avoid a situation where retirements are forced by environmental regulation and replacement capacity has not been procured proactively. Further discussion of environmental regulations is provided in Sections 4.4 and 6.2.

Evergy Metro: The 2023 Preferred Plan continues to include new investments in wind and solar resources though at a reduced level, and shifts the timing of wind resource additions to the early 2030s. Thermal resource additions increased above past Preferred Plans and the timing has shifted from 2040 to the late 2030s.

Additionally, the refresh of the demand response potential study shows value in choosing the “Realistically Achievable Potential Plus” (RAP+) level of demand-side management programs for Evergy Missouri West over the Realistically Achievable Potential (RAP) level. For Evergy Metro, the combination of this level of Missouri DSM and the “low” level of Kansas DSM is only $14 million higher cost over the 20-year planning horizon (<0.1% of overall costs) compared to the lowest cost plan, which included the RAP- level of DSM for Missouri in addition to the “low” level of Kansas DSM. To enable consistent implementation across Missouri jurisdictions, in addition to providing additional capacity which can prepare Metro for the risk of accelerated coal retirements which are not currently in its Preferred Portfolio, the RAP+ level of DSM is included in Metro’s new Preferred Portfolio. The new study shows much lower demand response potential than was forecasted in the last study, so the level of capacity and energy reductions which can be achieved from all programs are smaller.

Table 5: Evergy Kansas Central Preferred Portfolio Comparison

Note: All dates shown in this summary are end-of-year unless otherwise noted. Capacity balance views shown elsewhere in this document represent summer capacity impacts which means that additions are typically shown in the following year (the year in which they will be available for summer capacity)

	2021 Triennial IRP	**2022 IRP Annual Update**	**2023 IRP Annual Update**
Retirements	Lawrence 4 in 2023 Lawrence 5 in 2023 Jeffrey 3 in 2030 LaCygne 1 in 2032 LaCygne 2 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039	Lawrence 4 in 2024 Lawrence 5 in 2024 (Coal) Jeffrey 3 in 2030 LaCygne 1 in 2032 LaCygne 2 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039	Lawrence 4 in 2028 Lawrence 5 in 2028 (Coal) Jeffrey 3 in 2030 Jeffrey 2 in 2030 LaCygne 1 in 2032 LaCygne 2 in 2039 Jeffrey 1 in 2039
Wind Additions	300 MW in 2025 300 MW in 2026	350 MW in 2025 270 MW in 2026 300 MW in 2041	199 MW in 5/2023 200 MW in 2024 150 MW in 2032 150 MW in 2033 150 MW in 2040
Solar Additions	350 MW in 2023 300 MW in 2028 300 MW in 2029 300 MW in 2030 300 MW in 2031 300 MW in 2032	190 MW in 2024 180 MW in 2028 270 MW in 2029 270 MW in 2030 270 MW in 2031 270 MW in 2032 270 MW in 2033 270 MW in 2034 270 MW in 2035 300 MW in 2039 150 MW in 2041	150 MW in 2026 150 MW in 2027 150 MW in 2028 300 MW in 2031 150 MW in 2034 150 MW in 2041
Thermal Additions	466 MW CT in 2033 233 MW CT in 2038 1,631 MW CT in 2040	338 MW Lawrence 5 to NG in 2024 237 MW CT in 2036 418 MW CC in 2036 474 MW CT in 2040 418 MW CC in 2040	176 MW Jeffrey 8% share in 2023 338 MW Lawrence 5 to NG in 2028 520 MW CC in 2027 520 MW CC in 2028 238 MW CT in 2032 238 MW CT in 2035 520 MW CC in 2038 520 MW CC in 2039 238 MW CT in 2039
New DSM Programs	RAP-	RAP-	Low DSM

Table 6: Evergy Metro Preferred Portfolio Comparison

Note: All dates shown in this summary are end-of-year unless otherwise noted. Capacity balance views shown elsewhere in this document represent summer capacity impacts which means that additions are typically shown in the following year (the year in which they will be available for summer capacity)

	2021 Triennial IRP	2022 IRP Annual Update	2023 IRP Annual Update
Retirements	LaCygne 1 in 2032 Iatan 1 in 2039 LaCygne 2 in 2039	LaCygne 1 in 2032 Iatan 1 in 2039 LaCygne 2 in 2039	LaCygne 1 in 2032 Iatan 1 in 2039 LaCygne 2 in 2039
Wind Additions	120 MW in 2025 120 MW in 2026	150 MW in 2024 150 MW in 2025 108 MW in 2026 450MW in 2041	150 MW in 2031 150 MW in 2032 150 MW in 2041
Solar Additions	230 MW in 2024 120 MW in 2028 120 MW in 2029 120 MW in 2030 120 MW in 2031 120 MW in 2032	72 MW in 2028 108 MW in 2029 108 MW in 2030 108 MW in 2031 108 MW in 2032 108 MW in 2033 108 MW in 2034 108 MW in 2035	150 MW in 2029 150 MW in 2030 150 MW in 2033 150 MW in 2040
Thermal Additions	699 MW CT in 2040	418 MW CC in 2040	260 MW CC in 2037, 2038, 2039
New DSM Programs	RAP MO/ RAP- KS	RAP MO/ RAP- KS	RAP+ MO/ Low KS

Table 7: Evergy-Level Preferred Plan Comparison

Note: All dates shown in this summary are end-of-year unless otherwise noted. Capacity balance views shown elsewhere in this document represent summer capacity impacts which means that additions are typically shown in the following year (the year in which they will be available for summer capacity)

	2021 Triennial IRP	2022 IRP Annual Update	2023 IRP Annual Update
Retirements	Lawrence 4 in 2023 Lawrence 5 in 2023 Lake Road 4/6 in 2024 Jeffrey 3 in 2030 La Cygne 1 in 2032 La Cygne 2 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039 atan 1 in 2039	Lawrence 4 in 2024 Lawrence 5 in 2024 (Coal) Jeffrey 3 in 2030 Lake Road 4/6 in 2030 La Cygne 1 in 2032 La Cygne 2 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039 atan 1 in 2039	Lawrence 4 in 2028 Lawrence 5 in 2028 (Coal) Jeffrey 3 in 2030 Jeffrey 2 in 2030 *(Placeholder for add'l accelerated retirement)* Lake Road 4/6 in 2030 La Cygne 1 in 2032 La Cygne 2 in 2039 Jeffrey 1 in 2039 atan 1 in 2039
Wind Additions	500 MW in 2025, 2026	300 MW in 2024 500 MW in 2025 450 MW in 2026 450 MW in 2041	199 MW in 5/2023 200 MW in 2024 150 MW in 2029, 2030 300 MW in 2031 450 MW in 2032 300 MW in 2033 150 MW in 2040, 2041
Solar Additions	350 MW in 2023, 2024 500 MW in 2028, 2029, 2030, 2031, 2032	190 MW in 2024 300 MW in 2028 450 MW in 2029, 2030, 2031, 2032, 2033, 2034, 2035 150 MW in 2036	300 MW in 2026 150 MW in 2027 300 MW in 2028, 2029, 2030, 2031 150 MW in 2033, 2034, 2040 300 MW in 2041
Thermal Additions		338 MW Lawrence 5 to NG in 2028	176 MW in 2023 143 MW in 5/2024 781 MW in 2027 338 MW Lawrence 5 to NG in 2028 521 MW in 2028 238 MW in 2032
"Firm Dispatchable"[1]	233 MW in 2036, 2037, 2039 2,796 MW in 2040	237 MW in 2036 418 MW in 2038 836 MW in 2039 948 MW in 2040	238 MW in 2035 260 MW in 2037 780 MW in 2038 1,278 MW in 2039
New DSM Programs	RAP- MO/KS	RAP MO/ RAP- KS	RAP+ MO/ Low KS

1) Similar to past IRPs, thermal additions beginning in 2035 are assumed to be non-emitting "firm, dispatchable resources"

SECTION 2: LOAD ANALYSIS AND LOAD FORECASTING UPDATE

2.1 CHANGES FROM THE 2021 TRIENNIAL IRP AND 2022 ANNUAL UPDATE

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 2022 vs ending June 2020.
- Class models in the 2023 KS Metro are the same as the 2021 Triennial filing: residential, small commercial, big commercial (medium, large, large power) and industrial. Class models in the 2023 KS central are the same as the 2021 Triennial filing: residential, commercial and industrial.
- DOE forecasts of appliance and equipment saturations and kwh/unit: Annual Energy Outlook (AEO) 2022 vs AEO 2020.
- Economic forecasts from Moody's Analytics: June 2022 vs June 2020.
- 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 2023 Update filing.
- The Company utilized Google Mobility Reports data through June of 2022 to account for load changes resulting from geolocation behaviors induced by the COVID19 pandemic.
- Recently announced new large industrial loads (e.g., Panasonic) have not been incorporated into the load forecasts described in this section. However, the latest projections for these loads are factored into Integrated Analysis for the purposes of determining capacity requirements.

Table 8, Table 9, and Figure 2 through Figure 5 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 2022 AEO resulting from updates to end-use efficiency and saturation estimates. The EIA's updates impact to the 2022 IRP Update short-term (2022-2027) 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 lower compared to 2021 due to lower Commercial intensity estimates long-term. Below is a summary of the impact by class.
- Residential: 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 2022 AEO is slightly less negative in the near term (2022-2027) and similar to the 2020 AEO thereafter. The difference in base load is explained by updated estimates of miscellaneous intensity as well as TV and related equipment.
- Commercial: Total commercial intensity trajectory declined from the 2020 AEO, with growth being slightly slower throughout the forecast period (2022-2042). The end-uses contributing to the change from the 2020 AEO intensity are primarily Cooling, Heating, Lighting and Miscellaneous in both the near-term and the long-term.
- Industrial: 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 2022. 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 2022 forecast compared to the 2020 forecast. The lower growth trajectory in the Economic forecast contributes to a lower growth trajectory in the load forecast.

- However, the growth trajectory of Company Commercial load since the 2022 Triennial IRP forecast partially offsets lower economic and end-use intensity forecasts.

2.1.1 EVERGY KANSAS CENTRAL

Table 8: Evergy Kansas Central Mid-Case Annual NSI and Peak Forecast

Native Load and Peak Forecast											
Date	Gross NL (MWh)		DSM	Net NL (MWh)		Gross Peak (MW)		DSM	Net Peak (MW)		Gross LF
2011	25,289,023			25,289,023		5,569			5,569		0.5184
2012	24,655,542	-2.5%		24,655,542	-2.5%	5,393	-3.2%		5,393	-3.2%	0.5219
2013	24,351,550	-1.2%		24,351,550	-1.2%	5,184	-3.9%		5,184	-3.9%	0.5362
2014	24,698,681	1.4%		24,698,681	1.4%	5,223	0.8%		5,223	0.8%	0.5398
2015	23,997,745	-2.8%		23,997,745	-2.8%	5,167	-1.1%		5,167	-1.1%	0.5302
2016	24,122,821	0.5%		24,122,821	0.5%	5,184	0.3%		5,184	0.3%	0.5312
2017	23,980,813	-0.6%		23,980,813	-0.6%	5,242	1.1%		5,242	1.1%	0.5193
2018	24,881,408	3.8%		24,881,408	3.8%	5,204	-0.7%		5,204	-0.7%	0.5458
2019	24,722,992	-0.6%		24,722,992	-0.6%	5,108	-1.8%		5,108	-1.8%	0.5525
2020	23,506,829	-4.9%		23,506,829	-4.9%	4,942	-3.3%		4,942	-3.3%	0.5430
2021	24,271,863	3.3%		24,271,863	3.3%	5,157	4.4%		5,157	4.4%	0.5373
2022	24,546,855	1.1%	0	24,546,855	1.1%	5,115	-0.8%	(24)	5,091	-1.3%	0.5478
2023	24,555,171	0.0%	0	24,555,171	0.0%	5,028	-1.7%	(22)	5,006	-1.7%	0.5575
2024	24,698,679	0.6%	0	24,698,679	0.6%	5,045	0.3%	(19)	5,026	0.4%	0.5589
2025	24,768,019	0.3%	0	24,768,019	0.3%	5,053	0.2%	(17)	5,036	0.2%	0.5596
2026	24,862,820	0.4%	0	24,862,820	0.4%	5,065	0.2%	(14)	5,051	0.3%	0.5603
2027	24,959,843	0.4%	0	24,959,843	0.4%	5,078	0.2%	(12)	5,066	0.3%	0.5611
2028	25,082,777	0.5%	0	25,082,777	0.5%	5,093	0.3%	(10)	5,083	0.3%	0.5622
2029	25,144,283	0.2%	0	25,144,283	0.2%	5,102	0.2%	(7)	5,095	0.2%	0.5626
2030	25,214,323	0.3%	0	25,214,323	0.3%	5,110	0.2%	(5)	5,105	0.2%	0.5633
2031	25,292,685	0.3%	0	25,292,685	0.3%	5,120	0.2%	(2)	5,118	0.2%	0.5639
2032	25,414,828	0.5%	0	25,414,828	0.5%	5,137	0.3%	(1)	5,136	0.4%	0.5648
2033	25,488,698	0.3%	0	25,488,698	0.3%	5,150	0.3%	0	5,150	0.3%	0.5650
2034	25,612,424	0.5%	0	25,612,424	0.5%	5,169	0.4%	0	5,169	0.4%	0.5656
2035	25,749,768	0.5%	0	25,749,768	0.5%	5,191	0.4%	0	5,191	0.4%	0.5663
2036	25,932,124	0.7%	0	25,932,124	0.7%	5,218	0.5%	0	5,218	0.5%	0.5673
2037	26,054,511	0.5%	0	26,054,511	0.5%	5,241	0.4%	0	5,241	0.4%	0.5675
2038	26,222,798	0.6%	0	26,222,798	0.6%	5,269	0.5%	0	5,269	0.5%	0.5681
2039	26,398,331	0.7%	0	26,398,331	0.7%	5,298	0.6%	0	5,298	0.6%	0.5688
2040	26,603,681	0.8%	0	26,603,681	0.8%	5,329	0.6%	0	5,329	0.6%	0.5699
2041	26,711,799	0.4%	0	26,711,799	0.4%	5,352	0.4%	0	5,352	0.4%	0.5698
2042	26,765,490	0.2%	0	26,765,490	0.2%	5,351	0.0%	0	5,351	0.0%	0.5710

Historical NL is weather normal, first 6 months of 2022 are weather normal
Historical Peak is weather normal, first 6 months of 2022 are weather normal

Gross Native Load (MWh) - Forecast		
Forecast Year	2023 Forecast	2021 IRP
5 Yrs	0.33%	0.92%
10 Yrs	0.35%	0.70%
15 Yrs	0.40%	0.66%
20 Yrs	0.43%	0.68%

Gross Peak (MW) - Forecast		
Forecast Year	2023 Forecast	2021 IRP
5 Yrs	-0.15%	0.51%
10 Yrs	0.04%	0.43%
15 Yrs	0.16%	0.43%
20 Yrs	0.23%	0.48%

Figure 2: Evergy Kansas Central Peak Forecasts – 2023 Annual Update Vs. 2021 Triennial IRP

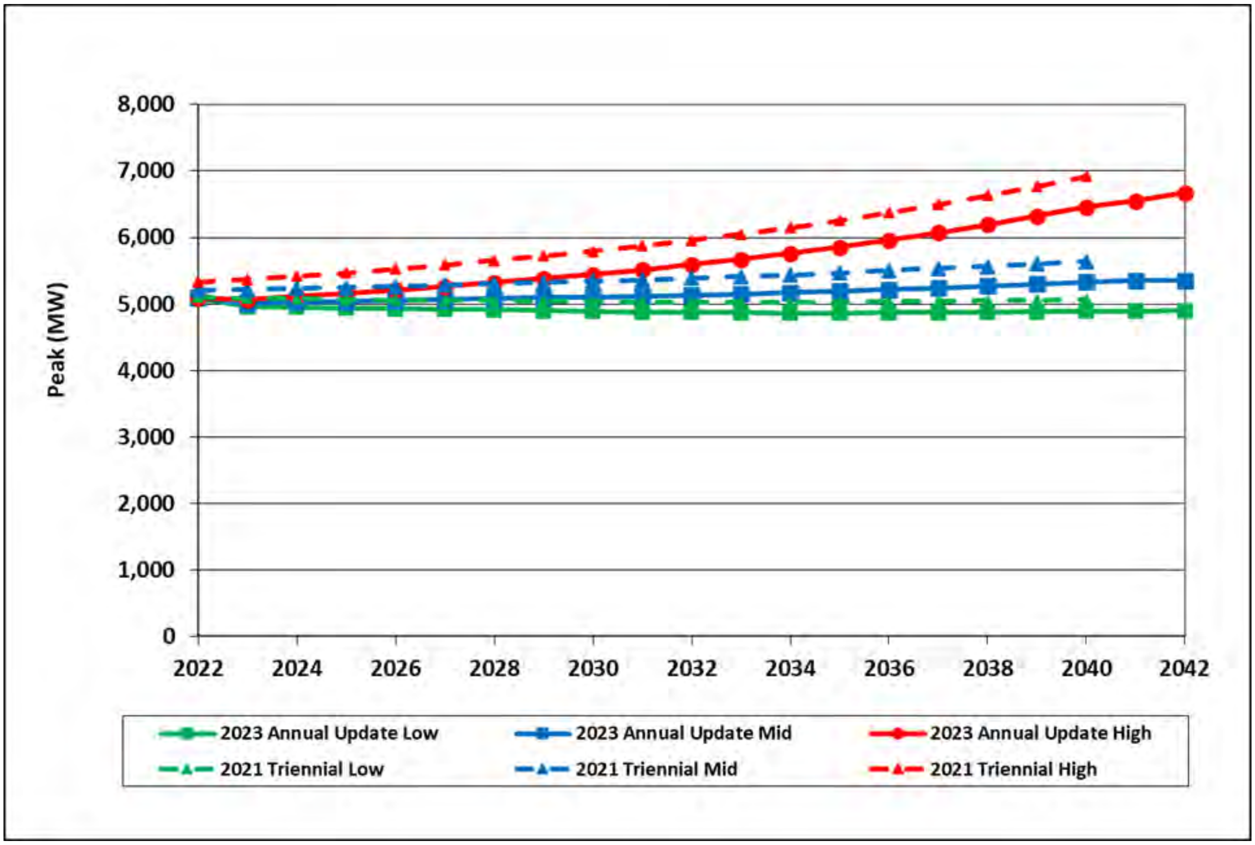
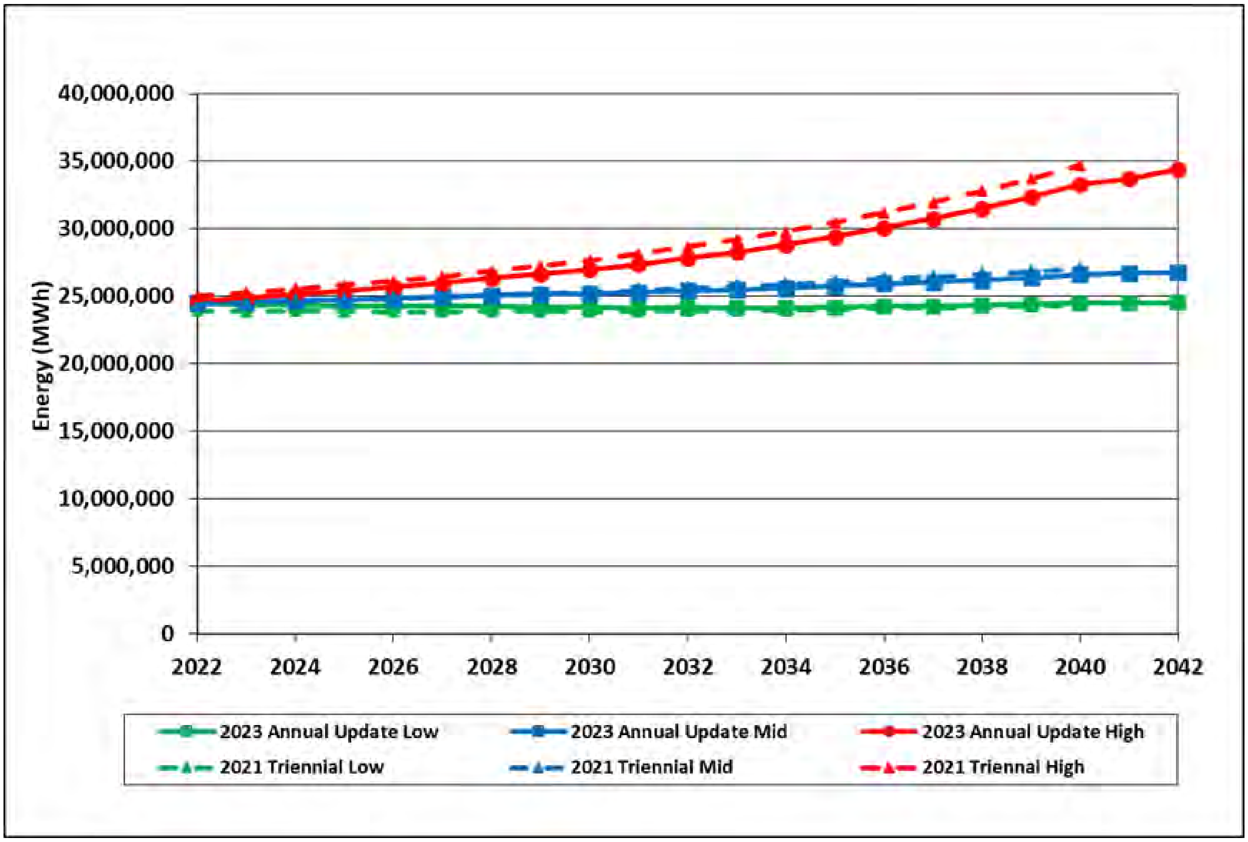


Figure 3: Evergy Kansas Central Energy Forecasts – 2023 Annual Update Vs. 2021 Triennial IRP



2.1.2 EVERGY METRO

Table 9: Evergy Metro Mid-Case Annual NSI and Peak Forecast

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	14,810,168			14,810,168		3,229				3,229		0.5236
2003	15,100,010	2.0%		15,100,010	2.0%	3,307	2.4%			3,307	2.4%	0.5212
2004	15,434,710	2.2%		15,434,710	2.2%	3,600	8.9%			3,600	8.9%	0.4894
2005	15,735,417	1.9%		15,735,417	1.9%	3,496	-2.9%			3,496	-2.9%	0.5138
2006	15,960,834	1.4%		15,960,834	1.4%	3,416	-2.3%			3,416	-2.3%	0.5334
2007	16,286,867	2.0%		16,286,867	2.0%	3,718	8.8%			3,718	8.8%	0.5001
2008	16,306,299	0.1%		16,306,299	0.1%	3,703	-0.4%			3,703	-0.4%	0.5027
2009	16,024,573	-1.7%		16,024,573	-1.7%	3,642	-1.6%			3,642	-1.6%	0.5023
2010	16,057,247	0.2%		16,057,247	0.2%	3,605	-1.0%			3,605	-1.0%	0.5084
2011	15,918,871	-0.9%		15,918,871	-0.9%	3,573	-0.9%			3,573	-0.9%	0.5086
2012	15,642,354	-1.7%		15,642,354	-1.7%	3,401	-4.8%			3,401	-4.8%	0.5250
2013	15,733,616	0.6%		15,733,616	0.6%	3,444	1.3%			3,444	1.3%	0.5215
2014	15,908,170	1.1%		15,908,170	1.1%	3,540	2.8%			3,540	2.8%	0.5130
2015	15,882,360	-0.2%		15,882,360	-0.2%	3,591	1.4%			3,591	1.4%	0.5193
2016	15,827,972	-0.3%		15,827,972	-0.3%	3,524	-1.9%			3,524	-1.9%	0.5127
2017	15,951,842	0.8%		15,951,842	0.8%	3,485	-1.1%			3,485	-1.1%	0.5225
2018	15,849,039	-0.6%		15,849,039	-0.6%	3,518	1.0%			3,518	1.0%	0.5143
2019	15,742,056	-0.7%	(12,242)	15,729,815	-0.8%	3,498	-0.6%			3,498	-0.6%	0.5137
2020	15,475,646	-1.7%	(72,099)	15,403,547	-2.1%	3,317	-5.2%			3,317	-5.2%	0.5326
2021	15,568,229	0.6%	(12,242)	15,555,988	1.0%	3,410	2.8%	(60)		3,350	1.0%	0.5212
2022	15,937,109	2.4%	(72,099)	15,865,009	2.0%	3,474	1.9%	(77)		3,397	1.4%	0.5237
2023	16,098,692	1.0%	(82,280)	16,016,412	1.0%	3,499	0.7%	(64)		3,435	1.1%	0.5252
2024	16,172,134	0.5%	(94,700)	16,077,434	0.4%	3,509	0.3%	(61)		3,448	0.4%	0.5261
2025	16,203,316	0.2%	(90,120)	16,113,196	0.2%	3,512	0.1%	(57)		3,455	0.2%	0.5267
2026	16,239,895	0.2%	(86,823)	16,153,072	0.2%	3,518	0.2%	(53)		3,465	0.3%	0.5270
2027	16,273,678	0.2%	(85,142)	16,188,537	0.2%	3,522	0.1%	(48)		3,474	0.3%	0.5275
2028	16,326,351	0.3%	(82,798)	16,243,553	0.3%	3,531	0.3%	(43)		3,488	0.4%	0.5278
2029	16,346,129	0.1%	(83,273)	16,262,856	0.1%	3,535	0.1%	(40)		3,495	0.2%	0.5279
2030	16,370,562	0.1%	(83,149)	16,287,413	0.2%	3,539	0.1%	(36)		3,503	0.2%	0.5281
2031	16,399,744	0.2%	(76,756)	16,322,988	0.2%	3,544	0.1%	(28)		3,516	0.4%	0.5282
2032	16,452,606	0.3%	(60,006)	16,392,600	0.4%	3,555	0.3%	(17)		3,538	0.6%	0.5283
2033	16,480,660	0.2%	(44,718)	16,435,942	0.3%	3,565	0.3%	(10)		3,555	0.5%	0.5277
2034	16,529,229	0.3%	(31,125)	16,498,104	0.4%	3,578	0.4%	(8)		3,570	0.4%	0.5274
2035	16,581,095	0.3%	(22,666)	16,558,429	0.4%	3,591	0.4%	(7)		3,584	0.4%	0.5271
2036	16,651,807	0.4%	(19,915)	16,631,893	0.4%	3,607	0.4%	(6)		3,601	0.5%	0.5270
2037	16,695,959	0.3%	(13,755)	16,682,204	0.3%	3,622	0.4%	(6)		3,616	0.4%	0.5262
2038	16,756,269	0.4%	(10,116)	16,746,153	0.4%	3,639	0.5%	(5)		3,634	0.5%	0.5256
2039	16,816,331	0.4%	(8,939)	16,807,393	0.4%	3,656	0.5%	(5)		3,651	0.5%	0.5251
2040	16,881,490	0.4%	(5,447)	16,876,043	0.4%	3,674	0.5%	(3)		3,671	1.5%	0.5245
2041	16,909,930	0.2%	(2,542)	16,907,388	0.2%	3,685	0.3%	(1)		3,684	0.4%	0.5238

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 IRP Update	2021 IRP
5 Yrs	0.85%	1.07%
10 Yrs	0.52%	0.74%
15 Yrs	0.45%	0.65%
20 Yrs	0.41%	0.65%

Gross Peak (MW) - Forecast		
Forecast Year	2022 IRP Update	2021 IRP
5 Yrs	0.63%	1.10%
10 Yrs	0.39%	0.69%
15 Yrs	0.38%	0.58%
20 Yrs	0.39%	0.56%

Figure 4: Evergy Metro Peak Forecasts – 2023 Annual Update Vs. 2021 Triennial IRP

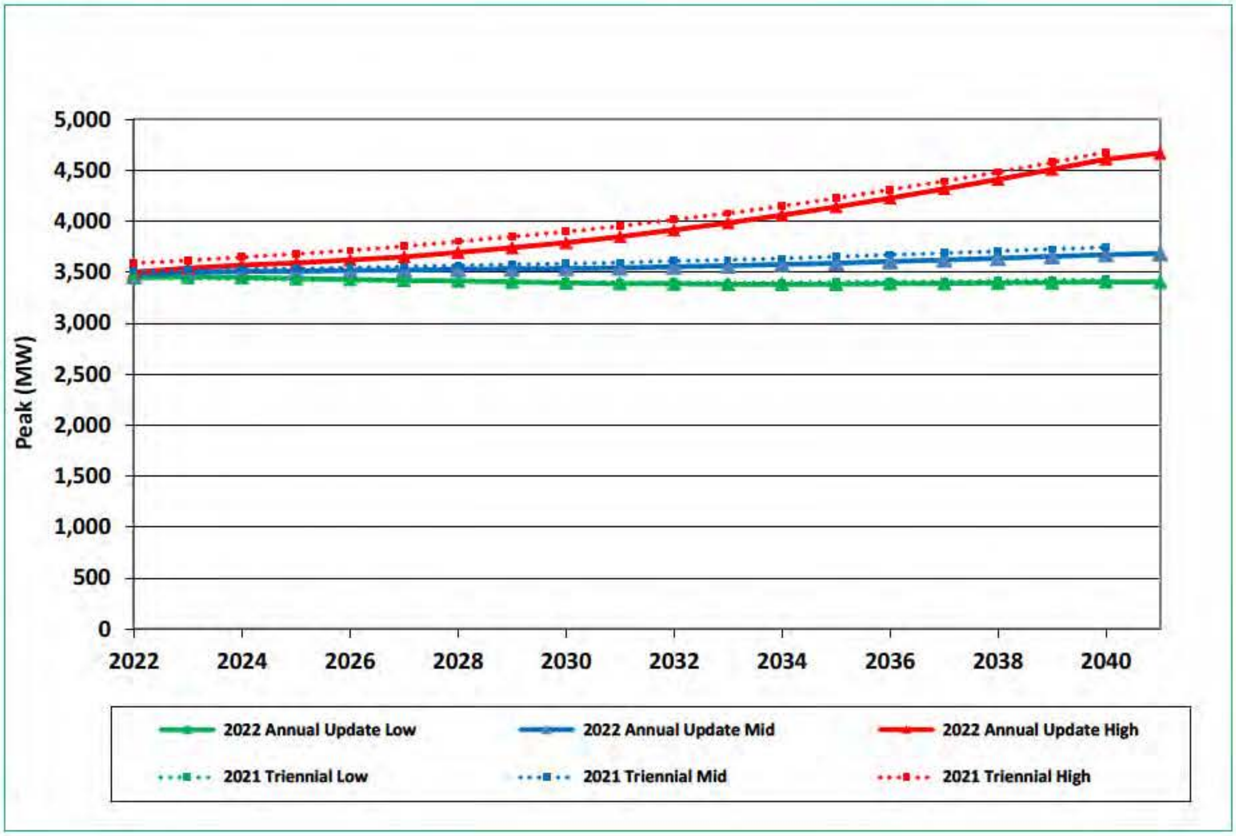
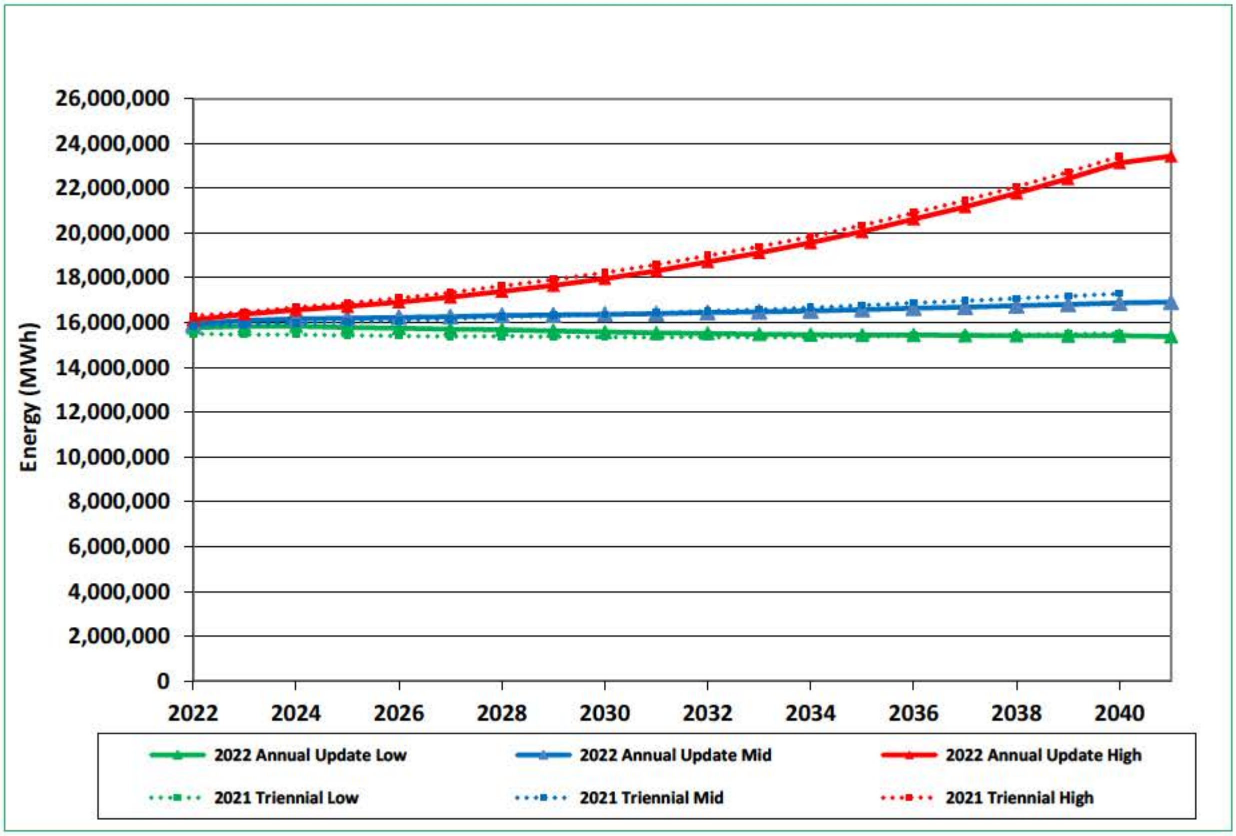


Figure 5: Evergy Metro Energy Forecasts – 2023 Annual Update Vs. 2021 Triennial IRP



2.1.3 ELECTRIFICATION FORECAST METHODOLOGY

Evergy's electrification forecasts are informed by light duty vehicle forecasts provided by the Electric Power Research institute and updated every 12-18 months. EPRI's forecasts consider recent registration data, a variety of publicly available forecasts and reports, short-term sales projections, and supportive policies (i.e. national and regional sales incentives). EPRI's model is intended to inform utility planning decisions by quantifying three potential future trajectories (low/med/high). The low and high trajectories are intended to be plausible bounding scenarios, while the medium trajectory represents a middle ground that is historically consistent with the EV adoption rate in Evergy's service territory.

In addition, Evergy's electrification forecast is informed by an electrification market potential assessment performed by 1898 & Company in 2020. Like the EPRI forecasts, 1898 considers supportive policies in addition to the technology asset life, economic barriers, and environmental barriers. Each technology was scored for each of the four barriers. The barriers affect how quickly adoption begins, how quickly adoption accelerates, and the existing stock turnover time. Based on the scoring of the barriers, an adoption forecast was developed for each technology leading to the electrification forecast.

SECTION 3: DEMAND-SIDE RESOURCE ANALYSIS UPDATE

3.1 PENDING KEEIA APPLICATION

Evergy currently has a pending application (22-EKME-254-TAR) for demand-side management programs in Kansas under the KEEIA framework. Specifically, there are two KEEIA proposals before the Commission, the first of which is a full suite of energy efficiency and demand response programs and a second more limited demand response focused plan. Each of these proposals will provide benefits to Kansas customers. A Commission order is expected soon.

3.2 CHANGES FROM THE 2021 TRIENNIAL IRP

Evergy developed a new DSM potential scenario for the 2023 annual IRP update for the Kansas Metro and Kansas Central jurisdictions. The new DSM potential scenario was developed by extending the existing KEEIA proposed full suite of energy efficiency and demand response programs (program years 2024-2027) for the full IRP planning cycle. For the extended period (program years 2028 and beyond), Evergy adapted the Missouri DSM potential study for use with the Kansas jurisdictions.

The extended portion of the Kansas DSM potential scenario was derived from the Missouri Metro RAP potential scenario in the most recent study conducted by AEG (see description next section). First the Missouri Metro RAP potential was shifted by four years to begin following the completion of the proposed full suite of KEEIA programs.

The Missouri Metro RAP potential was then scaled such that the continuation was at a comparable level to the full suite of proposed KEEIA programs. Workpapers for the Kansas Metro and Kansas Central DSM potential can be found in “KS DSM Estimations.xlsx”.

Figure 6 presents the 20-year cumulative annualized energy savings due to the potential demand-side programs for Evergy KS Metro. Figure 7 presents the 20-year cumulative annualized demand savings due to the potential demand-side programs for Evergy KS Metro. Figure 8 presents the 20-year cumulative annualized energy savings due to the potential demand-side programs for Evergy KS Central. Figure 9 presents the 20-year cumulative annualized energy savings due to the potential demand-side programs for Evergy KS Central.

The scenario described as “Alternate” below is references as the “Low” Kansas DSM scenario in Integrated Analysis.

Figure 6: EKM Cumulative Annual Energy (MWH) Savings

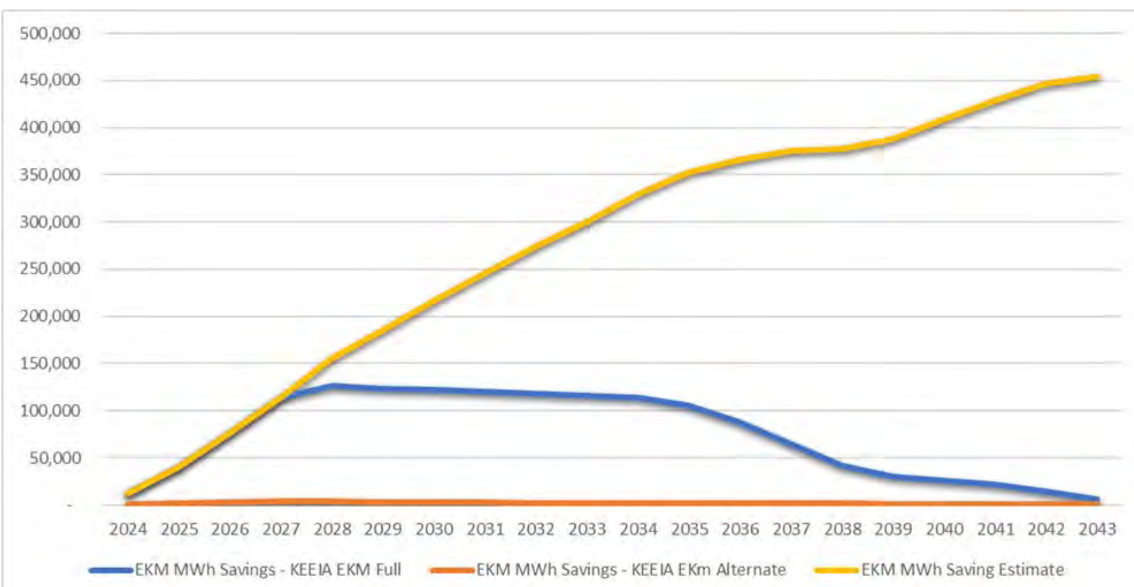


Figure 7: EKM Cumulative Annual Demand (MW) Savings

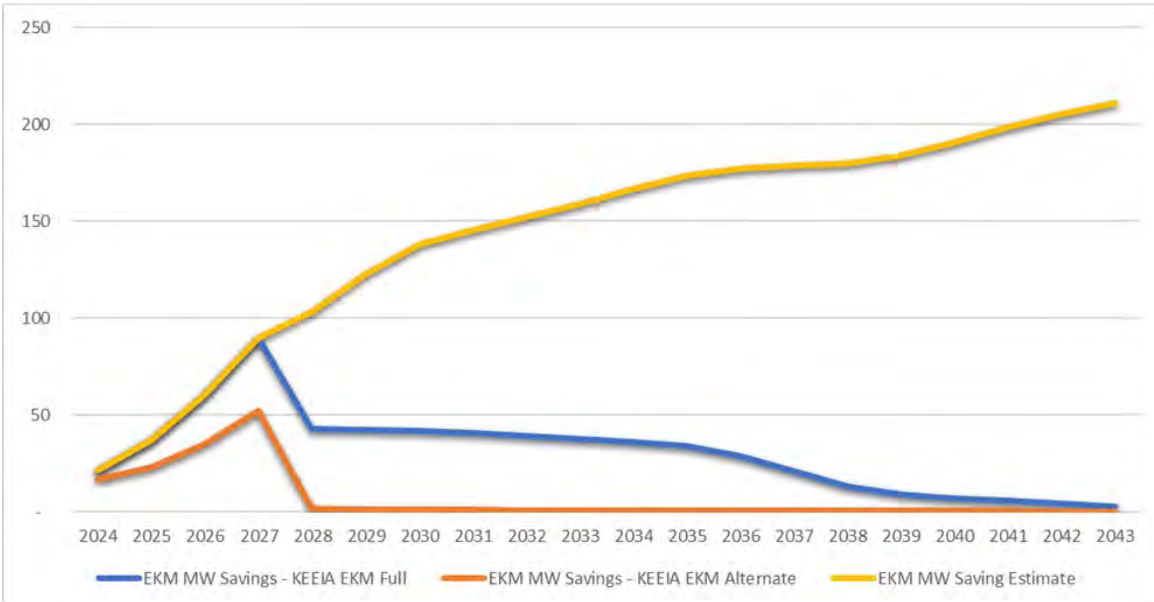


Figure 8: EKC Cumulative Annual Energy (MWH) Savings

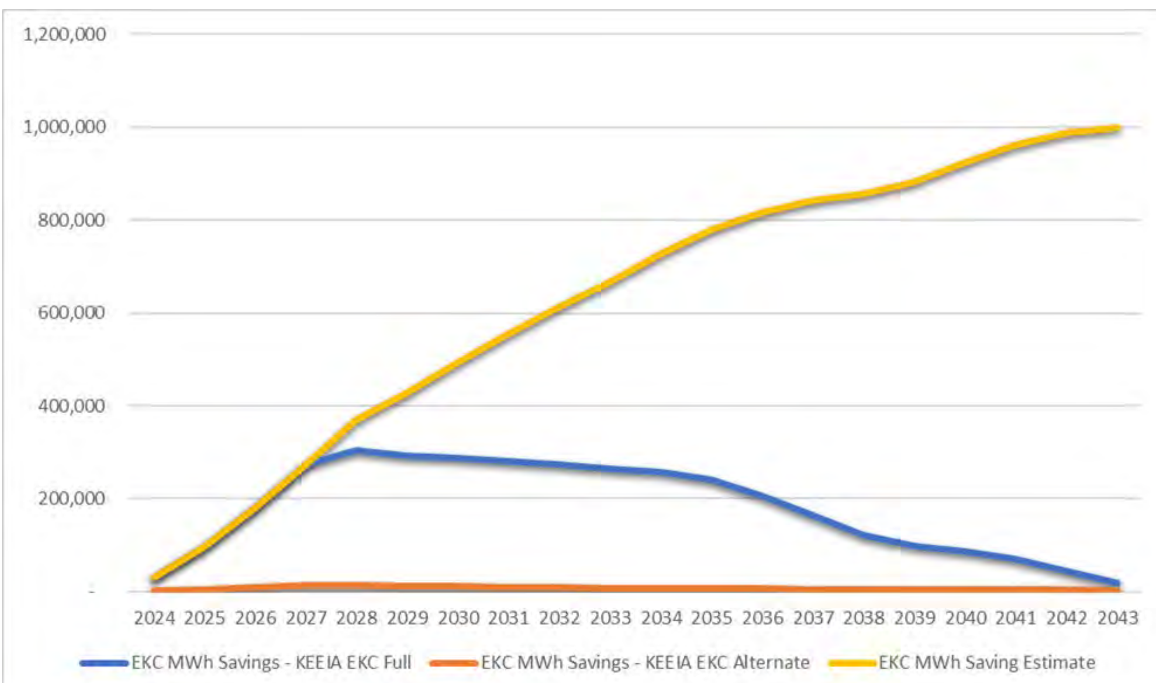


Figure 9: EKC Cumulative Annual Demand (MW) Savings

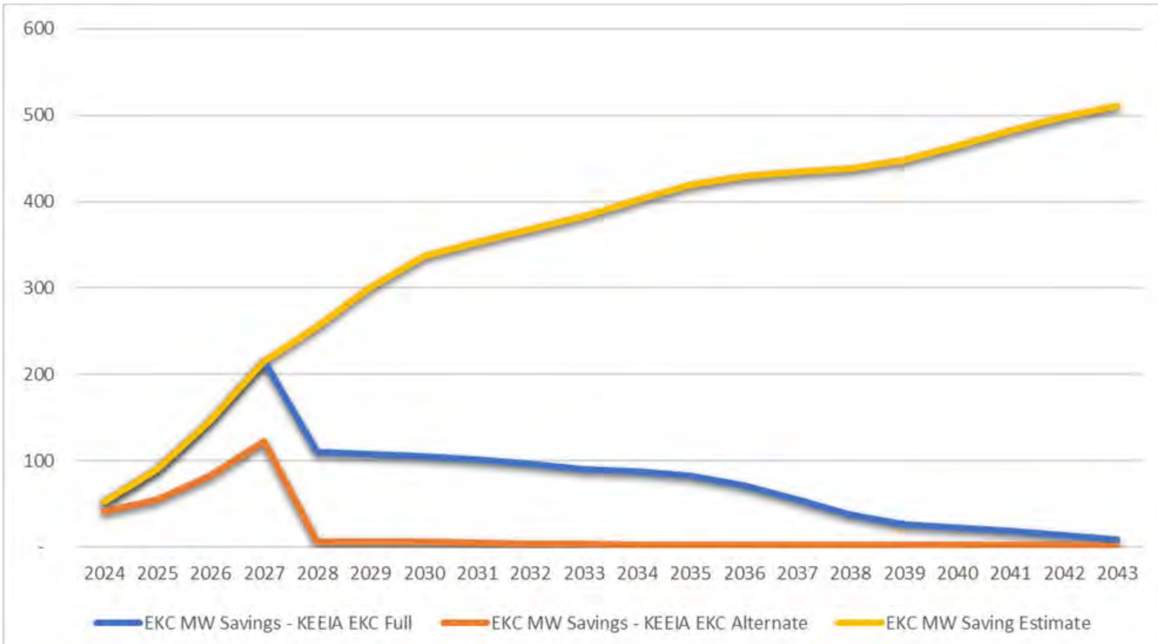


Table 10: Cumulative Energy and Demand Savings and Program Spend – Kansas Metro shows the cumulative energy and demand Savings and Program Spends for Evergy Kansas Metro in 20-year planning horizon. Table 11: Cumulative Energy and Demand Savings and Program Spend – Kansas Central shows the cumulative energy and demand Savings and Program Spends for Evergy Kansas Central in 20-year planning horizon.

Table 10: Cumulative Energy and Demand Savings and Program Spend – Kansas Metro

Year	Energy Savings (MWH)	Demand Savings (MW)	Program Spend (000's)
2024	12,517	21	$ 3,685
2025	40,651	37	$ 5,025
2026	76,025	61	$ 9,933
2027	113,416	90	$ 11,783
2028	156,041	103	$ 15,327
2029	185,312	122	$ 15,486
2030	216,568	138	$ 16,315
2031	245,422	145	$ 16,681
2032	273,647	152	$ 17,495
2033	299,988	159	$ 18,111
2034	329,017	167	$ 18,725
2035	352,239	174	$ 19,039
2036	366,237	177	$ 19,293
2037	375,511	179	$ 19,633
2038	377,378	180	$ 19,712
2039	388,564	184	$ 19,832
2040	409,141	191	$ 19,826
2041	429,311	198	$ 19,829
2042	446,691	205	$ 19,862
2043	454,462	211	$ 18,605

Table 11: Cumulative Energy and Demand Savings and Program Spend - Kansas Central

Year	Energy Savings (MWH)	Demand Savings (MW)	Program Spend (000's)
2024	29,278	53	$ 12,396
2025	94,499	90	$ 16,871
2026	180,235	147	$ 28,786
2027	273,291	216	$ 33,424
2028	368,322	255	$ 36,923
2029	428,720	300	$ 37,309
2030	493,458	337	$ 39,307
2031	553,440	353	$ 40,190
2032	612,461	368	$ 42,151
2033	666,431	383	$ 43,635
2034	727,318	401	$ 45,115
2035	779,646	419	$ 45,871
2036	816,072	430	$ 46,484
2037	843,529	435	$ 47,302
2038	855,573	439	$ 47,493
2039	882,294	449	$ 47,782
2040	924,433	465	$ 47,767
2041	961,458	482	$ 47,774
2042	988,396	498	$ 47,855
2043	998,753	511	$ 44,825

The entire Evergy 2023 DSM Market Potential Study conducted by AEG can be found in Appendix C and Appendix C1.

3.2.1 DSM POTENTIAL STUDY METHODOLOGY

Evergy engaged the Applied Energy Group (AEG) Team to conduct this Demand Side Management (DSM) Market Potential Study in 2023 for Evergy's Missouri jurisdictions. It evaluates various categories of electricity DSM resources in the residential, commercial, and industrial sectors for the years 2024-2043. The resource categories investigated are Energy Efficiency, Demand Response, and Demand-Side Rates.

The key objectives of the study are to:

- Perform a comprehensive analysis that complies with the respective statutory requirements of the Missouri Public Service Commission
- Develop annual electricity energy and peak demand potential estimates for the DSM resource categories by customer class for each Evergy jurisdiction for the time period of 2024 to 2043
- Develop baseline projections of annual electricity use and peak demand for each Evergy jurisdiction, accounting for future codes and standards, naturally occurring energy efficiency, opt-out customers, and smart connected devices
- Identify a subset of economic and program potential that is applicable to low-income customers
- Conduct a reliable, accurate and useful residential appliance saturation survey
- Quantify potential program savings from the DSM initiatives at various levels of cost
- Support Evergy's effort to offer programs to all customer market segments while achieving the ultimate goal of all cost-effective demand-side savings

The study assesses various tiers of potential including technical, economic, maximum achievable, and realistic achievable potential. Based on the RAP and MAP potential scenario results from the DSM Potential Study, AEG developed four scenarios for energy efficiency portfolio comprised of cost-effective measures. AEG also developed six scenarios for Demand Response and Demand - Side Rates portfolio to reflect the Commission's new TOU rate case order for the Missouri residents. These portfolios were considered during the integration phase of Evergy's IRP process to determine which DSM portfolio was optimal based on Evergy's supply options.

As part of the study, AEG conducted an appliance saturation analysis to collect a variety of appliance and end-use data from Residential customers across all of Evergy's service territories in Missouri and Kansas. The Residential Appliance Saturation Study (RASS) portion of the study and results can be found in "Exhibit A" of Evergy 2023 DSM Market Potential Study.

The entire Evergy 2023 IRP DSM Analysis conducted by AEG can be found Appendix C and confidential avoided costs in Appendix C1.

The next three tables show the descriptions for all scenarios.

Table 12: Scenarios Descriptions - Energy Efficiency Portfolio

Scenario	Participation Assumptions	Incentive Assumptions	Non-incentives
RAP	Participation directly pulled from incremental purchases in the Realistic Achievable Potential scenario in the Potential Study.	Incentive developed based on incremental costs from the Potential Study. Incentives assumed to be 50% of incremental costs (except Low Income which is 100%).	Non-incentives developed based on the incentive levels and benchmarked factors of Evergy 2021 actual spending and/or similar programs from other utilities.
MAP	Participation directly pulled from incremental purchases in the Maximum Achievable Potential scenario in the Potential Study.	Incentive developed based on incremental costs from the Potential Study. Incentives assumed to be 100% of incremental costs.	
RAP -	Participation represents 75% of the RAP levels.	Incentive developed based on incremental costs from the Potential Study. Incentives assumed to be 50% of incremental costs (except Low Income which is 100%).	
RAP +	Participation represents the median levels between the RAP and MAP participation.	Incentive developed based on incremental costs from the Potential Study. Incentives assumed to be 50% of incremental costs	

Table 13: Scenarios Descriptions - Demand Response and Demand - Side Rates Portfolio – MAP

Baseline (Base load)	Scenario	Assumptions	TOU Impact	DR/DSR Impact
All DR/DSR MAP Scenarios incorporate the EE MAP annual peak savings as a negative adjustment to Basliene MW. Because the EE savings in MAP are larger than RAP the MAP scenario reduces baseline MW more, leaving less potential for DR/DSR.	**MAP High-Retention**	Industry best practice participation and impacts across new DR programs, incremental growth in existing programs, highest possible retention on the default TOU (Standard) rate.	Highest TOU impact and reduction in total MW across MAP scenarios. This reduces potential for other DR/DSR programs.	Lowest DR/DSR impacts across all MAP scenarios because TOU and EE have the highest impacts on potential and lead to the lowest peak demand available for remaining programs to impact.
	MAP Medium Retention	Industry best practice participation and impacts across new DR programs, incremental growth in existing programs, medium level of retention on the default TOU (Standard) rate.	Medium TOU impact and reduction in total MW. This reduces potential for other DR/DSR programs (but by less than the High retention scenarios).	Higher DR/DSR impacts than the MAP High-Retention Scenario because TOU impacts on potential are lower and lead to more peak demand available for remaining programs to impact. EE impacts on potential remain the same across all MAP scenarios.
	MAP Low Retention	Industry best practice participation and impacts across new DR programs, incremental growth in existing programs, low of retention on the default TOU (Standard) rate.	Lowest TOU impact and reduction in total MW across MAP scenarios. This reduces potential for other DR/DSR programs (but by less than the Medium or High retention scenarios).	Highest DR/DSR impacts than the MAP Medium- and High-Retention scenarios because TOU impacts on potential are lowest and lead to the most peak demand available for remaining programs to impact. EE impacts on potential remain the same across all MAP scenarios.

Table 14: Scenarios Descriptions - Demand Response and Demand - Side Rates Portfolio – RAP

Baseline (Base load)	Scenario	Assumptions	TOU Impact	DR/DSR Impact
The DR/DSR RAP scenario similarly incorporates the EE RAP annual peak savings. RAP impacts from EE are lower than MAP impacts form EE and restrict potential less.	**RAP Low Retention**	Industry best practice participation and impacts across new DR programs, limited growth in existing programs, low of retention on the default TOU (Standard) rate, and assumption of a four-year learning curve to respond to the rate.	Same TOU retention as the MAP Low Retention scenario, but lower TOU impact in the early years due to a TOU-response learning curve, and slightly higher impacts in the out years because the RAP baseline is higher than the MAP baseline.	Similar DR/DSR impacts as the MAP Low-Retention Scenario because TOU impacts on potential are lowest and lead to the most peak demand available for remaining programs to impact. EE impacts on potential are smaller in RAP scenarios than MAP scenario. Slightly lower DR/DSR impacts than MAP because of limited growth in existing programs.
The DR/DSR RAP scenario similarly incorporates the EE RAP annual peak savings. RAP impacts from EE are lower than MAP impacts form EE and restrict potential less.	**RAP Plus**	Industry best practice impacts and 10% increase in participation from RAP across all DR/DSR programs, low of retention on the default TOU (Standard) rate, and assumption of a four-year learning curve to respond to the rate.	Same TOU retention and TOU impacts as the RAP Low Retention Scenario.	Higher DR/DSR impacts across all RAP and MAP scenarios because participation increased by 10% (excluding TOU) and TOU and EE have the lowest impact on potential, lead to the most peak demand available for remaining programs to impact.
The DR/DSR RAP scenario similarly incorporates the EE RAP annual peak savings. RAP impacts from EE are lower than MAP impacts form EE and restrict potential less.	**RAP Minus**	Industry best practice impacts and 15% decrease in participation from RAP across all DR/DSR programs, a 15% decrease in the low of retention rate on the default TOU (Standard) rate, and assumption of a four-year learning curve to respond to the rate.	Lowest TOU impacts across all scenarios because of a 15% decrease in the default TOU retention rate. TOU impacts are lowest in the early years due to a TOU-response learning curve.	Lowest DR/DSR impacts across all RAP and MAP scenarios because participation decreased by 15% (including TOU retention on the deafult rate).

SECTION 4: SUPPLY-SIDE RESOURCE ANALYSIS UPDATE

4.1 MARKET CONDITIONS AND FUTURE OUTLOOK

Evergy considers current and future market conditions in developing its 20-year forward looking forecasts for the IRP. Starting with the 2022 IRP Annual Update, Evergy contracted with 1898&Co. to produce 20-year market price forecasts using SPP's transmission planning models as a baseline.

SPP conducts the integrated transmission planning process (ITP) on an annual basis, to assess reliability and economic transmission needs up to 10 years in the future. Every five years, SPP also performs a 20-year assessment. To perform these transmission assessments, SPP develops different future resource mix scenarios based on stakeholder feedback, including utility IRP plans. These resource mix assumptions, which include retirements or continued operation of existing resources and additions of new resources, enable the models to predict future economic dispatch of the system, transmission congestion, and resulting price differentials between load and resources.

For the 2023 IRP Annual Update, 1898&Co. used the most recent ITP models to produce market prices using Evergy's load and fuel price assumptions, including high, mid, and low natural gas price scenarios. The most recent ITP included forecasting models for years 2, 5, 10 and 20.

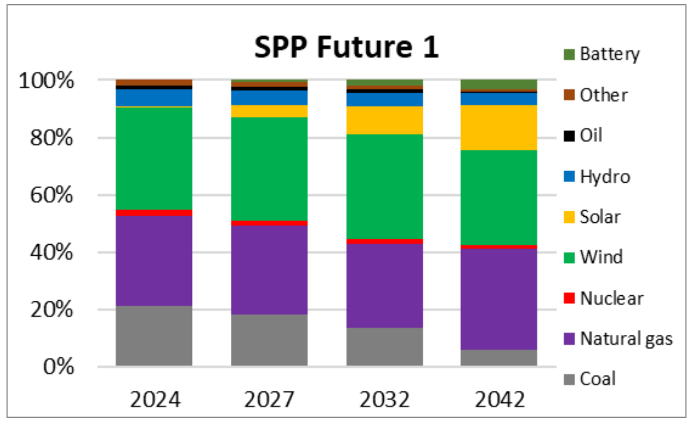
4.1.1 OVERVIEW OF SPP ITP FUTURES

The SPP Future 1 case represents a "business as usual" case with longer retention of existing resources, assuming by 2042 coal resources 56 years and older as well as natural gas and oil generators 50 years and older will retire. The 2024 planning model reflects near-term transmission upgrades and resource additions and is the same for all Futures described.

Figure 10: SPP Future 1 Overview

SPP Future 1				
Resource	2024	2027	2032	2042
Coal	21%	18%	14%	6%
Natural gas	31%	31%	29%	35%
Nuclear	2%	2%	2%	1%
Wind	35%	36%	36%	33%
Solar	1%	4%	10%	16%
Hydro	6%	5%	5%	4%
Oil	2%	1%	1%	0%
Other	2%	1%	1%	1%
Battery	0%	1%	2%	3%

Source: 1898&Co.

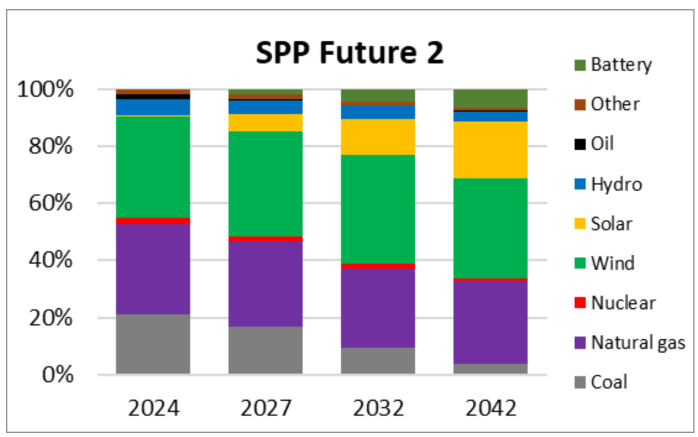


The SPP Future 2 case is an emerging technologies scenario, incorporating growth of electric vehicles and distributed generation as well as higher penetration of renewables and earlier retirement of existing generation. The ages for retirements are reduced to 52 years for coal units and 48 years for natural gas and oil units. Solar and battery resources account for a larger portion of 2042 capacity.

Figure 11: SPP Future 2 Overview

SPP Future 2				
Resource	2024	2027	2032	2042
Coal	21%	17%	9%	4%
Natural gas	31%	30%	28%	29%
Nuclear	2%	2%	2%	1%
Wind	35%	36%	38%	35%
Solar	1%	6%	13%	20%
Hydro	6%	5%	4%	4%
Oil	2%	0%	0%	0%
Other	2%	1%	1%	1%
Battery	0%	2%	4%	7%

Source: 1898&Co.

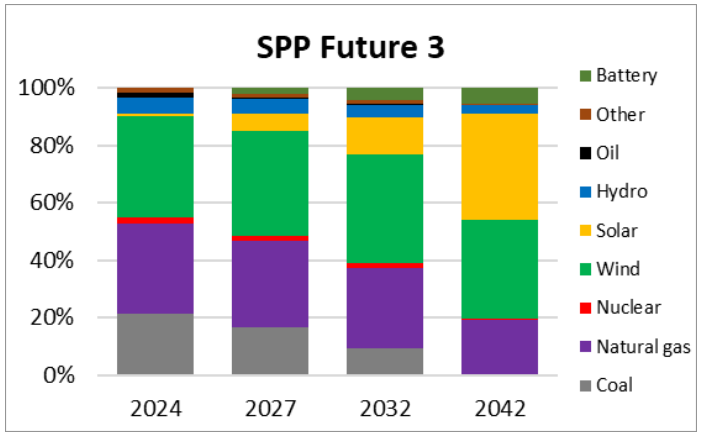


The SPP Future 3 case models accelerated decarbonization. All coal and oil resources are retired by 2042 and new resource build is driven by targeted emissions reductions of approximately 95% from 2017 by 2042, leading to much higher reliance on solar. Future 3 is only modeled for 2042, so years 5 and 10 (2027 and 2032) reflect Future 2 models.

Figure 12: SPP Future 3 Overview

SPP Future 3				
Resource	2024	2027	2032	2042
Coal	21%	17%	9%	0%
Natural gas	31%	30%	28%	19%
Nuclear	2%	2%	2%	1%
Wind	35%	36%	38%	34%
Solar	1%	6%	13%	37%
Hydro	6%	5%	4%	3%
Oil	2%	0%	0%	0%
Other	2%	1%	1%	1%
Battery	0%	2%	4%	5%

Source: 1898&Co.



The Evergy market price forecasts for the 2023 IRP use a combination of the SPP Futures models. Evergy believes that Future 2 is the most representative forecast considering the recent pace of resource additions in SPP, interconnection queue activity and utility resource plans. However, the IRP also uses market prices from Future 3 to forecast a potential future with more stringent carbon regulation. Evergy believes this Future 3 scenario is particularly informative given the EPA's recently proposed Greenhouse Gas rules, which would drive a similarly aggressive pace of decarbonization.

4.1.2 PRICING ENDPOINTS

Consistent with the 2021 Triennial IRP, Evergy identified natural gas prices and carbon emissions policy as the critical factors to include in its market price forecasts. Nine price series were developed using combinations of high, mid, low natural gas price forecasts and high, mid, and low (no) carbon restriction scenarios. The natural gas forecasts and carbon emissions policy forecasts were updated as explained in later sections. Evergy did not change the 2023 IRP probabilities for each natural gas – carbon emissions policy scenario from the 2021 and 2022 IRPs.

Table 15: Market Pricing Endpoints and Probabilities

Endpoint	NG Price Forecast	Future	Carbon Restriction	Probability
H3C	High	Future 3	Future 3	3%
H2C	High	Future 2	H2C Model	9%
H2N	High	Future 2	None	3%
M3C	Mid	Future 3	Future 3	10%
M2C	Mid	Future 2	M2C Model	30%
M2N	Mid	Future 2	None	10%
L3C	Low	Future 3	Future 3	7%
L2C	Low	Future 2	L2C Model	21%
L2N	Low	Future 2	None	7%

Evergy also did not change the probabilities for load forecast endpoints compared to the 2022 Annual Update. As a result, the overall endpoint probabilities used for Integrated Analysis are the same as those used in the 2022 Annual Update:

Table 16: Critical Uncertain Factor Probability Distribution

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

Table 17: 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%

4.1.3 NATURAL GAS PRICES

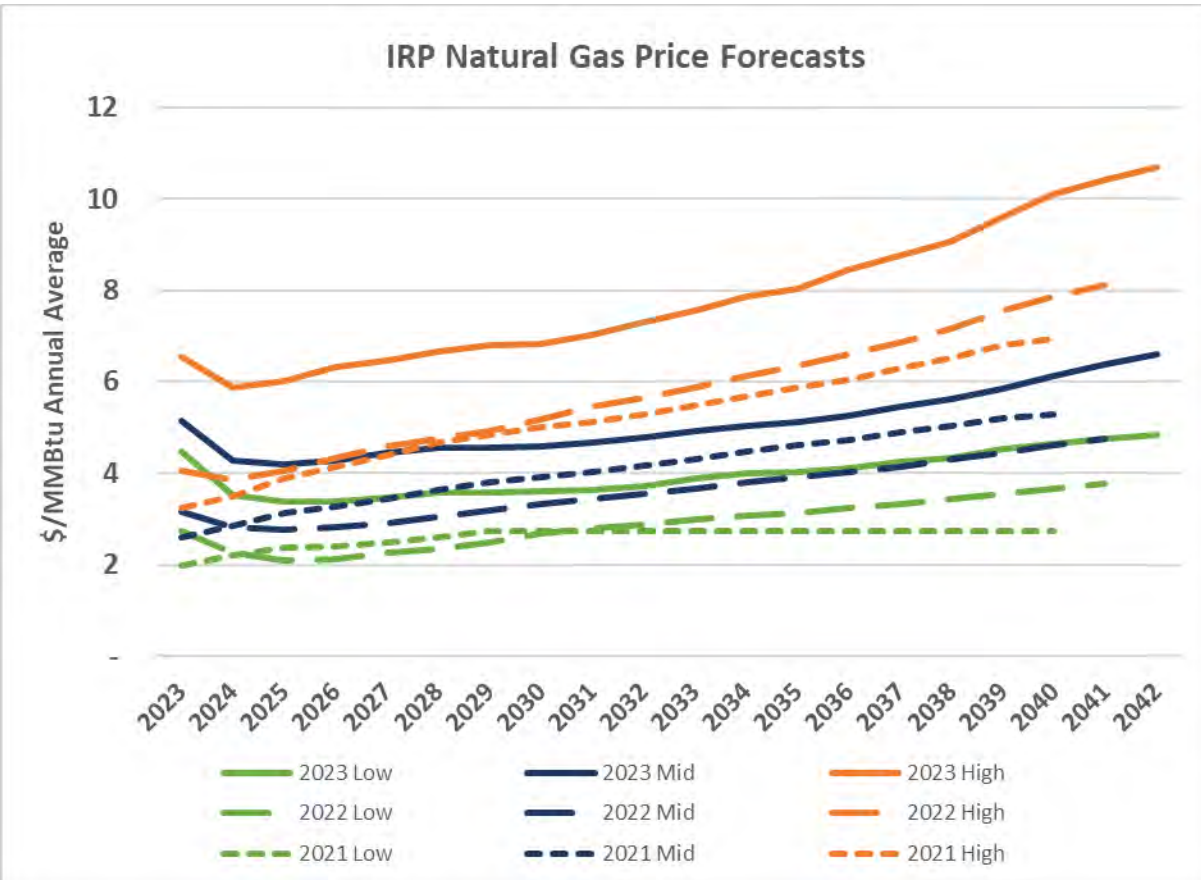
Natural gas forecast prices increased for the 2023 IRP in comparison with previous forecasts.

Evergy updates the IRP natural gas forecast annually based on the forecast used for internal budgeting, which is developed from vendor forecasts and forward markets. Last year, in response to Evergy's 2022 IRP filings, stakeholders noted a disconnect between the volatile and higher natural gas prices seen in the markets in late 2021 and early 2022 and the lower long term forecast prices in the IRP. The 2023 forecast reflects higher natural gas prices. Natural gas prices have been affected by the Ukraine War, supply chain pressures, global demand, and inflation. While future natural gas prices are uncertain, there are fundamental factors supporting the higher forecast including higher breakeven production costs, producer discipline, and increased global demand despite current lower natural gas prices compared to last year.

The high and low forecasts were developed by using the mid forecast and scaling it based on the fundamental supply and demand forecasts in the EIA Annual Energy Outlook model. The EIA builds its forecasts considering a variety of factors, including current laws and regulations, current assessments of economic and demographic trends, technology improvements, compounded annual economic growth, oil and natural gas supply and demand, and renewable energy cost cases. Key drivers for US natural gas production volumes include EIA's outlook on international prices and US LNG exports, as well as technology assumptions. Evergy used the "High Oil and Gas Supply" to calculate the low natural gas price forecast, and the "Low Oil and Gas Supply" for the high natural gas price forecast.

This method was used beginning in the 2022 IRP to derive a wider range of prices based on changes in fundamental assumptions. For the 2021 IRP, the high and low forecasts were derived statistically from the range of vendor forecasts, with the low forecast capped at the five-year historical average.

Figure 13: IRP Natural Gas Price Forecast Comparison



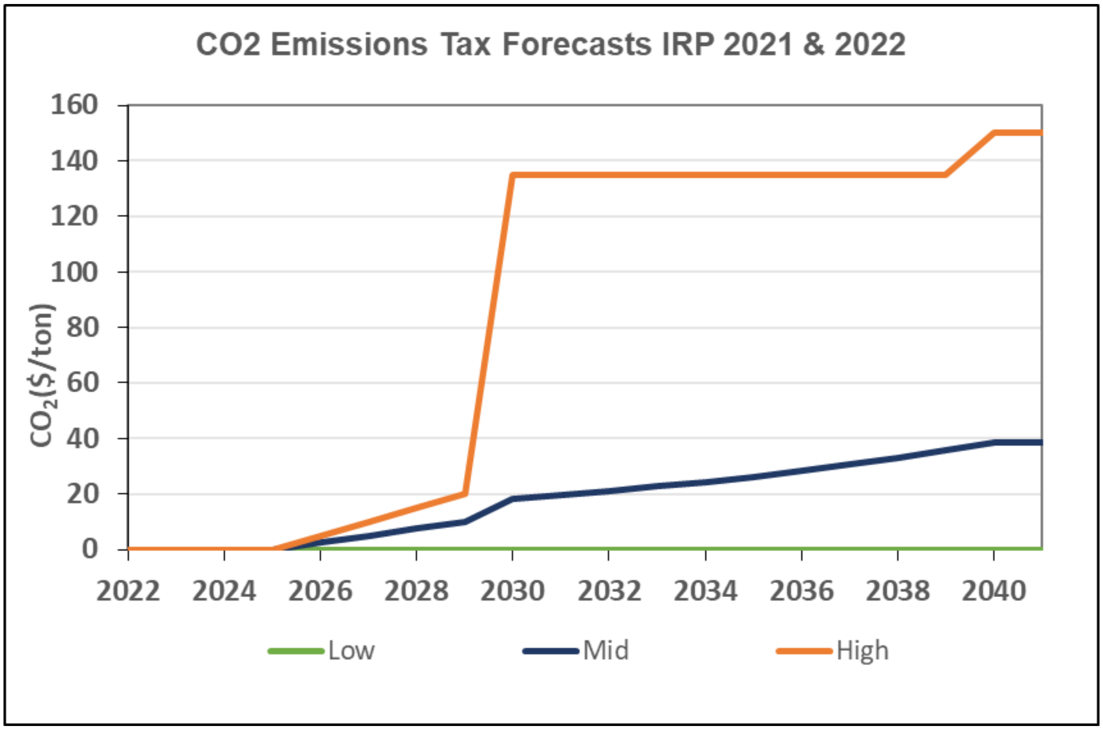
The 2023 IRP natural gas forecasts reflected in the above charts are based on forecasts provided by these third-party sources:

- IHS Markit
- Energy Information Administration
- S&P Global Platts
- Energy Ventures Analysis
- CME Futures
- ICE

4.1.4 CARBON RESTRICTIONS

Since the 2021 Triennial IRP, Evergy has modeled three levels of potential future carbon emissions policies. For the 2021 and 2022 IRPs, the policies were modeled as a carbon emission tax, while for the 2023 IRP they were modeled with both restrictions on carbon emissions production and carbon emissions taxes.

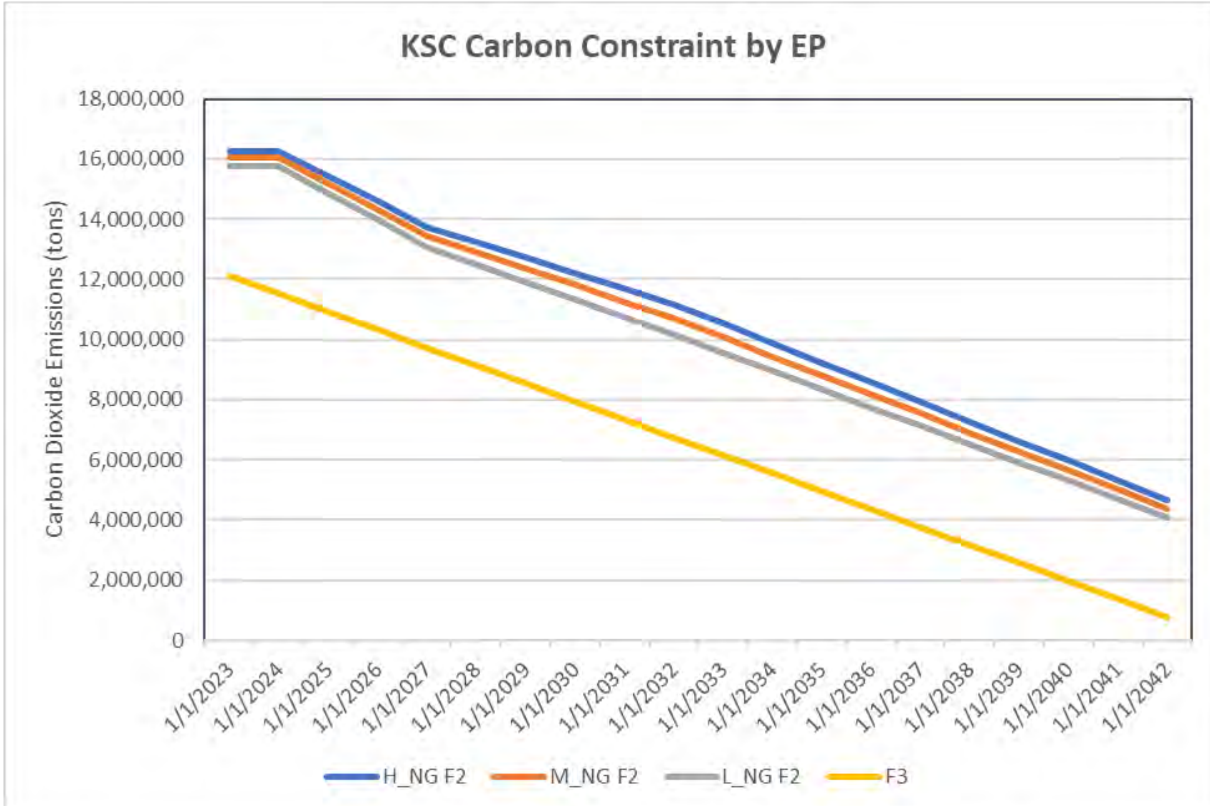
Figure 14: Carbon Tax Forecasts IRP 2021 & 2022



For the 2023 IRP, Evergy modeled carbon restrictions using assumptions built into the SPP futures models, aligning emissions reduction scenarios with market forecast expectations. Evergy discontinued using vendor carbon tax forecasts. Vendor forecasts were no longer available or were outdated considering the current administration and recent policy actions. In addition, Evergy currently expects future carbon policies to be in the form of incentives (such as those in the IRA), or requirements for physical emissions reductions, rather than carbon taxes.

The low forecast for the 2023 IRP has no emissions restrictions with market prices developed using the Future 2 pricing model. The mid forecast uses the same market price forecast, but employs a carbon emissions restriction consistent with the dispatch solution of the pricing model. The CO_2 production constraint mirrors Evergy's anticipated emission levels within the SPP market (e.g., if the dispatch in the pricing model produced a 70% reduction in Evergy Metro's carbon emissions in 2042, the carbon restriction applied in the IRP dispatch model for 2042 is 70%). The high forecast is consistent with the assumptions in the SPP Future 3 model which was engineered with an explicit carbon reduction goal of an approximately 95% reduction in CO_2 production from 2017 levels. Evergy used the same logic to ratably restrict emissions from historic 2017 CO_2 production levels to culminate 2042 with a 95% reduction. The high forecast also incorporates a carbon tax which ramps to $25/ton by the end of the twenty-year horizon, consistent with Future 3.

Figure 15: Kansas Central Carbon Constraint by Endpoint [1]



[1] H_NG F2: High Natural Gas, Mid Carbon restriction; M_NG F2: Mid Nat Gas, Mid Carbon; L_NG F2: Low Nat Gas, Mid Carbon; F3: High Carbon Restriction (applies in all gas price scenarios)

Figure 16: Evergy Metro Carbon Constraint by Endpoint

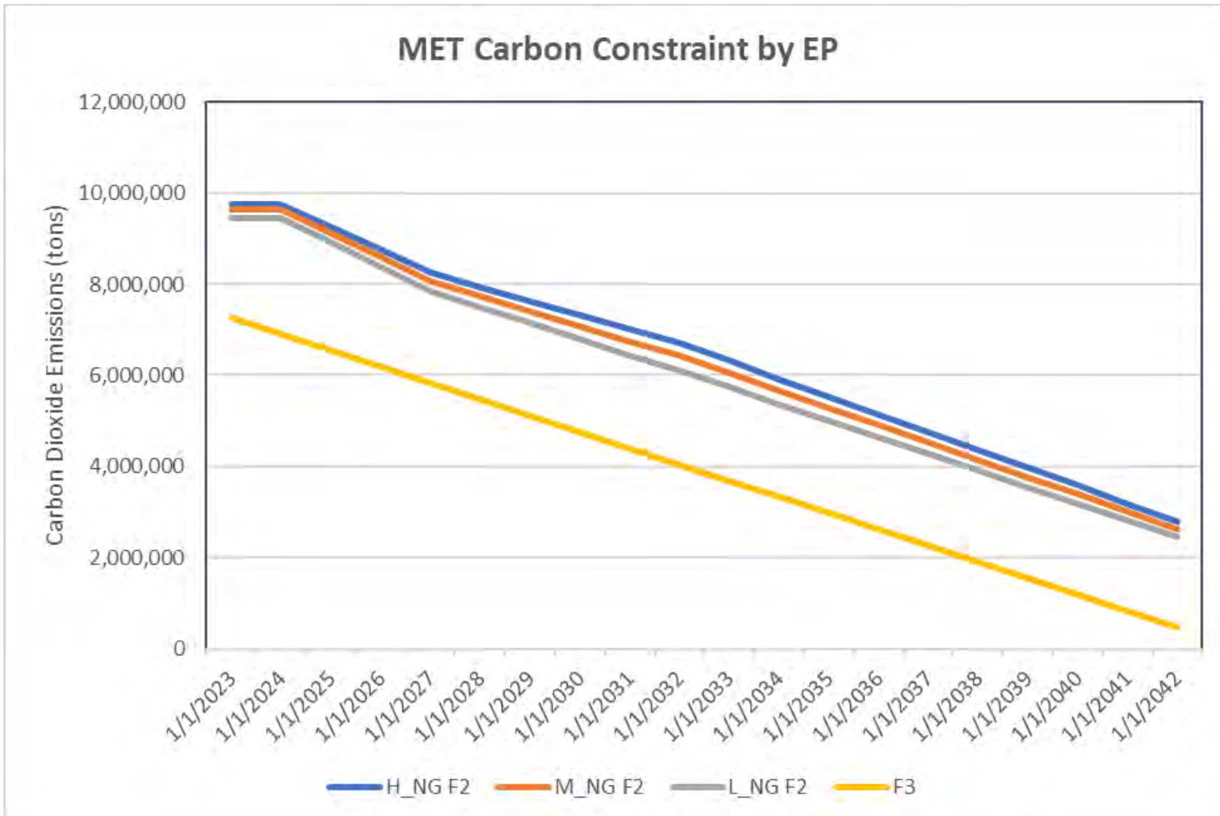


Table 18: Future 3 Carbon Tax ($/ton)

	Price
2023	0
2024	0
2025	0
2026	0
2027	0
2028	0
2029	0
2030	0
2031	0
2032	0
2033	2.5
2034	5
2035	7.5
2036	10
2037	12.5
2038	15
2039	17.5
2040	20
2041	22.5
2042	25

In order to achieve SPP Future 3 emissions goals, breakthroughs would be needed in dispatchable carbon-emissions-free technology. Newer combined cycles and combustion turbines are engineered to burn cleaner fuels including hydrogen or ammonia blends. However, refining and transport of these fuels is still cost prohibitive. Improvements in carbon capture and sequestration technologies are another option for reducing or eliminating emissions. US government subsidies are encouraging innovation in these areas. Because achieving Future 3 would be unlikely based on current technology, new combined cycles and combustion turbines were assumed to have zero emissions beginning in 2036 for Future 3 models, representing the necessary technological breakthroughs. Additionally, carbon-free energy was assumed to be available in all models for $300/MWh in case the fleet was unable to generate enough energy, or carbon-free energy to serve load. This price point is based on the current typical price of fuel oil-fired peaking units which, although clearly not representative of actual carbon-free energy, provides a “scarcity price” proxy for the cases when Evergy is unable to meet its own load.

4.1.5 CONGESTION AND NODAL PRICES

Since the 2022 IRP Annual Update, Evergy has incorporated transmission congestion in its modeling by using market prices at different nodes/zones within the SPP system. The 2021 Triennial IRP used a single market clearing price for all load and resources but included some dispatch adjustments to align resource capacity factors with historical averages.

The 2023 IRP pricing models, based on the SPP ITP models, reflect current transmission topology and near-term transmission upgrades. The models use economic dispatch, considering transmission limits, to calculate nodal pricing. The 2022 and 2023 IRP both used pricing at the following locations:

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

Because these models are used to identify future transmission needs, congestion tends to increase in future model years as new resources are assumed without corresponding transmission upgrades that might improve their economic deliverability to load. The base models are likely to overestimate future congestion, however future transmission upgrades are uncertain. The long-term transmission planning processes attempt to identify and select beneficial transmission projects that can reduce the total costs to serve load. Development of new resources may exacerbate congestion, but it can take time for potential savings to reach a tipping point where transmission becomes cost effective. Lags in planning and uncertainty around the timing and viability of new resource additions can also delay new transmission investment. Given the significant build-out of renewable resources between 2032 and 2042, which is not accompanied by enabling transmission investment and thus results in a significant increase in congestion in the "base" SPP model, Evergy assumes congestion is held constant over this second decade of the planning horizon.

The new SPP ITP models, used for the 2023 IRP pricing, reflect increased congestion, particularly in the western part of Evergy's footprint.

Figure 17: Kansas Central Average Annual Prices for Nodes in 2023 IRP Mid NG Future 2

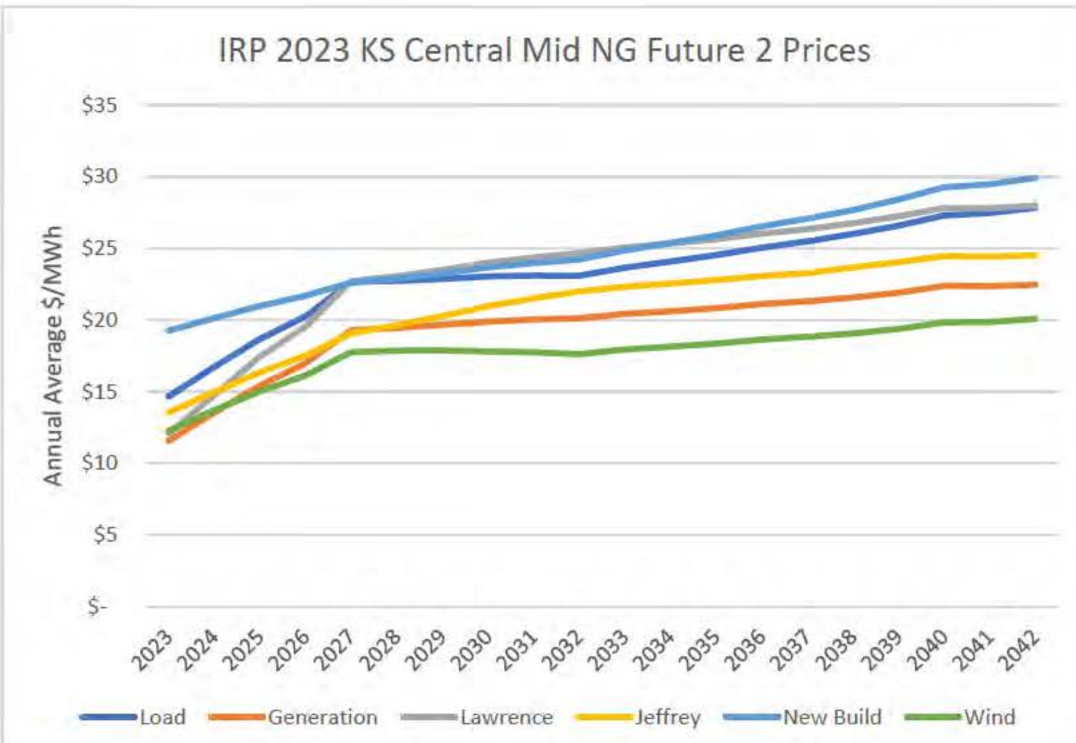
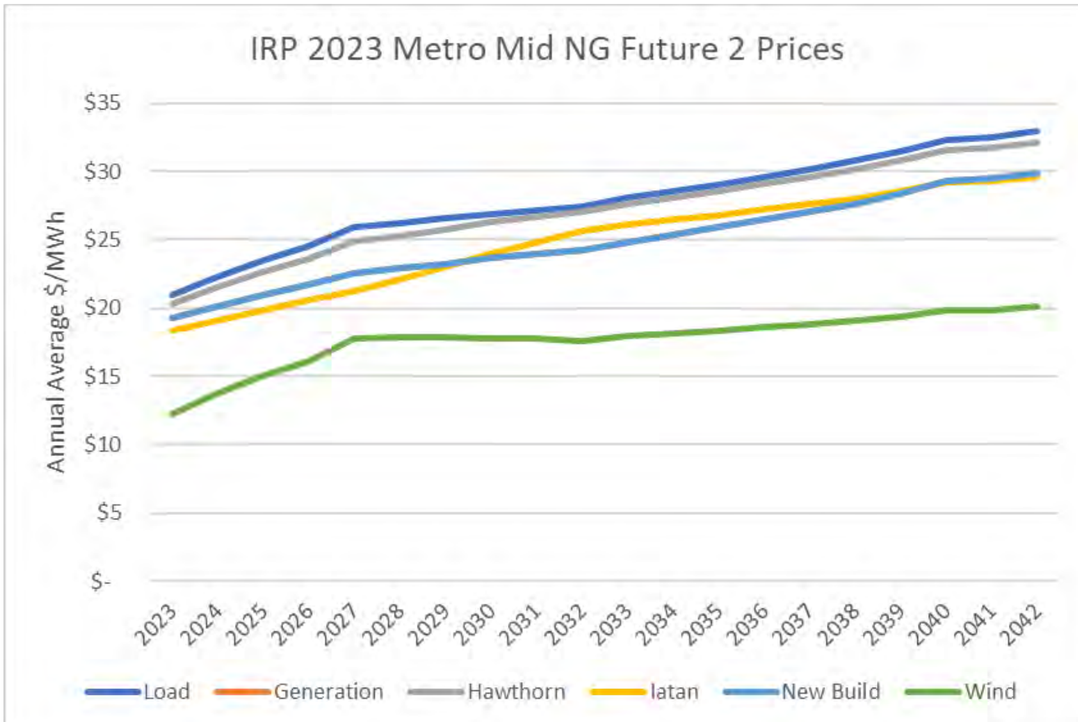


Figure 18: Metro Average Annual Prices for Nodes in 2023 IRP Mid NG Future 2



Note: "New Build" node is equivalent to Metro Generation load. As a result, Metro generation is not visible on chart

Future 3, used for the high carbon restriction scenarios in IRP 2023 predicts a decreasing price future, as resource additions continue to have fixed costs, but no production costs. Market prices are driven down by a high penetration of zero cost renewable resources, that may also have production tax credits, making their marginal production cost negative.

Figure 19: Average Annual Prices for Kansas Central Nodes in 2023 IRP Mid NG Future 3

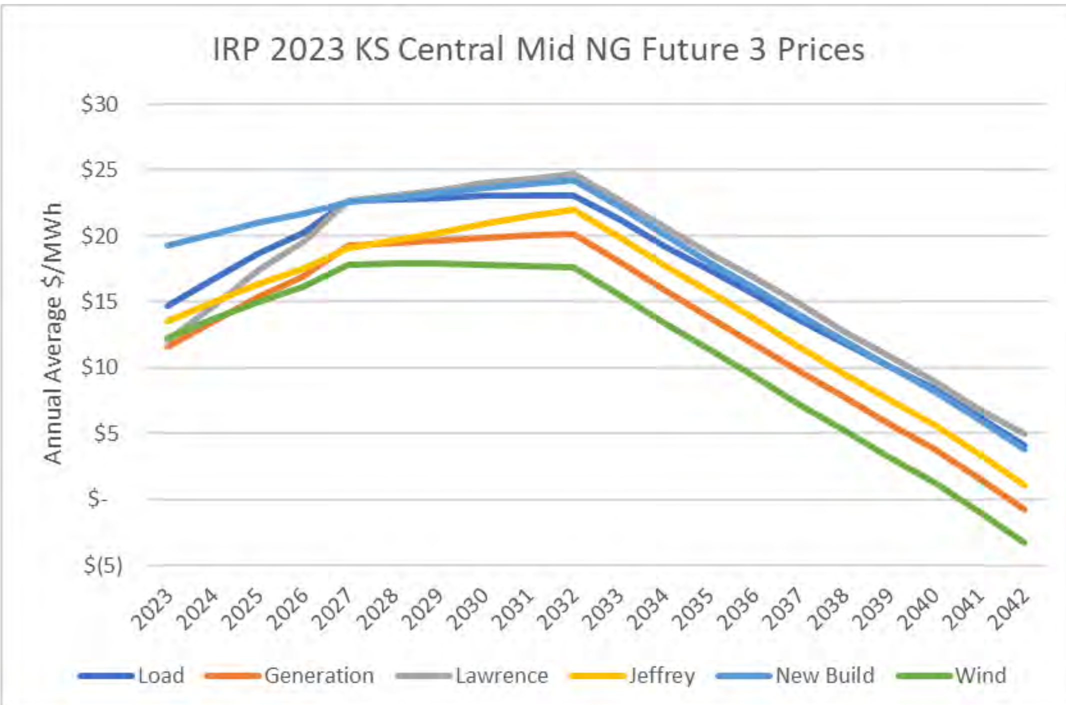
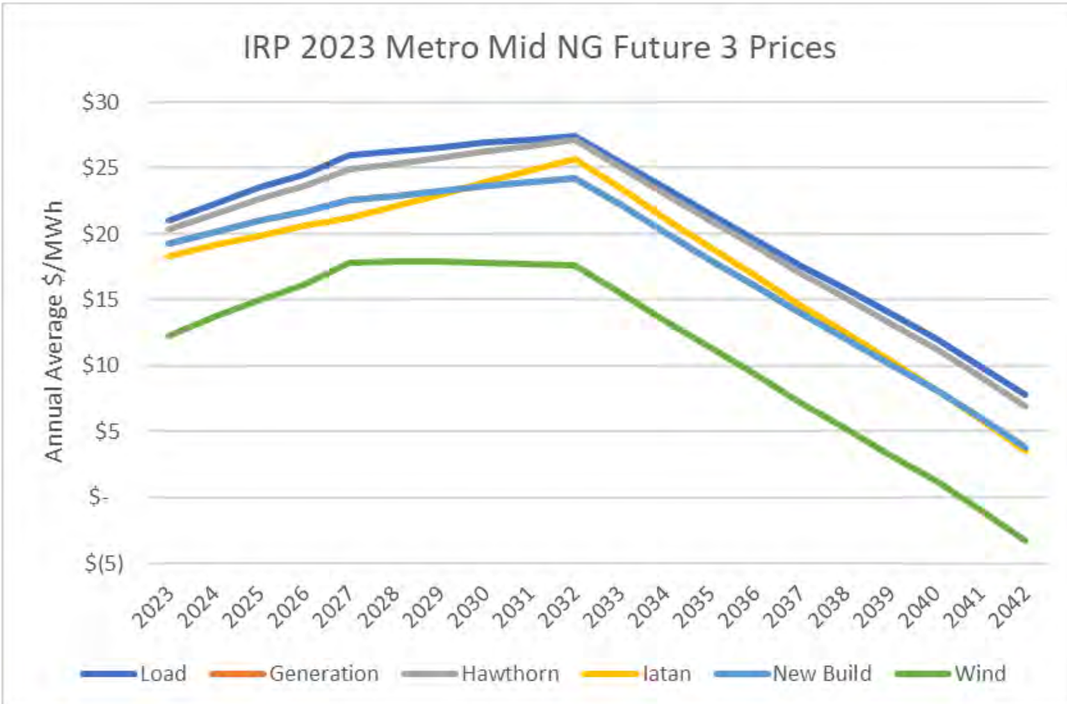


Figure 20: Average Annual Prices for Metro Nodes in 2023 IRP Mid NG Future 3

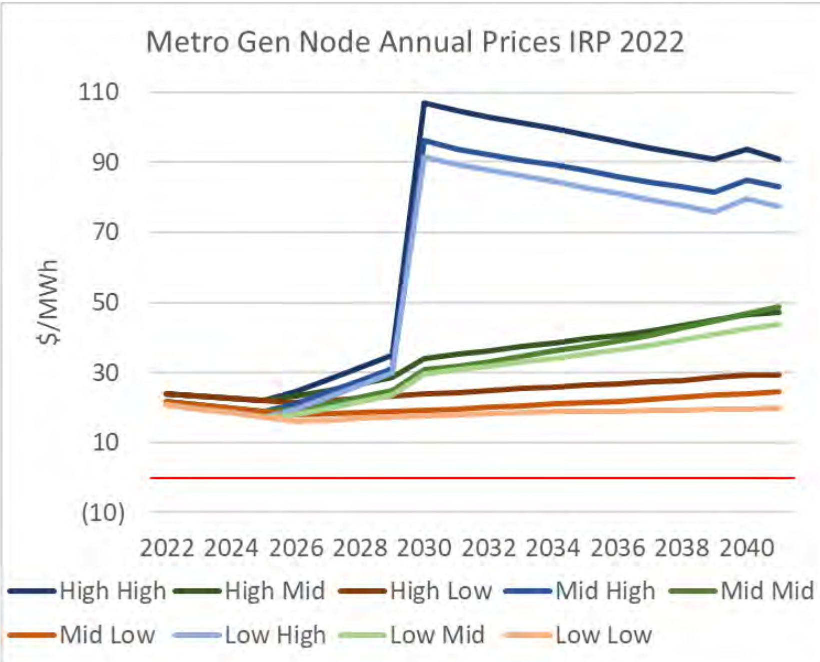


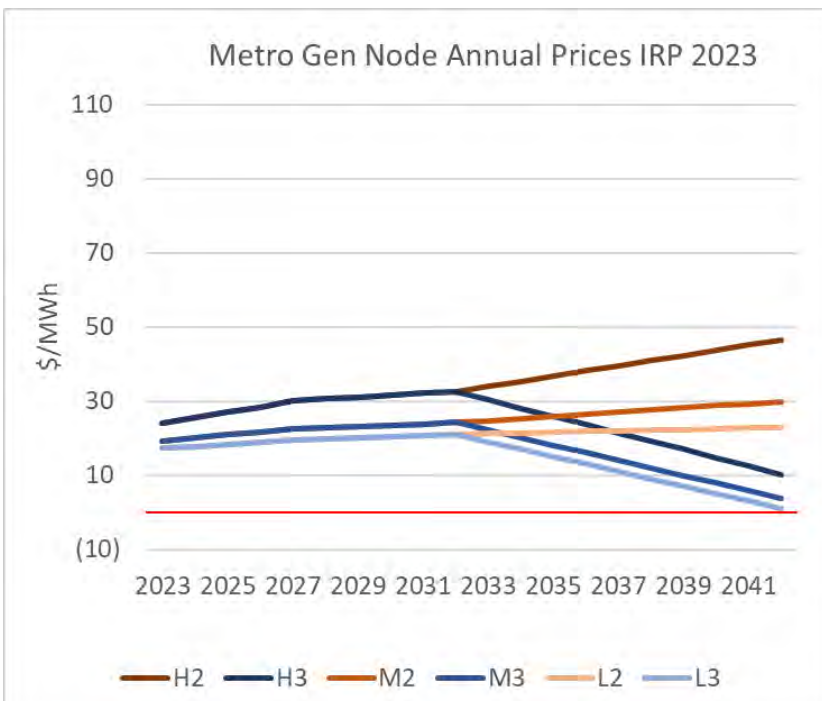
Note: "New Build" node is equivalent to Metro Generation load. As a result, Metro generation is not visible on chart.

Prices are also generally lower than prices in the 2021 and 2022 IRPs due to higher expected renewable penetration in the future resource mix. Prices in the 2021 and 2022 IRPs also reflected explicit carbon emissions taxes for the mid and high carbon scenarios which resulting in higher production costs and higher market prices. The change in planning assumption to a carbon restriction results in lower prices as the tax no longer impacts production costs.

Figure 21: 2022 IRP and 2023 IRP Market Price Comparison

Note: Evergy Metro Generation Node is used in the graphs below for comparison purposes as a relatively "average" pricing node

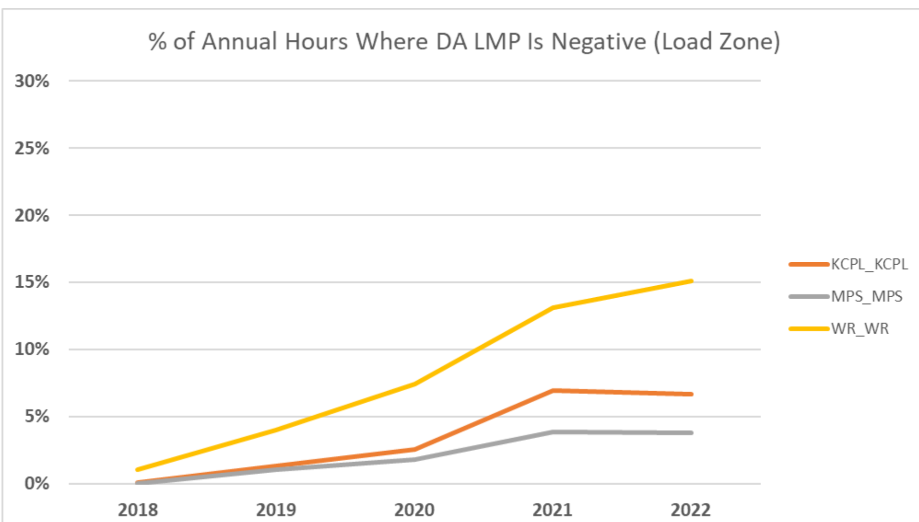




4.1.6 NEGATIVE PRICES

The 2023 market price forecasts reflect the negative pricing that has been observed in SPP and predict that the number of negative-priced hours in SPP will continue to grow. When Evergy began using SPP ITP models for its pricing forecast in the 2022 IRP, it also introduced negative pricing into the IRP analysis. The previous software, used for the 2021 Triennial IRP and prior IRPs did not calculate negative prices. The 2022 IRP price forecasts had a small percentage of negative prices, which was consistent with the modeling assumptions in the most current version of the SPP ITP model available, which had slightly dated assumptions given the pace of change in SPP resource additions. The 2023 market price forecasts have the most up-to-date planning assumptions and align more closely with recent SPP experience.

Figure 22: Actual Day Ahead Negative Prices at Load



KCPL_KCPL: Metro

MPS_MPS: Missouri West

WR_WR: Kansas Central

Figure 23: 2023 IRP Modeled Negative Prices at Kansas Central Load

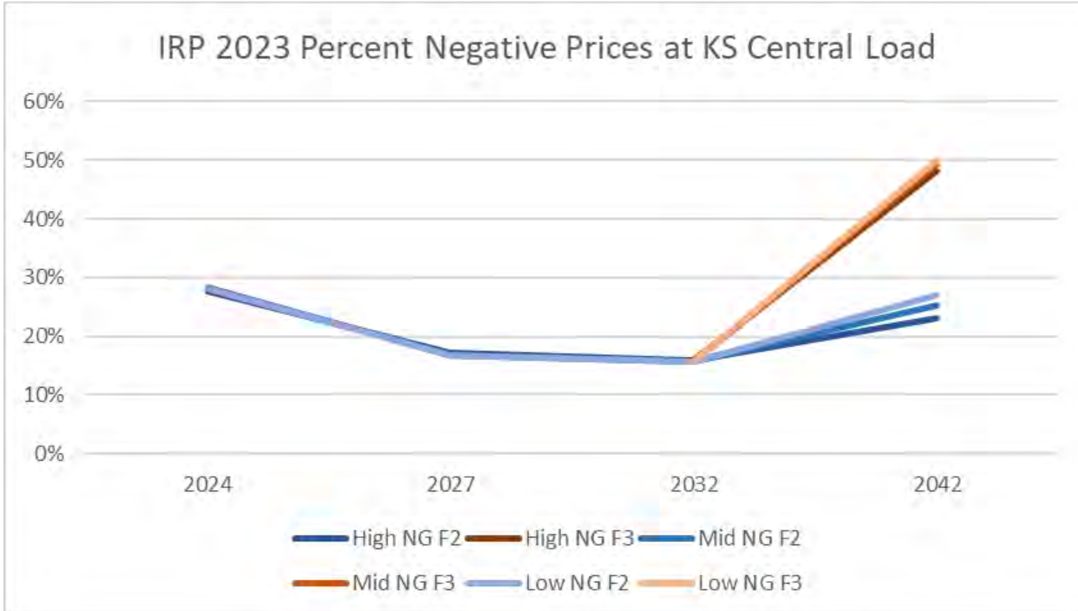


Figure 24: 2023 IRP Modeled Negative Prices at Metro Load

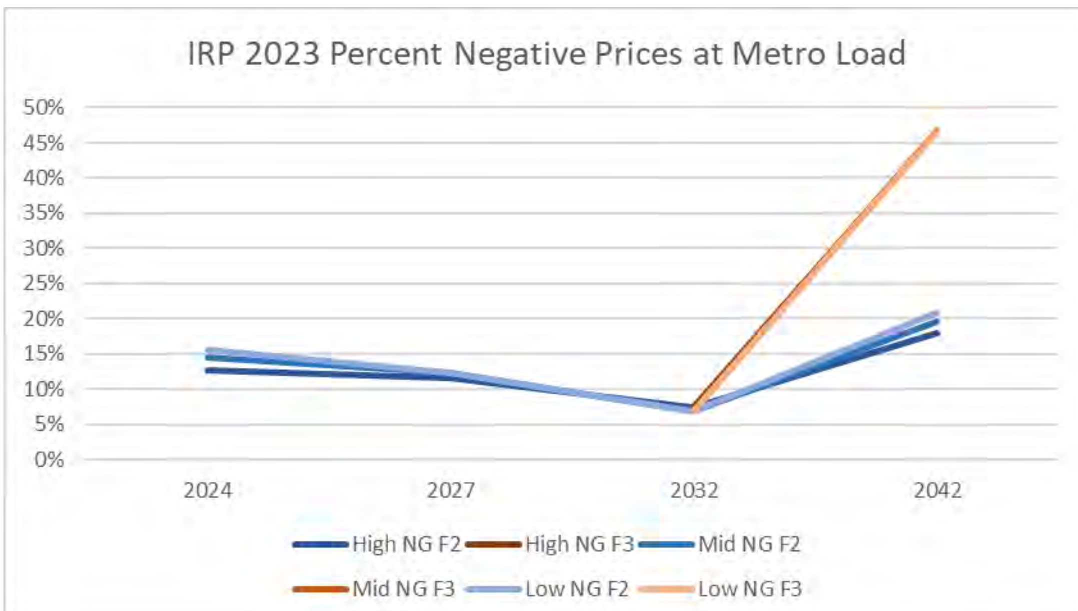


Figure 25: Actual Day Ahead Negative Prices at Generator Nodes

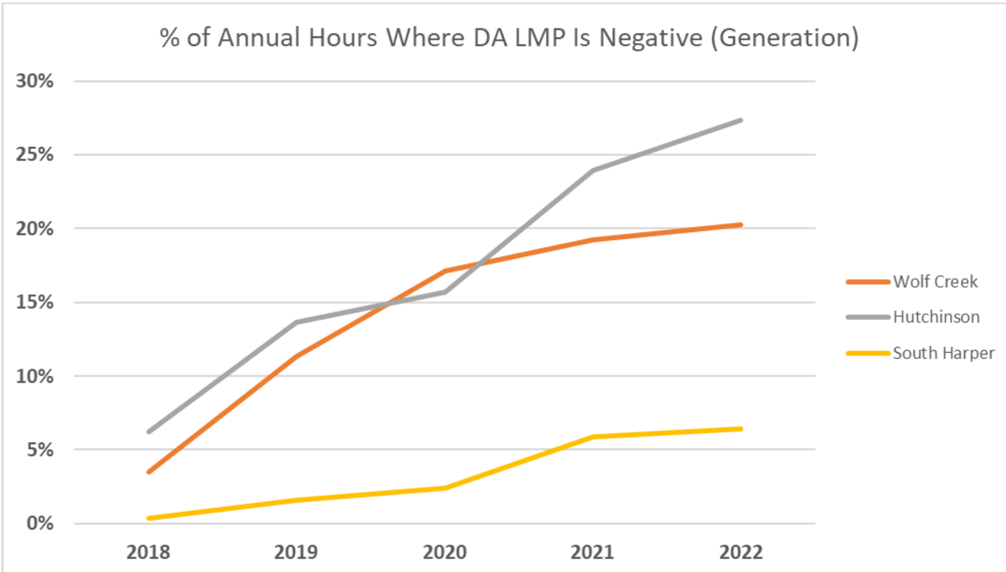


Figure 26: 2023 IRP Modeled Negative Prices at Kansas Central Generator Nodes

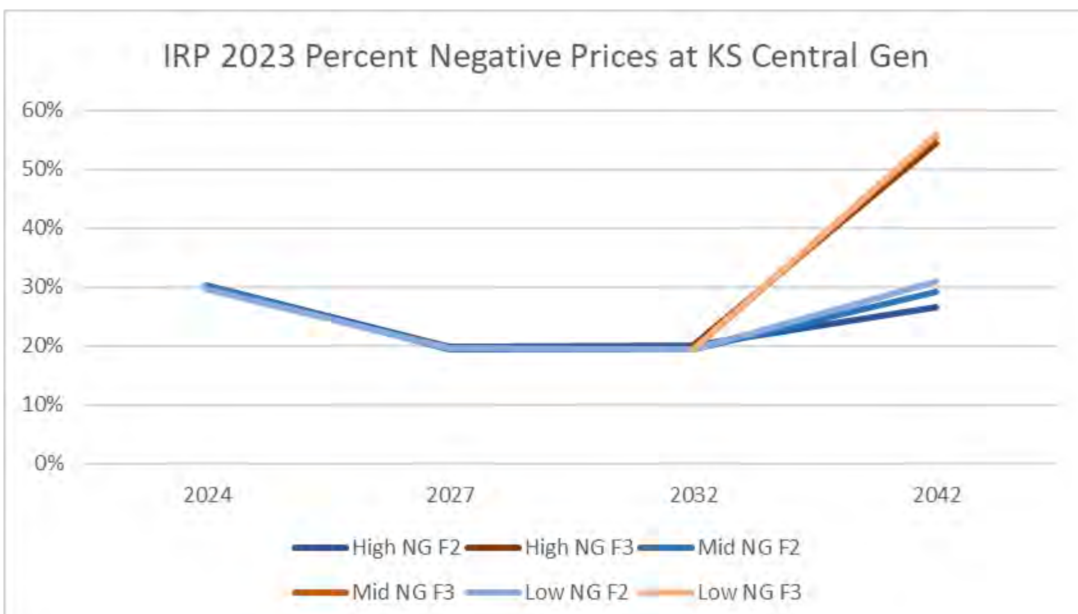


Figure 27: 2023 IRP Modeled Negative Prices at Metro Generator Nodes

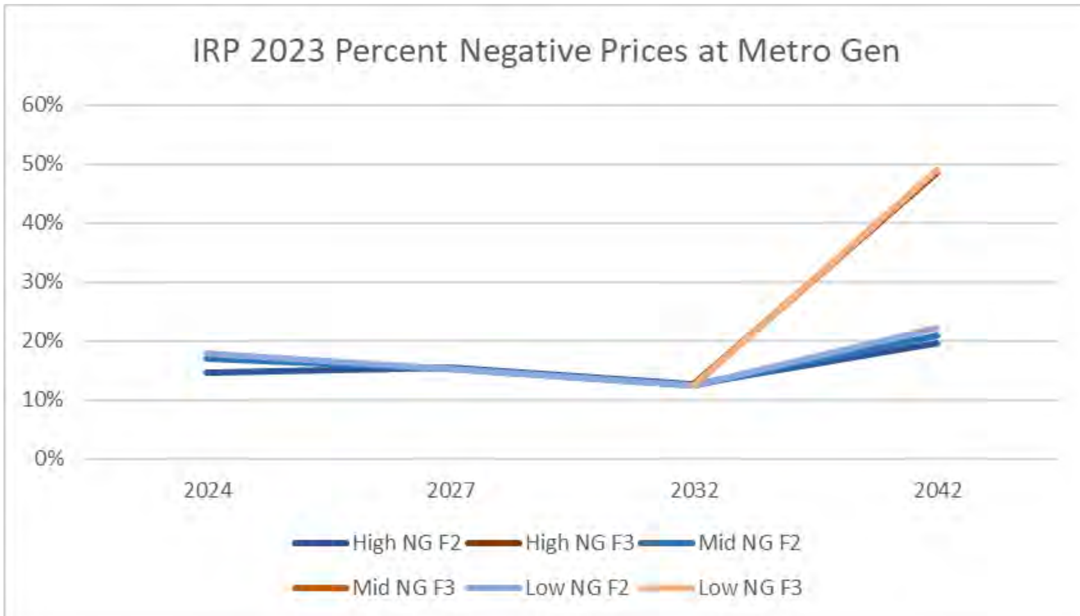


Figure 28: Actual Day Ahead Negative Prices at Wind Nodes

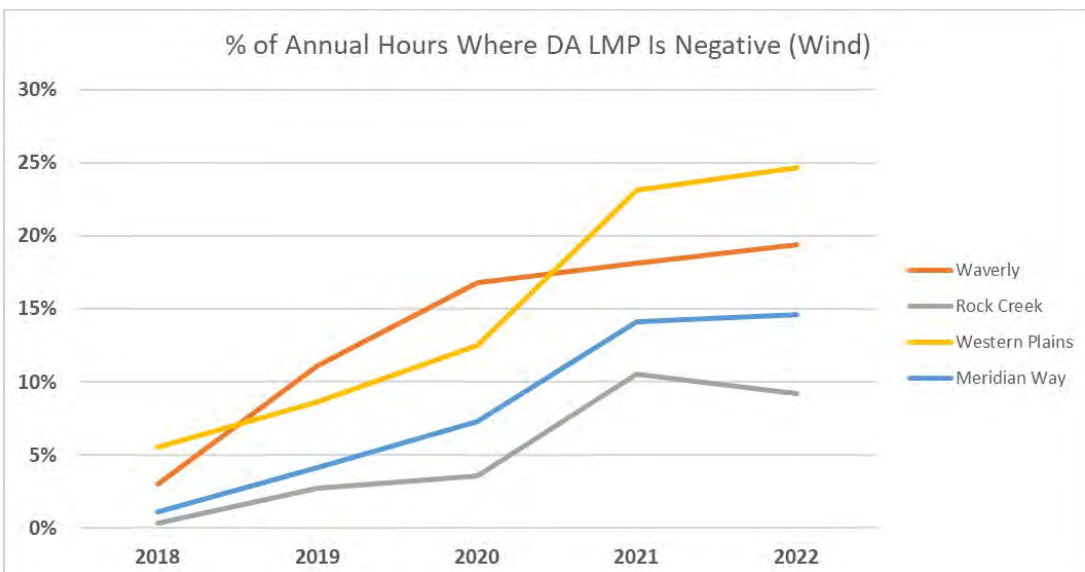
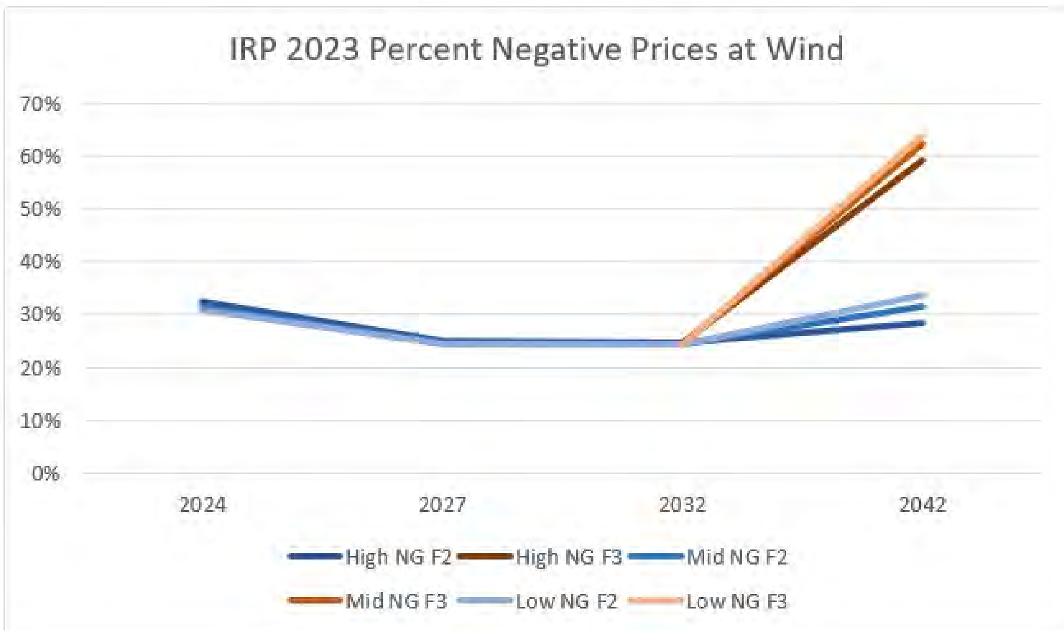


Figure 29: 2023 IRP Modeled Negative Prices at Wind Nodes



4.2 SUPPLY-SIDE TECHNOLOGY CHANGES FROM THE 2021 TRIENNIAL IRP

For the 2023 Annual Update, Evergy considered more options for resource additions, based on stakeholder feedback and solicitation of offers for resources.

2023 Request for Proposal (RFP)

In January 2023, Evergy issued a request for proposals for new resources. In March 2023, Evergy received offers for wind, solar, solar-hybrid, and battery storage resources from various suppliers, with different contract structures, locations, and technologies offered. Evergy used the information from the RFP to estimate the near-term availability of resources, expected costs, and operating characteristics. Evergy received offers for both Build-Transfer (i.e., owned resources) and Power Purchase Agreements (PPA) through this RFP, however, all resources evaluated in this IRP are assumed to be owned, consistent with the approach used in past IRPs. This consistency of assumptions enables better comparison of "generic" resource options and leaves the evaluation of different ownership structures (e.g., PPA) to more detailed analysis during the resource procurement process.

Natural Gas Resources

Evergy is currently conducting a study to determine optimal locations to build new natural gas resources in the future. While the study is not complete in time for this IRP filing, resource specifications and costs were updated in the IRP modeling analysis. Evergy has determined that due to interconnection queue times and siting needs, the earliest operational year for a new natural gas resource is 2028.

Other Resources

Evergy considered the purchase of ownership shares of Dogwood Energy Center for Missouri West based on the results of a late 2022 capacity Request for Proposal. If purchased, this resource would be available to Missouri West in 2024.

Evergy also considered the addition of Persimmon Creek Wind and the currently-merchant 8% share of Jeffrey Energy Center for Kansas Central.

Discussion of Resource Options and Economics

Key changes in market conditions in the past few years have driven changes to expected availability and installed costs of new resources. Last year, Evergy noted high inflation and supply chain pressures increasing the cost of materials and limiting their availability. Uncertainty around US government trade policies and tariffs also contributed to solar panel scarcity.

The Inflation Reduction Act, which was passed after the 2022 IRP filing, extended and created new incentives for zero-carbon-emitting resources. Currently US agencies are formalizing regulations which will clarify how resources will qualify and account for these incentives. Despite some uncertainties about the final rules, The Inflation Reduction Act may be spurring demand for qualifying projects, as intended by lawmakers.

The SPP interconnection queue continues to be highly backlogged, slowing the ability of new projects to assess their economic viability considering transmission upgrade costs, and increasing their lag time to achieve commercial operation.

While the addition of new resources is likely to be slowed, the need for new resources is forecasted to increase. As part of its electric reliability planning, SPP ensures that it has the resources to meet demand at all times. SPP requires Evergy and all load-serving entities to own or contract for enough capacity to meet this objective. SPP uses updated weather and system operational data as well as lessons learned from events such as Winter Storm Uri to perform reliability studies. Recently, SPP raised the summer reserve margin from 12% to 15% of peak load beginning in summer 2023. This means that load-serving entities must maintain more capacity as a percent of load. SPP Stakeholders continue to work through future rule changes affecting capacity needs, including winter reserve margin requirements, which are currently voluntary. SPP is also considering changes to how much credit it gives to each resource to meet capacity needs, termed capacity accreditation. This summer, SPP planned to implement Effective Load Carrying Capability (ELCC), which aligns capacity accreditation with resource contribution at peak times for resources that are limited by weather (Wind, Solar) or duration (Batteries), effectively decreasing the credit these resources receive, however it was postponed by a FERC decision. Evergy expects ELCC, or a similar capacity accreditation method to be implemented in the future, as well as a new method that will decrease capacity accreditation for other non-fuel-limited resources based on operational performance, specifically forced outage history (performance-based accreditation).

Refreshed capital cost assumptions for new resources are shown in Table 19 below. Capital cost assumptions for the same resources are shown for the 2021 Triennial IRP and the 2022 Annual Update for comparison. "First Year" represents the first year in which the resource option was assumed to be available based on RFP results and/or expected construction timeline. "Capacity" shown in the table below represents the assumed size of one "project" of that resource type, which was an input into capacity expansion modeling (described further in 5.2)

Table 19: Supply-Side Technology Options ** Confidential **

[redacted]

Installed capital costs for zero-emitting technologies rose substantially and longer lead times to commercial operation were observed based on the 2023 RFP offers.

The capital cost increases may be mitigated by the increased incentive values provided by the Inflation Reduction Act. Evergy incorporated expected Inflation Reduction Act incentives in the modeling of new resource economics, including a 10-year production tax credit (PTC) for wind and solar, which are valued as reducing revenue requirements by 100% of the pre-tax value for every MWh of output. Wind and Solar resources were assumed to be dispatchable, offering into the market at the negative value of the credit to enable production and receipt of the credits, if economic. Batteries were expected to receive an investment tax credit (ITC) of 30% of installed cost upon commercial operation. It should be noted that the ITC for batteries in the Inflation Reduction act is not subject to normalization rules like other ITC credits have been in the past. This exclusion is exclusive to battery storage. The Inflation Reduction Act phases out incentives as US targets are achieved. Both PTC and ITC credit eligibility for new resources was assumed to reduce to 75% in 2034, 50% in 2035, and end in 2036.

Table 20: Inflation Reduction Act Incentives Modeled for New Resources

Resource	Incentive Modeled	Max Capacity Factor	Max Incentive (2023 $/kW)
Wind	PTC, 10 Years	48%	1,421
Solar	PTC, 10 Years	26%	756
Battery	ITC Upfront	17%	489
Solar-Hybrid	PTC, 10 Years Solar; ITC Upfront Battery	42%	639

Note: Currently operating resources were modeled based on years of remaining PTC eligibility. ITC incentive based on installed cost.

Installed cost estimates decreased for Combustion Turbine and Combined Cycle technologies. These cost decreases may be due to better information as opposed to actual technological improvements. Past costs were based on publicly available information, and likely did not reflect regional differences. Costs this year reflect engineering firm estimates particular to Evergy.

Last year, Evergy planned to wait on Combined Cycle and Combustion Turbine additions until technological improvements in carbon reduction were potentially attainable in the 2036 timeframe. Evergy did not model additions of these resources before 2036, reasoning that existing zero-emitting resources could economically replace retiring coal and meet load growth until that time. This year, based on Evergy's forecasted need for more capacity earlier due to SPP requirements as well as potential load growth, Evergy will consider building natural gas-fired resources sooner. Evergy assumes that these resources will procure firm natural gas transportation to ensure energy production is available when needed and capacity will be accredited by SPP, and includes these costs in modeling. These resources, while not zero-emitting, still offer considerable carbon emissions reductions compared to coal resources and the availability of hydrogen-capability technologies will allow Evergy to transition to non-emitting operations over time. For Evergy's Future 3 modeling (High carbon restriction scenario), new natural gas resources (CT or CC) are assumed to become carbon-free in years beyond 2035, consistent with the expected technological innovation that would need to occur to achieve minimal emissions system-wide.

Costs modeled for all new resources in future years reflect the expectation of continued technology improvements over time, based on publicly available capital cost forecasts from the Energy Information Administration (EIA) and the National Renewable Energy Laboratory (NREL). The cost curves available in these forecasts were averaged and applied to the near-term capital costs.

4.3 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 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. IRP modeling also includes updated Operations & Maintenance (O&M) cost forecasts for each unit. These forecasts are based on current expectations for long-term O&M costs and factor in recent and planned cost reduction efforts at each site.

4.4 ENVIRONMENTAL REGULATION CHANGES FROM THE 2021 TRIENNIAL IRP

Material changes from 2022 are shown in italics.

4.4.1 AIR EMISSION IMPACTS

4.4.1.1 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.

4.4.1.2 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 January 2023, the EPA proposed strengthening the primary annual PM2.5 (particulate matter less than 2.5 microns in diameter) NAAQS. The EPA is proposing to lower the primary annual PM2.5 NAAQS from 12.0 µg/m3 (micrograms per cubic meter) to a level that would be between 9.0 and 10.0 µg/m3. The EPA is proposing to retain the other PM NAAQS at their current levels*. Future non-attainment of revised standards could require additional reduction technologies, emission limits, or both on fossil-fueled units.

4.4.1.3 <u>Ozone</u>

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 March 2023, the EPA released a revised draft Policy Assessment for Reconsideration of the Ozone NAAQS recommending the EPA retain the current 2015 Ozone NAAQS. EPA anticipates issuing a proposed decision in the reconsideration of the ozone NAAQS in 2024.* 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.

4.4.1.4 <u>Sulfur Dioxide</u>

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.

4.4.1.5 <u>Carbon Monoxide</u>

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.

4.4.1.6 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.

4.4.1.7 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 and Oklahoma beginning in 2023 *with additional reductions in future years. In March 2023, the EPA issued the final ITFIPs for twenty-three states, including Missouri and Oklahoma*. 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.

4.4.1.8 <u>Regional Haze</u>

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. *MDNR submitted the Missouri SIP revision to the EPA in August 2022, however, they failed to do so by the EPA's revised submittal deadline of August 15, 2022. As a result, on August 30, 2022, the EPA published "finding of failure" with respect to Missouri and fourteen other states for failing to submit their Regional Haze SIP revisions by the applicable deadline. This finding of failure established a two-year deadline for the EPA to issue a Regional Haze federal implementation plan (FIP) for each state unless the state submits and the EPA approves a revised SIP that meets all applicable requirements before the EPA issues the FIP.* 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. *In March 2023, several environmental organizations notified the EPA of their intent to sue for failure of the EPA to timely approve or disapprove of the SIP revisions submitted by Kansas and seven other states.*

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

Evergy Metro's existing emission controls at its La Cygne, Iatan and Hawthorn Generating Stations maintain compliance with these requirements. Future visibility progress goals could result in additional SO_2, NO_x and PM controls or reduction technologies on fossil-fired units.

4.4.1.9 Greenhouse Gases

In May 2023, the EPA proposed CO2 emission limits and guidelines for fossil fuel fired electric generating units. The proposal regulations would impose CO_2 emission limitations for existing coal, oil and natural gas-fired boilers, existing large natural gas fired combined cycle combustion turbines and new natural gas *fired simple and combined cycle combustion turbines. EPA established these proposed emission limitations based on utilizing such technologies as hydrogen co-firing with natural gas, and carbon capture and sequestration (CCS). It is highly likely this proposed regulation will face administrative and legal challenges prior to finalization. However, this regulation could require hydrogen co-firing with natural gas, natural gas co-firing with coal, reduced generation, carbon capture and sequestration alternate generation, or demand reduction technologies.*

4.4.1.10 Mercury and Air Toxics Standards

In April 2023, the EPA released a proposal to tighten certain aspects of the mercury and air toxics standards (*MATS) rule. The EPA is proposing to lower the emission limit for particulate matter (PM), require the use of PM continuous emissions monitors (CEMS) and lower the mercury emission limit for lignite coal-fired electric generating units (EGUs). The EPA is also soliciting comment on further strengthening of the PM emission limitation beyond the proposal*. *When implemented in 2016*, 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 the current *or proposed* standards. *However, further strengthening of the PM emission limitation could require* Evergy Kansas Central to *consider additional PM controls* at the Jeffrey Energy Center.

4.4.2 WATER EMISSION IMPACTS

4.4.2.1 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 proposed this supplemental rulemaking on March 29, 2023. In the 2023 proposal EPA removes the 10% volumetric purge allowance on bottom ash wastewater and proposes zero liquid discharge for both FGD wastewater and bottom ash wastewater. In addition, the proposal established new discharge limitations for coal combustion residual (CCR) leachate. Compliance with these new limitations must be as soon as feasible no later than December 31, 2029.* Evergy is currently in compliance with this regulation, and intends any required upgrades to be in place prior to the 2029 deadline.

4.4.2.2 Clean Water Act Section 316(A)

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

4.4.2.3 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.

4.4.2.4 Zebra Mussel Infestation

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

4.4.2.5 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.

4.4.3 WASTE MATERIAL IMPACTS

4.4.3.1 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 Metro 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.*

In May 2023, EPA released a proposed rulemaking on legacy CCR units. This regulation, if finalized, will expand the number of CCR units subject to regulation under the Federal CCR rule. 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 5: INTEGRATED RESOURCE ANALYSIS UPDATE

5.1 CHANGES FROM THE 2021 TRIENNIAL IRP

Evergy submitted its 2021 Triennial IRP filing on June 3, 2021, and updated its resource plan on June 10, 2022, with its 2022 IRP Annual Update filing. This year's 2023 IRP Annual Update reflects updated information and forecasts based on market and policy changes and additional studies that have occurred in the past year.

Changes from the 2021 Triennial IRP and 2022 Annual Update:

- Updated market pricing reflecting latest SPP transmission planning model assumptions of future resource mix and potential transmission congestion
- Updated fuel price forecasts, including high, mid, and low natural gas price scenarios
- Carbon Dioxide emissions limitations scenarios reflecting future environmental risks, including high, mid, and low (no) restrictions
- Updated cost estimates and timing assumptions for resource additions based on Request for Proposal (RFP) results
- Modeling of battery storage and hybrid resources as supply-side options
- Inclusion of incentives for new renewable and storage resources based on Inflation Reduction Act
- Updated load forecasts including large new customers in both Missouri and Kansas, and considerations for future large customer growth based on existing economic development pipeline
- Updated demand response potential study, including four Missouri program options
- Included possible reductions in peak demand from Missouri Commission-ordered mandatory time of use rates
- Refreshed demand response options for Kansas customers based on KEEIA filings pending before the Kansas Commission

- Updated planning reserve margin consistent with SPP rule changes enacted in 2022
- Increased focus on planning for utility-level (as opposed to Evergy-level) resource needs to better identify each utility's specific energy and capacity needs in the future, reduced level of assumed market availability (for both capacity and energy) and reliance on other Evergy affiliates to meet long-term customer needs
- Expanded use of PLEXOS software for production cost modeling and capacity expansion, which was first implemented for 2022 IRP
- Annual refresh of data for existing generators (Capital and Operations & Maintenance costs)

5.2 ALTERNATIVE RESOURCE PLAN DEVELOPMENT

5.2.1 CAPACITY EXPANSION PLANNING

Capacity expansion planning involves using a long-term wholesale market simulation model (Evergy utilizes PLEXOS) which is designed to generate the lowest-cost resource plan given a set of resource options, a given market scenario (e.g., natural gas prices, wholesale energy prices, emissions constraints), and a forecasted capacity requirement (i.e., forecasted load plus planning reserve margin). Evergy's goal in this Annual Update was to use Capacity Expansion to the fullest extent practical in selecting the lowest-cost resource additions. To that end, no supply-side resource additions were "hard-coded" into pre-made resource plans for the purpose of arriving at Evergy Kansas Central and Evergy Metro's Preferred Portfolios. The only portion of the Alternative Resource Plans used in this filing which were manually tested were plant retirements and demand-side management portfolio additions. This is so that it is easier to compare different options side-by-side to see what trade-offs may exist between decisions. Even in testing these decisions, however, Capacity Expansion was still used to develop the lowest-cost portfolio of supply-side resources (e.g., if a higher level of DSM was assumed, then Capacity Expansion would build less resources as part of the optimized resource plan). This approach makes comparison somewhat more complicated than the past approach where plans could be compared on a truly apples-to-apples basis (i.e., because only one item in the whole plan changed and thus the difference in cost between the two plans is driven specifically by that one item), but it also more accurately depicts the integrated nature of resource planning, where every decision has an impact on future decisions and a portfolio should be viewed holistically as opposed to looking at an individual decision in a vacuum.

Unless otherwise noted in the description of the Modeling Approach below, capacity expansion modeling was performed using the “Mid-Mid-Mid” endpoint, based on the Mid natural gas price forecast, Mid load forecast, and Mid level of carbon restrictions (based on SPP Future 2 model as described in 3.1.4). This was, again, to provide easier comparisons between resource plans because a capacity expansion model will often generate different resource plans in different market scenarios. Evergy believes this approach provides a viable assessment of our current “base” expectations and that using these capacity expansion results, with revenue requirements for these Alternative Resource Plans calculated across all 27 endpoints, enables a robust analysis of these “base-case” Alternative Resource Plans across a wide variety of potential future scenarios.

For this year’s Annual Update, the supply-side options available for selection by Evergy Kansas Central and Metro in each year are outlined below. In each year, the model could select up to the number of megawatts listed in the table below by selecting “projects” of that resource type. The capacity and cost of each resource type are included in Table 19. In any given year, resource additions were constrained to only one “project” per year based on Evergy Metro’s assumed ability to finance these additions. This assumption also ensures that resources are added ratably over time as opposed to being stacked in one year, to drive more stable rate impacts over time. As an example, in 2027, capacity expansion for Evergy Metro could select *either* 150 MW of wind, 150 MW of battery storage, 150 MW of solar-storage hybrid, *or* 150 MW of solar. In 2028, it could select any of those options *or* a 260 MW combined cycle (based on an assumed ½ combined cycle project, on the assumption that CC builds can likely be shared across jurisdictions to drive economies of scale) *or* a 238 MW combustion turbine. The phased in availability of options in the table below is based on Request for Proposal responses (e.g., no solar projects received in the RFP had in-service dates in 2025 and thus solar was not an option available for capacity expansion in 2025) or expected construction timeline (i.e., five years is currently the expected shortest time required to build new natural gas resources given SPP interconnection queue delays and permitting / construction timelines).

Table 21: Maximum MW Available by Resource Type by Year (Kansas Central)

Resource	2023	2024	2025	2026	2027	2028	2034	2037	2039	2040
Wind			200	300	300	300	300	300	300	300
Solar				150	300	300	300	300	300	450
Battery				300	300	300	300	450	450	450
Solar Hybrid					267	267	534	534	267	267
Combined Cycle						520	520	520	520	520
Comb. Turbine						952	952	952	952	952
Persimmon Wind	199									
Jeffrey 8% Share		176								

Note: Each year shown represents the MW available by resource type in that year and following years until the next year shown in the table, which represents updated constraints

Table 22: Maximum MW Available by Resource Type by Year (Evergy Metro)

Resource	2026	2027	2028	2034	2039
Wind	150	150	150	150	150
Solar	150	150	150	150	150
Battery	150	150	150	150	150
Solar Hybrid				267	
Combined Cycle			260	260	260
Combustion Turbine			476	476	476

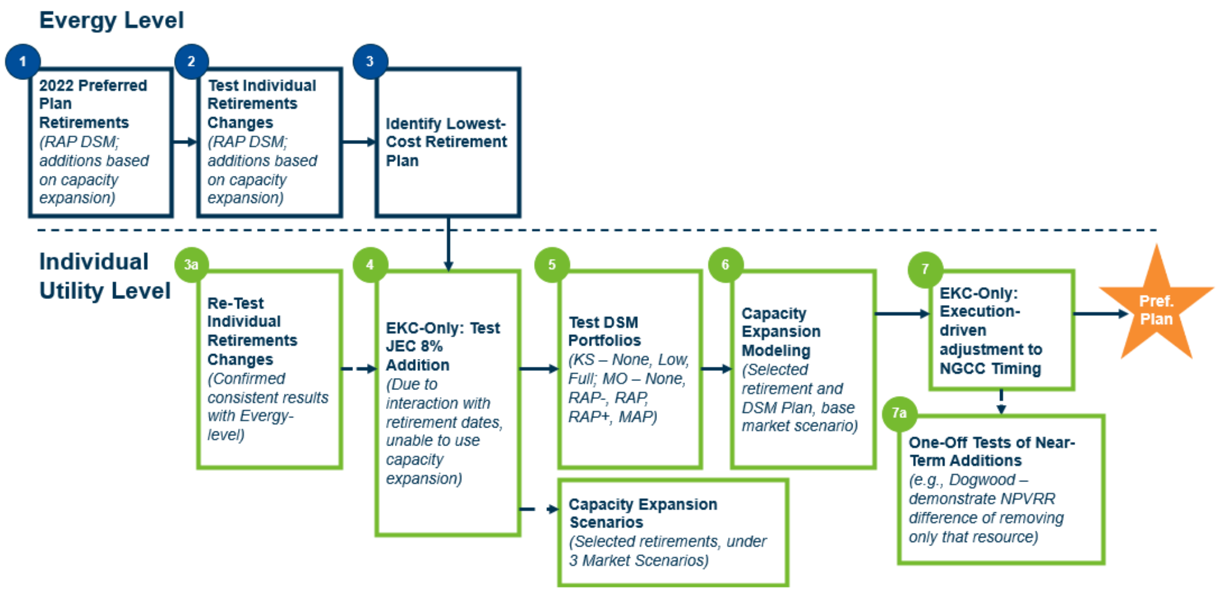
Note: Each year shown represents the MW available by resource type in that year and following years until the next year shown in the table, which represents updated constraints

5.2.2 OVERALL MODELING APPROACH

As described previously, the updated modeling approach for the 2023 Annual Update focused primarily on performing capacity expansion planning at the individual utility level (as opposed to the Evergy level) to ensure a targeted assessment of each utility's customers' energy and capacity needs. However, due to the large number of co-owned coal units in Evergy's portfolio, potential plant retirement options were tested at the Evergy level first before moving to the individual utility level. From there, these retirements were re-tested at the individual utility level, different demand-side management portfolios were compared, capacity expansion was performed in a "High" scenario (high natural gas prices, high carbon restriction) and "Low" scenario (low natural gas prices, no carbon restriction), and ultimately a Preferred Portfolio was generated using the selected plant retirement plan, selected DSM portfolio, and with capacity expansion-generated supply-side resource additions. In order to ease comparison of resource plans, particularly as it relates to near-term decisions (e.g., addition of the Persimmon Creek wind farm for Kansas Central), additional plans were created where that resource addition was removed as a capacity expansion option and a new lowest-cost plan was generated. As a result, the resource plans were compared to this new plan to show the cost savings created by that specific decision. Because Evergy Metro's Preferred Portfolio does not include resource additions until 2030, no plans were analyzed for Evergy Metro as a part of this modeling step.

Given this process is very different from the process used in past IRPs, and in order to make the process more transparent, the results outlined below will be described in the various stages outlined in the graphic below.

Figure 30: High-Level Modeling Approach



5.3 <u>EVERGY-LEVEL RETIREMENT ANALYSIS</u>

As described above, Evergy-level modeling was used to determine whether changing the coal retirements from the 2022 Preferred Portfolio could result in lower NPVRR. This analysis was performed primarily at the Evergy level (as opposed to the Evergy Metro level) due to the number of jointly-owned units in Evergy's portfolio. However, additional testing was performed at the individual utility level to ensure any change in retirements at the Evergy level was also beneficial or approximately neutral for the individual utilities (results described below).

Table 23: Evergy Joint Planning Alternative Resource Plan Naming Convention

Demand-Side Management Potential	Early Retirements	Coal to NG	Other
B. RAP MO, No DSM KS	A. None (2021/22 Preferred Plan)	A. Lawrence 5 to NG 2024	A. None
J. MAP MO, Full DSM KS	B. Extend Lawrence 4 & 5 to 2028	B. Lawrence 5 to NG 2029	D. High/High
	C. Jeffrey 2 Retires 2030	C. Hawthorn 5 to NG 2027	E. Low/Low
	D. Iatan 1 Retires 2030	D. Jeffrey 3 to NG 2030	F. Only Renewable/Storage Build
	E. Hawthorn 5 Retires 2027	E. Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039	N. No Major Environmental Costs
	F. LaCygne 2 Retires 2032		
	G. Jeffrey 1 & 2 Retire 2030		
	H. Extend Lawrence 4 & 5 to 2028, Extend all others past 2042		
	I. Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030		
	J. All Earliest Retirements		
	K. Extend Lawrence 4 & 5 to 2028, Extend Jeffrey 3 to 2039		
	L. Extend Lawrence 4 & 5 to 2028, Extend Jeffrey 3 to 2039, Iatan 1 Retires 2030, LaCygne 2 Retires 2032		

Note: Letters which are excluded from naming convention above (e.g., "A" Demand Response Potential) were used in IRP development for one or more utilities but not used at the Evergy Joint Planning level.

Table 24: Overview of Joint-Planning Resource Plans

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Evergy BAAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2031 450 MW Wind 2032 450 MW Wind 2034 150 MW Wind 2035 300 MW Wind 2041 450 MW Wind 2042	300 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 150 MW Solar 2031 300 MW Solar 2033 150 MW Solar 2041		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CT (238 MW) in 2039 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BACA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 K Hawthorn5: Dec 31, 2026 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 150 MW Wind 2033 450 MW Wind 2034 150 MW Wind 2035 450 MW Wind 2041 450 MW Wind 2042	150 MW Solar 2027 300 MW Solar 2028 300 MW Solar 2029 600 MW Solar 2030 600 MW Solar 2031		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Coal to NG (375 MW) in 2027 1 CT (238 MW) in 2033 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CT (238 MW) in 2039 2 CC (1041 MW) in 2039 3 CC (1,562 MW) in 2040
Evergy BADA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: Dec 31, 2029 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 450 MW Wind 2033 450 MW Wind 2034 300 MW Wind 2035 450 MW Wind 2042	150 MW Solar 2028 450 MW Solar 2029 600 MW Solar 2030 600 MW Solar 2031 150 MW Solar 2035 300 MW Solar 2041		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Jeffrey 3 NG (727 MW) in 2030 1 CC (521 MW) in 2037 1 CC (521 MW) in 2038 1 CC (521 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BAEA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: December 31, 2029 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 2: December 31, 2038 Iatan 1: Dec 31, 2039 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2031 450 MW Wind 2032 450 MW Wind 2033 450 MW Wind 2034 300 MW Wind 2041 450 MW Wind 2042	150 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 150 MW Solar 2031 450 MW Solar 2035		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Jeffrey 3 NG (727 MW) in 2030 1 CC (521 MW) in 2037 1 CC (521 MW) in 2038 1 CC (521 MW) in 2039 Jeffrey 2 NG (730 MW) in 2039 2 CC (1041 MW) in 2040

Table 25: Overview of Joint-Planning Resource Plans (continued)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Evergy BBBA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2031 450 MW Wind 2032 450 MW Wind 2034 150 MW Wind 2035 300 MW Wind 2041 450 MW Wind 2042	300 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 150 MW Solar 2031 300 MW Solar 2033 150 MW Solar 2041		Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CT (238 MW) in 2039 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BCAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 2&3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 150 MW Wind 2033 450 MW Wind 2034 450 MW Wind 2041 450 MW Wind 2042	450 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 300 MW Solar 2031 150 MW Solar 2040		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 2 CC (1041 MW) in 2039 2 CC (1041 MW) in 2040
Evergy BDAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Iatan 1: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1&2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 150 MW Wind 2033 450 MW Wind 2034 300 MW Wind 2035 300 MW Wind 2041 450 MW Wind 2042	300 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 300 MW Solar 2031 150 MW Solar 2035		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CC (521 MW) in 2033 1 CT (238 MW) in 2036 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BEAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Hawthorn 5: December 31, 2027 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1&2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 450 MW Wind 2034 150 MW Wind 2035 300 MW Wind 2041 450 MW Wind 2042	150 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 600 MW Solar 2031 150 MW Solar 2041	150 MW Hybrid-Solar 2033 117 MW Hybrid-Battery 2033	Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 1 CC (521 MW) in 2028 1 CC (521 MW) in 2033 1 CT (238 MW) in 2036 1 CC (521 MW) in 2038 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BFAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039 Jeffrey 1: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2031 150 MW Wind 2032 450 MW Wind 2034 300 MW Wind 2035 300 MW Wind 2041 450 MW Wind 2042	300 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 300 MW Solar 2032 150 MW Solar 2035		Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 1 CT (238 MW) in 2032 2 CC (1041 MW) in 2033 1 CT (238 MW) in 2036 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040

Table 26: Overview of Joint-Planning Resource Plans (continued)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Evergy BGAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 1, 2, & 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2032 150 MW Wind 2033 450 MW Wind 2034 300 MW Wind 2035 450 MW Wind 2041 450 MW Wind 2042	600 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 150 MW Solar 2032 150 MW Solar 2040		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 3 CT (714 MW) in 2031 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CC (521 MW) in 2039 2 CC (1041 MW) in 2040
Evergy BHAA	RAP MO, No DSM KS;	Lawrence 4: Dec 31, 2028 Lawrence 5 Coal: Dec 31, 2028 Lake Road 4/6: Dec 31, 2030	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2029 450 MW Wind 2030 450 MW Wind 2031 450 MW Wind 2032 450 MW Wind 2033 450 MW Wind 2034 300 MW Wind 2042	150 MW Solar 2029 600 MW Solar 2035 750 MW Solar 2041		Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2037 2 CC (1041 MW) in 2039 1 CC (521 MW) in 2040 1 CC (521 MW) in 2042
Evergy BIBA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039 Jeffrey 1: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 150 MW Wind 2033 450 MW Wind 2034 450 MW Wind 2041 450 MW Wind 2042	450 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 300 MW Solar 2031 150 MW Solar 2040		Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2031 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 2 CC (1041 MW) in 2039 2 CC (1041 MW) in 2040
Evergy BIBD	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039 Jeffrey 1: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2026 450 MW Wind 2030 450 MW Wind 2032 450 MW Wind 2034 450 MW Wind 2035	600 MW Solar 2027 600 MW Solar 2028 600 MW Solar 2029 300 MW Solar 2031	150 MW Hybrid-Solar 2033 117 MW Hybrid-Battery 2033	Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2031 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CC (521 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BIBE	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1 & 2: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039		150 MW Solar 2029 600 MW Solar 2030 600 MW Solar 2032 300 MW Solar 2033 150 MW Solar 2034		Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2031 2 CT (476 MW) in 2031 1 CC (521 MW) in 2033 1 CT (238 MW) in 2036 1 CT (238 MW) in 2037 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040

Table 27: Overview of Joint-Planning Resource Plans (continued)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Evergy JEAF	MAP MO, Full DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Hawthorn 5: Dec 31, 2027 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2032 3000 MW Wind 2032	1200 MW Solar 2028 750 MW Solar 2031 150 MW Solar 2033 150 MW Solar 2040	1200 MW Hybrid-Solar 2033 936 MW Hybrid-Battery 2033 750 MW Battery-Gen 2039 1500 MW Battery-Wind 2039 900 MW Battery-Gen 2040	Lawrence 5 NG (338 MW) in 2024
Evergy JJAF	MAP MO, Full DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Hawthorn 5: Dec 31, 2025 Jeffrey 1, 2, & 3: Dec 31, 2030 LaCygne 1 & 2: Dec 31, 2030 Iatan 1 & 2: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030	199 MW Persimmon Wind 2023 200 MW Wind 2025 2250 MW Wind 2026 2400 MW Wind 2033	150 MW Solar 2026 1800 MW Solar 2031	150 MW Battery-Gen 2026 150 MW Battery-Wind 2026 150 MW Battery-Wind 2028 1200 MW Battery-Gen 2030 1500 MW Battery Wind 2030 1500 MW Hybrid-Solar 2030 1170 MW Hybrid-Battery 2030 150 MW Hybrid-Solar 2032 117 MW Hybrid-Battery 2032 150 MW Hybrid-Solar 2033 117 MW Hybrid-Battery 2033	Lawrence 5 NG (338 MW) in 2024

Note: For these modeled resource plans, Dogwood and Jeffrey 8% were assumed to be in place in all plans with capacity expansion used to solve for all other resource additions. Because this modeling is being used only to assess which retirement changes reduce costs, these decisions around builds are not critical (as long as the approach used for all retirements is consistent). The evaluation of resource additions for the ultimate Preferred Portfolio occurred at the individual utility level and did not include any hardcoded resource additions (Section 6.6).

5.4 REVENUE REQUIREMENT – EVERGY-LEVEL RETIREMENT ANALYSIS

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 28 below.

These results, along with the by-scenario results in Section 6.5, indicate that an earlier retirement of Jeffrey Unit 2 in 2030, as well as a delay of the Lawrence Unit 4 retirement and Lawrence Unit 5 transition to natural gas, is more economic than the 2022 Preferred Portfolio. Based on this, and supported by Kansas Central-level modeling below, the 2023 Preferred Portfolio for Kansas Central includes the delayed retirement of Lawrence Unit 4, the delayed transition of Lawrence Unit 5 to natural gas, and the retirement of its portion of Jeffrey Unit 3 in 2030. There is still significant uncertainty around different environmental regulations which could drive the retirement of Jeffrey Unit 2 or a different Evergy coal unit and thus Jeffrey Unit 2 still remains a “placeholder” for an accelerated retirement. However, given recent regulation released by the Environmental Protection Agency (EPA), it seems more probable that all units would need to install Best Available Control Technology in order to continue operating beyond the early 2030s. Given Jeffrey Units 2 and 3 are the only large units in Evergy’s fleet without Selective Catalytic Reduction (SCR) systems, the capital forecasts used in this IRP (and prior IRPs) assume that SCRs would need to be added if the units do not retire by 2031. This large capital cost to continue operations make these units the most attractive options for early retirement.

Evergy Metro is not an owner of either of these units, thus these retirements do not impact Evergy Metro’s Preferred Portfolio.

Table 28: Joint-Planning Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR ($M)	Difference	Description
1	BIBA	62,248		Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030
2	BCAA	62,295	47	Jeffrey 2 Retires 2030
3	BBBA	62,382	135	Extend Lawrence 4 & 5 to 2028
4	BAAA	62,430	182	2021/22 Preferred Portfolio
5	BIBD	62,449	201	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; High/High
6	BDAA	62,604	356	Iatan 1 Retires 2030
7	BGAA	62,608	360	Jeffrey 1 & 2 Retire 2030
**[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**
9	BADA	62,707	459	Jeffrey 3 to NG 2030
10	BACA	62,742	494	Hawthorn 5 to NG 2027
11	BAEA	62,753	505	Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039
12	BEAA	62,757	510	Hawthorn 5 Retires 2027
13	BHAA	62,778	531	Extend Lawrence 4 & 5 to 2028, Extend all others past 2042
14	BIBE	64,405	2,157	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Low/Low

5.5 BY-SCENARIO RESULTS – EVERGY-LEVEL RETIREMENT ANALYSIS

Table 29, Table 30, and Table 31 show the expected value of NPVRR for the joint plans assuming high, mid, and low CO_2 restrictions.

Table 29: Joint Plan Results - High CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	BIBD	62,747		Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; High/High
2	BIBA	62,917	170	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030
3	BCAA	62,942	196	Jeffrey 2 Retires 2030
4	BGAA	63,236	490	Jeffrey 1 & 2 Retire 2030
5	BBBA	63,580	833	Extend Lawrence 4 & 5 to 2028
6	BDAA	63,595	848	Iatan 1 Retires 2030
7	BAAA	63,605	859	2021/22 Preferred Portfolio
**[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**
9	BACA	63,819	1,073	Hawthorn 5 to NG 2027
10	BEAA	63,946	1,199	Hawthorn 5 Retires 2027
11	BADA	64,455	1,709	Jeffrey 3 to NG 2030
12	BAEA	64,601	1,855	Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039
13	BHAA	65,208	2,462	Extend Lawrence 4 & 5 to 2028, Extend all others past 2042
14	BIBE	66,941	4,195	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Low/Low

Table 30: Joint Plan Results - Mid-CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	BIBA	62,174		Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030
2	BBBA	62,184	10	Extend Lawrence 4 & 5 to 2028
3	BCAA	62,226	52	Jeffrey 2 Retires 2030
4	BAAA	62,236	62	2021/22 Preferred Portfolio
5	BADA	62,366	192	Jeffrey 3 to NG 2030
6	BHAA	62,368	194	Extend Lawrence 4 & 5 to 2028, Extend all others past 2042
7	BAEA	62,384	210	Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039
8	BIBD	62,417	243	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; High/High
9	BDAA	62,445	271	Iatan 1 Retires 2030
**[redacted]		[redacted]	[redacted]	[redacted]**
11	BGAA	62,522	348	Jeffrey 1 & 2 Retire 2030
12	BEAA	62,534	361	Hawthorn 5 Retires 2027
13	BACA	62,553	379	Hawthorn 5 to NG 2027
14	BIBE	64,500	2,327	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Low/Low

Table 31: Joint Plan Results - No CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	BHAA	61,580		Extend Lawrence 4 & 5 to 2028, Extend all others past 2042
2	BIBE	61,583	3	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Low/Low
3	BBBA	61,781	201	Extend Lawrence 4 & 5 to 2028
4	BIBA	61,800	220	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030
5	BAAA	61,835	255	2021/22 Preferred Portfolio
6	BCAA	61,854	274	Jeffrey 2 Retires 2030
7	BADA	61,982	402	Jeffrey 3 to NG 2030
8	BAEA	62,011	431	Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039
9	BDAA	62,090	510	Iatan 1 Retires 2030
**[redacted]	[redacted]	[redacted]	[redacted]	[redacted]*
11	BACA	62,233	653	Hawthorn 5 to NG 2027
12	BGAA	62,237	657	Jeffrey 1 & 2 Retire 2030
13	BEAA	62,238	658	Hawthorn 5 Retires 2027
14	BIBD	62,247	667	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; High/High

5.6 KANSAS CENTRAL RESOURCE PLANS

To make results more clear given the increased use of capacity expansion modeling in this IRP, Kansas Central analysis will be divided into seven sections, which ultimately culminate in the creation of 21 Alternative Resource Plans.

- Testing retirement options to ensure alignment with Evergy-level analysis
- Testing of Jeffrey Energy Center 8% addition
- Evaluation of Capacity Expansion sensitivities (perform capacity expansion under different market price scenarios to supplement “Base” modeling)
- Testing DSM portfolio levels to identify lowest-cost option
- Portfolio development using Capacity Expansion modeling
- Incremental tests of near-term decisions (e.g., Persimmon Creek addition) to assess robustness across scenarios and impact on NPVRR
- Modify resource addition sequence based on execution considerations

Supply-side resource additions other than the Jeffrey 8% (which could not be modeled using capacity expansion) were not an input into any of these Alternative Resource Plans. All additions were selected using capacity expansion modeling subject to the constraints denoted by the “Other” column above.

Table 32: Evergy Kansas Central Alternative Resource Plan Naming Convention

Demand Response Potential	Early Retirements	Coal to NG	Other
A. Low DSM	A. None (2021/22 Preferred Portfolio)	A. Lawrence 5 to NG 2024 (2021/22 Preferred Portfolio)	A. None
B. No DSM	B. Extend Lawrence 4 & 5 to 2028	B. Lawrence 5 to NG 2029	G. Jeffrey 8% Share
I. Full DSM	C. Jeffrey 2 Retires 2030	D. Jeffrey 3 to NG 2030	H. Jeffrey 8% Share, High/High
	F. LaCygne 2 Retires 2032	E. Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039	I. Jeffrey 8% Share, Low/Low
	G. Jeffrey 1 & 2 Retire 2030		J. Jeffrey 8% Share, No Persimmon Wind
	H. Extend Lawrence 4 & 5 to 2028, Extend all others past 2042		K. Jeffrey 8% Share, No 2025 Wind
	I. Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030		L. Jeffrey 8% Share, No Persimmon Wind, No 2025 Wind
	K. Extend Lawrence 4 & 5 to 2028, Extend Jeffrey 3 to 2039		M. Jeffrey 8% Share, Earlier CC Build
	L. Extend Lawrence 4 & 5 to 2028, Extend Jeffrey 3 to 2039, LaCygne 2 Retires 2032		N. Jeffrey 8% Share, No Major Environmental Costs

Table 33: Evergy Kansas Central Alternative Resource Plan Overview

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Kansas Central ABBG	Low DSM	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2031 150 MW Wind 2034 150 MW Wind 2035 150 MW Wind 2042	150 MW Solar 2028 300 MW Solar 2029 300 MW Solar 2030 300 MW Solar 2032 300 MW Solar 2041		Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CT (238 MW) in 2031 1 CC (521 MW) in 2033 1 CC (521 MW) in 2037 1 CC (521 MW) in 2039 1 CT (238 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040
Kansas Central AIBG	Low DSM	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2041	150 MW Solar 2027 300 MW Solar 2028 300 MW Solar 2029 300 MW Solar 2032 150 MW Solar 2035 300 MW Solar 2042		Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2030 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CT (238 MW) in 2036 1 CC (521 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040
Kansas Central AIBM	Low DSM	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2041	150 MW Solar 2027 150 MW Solar 2028 150 MW Solar 2029 150 MW Solar 2030 150 MW Solar 2031 300 MW Solar 2032 150 MW Solar 2035 300 MW Solar 2042		Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2028 1 CC (521 MW) in 2029 1 CT (238 MW) in 2033 1 CT (238 MW) in 2036 1 CC (521 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040
Kansas Central BAAA	No DSM	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2029 150 MW Wind 2034 150 MW Wind 2035 150 MW Wind 2041 150 MW Wind 2042	300 MW Solar 2028 300 MW Solar 2030 300 MW Solar 2031 300 MW Solar 2032	150 MW Battery-Gen 2026 150 MW Battery-Wind 2026	Lawrence 5 NG (338 MW) in 2024 1 CC (521 MW) in 2033 1 CC (521 MW) in 2037 1 CC (521 MW) in 2039 1 CT (238 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040
Kansas Central BAAG	No DSM	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2035 150 MW Wind 2041 150 MW Wind 2042	300 MW Solar 2028 300 MW Solar 2029 300 MW Solar 2030 300 MW Solar 2031	150 MW Battery-Wind 2026	Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 1 CT (238 MW) in 2032 1 CT (238 MW) in 2033 1 CC (521 MW) in 2036 1 CC (521 MW) in 2038 1 CC (521 MW) in 2039 1 CC (521 MW) in 2040
Kansas Central BADG	No DSM	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3 Coal: Dec 31, 2029 LaCygne 1: Dec 31, 2032 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2034 150 MW Wind 2035 150 MW Wind 2042	300 MW Solar 2029 300 MW Solar 2032 300 MW Solar 2033 300 MW Solar 2041	150 MW Battery-Wind 2026	Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 3 NG (669 MW) in 2030 1 CC (521 MW) in 2036 1 CC (521 MW) in 2038 1 CC (521 MW) in 2039 1 CC (521 MW) in 2040
Kansas Central BAEG	No DSM	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3 Coal: Dec 31, 2029 LaCygne 1: Dec 31, 2032 Jeffrey 2 Coal: Dec 31, 2038 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2029 150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2034 150 MW Wind 2035 150 MW Wind 2041 150 MW Wind 2042	300 MW Solar 2028 300 MW Solar 2032 300 MW Solar 2033	150 MW Battery-Wind 2026	Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 3 NG (669 MW) in 2030 1 CC (521 MW) in 2037 Jeffrey 2 NG (672 MW) in 2039 1 CC (521 MW) in 2039 1 CC (521 MW) in 2040

Table 34: Evergy Kansas Central Alternative Resource Plan Overview (Cont.)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Kansas Central BBBA	No DSM	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2035 150 MW Wind 2041 150 MW Wind 2042	300 MW Solar 2028 300 MW Solar 2029 300 MW Solar 2030 300 MW Solar 2031	150 MW Battery-Wind 2026	Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2032 1 CC (521 MW) in 2036 1 CC (521 MW) in 2039 1 CT (238 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040 1 CT (238 MW) in 2041
Kansas Central BBBG	No DSM	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2031 150 MW Wind 2034 150 MW Wind 2035 150 MW Wind 2042	150 MW Solar 2028 300 MW Solar 2029 300 MW Solar 2030 300 MW Solar 2032 300 MW Solar 2041		Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CT (238 MW) in 2031 1 CC (521 MW) in 2033 1 CC (521 MW) in 2037 1 CC (521 MW) in 2039 1 CT (238 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040
Kansas Central BCAA	No DSM	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 2 & 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2034 150 MW Wind 2035 150 MW Wind 2041	150 MW Solar 2027 300 MW Solar 2028 300 MW Solar 2029 300 MW Solar 2030 300 MW Solar 2032 300 MW Solar 2042	150 MW Battery-Gen 2026 150 MW Battery-Wind 2026	Lawrence 5 NG (338 MW) in 2024 1 CC (521 MW) in 2031 1 CC (521 MW) in 2033 1 CT (238 MW) in 2036 1 CC (521 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040
Kansas Central BCAG	No DSM	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 2 & 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2030 150 MW Wind 2034 150 MW Wind 2041	150 MW Solar 2027 300 MW Solar 2028 300 MW Solar 2029 300 MW Solar 2032 300 MW Solar 2035 300 MW Solar 2042	150 MW Battery-Wind 2026	Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 1 CT (238 MW) in 2030 1 CC (521 MW) in 2031 1 CC (521 MW) in 2033 1 CC (521 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040 1 CT (238 MW) in 2041
Kansas Central BFAG	No DSM	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 LaCygne 1 & 2: Dec 31, 2032 Jeffrey 1 & 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2032 150 MW Wind 2034 150 MW Wind 2035 150 MW Wind 2041 150 MW Wind 2042	300 MW Solar 2028 300 MW Solar 2029 300 MW Solar 2030 300 MW Solar 2031	150 MW Battery-Wind 2026	Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 1 CT (238 MW) in 2032 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CC (521 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040 1 CT (238 MW) in 2041
Kansas Central BGAG	No DSM	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 1, 2, & 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2039 150 MW Wind 2041 150 MW Wind 2042	150 MW Solar 2026 300 MW Solar 2027 300 MW Solar 2028 300 MW Solar 2032 150 MW Solar 2035	150 MW Battery-Wind 2026	Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 1 CC (521 MW) in 2029 1 CC (521 MW) in 2030 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CT (238 MW) in 2036 1 CC (521 MW) in 2040 1 CT (238 MW) in 2041
Kansas Central BIBG	No DSM	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2041	150 MW Solar 2027 300 MW Solar 2028 300 MW Solar 2029 300 MW Solar 2032 150 MW Solar 2035 300 MW Solar 2042		Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2030 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CT (238 MW) in 2036 1 CC (521 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040

Table 35: Evergy Kansas Central Alternative Resource Plan Overview (Cont.)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Kansas Central BIBH	No DSM	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2026 150 MW Wind 2033 150 MW Wind 2034	300 MW Solar 2027 300 MW Solar 2028 300 MW Solar 2029 300 MW Solar 2032	150 MW Hybrid-Solar 2035 117 MW Hybrid-Battery 2035	Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2030 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CC (521 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040 1 CT (238 MW) in 2041
Kansas Central BIBI	No DSM	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	200 MW Wind 2025	300 MW Solar 2028 300 MW Solar 2029 300 MW Solar 2032 150 MW Solar 2034		Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 2 CT (476 MW) in 2030 1 CC (521 MW) in 2031 1 CC (521 MW) in 2033 1 CT (238 MW) in 2037 1 CC (521 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040
Kansas Central BIBJ	No DSM	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	200 MW Wind 2025 150 MW Wind 2026 150 MW Wind 2033 150 MW Wind 2035 150 MW Wind 2041 150 MW Wind 2042	150 MW Solar 2027 300 MW Solar 2028 300 MW Solar 2029 300 MW Solar 2032 300 MW Solar 2034		Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2030 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CT (238 MW) in 2036 1 CC (521 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040
Kansas Central BIBK	No DSM	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 150 MW Wind 2026 150 MW Wind 2033 150 MW Wind 2035 150 MW Wind 2041 150 MW Wind 2042	150 MW Solar 2027 300 MW Solar 2028 300 MW Solar 2029 300 MW Solar 2032 300 MW Solar 2034		Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2030 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CT (238 MW) in 2036 1 CC (521 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040
Kansas Central BIBL	No DSM	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	150 MW Wind 2026 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2035 150 MW Wind 2038 150 MW Wind 2041 150 MW Wind 2042	300 MW Solar 2027 300 MW Solar 2028 300 MW Solar 2029 300 MW Solar 2032		Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2030 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CT (238 MW) in 2036 1 CC (521 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040
Kansas Central IBBG	Full DSM	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2029 150 MW Wind 2033 150 MW Wind 2035 150 MW Wind 2041 150 MW Wind 2042	300 MW Solar 2030 300 MW Solar 2031 300 MW Solar 2032 300 MW Solar 2034		Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CT (238 MW) in 2033 1 CC (521 MW) in 2037 1 CC (521 MW) in 2039 1 CT (238 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040
Kansas Central IIBG	Full DSM	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Jeffrey 1: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2035 150 MW Wind 2041 150 MW Wind 2042	300 MW Solar 2028 300 MW Solar 2029 300 MW Solar 2030 300 MW Solar 2032		Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CT (238 MW) in 2036 1 CC (521 MW) in 2039 1 CC (521 MW) in 2040 1 CT (238 MW) in 2040

5.7 REVENUE REQUIREMENT – KANSAS CENTRAL

Table 36: Retirement Re-Testing

Evergy Kansas Central Twenty-Year Net Present Value Revenue Requirement

Kansas Central Retirement Rankings

Rank	Plan	NPVRR ($M)	Difference	Description
1	BIBG	31,880		No DSM; Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Jeffrey 8% Share
2	BBBG	31,899	19	No DSM; Extend Lawrence 4 & 5 to 2028; Jeffrey 8% Share
3	BCAG	31,997	118	No DSM; Jeffrey 2 Retires 2030; Jeffrey 8% Share
4	BAAG	32,031	151	No DSM; Jeffrey 8% Share
** [redacted]		[redacted]	[redacted]	[redacted] **
6	BGAG	32,331	451	No DSM; Jeffrey 1 & 2 Retire 2030; Jeffrey 8% Share

At the Kansas Central level, extending the retirement of Lawrence 4 and the transition of Lawrence 5 to natural gas-only operations to 2028, combined with the retirement of Jeffrey 2 in 2030, reduced costs by $151 million compared to a plan with the 2021/2022 Preferred Portfolio retirements (BAAG). All modeled scenarios assume no Kansas DSM and the inclusion of Jeffrey 8% to maintain consistency. DSM and Jeffrey 8% decisions are evaluated in subsequent sections.

Table 37: Jeffrey Energy Center 8% Addition

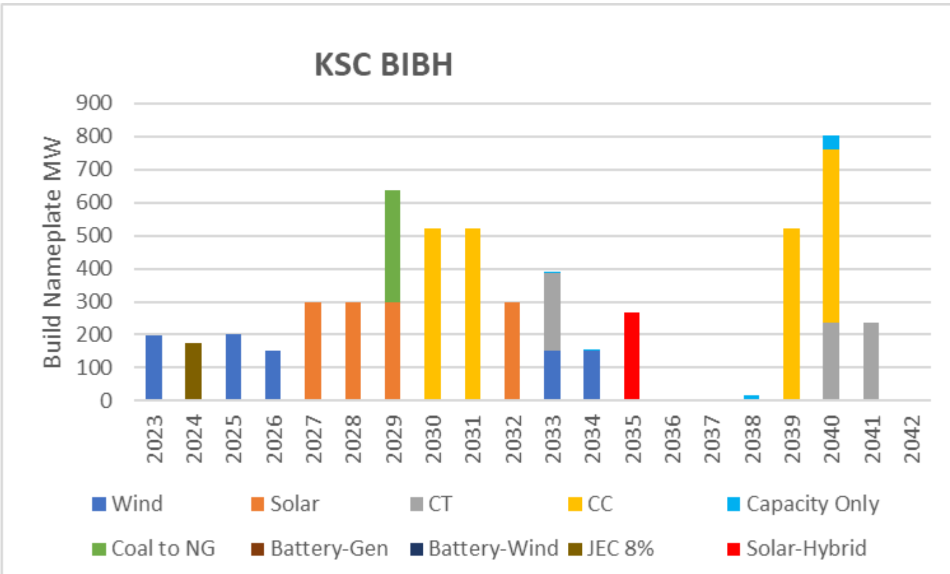
Evergy Kansas Central Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR ($M)	Difference	Description
1	BCAG	31,997		No DSM; Jeffrey 2 Retires 2030; Jeffrey 8% Share
2	BCAA	32,026	29	No DSM; Jeffrey 2 Retires 2030

Removing the Jeffrey 8% from a plan which includes the Jeffrey 2 retirement in 2030 increases costs by $29 million, indicating that the inclusion of Jeffrey 8% in Kansas Central's portfolio is favorable on an expected value basis.

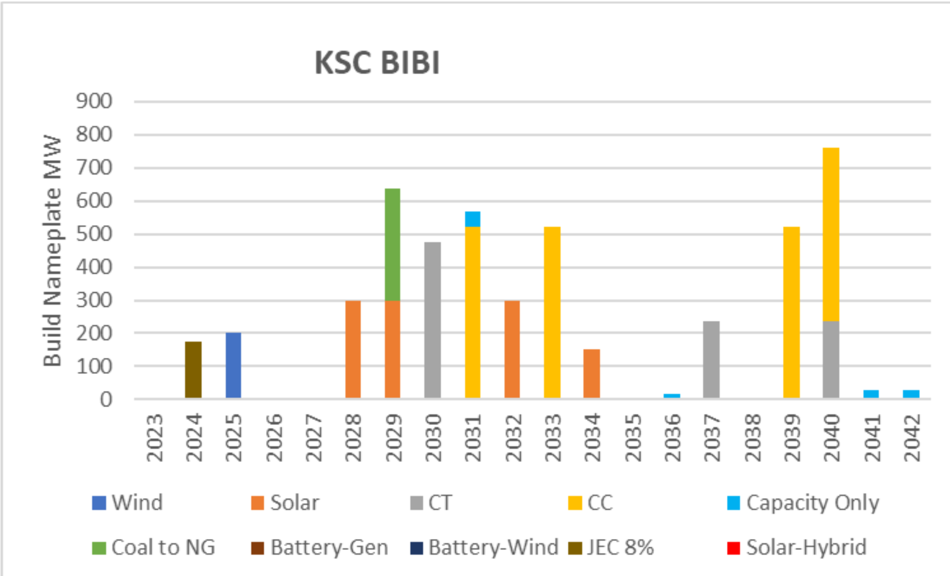
Figure 31: Capacity Expansion "High" Scenario Supply-Side Additions

Assumes Jeffrey 8%



Capacity expansion modeling performed specifically in the High Gas – High Carbon Restriction ("High/High" or "High") scenario shows an increased level of wind builds compared to the Preferred Portfolio given the increased value of zero-carbon energy in a heavily carbon-restricted market. Despite high gas prices and carbon restrictions, capacity expansion also builds new thermal plants in 2030, 2031, 2033, and 2039, 2040, and 2041 as part of the lowest-cost plan. In this scenario, new thermal resources are assumed to transition to non-emitting operations beyond 2035. This scenario also includes the addition of a hybrid (solar and storage) resource in 2035.

Figure 32: Capacity Expansion "Low" Scenario Supply-Side Additions



Capacity expansion modeling performed specifically in the Low Gas – Low Carbon Restriction ("Low/Low" or "Low") scenario shows delayed near-term solar builds compared to the Preferred Portfolio and less new wind given the reduced value of zero-carbon energy without the imposition of carbon restrictions. Consistent with the Preferred Plan, this scenario selects thermal additions throughout the 2030s, but these additions are more heavily weighted toward Combustion Turbines (as opposed to Combined Cycle plants). This is, again, driven by the reduced value of low- or zero-carbon energy which makes higher capacity factor Combined Cycles less valuable compared to Combustion Turbines (which are largely a capacity resource – as opposed to an energy resource).

Table 38: DSM Portfolio Comparison

Kansas Central Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR ($M)	Difference	Description
1	IIBG	31,742		Full DSM; Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Jeffrey 8% Share
2	BIBG	31,880	138	No DSM; Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Jeffrey 8% Share
3	AIBG	31,901	159	Low DSM; Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Jeffrey 8% Share

The lowest-cost DSM option is the KEEIA settlement which includes a broader set of programs, with an assumption of continued implementation over time to reach a "full" level of implementation in the long-term. Due to uncertainty around the pending case, and to avoid delaying new capacity builds on the basis of "full" implementation which may not be realized, the Commission Staff settlement for a more targeted set of programs, with only short-term implementation over three years, was selected as part of the Preferred Portfolio. The fact that this is a higher cost option demonstrates the long-term value of DSM programs and their ability to delay capacity needs over time, but the Company believes that selecting this "Low" DSM implementation is the most prudent path to plan around at this time. Notably, the "Low" level is higher cost than the "No DSM" option. This is because the "Low" scenario assumes only a very short-term implementation of DSM programs based on the current pending settlement and that, beyond that initial set of programs, DSM programs do not continue or expand. This short-term approach to DSM produces limited value from a capacity perspective because it is not available long enough to mitigate the need for new resource additions. Despite this, given the "Low" portfolio provides a first step toward an eventual "Full" implementation, it is selected as part of the Kansas Central Preferred Portfolio.

Figure 33: Capacity Expansion-Generated Supply-Side Additions

Jeffrey 2 Retirement, "Low" DSM

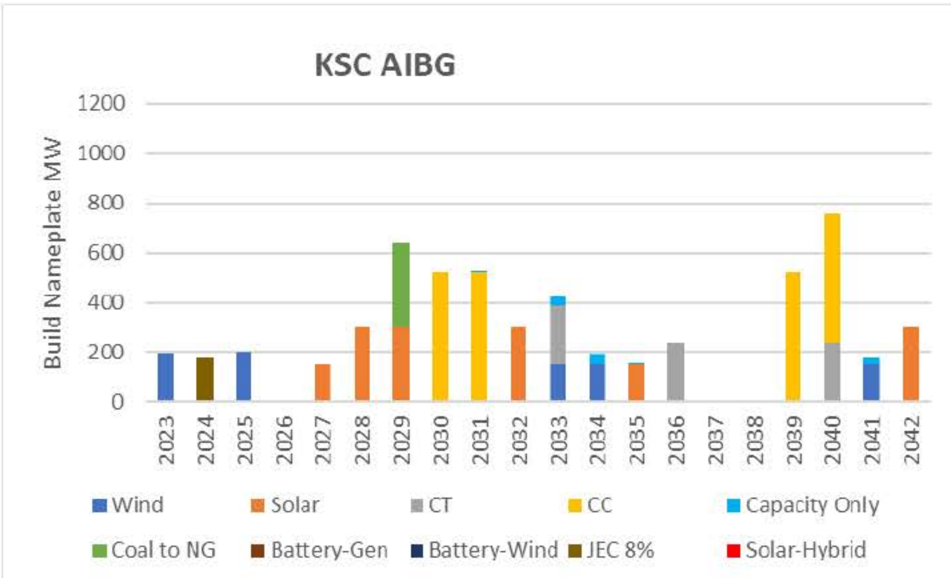


Table 39: Plan Comparison with and without Persimmon Creek Addition

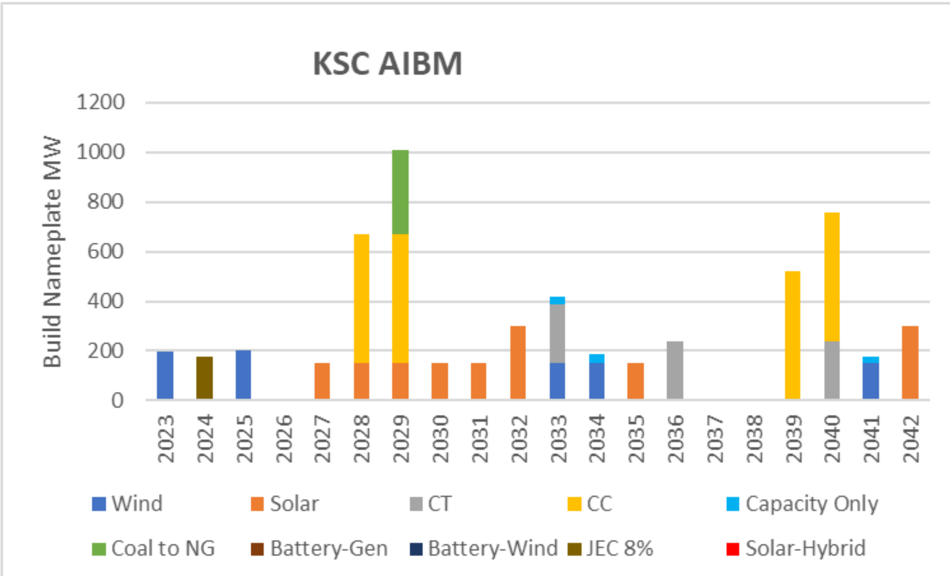
Kansas Central Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR ($M)	Difference	Description
1	BIBG	31,880		No DSM; Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Jeffrey 8% Share
2	BIBJ	31,924	44	No DSM; Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Jeffrey 8% Share, No Persimmon Wind

To supplement these analyses, BIBJ was generated using capacity expansion with Persimmon Creek removed as a candidate supply-side resource option. This analysis was done to show the impact of Persimmon Creek on the costs of the resource plan, while retaining use of capacity expansion to generate the lowest-cost resource plan.

Figure 34: Updated Execution Plan

Resequencing of 2028-2031 builds



As described in more detail in Section 6.3, slightly accelerating Kansas Central's identified Combined Cycle plants will allow coordinating with Evergy Missouri West's identified 2028 Combined Cycle plant. In addition, targeting an earlier in-service date provides additional flexibility in serving near-term economic development and mitigates risks of delays caused by interconnection or permitting, for example. In parallel with this acceleration of the Combined Cycle builds, a portion of the 2028 and 2029 identified solar builds was delayed to 2030 and 2031. This adjustment allows ongoing ratable solar builds and avoids overloading builds in 2028 and 2029. Because this adjusted plan differs from the capacity expansion-generated plan, it will, by definition, increase costs compared to AIBG. However, Evergy believes this is a more executable Preferred Portfolio which more appropriately manages risk. As the results show below, the NPVRR impact of this change is $148 million (AIBG versus AIBM).

Table 40: All Alternative Resource Plans

Kansas Central Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR ($M)	Difference	Description
1	IIBG	31,742		Full DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share
2	IBBG	31,850	108	Full DSM; Extend Lawrence 4 & 5 to 2029; Jeffrey 8% Share
3	BIBG	31,880	138	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share
4	BBBG	31,899	157	No DSM; Extend Lawrence 4 & 5 to 2029; Jeffrey 8% Share
5	AIBG	31,901	159	Low DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share
6	BBBA	31,907	165	No DSM; Extend Lawrence 4 & 5 to 2029
7	BIBH	31,911	169	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, High/High
8	ABBG	31,919	177	Low DSM; Extend Lawrence 4 & 5 to 2029; Jeffrey 8% Share
9	BIBJ	31,924	182	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, No Persimmon Wind
10	BIBK	31,961	219	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, No Persimmon Wind
11	BCAG	31,997	255	No DSM; Jeffrey 2 Retires 2030; Jeffrey 8% Share
12	BCAA	32,026	284	No DSM; Jeffrey 2 Retires 2030
13	BIBL	32,028	286	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, No Persimmon Wind, No 2025 Wind
14	BAAG	32,031	289	No DSM; Jeffrey 8% Share
15	BAAA	32,041	299	No DSM
16	AIBM	32,049	307	Low DSM; Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Jeffrey 8% Share, Earlier CC Build
** [redacted]	[redacted]	[redacted]	[redacted]	[redacted] **
18	BADG	32,191	449	No DSM; Jeffrey 3 to NG 2030; Jeffrey 8% Share
19	BAEG	32,253	511	No DSM; Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039; Jeffrey 8% Share
20	BIBI	32,278	536	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, Low/Low
21	BGAG	32,331	589	No DSM; Jeffrey 1 & 2 Retire 2030; Jeffrey 8% Share

5.8 BY-SCENARIO RESULTS – KANSAS CENTRAL

Table 41, Table 42, and Table 43 show the expected value of NPVRR for Evergy West alternative resource plans assuming high, mid, and low CO_2 restrictions.

Table 41: Kansas Central Plan Results – High CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	BIBH	32,020		No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, High/High
2	BIBG	32,030	10	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share
3	AIBG	32,050	31	Low DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share
4	BIBJ	32,079	60	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, No Persimmon Wind
5	IIBG	32,110	90	Full DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share
6	BIBK	32,117	98	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, No Persimmon Wind
7	BCAG	32,138	119	No DSM; Jeffrey 2 Retires 2030; Jeffrey 8% Share
8	BCAA	32,154	135	No DSM; Jeffrey 2 Retires 2030
9	BBBA	32,156	136	No DSM; Extend Lawrence 4 & 5 to 2029
10	BIBL	32,202	183	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, No Persimmon Wind, No 2025 Wind
11	BBBG	32,235	215	No DSM; Extend Lawrence 4 & 5 to 2029; Jeffrey 8% Share
12	ABBG	32,254	235	Low DSM; Extend Lawrence 4 & 5 to 2029; Jeffrey 8% Share
**[redacted]		[redacted]	[redacted]	[redacted]**
14	BAAA	32,323	304	No DSM
15	BGAG	32,382	362	No DSM; Jeffrey 1 & 2 Retire 2030; Jeffrey 8% Share
16	BIBI	32,422	402	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, Low/Low
17	BAAG	32,443	423	No DSM; Jeffrey 8% Share
18	AIBM	32,449	430	Low DSM; Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Jeffrey 8% Share, Earlier CC Build
19	IBBG	32,619	600	Full DSM; Extend Lawrence 4 & 5 to 2029; Jeffrey 8% Share
20	BADG	32,696	676	No DSM; Jeffrey 3 to NG 2030; Jeffrey 8% Share
21	BAEG	33,004	985	No DSM; Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039; Jeffrey 8% Share

Table 42: Kansas Central Plan Results – Mid CO2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	IIBG	31,666		Full DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share
2	IBBG	31,693	27	Full DSM; Extend Lawrence 4 & 5 to 2029; Jeffrey 8% Share
3	BBBG	31,864	198	No DSM; Extend Lawrence 4 & 5 to 2029; Jeffrey 8% Share
4	BBBA	31,883	217	No DSM; Extend Lawrence 4 & 5 to 2029
5	BIBG	31,883	217	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share
6	ABBG	31,885	219	Low DSM; Extend Lawrence 4 & 5 to 2029; Jeffrey 8% Share
7	AIBG	31,903	237	Low DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share
8	BIBH	31,920	254	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, High/High
9	BIBJ	31,924	258	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, No Persimmon Wind
10	BAAG	31,959	293	No DSM; Jeffrey 8% Share
11	BIBK	31,960	294	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, No Persimmon Wind
12	AIBM	31,989	323	Low DSM; Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Jeffrey 8% Share, Earlier CC Build
13	BCAG	31,994	328	No DSM; Jeffrey 2 Retires 2030; Jeffrey 8% Share
14	BAAA	32,009	343	No DSM
15	BIBL	32,022	356	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, No Persimmon Wind, No 2025 Wind
16	BCAA	32,024	358	No DSM; Jeffrey 2 Retires 2030
** [redacted]	[redacted]	[redacted]	[redacted]	[redacted] **
18	BAEG	32,105	439	No DSM; Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039; Jeffrey 8% Share
19	BADG	32,111	445	No DSM; Jeffrey 3 to NG 2030; Jeffrey 8% Share
20	BGAG	32,334	668	No DSM; Jeffrey 1 & 2 Retire 2030; Jeffrey 8% Share
21	BIBI	32,430	764	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, Low/Low

Table 43: Kansas Central – No CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	IBBG	31,552		Full DSM; Extend Lawrence 4 & 5 to 2029; Jeffrey 8% Share
2	IIBG	31,602	50	Full DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share
3	BBBG	31,665	114	No DSM; Extend Lawrence 4 & 5 to 2029; Jeffrey 8% Share
4	BIBI	31,677	125	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, Low/Low
5	ABBG	31,687	135	Low DSM; Extend Lawrence 4 & 5 to 2029; Jeffrey 8% Share
6	BIBG	31,721	169	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share
7	BBBA	31,729	177	No DSM; Extend Lawrence 4 & 5 to 2029
8	AIBG	31,742	190	Low DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share
9	BIBJ	31,769	217	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, No Persimmon Wind
10	BIBH	31,774	222	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, High/High
11	BIBK	31,808	256	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, No Persimmon Wind
12	AIBM	31,827	275	Low DSM; Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Jeffrey 8% Share, Earlier CC Build
13	BAAG	31,833	282	No DSM; Jeffrey 8% Share
14	BAAA	31,854	302	No DSM
15	BCAG	31,867	315	No DSM; Jeffrey 2 Retires 2030; Jeffrey 8% Share
16	BIBL	31,871	319	No DSM; Extend Lawrence 4 & 5 to 2029, Jeffrey 2 Retires 2030; Jeffrey 8% Share, No Persimmon Wind, No 2025 Wind
17	BCAA	31,903	351	No DSM; Jeffrey 2 Retires 2030
18	BADG	31,929	377	No DSM; Jeffrey 3 to NG 2030; Jeffrey 8% Share
** [redacted]		[redacted]	[redacted]	[redacted] **
20	BAEG	31,945	393	No DSM; Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039; Jeffrey 8% Share
21	BGAG	32,270	718	No DSM; Jeffrey 1 & 2 Retire 2030; Jeffrey 8% Share

5.9 EVERGY METRO RESOURCE PLANS

To make results more clear given the increased use of capacity expansion modeling in this IRP, the Evergy Metro analysis will be divided into four sections, which ultimately culminate in the creation of 22 Alternative Resource Plans.

- Testing retirement options to ensure alignment with Evergy-level analysis
- Evaluation of Capacity Expansion sensitivities (perform capacity expansion under different market price scenarios to supplement “Base” modeling)
- Testing DSM portfolio levels to identify lowest-cost option
- Resource plan development using Capacity Expansion modeling

Supply-side resource additions were not an input into any of these Alternative Resource Plans. All additions were selected using capacity expansion modeling subject to the constraints denoted by the “Other” column above.

Table 44: Evergy Metro Alternative Resource Plan Naming Convention

Demand-Side Management Potential	Early Retirements	Coal to NG	Other
A. RAP MO, Low DSM KS	A. None (2021/22 Preferred Portfolio)	A. None (2021/22 Preferred Portfolio)	A. None
B. RAP MO, No DSM KS	D. Iatan 1 Retires 2030	C. Hawthorn 5 to NG 2027	D. High/High
C. MAP MO, Low DSM KS	E. Hawthorn 5 Retires 2027		E. Low/Low
D. MAP MO, No DSM KS	F. LaCygne 2 Retires 2032		O. No New Renewables or Storage
E. RAP+ MO,Low DSM KS	M. No Retirements		
F. RAP+ MO, No DSM KS			
G. RAP- MO, Low DSM KS			
H. RAP- MO, No DSM KS			
I. RAP MO, Full DSM KS			
J. MAP MO, Full DSM KS			
K. RAP+ MO, Full DSM KS			
L. RAP- MO, Full DSM KS			
M. No DSM			

Table 45: Evergy Metro Alternative Resource Plan Overview

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
MET AAAA	RAP DSM - MO Low DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2042	150 MW Solar 2030 150 MW Solar 2034		1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040 1 CT (238 MW) in 2040
MET BAAA	RAP DSM - MO No DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2042	150 MW Solar 2030 150 MW Solar 2034		1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040 1 CT (238 MW) in 2040
MET BAAD	RAP DSM - MO No DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034	150 MW Solar 2028 150 MW Solar 2029 150 MW Solar 2035		1/2 CC (260 MW) in 2037 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040 1/2 CC (260 MW) in 2042
MET BAAE	RAP DSM - MO No DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039		150 MW Solar 2032 150 MW Solar 2033		1 CT (238 MW) in 2036 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040 1 CT (238 MW) in 2040
MET BACA	RAP DSM - MO No DSM - KS	Hawthorn 5 Coal: Dec 31, 2026 LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2042	150 MW Solar 2028 150 MW Solar 2030 150 MW Solar 2031		Hawthorn 5 NG (375 MW) in 2027 1/2 CC (260 MW) in 2036 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040 1 CT (238 MW) in 2040
MET BDAA	RAP DSM - MO No DSM - KS	Iatan 1: Dec 31, 2030 LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2029 150 MW Solar 2030 150 MW Solar 2035 150 MW Solar 2041	150 MW Battery-Wind 2031	1/2 CC (260 MW) in 2033 1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2040
MET BDCA	RAP DSM - MO No DSM - KS	Hawthorn 5 Coal: Dec 31, 2026 Iatan 1: Dec 31, 2030 LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039	150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2028 150 MW Solar 2030 150 MW Solar 2032 150 MW Solar 2041		Hawthorn 5 NG (375 MW) in 2027 1/2 CC (260 MW) in 2031 1/2 CC (260 MW) in 2033 1/2 CC (260 MW) in 2036 1/2 CC (260 MW) in 2040
MET BEAA	RAP DSM - MO No DSM - KS	Hawthorn 5: Dec 31, 2027 LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2042	150 MW Solar 2030 150 MW Solar 2031 150 MW Solar 2034		2 CT (476 MW) in 2028 1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040 1 CT (238 MW) in 2040

Table 46: Evergy Metro Alternative Resource Plan Overview (Continued)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
MET BFAA	RAP DSM - MO No DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2032 Iatan 1: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2042	150 MW Solar 2030 150 MW Solar 2031 150 MW Solar 2034 150 MW Solar 2041		1/2 CC (260 MW) in 2033 1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040
MET BMAA	RAP DSM - MO No DSM - KS	None	150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034	150 MW Solar 2030 150 MW Solar 2041		1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040 1/2 CC (260 MW) in 2042
MET CAAA	MAP DSM - MO Low DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2042	150 MW Solar 2031 150 MW Solar 2034 150 MW Solar 2041		1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040
MET DAAA	MAP DSM - MO No DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2042	150 MW Solar 2031 150 MW Solar 2034 150 MW Solar 2041		1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040
MET EAAA	RAP+ DSM - MO Low DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2042	150 MW Solar 2030 150 MW Solar 2031 150 MW Solar 2034 150 MW Solar 2041		1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040
MET EAAO	RAP+ DSM - MO Low DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039				1/2 CC (260 MW) in 2033 1/2 CC (260 MW) in 2037 1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040
MET FAAA	RAP+ DSM - MO No DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2042	150 MW Solar 2030 150 MW Solar 2031 150 MW Solar 2034 150 MW Solar 2041		1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040
MET GAAA	RAP- DSM - MO Low DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034	150 MW Solar 2030 150 MW Solar 2031 150 MW Solar 2035 150 MW Solar 2042		1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040 1 CT (238 MW) in 2040

Table 47: Evergy Metro Alternative Resource Plan Overview (Continued)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
MET HAAA	RAP- DSM - MO No DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034	150 MW Solar 2030 150 MW Solar 2031 150 MW Solar 2034 150 MW Solar 2041		1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040 1 CT (238 MW) in 2040
MET IAAA	RAP DSM - MO Full DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2042	150 MW Solar 2031 150 MW Solar 2034 150 MW Solar 2041		1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040
MET JAAA	MAP DSM - MO Full DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2033	150 MW Solar 2030 150 MW Solar 2031 150 MW Solar 2034 150 MW Solar 2041		1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040 1/2 CC (260 MW) in 2042
MET KAAA	RAP+ DSM - MO Full DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033	150 MW Solar 2030 150 MW Solar 2034 150 MW Solar 2035		1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040 1/2 CC (260 MW) in 2042
MET LAAA	RAP- DSM - MO Full DSM - KS	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2042	150 MW Solar 2031 150 MW Solar 2034 150 MW Solar 2041		1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040
MET MAAA	No DSM	LaCygne 1: Dec 31, 2032 LaCygne 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2029 150 MW Solar 2030 150 MW Solar 2035	150 MW Battery-Wind 2031	1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040 1 CT (238 MW) in 2040

5.10 REVENUE REQUIREMENT – EVERGY METRO

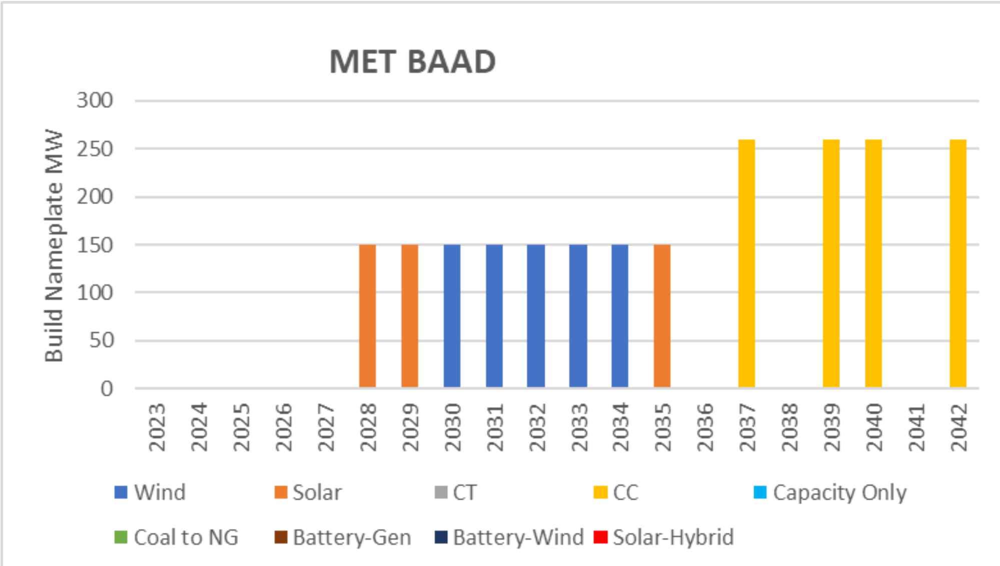
Table 48: Retirement Re-Testing

Evergy Metro Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR ($M)	Difference	Description
1	BAAA	20,408		RAP MO, No DSM KS; 2021/2022 Preferred Plan
**[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**
3	BMAA	20,422	14	RAP MO, No DSM KS; No Retirements
4	BDAA	20,424	16	RAP MO, No DSM KS; Iatan 1 Retires 2030
5	BACA	20,506	98	RAP MO, No DSM KS; Hawthorn 5 to NG 2027
6	BDCA	20,574	166	RAP MO, No DSM KS; Iatan 1 Retires 2030, Hawthorn 5 to NG 2027
7	BEAA	20,578	170	RAP MO, No DSM KS; Hawthorn 5 Retires 2027

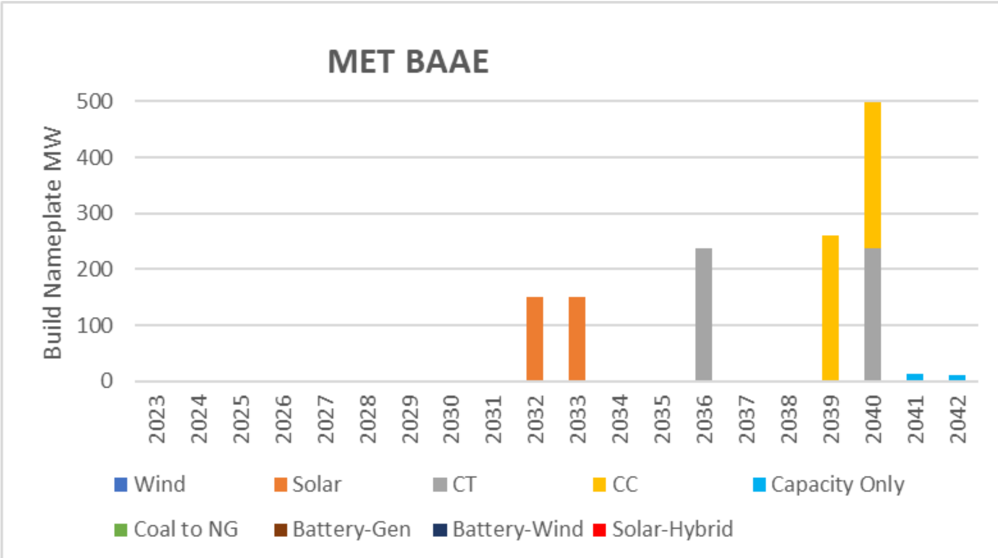
At the Metro level, 2021/2022 Preferred Portfolio retirements are the lowest cost option. This is consistent with Evergy level results because Metro does not own a portion of either Lawrence Energy Center or Jeffrey-2. The second-lowest cost retirement option for Metro includes the accelerated retirement of La Cygne 2 in 2032. However, this retirement is not economic at the Evergy level or for Evergy Kansas Central (which owns the other 50% of La Cygne 2).

Figure 35: Capacity Expansion "High" Scenario Supply-Side Additions (BAAD)



Capacity expansion modeling performed specifically in the High Gas – High Carbon Restriction ("High/High" or "High") scenario shows earlier solar builds and an increased level of wind builds compared to the Preferred Portfolio given the increased value of zero-carbon energy in a heavily carbon-restricted market. Despite high gas prices and carbon restrictions, capacity expansion also builds additional Combined Cycle plants in 2037, 2039, 2040, and 2042 as part of the lowest-cost plan. In this scenario, new Combined Cycle resources are assumed to transition to non-emitting operations beyond 2035. Given Metro's large coal fleet, this plan demonstrates the elevated need for new sources of carbon-free energy if stringent carbon restrictions are in place.

Figure 36: Capacity Expansion "Low" Scenario Supply-Side Additions (BAAE)



Capacity expansion modeling performed specifically in the Low Gas – Low Carbon Restriction ("Low/Low" or "Low") scenario shows a reduced level of solar builds compared to the Preferred Portfolio and no new wind given the reduced value of zero-carbon energy without the imposition of carbon restrictions. Consistent with the Preferred Portfolio, this scenario selects thermal additions late in the plan, but these additions are slightly earlier and more heavily weighted toward Combustion Turbines (as opposed to Combined Cycle plants). This is, again, driven by the reduced value of low- or zero-carbon energy which makes higher capacity factor . Combined Cycles less valuable compared to Combustion Turbines (which are largely a capacity resource – as opposed to an energy resource.

Table 49: DSM Portfolio Comparison

Evergy Metro Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR ($M)	Difference	Description
1	GAAA	20,402		RAP- MO, Low DSM KS
2	FAAA	20,408	6	RAP+ MO, No DSM KS
3	BAAA	20,408	6	RAP MO, No DSM KS
4	IAAA	20,413	11	RAP MO, Full DSM KS
5	LAAA	20,414	11	RAP- MO, Full DSM KS
6	EAAA	20,416	14	RAP+ MO, Low DSM KS
7	AAAA	20,417	14	RAP MO, Low DSM KS
8	HAAA	20,421	18	RAP- MO, No DSM KS
9	KAAA	20,421	19	RAP+ MO, Full DSM KS
10	MAAA	20,467	65	No DSM
11	CAAA	20,677	275	MAP MO, Low DSM KS
12	DAAA	20,669	266	MAP MO, No DSM KS
13	JAAA	20,690	288	MAP MO, Full DSM KS

Holding the retirement plan constant across all Plans and allowing capacity expansion to solve for the lowest-cost portfolio of supply-side resources, RAP- is the lowest cost Missouri DSM portfolio for Metro. However, the differences in NPVRR created by selecting either RAP or RAP+ as opposed to RAP- are very small compared to overall costs. To enable consistent implementation across Missouri jurisdictions, in addition to providing additional capacity which can prepare Metro for the risk of accelerated coal retirements which are not currently in its Preferred Portfolio, the RAP+ level of DSM is included in Metro's new Preferred Portfolio. The differences created by selecting "No" or "Full" Kansas DSM (as opposed to "Low") are also minor, with moving to No Kansas DSM reducing costs by $8 million and moving to Full Kansas DSM increasing costs by $5 million. Again, to enable consistent implementation across Kansas jurisdictions, the "Low" level of Kansas DSM is included in Metro's new Preferred Plan, consistent with Kansas Central.

Figure 37: Preferred Portfolio Supply-Side Additions (Capacity Expansion-Generated)

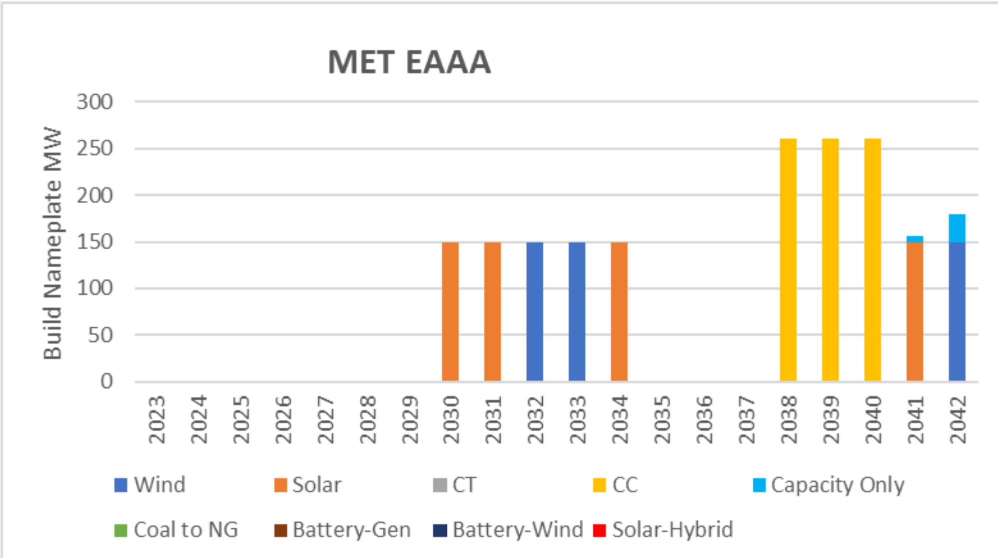


Table 50: All Alternative Resource Plans

Evergy Metro Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR ($M)	Difference	Description
1	GAAA	20,402		RAP- MO, Low DSM KS
2	FAAA	20,408	6	RAP+ MO, No DSM KS
3	BAAA	20,408	6	RAP MO, No DSM KS
4	IAAA	20,413	11	RAP MO, Full DSM KS
**[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**
6	LAAA	20,414	11	RAP- MO, Full DSM KS
7	EAAA	20,416	14	RAP+ MO, Low DSM KS
8	AAAA	20,417	14	RAP MO, Low DSM KS
9	HAAA	20,421	18	RAP- MO, No DSM KS
10	BAAD	20,421	18	RAP MO, No DSM KS; High/High
11	KAAA	20,421	19	RAP+ MO, Full DSM KS
12	BMAA	20,422	20	RAP MO, No DSM KS; No Retirements
13	BDAA	20,424	21	RAP MO, No DSM KS; Iatan 1 Retires 2030
14	MAAA	20,467	65	No DSM
15	BACA	20,506	103	RAP MO, No DSM KS; Hawthorn 5 to NG 2027
16	BDCA	20,574	171	RAP MO, No DSM KS; Iatan 1 Retires 2030, Hawthorn 5 to NG 2027
17	BEAA	20,578	176	RAP MO, No DSM KS; Hawthorn 5 Retires 2027
18	EAAO	20,610	207	RAP+ MO, Low DSM KS; No New Renewables or Storage
19	DAAA	20,669	266	MAP MO, No DSM KS
20	CAAA	20,677	275	MAP MO, Low DSM KS
21	JAAA	20,690	288	MAP MO, Full DSM KS
22	BAAE	21,030	627	RAP MO, No DSM KS; Low/Low

Utilizing the lowest-cost retirement plan (2021/2022 Preferred Portfolio) and selected DSM options (“Low” Kansas, RAP+ Missouri), based on a Mid/Mid (mid natural gas price, mid carbon restriction) scenario, capacity expansion generates the resource addition portfolio shown in Figure 37. This plan (EAAA) is not the lowest-cost plan, but the difference in NPVRR between it and the lowest cost plan is explained by the DSM choices explained above. This plan is ultimately selected as Metro’s Preferred Portfolio.

5.11 BY-SCENARIO RESULTS – EVERGY METRO

Table 51, Table 52, and Table 53 show the expected value of NPVRR for Evergy Kansas Central alternative resource plans assuming high, mid, and low CO_2 restrictions.

Table 51: Evergy Metro Plan Results – High CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	BAAD	20,595		RAP MO, No DSM KS; High/High
2	BDCA	20,649	55	RAP MO, No DSM KS; Iatan 1 Retires 2030, Hawthorn 5 to NG 2027
**[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**
4	BDAA	20,769	175	RAP MO, No DSM KS; Iatan 1 Retires 2030
5	BACA	20,822	228	RAP MO, No DSM KS; Hawthorn 5 to NG 2027
6	GAAA	20,954	359	RAP- MO, Low DSM KS
7	EAAO	20,991	396	RAP+ MO, Low DSM KS; No New Renewables or Storage
8	BAAA	21,016	422	RAP MO, No DSM KS
9	AAAA	21,024	430	RAP MO, Low DSM KS
10	BEAA	21,038	444	RAP MO, No DSM KS; Hawthorn 5 Retires 2027
11	KAAA	21,046	451	RAP+ MO, Full DSM KS
12	FAAA	21,049	454	RAP+ MO, No DSM KS
13	EAAA	21,057	462	RAP+ MO, Low DSM KS
14	IAAA	21,066	472	RAP MO, Full DSM KS
15	MAAA	21,089	495	No DSM
16	LAAA	21,100	506	RAP- MO, Full DSM KS
17	HAAA	21,121	526	RAP- MO, No DSM KS
18	BMAA	21,261	667	RAP MO, No DSM KS; No Retirements
19	DAAA	21,375	781	MAP MO, No DSM KS
20	CAAA	21,384	789	MAP MO, Low DSM KS
21	JAAA	21,447	852	MAP MO, Full DSM KS
22	BAAE	22,391	1,797	RAP MO, No DSM KS; Low/Low

Table 52: Evergy Metro Plan Results – Mid CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	BMAA	20,282		RAP MO, No DSM KS; No Retirements
2	LAAA	20,297	15	RAP- MO, Full DSM KS
3	FAAA	20,298	16	RAP+ MO, No DSM KS
4	IAAA	20,301	19	RAP MO, Full DSM KS
5	HAAA	20,302	20	RAP- MO, No DSM KS
6	KAAA	20,304	22	RAP+ MO, Full DSM KS
7	BAAA	20,306	24	RAP MO, No DSM KS
8	EAAA	20,306	24	RAP+ MO, Low DSM KS
9	GAAA	20,311	29	RAP- MO, Low DSM KS
10	AAAA	20,314	32	RAP MO, Low DSM KS
11	MAAA	20,364	83	No DSM
12	BDAA	20,383	101	RAP MO, No DSM KS; Iatan 1 Retires 2030
**[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**
14	BAAD	20,404	123	RAP MO, No DSM KS; High/High
15	BACA	20,456	174	RAP MO, No DSM KS; Hawthorn 5 to NG 2027
16	BEAA	20,493	211	RAP MO, No DSM KS; Hawthorn 5 Retires 2027
17	JAAA	20,549	267	MAP MO, Full DSM KS
18	DAAA	20,550	268	MAP MO, No DSM KS
19	CAAA	20,558	276	MAP MO, Low DSM KS
20	BDCA	20,577	295	RAP MO, No DSM KS; Iatan 1 Retires 2030, Hawthorn 5 to NG 2027
21	EAAO	20,651	369	RAP+ MO, Low DSM KS; No New Renewables or Storage
22	BAAE	20,930	648	RAP MO, No DSM KS; Low/Low

Table 53: Evergy Metro – No CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	BAAE	19,969		RAP MO, No DSM KS; Low/Low
2	BMAA	20,005	36	RAP MO, No DSM KS; No Retirements
3	HAAA	20,076	107	RAP- MO, No DSM KS
4	LAAA	20,077	108	RAP- MO, Full DSM KS
5	FAAA	20,096	128	RAP+ MO, No DSM KS
6	IAAA	20,096	128	RAP MO, Full DSM KS
7	EAAA	20,105	136	RAP+ MO, Low DSM KS
8	EAAO	20,106	137	RAP+ MO, Low DSM KS; No New Renewables or Storage
9	BAAA	20,109	140	RAP MO, No DSM KS
10	AAAA	20,117	148	RAP MO, Low DSM KS
11	GAAA	20,125	156	RAP- MO, Low DSM KS
12	KAAA	20,149	180	RAP+ MO, Full DSM KS
13	MAAA	20,153	184	No DSM
**[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**
15	BDAA	20,200	231	RAP MO, No DSM KS; Iatan 1 Retires 2030
16	BAAD	20,296	327	RAP MO, No DSM KS; High/High
17	DAAA	20,319	350	MAP MO, No DSM KS
18	CAAA	20,327	358	MAP MO, Low DSM KS
19	BACA	20,339	370	RAP MO, No DSM KS; Hawthorn 5 to NG 2027
20	JAAA	20,358	389	MAP MO, Full DSM KS
21	BEAA	20,372	403	RAP MO, No DSM KS; Hawthorn 5 Retires 2027
22	BDCA	20,488	520	RAP MO, No DSM KS; Iatan 1 Retires 2030, Hawthorn 5 to NG 2027

5.12 SUMMARY AND EVALUATION

The lowest-cost plan for Evergy Kansas Central includes a delay to 2028 of the retirement of Lawrence Unit 4 and the transition of Lawrence Unit 5 to natural gas, the accelerated retirement of Jeffrey Unit 2 in 2030, and the “Full” level of KEEIA implementation. However, due to uncertainty around the results of the KEEIA docket, and to avoid delaying necessary capacity additions when DSM may not materialize, Kansas Central has selected the “Low” level of DSM as part of its Preferred Portfolio in this Annual Update. Similarly, the Kansas Central Preferred Portfolio includes an adjustment to the sequence of new build resources in order to mitigate execution risk and ensure new capacity resources are added in a timely manner to prepare for future retirements and enable economic development.

The lowest-cost plan for Evergy Metro includes the same coal retirements as the 2022 Preferred Portfolio, “Low” Kansas DSM implementation, and RAP+ Missouri implementation. Based on the small NPVRR difference ($14 million across overall 20-year NPVRR of $20.4 billion), in order to enable consistency with Missouri West’s DSM implementation and to provide some additional capacity for Evergy Metro in the event that it ultimately has an accelerated retirement beyond its current Preferred Portfolio, (EAAA) includes RAP+ level of Missouri DSM in addition to the “Low” level of Kansas DSM.

SECTION 6: PREFERRED PORTFOLIO SELECTION AND RESOURCE ACQUISITION STRATEGY

6.1 2022 ANNUAL UPDATE PREFERRED PORTFOLIO

The Company has selected AIBM as its Preferred Portfolio for Kansas Central and EAAA as its Preferred Portfolio for Metro. These plans are among the lowest-cost plans generated by capacity expansion modeling in this Annual Update, with the only difference compared to the lowest-cost plan being the level of DSM implementation (higher for Metro Missouri and lower for Kansas Central) and adjustments to resource addition sequencing based on execution considerations.

Due to the many changes in planning considerations over the past year, the Preferred Portfolios selected for Kansas Central and Evergy Metro in this 2023 IRP Annual Update differ from the 2021 Triennial and 2022 IRP Preferred Portfolios.

> *Kansas Central:* The 2023 Preferred Portfolio reduces the amount of wind and solar added over the planning horizon and, instead includes the addition of approximately 1,000 MW of hydrogen-capable natural gas-fired combined cycle capacity in the late 2020s in order to meet increasing capacity requirements, serve new customer demand, and prepare for future coal retirements.
>
> Additionally, the Company modeled the two settlements currently before the Commission related to implementation of Demand Side Management (DSM) programs under the Kansas Energy Efficiency Investment Act (KEEIA). The lowest-cost option identified through IRP modeling is the settlement which includes a broader set of programs, with an assumption of continued implementation over time to reach a “full” level of implementation in the long-term. Due to uncertainty around the pending case, and to avoid delaying new capacity builds on the basis of “full” implementation which may not be realized, the Commission Staff settlement for a more targeted set of programs, with only short-term implementation over three years, was selected as part of the Preferred

Portfolio. The fact that this is a higher cost option demonstrates the long-term value of DSM programs and their ability to delay capacity needs over time, but the Company believes that selecting this "Low" DSM implementation is the most prudent path to plan around at this time.

Finally, in the 2022 Annual Update, Evergy identified the potential for an additional accelerated retirement which could be economically replaced, but at that time chose not to identify a specific unit for retirement as part of the Preferred Portfolio due to the uncertainty around which specific unit would ultimately be the best candidate for retirement. In this Annual Update, Jeffrey Unit 2 has been identified for 2030 retirement as part of the Preferred Portfolio. There is still significant uncertainty around different environmental regulations which could drive the retirement of Jeffrey Unit 2 or a different Evergy coal unit and thus Jeffrey Unit 2 still remains a "placeholder" for an accelerated retirement. However, given recent regulation released by the Environmental Protection Agency (EPA), it seems more probable that all units would need to install Best Available Control Technology in order to continue operating beyond the early 2030s. Given Jeffrey Units 2 and 3 are the only large units in Evergy's fleet without Selective Catalytic Reduction (SCR) systems, the capital forecasts used in this IRP (and prior IRPs) assume that SCRs would need to be added if the units do not retire by 2031. This large capital cost to continue operations make these units the most attractive options for early retirement. Evergy will continue to monitor environmental regulations and make adjustments to retirement plans as needed if conditions change, but at this time believes it is prudent to plan around a medium-term retirement of both Jeffrey Units 2 and 3 in order to avoid a situation where retirements are forced by environmental regulation and replacement capacity has not been procured proactively. Further discussion of environmental regulations is provided in Sections 4.4 and 6.2.

Evergy Metro: The 2023 Preferred Plan continues to include new investments in wind and solar resources though at a reduced level, and shifts the timing of wind resource additions to the early 2030s. Thermal additions increased above past Preferred Plans and the timing has shifted from 2040 to the late 2030s. Capacity expansion modeling was performed at the Evergy Metro level in this Annual Update and Evergy Metro has significant capacity length until La Cygne Unit 1 retires in 2032, new resource additions specific to Evergy Metro are delayed until the early 2030s. In past IRPs, Evergy Metro received a share of all resource additions which were shown to be cost-effective at the Evergy level. This new approach creates a Preferred Portfolio where new resources are clearly tied to capacity and energy needs specific to Evergy Metro's customers. However, this approach does create risk that Evergy Metro could be forced to retire additional coal in the 2030 timeframe (Hawthorn Unit 5, for example, which continues to face pressure from environmental advocacy groups and Kansas City, Missouri) and then be forced to add new capacity on a reactive basis, which is likely to be more costly for customers. In addition, the plans which include the additional accelerated retirement of either **[redacted]** are currently very close to the cost of Evergy Metro's Preferred Portfolio. Because both of those units are shared with other Evergy utilities and neither are favorable retirement options at the Evergy level (or for Evergy Kansas Central or Evergy Missouri West), neither is included in the Evergy Metro Preferred Portfolio. However, these economics could change over time and ultimately either retirement could be accelerated. To mitigate that risk, it is important that Evergy Metro continues to monitor these uncertainties (as described in Section 6.2) and quickly make adjustments in future IRPs if these accelerated retirements become more likely.

Additionally, the refresh of the demand response potential study shows value in choosing the RAP+ level of demand-side management programs over the RAP level selected in the 2022 Annual Update for Missouri West. For Metro, the combination of this level of Missouri DSM and the "low" level of Kansas DSM is only $14 million higher cost over the 20-year planning horizon (<0.1% of overall costs) compared to the lowest cost plan, which included the RAP- level of DSM for Missouri in addition to the “low” level of Kansas DSM. To enable consistent implementation across Missouri jurisdictions, in addition to providing additional capacity which can prepare Metro for the risk of accelerated coal retirements which are not currently in its Preferred Portfolio, the RAP+ level of DSM is included in Metro’s new Preferred Portfolio and the new study shows much lower demand response potential than was forecasted in the last study, so the level of capacity and energy reductions which can be achieved from all programs are smaller.

The Preferred Portfolios outlined below are directionally consistent with Evergy’s most recent 2022 Capital Investment Plan (CIP) filing in terms of scale and cost of additions over the next five years, however there will likely be a shift in timing from the 2024-2026 timeframe to the 2027-2029 timeframe in the next CIP filing based on this IRP Update. Continuing siting, engineering, and procurement activities and more detailed evaluation of new emissions compliant, hydrogen capable natural gas resources will further refine capital requirement estimates which will be included in future CIP filings, beginning with 2024.

The Preferred Portfolio KSC AIBM has been selected for Evergy Kansas Central is shown in Table 54 below:

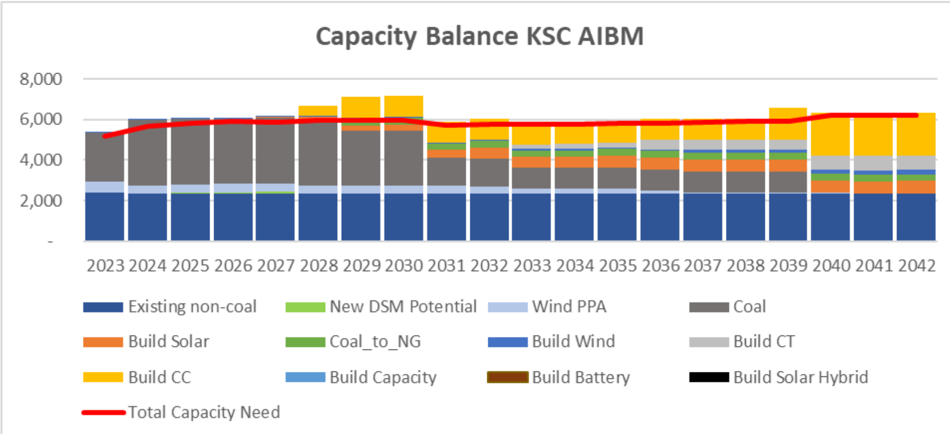
Table 54: Evergy Kansas Central Preferred Portfolio AIBM

Year	Wind (MW)	Solar (MW)	Battery (MW)	Thermal (MW)	Capacity Only (Annual MW)	DSM (Annual MW)	Retirements (MW)
2023	199	0	0	0	0	100	0
2024	0	0	0	176	0	100	0
2025	200	0	0	0	0	140	0
2026	0	0	0	0	0	153	0
2027	0	150	0	0	0	179	0
2028	0	150	0	521	0	100	0
2029	0	150	0	859	0	98	493
2030	0	150	0	0	0	96	0
2031	0	150	0	0	0	94	1349
2032	0	300	0	0	0	92	0
2033	150	0	0	238	32	89	380
2034	150	0	0	0	39	89	0
2035	0	150	0	0	0	89	0
2036	0	0	0	238	0	89	0
2037	0	0	0	0	0	88	0
2038	0	0	0	0	0	88	0
2039	0	0	0	521	0	88	0
2040	0	0	0	759	0	88	1007
2041	150	0	0	0	28	88	0
2042	0	300	0	0	0	88	0

Note: 2024 Thermal Additions reflect Jeffrey 8%; 2029 Thermal Additions include LEC 5 transition to natural gas

6.1.1 EVERGY KANSAS CENTRAL PREFERRED PORTFOLIO COMPOSITION

Figure 38: Evergy Kansas Central Preferred Portfolio Capacity Balance



The Evergy Kansas Central Preferred Portfolio includes the following renewable additions: 199 MW of wind generation in May-2023 (Persimmon Creek), 200 MW of wind generation in 2024, and 150 MW of wind generation in 2032, 2033, and 2040. Additionally, 150 MW of solar generation in each year 2026 through 2030, 300 MW of solar generation in 2031, 150 MW of solar generation in 2034, and 300 MW of solar generation in 2041. Over the 20-year planning period, total renewable additions equal 849 MW of wind generation and 1,500 MW of solar generation. Also, new thermal resources are added in 2027 and 2028 to meet increasing Resource Adequacy requirements, support new customer loads, and replace retiring coal capacity beginning in 2027, including two combined cycle units. Later in the planning horizon, additional thermal resources are added to support further retirements, including 3 combustion turbines and 2 combined cycle units. The Preferred Portfolio includes the "Low" level of Kansas DSM implementation for Evergy Kansas Central.

Note: All dates listed in this summary are end-of-year unless otherwise noted. Capacity balance views shown elsewhere in this document represent summer capacity impacts which means that additions are typically shown in the following year (the year in which they will be available for summer capacity)

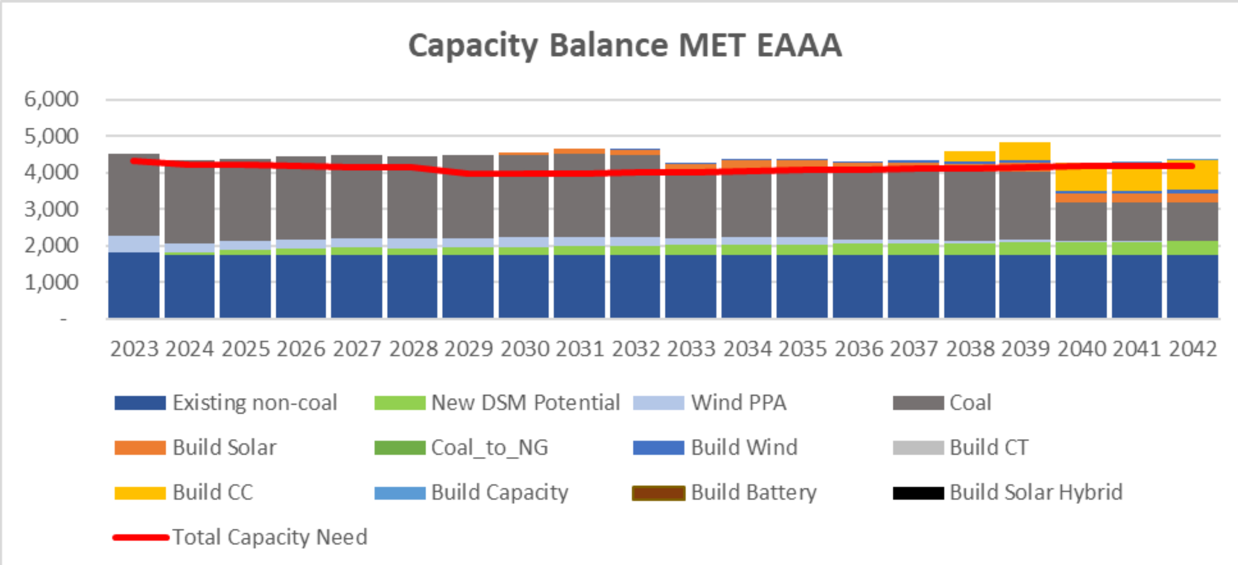
The Evergy Metro Preferred Portfolio EAAA for the 20-year planning period is shown in Table 55 below:

Table 55: Evergy Metro Preferred Portfolio

Year	Wind (MW)	Solar (MW)	Battery (MW)	Thermal (MW)	Capacity Only (Annual MW)	DSM (Annual MW)	Retirements (MW)
2023	0	0	0	0	0	51	0
2024	0	0	0	0	0	86	0
2025	0	0	0	0	0	142	0
2026	0	0	0	0	0	178	0
2027	0	0	0	0	0	206	0
2028	0	0	0	0	0	187	0
2029	0	0	0	0	0	199	0
2030	0	150	0	0	0	211	0
2031	0	150	0	0	0	222	0
2032	150	0	0	0	0	232	0
2033	150	0	0	0	0	236	380
2034	0	150	0	0	0	244	0
2035	0	0	0	0	0	256	0
2036	0	0	0	0	0	267	0
2037	0	0	0	0	0	279	0
2038	0	0	0	260	0	290	0
2039	0	0	0	260	0	299	0
2040	0	0	0	260	0	308	832
2041	0	150	0	0	6	316	0
2042	150	0	0	0	30	324	0

6.1.2 PREFERRED PORTFOLIO COMPOSITION

Figure 39: Evergy Metro Preferred Portfolio Capacity Balance



The Evergy Metro Preferred Portfolio includes the following renewable additions: 150 MW of wind generation in years 2031, 2032, and 2041. Additionally, 150 MW of solar generation in 2029, 2030, 2033, and 2040. Over the 20-year planning period, total renewable additions equal 450 MW of wind generation and 600 MW of solar generation. Also, thermal resources are modeled to replace retiring coal capacity beginning in 2037, including 781 MW of new Combined Cycle units. The Preferred Portfolio includes the RAP+ level of DSM for Evergy Metro Missouri and "Low" DSM for Evergy Metro Kansas.

Note: All dates listed in this summary are end-of-year unless otherwise noted. Capacity balance views shown elsewhere in this document represent summer capacity impacts which means that additions are typically shown in the following year (the year in which they will be available for summer capacity)

6.2 MONITORING CHANGING CONDITIONS AND MAINTAINING FLEXIBILITY

The primary goals in selecting a Preferred Portfolio 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 Kansas Central's and Evergy Metro'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: As expected, the dramatic increase in natural gas prices seen in late 2021 and 2022 has subsided and natural gas prices have now returned to levels seen in 2020 and prior. The experience of those elevated prices, however, demonstrated the value of considering a wide range of potential price scenarios in resource planning analysis given the large amount of uncertainty inherent in forecasting commodity prices. To that end, Evergy has utilized a wider range (lower "Low" and higher "High") of natural gas price forecasts in this 2023 IRP, created based on both publicly-available and proprietary third-party forecasts. The Preferred Portfolio has been tested across this wide range of potential commodity price futures, as described in the Integrated Risk Analysis section.

Renewable Resource Construction Costs: Driven by tight supply chains, increasing incentives for "on-shoring" of manufacturing, and increased demand driven by the Inflation Reduction Act, there has been an increase in the construction cost for new renewable generation. Evergy has incorporated this increase into the cost assumptions utilized for this IRP based on the results of its early 2023 All-Source Request for Proposal (RFP). Based on these near-term prices for renewable projects, a third-party cost curve is then used to forecast future cost reductions and to create a long-term forecast for renewable resource costs. These increased costs, combined with the delayed availability of solar projects based on the RFP, have, based on capacity expansion modeling results explained in the Integrated Risk Analysis section, resulted in less renewable additions during the first few years of the Preferred Portfolio.

SPP Interconnection Queue: The SPP Interconnection Queue continues to be severely backlogged, although SPP is making progress in addressing this issue and redesigning its processes to mitigate the risk of future backlogs. 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 Portfolio 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. Evergy is closely monitoring SPP's development of the Consolidated Planning Process and the Joint Targeted Interconnection Queue study, which both should serve to provide improved schedule and upgrade cost certainty for future resource additions. In parallel, Evergy is working with SPP and other members to develop other methods to ensure the Interconnection Queue does not become a barrier to ensuring the reliability of the SPP system or the ability of members to meet their resource adequacy requirements.

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: 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).

Economic Development: 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. Based on accelerated activity in this economic development space since the 2022 Annual Update, Kansas Central has included a buffer of 150 MW and Metro a buffer of 60-100 MW above the respective current SPP capacity requirements beginning in 2026 in this Annual Update. The current Evergy Kansas Central and Evergy Metro pipeline for potential economic development which could be online by 2026 far exceeds this amount, but this small buffer mitigates the risk of being unable to serve new customers in a timely manner while also mitigating the risk of increasing SPP capacity requirements (described in more detail below). While planning to serve the full economic development pipeline would likely result in procuring / building capacity for customers who did not ultimately materialize, having this small buffer is critical for allowing Evergy Kansas Central and Evergy Metro to support timely growth in its service territory. Evergy is taking a similar approach to planning for potential new economic development projects across each of its jurisdictions.

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. SPP is currently expecting to implement an interim winter resource adequacy requirement for the 2024/2025 winter season (based on applying the summer reserve margin to winter load), with the implementation of a standalone winter requirement in the following winter. It is still uncertain how this standalone requirement will be implemented, thus Evergy continues to participate actively in SPP policy development.

Resource Accreditation: Earlier this year, FERC rejected SPP's proposal to implement the Effective Load Carrying Capability (ELCC) methodology for renewable accreditation, which would reduce the capacity credit given to renewable resources. ELCC remains the industry standard for renewable accreditation and FERC's stated rationale for rejecting the proposal was based largely on the discrepancy between accreditation approaches for renewable and thermal generators. In response to this feedback, SPP is currently planning to file parallel requests with FERC to implement ELCC and Performance-Based Accreditation for thermal generators at the same time in 2026. This parallel implementation creates significant uncertainty around capacity accreditation which will be received beginning in 2026 given these two methodologies are more "black-box" and they create variability in the credit a resource will receive from season to season and year to year. To factor in this risk and uncertainty, capacity expansion modeling in the 2023 Annual Update allowed a lower level of market capacity purchases for each jurisdiction beginning in 2026. This reflects the expectation that excess capacity available in SPP will decline and other Load-Responsible Entities (LRE) will be less willing to sell their excess in order to manage their own resource adequacy risk.

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. SPP continues to evaluate this requirement in the context of other Resource Adequacy Requirement changes (particularly for the winter).

Reserve Margin: Soon after the 2022 Annual Update was filed, SPP increased the Planning Reserve Margin (i.e., the amount of accredited capacity that an LRE must maintain in excess of its load) from 12% to 15% beginning with the summer 2023 season. SPP has also indicated that they expect future increases to the

Reserve Margin as the resource mix continues to become more intermittent and we see more extreme weather. At this time, it is uncertain when the next increase could be implemented, but it's possible it could be as soon as 2025 or 2026 summer. Based on SPP's preliminary evaluations of potential winter Resource Adequacy Requirements, it is also possible that the winter Reserve Margin will be much higher than the summer Reserve Margin. To mitigate some of the impact of future reserve margin increases, in addition to the buffer for economic development activity mentioned above, an additional buffer of 90 MW has been added to Kansas Central's capacity requirements beginning in 2024.

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 couple of years 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). NERC has established Standard Drafting Teams to develop new Reliability Standards which will require the performance of Energy Assessments. It is uncertain how these potential Standards will ultimately impact SPP analysis and requirements, but Evergy continues to monitor them closely.

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

The passage of the Inflation Reduction Act and the EPA publishing several more stringent draft rules for fossil plants have demonstrated it is more likely that carbon reductions will be realized through a mix of renewable incentives (e.g., Production Tax Credits), carbon emission caps, and other stringent emission restrictions on fossil plants which drive the need for new retrofits. As a result of these changes, Evergy moved away from exclusively using a carbon tax (which was used in historical IRPs, including the 2022 Annual Update) to utilize carbon restriction scenarios instead, which are aligned with carbon restriction scenarios developed through the SPP economic model development process. As a result of this change, a higher level of carbon restrictions actually drives down average SPP energy market prices (as renewables are build out aggressively based on incentives and the need for carbon-free energy) and drives up fixed costs as fossil plants must be retrofitted or replaced with other non-emitting resources. As opposed to a carbon tax, which is a variable cost that impacts a resource's market offer cost, these fixed costs are not recoverable in the SPP energy market and thus do not drive up energy prices. It is possible that ultimately a CO_2 tax may become the more likely scenario again, thus Evergy continues to monitor policy developments to determine whether an adjustment is necessary, but for this Update, an "incentives plus restrictions" approach is more representative of Evergy's expectations for the future.

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 Portfolio. Specifically, the IRP process utilizes the latest understanding of the inputs outlined below in order to confirm the prior Preferred Portfolio and new Preferred Portfolio through the resource planning 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. For this IRP, Evergy has evaluated additional potential natural gas conversions at Jeffrey Energy Center and Hawthorn Unit 5. At this stage, retiring Jeffrey Units 2 and 3 is more economic than converting them to natural gas and retaining Hawthorn Unit 5 as a coal plant is more economic than converting to gas given the high cost of natural gas firm service required for capacity accreditation and the very low expected capacity factor of converted coal units. However, Evergy will continue to evaluate these options in the future as an alternative to retirement given the potential conversion offers to retain accredited capacity, reduce the need for environmental retrofits, and reduce operating costs.

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 (e.g., expected demand, expected renewable output, gas prices) which will vary from season to season.

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.

Increases in load forecast and/or Resource Adequacy requirements: As described above, Evergy has seen increased economic development activity and ongoing changes to SPP Resource Adequacy requirements. Either of these factors could cause a change to a retirement decision if, for example, a unit needs to be retained to serve a new large load or to meet an increased capacity requirement.

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. Primary considerations when making final resource additions decisions are outlined below.

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 KEEIA (Kansas) and MEEIA (Missouri) processes and thus points of commitment align with those approvals. These approval processes, and the potential studies and stakeholder processes which support them, are the primary driver of ultimate DSM implementation.

6.3 IMPLEMENTATION PLAN - EVERGY KANSAS CENTRAL

The Evergy Kansas Central resource plan contemplates the addition of 199 MW of wind in 2023, 200 MW of wind in 2024 and 150 of solar in 2026. The 199 MW of wind in 2023 is the previously purchased and identified Persimmon Creek wind farm in Northwest Oklahoma. This project has been in included in Evergy's 2023 rate case for consideration and is further supported by this IRP. As the resource was already existing and operating in SPP service, the typical construction timelines were not required for that asset selection.

The 2024 wind addition is modeled from responses to Evergy's 2023 All-Source RFP. Evergy plans to evaluate the offered supply side resources and move forward with the acquisition process out of the RFP offered projects. For construction of wind assets, the timeline will vary depending on site control and SPP maturity with high level major milestones falling within a range depicted in Table 56 below. Evergy expects to continue negotiations with the respondents to the 2023 All-Source RFP in 2023 to complete the 2024 wind additions contemplated in the IRP. These activities will be completed in anticipation of future regulatory proceedings which could include predetermination, certificates of convenience and necessity, general rate cases or abbreviated rate cases.

Table 56: 2024 Wind Implementation Milestones

Illustrative Milestone Schedule (By Developer or Evergy)	Outside Completion
Site Control Complete	December 2022
Environmental and Land Permitting Complete	December 2022
Major Commercial Agreements Complete (BTA, EPC, etc.)	December 2022
Regulatory Approvals	TBD
Detailed Design and Engineering	June 2023
Equipment Acquisition and Delivery	January 2024
Construction Complete	November 2024
Testing and Commissioning	December 2024
Commercial Operation	December 2024

The 2026 solar addition is modeled from responses to Evergy's 2023 All-Source RFP. Evergy plans to evaluate the offered supply side resources and move forward with the acquisition process out of the RFP offered projects. While end-of-year 2026 is slightly outside the 3-year window for implementation plans, there will be activity that takes place in the planning window for the solar farm. For construction of solar assets, the timeline will vary depending on site control and SPP maturity with high level major milestones falling within a range with outside dates depicted in Table 57 below. Evergy expects to continue negotiations with the respondents to the 2023 All-Source RFP in 2023 to in preparation for the 2026 solar additions contemplated in the IRP. These activities will be completed in anticipation of future regulatory proceedings which could include predetermination, certificates of convenience and necessity, general rate cases or abbreviated rate cases.

Table 57: 2026 Solar Implementation Milestones

Illustrative Milestone Schedule (By Developer or Evergy)	Outside Completion
Site Control Complete	December 2023
Major Commercial Agreements Complete (BTA, EPC, etc.)	June 2024
Environmental and Land Permitting Complete	October 2024
Regulatory Approvals	January 2025
Detailed Design and Engineering	January 2025
Equipment Acquisition and Delivery	January 2026
Construction Complete	October 2026
Testing and Commissioning	November 2026
Commercial Operation	December 2026

In addition to the renewable additions identified above, the IRP has identified a need for firm, dispatchable generation in 2027 (520 MW) and 2028 (520 MW) for Kansas Central. While commercial operation for these sites is outside the traditional implementation period for the IRP, there are significant steps that need to be completed within three years to be successful by those dates. As of June 2023, there are 33.9 GW of projects in the SPP interconnection queue for SPP Central which is composed of Kansas and Missouri. However, there are only 167 MW of thermal interconnection positions within that backlog. In order for Evergy to successfully place a site in service by 2027 Evergy anticipates competitively bidding the vast majority of costs within the hydrogen blending capable combined cycle projects but understands that, with a lack of thermal offerings in the 2023 All-Source RFP, projects will ultimately be delivered by Evergy. To that end, Evergy launched a Conventional Generation Siting Study in the Spring of 2023 to select sites and technologies that will be favorable for future conventional generation use. This study will serve as feed-stock for the initial design and engineering of the projects. Early-stage activities will represent a small portion of the overall cost of the project and will be completed in anticipation of future regulatory proceedings which may include predetermination and certificates of convenience and necessity. An anticipated project acquisition milestone schedule is depicted below.

Table 58: Combined Cycle Implementation Milestones

Illustrative Milestone Schedule (By Developer or Evergy)	Phase I (2027) Outside Completion	Phase II (2028) Outside Completion
Site Control Complete	December 2023	December 2023
SPP Large Generator Interconnection Application	December 2023	December 2023
Environmental and Land Permitting Complete	October 2024	October 2024
Design Spec & Engineering, Procurement, and Construction Award	October 2024	October 2024
State Utility Regulatory Approvals (CCN and/or Predetermination)	December 2024	December 2024
Detailed Design and Engineering	April 2025	April 2025
Major Equipment Requisition	July 2025	July 2025
Major Equipment Acquisition and Delivery	March 2027	March 2028
Construction Complete	July 2027	July 2028
Testing and Commissioning	November 2027	November 2028
Commercial Operation	December 2027	December 2028

In order to achieve a more optimized hydrogen blending capable combined-cycle build plan across all of Evergy's utilities including Kansas Central, the Kansas Central site of ~520 MW in 2027 will reflect a partial ownership of a site that is expected to fulfill Evergy Missouri West's needs that year as well. This, in combination with pulling Phase-II of EKC's build forward just a couple of years to 2028, allows for a more fully optimized deployment of resources and a cohesive strategy to build out hydrogen capable firm-dispatchable resources. This should allow Evergy and the eventual supporting stakeholders both internally and externally to focus on the delivery of the CCGT projects for the benefit of Kansas Central customers.

There are also environmental retrofit projects continuing or expected to be continued or initiated during the three-year implementation period. Table 59 below provides estimated dates for major projects currently expected.

Table 59: Evergy Kansas Central Environmental Retrofit Project Timeline

Milestone Description	2023 IRP Date Range
Jeffrey 1 - Fly Ash Landfill Area 1 Closure Design	2021 - 2024
Jeffrey 1 - Fly Ash Landfill Area 1 Cover	2023 - 2028
Jeffrey 1 - Fly Ash Landfill Area 2 Cover	No longer planned
Jeffrey 1 - FGD Landfill Leachate Pond	2021
Jeffrey 1 - FGD Landfill Cell 1C Cover	2021 - 2024
Jeffrey 1 - Bottom Ash Settling Area Closure	2021 - 2026
Jeffrey 1 - Bottom Ash Landfill Capping	2021 - 2026
Jeffrey 1 - Bottom Ash Conversion	2021
Jeffrey 1 - Effluent Guidelines FGD Wastewater	2021 - 2025
Jeffrey 2 - Fly Ash Landfill Area 1 Closure Design	2021 - 2024
Jeffrey 2 - Fly Ash Landfill Area 1 Cover	2023 - 2026
Jeffrey 2 - Fly Ash Landfill Area 2 Cover	No longer planned
Jeffrey 2 - FGD Landfill Leachate Pond	2021
Jeffrey 2 - FGD Landfill Cell 1C Cover	2021 - 2024
Jeffrey 2 - Bottom Ash Settling Area Closure	2021 - 2026
Jeffrey 2 - Bottom Ash Landfill Capping	2021 - 2026
Jeffrey 2 - Bottom Ash Conversion	2021
Jeffrey 2 - Effluent Guidelines FGD Wastewater	2021 - 2025
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	No longer planned
Jeffrey 3 - FGD Landfill Leachate Pond	2021
Jeffrey 3 - FGD Landfill Cell 1C Cover	2021 - 2024

Jeffrey 3 - Bottom Ash Settling Area Closure	2021 - 2026
Jeffrey 3 - Bottom Ash Landfill Capping	2021 - 2026
Jeffrey 3 - Bottom Ash Conversion	2021
Jeffrey 3 - Effluent Guidelines FGD Wastewater	2021 - 2025
La Cygne 1 - Upper AQC Cover, Dewatering, Grading, Install	2021 - 2034
La Cygne 1 - Lower AQC Cover, Dewatering, Grading, Install	2021 - 2034
La Cygne 1 - Upper AQC Stormwater Reroute	2021
La Cygne 1 - Landfill Stormwater Reroute	2021
La Cygne 1 - Landfill Cover	2021 - 2034
La Cygne 1 - New Landfill Construction	2022-2026
La Cygne 2 - Upper AQC Cover, Dewatering, Grading, Install	2021 - 2034
La Cygne 2 - Lower AQC Cover, Dewatering, Grading, Install	2021 - 2034
La Cygne 2 - Bottom Ash Pond Clean Closure	2021
La Cygne 2 - Upper AQC Stormwater Reroute	2021
La Cygne 2 - Landfill Stormwater Reroute	2021
La Cygne 2 - Landfill Cover	2021 - 2034
La Cygne 1 - New Landfill Construction	2022-2026
Lawrence 4 - Landfill Cover	2021 - 2028
Lawrence 5 - Landfill Cover	2021 - 2028
Lawrence 4 - Ash Pond Closure	2021
Lawrence 5 - Ash Pond Closure	2021
Lawrence 4 - Cell 5/6 Construction	2024 - 2025
Lawrence 5 - Cell 5/6 Construction	2024 - 2025

6.4 IMPLEMENTATION PLAN – EVERGY METRO

Evergy Metro has several environmental retrofit projects continuing or expected to be continued or initiated during the three-year implementation period. Table 60 below provides estimated dates for major projects currently expected.

Table 60: Evergy Metro Environmental Retrofit Project Timeline

Milestone Description	2023 IRP Date Range
Hawthorn 5 - Intake Modification	2021 - 2024
Hawthorn 5 - Groundwater Monitoring Program	2021 - 2024
Hawthorn 5 - Outfall 008 Weir Box	2022
Hawthorn 5 - Outfall 009 Weir Box	2022
Iatan 1 - Landfill Phase 1B Cover	2021 - 2023
Iatan 1 - Landfill Phase 2B Cover	2023 - 2024
Iatan 1 - Landfill Phase 2A Cover	2025-2026
Iatan 1 - Ash Pond Closure	2021
Iatan 1 - Intake Modification	2021 - 2023
Iatan 2 - Landfill Phase 1B Cover	2021 - 2023
Iatan 2 - Landfill Phase 2B Cover	2023 - 2024
Iatan 1 - Landfill Phase 2A Cover	2025-2026
La Cygne 1 - Upper AQC Cover, Dewatering, Grading, Install	2021 - 2034
La Cygne 1 - Lower AQC Cover, Dewatering, Grading, Install	2021 - 2034
La Cygne 1 - Upper AQC Stormwater Reroute	2021
La Cygne 1 - Landfill Stormwater Reroute	2021
La Cygne 1 - Landfill Cover	2021 - 2034
La Cygne 1 - New Landfill Construction	2022-2026
La Cygne 2 - Upper AQC Cover, Dewatering, Grading, Install	2021 - 2034
La Cygne 2 - Lower AQC Cover, Dewatering, Grading, Install	2021 - 2034

La Cygne 2 - Bottom Ash Pond Clean Closure	2021
La Cygne 2 - Upper AQC Stormwater Reroute	2021
La Cygne 2 - Landfill Stormwater Reroute	2021
La Cygne 2 - Landfill Cover	2021-2034
La Cygne 2 - new Landfill Construction	2022-2026

SECTION 7: 2021 IRP JOINT AGREEMENT RESPONSES

Resolved alleged Concerns and Deficiencies which were not addressed in the 2022 Annual Update are addressed as follows:

7.1 STAFF OF THE KANSAS CORPORATION COMMISSION (STAFF)

Staff Concern 3 – A description of reliability considerations can be found in Section 6.2. A standalone reliability analysis of extreme weather effects on resources will be in the next Triennial IRP.

Staff Concern 6 – Evergy will work with parties to identify specific T&D information which will be included in its next Triennial filing.

7.2 CITIZENS UTILITY RATE BOARD (CURB)

CURB Concern 2 – Evergy will continue to work with stakeholders to develop DSM inputs for multiple levels of savings that will be evaluated in the future IRP updates and triennial filings. The results of the DSM application docket will be incorporated in the next triennial filing.

7.3 CLIMATE AND ENERGY PROJECT (CEP)

CEP B – Evergy will continue to work with stakeholders to develop DSM inputs for multiple levels of savings that will be evaluated in the future IRP updates and triennial filings. The results of the DSM application docket will be incorporated in the next triennial filing.

7.4 RENEW MISSOURI

Addressed in 2022 Annual Update

7.5 KANSAS ELECTRIC POWER COOPERATIVE, INC. (KEPCO)

KEPCO A – Evergy is utilizing a capacity expansion model beginning with the 2022 Annual Update. A description of reliability considerations can be found in Section 6.2. A standalone reliability analysis of extreme weather effects on resources will be in the next Triennial IRP.

KEPCO B – Analysis related to Jeffrey Energy Center environmental retrofits provided below as described in response to KEPCO comments on 2022 Annual Update. This analysis demonstrates the significance of the assumed environmental costs in driving the economics of the Jeffrey 2 and 3 2030 retirements. However, particularly given recent EPA activity, Evergy continues to believe that completing these retrofits will be required in the early 2030s. Evergy will continue to monitor environmental regulations and make changes to its retirement plans in the years between now and 2030, but planning around these likely future expenses is necessary to ensure replacement capacity is in place if and when regulations change and retrofits become required.

Table 61: Kansas Central Jeffrey Environmental Cost Sensitivity Rankings

Rank	Plan	NPVRR ($M)	Difference	Description
1	AKBN	31,695		Low DSM; Extend Lawrence 4 & 5 to 2028, Extend Jeffrey 3 to 2039; Jeffrey 8% Share, No Major Environmental Costs
2	ABBN	31,740	45	Low DSM; Extend Lawrence 4 & 5 to 2028; Jeffrey 8% Share, No Major Environmental Costs
3	ALBN	31,752	57	Low DSM; Extend Lawrence 4 & 5 to 2028, Extend Jeffrey 3 to 2039, LaCygne 2 Retires 2032; Jeffrey 8% Share, No Major Environmental Costs
4	AIBG	31,901	206	Low DSM; Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Jeffrey 8% Share
5	ABBG	31,919	224	Low DSM; Extend Lawrence 4 & 5 to 2028; Jeffrey 8% Share

These results show that, if major environmental retrofits are not required, extending the Jeffrey 3 retirement to 2039 is lower cost than retiring it in 2030. However, the retirement only increases costs by $45 million compared to the extension, even without the assumed environmental costs. Additionally, the retirement of La Cygne in 2032 (which is an attractive retirement option for Evergy Metro), only increases costs by $57 million compared to retiring only La Cygne 1 in the 2030-2032 timeframe. While these are certainly meaningful cost differences, they can also very easily be overcome by changes in capital costs or expected revenues from either unit. In this scenario where major environmental retrofits are not needed for either Jeffrey Unit 2 or 3, accelerating the retirement of Jeffrey 2 to 2030 increases costs much more significantly than just including the Jeffrey 3 retirement in 2030.

Intuitively, all of these results without major environmental costs are higher cost than a plan which assumes Jeffrey 2 continues to operate and environmental retrofits are required (ABBG) or when Jeffrey 2 is retired in 2030 to avoid environmental retrofit costs and thus new capacity is needed sooner (AIBG).

Table 62: Evergy-Level Jeffrey Environmental Cost Sensitivity Rankings

Rank	Plan	NPVRR ($M)	Difference	Description
1	BBBN	62,194		Extend Lawrence 4 & 5 to 2028; No Major Environmental Costs
2	BIBA	62,248	53	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030
3	BKBN	62,281	87	Extend Lawrence 4 & 5 to 2028, Extend Jeffrey 3 to 2039; No Major Environmental Costs
4	BLBN	62,344	150	Extend Lawrence 4 & 5 to 2028, Extend Jeffrey 3 to 2039, Iatan 1 Retires 2030, LaCygne 2 Retires 2032; No Major Environmental Costs
5	BBBA	62,382	188	Extend Lawrence 4 & 5 to 2028

At the Evergy level, the retirement of Jeffrey 3 in 2030 (BBBN) and the retirement of Jeffrey 2 and 3 in 2030 (BIBA) are both lower-cost plans than having both units retire in 2039, even without major environmental costs assumed (BKBN).

KEPCO D – Evergy will continue to work with stakeholders to develop DSM inputs for multiple levels of savings that will be evaluated in the future IRP updates and triennial filings. The results of the DSM application docket will be incorporated in the next triennial filing.

7.6 MCPHERSON BPU

McPherson BPU 3 - A description of reliability considerations can be found in Section 6.26.2. A standalone reliability analysis of extreme weather effects on resources will be in the next Triennial IRP.

7.7 NEW ENERGY ECONOMICS (NEE)

NEE 3 — Solar hybrid and battery storage resource options considered in capacity expansion modeling

NEE 4 — 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 6 –- Evergy will continue to work with stakeholders to develop DSM inputs for multiple levels of savings that will be evaluated in the future IRP updates and triennial filings. The results of the DSM application docket will be incorporated in the next triennial filing.

NEE 7 –- A description of reliability considerations can be found in Section 6.2. A standalone reliability analysis of extreme weather effects on resources will be in the next Triennial IRP.

7.8 SIERRA CLUB (SC)

Sierra Club Deficiency 7 - Solar hybrid and battery storage resource options considered in capacity expansion modeling

Evergy 2023 DSM Market Potential Study

Prepared for: Evergy

Prepared by: Applied Energy Group, Inc.

Date: May 15, 2023

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1 | Introduction

Evergy Services, Inc. (Evergy) engaged Applied Energy Group (AEG) to conduct a Demand-Side Management (DSM) Market Potential Study. The DSM Market Potential Study was conducted to support Evergy's Missouri Integrated Resource Plan (IRP) and Missouri Energy Efficiency Investment Act (MEEIA) Cycle 4 regulations, specifically to satisfy the demand-side analysis requirements of the Missouri resource planning regulations.

Evergy provides clean, safe, and reliable energy to 1.7 million customers in Kansas and Missouri through its operating subsidiaries, Evergy Kansas Central, Evergy Metro, and Evergy Missouri West. The DSM Market Potential Study evaluated energy efficiency, demand response, and demand-side rates for Every's Missouri jurisdictions, Every Metro and Evergy Missouri West.

The key objectives of the study included the following:

- Perform a comprehensive analysis that complies with the statutory requirements of the Missouri Public Service Commission (PSC).
- Provide credible and transparent estimation of the technical, economic, and achievable energy efficiency (EE), demand response (DR), and demand-side rate (DSR) potential by year over the next 20 years for Every Metro and Evergy Missouri West.
- Conduct a reliable, accurate, and useful residential appliance saturation survey to inform projections of current and future energy consumption and associated DSM potential.
- Develop a portfolio of energy efficiency and demand response IRP bundles utilizing the potential results.
- Support Evergy's Demand-Side Resource Analysis under 4 CSR 240-22.050 for the 2023 IRP filing.

1.1 Stakeholder Engagement

AEG facilitated a series of workshops with Evergy stakeholders to solicit feedback on key deliverables throughout the study. Evergy stakeholders included representatives from a variety of organizations with an interest in utility-sponsored DSM activities within the state of Missouri, including representatives from the Missouri PSC, Sierra Club, National Resource Defense Council (NRDC), Renew Missouri, and Missouri Office of Public Counsel (OPC), among others. The table below provides an overview of the workshops offered to stakeholders throughout the study.

Date	Workshop	Topics Covered
5/25/2022, 5/26/2022	Stakeholder Kickoff Meeting and Strategic Issues Forum	• Potential study objectives, analysis approach, and methodology • Project timeline • Measure list and source hierarchy
9/26/2022	Draft Energy Efficiency Potential Results Workshop	• Initial draft results of the energy efficiency potential analysis • Residential Appliance Saturation Survey results
10/17/2022	Draft Demand Response and Demand-Side Rates Potential Workshop	• Initial draft results of the demand response and demand-side rate potential analysis
10/27/2022	Draft DSM Potential Results Workshop	• Revised results of the DSM Potential Study

1.2 Report Contents

The report is divided into two chapters:

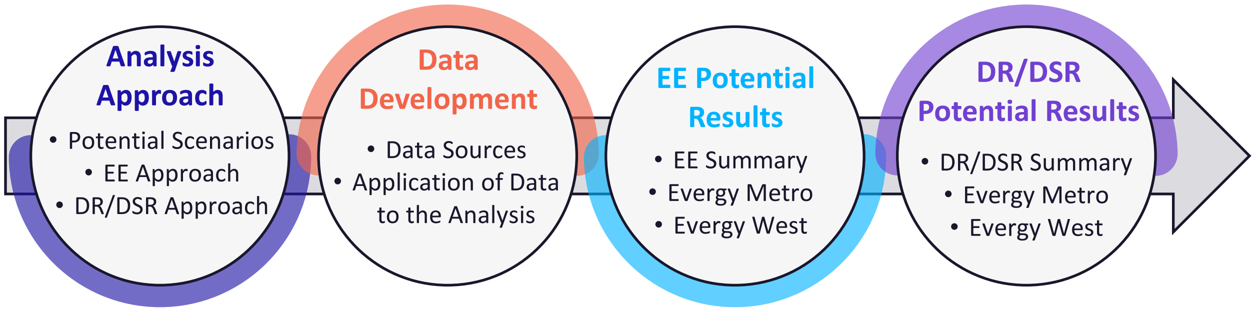
- **Chapter 2 – DSM Potential Study** describes the analysis and results of the energy efficiency, demand response, and demand-side rates potential.
- **Chapter 3 – DSM Energy Efficiency IRP Bundle Development** describes the IRP bundle development for energy efficiency resources.

1.3 Abbreviations and Acronyms

Acronym	Explanation
ADR	Automatic Demand Response
AEO	U.S. EIA Annual Energy Outlook
C&I	Commercial and Industrial
CBECS	U.S. EIA Commercial Building Energy Consumption Survey
DEEM	AEG's Database of Energy Efficiency Measures
DHW	Domestic Hot Water
DLC	Direct Load Control
DOE	U.S. Department of Energy
DR	Demand Response
DSR	Demand-Side Rate
DSM	Demand Side Management
EE	Energy Efficiency
EIA	U.S. Energy Information Administration
EUI	Energy Use Index
EV	Electric Vehicle
GW/GWh	Gigawatt/Gigawatt hour
IRP	Integrated Resource Plan
MAP	Maximum Achievable Potential
MEEIA	Missouri Energy Efficiency Investment Act
NWPCC	Northwest Power and Conservation Council
NRDC	National Resource Defense Council
OPC	Office of Public Counsel
PSC	Public Service Commission
RAP	Realistic Achievable Potential
RASS	Residential Appliance Saturation Survey
RECS	U.S. EIA Residential Energy Consumption Survey
RTF	NWPCC Regional Technical Forum
SAE	Statistically Adjusted End-use
TOU	Time-of-Use Rate
TRC	Total Resource Cost Test
TRM	Technical Reference Manual
UEC	Unit Energy Consumption

2 | DSM Potential Study

This chapter presents the DSM Market Potential Study in four sections:



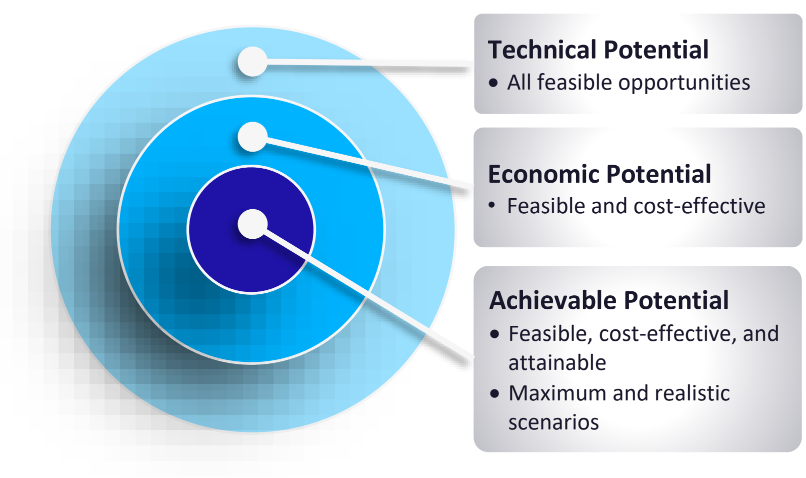
2.1 Analysis Approach

This section describes AEG's approach to estimating the potential for energy efficiency, demand response, and demand-side rates. We begin with an overview of the potential scenarios assessed in the DSM Market Potential Study, then detail the analysis approach by resource.

2.1.1 Potential Scenarios

It is standard practice to estimate three different levels of potential, as described and illustrated in Figure 2-1. The calculation of each level of potential is described later in this chapter.

Figure 2-1 Potential Scenarios



- **Technical Potential** considers all feasible potential, regardless of cost or potential customer uptake. Technical potential is a theoretical construct, assuming that all equipment is upgraded to the most efficient option at the time of replacement and that all retrofit measures are installed over time, regardless of what might be achievable in the market.
- **Economic Potential** includes all cost-effective opportunities without adjusting for expected customer uptake. Measure-level cost-effectiveness was measured by the Total Resource Cost (TRC) Test.
- **Achievable Potential** estimates of the potential that could be cost-effectively acquired under a given set of conditions, considering expected customer participation levels.
  - *Maximum Achievable Potential* is a subset of economic potential that attempts to identify maximum savings realized under ideal market, implementation, and customer preference conditions.
  - *Realistic Achievable Potential* is a subset of economic potential that reflects expected program participation given barriers to customer acceptance, non-ideal implementation conditions, and limited program budgets.

Table 2-1 identifies the resources assessed in each potential scenario. Of note:

- Demand response and demand-side rate resources do not exist in the absence of utility programs, and estimating technical and economic potential does not provide meaningful information on the available resource size. Therefore, these resources are excluded from the technical and economic potential scenarios.

Table 2-1 Resources Considered by Potential Scenario

Scenario	Energy Efficiency	Demand Response	Demand-Side Rates
Technical Potential	√		
Economic Potential	√		
Maximum Achievable Potential	√	√	√
Realistic Achievable Potential	√	√	√

2.1.2 Energy Efficiency Analysis Approach

Energy efficiency resources reduce the energy required to power end-use technologies while providing the same level of service to the customer. AEG used a bottom-up approach to perform the potential analysis, following these major steps:

1. **Residential Appliance Saturation Survey (RASS)**. Conducted primary market research of Evergy's residential customers in their Missouri and Kansas service territories.
2. **Market Characterization**. Performed a market characterization to describe electricity use for the study's base year for the residential, commercial, and industrial sectors (2021). The market characterization included utility data, primary data collected from the RASS, and secondary data sources.
3. **Baseline Projection.** Developed a reference baseline projection of electricity consumption by jurisdiction, sector, segment, end-use, and technology for 2022 through 2043 without future DSM programs.
4. **Measure Development.** Defined and characterized energy efficiency measures to be applied to sectors, segments, and end-uses.
5. **Calculation of Energy Efficiency Potential.** Estimated technical, economic, maximum achievable, and realistic achievable energy efficiency potential at the measure level for 2024 through 2043.

2.1.2(a) Residential Appliance Saturation Survey

AEG performed primary market research of Evergy's residential customers in their Missouri and Kansas service territories. Separate surveys were conducted in each of the four regions of the service area, including: Missouri West, Missouri Metro, Kansas Metro, and Kansas Central. The survey sample was stratified by usage and net metering status within each area. The initial sample consisted of 18,000 mail customers and 46,000 email customers. Due to a low response rate, another 80,003 email customers were added to the sample. Survey results were used to develop the market characterizations for the potential study, especially for segmentation, use per household, and appliance saturations.

The RASS can be found in ***Exhibit A. RASS Results***.

2.1.2(b) Energy Efficiency Market Characterization

To estimate the potential impacts of energy efficiency, it is first necessary to understand how much energy is used today and what equipment is currently in service. The market characterization began with a segmentation of each jurisdiction's footprint to quantify electricity use by sector, segment, end-use application, and the current set of technologies in use in 2021. For this, we relied on information from Evergy and the RASS, augmented with secondary sources. The segmentation scheme is presented in Table 2-2.

- **Opt-Out Customers.** Some of Evergy's largest Commercial and Industrial customers are eligible to opt-out of the utility's energy efficiency program and manage their energy independently. To reflect this situation, AEG separated opt-out customers into a segment and removed them from the potential, as they will not contribute savings to Evergy's program portfolio.

Table 2-2 Overview of Energy Efficiency Segmentation Scheme

Dimension	Segmentation Variable	Description
1	Jurisdiction	Evergy Metro, Evergy Missouri West
2	Sector	Residential, Commercial, Industrial
3	Segment	**Residential:** Single Family, Single Family – Low Income, Multi-Family, Multi-Family – Low Income **Commercial:** Large Office, Small Office, Retail, Restaurant, Grocery, School, College, Healthcare, Lodging, Data Center, Warehouse, Miscellaneous, Opt-Out **Industrial:** Food Production, Chemicals/Pharmaceuticals, Electronic Equipment, Primary Metals, Stone/Clay/Glass, Transportation Equipment, Rubber/Plastics, Waste/Wastewater, Other Industrial, Opt-Out
4	Vintage	Existing and new construction
5	End-uses	Cooling, space heating, lighting, water heater, motors, etc. (as appropriate by sector)
6	Appliances/End-Uses and Technologies	Energy efficiency technologies, such as lamp and fixture type, central air conditioner type, motors by application, etc.
7	Equipment Efficiency for New Purchases	Baseline and higher-efficiency options as appropriate for each technology

With the segmentation scheme defined, AEG performed a high-level market characterization of electricity sales and customers by jurisdiction, sector, and segment in the base year. Then detailed market profiles were developed to fully describe electricity consumption in the base year at each level of the segmentation.

2.1.2(c) Energy Efficiency Baseline Projection

The baseline projection describes forecasted energy consumption in the absence of future Evergy DSM programs and provides the foundation against which potential savings are measured. AEG developed a reference baseline in alignment with Evergy's anticipated annual customer growth by sector and incorporated current and known future building codes and equipment efficiency standards to avoid overstating the potential that could be realized through new programs. AEG checked the baseline projection against each jurisdiction's official load forecast for reasonableness. However, the baseline projection was developed as an independent projection for the potential model to ensure that baseline assumptions were consistent with those used to assess measure savings and applicability.

2.1.2(d) Energy Efficiency Measure Development

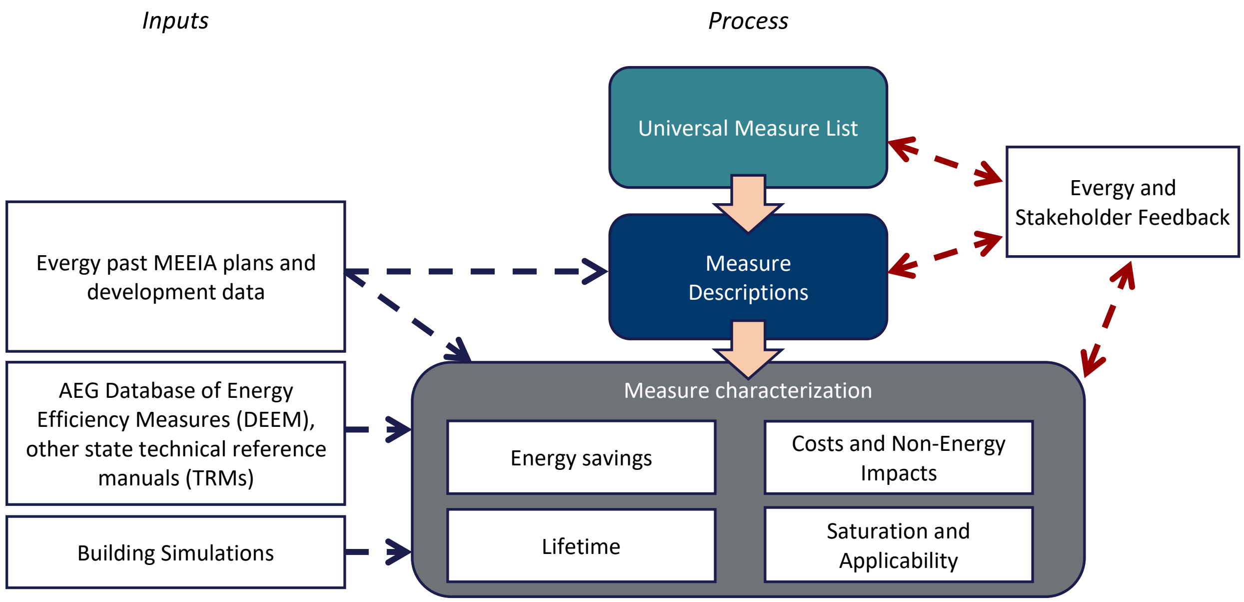
The framework for assessing savings, costs, and other attributes of energy efficiency measures involves the following:

- Identifying the list of energy efficiency measures to include in the analysis.
- Determining their applicability to each market sector and segment.
- Fully characterizing each measure.

- Preparing for integration with the greater potential modeling process.

Figure 2-2 outlines the framework for measure analysis.

Figure 2-2 Approach for Energy Efficiency Measure Assessment



AEG compiled robust lists of energy efficiency measures for each customer sector. The measure lists covered all major types of end-use equipment as well as devices and actions that reduce energy consumption when installed or implemented. Particular focus was given to including the latest available data on emerging technologies from AEG's in-depth research and participation in technical working groups nationwide.

After the lists were finalized, AEG identified the most appropriate source for each parameter and assembled information for all measures to reflect equipment performance, incremental costs, and lifetimes. AEG created a comprehensive measure characterization database to summarize the data. These characteristics form the basis for determining measure-level savings and cost-effectiveness as well as the subsequent build-up to the sector-level potential by scenario. Table 2-3 presents the measure source hierarchy.

Table 2-3 Energy Efficiency Measure Source Hierarchy

Priority Level	Resource	Details/Examples
1	Evergy program data	Reports, Evaluations, Installation Data
2	Well-Vetted Sources Within Region	Illinois Technical Reference Manual (TRM), Missouri TRM
3	National Department of Energy (DOE) Sources	Annual Energy Outlook, ENERGY STAR, DOE Technical Documents, etc.
4	Well-Vetted Sources Outside Region	State-wide technical reference documents, etc.
5	AEG Technical Research	Various Resources, as Required

The modeled measures fall into two types based on their application:

- **Equipment measures** are efficient energy-consuming equipment that save energy by providing the same service with a lower energy requirement than a standard unit. An example is a residential central air conditioner (SEER 18) that replaces a standard efficiency central air conditioner (SEER 14). For equipment measures, many efficiency levels may be available for a given technology, ranging from the baseline unit to the most efficient commercially available product. These measures are applied on a stock-turnover basis and, in general, are referred to as lost opportunity measures because once a purchase decision is made, there will not be another opportunity to improve the efficiency of that equipment (absent early replacement at increased cost) until the end of its useful life.

- **Non-equipment measures** save energy by reducing the need for delivered energy but do not involve replacing or purchasing major end-use equipment (such as an air conditioner or water heater). Measure installation is not tied to equipment reaching the end of useful life, so these are generally categorized as "retrofit" measures. An example is insulation that modifies a household's space heating consumption but does not change the heating system efficiency. The existing insulation can be upgraded without waiting for existing equipment to malfunction and save energy used by the heating system. Non-equipment measures typically fall into one of the following categories:
  - Building shell (windows, insulation, roofing material)
  - Equipment controls (smart thermostats, lighting motion controls, water heater setback)
  - Equipment maintenance (heat pump commissioning, setpoint adjustments)
  - Displacement measures (destratification fan to reduce the use of HVAC systems)
  - Whole-building design (advanced new construction design)
  - Commissioning, retro-commissioning, and energy management
  - Behavioral actions

2.1.2(e) Calculation of Energy Efficiency Potential

AEG's approach to estimating energy efficiency potential aligns with industry-standard practice and terminology. Energy efficiency potential is estimated by developing an alternate projection of energy consumption if efficient measures are adopted and calculating the difference from the baseline projection. In these alternate projections, measures are adopted only where they are applicable (e.g., insulation will only save electricity in homes with electric heating or cooling) and where they are not already installed (e.g., if a home already has high levels of insulation, there is no potential associated with installing insulation). For this study, AEG estimated four levels of potential:

Technical Potential

The calculation of technical potential is a straightforward algorithm, aggregating the full, energy-saving effects of all individual energy efficiency measures included in the study at their maximum theoretical deployment levels, adjusting for technical applicability, stacking of measures, and interactive effects. Equipment replacement measures are naturally constrained by the lifetime and decay rate of the units being replaced. While all retrofit resources could theoretically be acquired in the first year, this would skew the potential for equipment measures and provide an inaccurate picture of measure-level potential. Therefore, the study assumes these opportunities will occur over 20 years, a common timeframe for complete retrofit realization in potential studies.

Stacking of Measures. It is important to consider interactions between measures when applied within the same space to avoid double counting, which could result in savings greater than 100% of equipment consumption. These interactions are automatically handled within LoadMAP; for these measures, the baseline is modified for each subsequent measure. First, LoadMAP computes the total savings of each measure on a standalone basis, then assigns a stacking priority such that "integrated" or "stacked" savings are calculated as a percent reduction to the running total of baseline energy remaining in each end-use after the previous measures have been applied. This ensures that the available baseline energy shrinks in proportion to the number of measures applied, as it would in reality. The stacking priority is based on the levelized cost of conserved energy, such that the most economical measures that are more likely to be cost-effective and offered to customers through programs will be the first to be applied to the modeled population.

Related and Exclusive Measures. AEG's modeling approach also accounts for the exclusivity of certain measure options. For instance, if a SEER 18 central air conditioner is installed in a single-family home, the model will not allow that same home to install another central air conditioning until the new option has reached the end of its useful life. For non-equipment measures, base saturations and applicability are defined such that measures do not overlap. For example, we model two applications of ceiling insulation – the first assumes the installation of insulation where there previously was none, while the second upgrades pre-existing insulation if it falls under a certain threshold. AEG leveraged a variety of resources to estimate the appropriate remaining markets for measures, including the 2022 RASS, market research from Evergy's past potential study reports, the US Energy Information Administration's (EIA) Residential Energy Consumption Survey (RECS) and Commercial Building Energy Consumption Survey (CBECS), and utility-provided program achievements.

Economic Potential

To estimate economic potential, AEG performed measure-level cost-effectiveness screening each year of the analysis using the TRC test. Costs included the full or incremental cost of the measure (depending on the application) and an assumed program administration cost. Benefits included (1) the avoided cost of electric generation, transmission, and generation; and (2) quantifiable water and operations and maintenance savings.

AEG's LoadMAP model performs the cost-effectiveness screening dynamically and on an annual basis, considering changing savings, costs, and benefits over time. Thus, measures can pass the economic screen for some, but not all, of the years in the forecast.

It is important to note the following about the economic screen:

- Cost-effectiveness was assessed at the measure level based on gross savings (i.e., not adjusted for potential free-ridership), reflecting that the potential study is attempting to assess cost-effectiveness without assuming or prescribing specific acquisition strategies or delivery mechanisms. Net-to-gross adjustments are applied during the development of program offerings.
- The economic evaluation of each measure was conducted relative to a baseline condition, such as minimum federal standard equipment or average existing building shell conditions.
- The economic evaluation was conducted only for measures applicable to each building type and vintage. Thus, measures deemed not applicable to a building type and vintage were excluded for that application.

Achievable Potential

To develop achievable potential estimates, AEG applied market adoption rates for each measure to estimate the percentage of customers that may elect to adopt each measure. The market adoption rates consider barriers such as imperfect information, supplier constraints, technology availability, and individual consumer preferences. Market adoption rates intend to establish a path to full market maturity for each measure or technology group and ensure resource planning stays within acquisition capabilities.

Customer adoption rates were applied to economic potential to estimate two levels of achievable potential:

- **Realistic Achievable Potential**. AEG established a base take rate from measure and program interest questions in surveys AEG has performed in nearby territories, which asked residential and business participants about their willingness to adopt or install several different kinds of measures under business-as-usual incentives. To capture adoption over time, AEG applied diffusion curves to the base adoption rates, reflecting the time required to develop stand-up programs, build customer awareness, and address potential barriers to participation. The curve's endpoint is calculated with a multiplier on the base rate and is constructed as a near-ideal case of customer participation. It still assumes business-as-usual incentives but posits optimal delivery structure, marketing, customer awareness, financial situation, and non-energy differences based on AEG's research into customer adoption rates and how these factors influence program participation. By combining the best-case factors from each category, AEG developed a combined lift factor for each segment.

- **Maximum Achievable Potential.** Similar to realistic achievable, AEG calculated a maximum adoption rate that included ideal program considerations and the additional lift possible from enhanced incentives (up to 100% of incremental cost). Maximum achievable adoption rates were held constant throughout the study, as they already represent the best-case adoption for each measure.

2.1.3 Demand Response/Demand-Side Rate (DR/DSR) Analysis Approach

In contrast to energy efficiency, where customers may choose to install energy-efficient technologies in the absence of utility programs, DR/DSR does not exist outside of utility offerings. Therefore, AEG relied on a programmatic view of DR/DSR to assess the potential as opposed to the technology view used to assess the potential from energy efficiency measures.

AEG used a bottom-up approach to perform the DR/DSR analysis, following these major steps:

1. **Market Characterization.** The segmentation included jurisdiction, sector, and customer size. Key assumptions around equipment saturations and customer counts align with the Energy Efficiency Market Characterization.
2. **Program Characterization.** AEG developed a comprehensive set of program options for the analysis, including direct load control, grid-interactive, manual, and rate-based options.
3. **Baseline Peak and Customer Forecasts.** AEG developed a reference baseline peak projection and customer growth forecast using the class-level MW and customer growth forecasts provided by Evergy.
4. **Potential Estimates.** Technical and economic potential is not meaningful because DR/DSR does not exist in the absence of utility programs. Instead, AEG estimated DR/DSR potential for five achievable potential scenarios based upon several assumptions, including:
    - Retention rates on the opt-out Time-of-Use (TOU) rate,
    - Programmatic parameters, including participation and costs, and
    - Adjustments to DR impacts to account for interactions with DSR.

2.1.3(a) DR/DSR Market Characterization

AEG segmented Evergy's customers by jurisdiction, sector, and customer size. Commercial and industrial (C&I) customers were segmented based on their non-coincident peak load, reflecting how programs are generally offered to customers. In general, the DR/DSR segmentation aligns with the energy efficiency segmentation, which allows the DR/DSR analysis to incorporate and properly weight segment-level saturations of enabling technologies (such as central cooling systems and water heating) and factor in the adoption of efficient equipment when determining customer eligibility for program options. Table 2-4 presents the segmentation scheme.

Table 2-4 Overview of DR/DSR Segmentation Scheme

Dimension	Segmentation Variable	Description		
1	Jurisdiction	Evergy Metro, Evergy Missouri West		
2	Sector	Residential, Commercial, Industrial		
3	Size (by maximum peak demand)	**Residential:** all customers		
		C&I:	Small C&I	≤30 kW
			Medium C&I	>30 kW and ≤500 kW
			Large C&I	>500 kW and ≤1,000 kW
			Extra-large C&I	>1,000 kW

2.1.3(b) DR/DSR Program Characterization

Unlike energy efficiency, DR/DSR does not exist in the absence of utility programs. Therefore, AEG characterized a set of program options to reflect how Evergy might acquire DR/DSR potential. Table 2-5 provides a list of the DR/DSR program options considered and notes which Evergy is currently offering to customers.

Table 2-5 Overview of DR/DSR Program Options Assessed

Program Option	Eligible Customers	Description	Currently Offered
Demand Response			
Firm Curtailment/Tariff	Medium C&I, Large C&I, Extra-Large C&I	Customers volunteer a specific amount of capacity during economic or emergency events called by the utility in return for a financial incentive. Customers must reduce to a specific level (i.e., a firm service level). Penalties apply for non-performance. Response times are usually 15 to 30 minutes.	√
C&I Automatic DR (ADR)	All C&I	Participating customers respond automatically to events using existing ADR-enabled equipment (BMS/EMS) or one purchased with incentives provided by the program.	
Residential Behavioral DR	Residential	Voluntary demand reductions in response to targeted behavioral messaging. Requires AMI technology.	
HVAC Direct Load Control (DLC)	Residential, Small C&I, Medium C&I	DLC switch installed on heating and/or cooling equipment.	
Domestic Hot Water Heater (DHW) DLC	Residential, Small C&I, Medium C&I	DLC switch installed on customer's equipment.	
Grid-Interactive Water Heaters	Residential, Small C&I, Medium C&I	CTA-2045 or other integrated communication port	
Connected Homes DLC	Residential	Internet-enabled control of operational cycles of white goods appliances, electronics, and lighting. Controlled by a central smart hub or smart speaker.	
Electric Vehicle (EV) Managed Charging	Residential	Control EV charging using (1) vehicle telematics and APIs through a third-party vendor or (2) traditional DLC of EV chargers.	
Connected Thermostat DLC	Residential, Small C&I, Medium C&I	Internet-enabled control of thermostat set points.	√
Smart Solar PV Inverter	Residential	Internet-enabled control that responds to grid fluctuations. Control can execute complex functions that support grid maintenance, including active power curtailment, voltage controls, and frequency controls.	
Battery Energy Storage DLC	Residential, All C&I	Internet-enabled control of battery charging and discharging.	√
Thermal Energy Storage DLC	All C&I	Internet-enabled control of thermal charging and discharging.	
Demand-Side Rates			
Critical Peak Pricing Rate	C&I	Charges customers higher rates during a particular block of hours that occurs only on event days.	
Time-Related Pricing Rate	Large C&I, Extra-Large C&I	Hourly rates vary by season and day-type based on historical locational marginal prices. Customers benefit from having visibility to hourly pricing for predefined periods. Requires AMI technology.	
TOU Rate	Residential	Charges customers higher rates during particular blocks of hours that occur every day (typically 2-3 blocks).	

TOU Rate for EV Owners	Residential	Customers must own and charge an EV. The EV would be an "enabling technology" that would enable customers to shift usage and demand off-peak during periods of higher rates.

AEG characterized each program option by:

- Defining the eligible pool of customers by controllable equipment,
- Gathering estimates of participation and peak demand reductions, and
- Assessing competition with other program options.

The following sections describe these steps in detail.

Controllable Equipment

Most program options rely either on grid-interactive technologies or separate equipment (e.g., a switch) that allows Evergy or a third-party to control load during an event. AEG developed forecasts of controllable equipment adoption through the energy efficiency assessment. Table 2-6 provides the program options dependent on controllable equipment.

Table 2-6 DR Enabling Equipment by Program Option

Source	Controllable Equipment	Program Option
Energy Efficiency Assessment	Central Air Conditioner, Heat Pump, Rooftop Units, Electric Furnace	HVAC DLC, Connected Thermostat DLC
	Connected Thermostat	Connected Thermostat DLC
	Electric Water Heater	DHW DLC, Grid-Interactive Water Heaters[1]
	Home Energy Management System	Smart Homes DLC
	Electric Vehicle Connected Charger	EV Managed Charging
	Batteries[2]	Battery Energy Storage DLC

AEG assumed that the advanced metering infrastructure (AMI) rollout was complete. Therefore, program options were not limited with regards to metering infrastructure.

Participation and Peak Impacts

If the program option is a current Evergy offering, AEG used actual participation rates and third-party evaluated savings. For program options not currently offered, AEG compiled secondary data to define the following parameters for each program option:

- **Steady-State Participation Rate**: the percentage of eligible customers expected to participate in the program option once it is fully up and running.
- **Peak Load Reduction:** the expected impact for an average participant during a system peak event.

For DR programs, AEG relied primarily on evaluation reports covering Evergy's existing program options (Residential and Business Demand Response), studies performed for other utilities in the Southwest Power Pool, and other nationally-cited research when more regional content was not available.

[1] AEG assumed that a conservative portion of electric water heaters were grid-interactive.

[2] To estimate the saturation of batteries, AEG used the solar PV saturation provided through the energy efficiency study as an upper bound.

For DSR programs, AEG developed estimates for customer eligibility, participation, and impacts for each rate option based on an extensive review of enrollment in full-scale, time-varying rates offered in the United States published by the Brattle Group[3] and benchmarked those results against findings from regional utilities.

Because Evergy needs to design, contract for, and market new offerings, most program options are expected to take several years to grow to their steady-state participation rate. AEG relied on the observed ramp rates from existing programs to forecast this growth. In the absence of an existing program, AEG referenced similar program options or assumed constant incremental growth through the ramp period. Most programs were assumed to fully mature in about five years.

Competition Between DR Program Options

Some of the program options target the same peak load. For example, the HVAC DLC and Connected Thermostat DLC programs target central cooling load in the summer. To avoid double-counting DR potential for these competing resources, AEG worked with Evergy to develop a program hierarchy or "loading order." In general, the hierarchy prioritized customers for existing programs over other DR resources by removing participants of programs higher in the hierarchy from the pool of customers eligible for programs lower in the hierarchy. Figure 2-3 provides an example of this loading order for Evergy's programs.

Figure 2-3 Example DR/DSR Program Option Hierarchy

	Program Option	Residential	Commercial	Industrial
Loaded First	Firm Curtailment		X	X
	Connected Thermostats	X	X	
	Domestic Hot Water Heater DLC	X	X	
	Grid-Interactive Water Heaters	X	X	
	EV Managed Charging	X		
	Smart EV	X		
	Connected Homes DLC	X		
	HVAC DLC	X	X	
	C&I Automatic DR		X	X
	Battery Energy Storage DLC	X	X	
	Smart Solar PV Inverter	X		
	Thermal Energy Storage DLC		X	X
	Critical Peak Pricing		X	X
	Time-Related Pricing		X	X
Loaded Last	Residential Behavioral DR	X		

Not all program options compete for the same peak load. AEG allowed dual enrollment in program options targeting separately metered equipment (e.g., EV Managed Charging) or distinct end uses (e.g., Connected Thermostat DLC and DHW DLC).

2.1.3(c) DR/DSR Baseline Peak and Customer Forecast

AEG developed the baseline peak demand forecast as follows:

1. Allocated system peak demand to each sector using base-year hourly peak demand data. Evergy provided customer forecasts by territory.
2. Segmented the non-residential peak load and customer forecasts by size based on an analysis of Evergy billing data.
3. Removed the peak demand savings potential generated through energy efficiency adoption forecasted in the MAP and RAP scenarios. The removal of the demand savings from the energy efficiency analysis was

[3] The Brattle Group (October 2021). *PC44 Time of Use Pilots: End of Pilot Evaluation*. Prepared for Maryland Public Service Commission. Available online: https://www.brattle.com/wp-content/uploads/2021/12/PC44-Time-of-Use-Pilots-End-of-Pilot-Evaluation.pdf

done to reduce any possible double counting and to account for energy efficiency savings before the DSR/DR savings are estimated.[4]

4. Adjusted the peak demand baseline to reflect the estimated impacts of the mandatory TOU rate under various retention scenarios (discussed below). This adjustment lowers the impacts of DR programs to account for the preexisting impact (and interaction) from the TOU rate.

[4] The interactions between potential demand-side rates, demand response options (DSR/DR) and the demand-side programs were accounted for through the integration of the demand-side program potential assessment results into the demand-side rate and demand response option analysis.

2.1.3(d) DR/DSR Potential Estimation

AEG estimated DR/DSR potential for two main scenarios:

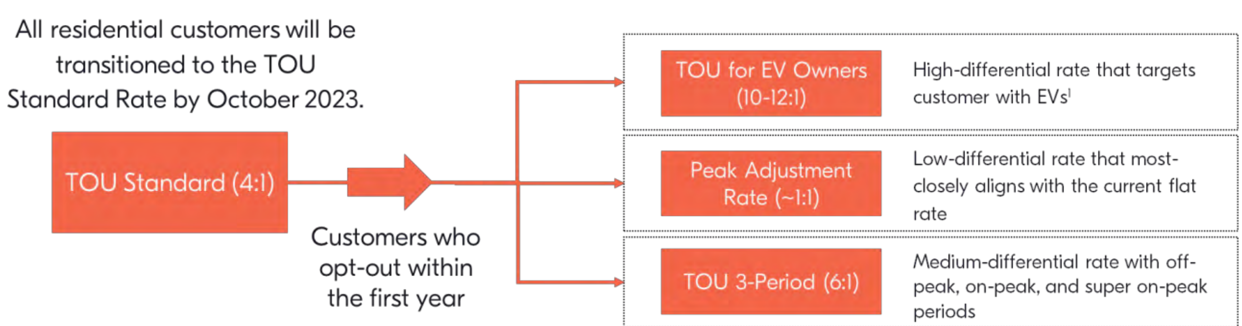
- **Maximum Achievable Potential (MAP)** included all cost-effective programs, incorporated growth in Evergy's existing programs to benchmarked participation levels (with associated increases in costs), and tested sensitivities around the forthcoming mandatory TOU rate for residential customers (see the MAP Scenario section below for details)
- **Realistic Achievable Potential (RAP)** included all cost-effective programs (based on the MAP results), restricted participation in Evergy's existing programs to current achieved levels, and tested sensitivities to participation in non-TOU program options.

MAP Scenario

During the potential assessment, Evergy received an order from the Missouri PSC to transition all residential customers to mandatory TOU rates by October 1, 2023.[5] In response to the order, AEG and Evergy modified the MAP analysis to focus on the effect that customer retention in the default TOU Standard rate would have on other DR and DSR program options. Specifically, we expect the average residential customer's peak demand to drop as they respond to pricing signals, which will reduce the amount of demand available for other program options to impact during peak hours.

As shown in Figure 2-4, Evergy plans to offer four residential TOU rates. Residential customers will be placed on the TOU Standard rate and then have the option to move to one of three other TOU rates. AEG assumed that (1) customers who opt out of the TOU Standard rate would do so within the first year, and (2) the majority would move into the Peak Adjustment Rate because of its familiarity and relatively low risk, especially since Evergy will not be offering any bill protection.

Figure 2-4 TOU Rates Descriptions



[1] The TOU EV rate will be open to all customers; however, since Evergy designed the rate for owners of EVs, AEG limited participation to this sub-population of customers.

Research shows that higher rate differentials (i.e., the difference in on-peak to off-peak rates) tend to elicit stronger customer responses and lead to larger decreases in on-peak hour consumption than rates with lower pricing differentials.[6] Therefore, the effect of Evergy's mandatory TOU rates on residential customer peak demand will be driven by the TOU Standard rate's ability to retain customers and which TOU rate opt-out customers choose to move towards.

[5] File No. ER-2022-0129. In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service.

File No. ER-2022-0130. In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service.

[6] The Brattle Group (October 2021). *PC44 Time of Use Pilots: End of Pilot Evaluation*. Prepared for Maryland Public Service Commission. Available online: https://www.brattle.com/wp-content/uploads/2021/12/PC44-Time-of-Use-Pilots-End-of-Pilot-Evaluation.pdf

AEG assumed a conservative retention rate of 50% to estimate MAP and then tested the sensitivity of impacts and program costs to changes in the TOU retention rate as shown in Table 2-7. For each sensitivity, AEG estimated the weighted impacts of the mandatory TOU rates, reduced the peak demand baseline forecast by the TOU impact, and then adjusted the impact assumptions for the other DR/DSR program options. The sensitivities also included increased costs of educating customers to support the increased retention in the TOU Standard rate.

Table 2-7 MAP Sensitivity Analysis

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

RAP Scenario

The RAP scenario differed from the MAP scenario by:

- Lowering the peak demand baseline by the peak demand reductions generated through energy efficiency technology adoption forecasted through the energy efficiency RAP potential assessment (as opposed to the MAP scenario, which made the same adjustment using the energy efficiency MAP potential assessment).
- Restricting participation in existing programs to levels currently achieved.
- Dampening the impacts of the mandatory TOU rates for the first few years to simulate a learning curve whereby customers become more effective at responding appropriately to pricing signals over time.

Like the MAP scenario, the RAP scenario assumed low retention in the TOU Standard rate. However, sensitivities around RAP focused on the effects of increasing or decreasing participation in the remaining DR and DSR program options. Table 2-8 shows that RAP Plus increased participation in non-TOU program options by 10% while RAP Minus decreased participation by 15% (including for the TOU Standard rate). AEG did not adjust marketing or incentive cost assumptions for the RAP Minus and RAP Plus scenarios.

Table 2-8 RAP Sensitivity Analysis

Sensitivity	Participation Adjustments	Cost Adjustments	TOU Standard Retention	TOU Impacts
RAP	**n/a**	**n/a**	**50% of all residential customers**	**4-year learning curve[1]**
RAP Plus	10% increase from RAP	No cost adjustment	50% of all residential customers	4-year learning curve[1]
RAP Minus	15% decrease from RAP	No cost adjustment	43% of all residential customers (15% decrease from RAP)	4-year learning curve[1]

[1]25% of impacts realized in Year 1, 50% of impacts realized in Year 2, 75% of impacts realized in Year 3, and 100% of impacts realized by Year 4 of being on a TOU rate.

DR/DSR Potential Estimation

AEG calculated the potential for each program option across the scenarios by first estimating participation in each year of the forecast period (via enabling equipment saturations, participation rates, and removing participation from programs higher in the program hierarchy) and multiplying it by the per-customer peak reductions.

The estimated potential includes impacts from existing and planned resources that Evergy already includes in its IRP model. AEG calibrated the impacts for these program options to meet Evergy's planned targets and then removed them from the total estimated potential so as not to double-count existing and planned resources. However, any associated growth in these program options was included as new, incremental potential.

AEG performed an economic screen based on each program's potential estimated in isolation (i.e., ignoring competition between resources) for the MAP scenario. These impacts represented the maximum potential achievable for each program, suggesting that if a program was not cost-effective under these near-perfect circumstances, it would not be a cost-effective option in a more restrictive case.

2.2 Data Development

This section details the key data sources used to complete this study and how the sources were applied. AEG prioritized Evergy-specific data, supplemented by regional and national data sources. Where possible, data were adapted to local conditions (e.g., using local weather and local sources for measure data).

2.2.1 Data Sources

The data sources are organized into the following categories:

- Evergy data
- Residential Appliance Saturation Survey (discussed in Section 2.1.2(a))
- Regional and national data sources
- AEG's databases and analysis tools
- Other secondary data and reports

2.2.1(a) Evergy Data

Our highest priority data sources for this study were those specific to Evergy and their customers, including:

- **Evergy Customer Data:** Evergy provided customer-level billing data for all sectors, including segment identifiers to parse out the various housing types and business types.
- **Load Research Data:** Load profiles and Statistically Adjusted End-use (SAE) outputs for residential and commercial customer types.
- **Avoided Costs:** Hourly avoided costs, which were combined with the hourly load profiles to produce appropriately shaped avoided costs for different end uses and customer types. The application of avoided costs is discussed further in section 2.2.2(a).
- **Discount Rate:** Evergy provided the discount rate to be used in economic NPV calculations.
- **Program Data & Evaluation:** Evergy provided evaluation results and program achievements for the last MEEIA cycle for energy efficiency and demand response, which AEG used to benchmark potential estimates and update key inputs to measures.
- **Previous potential study reports.**
- **Planned Program Achievements:** Evergy provided their planned resources for existing DR/DSR program options, which AEG calibrated to and benchmarked against other jurisdictions for reasonableness.

2.2.1(b) Regional and National Data Sources

- **2020 EIA Residential Energy Consumption Survey (RECS)** was partially released in 2022 and provided data on statewide equipment saturations. Missouri-specific results were used to benchmark the RASS results and fill gaps on equipment saturations not covered by the RASS.
- **2012 EIA Commercial Buildings Energy Consumption Survey (CBECS)** provides data on regional equipment saturations and intensities by building type.[7]
- **U.S. DOE Solid State Lighting Forecast Report (2019)** is a key source of input data for the AEG lighting model, including future projections of efficacy and cost by lighting type.
- **Evaluations, potential assessments, and other studies for DR/DSR programs run by regionally-located utilities**, including Ameren Missouri, Oklahoma Gas & Electric, Arizona Public Service, PSO Oklahoma, provided input assumptions and benchmarking. AEG referenced and benchmarked against nationally-cited studies, such as the 2021 Bonneville Power Administration Demand Response Potential Assessment, when regional sources were unavailable, less granular, or too tailored to the utility.
- **2016 KCP&L DSR research conducted by the Brattle Group**[8] (and the 2021 update to the Brattle Group's Arc of Price Responsiveness Curve[9]) provided impact and participation assumptions for time-varying rates based on the pricing differential between on-peak and off-peak periods based on a meta-analysis of evaluation and pilot studies across the country.

2.2.1(c) AEG Data

AEG maintains several databases and modeling tools that we use for forecasting and potential studies. Relevant data from these tools have been incorporated into the analysis and deliverables for this study.

- **AEG Energy Market Profiles.** For more than ten years, AEG has maintained profiles of end-use consumption for the residential, commercial, and industrial sectors. These profiles include market size, fuel shares, unit consumption estimates, annual energy use by fuel (natural gas and electricity), customer segment, and end-use for ten regions in the U.S. The EIA surveys (RECS, CBECS, and MECS), as well as state-level statistics and local customer research, provide the foundation for these regional profiles.
- **AEG's Database of Energy Efficiency Measures (DEEM).** AEG maintains an extensive database of efficient measure data for our studies. Our database draws upon reliable sources, including various state TRMs, the EIA Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case, DOE Technical Standard Documents, ENERGY STAR documentation, and AEG technical and market research.
- **Recent studies.** AEG has conducted more than 60 potential studies in the last five years. We checked input assumptions and analysis results against these studies within the region and across the country.

2.2.1(d) Other Secondary Data and Reports

A variety of secondary data sources and reports were used for this study, including:

- **2021-2022 EIA Annual Energy Outlook (AEO).** The AEO presents yearly energy projections and analyses.
- **American Community Survey.** The U.S. Census American Community Survey is an ongoing survey that provides data every year on household characteristics.
- **State and Regional TRMs:** These documents and databases provided well-cited estimates of energy and peak demand savings and algorithms, measure costs, and effective useful life for different jurisdictions

[7] The data release of the 2018 CBECS was incomplete at the time of this study.

[8] Memo submitted by the Brattle Group to the KCP&L Rate Analysis Team on July 1, 2016 identified rate options for consideration along with impact and participation assumptions. Not publicly available.

[9] https://www.brattle.com/wp-content/uploads/2021/12/PC44-Time-of-Use-Pilots-End-of-Pilot-Evaluation.pdf

across the United States and were used, including the Illinois TRM, Arkansas TRM, the Northwest Power and Conservation Council's (NWPCC) Regional Technical Forum (RTF) and 2021 Power Plan measure analysis workbooks, the California electronic TRM, and the Michigan Energy Measures Database, among others.

- **Other relevant resources:** Reports and measure data from the U.S. DOE (e.g., Technical Standard Documents), EPA ENERGY STAR specifications and data packages, Consortium for Energy Efficiency, and the American Council for an Energy-Efficient Economy. AEG also leverages case studies, academic and white papers, and project implementation data to true up cost and savings estimates for our technical and market research.

2.2.2 Application of Data to the Analysis

This section provides additional detail on how each of the data sources described above were used for each step of the study.

2.2.2(a) Data Application for Market Characterization

To disaggregate the top-level electric loads for Evergy into sectors and segments, AEG first used Evergy's detailed billing data to develop the residential survey sample and appropriate weighting groups. The RASS results were combined with the billing data segment identifiers to create percentages to distribute the total customers and electric load for residential. A similar process was used for nonresidential totals; however, the market research data portion leveraged the work done in past Evergy studies.

2.2.2(b) Data Application for Market Profiles

The specific data elements for the market profiles and the key data sources are shown in Table 2-9. To develop the market profiles for each segment, we used the following approach:

1. Develop control totals for each segment. These include market size, segment-level annual electricity use, and annual intensity. Control totals were based on actual utility sales and customer-level information.
2. Develop existing appliance saturations and the energy characteristics of appliances, equipment, and buildings using RASS survey results, trends from 2020 RECS, 2012/2018 CBECS, the 2021 AEO model for the East North Central region, and the American Community Survey.
3. Ensure calibration to actual base-year electricity sales in each jurisdiction, sector, and segment.
4. Compare and cross-check with other recent AEG studies.
5. Work with Evergy to verify the data aligns with their knowledge and experience.

Table 2-9 Data Applied for the Market Profiles

Model Inputs	Description	Key Sources
Market Size	Base-year residential dwellings, commercial floor space and industrial employees	Utility electric sales Utility customer account database 2022 RASS 2020 American Community Survey
Annual Intensity	Residential: Annual use per household Commercial: Annual use per square foot Industrial: Annual use per employee	Utility customer account database 2022 RASS 2020 American Community Survey 2020 RECS, 2012/2018 CBECS and MECS Prior Evergy study market profiles Other recent studies
Appliance/Equipment Saturations	Fraction of dwellings / floor space / employees with equipment/technology	Prior Evergy study market profiles/survey data 2022 RASS RECS 2020 CBECS 2012/2018 AEO 2021 2020 American Community Survey
UEC/EUI for Each End-Use Technology	**UEC**: Annual energy use in homes and buildings that have the technology **EUI:** Annual energy use per square foot/employee for a technology in floor space that has the technology	Building Simulations SAE data provided by Evergy AEO 2021 Technical data Engineering analysis AEG DEEM Recent AEG studies
Appliance/Equipment Age Distribution	Age distribution for each technology	2022 RASS Prior Evergy study Recent AEG studies
Efficiency Options for Each Technology	List of available efficiency options and annual energy use for each technology	Utility program data AEO 2021 Various state/regional TRMs EIA Building Technologies Reference Case AEG DEEM Recent AEG studies

2.2.2(c) Data Application for EE Baseline Projection

Table 2-10 summarizes the LoadMAP model inputs required to develop the baseline projection. These inputs are required for each segment within each sector, as well as for new construction and existing dwellings/buildings.

Table 2-10 Data Applied for the Baseline Projection in LoadMAP

Model Inputs	Description	Key Sources
Customer Growth Forecasts	Forecasts of new meter installation by sector	Utility growth forecast
Equipment Purchase Shares for Baseline Projection	Estimates of consumer behavior in the reference case regarding natural adoption of efficiency (above baseline) equipment	2021 AEO Purchase data ENERGY STAR sales and penetration data 2022 RASS

- **Equipment Standards.** The baseline projection incorporates known current and future equipment standards as of August 2022 for the residential, commercial, and industrial sectors. Table 2-11 and Table 2-12 extend through 2025, after which all standards are assumed to hold steady.

  Building Codes for New Construction. Missouri does not have a statewide building energy code; however, several localities have adopted their own. AEG's assumptions in modeling for new construction generally reflect a mix of IECC 2015 and 2018 with some amendments, reflective of the codes covering the largest of these jurisdictions.

Table 2-11 Residential Electric Equipment Standards

End Use	Technology	2021	2022	2023	2024	2025
Cooling	Central AC	SEER 13.0		SEER 14.0		
	Room AC	CEER 10.9				
Cool/Heating	Air-Source Heat Pump	SEER 14.0 / HSPF 8.2		SEER 15.0 / HSPF 8.8		
Water Heating	Water Heater (≤55 gallons)	EF 0.92				
	Water Heater (>55 gallons)	EF 2.05 (Heat Pump Water Heater)				
Lighting	General Service	EISA Compliant (18.6 lm/W)		EISA Compliant (45.0 lm/W)		
	Linear Fluorescent	T8 (80.0 lm/W lamp)				
Appliances	Refrigerator & Freezer	25% more efficient than the 1997 Final Rule (62 FR 23102)				
	Clothes Washer	IMEF 1.84 / WF 4.7				
	Clothes Dryer	UCEF 2.29				
Miscellaneous	Furnace Fans	ECM				

Table 2-12 Commercial and Industrial Electric Equipment Standards

End Use	Technology	2021	2022	2023	2024	2025
Cooling	Chillers	2016 ASHRAE 90.1				
	Roof Top Units	IEER 12.9		IEER 14.8		
	PTAC	EER 10.4				
Cool/Heating	Heat Pump	IEER 12.8 / COP 3.3		IEER 14.1 / COP 3.4		
	PTHP	EER 10.4 / COP 3.1				
Ventilation	All	Constant Air Volume/Variable Air Volume				
Lighting	General Service	EISA Compliant (18.6 lm/W)				
	Linear Lighting	T8 (80.0 lm/W lamp)				
	High Bay	High-Efficiency Ballast (56.0 lm/W lamp)				
Refrigeration	Walk-In	EERE–2010–BT–STD–0003				
	Reach-In	EERE–2010–BT–STD–0003				
	Glass Door	EERE–2010–BT–STD–0003				
	Open Display	EERE–2010–BT–STD–0003				
	Icemaker	EERE-2010-BT-STD-0037				
Motors	All	Expanded EISA 2007				
	Miscellaneous	N/A				

2.2.2(d) Energy Efficiency Measure Data Application

Table 2-13 details the energy-efficiency data inputs to the potential analysis and identifies the key sources used for each.

Table 2-13 Data Inputs for EE Measure Characteristics

Model Inputs	Description	Key Sources
Energy Impacts	The annual reduction in consumption attributable to each specific measure. Savings were developed as a percentage of the energy end-use that the measure affects.	Evergy Program & Evaluation Data DOE and EPA Data Illinois TRM V10 NWPCC/RTF Measure Data California eTRM AEG's DEEM and Research Other Secondary Sources
Costs	**Equipment Measures**: Includes the full cost of purchasing and installing the equipment on a per-household, per-square-foot, or per employee basis for the residential, commercial, and industrial sectors, respectively. **Non-Equipment Measures:** Existing buildings – full installed cost. New Construction - the costs may be either the full cost of the measure, or as appropriate, it may be the incremental cost of upgrading from a standard level to a higher efficiency level.	Evergy Program Data DOE and EPA Data Illinois TRM V10 NWPCC/RTF Measure Data California eTRM AEG's DEEM and Research AEO 2021 Other Secondary Sources
Measure Lifetimes	Estimates derived from the technical data and secondary data sources that support the measure demand and energy savings analysis.	Illinois TRM V10 NWPCC/RTF Measure Data AEG's DEEM and Research AEO 2021 Other Secondary Sources
Applicability	Estimate of the percentage of dwellings in the residential sector, square feet in the commercial sector, or employees in the industrial sector where the measure is applicable and where it is technically feasible to implement.	CBECS 2012/2018 RECS 2020 ENERGY STAR Market Data AEG DEEM Other Secondary Sources
On Market / Off Market Availability	Expressed as years for equipment measures to reflect when the equipment technology is available or no longer available in the market.	AEG appliance standards and building codes analysis

2.2.2(e) DR/DSR Program Data Application

Table 2-14 details the demand response inputs to the potential study analysis and identifies the key sources used for each.

Table 2-14 Data Inputs for DR/DSR Program Characteristics

Model Inputs	Description	Key Sources
Program Costs	Program costs consist of marketing and administrative, including program setup; equipment (e.g., technology required to control an electric water heater); labor and installation associated with installing new equipment or monitoring; and participation incentive.	Evergy's historical DR program incentives Review of programs in other jurisdictions
Hourly Avoided Costs	Avoided generation capacity and T&D capacity costs were provided by Evergy	Evergy
Participation	Programs achieve steady state participation after reaching full maturity, with earlier years following an S-curve of participation growth.	Evergy's historical and planned DR program participation Review of programs in other jurisdictions Industry expert judgement
Eligibility	Customers are eligible to participate in certain programs if they have the applicable technology; for example, an electric vehicle is a requirement for participation in an EV DR program. Eligibility rates are 100% for certain programs that don't require additional eligibility considerations.	Utility saturation data AEG appliance saturation analysis
Program Impacts	Existing program evaluations, planned program targets, and a review of operating programs in other jurisdictions	Evergy evaluations Review of programs in other jurisdictions
Customer Counts	Customer growth forecasts for residential and C&I provided by the utility. Commercial customers counts were allocated into small and large classes based on usage data from billing analysis.	Utility customer forecasts AEG billing data analysis

2.2.2(f) Avoided Cost Application

Evergy provided hourly load profiles (MW load in each hour of the typical year) for thirteen different sector and end use combinations (e.g. Large Commercial Cooling), and hourly avoided costs for the study period. AEG first converted the hourly load profiles to an index shape so that each hour is represented as a % of total load for the year, then multiplied these percent shapes by the hourly avoided costs to produce a stream of annual avoided cost values for each sector/end use combination. Finally, AEG deflated the annual values so that all values would be in real base-year dollars, which is necessary for the LoadMAP model. The capacity value ($ per kW-yr), which is a separate value stream for peak demand savings, was brought in as provided by Evergy except for setting the inflation rate to zero so that again, the model would have values in real dollar terms.

2.3 Energy Efficiency Potential Results

This section presents the cumulative potential from energy efficiency resources in absolute terms and relative to AEG's baseline projection. These savings draw upon forecasts of future consumption absent Evergy energy efficiency program activities. While the baseline projection accounted for past Evergy energy efficiency resource acquisition, the identified estimated potential is inclusive of (not in addition to) planned future program impacts.

We present summary-level potential for Evergy Metro and Evergy West. Detailed energy efficiency potential by sector, segment, and end use are presented in ***Exhibit B_Evergy West Potential Results*** and ***Exhibit C_Evergy Metro Potential Results***.

2.3.1 Evergy Metro Energy Efficiency Potential Summary

- **Technical Potential**, which reflects the adoption of all energy efficiency measures regardless of cost or customer preferences, is a theoretical upper bound on savings. Jurisdiction-wide cumulative savings for Evergy Metro in 2033 are 1,532 GWh, or 17.7% of the baseline projection.
- **Economic Potential** represents the amount of technical potential identified as cost-effective based on the TRC test. Cumulative savings in 2033 are 759 GWh, or 8.8% of the baseline projection.
- **Maximum Achievable Potential**, reflecting ideal conditions and high incentive levels, is estimated to be 430 GWh in 2033, or 5% of the baseline projection.
- **Realistic Achievable Potential**, accounting for additional barriers that might be experienced during program implementation, is estimated to be 275 GWh in 2033, or 3.2% of the baseline projection.

Table 2-15 summarizes Evergy Metro's energy efficiency potential for select years in GWh and as a percentage of the baseline projection.

Table 2-15 Cumulative Energy Efficiency Potential, Select Years (GWh) – Evergy Metro

	2024	2025	2026	2029	2033
Baseline Projection (GWh)	8,645	8,664	8,670	8,677	8,666
Cumulative Savings (GWh)					
Realistic Achievable Potential	26	53	81	164	275
Maximum Achievable Potential	43	88	134	265	430
Economic Potential	79	161	246	479	759
Technical Potential	179	356	531	1,001	1,532
Cumulative as % of Baseline					
Realistic Achievable Potential	0.3%	0.6%	0.9%	1.9%	3.2%
Maximum Achievable Potential	0.5%	1.0%	1.5%	3.1%	5.0%
Economic Potential	0.9%	1.9%	2.8%	5.5%	8.8%
Technical Potential	2.1%	4.1%	6.1%	11.5%	17.7%

Figure 2-5 shows the cumulative realistic achievable potential for select years, and Figure 2-6 shows forecasted sales under each potential case relative to the baseline projection.

Figure 2-5 Cumulative Energy Efficiency Potential, Select Years – Evergy Metro

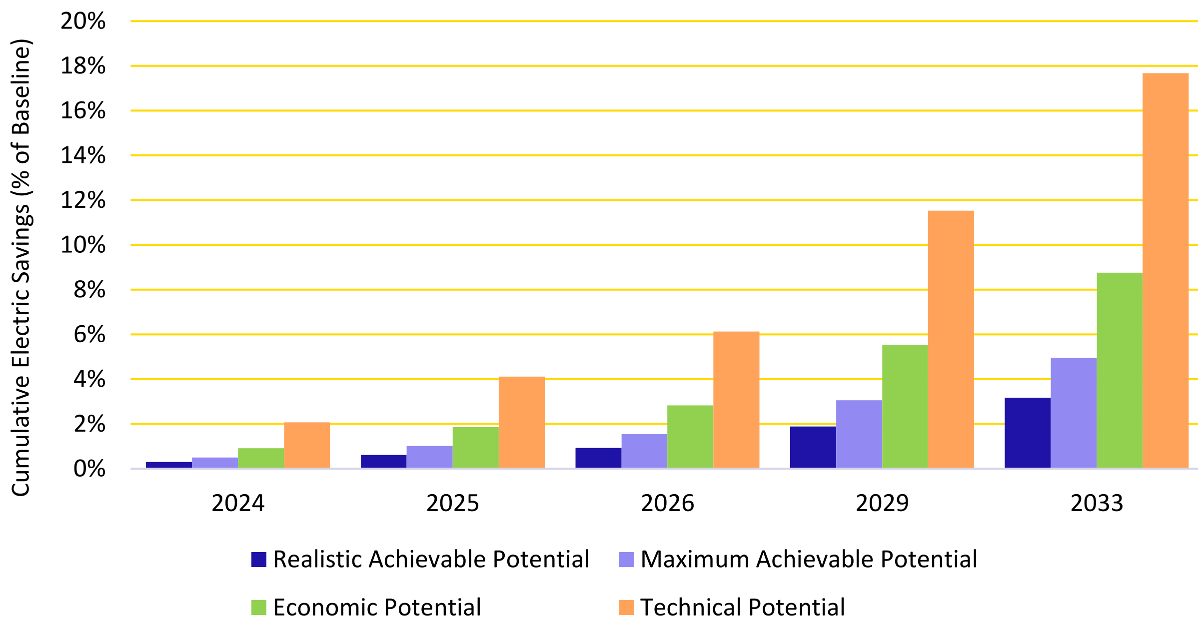


Figure 2-6 Annual Forecasted Sales by Energy Efficiency Case – Evergy Metro

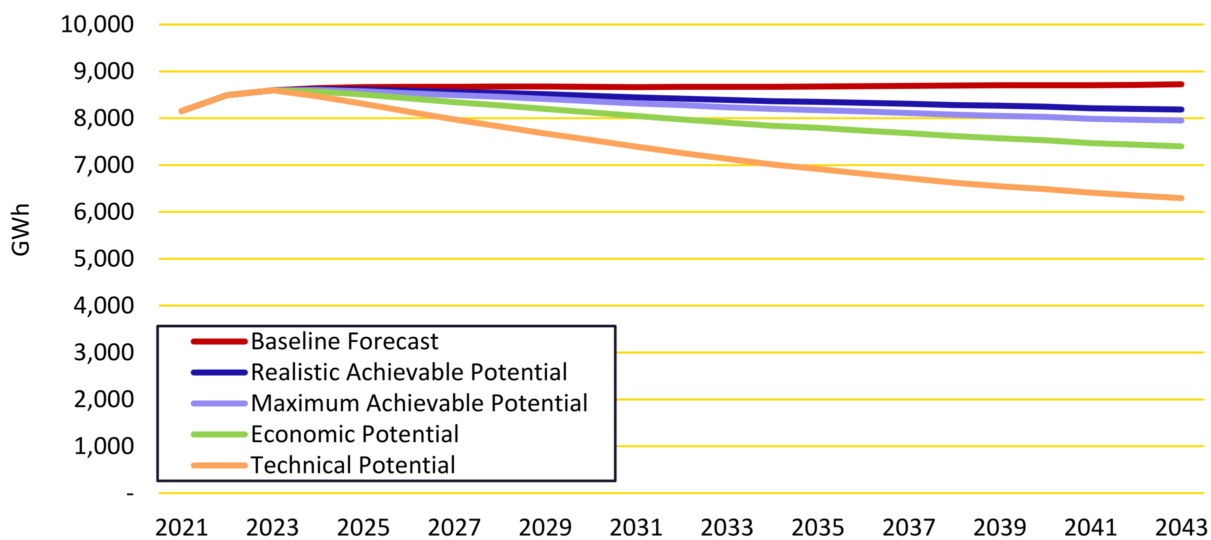


Table 2-16 presents top energy efficiency measures for Evergy Metro in 2026 for the Realistic Achievable Potential case, where the majority of savings come from linear and other LED interior lighting upgrades, particularly in the commercial and industrial sectors.

Table 2-16 Top Energy Efficiency Measures, Realistic Achievable Potential, 2026 (GWh) – Evergy Metro

Rank	Measure Name	Cumulative Savings (MWh)	% of Total
1	Commercial - Linear Lighting (LED 2020 (109 lm/W system) w/ Controls)	16,233	20.0%
2	Commercial - Retrocommissioning (Periodic recommissioning of building systems)	6,455	8.0%
3	Commercial - RTU (IEER 18.0 - ENERGY STAR (4.0))	5,917	7.3%
4	Commercial - Exempted Lighting (LED 2020 (95 lm/W))	4,296	5.3%
5	Commercial - Ventilation - Demand Controlled (Outdoor air controlled based on occupancy to meet ASHRAE 62.1)	4,082	5.0%
6	Residential - Central AC (SEER 18.0 (CEE Tier 2))	3,653	4.5%
7	Commercial - High-Bay Lighting (LED 2020 (132 lm/W) w/ Controls)	3,200	3.9%
8	Commercial - Server (ENERGY STAR (3.0))	2,656	3.3%
9	Residential - Connected Thermostat - ENERGY STAR (1.0) (Networked Installed)	2,118	2.6%
10	Residential - Ducting - Repair and Sealing (Sealed)	2,070	2.5%
11	Industrial - High-Bay Lighting (LED 2020 (132 lm/W) w/ Controls)	2,066	2.5%
12	Industrial - Linear Lighting (LED 2020 (109 lm/W system))	1,334	1.6%
13	Commercial - Ventilation - Variable Speed Control (VSD on fan motor)	1,297	1.6%
14	Residential - Ducting - Repair and Sealing - Aerosol (G.17 Aerosol Duct Sealing)	1,276	1.6%
15	Commercial - Water-Cooled Chiller (COP 12.13 (0.29 kW/ton))	1,086	1.3%
16	Commercial - POS Terminal (ENERGY STAR (7.1))	1,057	1.3%
17	Commercial - HVAC - Maintenance (Tune-up of unitary HVAC systems)	986	1.2%
18	Residential - Building Shell - Liquid-Applied Weather-Resistive Barrier	958	1.2%
19	Residential - Room AC - Recycling (Unit Removed)	948	1.2%
20	Residential - Refrigerator (CEE Tier 3 (20% above standard))	915	1.1%
	Total of Top 20 Measures	**62,602**	**77.1%**
	Total Savings - All Measures	**81,184**	**100.0%**

2.3.2 Evergy West Energy Efficiency Potential Summary

- **Technical Potential**, which reflects the adoption of all energy efficiency measures regardless of cost or customer preferences, is a theoretical upper bound on savings. Jurisdciction-wide cumulative savings for Evergy West in 2033 are 1,871 GWh, or 21% of the baseline projection.
- **Economic Potential** represents the amount of technical potential that is identified as cost-effective based on the TRC test. Cumulative savings in 2033 are 876 GWh, or 9.8% of the baseline projection.
- **Maximum Achievable Potential**, reflecting ideal conditions and high incentive levels, is estimated 477 GWh in savings in 2033, or 5.3% of the baseline projection.
- **Realistic Achievable Potential**, accounting for additional barriers that might be experienced during program implementation, is estimated to be 313 GWh in 2033, or 3.5% of the baseline projection.

Table 2-17 summarizes Evergy West's energy efficiency potential for select years in GWh and as a percentage of the baseline projection.

Table 2-17 Cumulative Energy Efficiency Potential, Select Years (GWh) – Evergy West

	2024	2025	2026	2029	2033
Baseline Projection (GWh)	8,818	8,849	8,868	8,907	8,926
Cumulative Savings (GWh)					
Realistic Achievable Potential	28	58	88	181	313
Maximum Achievable Potential	47	95	143	286	477
Economic Potential	90	181	274	540	876
Technical Potential	216	429	639	1,217	1,871
Cumulative as % of Baseline					
Realistic Achievable Potential	0.3%	0.7%	1.0%	2.0%	3.5%
Maximum Achievable Potential	0.5%	1.1%	1.6%	3.2%	5.3%
Economic Potential	1.0%	2.0%	3.1%	6.1%	9.8%
Technical Potential	2.4%	4.9%	7.2%	13.7%	21.0%

Figure 2-7 shows the cumulative realistic achievable potential for select years, and Figure 2-8 shows the forecasted energy efficiency potential relative to the baseline projection.

Figure 2-7 Cumulative Energy Efficiency Potential, Select Years) – Evergy West

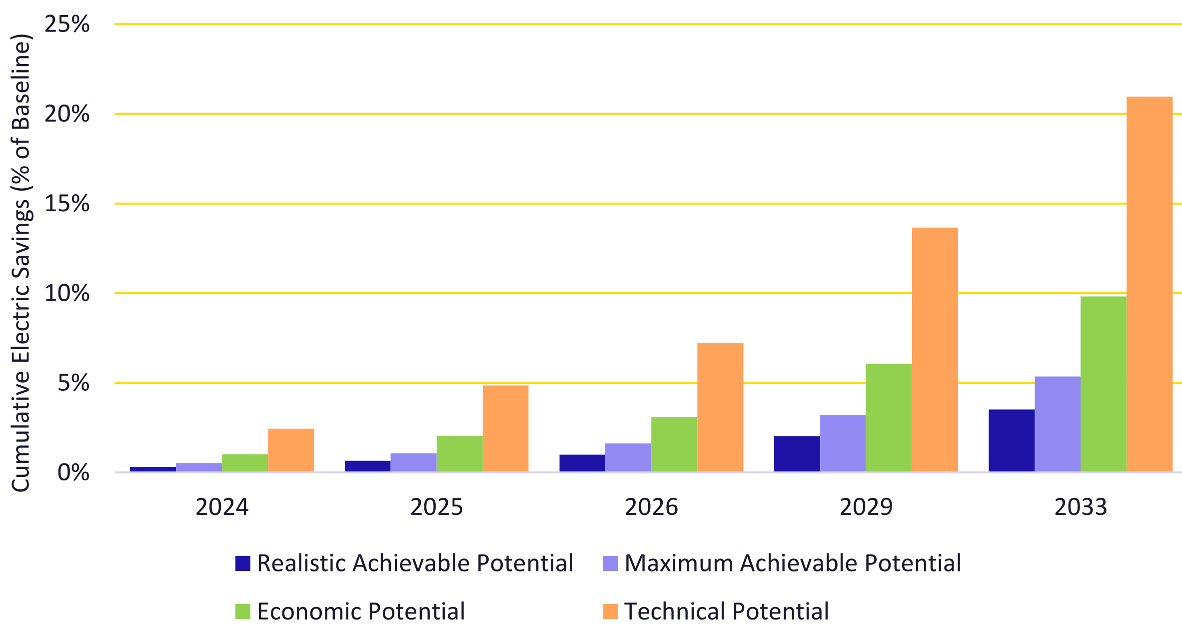


Figure 2-8 Annual Forecasted Sales by Energy Efficiency Case – Evergy West

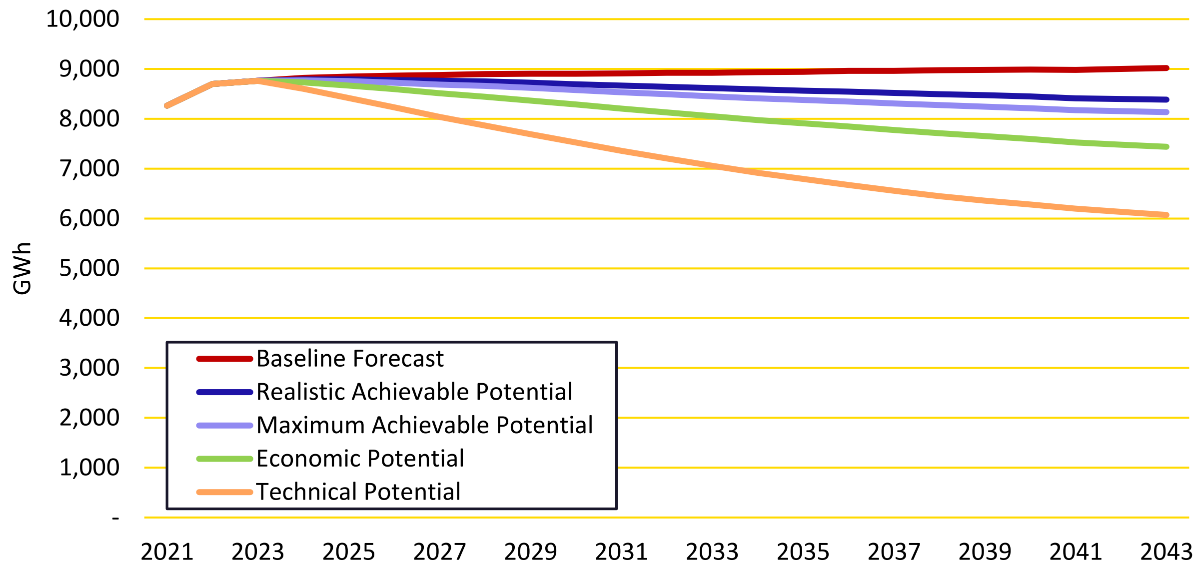


Table 2-18 presents top energy efficiency measures for Evergy West in 2026.

Table 2-18 Top Energy Efficiency Measures, 2026 (GWh) – Evergy West

Rank	Measure Name	Cumulative Savings (MWh)	% of Total
1	Commercial - Linear Lighting (LED 2020 (109 lm/W system) w/ Controls)	11,743	13.4%
2	Commercial - Retrocommissioning (Periodic recommissioning of building systems)	5,224	6.0%
3	Commercial - RTU (IEER 18.0 - ENERGY STAR (4.0))	5,010	5.7%
4	Residential - Central AC (SEER 18.0 (CEE Tier 2))	4,210	4.8%
5	Residential - Ducting - Repair and Sealing (Sealed)	3,818	4.4%
6	Residential - Furnace - Conversion to Air-Source Heat Pump	3,496	4.0%
7	Residential - Connected Thermostat - ENERGY STAR (1.0) (Networked Installed)	3,199	3.6%
8	Residential - Insulation - Floor Upgrade (R-30)	3,162	3.6%
9	Commercial - Ventilation - Demand Controlled (Outdoor air controlled based on occupancy to meet ASHRAE 62.1)	3,016	3.4%
10	Residential - Air-Source Heat Pump (SEER 16.0 / HSPF 9.2 (ENERGY STAR 6.1))	2,809	3.2%
11	Commercial - Exempted Lighting (LED 2020 (95 lm/W))	2,790	3.2%
12	Commercial - High-Bay Lighting (LED 2020 (132 lm/W) w/ Controls)	2,729	3.1%
13	Residential - Ducting - Repair and Sealing - Aerosol (G.17 Aerosol Duct Sealing)	2,489	2.8%
14	Industrial - High-Bay Lighting (LED 2020 (132 lm/W) w/ Controls)	2,437	2.8%
15	Residential - Central Heat Pump - Controls and Commissioning (Central Heat Pump with auxiliary heat control strategy, lockout settings, and other parameters)	1,949	2.2%
16	Residential - Building Shell - Liquid-Applied Weather-Resistive Barrier	1,659	1.9%
17	Industrial - Linear Lighting (LED 2020 (109 lm/W system))	1,532	1.7%
18	Residential - Water Heater - Drainwater Heat Recovery	1,438	1.6%
19	Commercial - Server (ENERGY STAR (3.0))	1,384	1.6%
20	Residential - Insulation - Ducting (R-8)	1,185	1.4%
	Total of Top 20 Measures	**65,278**	**74.4%**
	Total Savings - All Measures	**88,320**	**100.0%**

2.4 Demand Response / Demand-Side Rates Potential Results

This section presents the results of the DR and DSR potential analysis. We present summary-level summer peak potential for Evergy Metro and Evergy West. Detailed potential by program option and winter peak is presented in ***Exhibit B_Evergy West Potential Results*** and ***Exhibit C_Evergy Metro Potential Results***.

2.4.1 Evergy Metro DR/DSR Potential Summary

Table 2-19, Figure 2-9, and Figure 2-10 show the baseline projection and achievable potential for MAP and RAP scenarios in the DR/DSR potential for Evergy Metro. In 2033, achievable potential reaches an estimated 8% of baseline peak demand (147 MW in the RAP scenario and 155 MW in the MAP scenario, at generation). Potential generated through the mandatory TOU rates, maintenance of existing programs, and new DR/DSR resources all contribute to these estimates of achievable potential. The potential shown here does not include peak demand savings generated by energy efficiency adoption.

Because the MAP scenario tested the effects of the mandatory TOU rate, differences between RAP and MAP scenarios are minimal and lead to small differences in savings potential in the later years. Both scenarios exhibit similar trends over time, where potential increases in the first few years as the programs grow and then plateau as they reach maturity. However, the RAP scenario experiences a sharper increase in potential in those first years because of the TOU mandatory rates: AEG de-rated impacts from the TOU rates for the years few years of the study to simulate a learning curve, assuming that the longer the customers are on the rates, the better that customers will respond the rates' pricing signals. We did not apply a learning curve to the MAP scenario.

Table 2-19 Cumulative DR/DSR Potential, Select Years (Summer MW @ Generator) – Evergy Metro

	2024	2025	2026	2029	2033
Baseline Projection (MW)	1,841	1,845	1,848	1,864	1,885
Achievable Potential (MW)					
RAP	89	115	135	144	147
MAP	117	135	150	152	155
Achievable Potential (% of Baseline)					
RAP	5%	6%	7%	8%	8%
MAP	6%	7%	8%	8%	8%

Figure 2-9 DR/DSR Summer Potential by Scenario – Evergy Metro

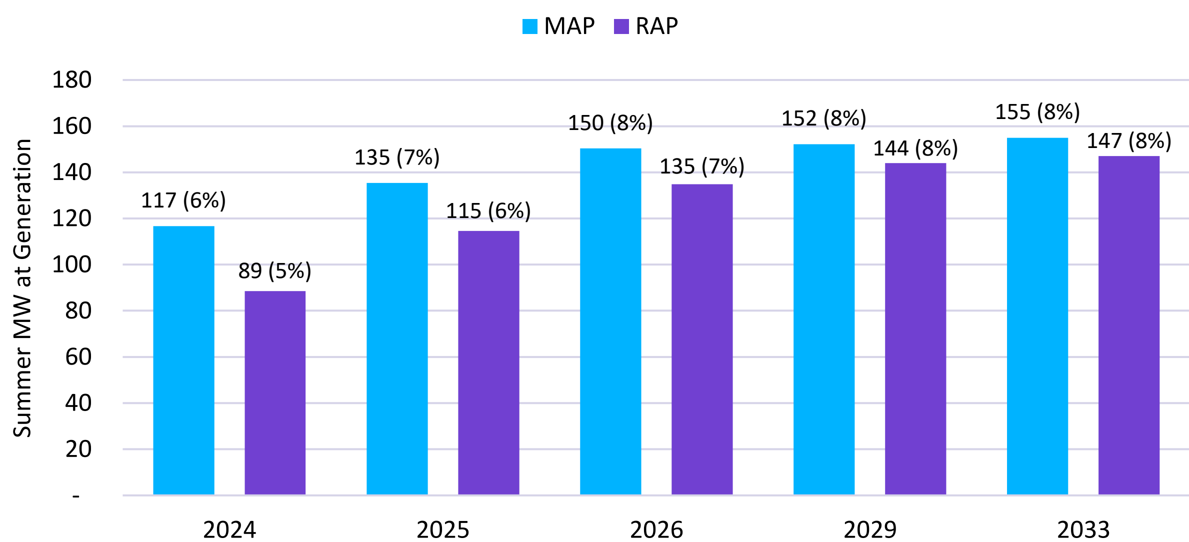
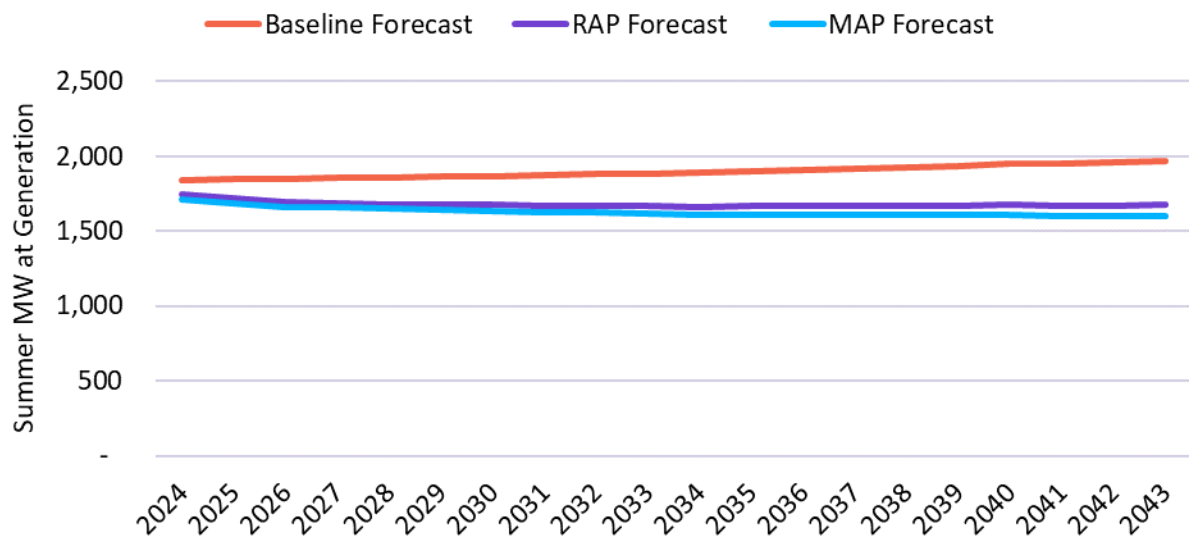


Figure 2-10 Annual DR/DSR Potential – Evergy Metro



2.4.1(a) Sensitivity Analysis – Evergy Metro

As discussed in Section 2.1.3, AEG used the MAP scenario to test sensitivities to the mandatory TOU rate the Missouri PSC ordered Evergy to transition residential customers to by October 1, 2023. As expected, potential increases with the level of TOU Standard retention, the TOU rate customers will first be opted onto. While Evergy plans to offer TOU rates with higher rate differentials than the TOU Standard rate, we assume that the majority of customers who opt out of the TOU Standard rate will move to the Peak Adjustment Rate, which has such a low-rate differential that impacts are negligible. However, in 2033, differences between the MAP scenario (based on a 50% TOU Standard retention rate) and MAP High Retention (based on an 85% TOU Standard retention rate) remain small, 15 MW and less than a one-percent change relative to the baseline peak demand.

Table 2-20 MAP DR/DSR Sensitivity Results, Select Years (Summer MW) – Evergy Metro

	2024	2025	2026	2029	2033
Baseline Projection (MW)	1,841	1,845	1,848	1,864	1,885
Achievable Potential (MW)					
MAP	**117**	**135**	**150**	**152**	**155**
MAP - Medium Retention	127	144	159	161	163
MAP - High Retention	135	151	165	167	170
Achievable Potential (% of Baseline)					
MAP	**6%**	**7%**	**8%**	**8%**	**8%**
MAP - Medium Retention	7%	8%	9%	9%	9%
MAP - High Retention	7%	8%	9%	9%	9%

AEG focused the RAP scenario sensitivity analysis on the effects of increasing or decreasing participation in the DR/DSR program options. At the extremes represented by RAP Minus and RAP Plus, DR/DSR potential changes 32 MW in Evergy Metro (1.7% of baseline peak demand) in 2033.

Table 2-21 RAP DR/DSR Sensitivity Results, Select Years (Summer MW) – Evergy Metro

	2024	2025	2026	2029	2033
Baseline Projection (MW)	1,841	1,845	1,848	1,864	1,885
Achievable Potential (MW)					
RAP Minus	76	98	116	124	127
RAP	**89**	**115**	**135**	**144**	**147**
RAP Plus	97	124	146	155	159
Achievable Potential (% of Baseline)					
RAP Minus	4%	5%	6%	7%	7%
RAP	**5%**	**6%**	**7%**	**8%**	**8%**
RAP Plus	5%	7%	8%	8%	8%

2.4.2 Every West DR/DSR Potential Summary

Table 2-22, Figure 2-11, and Figure 2-12 show the estimated achievable potential from DR/DSR for Evergy West. Potential as a percentage of baseline peak demand is slightly higher than Evergy Metro, with both RAP and MAP scenarios producing an achievable potential of 10% (204 MW and 208 MW at generation, respectively). Excepting existing programs, for which AEG calibrated to actual program achievements, AEG used the same impact and participation assumptions for Evergy West and Every Metro. Therefore, differences in savings are largely driven by differences in customer composition and peak demand.

Table 2-22 Cumulative DR/DSR Potential, Select Years (Summer MW) – Evergy West

	2024	2025	2026	2029	2033
Baseline Projection (MW)	1,962	1,970	1,979	2,009	2,049
Achievable Potential (MW)					
RAP	128	161	187	201	204
MAP	162	184	202	206	208
Achievable Potential (% of Baseline)					
RAP	7%	8%	9%	10%	10%
MAP	8%	9%	10%	10%	10%

Figure 2-11 DR/DSR Summer Potential by Scenario – Evergy West

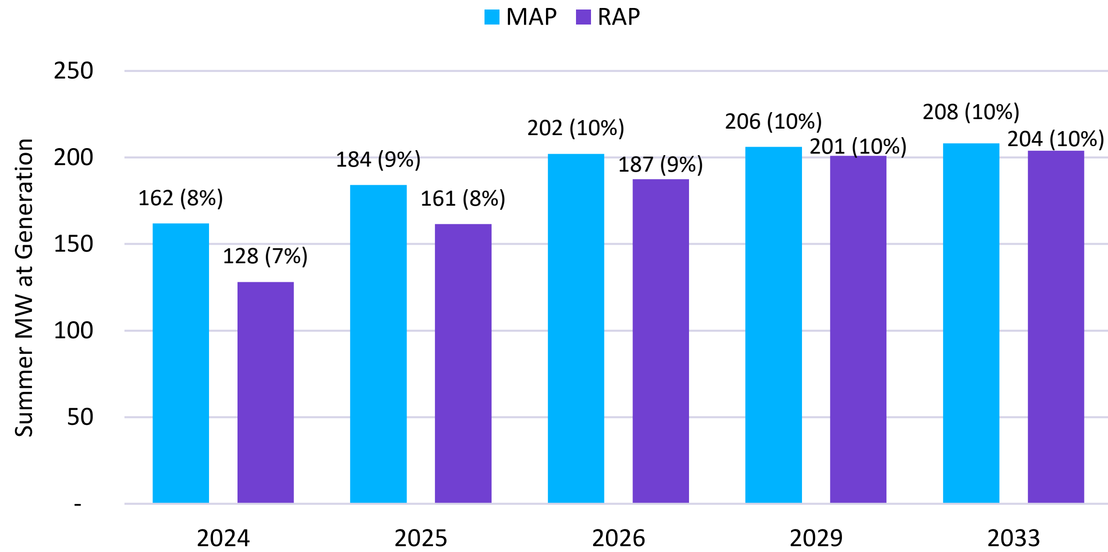
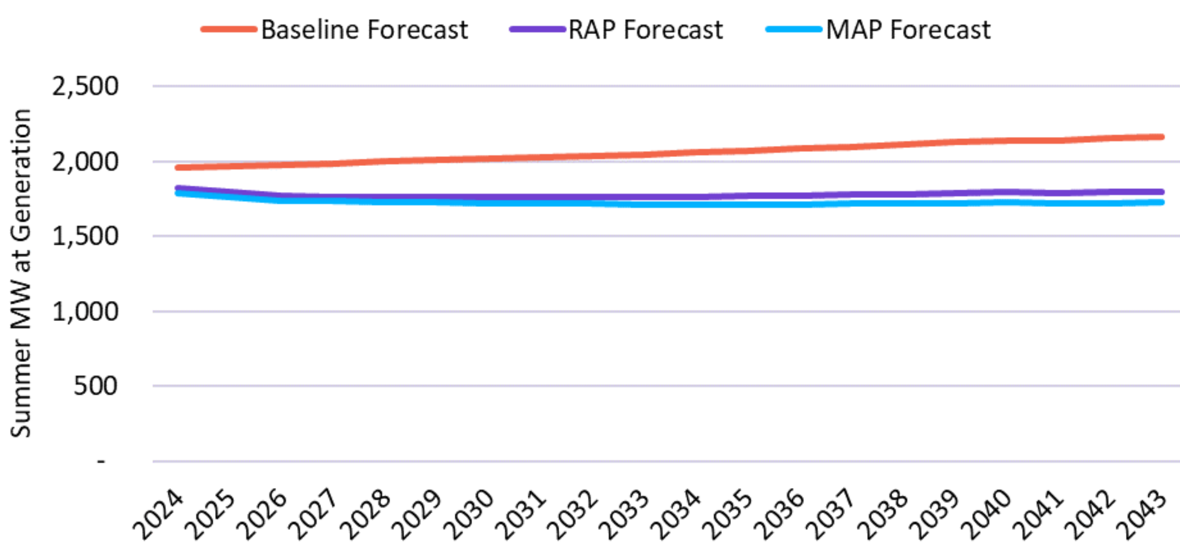


Figure 2-12 Annual DR/DSR Summer Potential – Evergy West



2.4.2(a) Sensitivity Analysis – Evergy West

MAP potential sensitivity analysis for Evergy West resulted in similar findings to Evergy Metro. Potential increases with the level of TOU Standard retention, but by 2033, the increases from the MAP scenario remain small and represent, at most, not even a one-percent change relative to the baseline peak demand.

Table 2-23 MAP DR/DSR Sensitivity Results, Select Years (Summer MW) – Evergy West

	2024	2025	2026	2029	2033
Baseline Projection (MW)	1,962	1,970	1,979	2,009	2,049
Achievable Potential (MW)					
MAP	**162**	**184**	**202**	**206**	**208**
MAP - Medium Retention	175	195	213	217	219
MAP - High Retention	185	204	222	225	227
Achievable Potential (% of Baseline)					
MAP	**8%**	**9%**	**10%**	**10%**	**10%**
MAP - Medium Retention	9%	10%	11%	11%	11%
MAP - High Retention	9%	10%	11%	11%	11%

Results from the sensitivity analysis around RAP potential remain similar for Evergy West as observed for Evergy Metro. At the extremes represented by RAP Minus and RAP Plus, DR/DSR potential changes a total of 44 MW in Evergy West (2.3% of baseline peak demand) in 2033.

Table 2-24 RAP DR/DSR Sensitivity Results, Select Years (Summer MW) – Evergy West

	2024	2025	2026	2029	2033
Baseline Projection (MW)	1,962	1,970	1,979	2,009	2,049
Achievable Potential (MW)					
RAP Minus	110	138	161	173	176
RAP	**128**	**161**	**187**	**201**	**204**
RAP Plus	140	175	203	217	220
Achievable Potential (% of Baseline)					
RAP Minus	6%	7%	8%	9%	9%
RAP	**7%**	**8%**	**9%**	**10%**	**10%**
RAP Plus	7%	9%	10%	11%	11%

3 | DSM Energy Efficiency IRP Bundle Development

The final step of the 2023 IRP engagement was to develop a portfolio of energy efficiency and demand response IRP bundles utilizing the potential results to support Evergy's Demand-Side Resource Analysis under 4 CSR 240-22.050 for the 2023 IRP filing. Section 3 details the approach and results for the development of the energy efficiency bundles. The demand response and demand side rate resources for the 2023 IRP filing are detailed in Section 2.1.3 and Section 2.4.

3.1 Analysis Approach

This section describes the analysis approach taken for the study and the data sources used to develop the DSM Energy Efficiency IRP Bundles.

3.1.1 Overview of Analysis Approach

AEG used a bottom-up approach to develop the IRP bundles, incorporating the findings from the measure-level EE potential. The analysis conducted for the energy efficiency potential study reflects a measure-level approach to cost-effectiveness and potential estimation. In order to meet the rules set forth under 4 CSR 240-22.050, an additional set of steps were required to combine measures into program bundles based on target market and delivery method, as well as to assign program costs.

AEG developed the program bundles using the maximum and realistic achievable measure-level potential results, working closely with Evergy to develop cost-effective bundles. Multiple program bundle scenarios were developed to support Evergy's Demand-Side Resource Analysis under 4 CSR 240-22.050 for the 2023 IRP filing.

The DSM bundles were specifically developed for the 2023 IRP analysis. While the results of the IRP analysis can inform program designs in future MEEIA filings, program design for future implementation should be tailored to the current needs and market conditions within the Evergy service territory. Therefore, the DSM savings and budgets developed for the 2023 IRP process may differ from the actual implementation of specific current and future Evergy DSM programs.

3.1.2 IRP Bundle Design Approach

As required by 4 CSR 240-22.050, Evergy must achieve all cost-effective demand-side savings. AEG utilized measure and participation data from the comprehensive DSM Potential Study to inform and develop the proposed DSM IRP Bundles Design.

As part of the potential study, AEG:

- Developed a comprehensive list of EE measures
- Characterized each measure with energy and demand savings, incremental cost, service life, and other performance factors.
- Screened the measures for cost-effectiveness dynamically, taking into account changing savings and cost data over time. Thus, some measures pass the economic screen (i.e., a TRC benefit-cost ratio greater than or equal to 1.0) for some — but not all — of the years in the projection.

The DSM Potential Study measure-level MAP and RAP results served as the foundation for the development of the bundles. In order to maintain alignment, results from the potential study were exported into the DSM Bundles Design. The measures were vetted for inclusion in a DSM program bundle and re-screened for cost-effectiveness. Measures were added to bundles as they became cost-effective throughout the timeframe.

There are several differences between measure-level and bundled savings and general considerations to note that occur when translating the measure-level potential to bundles. These differences and considerations are as follows:

- May include multiple efficiency levels for a specific technology over the projection.
- May exclude some measures with very small potential or implementation challenges, such as stoves, microwaves, monitors, laptops, and TVs.
- Addition of administrative & delivery costs may render certain measures or bundles not cost-effective.
- Participation rates adjusted to reflect different IRP scenarios.
- Net to gross and realization rates impact savings.

Figure 3-1 outlines the framework for developing the IRP Bundles.

Figure 3-1 Analysis Framework

Measure/Program List	1.Created a program list based on Evergy's existing program structure. Added new programs based on screened measures from the potential study. 2.Added screened measures from the potential study to relevant program(s). 3.Aggregated programs where it made sense.
Measure Characterization	1.Brought in unit savings, incremental cost, and participation data for each measure on the measure list from the potential study into the BenCost (AEG's Planning Tool). 2.Assigned NTG from MEEIA Cycle 3.
Incentive Development	1.Assigned 50% of incremental cost to develop incentive for all RAP scenarios, 100% for MAP. 2.For outlier measures – made manual adjustments to reflect more realistic payments incentives.
Developed Non Incentive Budgets	1.Bucketed all program non-incentive costs into one category. 2.Benchmarked to Evergy current programs. 3.Created Non-Incentive % of total budget factor to assign by program. 4.For new programs benchmarked non-incentive costs from utility's with similar program across the country. 5.Included Portfolio level marketing, administration and evaluation.
Model QC	1.Reviewed measures and programs by looking at TRC ratios and $/kWh. 2.Compared recent MEEIA portfolio perfomance and previous IRP. 3.Adjusted measures where applicable.

All bundles were designed with cost-effective measures. Measures were bundled based on the end-use, sector, and implementation strategy. Incentive costs and non-incentive costs were assigned to bundles. Options were rescreened after measure bundling and cost assignment. Cost effectiveness at the option level was balanced with implementation considerations.

3.1.2(a) Utility Program Review

AEG reviewed ed current programs and recently filed plans for utilities across the country. The review informed the design of the bundles and identified new opportunities.

AEG took the following steps in the review:

1. Compared potential study results to other utility offerings to assess new opportunities that filled gaps in the current MEEIA portfolio.
2. Searched for utilities with comparable programs targeting a new measure or customer segment.

3. Assessed the applicability of each option for the IRP bundle development and potential future MEEIA application.
4. Added measures to existing bundles (i.e., LED Grow Lights for Indoor Agriculture) or created new programs (i.e., Residential New Construction) that integrated learnings from the review and

Results of the utility program review can be accessed in **Exhibit D_Evergy Utility Program Review.**

3.1.2(b) Cost-Effectiveness Screening

The Total Resource Cost Test (TRC) is the primary method of assessing the cost-effectiveness of energy efficient measures and bundles, considering the effects on both participating and non-participating customers. The TRC test is a widely accepted methodology that has been used across the United States for over twenty-five years. TRC measures the net costs and benefits of an energy efficiency bundle as a resource option based on the total costs of the bundle, including both the participant's and the utility's costs.

In total, five benefit-cost tests were utilized to analyze bundle design cost-effectiveness from different perspectives:

- Participant Cost Test quantifies the benefits and costs to the customer due to bundle participation.
- Ratepayer Impact Measure measures what happens to a customer's rates due to changes in utility revenues and operating costs.
- Utility Cost Test measures the net costs of a bundle as a resource option based on the costs incurred by the program administrator, excluding any net costs incurred by the participant.
- Societal Cost Test measures the effects of a bundle on society as a whole.

The cost-effectiveness analysis was performed using Evergy-specific data. The input data gathered for the model included:

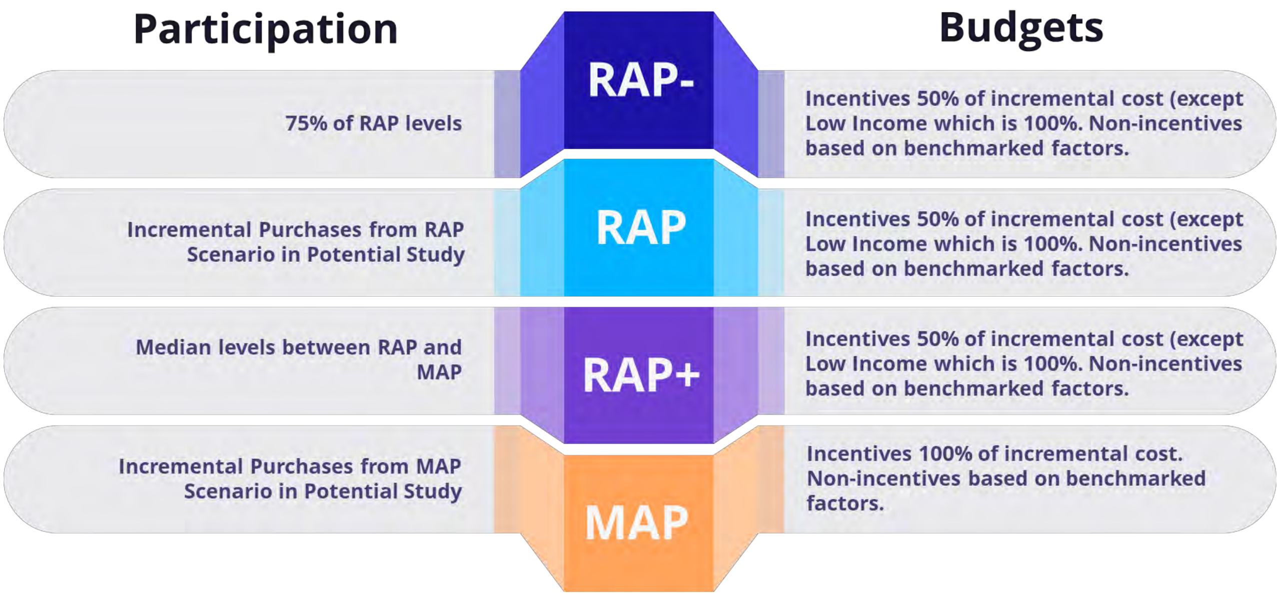
Table 3-1 Cost-Effectiveness Model Inputs

General Inputs	Specific-Project Inputs
Retail Rate ($/kWh)	Utility Project Costs (Administrative & Incentives)
Commodity Cost ($/kWh)	Direct Participant Project Costs ($/Participant)
Demand Cost ($/kW-Year)	Measure Life (Years)
Discount Rate (%)	kW/Participant Saved (Net and Gross)
Inflation Rate (%)	Number of Participants
Line Losses (%)	

3.1.2(c) Bundle Design Scenarios

Based on the RAP and MAP potential scenario results from the DSM Potential Study, AEG developed four portfolios comprised of cost-effective measures. Each of these portfolios was considered during the integration phase of Evergy's IRP process to determine which DSM portfolio was optimal based on Evergy's supply options:

Figure 3-2 Bundle Design Scenarios



3.2 DSM Portfolio Framework

This section describes several components that are considered when developing and implementing DSM bundles. Key considerations, such as budget flexibility, marketing plans, and evaluation plans, are important for designing budgets and selecting delivery methods.

3.2.1 Bundle Offerings

Bundle eligibility has been defined broadly to make bundles as inclusive as possible. In general, participation guidelines are designed to include all customer sectors and end uses.[10] Bundle offerings were intending to be broad program designs in order to allow for maximum flexibility for future MEEIA program offerings.

3.2.2 Outreach, Marketing and Communications

Outreach, marketing and communications are critical mechanisms for ensuring customers and trade allies are aware of, and participate in, the portfolio of bundles. The DSM bundle portfolio relies on a combination of education and customer incentives to advance energy efficiency. The bundles have been designed to maximize participation given industry best practices. Educating customers and trade allies on the benefits of energy efficiency can help speed the adoption of energy efficient measures and promote market transformation.

Customer incentives are the primary mechanism for bundle delivery. Through this mechanism, customers receive rebates to purchase energy efficient equipment and services through existing market actors including contractors, equipment dealers and retailers. To achieve the portfolio's long-term savings goals, it is necessary for Evergy and the implementation contractors to engage customers, trade allies, and state and local agencies. Targeting trade allies and leveraging relationships with stakeholders increases awareness and promotes the market adoption of high efficiency equipment/systems.

DSM bundle outreach, marketing and communication activities may include a mix of:

- Evergy website should act as a central location and portal for customer and trade ally participation, providing up-to-date access on DSM bundles, incentive offerings, rebate applications, etc.

[10] Customer sectors account for only those sectors that pay the DSIM charge.

- Television, radio, print, direct mail, and magazine advertisements.
- News story press releases resulting in newspaper and television news stories.
- Brochures and literature.
- Outreach, education seminars, and speaking events.
- E-mails, newsletters, round tables, and customizable brochures for trade allies.

Outreach, marketing and communications will be discussed in more detail within the bundle descriptions later in this report.

3.2.3 Net-to-Gross Impacts

Net-to-Gross (NTG) ratios adjust the gross energy and demand savings associated with a bundle to reflect the overall effectiveness of the bundle, taking into account free riders and spillover. Free riders and spillover, as determined from an impact evaluation, are defined as:

- Free Riders: Customers who participate in energy efficiency bundles that would have engaged in the efficient behavior in the absence of the bundle. The inclusion of free riders overestimates the energy and demand savings associated with a bundle.
- Spillover: Customers who engage in energy efficient behavior due to some influence of a bundle but who do not participate in a bundle. For example, if a customer purchases an air purifier through the Energy Savings Products Bundle and then chooses to purchase an ENERGY STAR® clothes dryer after learning about the benefits of energy efficiency.

Spillover and free ridership act in opposing directions, with spillover increasing a bundle's energy and demand savings while free ridership diminishes a program's savings.

Evergy should make an effort to minimize free ridership and maximize spillover by:

- Modifying incentives to respond to market conditions, as needed and practical.
- Verifying customer eligibility to ensure the customer is an Evergy customer, as practical.
- Increasing marketing of Evergy's DSM portfolio.

Evergy bundle adjustments to address free ridership and spillover should not negatively impact bundle implementation or continuity (e.g., Evergy should not modify incentive levels with a frequency that would compromise bundle stability and the customer experience). Evergy should work with bundle implementation contractors as well as the evaluation contractor(s) to determine if additional action is needed to minimize free ridership and maximize spillover.

3.2.4 Evaluation, Measurement and Verification

Evaluation, measurement, and verification (EM&V) is designed to support the need for public accountability, oversight and cost-effective bundle improvements and documentation of the effects of ratepayer funded efficiency bundles. Evergy should engage an EM&V contractor(s) to conduct process and impact evaluations of the EE bundles. It is important in the bundle design phase to allocate a sufficient amount of budget for process and impact evaluations to be performed at appropriate intervals on the relevant portions of the portfolio.

EM&V is recommended on a multi-year rotating schedule (evergy 3-4 years). A process and impact evaluation should be conducted on each bundle at least once during the multi-year bundle cycle. The EM&V budget is presented on an annual basis but may be spent at any point during the bundle cycle. The process and impact evaluations need not be conducted at the same time. Process evaluations are typically conducted earlier in the bundle cycle so that any issues uncovered can be addressed immediately, ensuring optimal bundle performance. Impact evaluations are typically conducted later in the bundle cycle when bundle results are accessible and apparent.

3.2.4(a) Process Evaluations

Process evaluations ensure that a bundle is operating as intended and provides information that can enable improvements in both the bundle design and implementation. Process evaluations assess customer understanding, attitudes about, and satisfaction with the bundle and other educational activities. The EM&V contractor assesses the effectiveness of the marketing and outreach, trade ally involvement, and whether implementation milestones are met adequately and on schedule. These evaluations use sales and promotion data maintained by the tracking system as well as customer survey data.

A good process evaluation:

- Assists bundle implementers and managers structure bundles to achieve cost-effective savings while maintaining high levels of customer satisfaction.
- Determines awareness levels to refine marketing strategies and reduce barriers to participation.
- Provides recommendations for changing the bundle's structure, management, administration, design, delivery, operations or targets.
- Determines if specific best practices should be incorporated.

3.2.4(b) Impact Evaluations

Impact evaluations estimate gross and net demand, energy savings and the cost-effectiveness of installed systems. They are used to verify measure installations, identify key energy assumptions and provide the research necessary to calculate defensible and accurate savings attributable to the bundle. The selected EM&V contractor develops an evaluation plan that ensures the appropriate measurement of savings in compliance with industry protocols. The impact evaluation also includes an evaluation of net-to-gross components.

3.3 Proposed DSM IRP Bundles

Evergy's proposed DSM bundle portfolio for 2024 through 2043 are comprised of six residential bundles and two non-residential bundles. Each bundle targets multiple end uses and offers residential, commercial and industrial customers an opportunity to achieve significant energy savings through participation. The 2024-2043 bundles are listed with a brief description in Table 4-1.

Evergy's portfolio:

- Is cost-effective at portfolio level.
- Expands and/or coordinates with existing Evergy energy efficiency programs.
- Provides a broad range of energy efficiency opportunities to all Evergy customers.
- Represents broad program categories that Evergy can draw upon for upcoming MEEIA program planning.

The proposed bundle design delivers an effective and balanced portfolio of energy and peak demand savings opportunities across all customer segments. Each bundle was designed to leverage the mix of best-practice measures and technologies, delivery strategies, and target markets in order to most effectively deliver bundles and measures to Evergy customers. The bundles were designed to be broad enough to allow for flexiblilty in nuanced implementation strategies for specific measures or target markets.

The proposed DSM portfolio includes a suite of bundles that offer customers a variety of opportunities to participate in energy efficiency. Evergy's programs have been aligned to offer customers consistent programs and incentives across both service territories. This will allow Evergy to streamline implementation and marketing activities and provide equitable programs to all of their customers, regardless of whether they are located within Evergy West and Evergy Metro territories. The bundles described in Table 3-2 are inclusive of existing Evergy programs and go beyond the current programs.

Table 3-2 Proposed DSM Bundle Descriptions, 2024-2043

Bundle	Description
Energy Savings Products	Rebates to purchase and install qualifying energy efficient HVAC equipment, appliances, electronics, and water heating measures.
Heating, Cooling, and Weatherization.[11]	Incentives for purchase and installation of qualifying energy efficient HVAC equipment, appliances, weatherization, and water heating measures.
Income Eligible Multifamily	The program aims to provide direct install measures in housing units and common area measures to multi-family buildings, targeting income eligible customers.
Income Eligible Single Family	The program leverages the existing Missouri Weatherization Assistance Program to provide qualifying customers with approved energy efficiency measures and equipment. Targets income eligible customers and provides fully subsidized measures.
Research and Pilot	Customers are provided an incentive to turn in inefficienct refrigerators, freezers and room air conditioners to be recycled.
Residential New Construction	Incentives for installation of new, qualifying energy efficient measures for the purposes of new construction projects.
Commercial Prescriptive	C&I customers may receive prescriptive rebates for purchasing energy efficient equipment for commercial and industrial facilities.
Commercial Custom	C&I customers may receive custom rebates for purchasing energy efficient equipment for commercial and industrial facilities.

3.3.1 DSM Portfolio Scenario Results

Figure 3-3 presents the proposed annual budgets (in thousands of dollars) for each of the four portfolio scenarios.

Figure 3-3 Proposed Annual Budgets by Scenario (thousands of dollars)

West Scenario	2024	2025	2026	2028	2033	2043
RAP Minus	$9,549,515	$10,149,714	$10,639,668	$11,972,716	$13,769,851	$12,109,077
RAP	$12,732,687	$13,532,952	$14,186,225	$15,963,621	$18,359,801	$16,145,437
RAP Plus	$17,327,508	$18,250,339	$18,951,675	$20,897,758	$22,958,129	$17,788,340
MAP	$44,616,450	$46,731,098	$48,240,505	$52,614,642	$56,109,967	$39,961,488
West Scenario	**2024**	**2025**	**2026**	**2028**	**2033**	**2043**
RAP Minus	$8,696,261	$9,608,626	$10,164,461	$11,316,043	$12,898,619	$11,181,936
RAP	$11,595,015	$12,811,501	$13,552,614	$15,088,058	$17,198,159	$14,909,247
RAP Plus	$16,032,082	$17,673,058	$18,512,196	$20,174,001	$21,944,310	$16,736,732
MAP	$41,314,818	$45,474,009	$47,353,303	$50,884,261	$53,863,335	$38,076,924

[11] Whole Home Efficiency option is designed to encompass a range of general whole home designs including PAYS.

Figure 3-4 presents the proposed annual incremental energy savings for each of the five portfolio scenarios.

Figure 3-4 Proposed Annual Incremental Energy Savings by Scenario (Net MWh)

West Scenario	2024	2025	2026	2028	2033	2043
RAP Minus	21,273	22,982	23,195	24,378	26,779	22,171
RAP	28,364	30,643	30,927	32,504	35,706	29,561
RAP Plus	38,052	40,817	40,769	41,990	44,073	32,429
MAP	47,709	50,959	50,562	51,397	52,291	34,777
Metro Scenario	**2024**	**2025**	**2026**	**2028**	**2033**	**2043**
RAP Minus	20,783	23,014	23,044	23,481	25,222	20,258
RAP	27,711	30,686	30,725	31,307	33,629	27,011
RAP Plus	37,687	41,523	41,130	41,100	42,123	30,124
MAP	47,643	52,350	51,517	50,862	50,556	32,304

Figure 3-5 presents the proposed annual incremental summer demand savings for each of the four portfolio scenarios.

Figure 3-5 Proposed Annual Incremental Summer Demand Savings by Scenario (Net MW)

West Scenario	2024	2025	2026	2028	2033	2043
RAP Minus	6	6	7	7	8	5
RAP	8	8	9	9	10	7
RAP Plus	11	11	12	12	13	8
MAP	14	14	14	15	15	8
Metro Scenario	**2024**	**2025**	**2026**	**2028**	**2033**	**2043**
RAP Minus	5	6	6	6	7	5
RAP	7	8	8	9	9	7
RAP Plus	10	11	11	11	12	7
MAP	13	14	14	14	14	7

The comprehensive IRP results for the DR/DSR and Energy Efficiency can be found in workpapers for ***Evergy Metro 2023 IRP Data and Evergy West 2023 IRP Data***.

Applied Energy Group, Inc.
2300 Clayton Road, Suite 1370
Concord, CA 94520
P: 510-982-3526

AEG

APPLIED ENERGY GROUP

Residential Appliance Saturation Survey

Prepared for: evergy

Date: August 2022

Overview and Objectives

Objectives	• Gather current information about residential customers in Missouri and Kansas service areas • Maintain consistency with previous RASS studies
Topics	• Customer and dwelling characteristics • Appliance saturations • Special topics
Approach	• Targets = 800 per service territory; 3,200 total • Anticipate 550 single-family and 250 multi-family homes • Formal sample design step • Mail-to-web and email-to-web data collection
Results	• Support development of residential market profiles in Market Potential Study • Provide appliance saturations for load forecasts

Methodology

Target Population and Sample Design

Separate surveys for four service areas:

- Missouri West
- Missouri Metro
- Kansas Metro
- Kansas Central

AEG designed the sample to target survey results with ±10% precision at the 90% confidence level by:

- Service territory
- Usage category within each service territory
- Net metering status

We also oversampled customers with email addresses to reduce the cost of data collection.

- The initial sample consisted of 18,000 mail customers and 46,000 email customer.
- Due to low response rate, another 80,003 email customers were added to the sample

Data Collection

Each customer in the sample was mailed or emailed a survey invitation

- The email invitation was sent directly from Evergy
- A postcard invitation was mailed by Ward Research, AEG's subcontractor
- The invitation included a URL/link and a unique password
- Reminders were sent 3 – 7 days later
- A total of 3,179 surveys were completed

Service Territory	Completed Surveys
Missouri West	819
Kansas Metro	816
Missouri Metro	741
Kansas Central	821
Total	3,197

Survey Results

Population estimates were developed by applying expansion weights to the sample

- The sample weights were calculated based on the sample design
- Includes stratification based on service territory, net metering, usage and email address
- Adjusted for nonresponse
- Ensures that weighted data represents the population

Missouri Customers

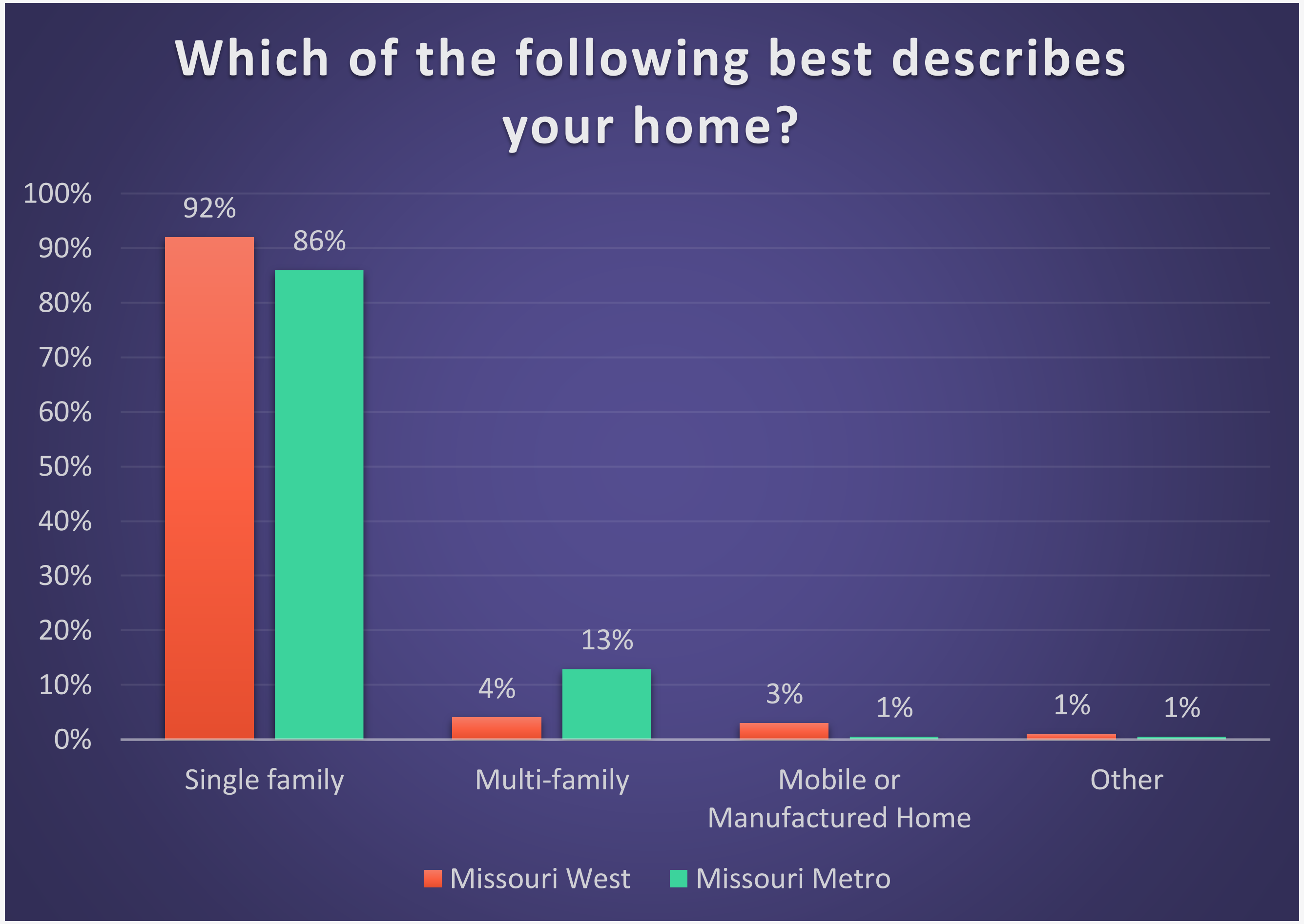
Type of Home

A large majority of Missouri customers live in single-family homes.

Missouri Metro has a greater proportion of multi-family households.

The proportion of customers living in single-family homes has increased since the 2019 study.

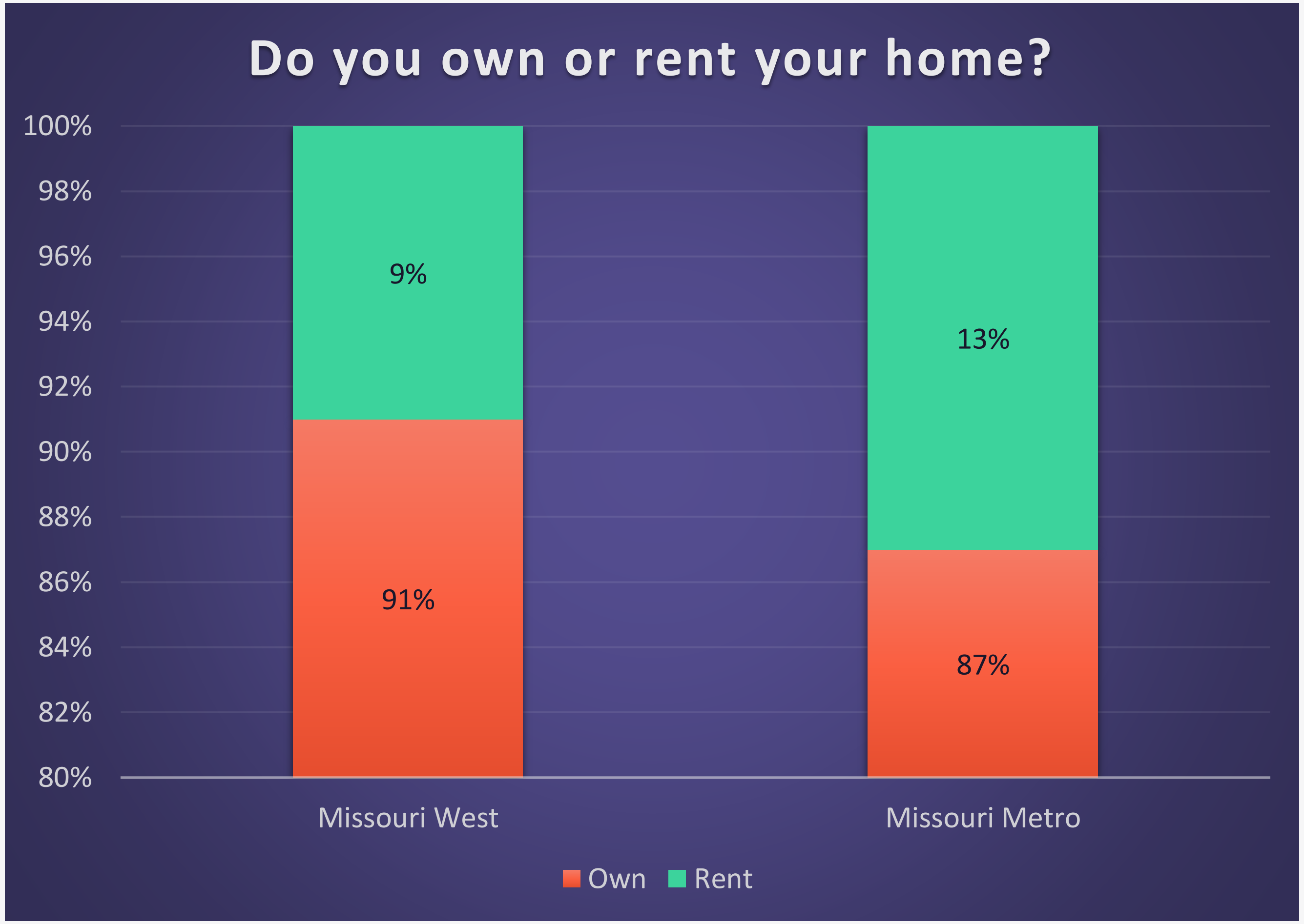
- At that time 84% of Missouri West and 71% of Missouri Metro customers resided in single-family homes.



Home Ownership

Most Missouri customers own their homes.

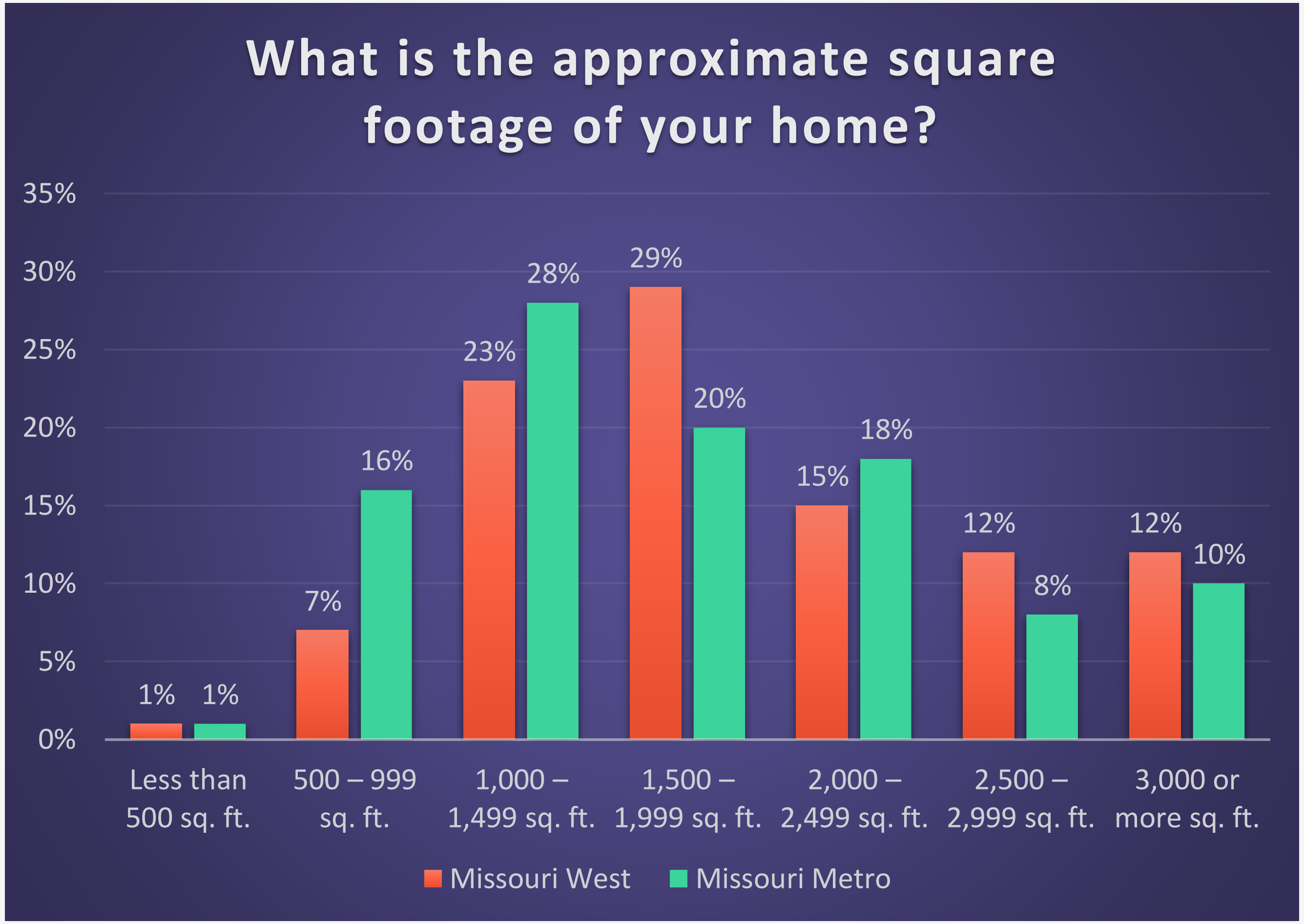
Not surprisingly, given the higher number of customers living in multi-family homes, more Missouri Metro customers rent their homes.



Size of Home – All Homes

About half of all customers in both service territories live in homes 1,000 – 1,999 square feet.

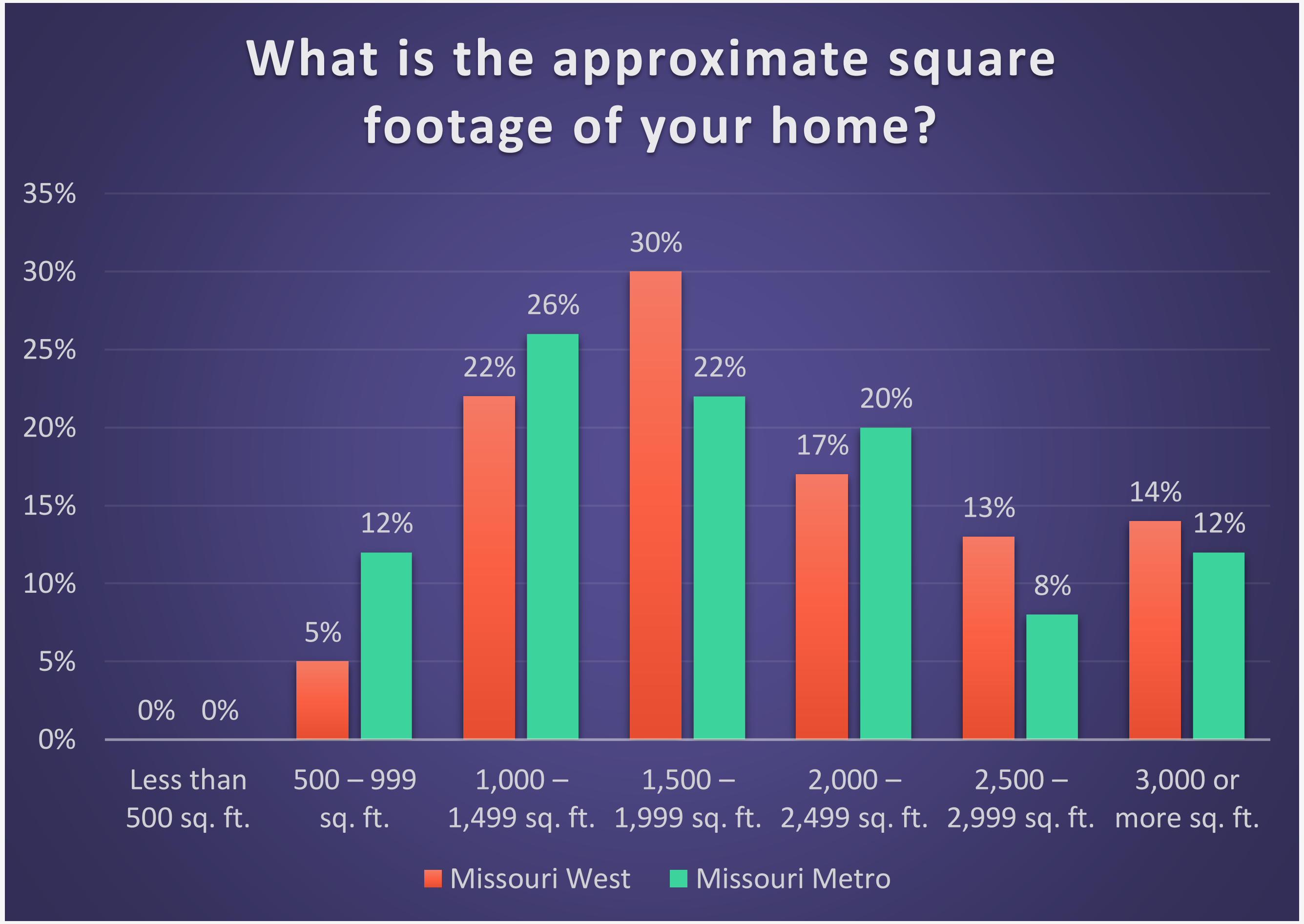
A larger proportion of Missouri West customers live in homes under 1,500 square feet.



Size of Home – Single Family

Given that a large majority of Missouri customers live in single-family homes, the distribution of size is very similar to the entire population shown in the previous chart.

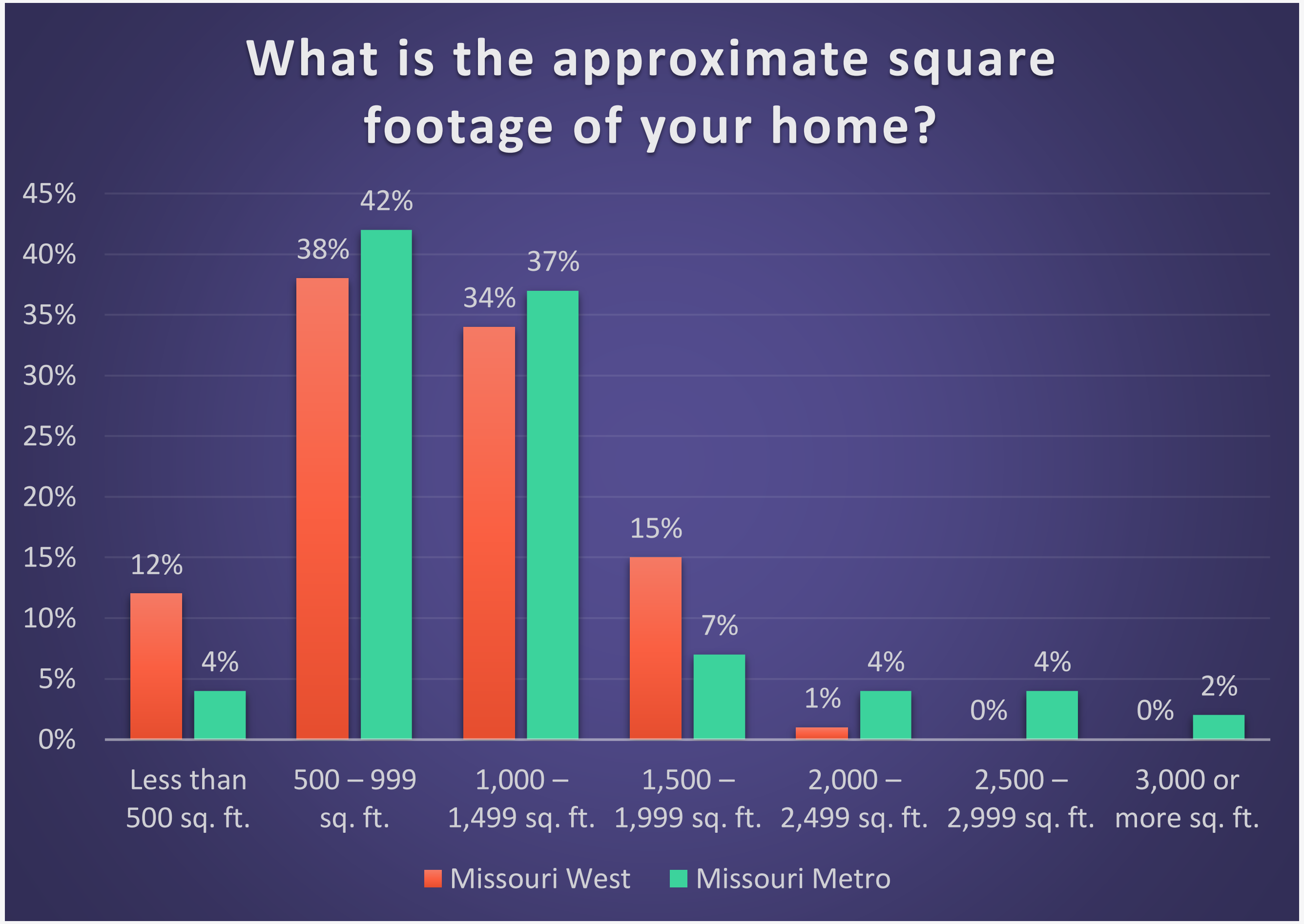
A small percentage of single-family homes are under 1,000 square feet.



Size of Home – Multi-Family

Most multi-family homes are under 1,500 square feet.

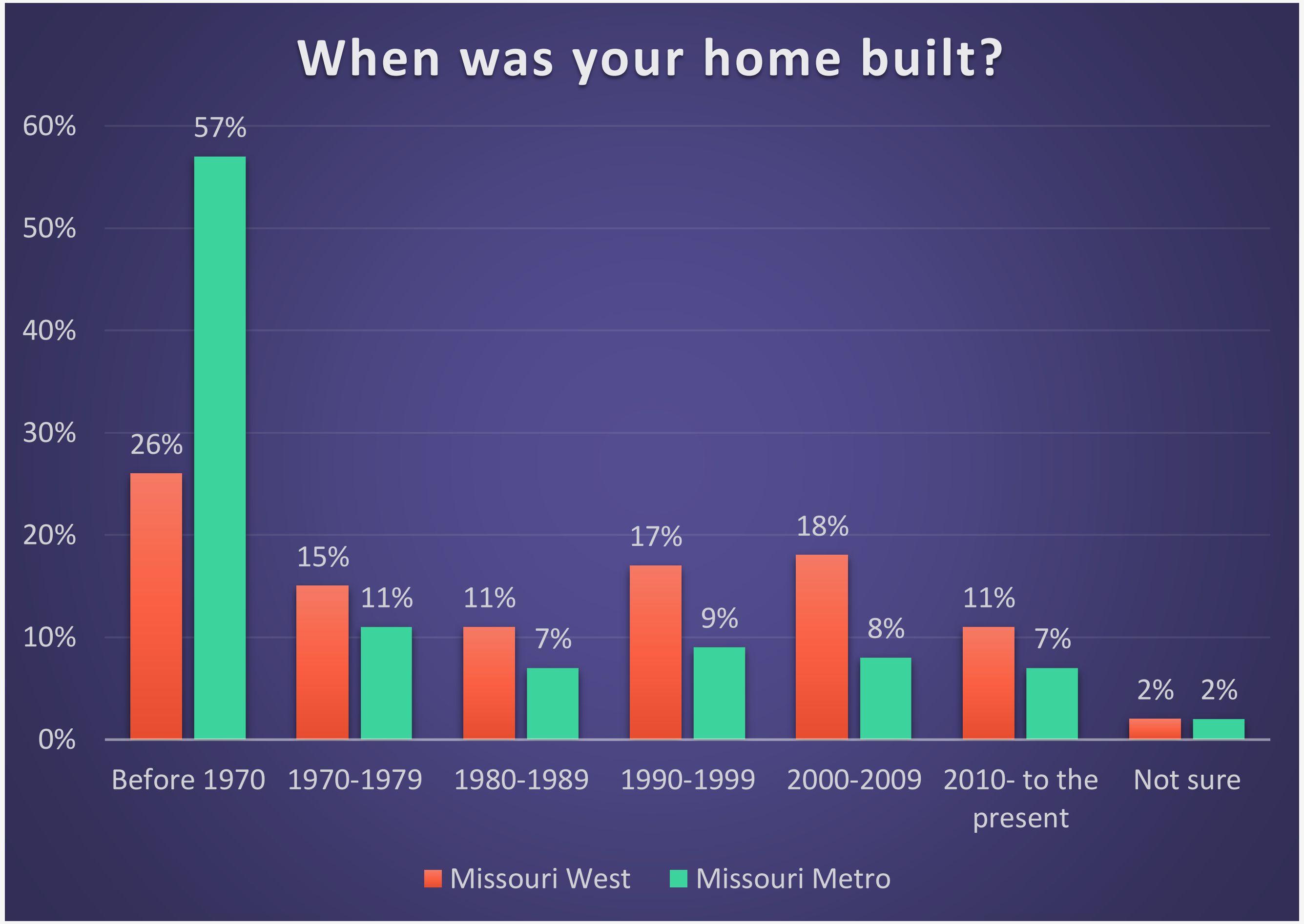
Missouri Metro has a larger proportion of multi-family homes larger than 2,000 square feet.



Age of Home

A majority of Missouri Metro customers live in homes built before 1970, which may indicate there is an opportunity among these customers for weatherization and other energy efficiency upgrades.

About one in ten homes were built in the last 12 years.



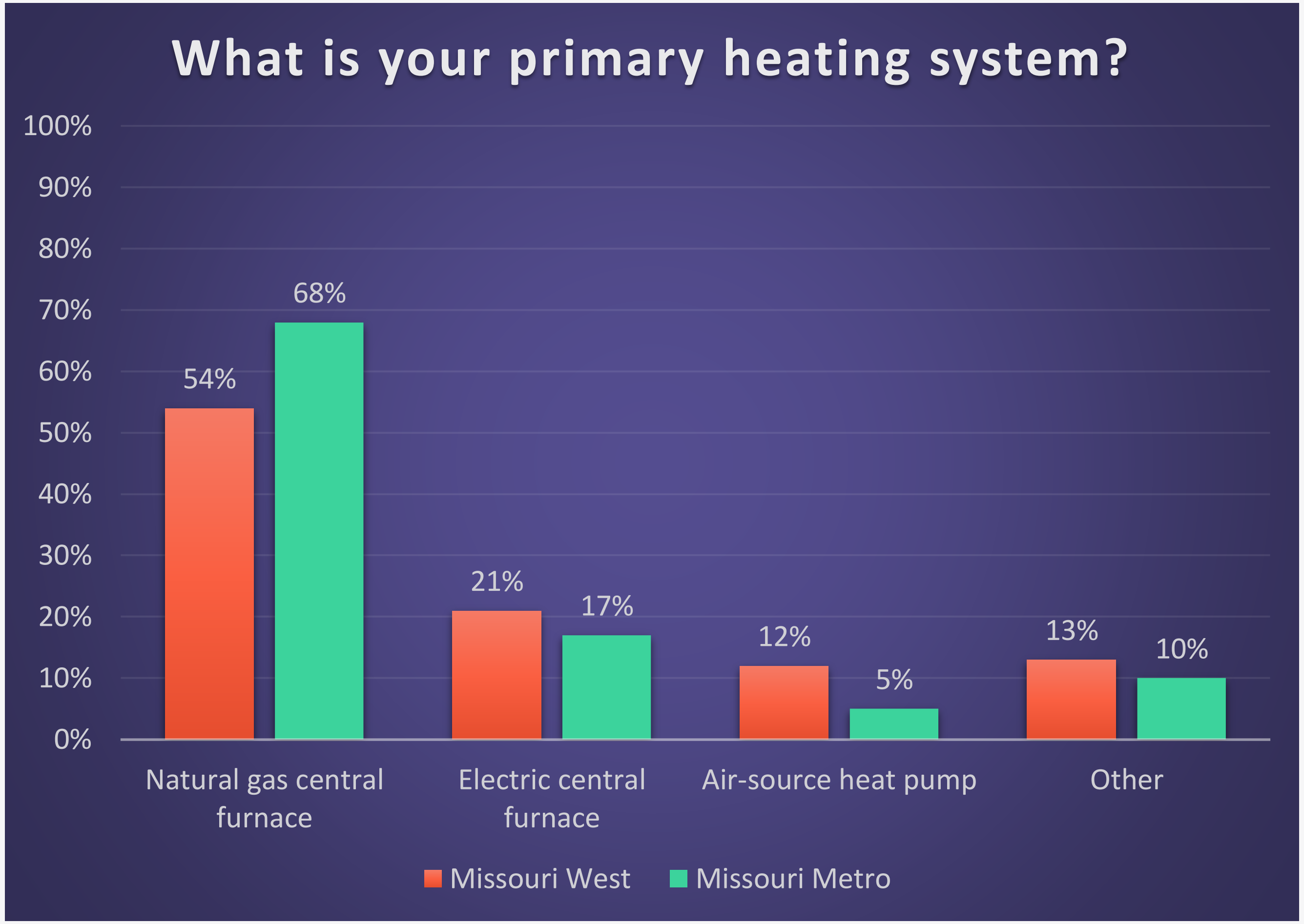
Space Heating, Cooling, and Water Heating

Primary Space Heating System

The majority of Missouri customers use natural gas central furnaces as their primary heating source.

The saturation of natural gas furnaces has grown in Missouri Metro's service territory since 2019 – at that time 58% used natural gas furnaces as their primary heating source.

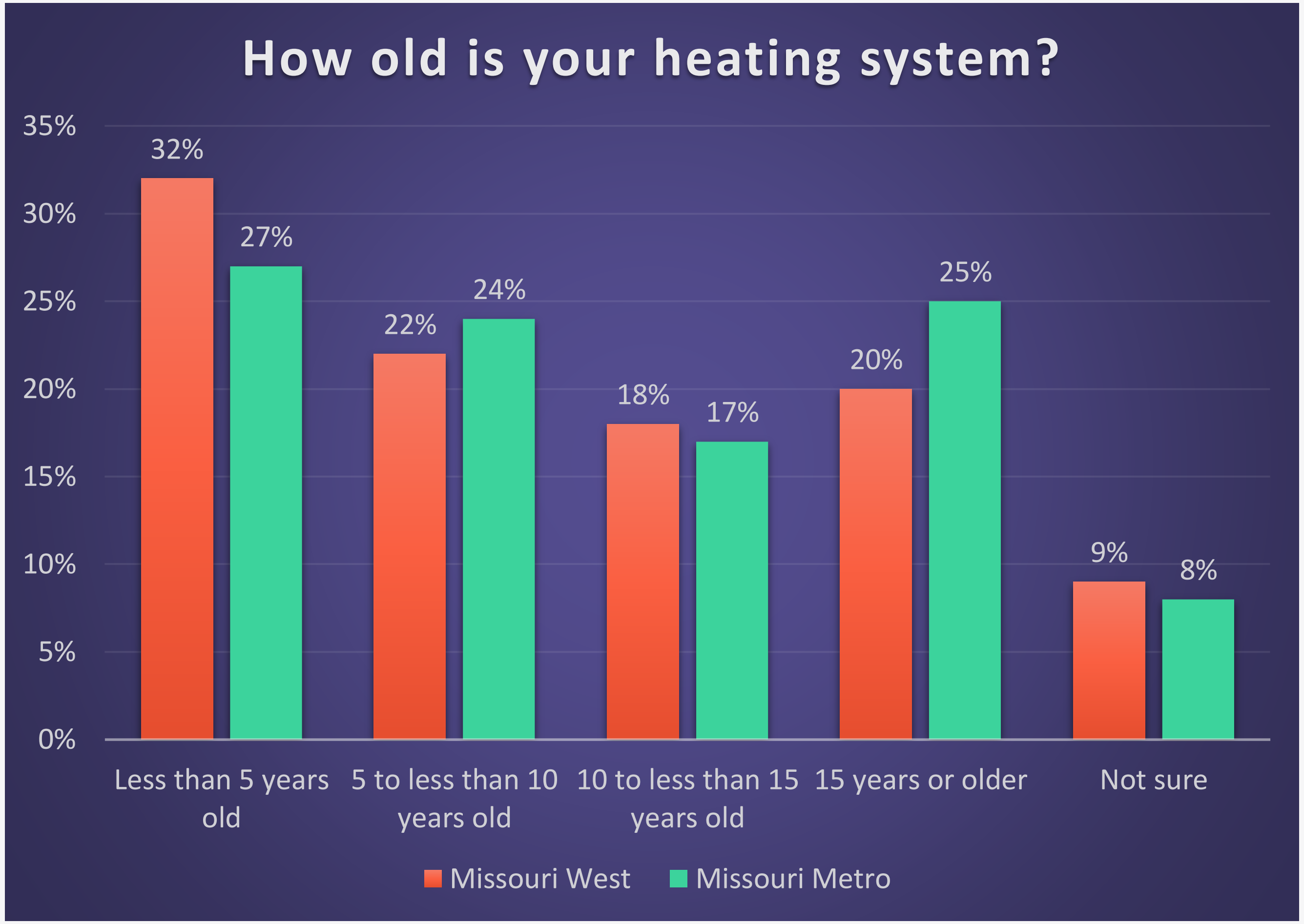
100% of customers who have heat pumps say they use electric heat for back up.



Age of Heating System

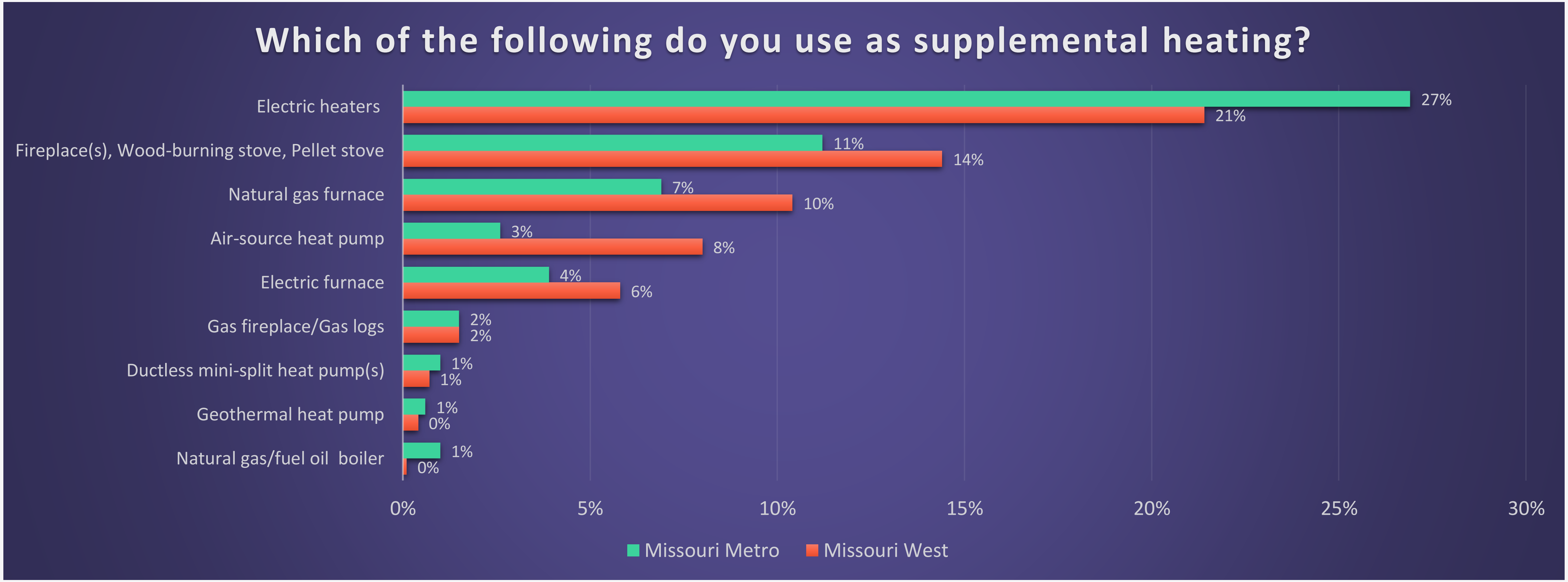
More than 1 in 5 Missouri customers have a heating system that is nearing the end of its useful life.

An opportunity exists for high efficiency HVAC upgrades among this group.



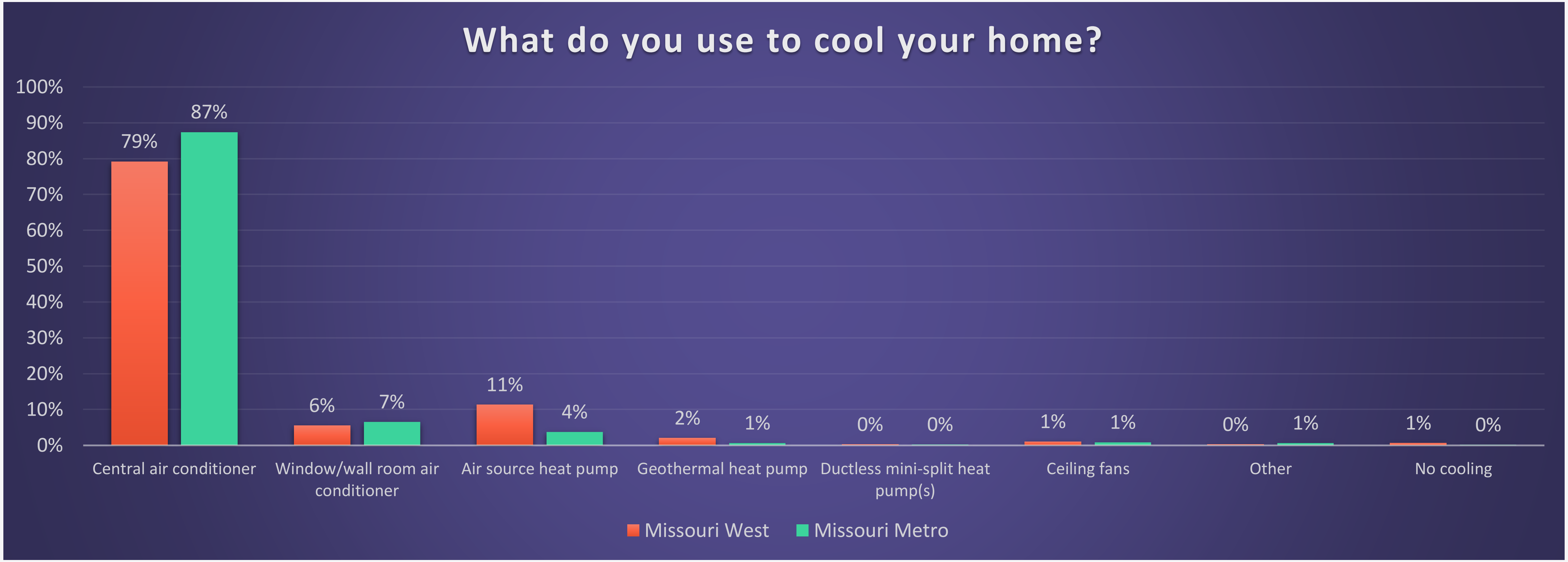
Secondary Heating System

Electric heaters are used as supplemental heating for the largest group of customers, followed by fireplaces, wood burning stoves and pellet stoves.



Primary Cooling System

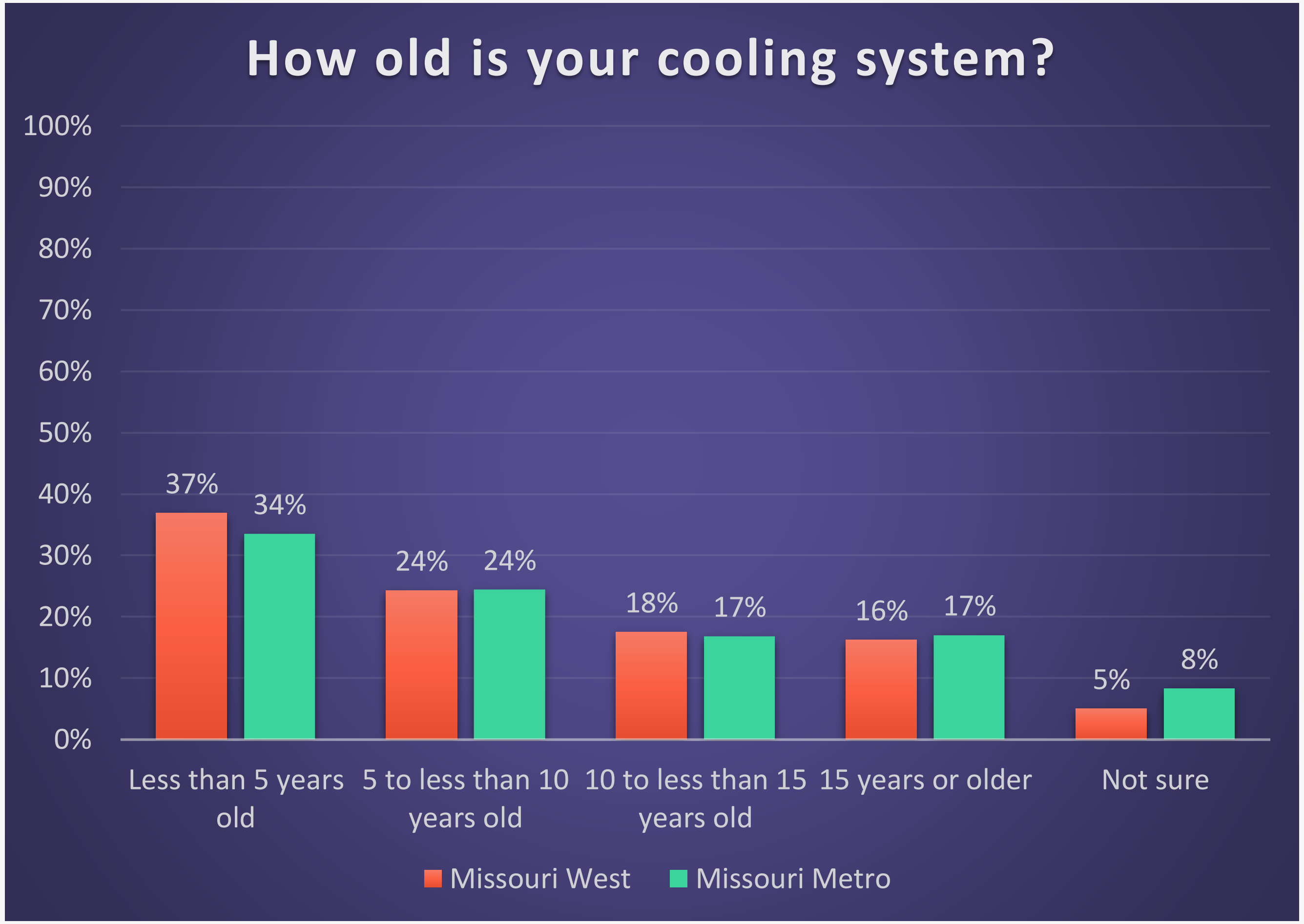
A large majority of Missouri customers have central air conditioners.



Age of Cooling System

More than a third of cooling systems are less than 5 years old.

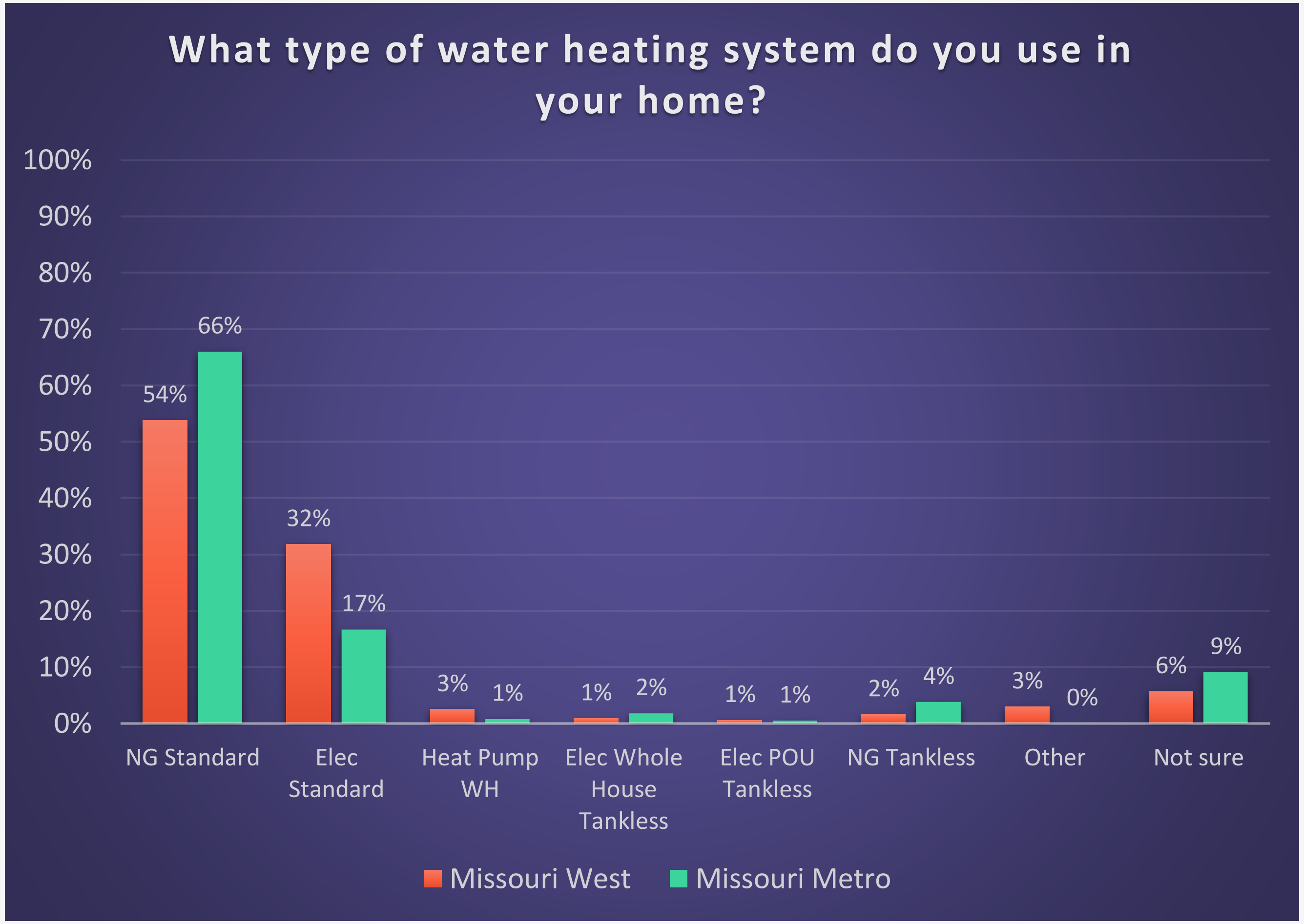
Sixteen to 17% of cooling systems are nearing the end of their useful life.



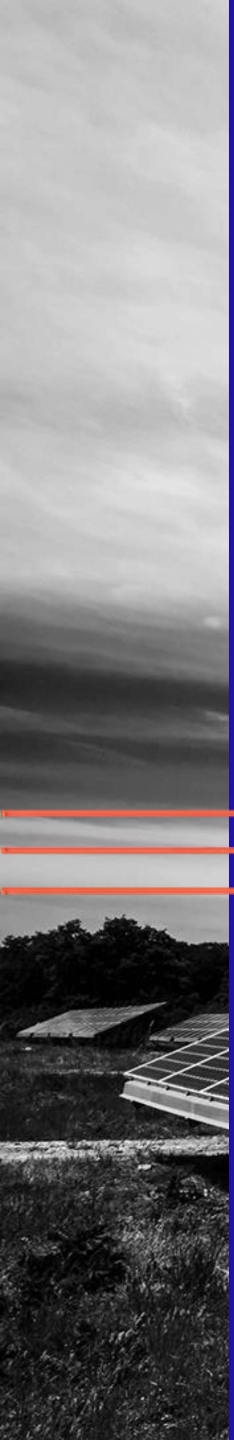
Type of Water Heater

The majority of Missouri customers have natural gas standard water heaters.

The proportion of natural gas water heaters has grown in the Missouri Metro service territory. In 2019, 53% had natural gas standard systems.



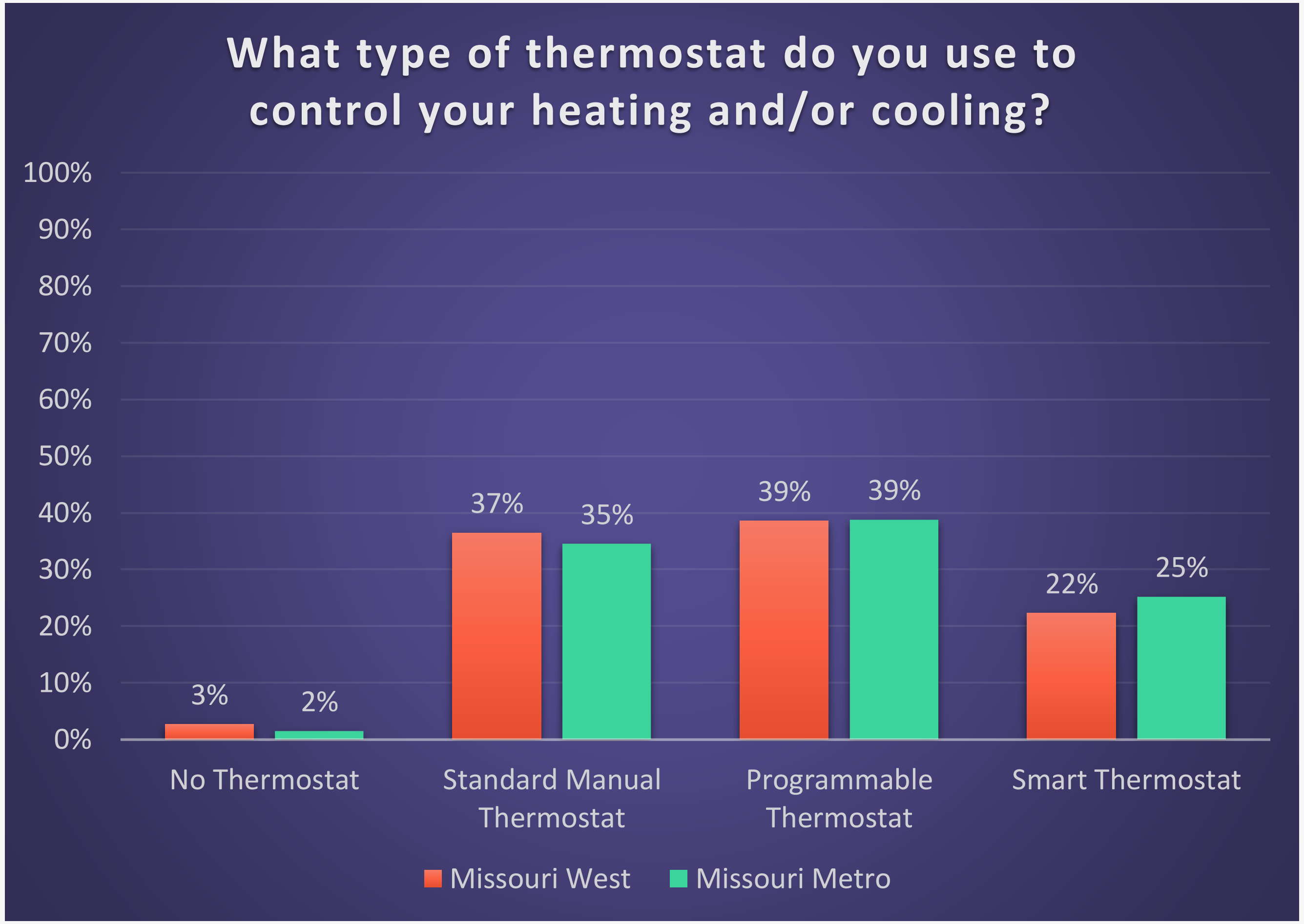
Thermostat



Type of Thermostat

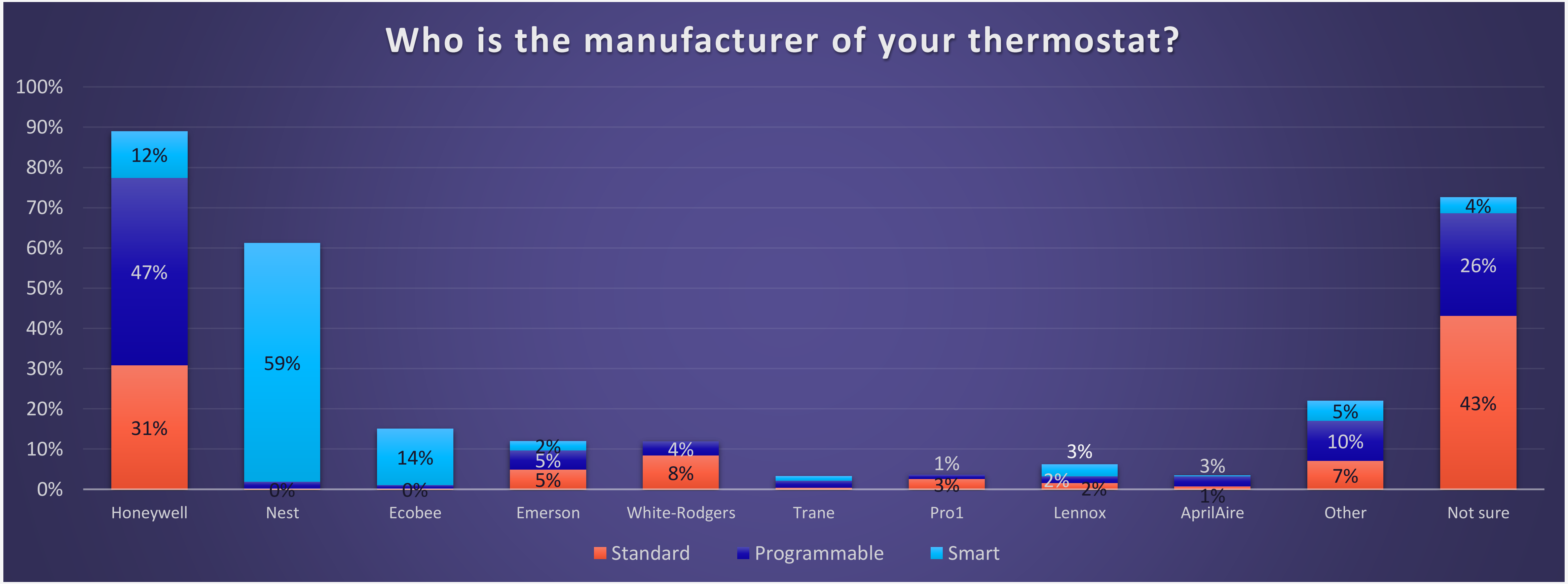
Over a third of Missouri customers have standard manual thermostats.

61% to 64% of customers have programmable or smart thermostats. This is significantly higher than 2019 when 43% of customers in Evergy's service territory (including Kansas customers) had programmable thermostats.



Type of Thermostat by Manufacturer

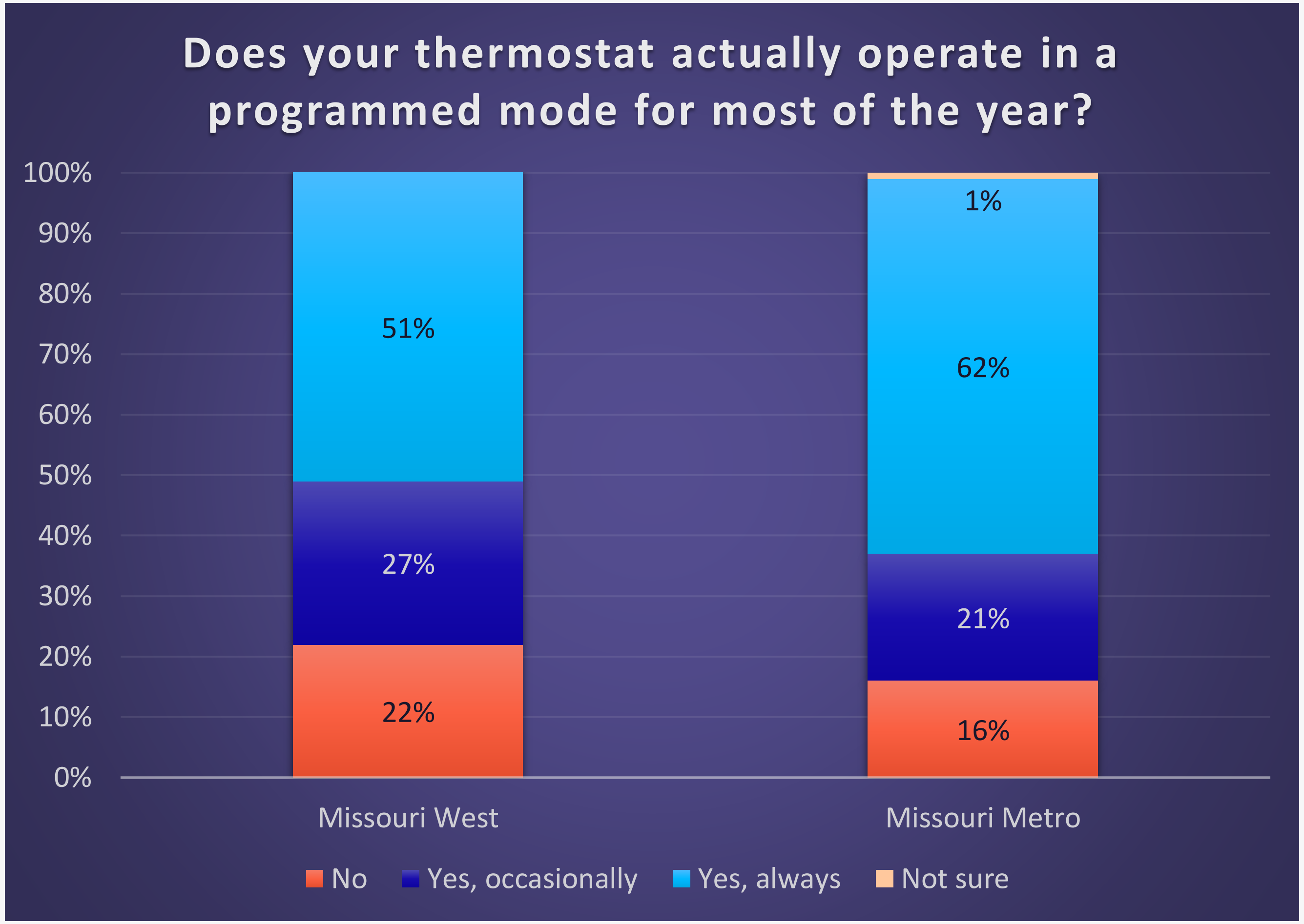
Based on the response to the thermostat manufacturer question, respondents appear to correctly identify their type of thermostat.



Programmable Thermostat Use

About half of Missouri West customers and a little under two-thirds of Missouri Metro customers always operate their thermostat in programmed mode.

This indicates an opportunity for customer education on how to operate their heating and cooling systems more efficiently.



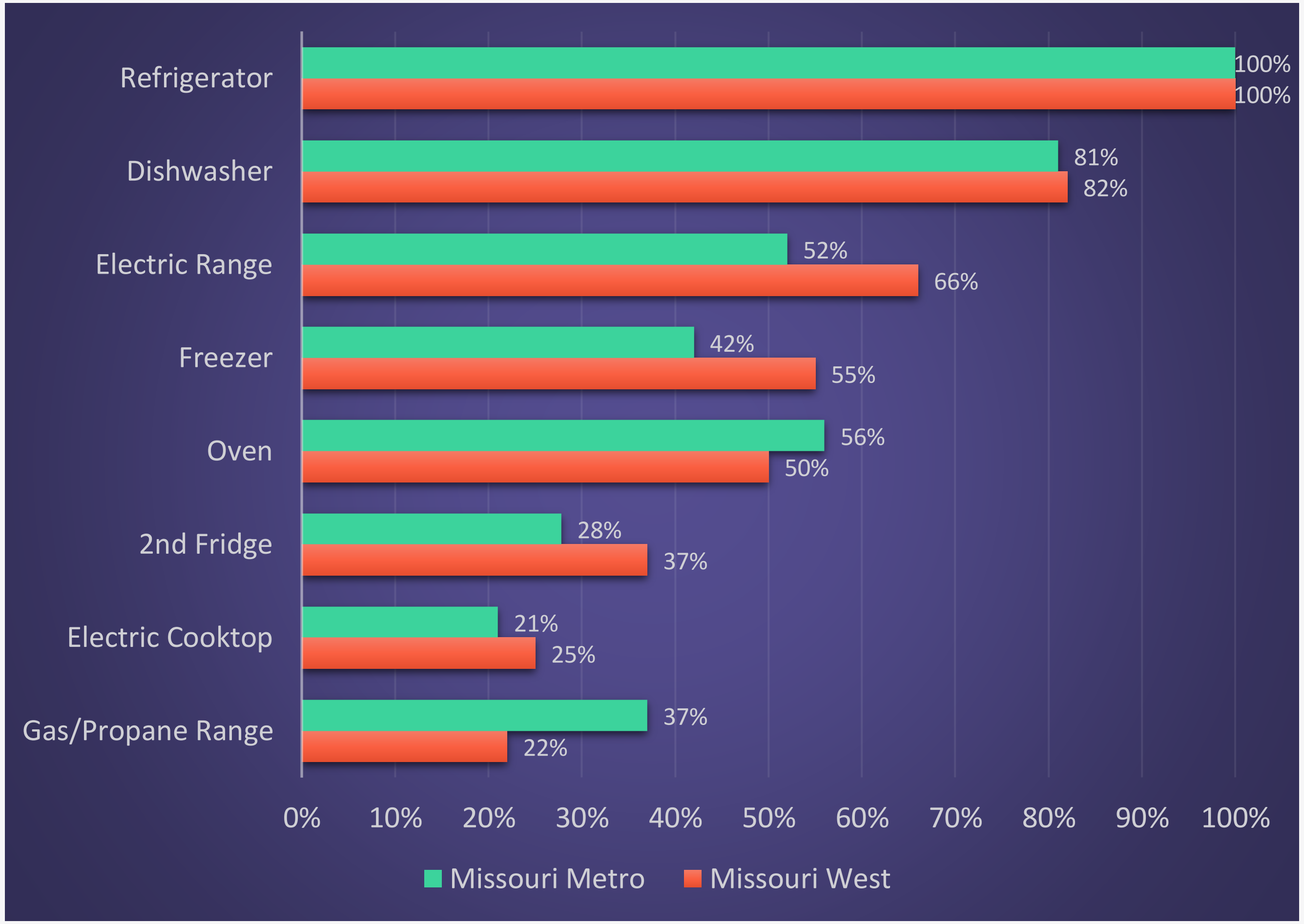
Appliances and Electronics

Kitchen Appliances

The majority of Missouri customers have a refrigerator, dishwasher and electric range.

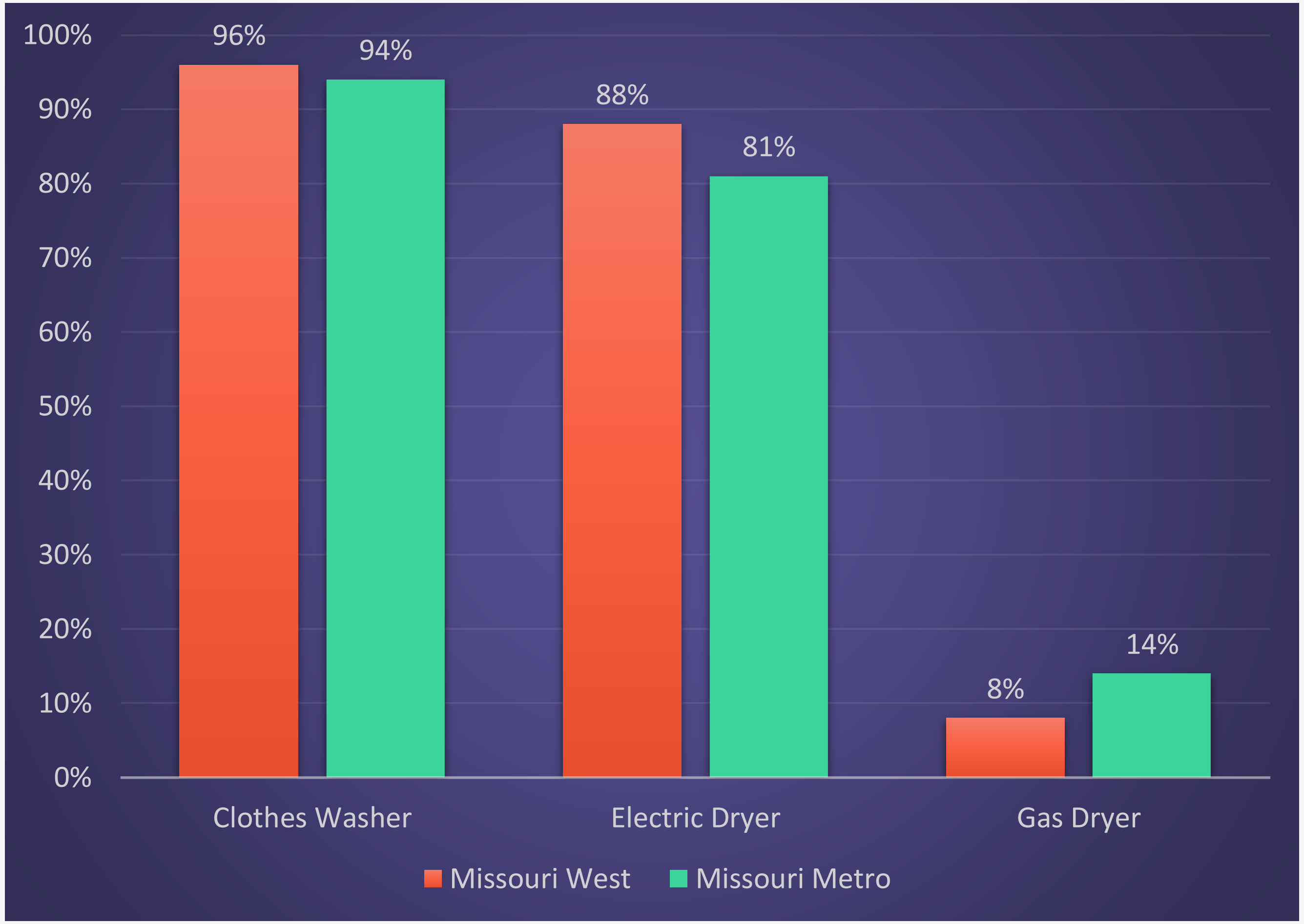
28% of Missouri Metro customers and 37% of Missouri West customers have a second fridge.

A large proportion of customers in both service territories have a stand-alone freezer.



Laundry Equipment

Most Missouri customers have clothes washers and electric clothes dryers.

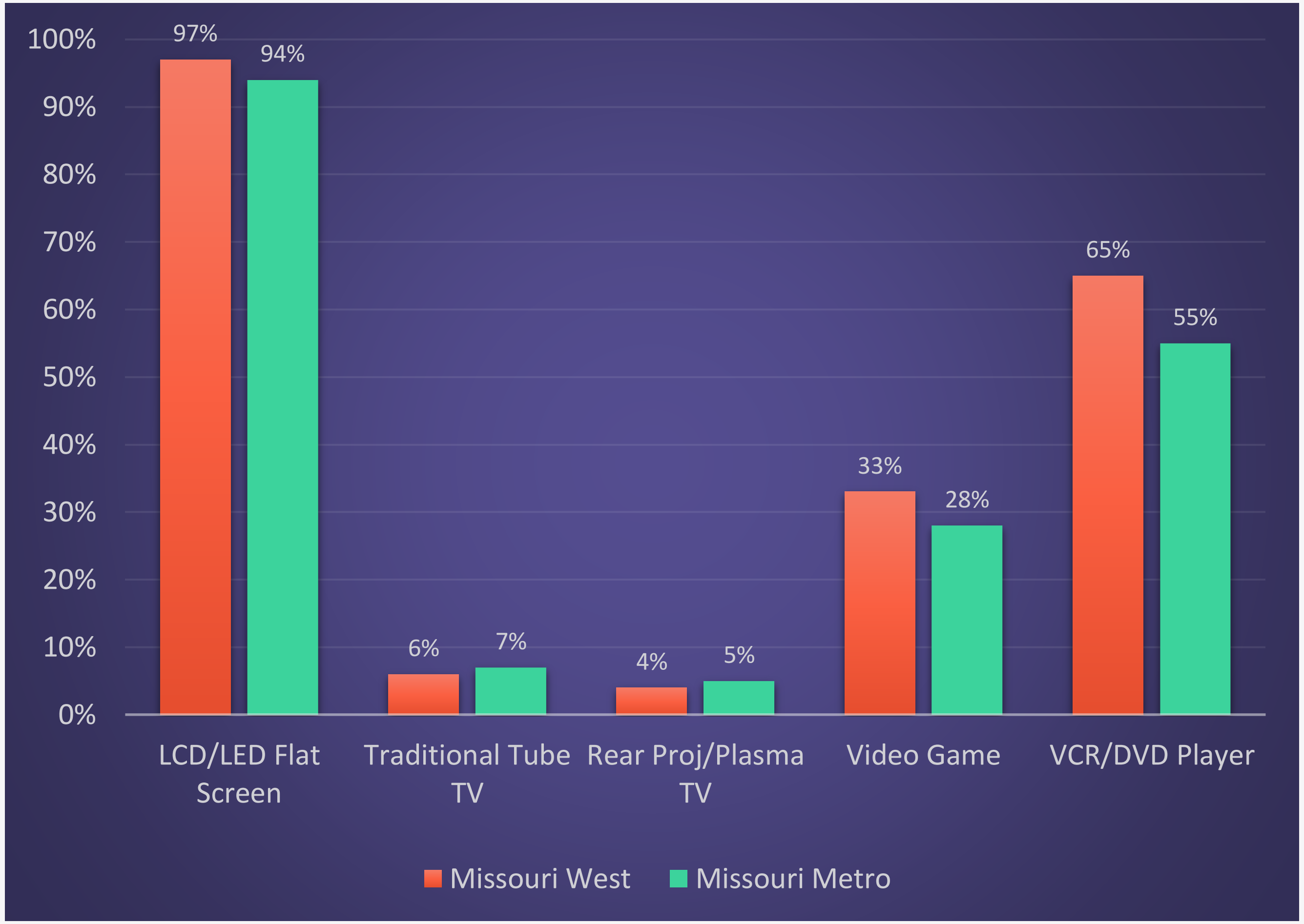


Entertainment Equipment

The mean number of TVs in both Missouri service territories is 2.

A third of Missouri West customers have video game consoles and almost two-thirds have VCR/DVD players.

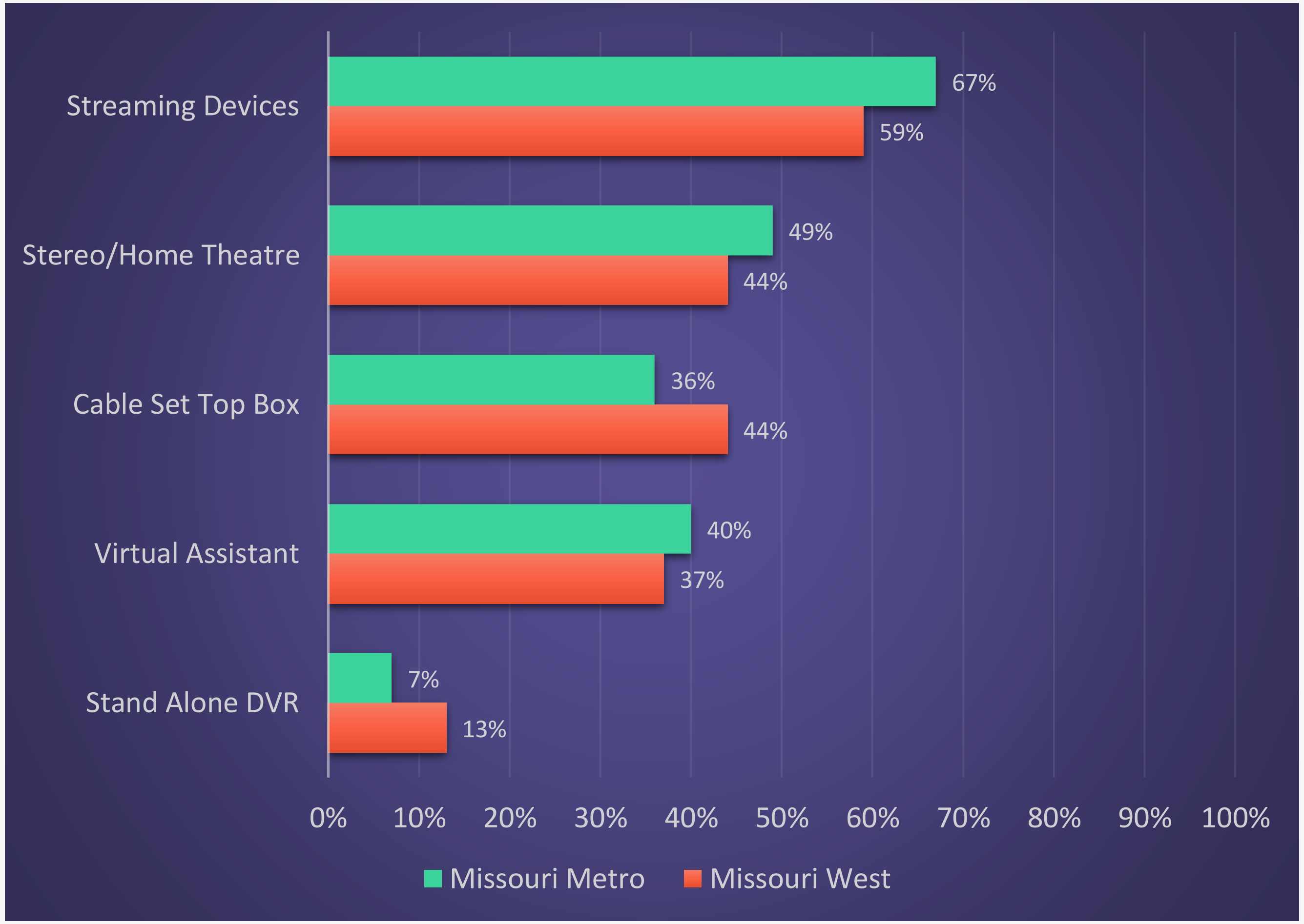
Over a quarter of Missouri Metro customers have video game consoles and over half have a VCR/DVD players.



Electronic Accessories

The majority of Missouri customers have streaming devices – an increase from 2019 when 45% of Metro customers and 42% of West customers had these devices.

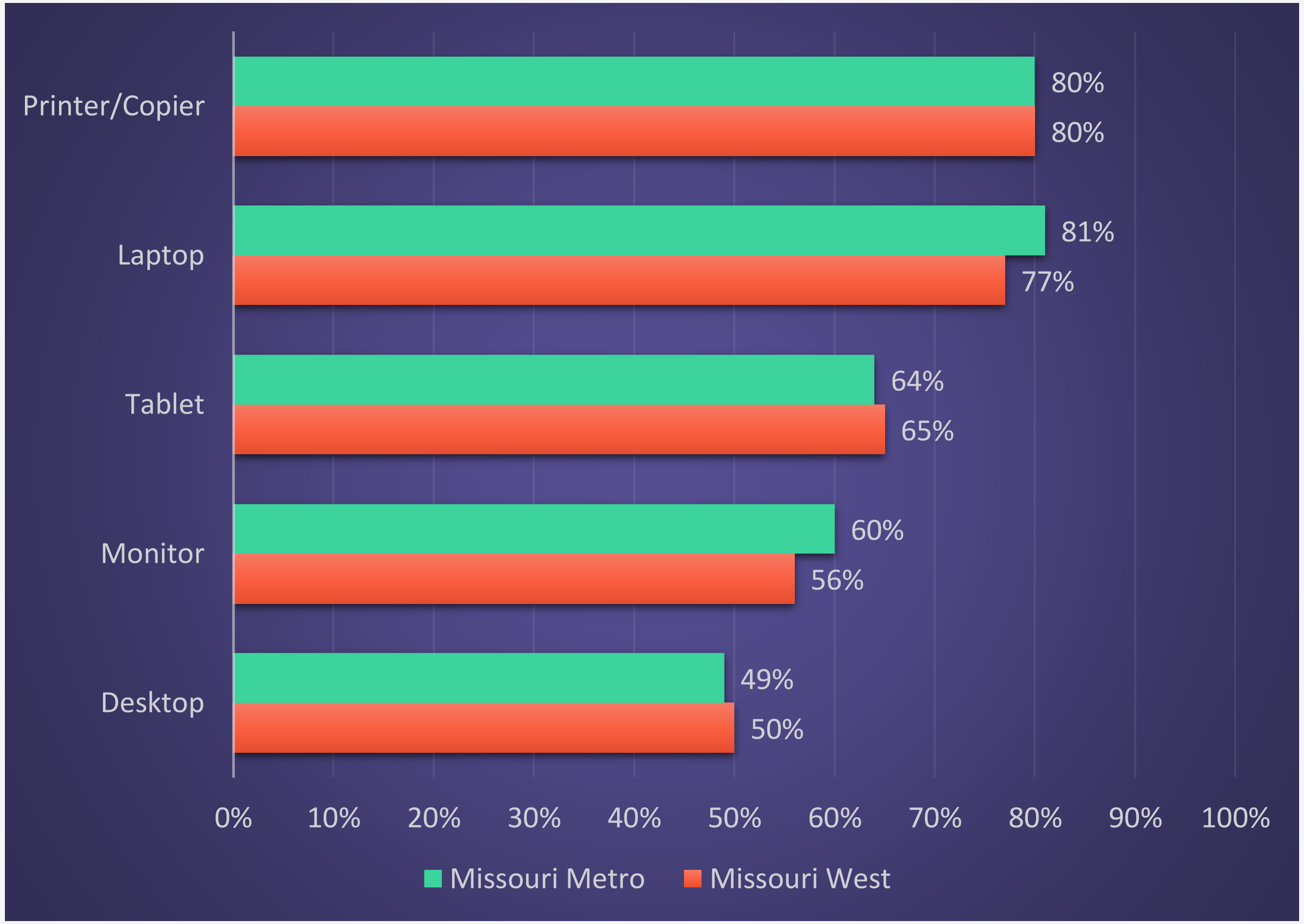
There was also an increase in virtual assistants – up from 26% of Metro customers and 25% of West customers in 2019.



Computer and Office Equipment

Computer and office equipment is prevalent in Missouri customer homes.

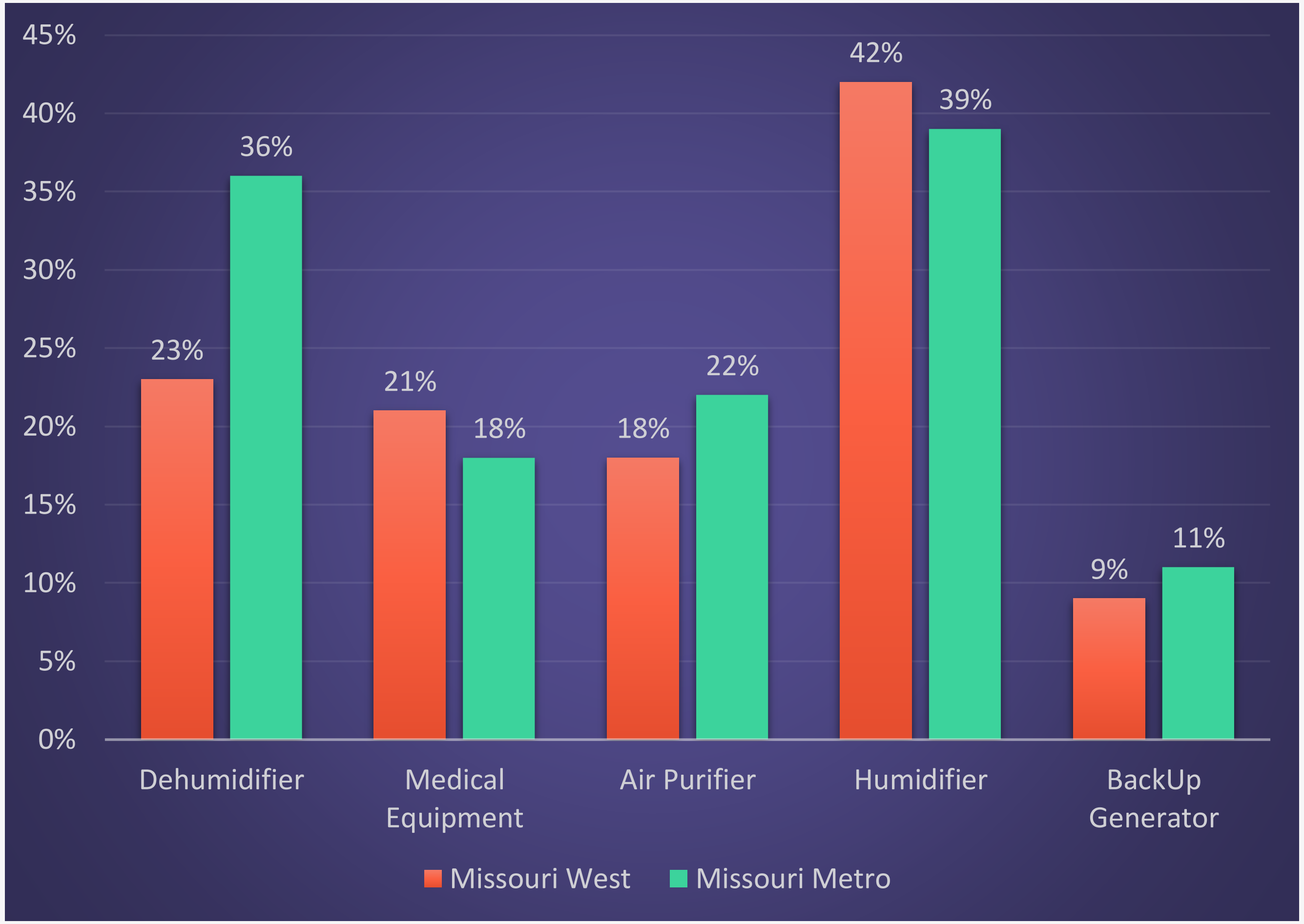
The saturation of this equipment has grown in all categories since 2019 by 3% - 16%.



Other Types of Equipment

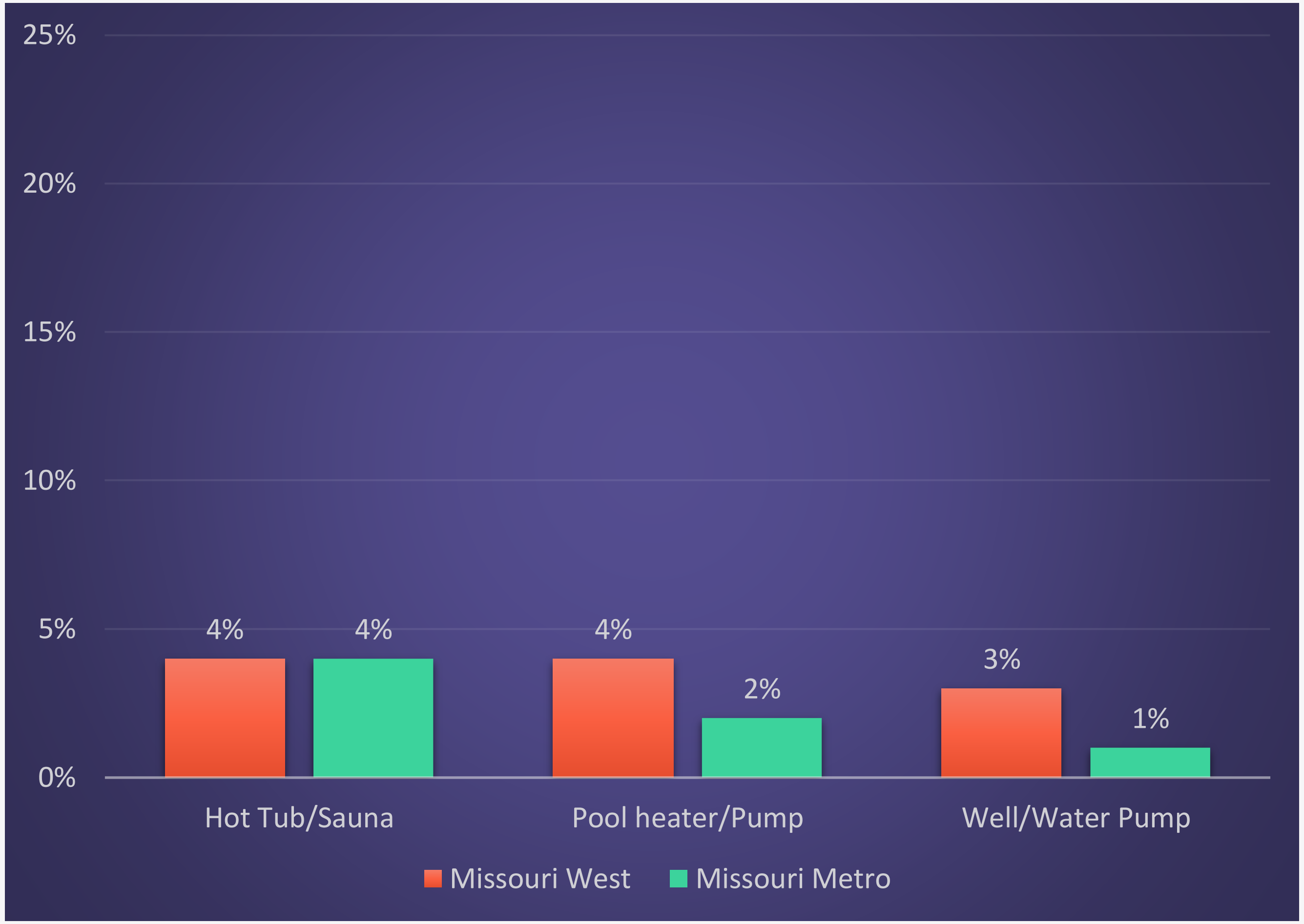
Humidifiers and dehumidifiers are owned by 23% - 42% of Missouri customers.

A larger proportion of Missouri Metro customers have dehumidifiers in their homes.



Pools, Pumps and Spas

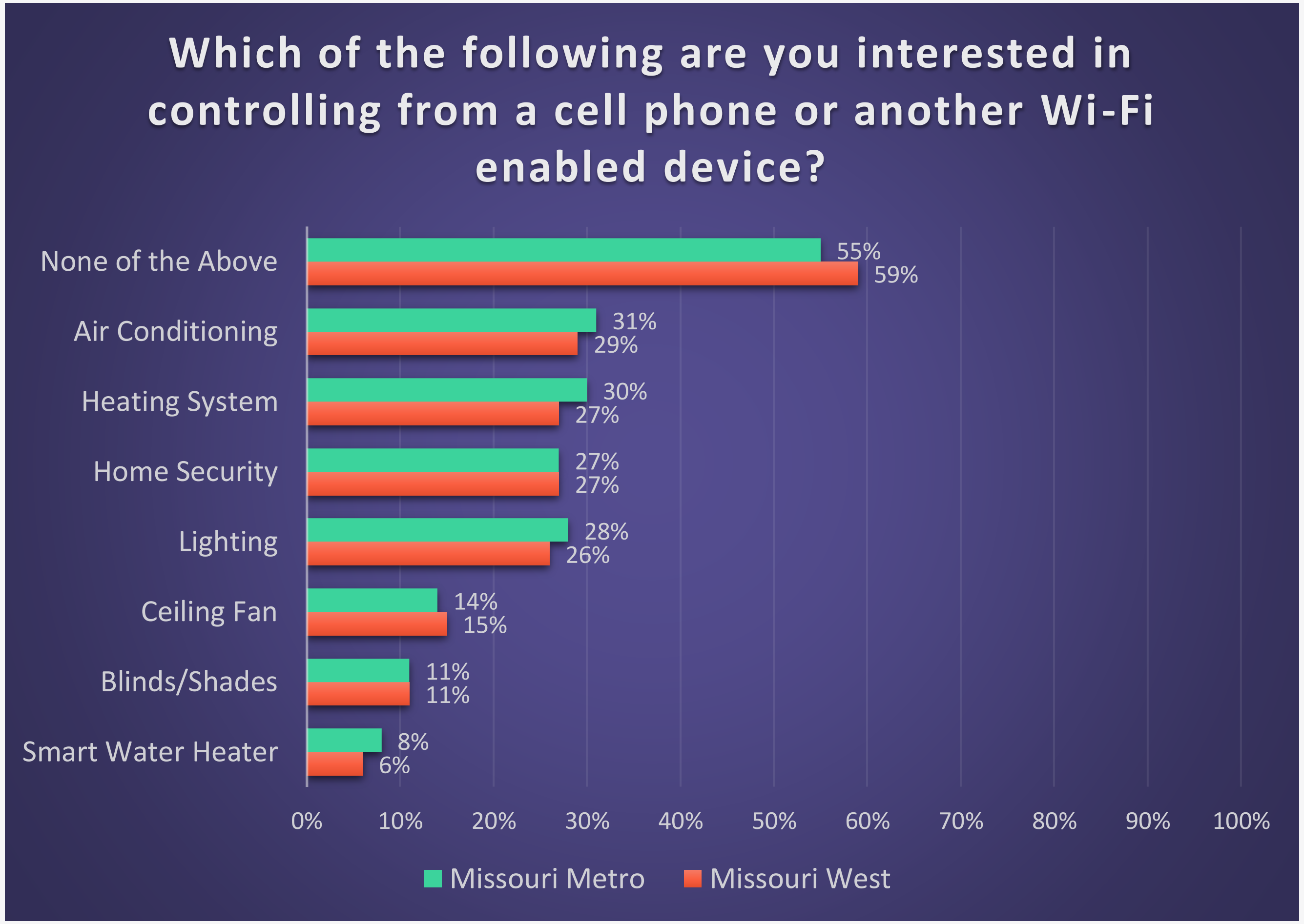
Very few Missouri customers have pools, pumps, or spas.



Interest in Smart Controls

The majority of customers are not interested in smart controls.

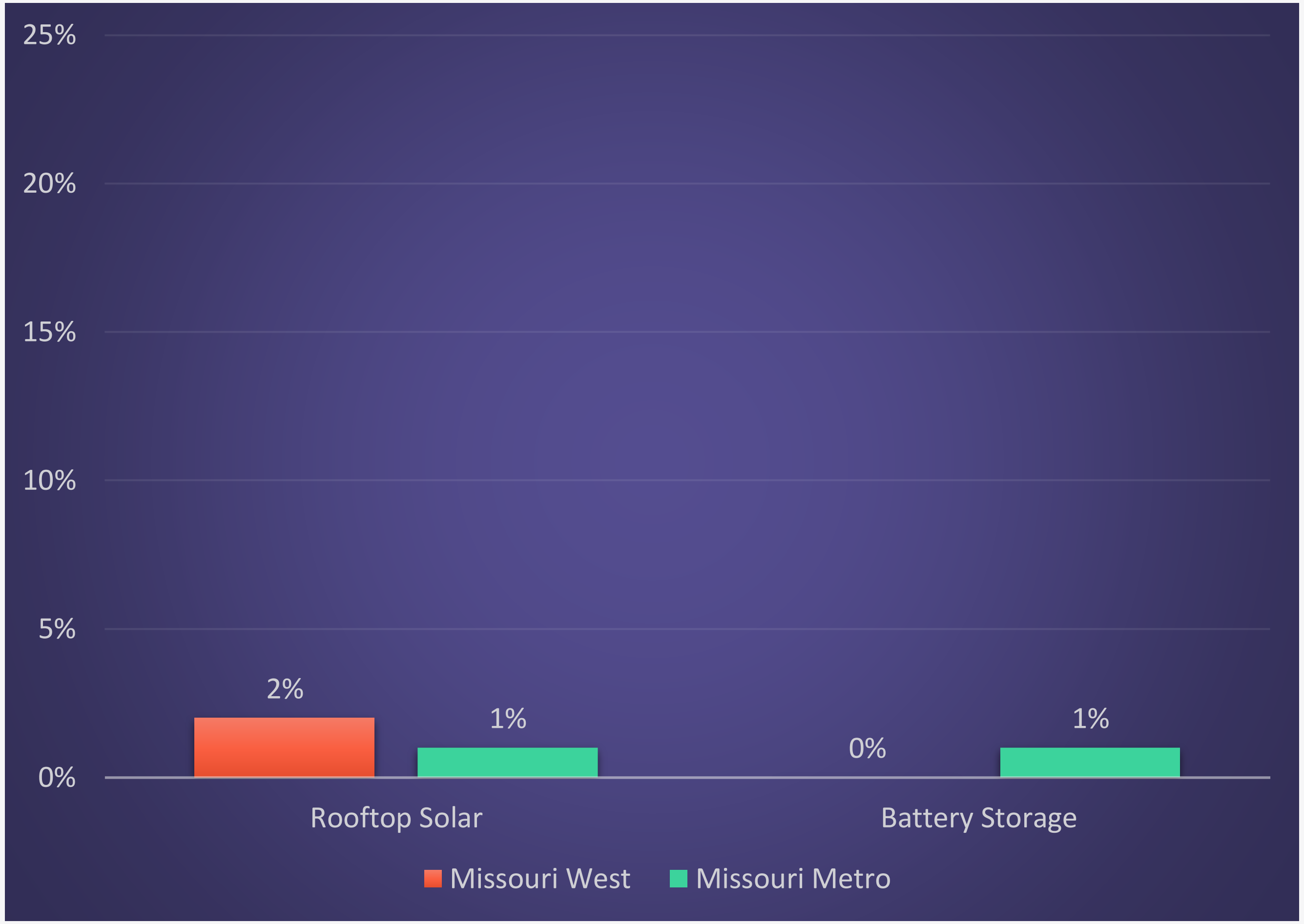
The highest interest is in controlling HVAC, security and lighting.



Solar and Electric Vehicles

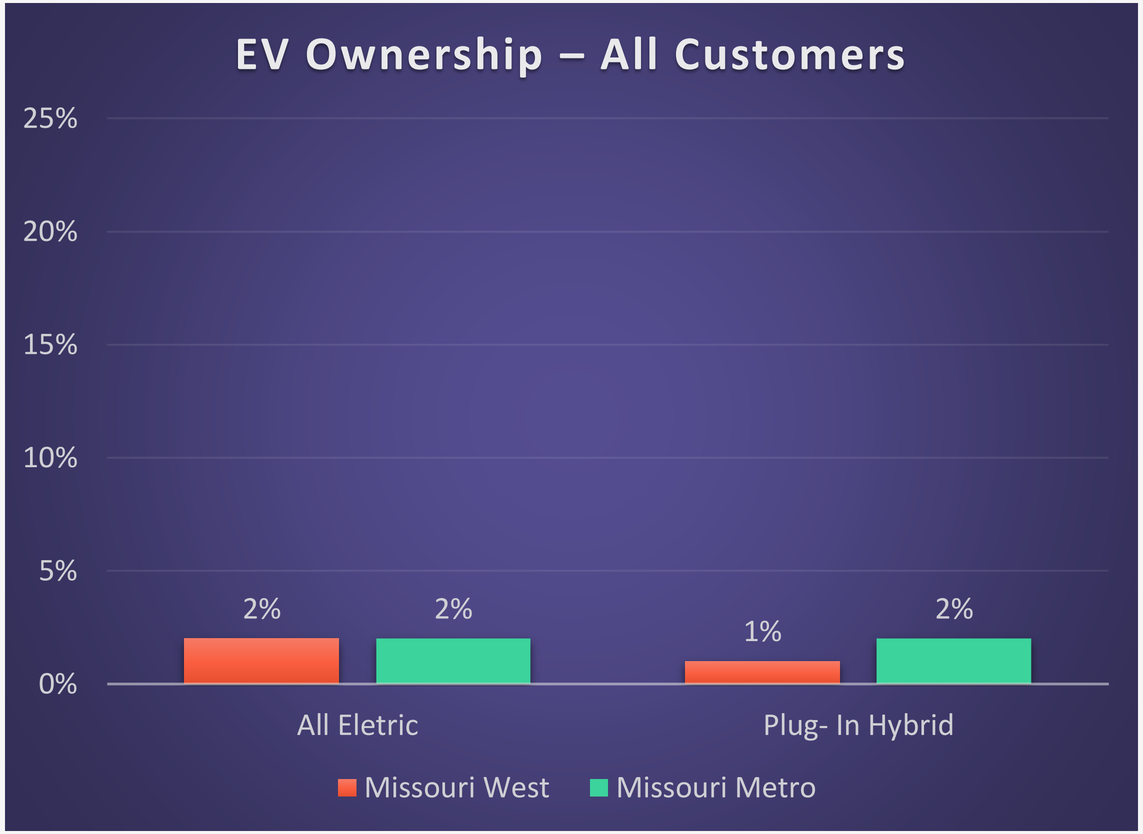
Rooftop Solar and Battery Storage

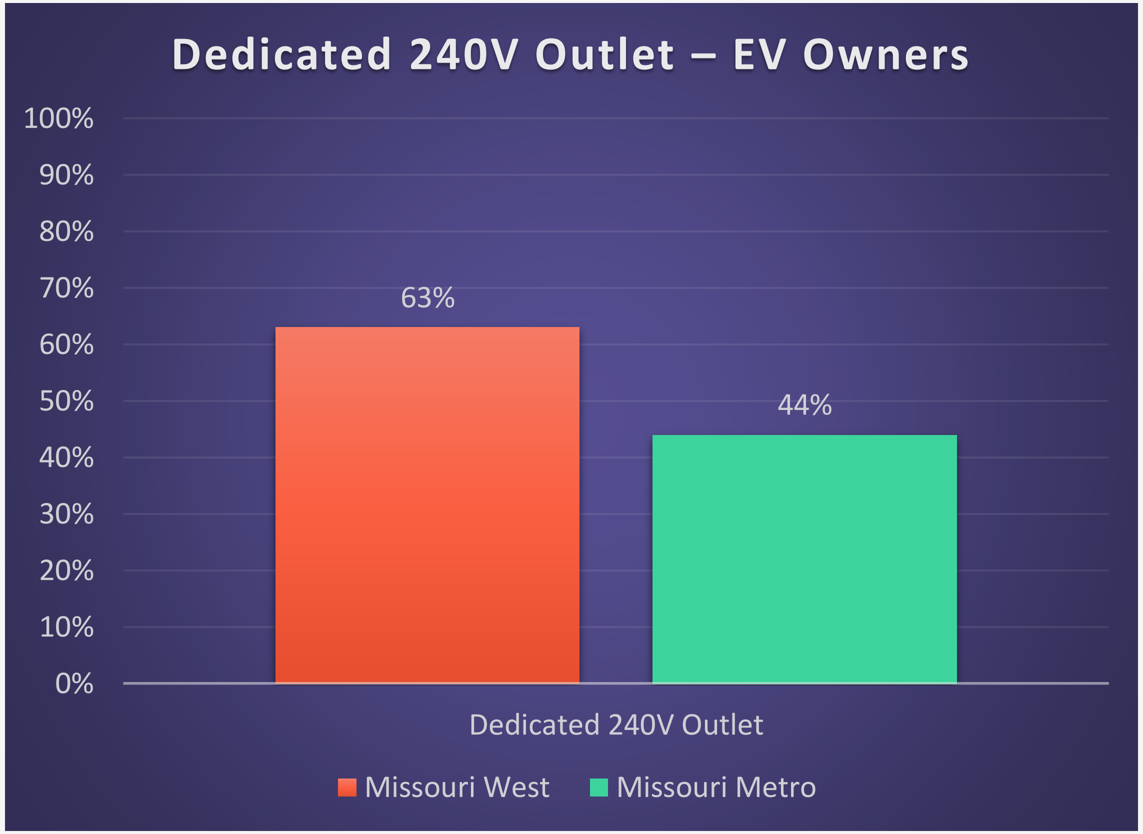
Few Missouri customers have rooftop solar or battery storage.



Electric Vehicles

Few Missouri customers own all-electric or plug-in hybrid vehicles. Of those that do, significant proportions have a dedicated 240V outlet, with larger proportions in the West.





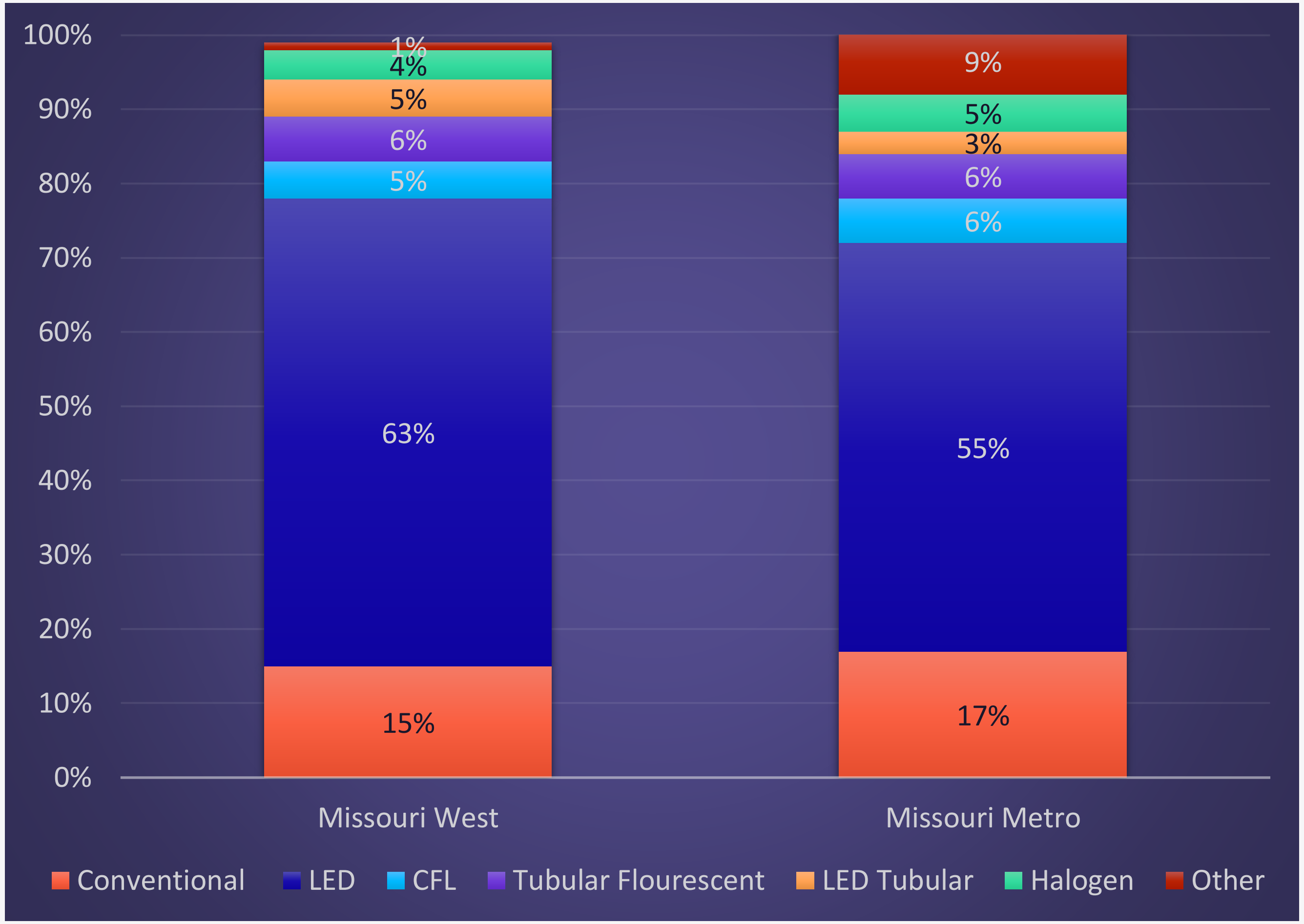
Energy Efficiency

Proportion of Lighting by Type of Bulb

The majority of lamps are LED.

In the last few years, LED lighting has increased while conventional incandescent lighting has decreased.

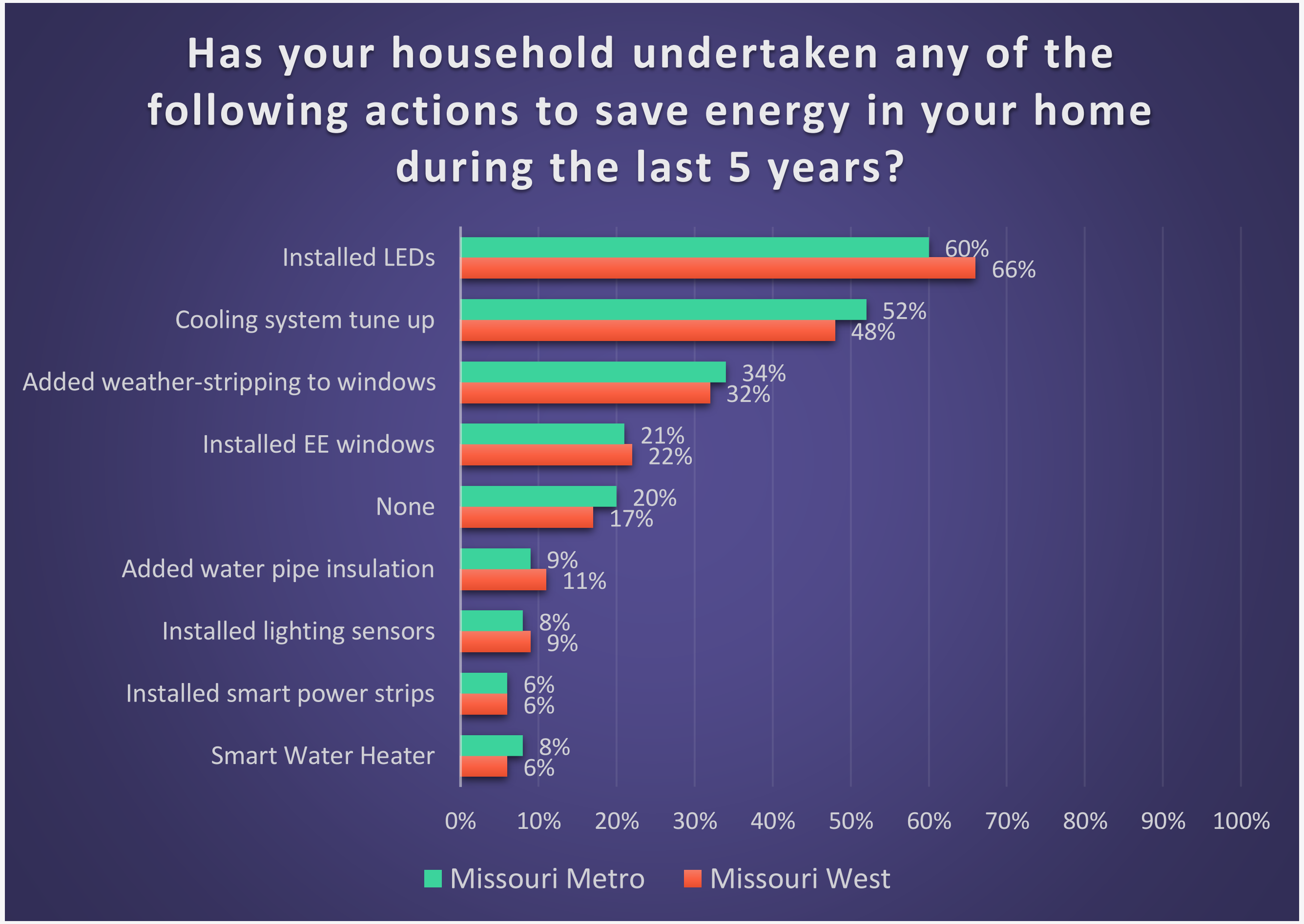
In 2019, 34% of Missouri Metro and 36% of Missouri West customers had LEDs.



Energy Efficient Actions

Eighty to 83% of Missouri customers have taken at least one action to save energy in the last 5 years.

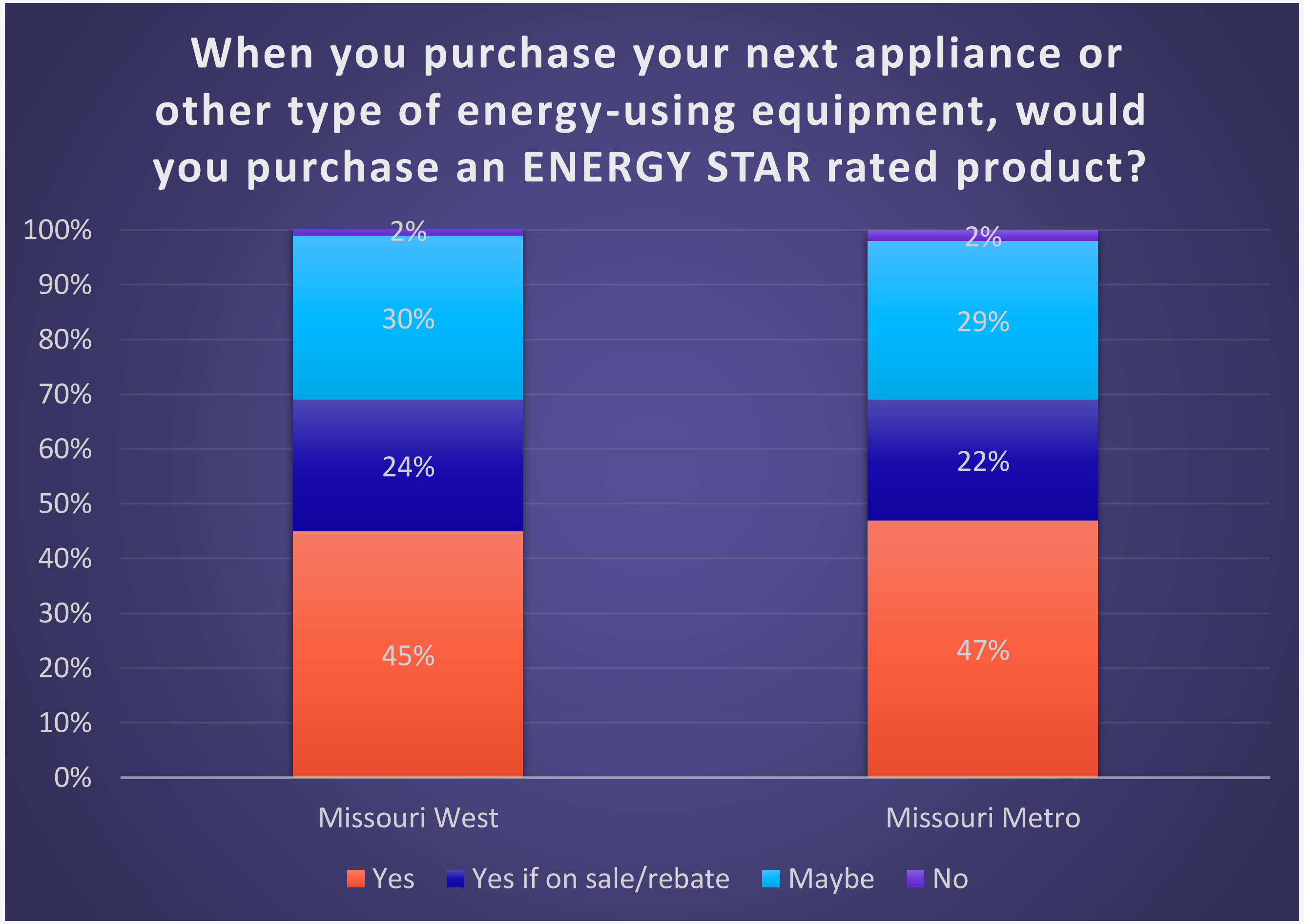
Not surprisingly, based on the growth in LEDs illustrated in the previous slide, a large majority of Missouri customers have installed LEDs to save energy.



Plan to Purchase Energy Star

A little less than half of Missouri customers plan to purchase Energy Star models when they are in the market for their next appliance.

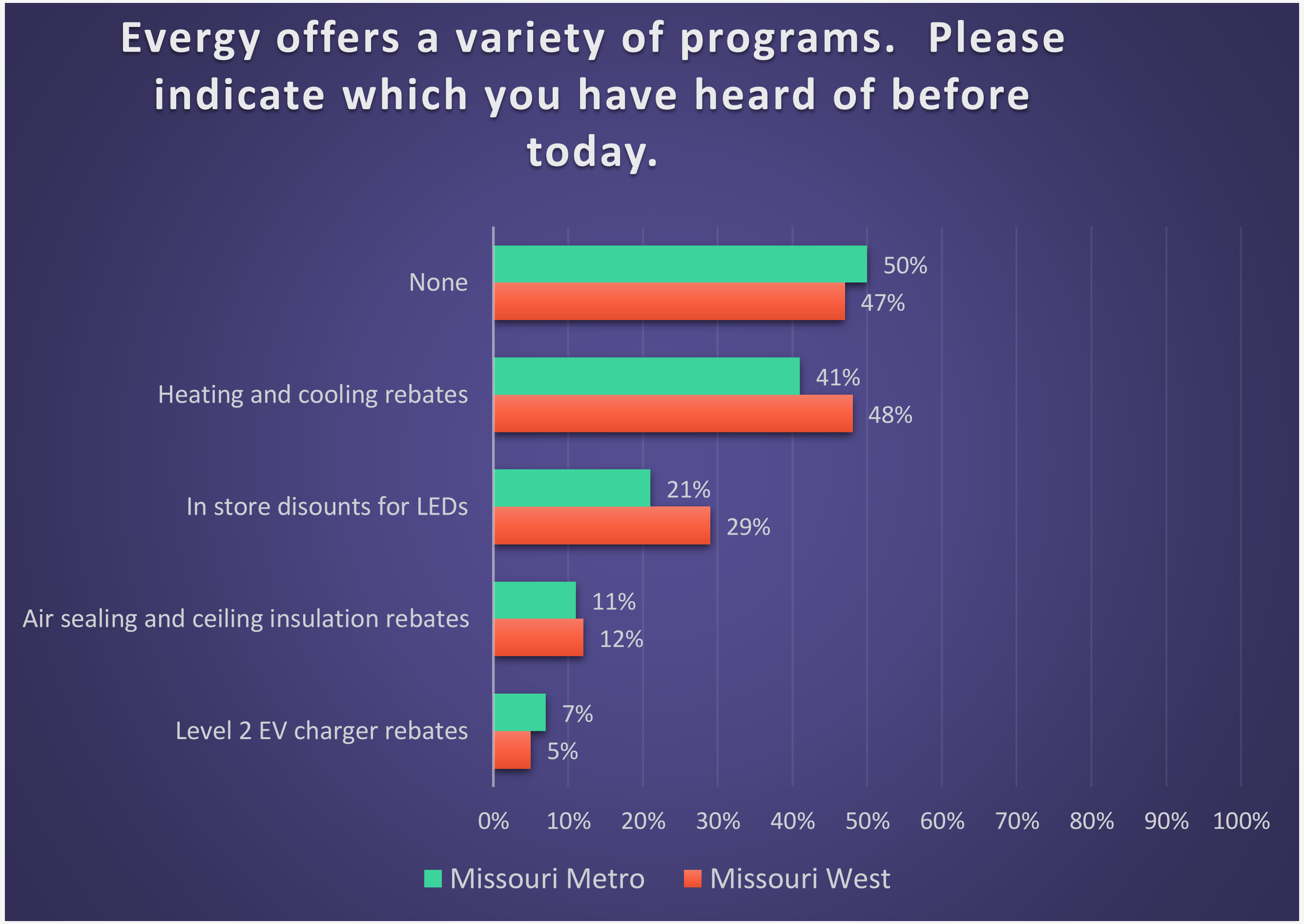
The prime market for EE programs is the 22-24% who say they will purchase Energy Star if there is a discount along with the 29-30% that are on the fence.



Awareness of Evergy EE Programs

About a half of Missouri customers have not heard of any Evergy Programs.

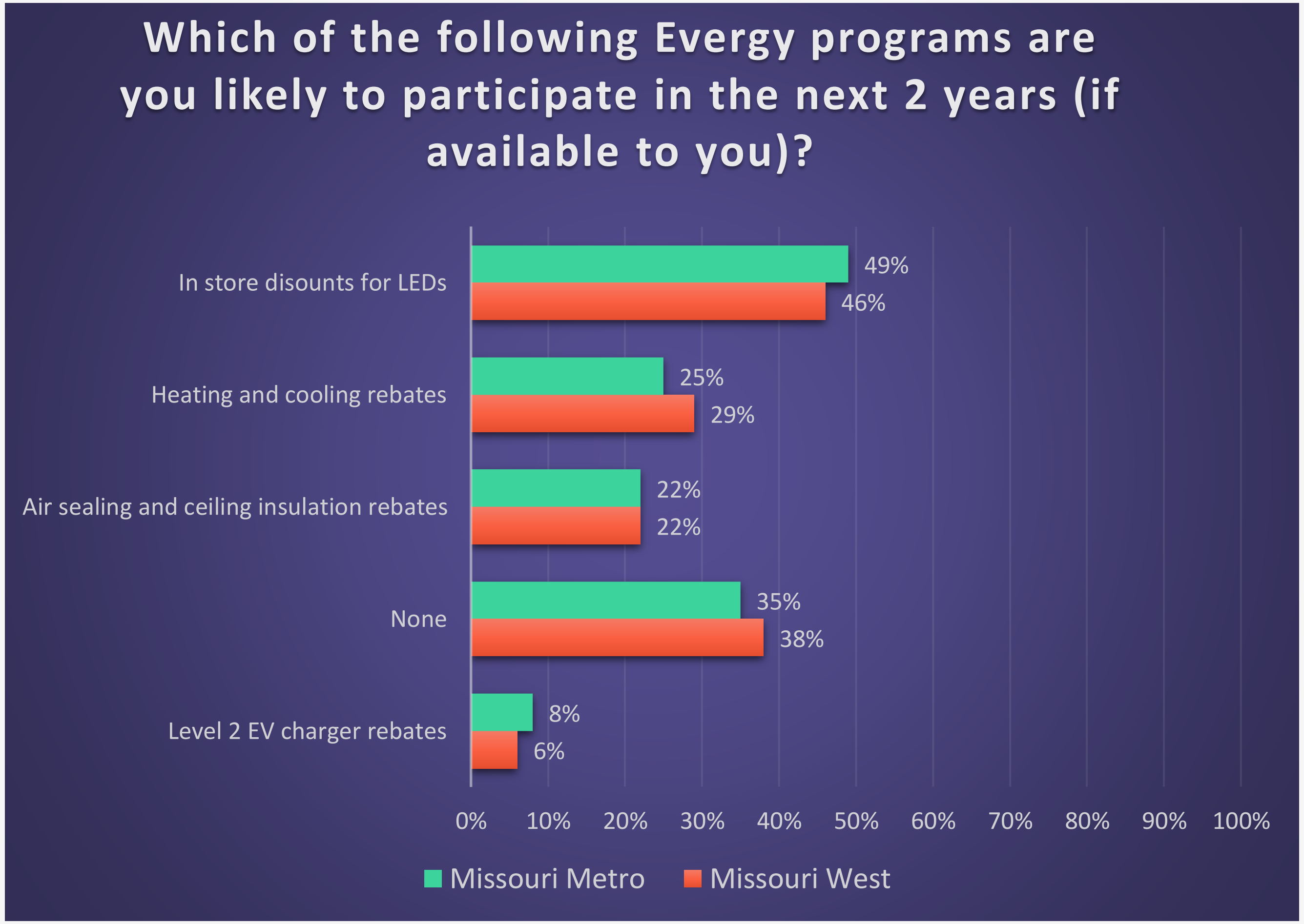
The program with the highest level of awareness is heating and cooling rebates.



Likelihood of Participating in Evergy EE Programs

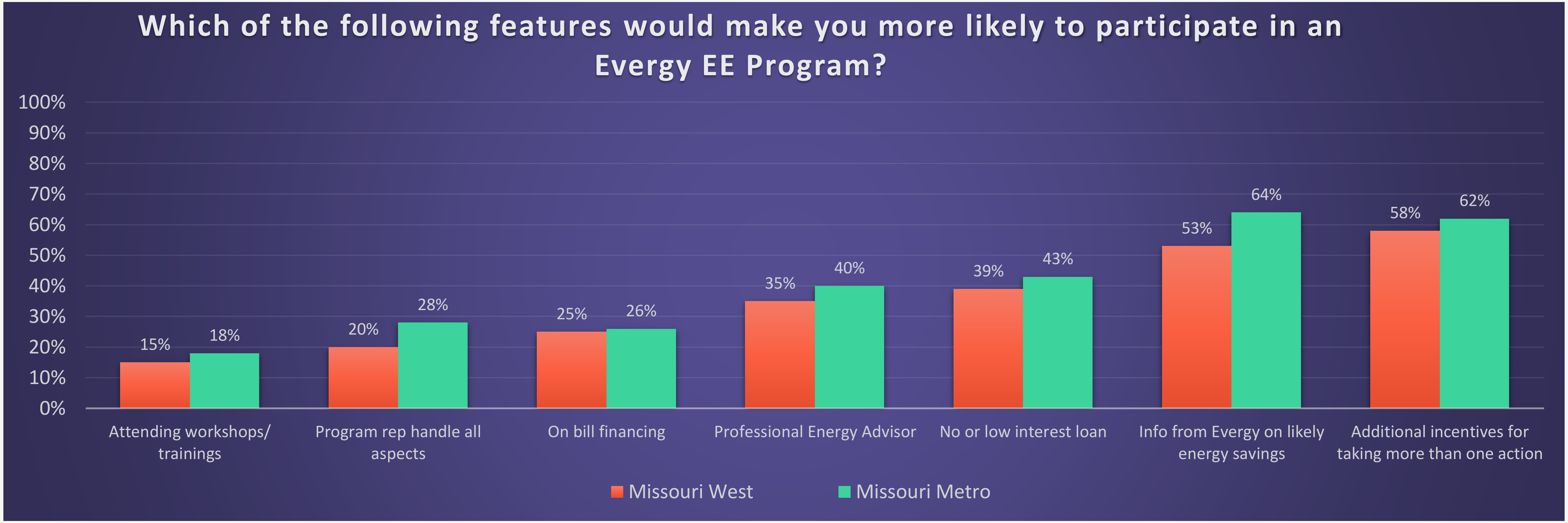
In-store discount lighting programs are the most popular among Missouri customers.

More than a third say they will not participate in any programs in the next two years.



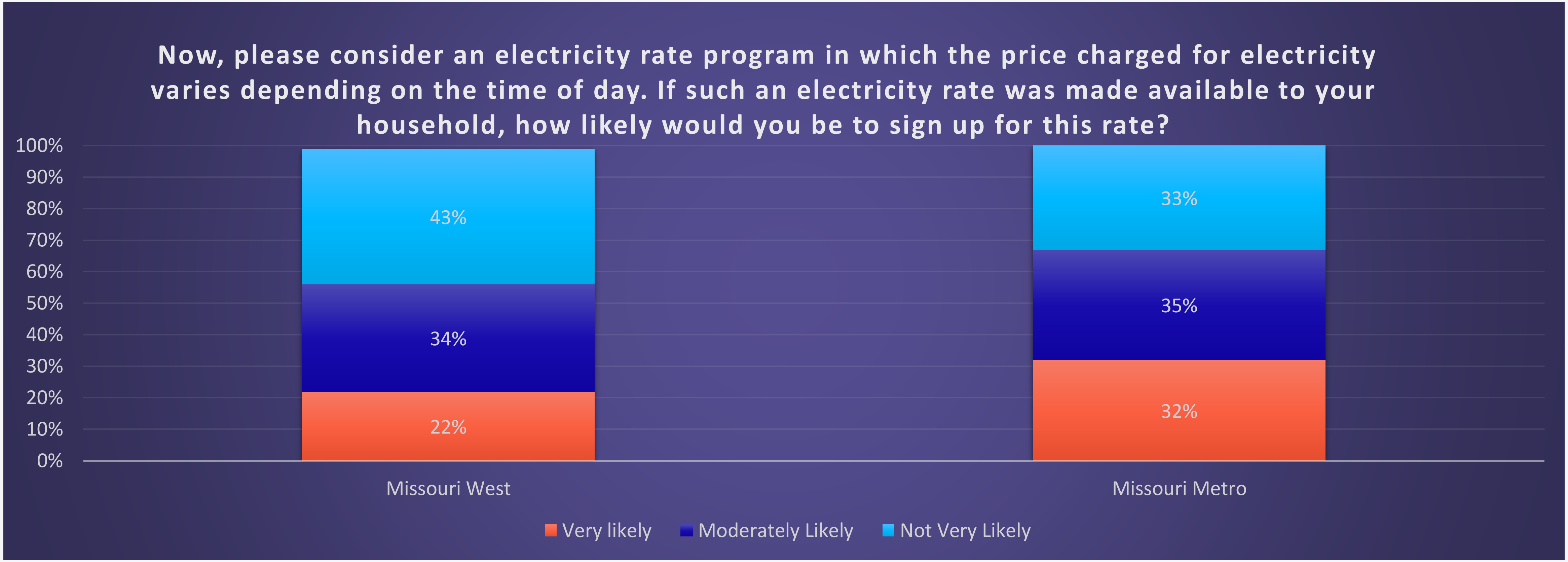
Program Features that Would Influence Participation

Bundled incentives that provide customers with additional savings for taking more than one EE action and information from Evergy on likely energy savings are the features most likely to influence participation.



Interest in Time-of-Day Rate

There is moderate interest in a time-of-day program, with Missouri Metro customers indicating a higher level of interest.

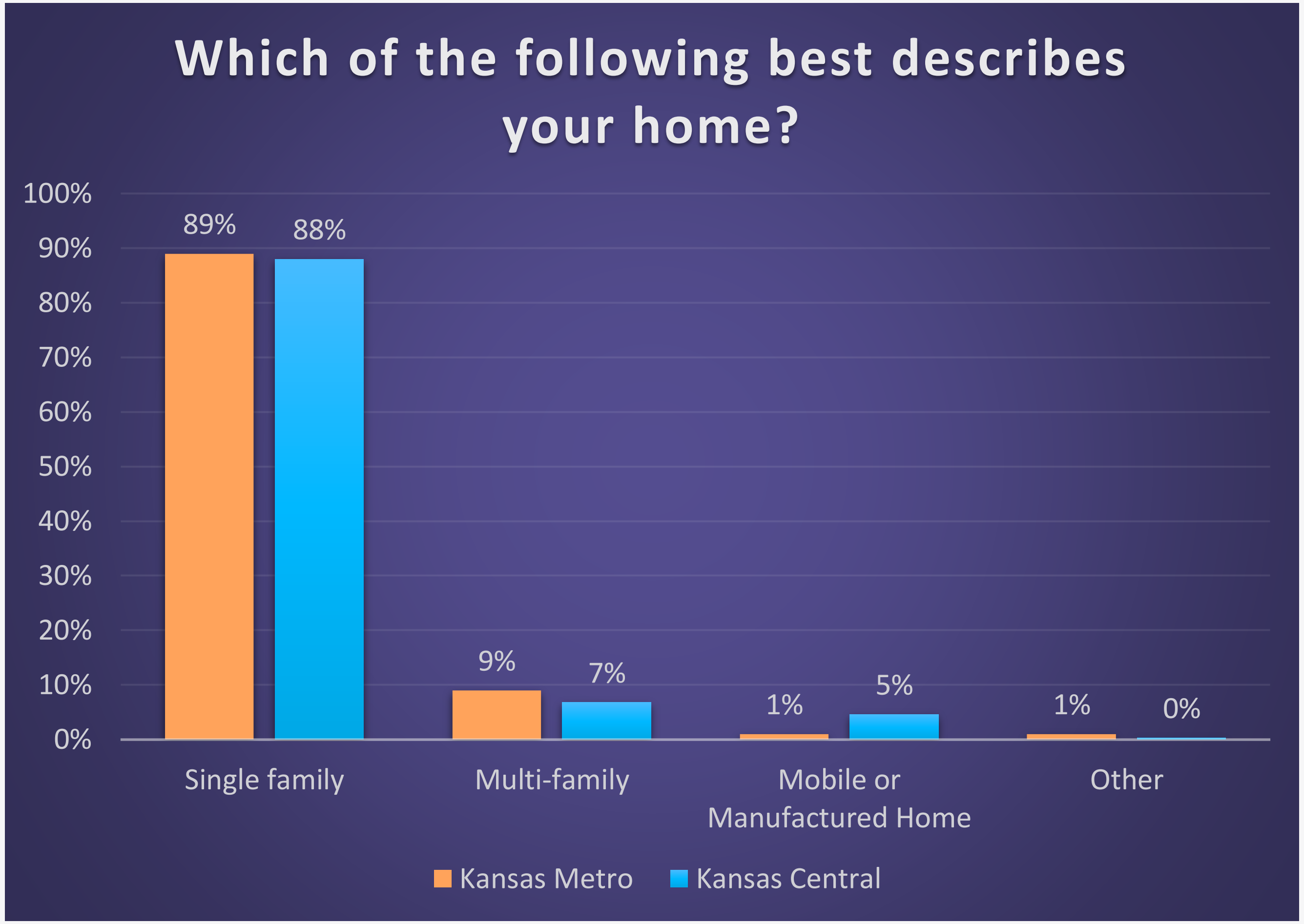


Kansas Customers

Type of Home

A large majority of Kansas customers live in single family homes.

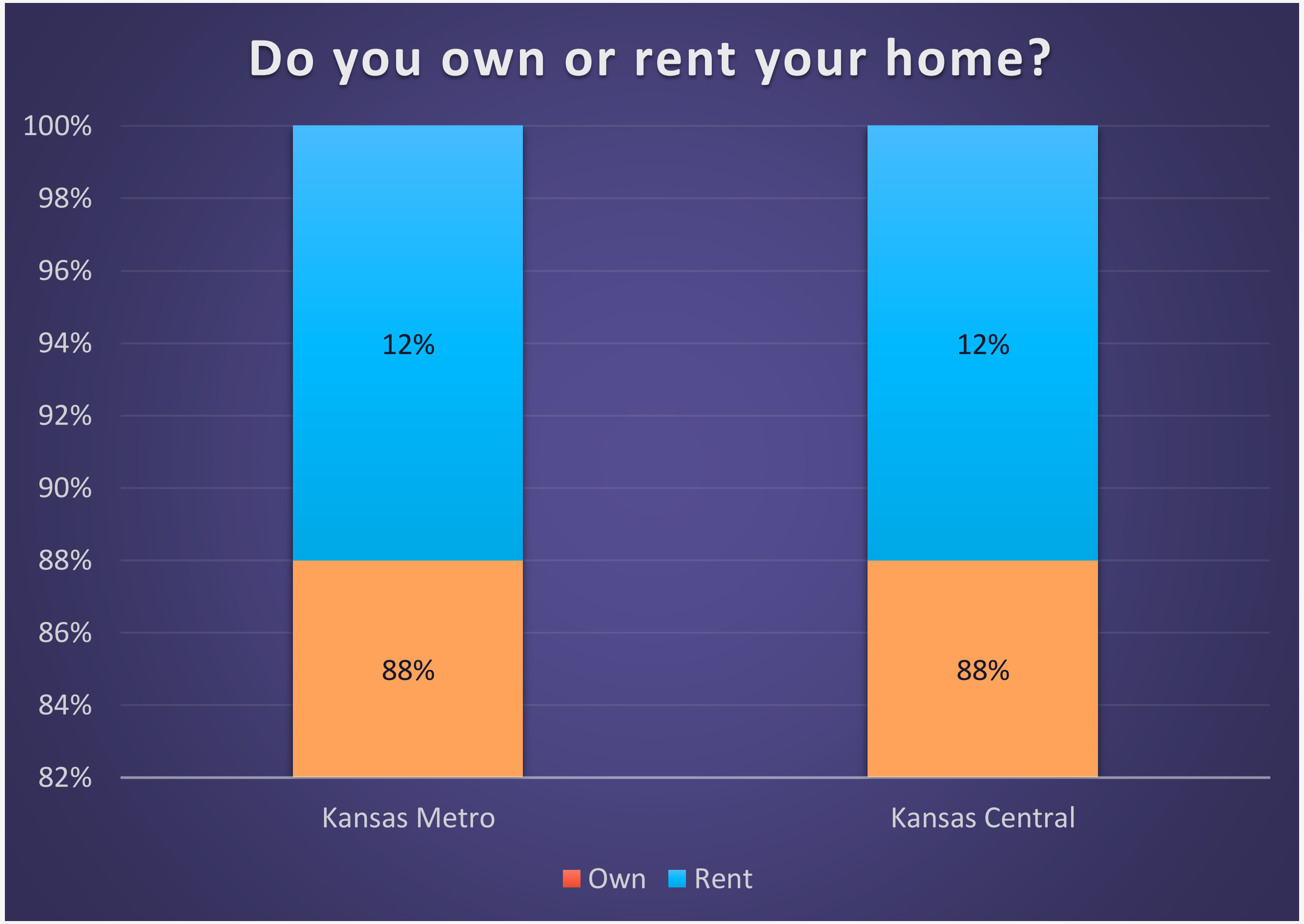
5% of Kansas Central customers live in a mobile or manufactured home.



Home Ownership

Home ownership among Kansas customers largely mirrors the proportion of customers living in single family homes.

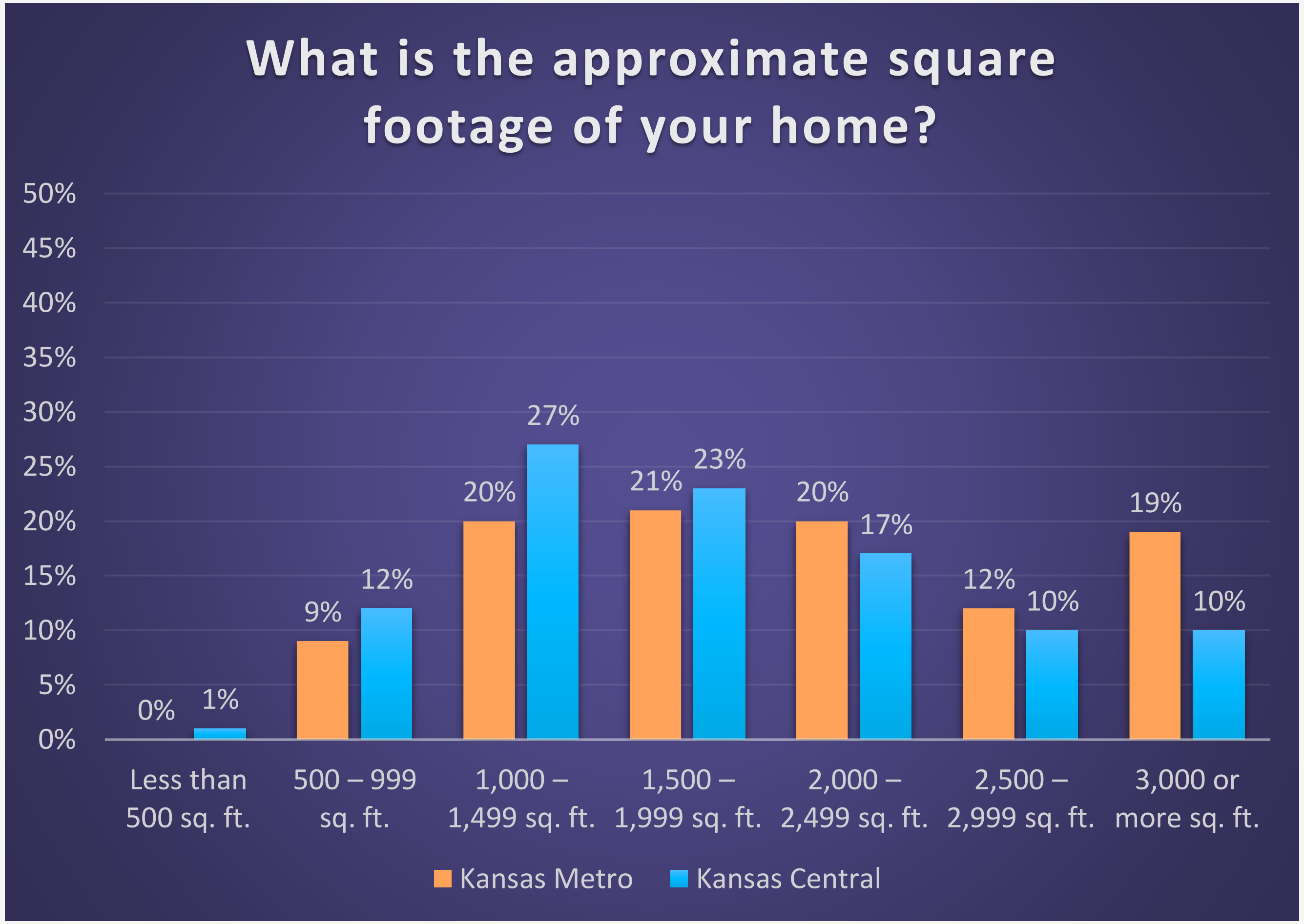
The proportion of customers who own their home has increased since 2019 with 74% of Metro and 76% of Central customers owning homes at that time.



Size of Home – All Homes

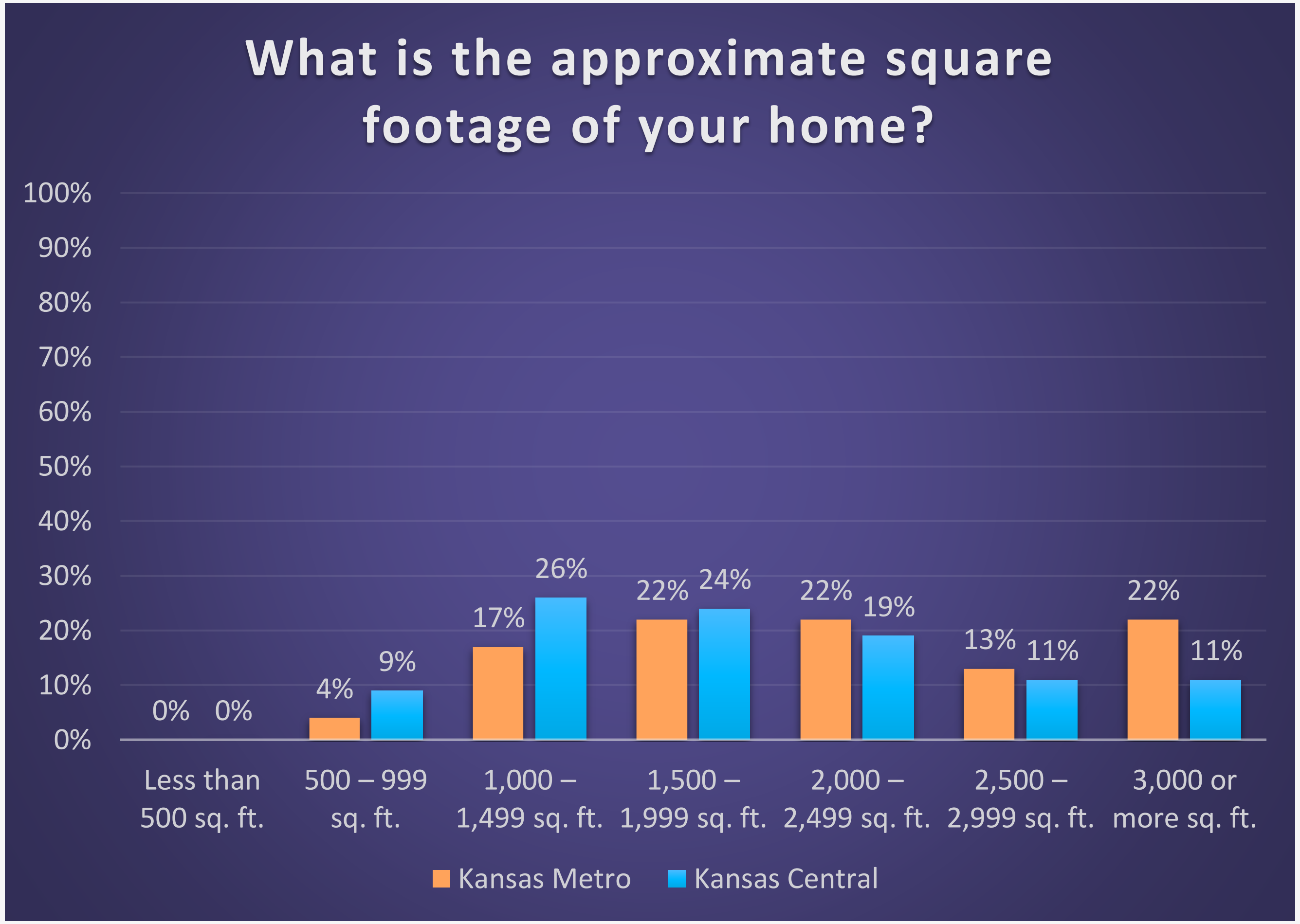
More than a third of Kansas Central customers live in homes less than 1,500 square feet.

While the majority of Kansas Metro customers live in homes larger than 2,000 square feet.



Size of Home – Single Family

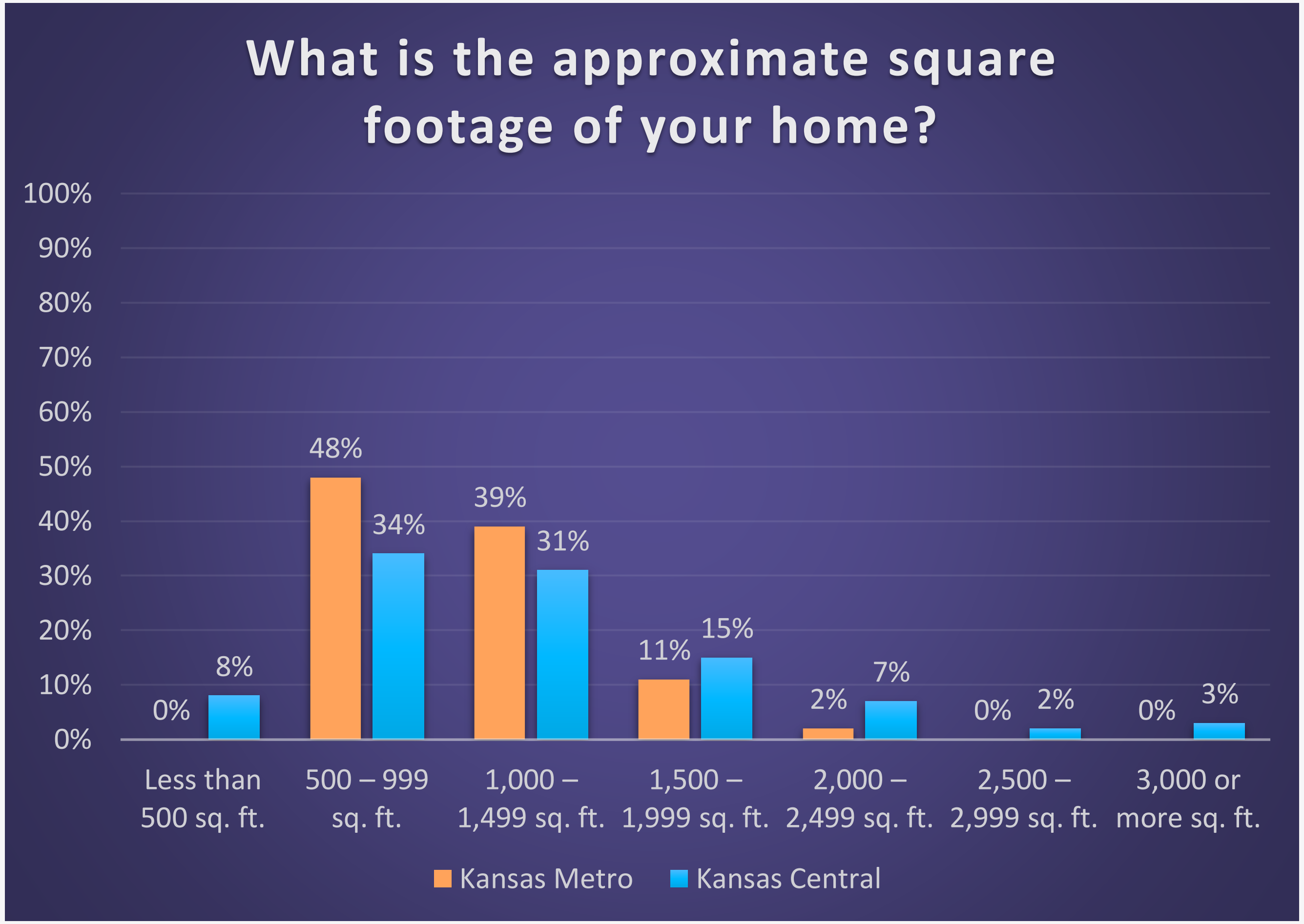
Not surprisingly, given the large proportion of Kansas customers residing in single-family homes, square footage of single-family homes is very similar to the entire Kansas population shown in the previous slide.



Size of Home – Multi-Family

The majority of multi-family homes in Kansas are less than 1,500 square feet.

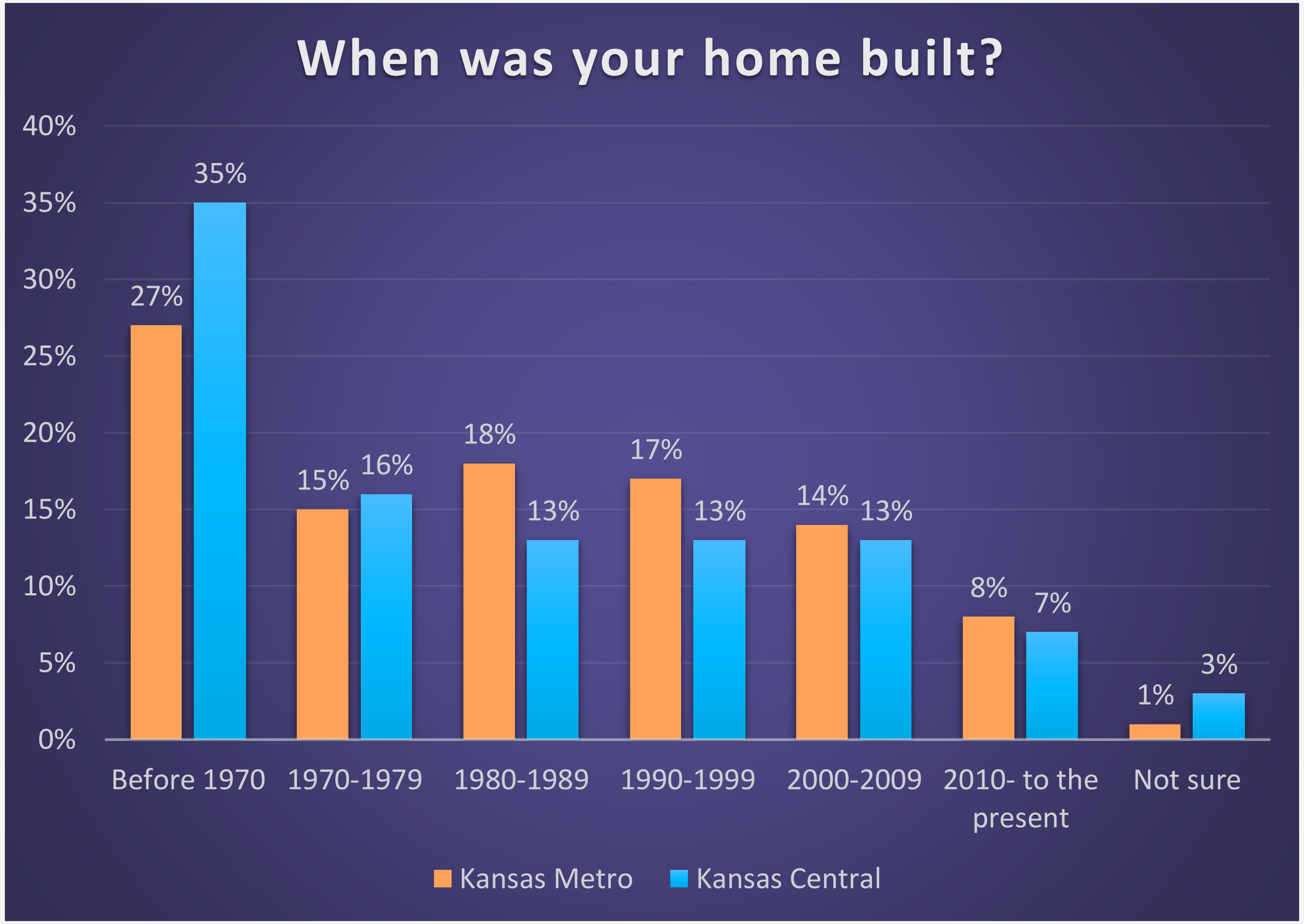
Kansas Metro customers tend to live in smaller multi-family homes compared to Kansas Central customers.



Age of Home

More than a quarter of Kansas Metro and more than a third of Kansas Central customers live in homes built before 1970.

Only 7-8% of Kansas homes have been built in the last 12 years.

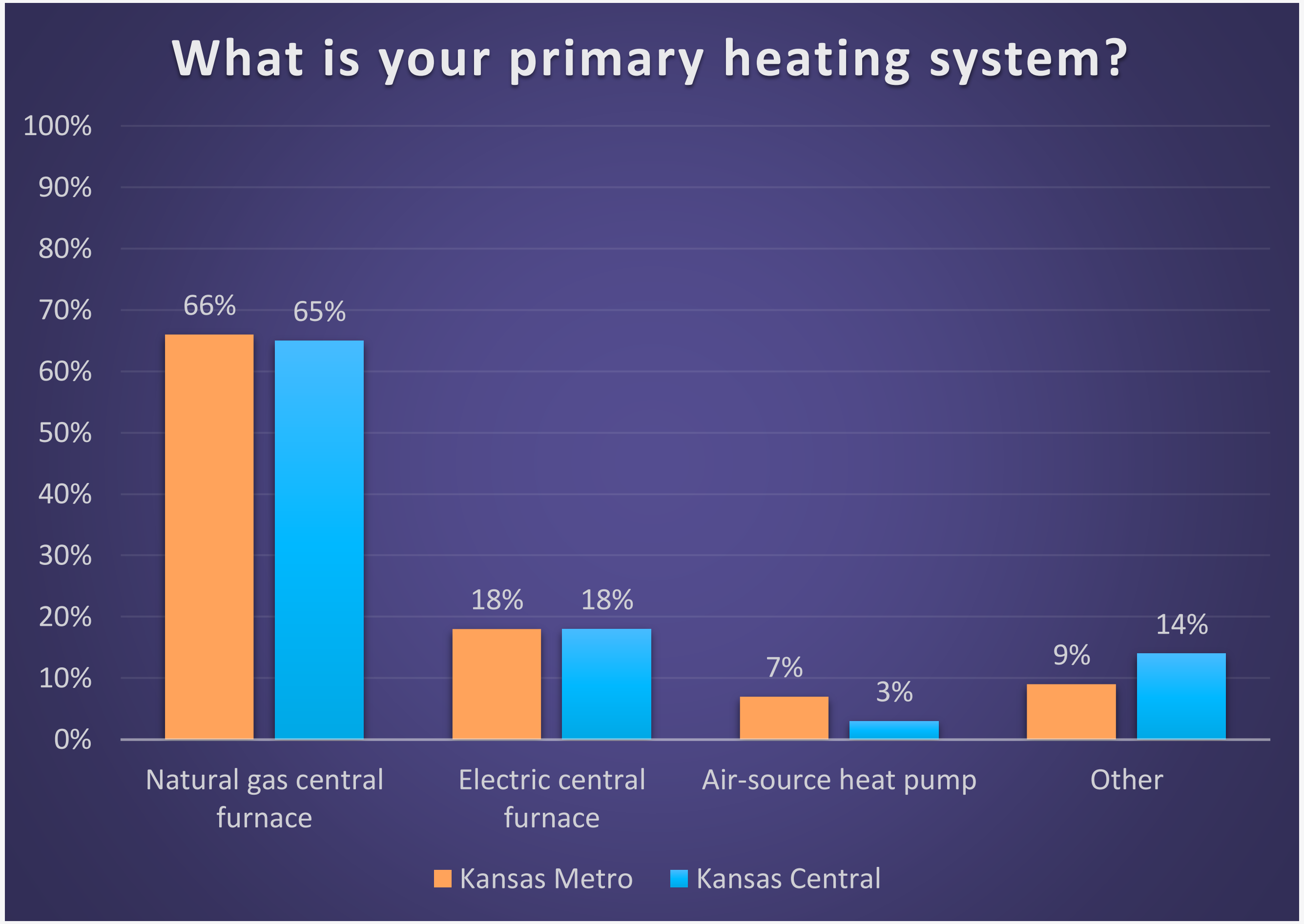


Heating, Cooling, and Water Heating

Primary Heating System

About two-thirds of Kansas customers have natural gas central furnaces as their primary heating system.

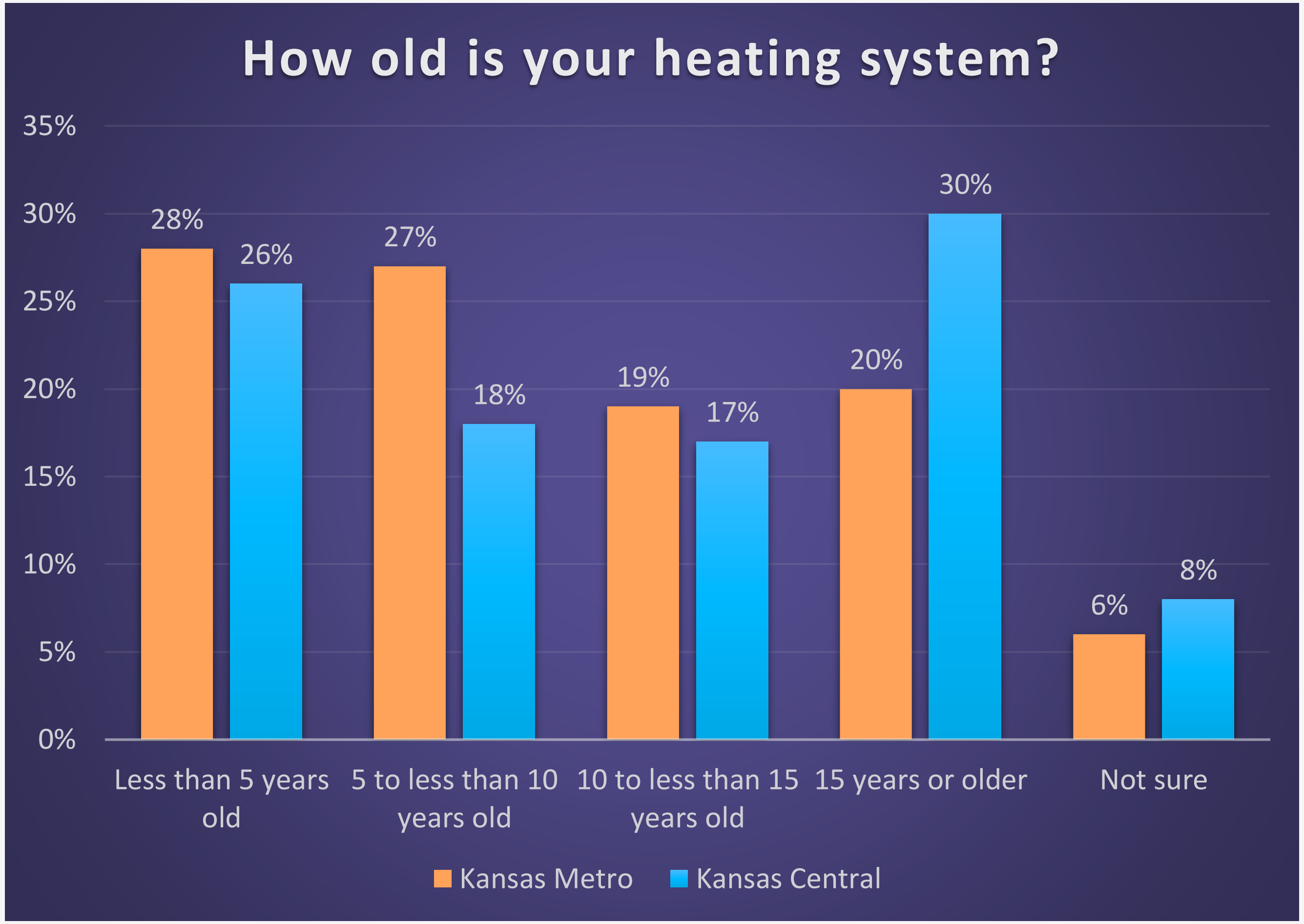
The saturation of electric central furnaces has decreased since 2019, from 30% (Metro) and 25% (Central).



Age of Heating System

Kansas Central has a significant opportunity for EE HVAC programs, with 30% of households having a heating system near the end of its useful life.

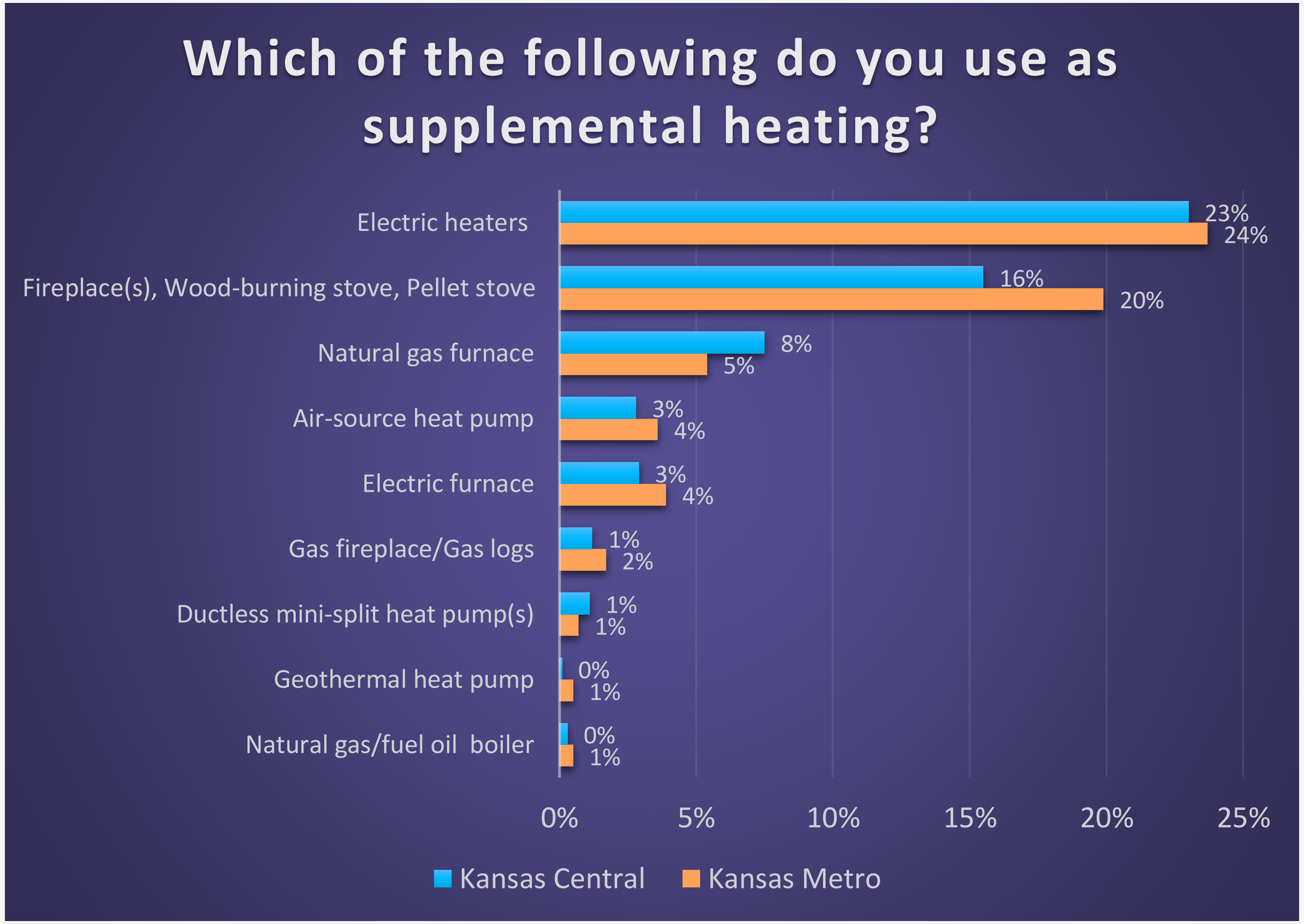
20% of Kansas Metro customers have a heating system that is nearing replacement.



Secondary Heating System

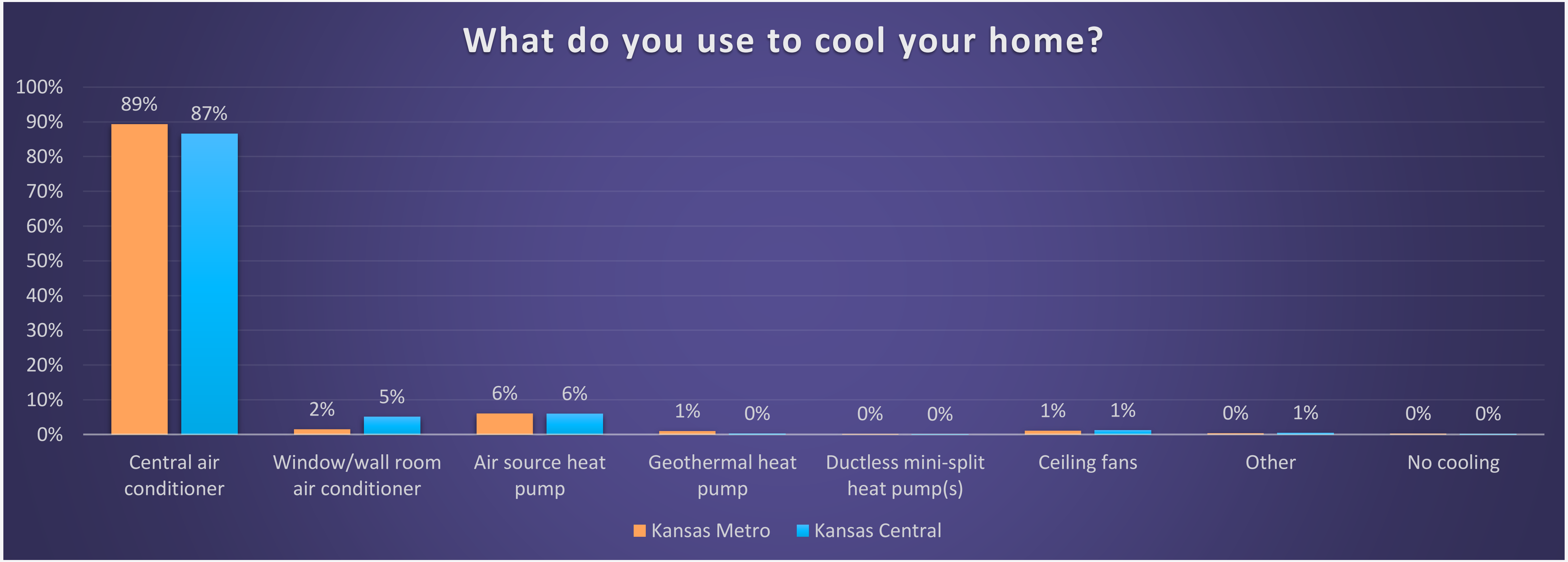
Electric heaters are the secondary heating system used by about one quarter of Kansas customers.

Fireplaces, wood-burning stoves and pellet stoves are second choice for 16 – 20% of Kansas households.



Primary Cooling System

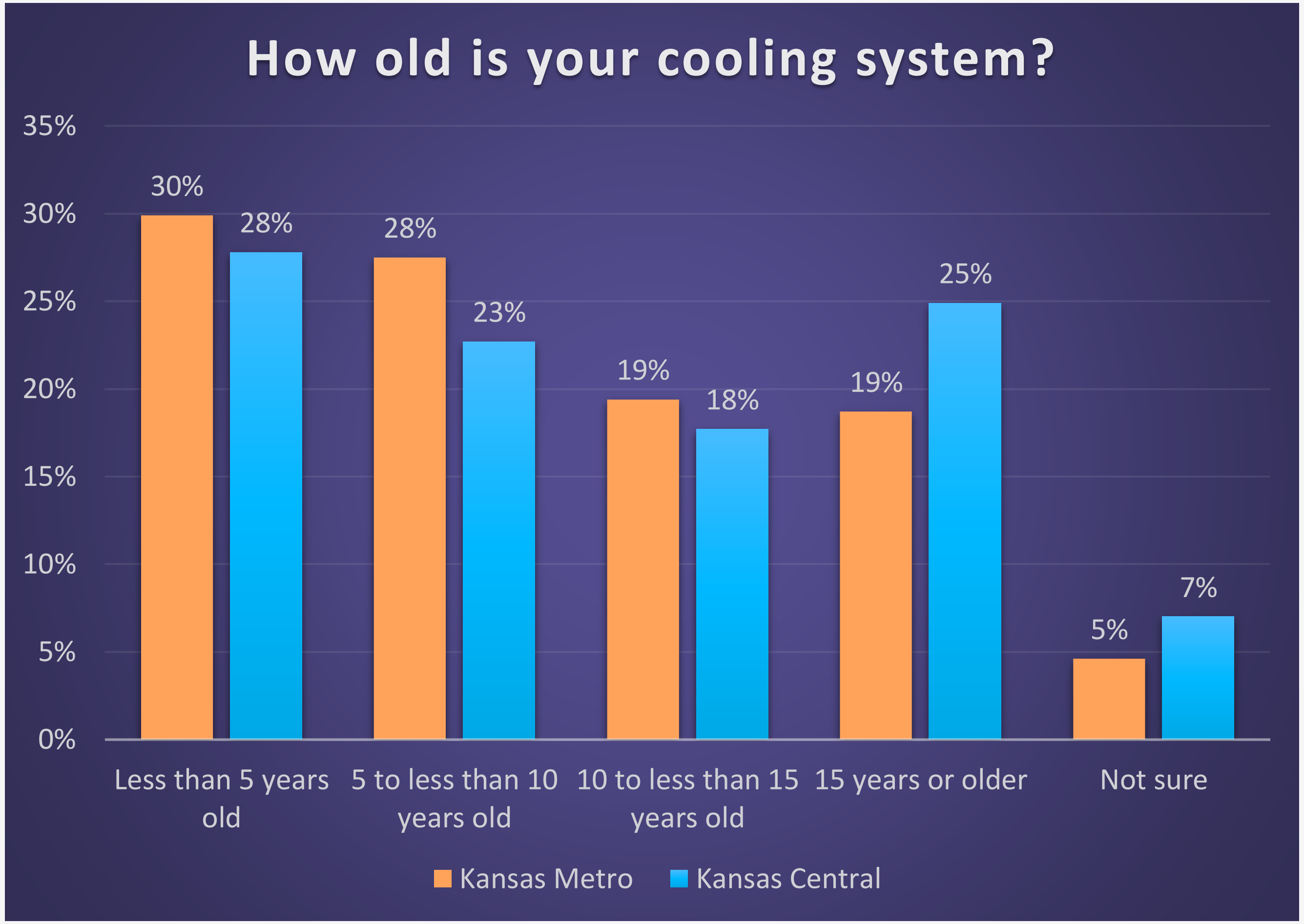
Most Kansas customers have central air conditioning. Very few rely on window/wall units.



Age of Cooling System

Over half of cooling systems in Kansas are less than 10 years old.

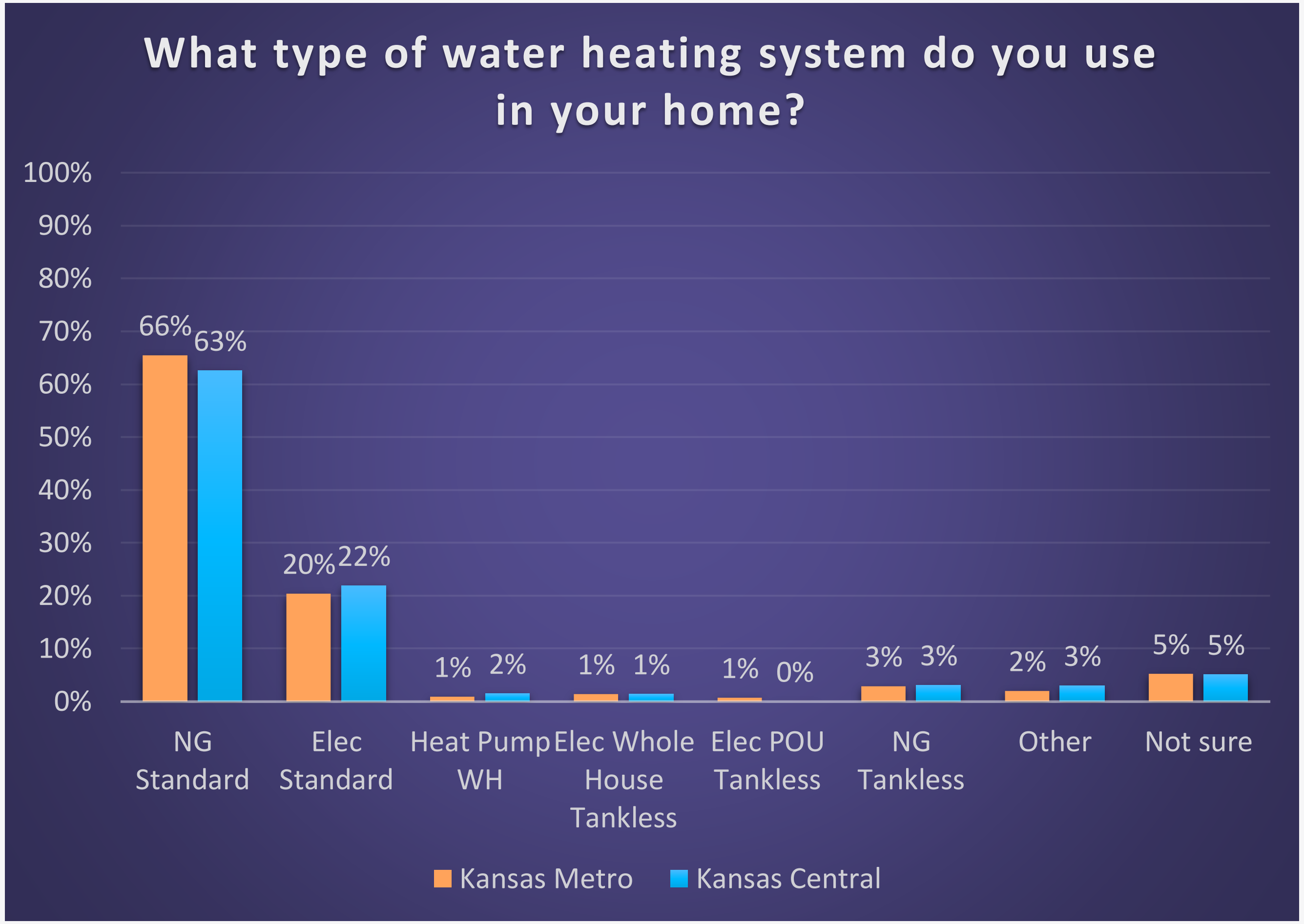
A quarter of Kansas Central customers and 19% of Kansas Metro customers have cooling systems nearing replacement.

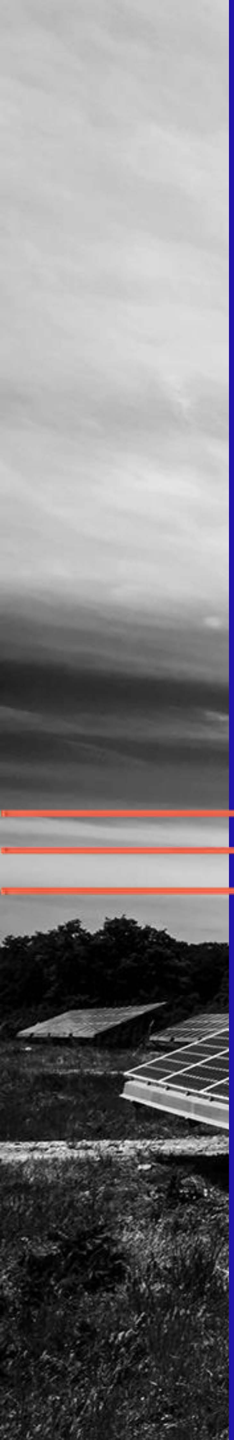


Type of Water Heater

Natural gas is the primary fuel used for water heating in Kansas; 69% of Kansas Metro and 65% of Kansas Central customers have natural gas water heaters.

Few Kansas customers have newer technologies such as heat pump water heaters or tankless systems.



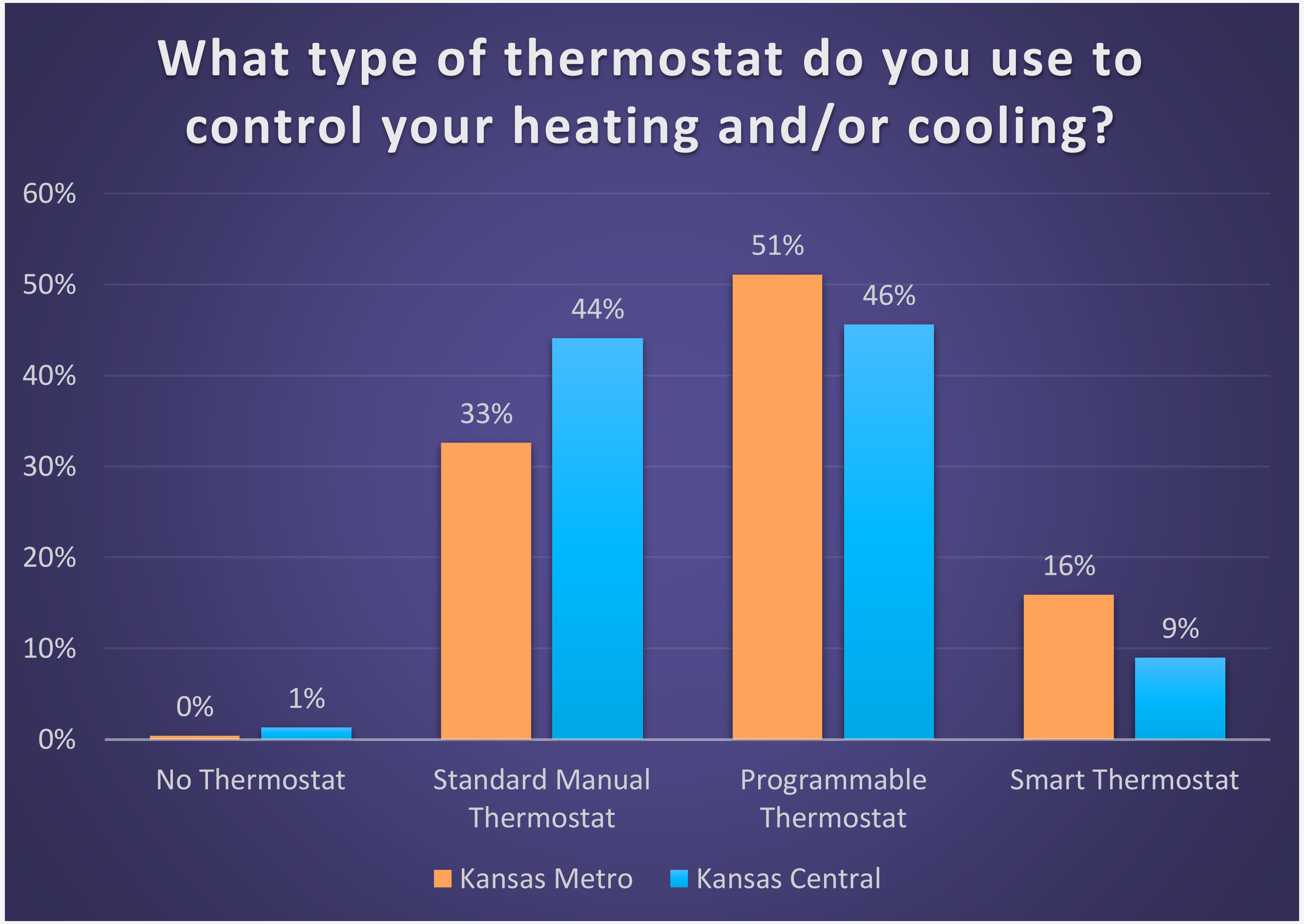


Thermostat

Type of Thermostat

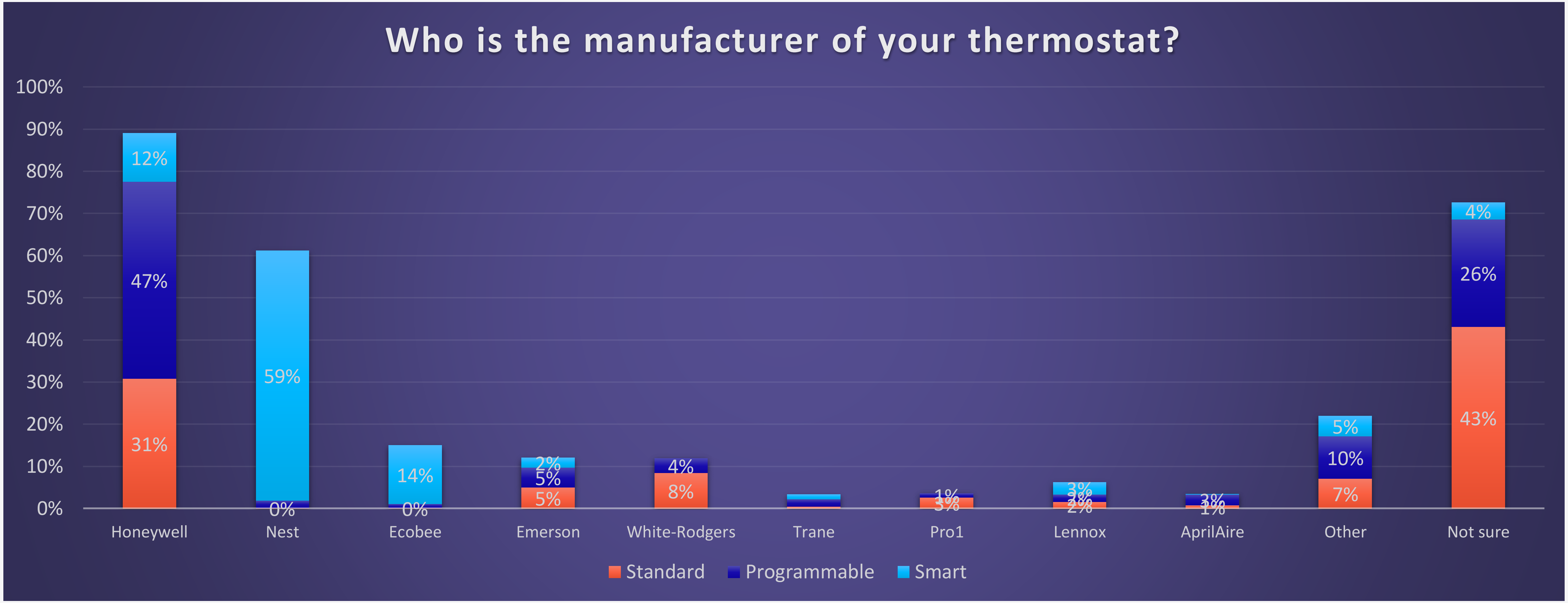
Over a third of Kansas Metro customers and 44% of Kansas Central customers have standard manual thermostats.

54% to 67% of customers have programmable/smart thermostats which is significantly higher than 2019 when 43% of customers in Evergy' s service territory (including Missouri customers) had programmable thermostats.



Type of Thermostat by Manufacturer

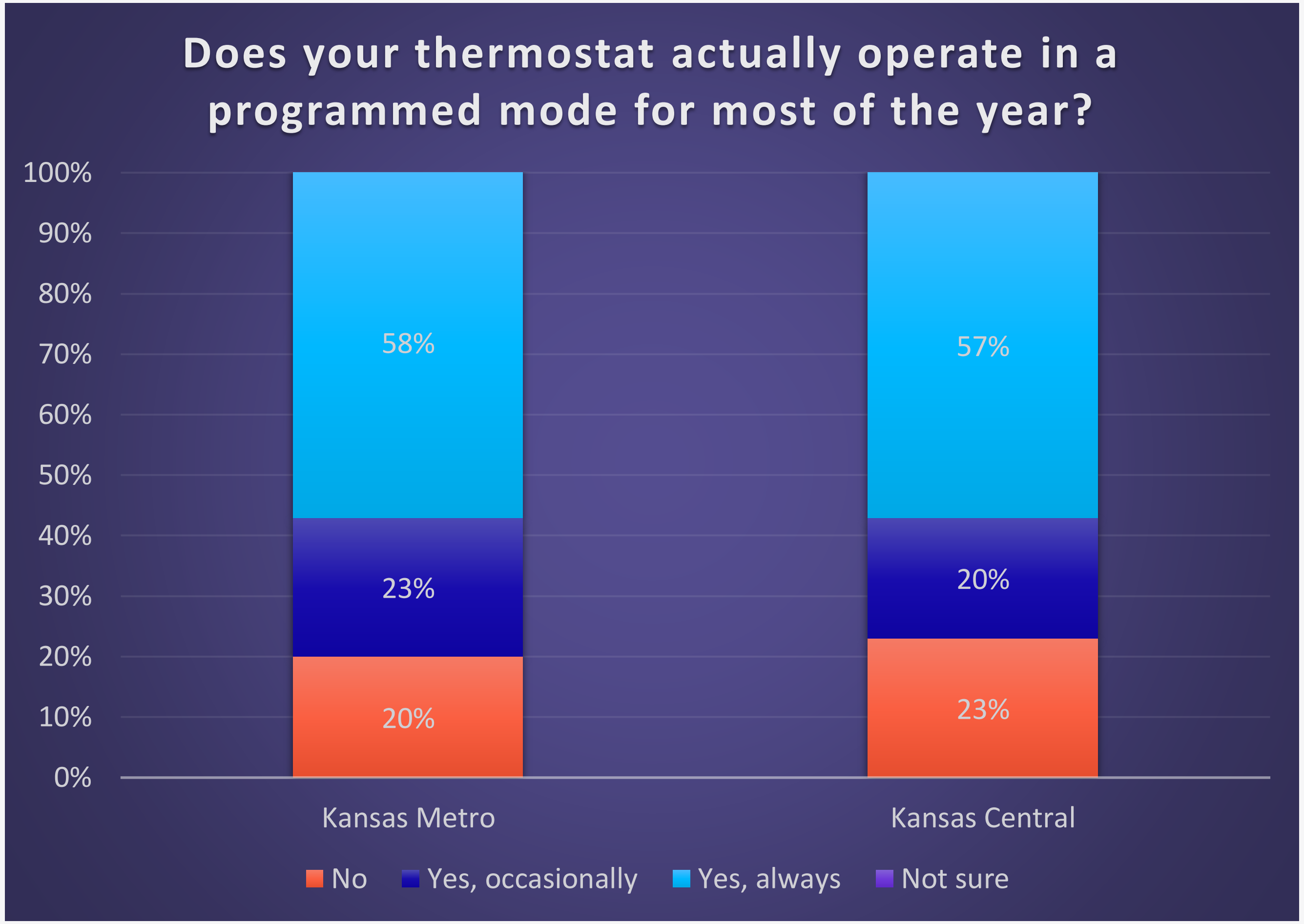
Based on the response to the thermostat manufacturer question, respondents appear to correctly identify their type of thermostat.



Programmable Thermostat Use

More than half of Kansas customers always operate their thermostat in programmed mode.

There is an opportunity with the remaining 43% for customer education on how to operate their heating and cooling systems more efficiently.



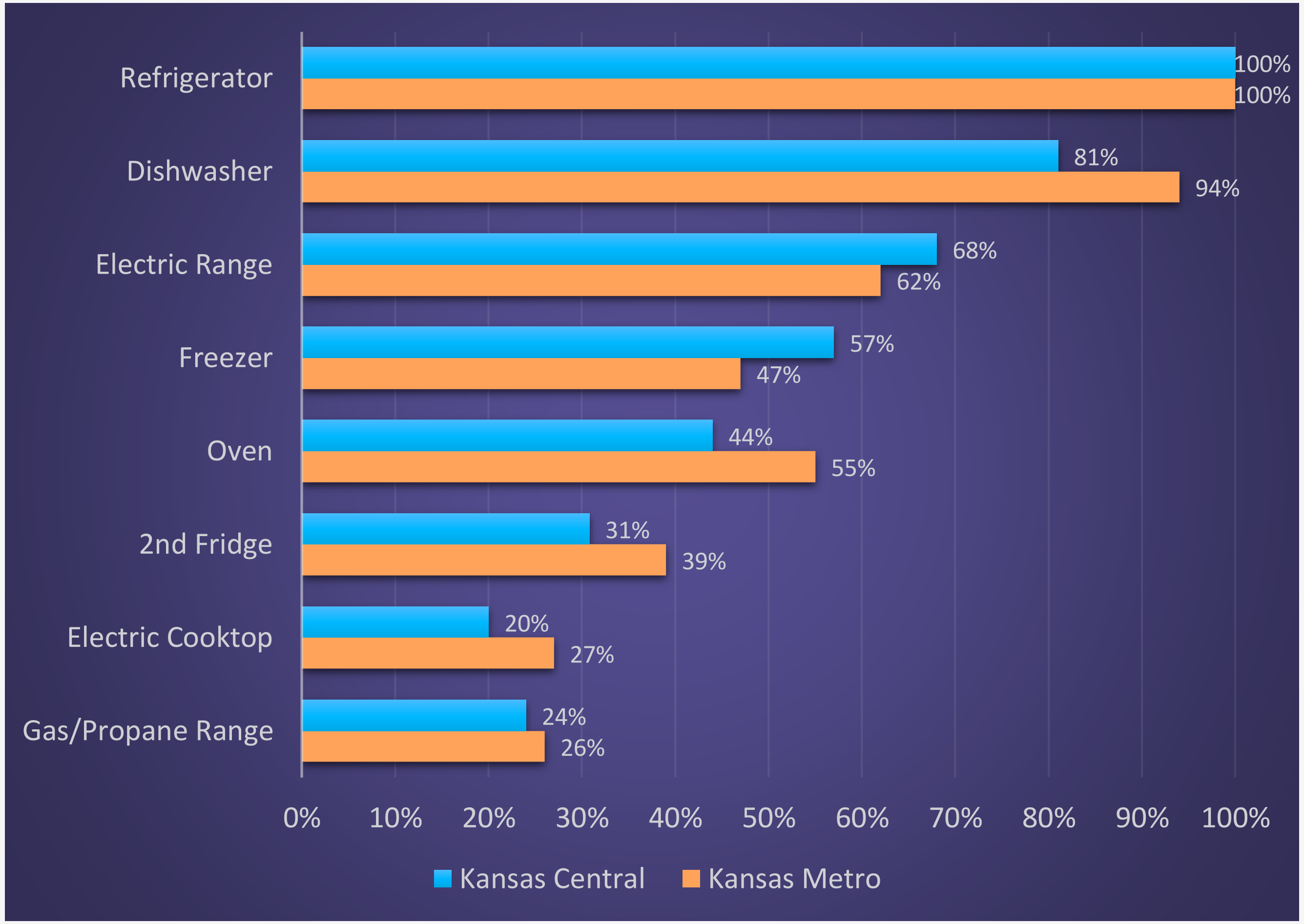
Appliances and Electronics

Kitchen Appliances

The majority of Kanas customers have a refrigerator, dishwasher and electric range.

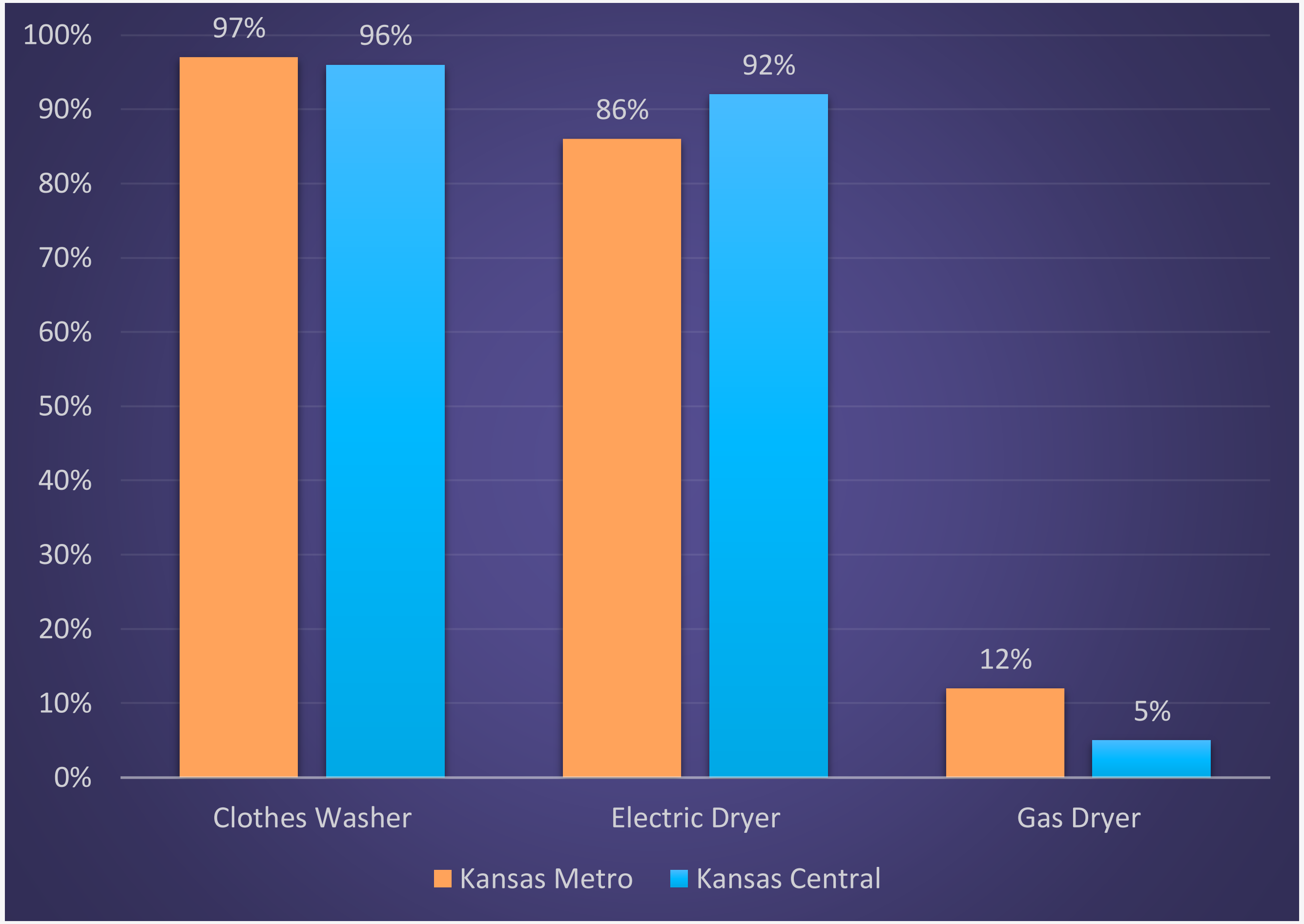
39% of Kansas Metro and 31% of Kansas Central customers have a second fridge.

57% of Kansas Central and 47% of Kansas Metro customers have a stand-alone freezer.



Laundry Equipment

A large majority of Kansas customers have a clothes washer and an electric dryer.

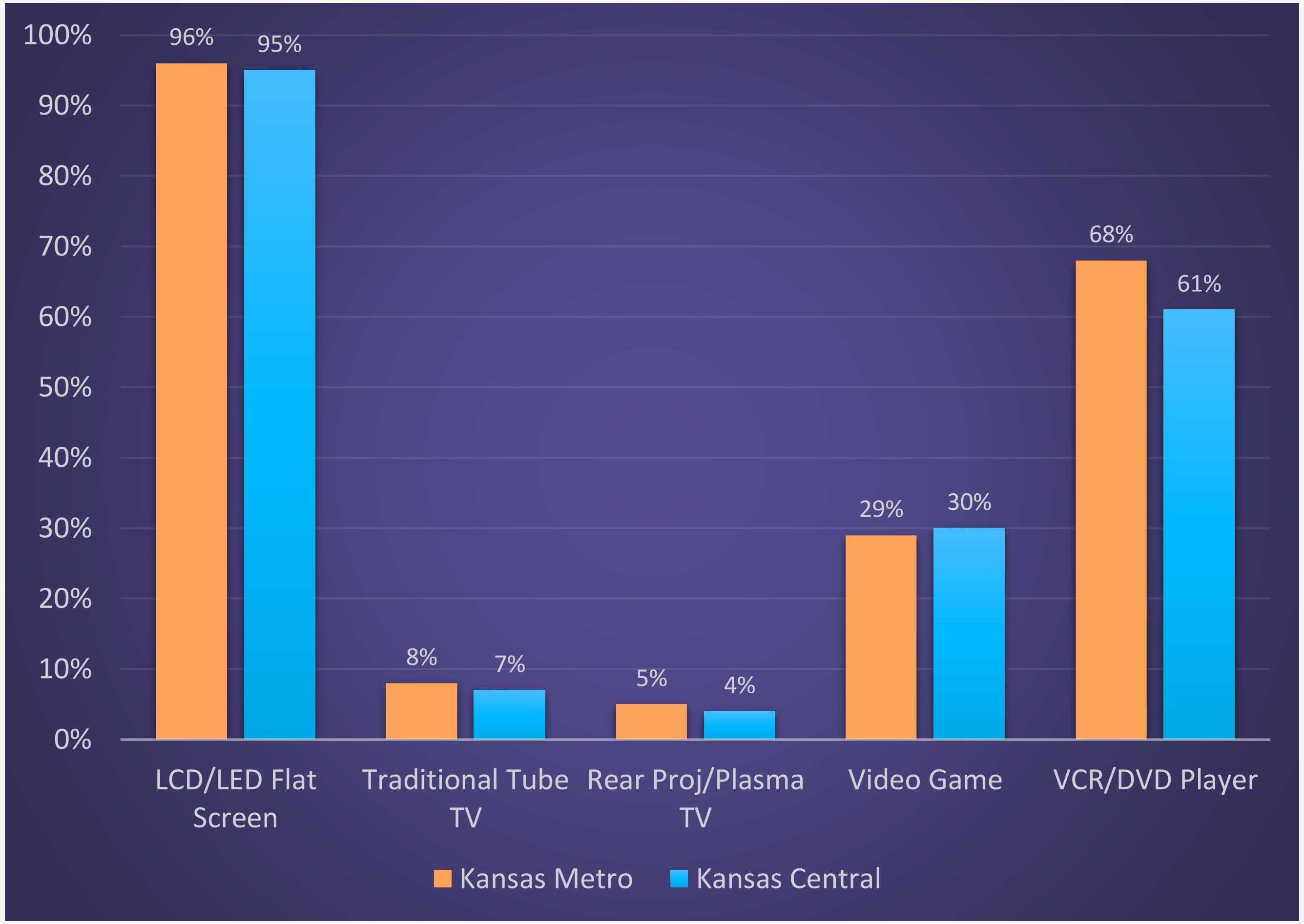


Entertainment Equipment

The mean number of TVs is 3 in Kansas Metro households and 2 in Kansas Central households. The vast majority of those are LCD/LED flat screen.

Less than third have video game consoles.

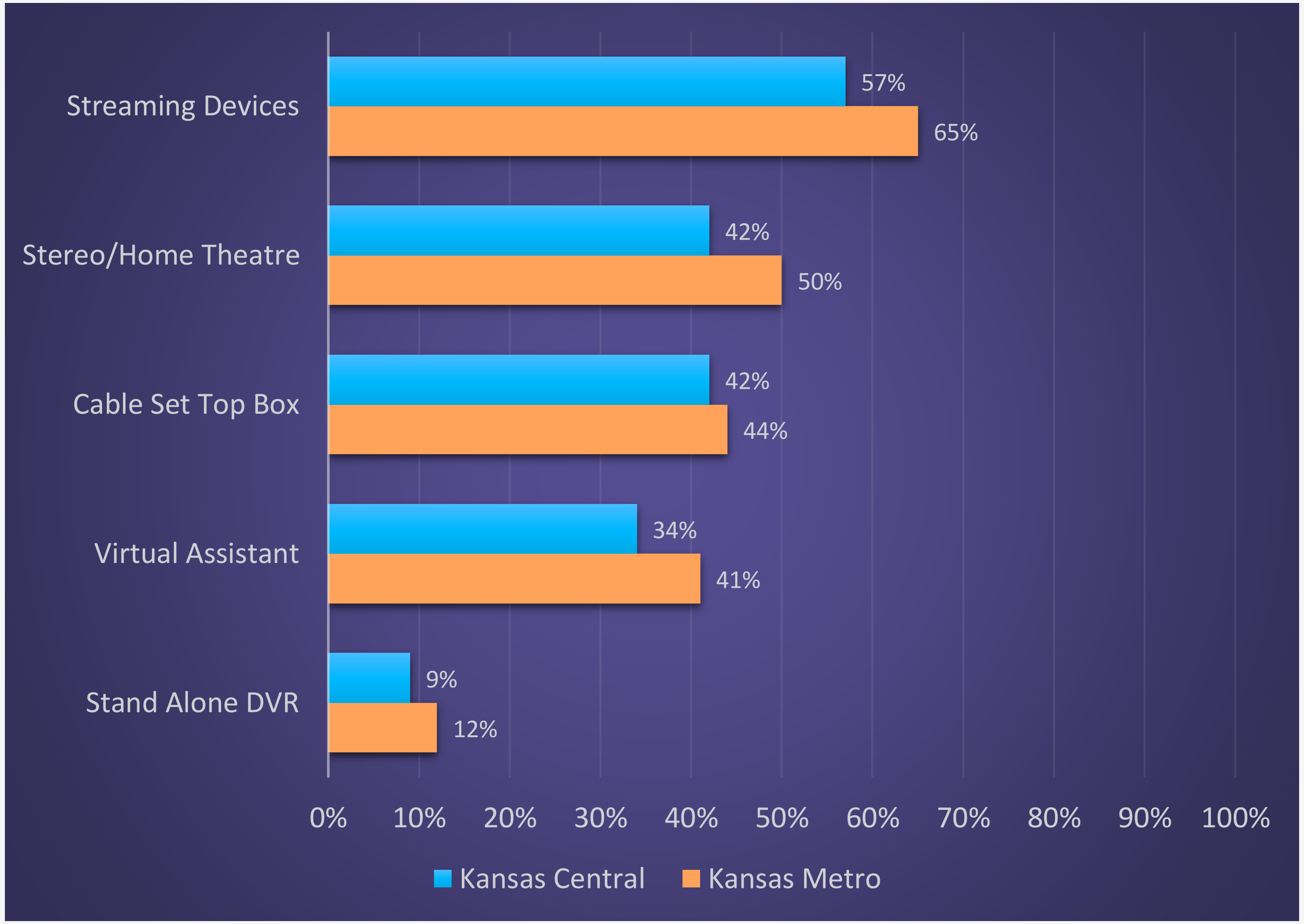
68% of Kansas Metro and 61% of Kansas Central customers have a VCR/DVD player.



Electronic Accessories

Streaming devices have shown significant growth since 2019, up from 48% of Kansas Metro and 39% of Kansas Central households.

The saturation of virtual assistants has also increased. In 2019 29% of Kansas Metro and 21% of Kansas Central customers had virtual assistants.

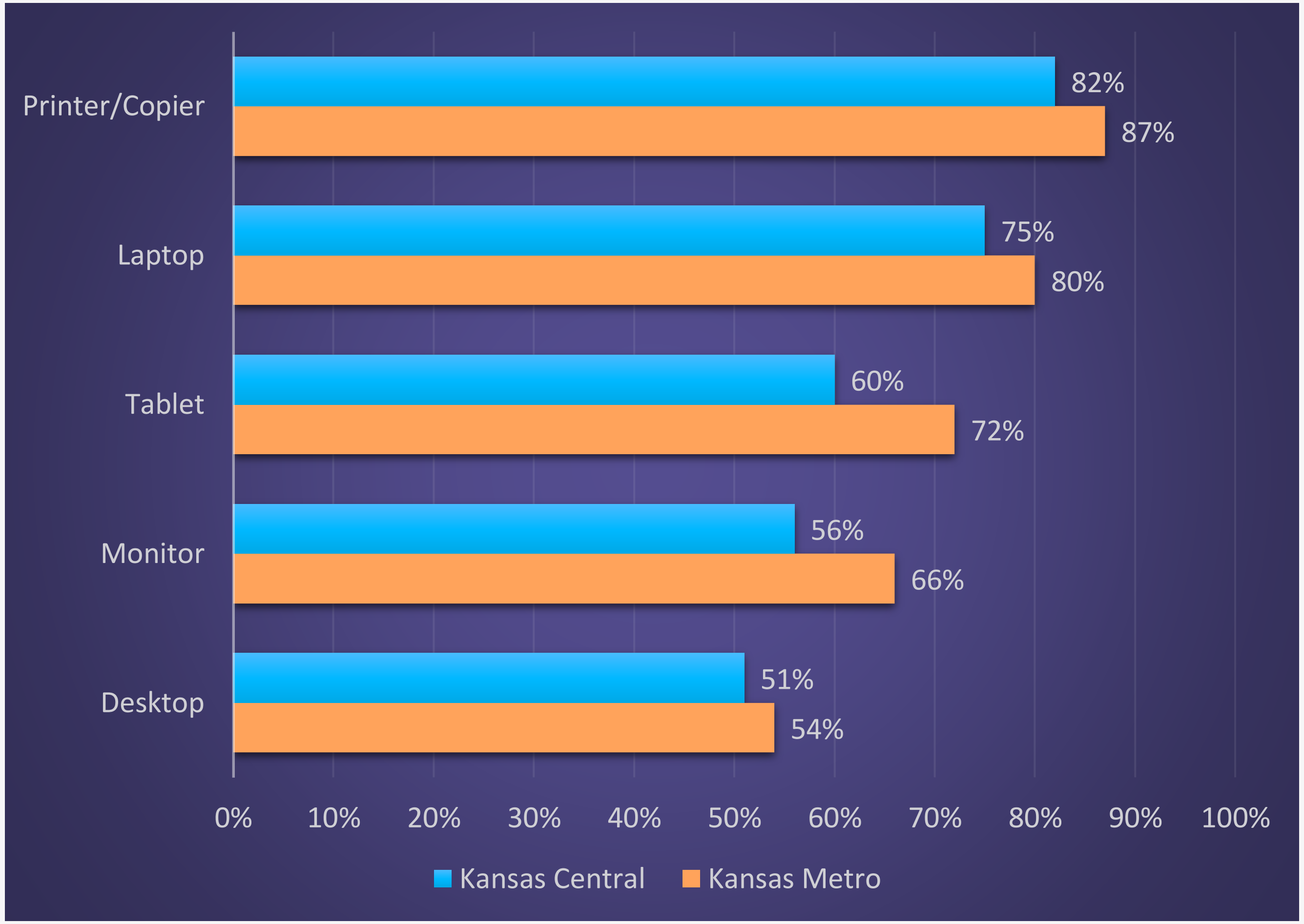


Computer and Office Equipment

Computer and office equipment is prevalent in most Kansas homes.

Most equipment in this category has seen an increase since 2019, with monitors showing the largest growth.

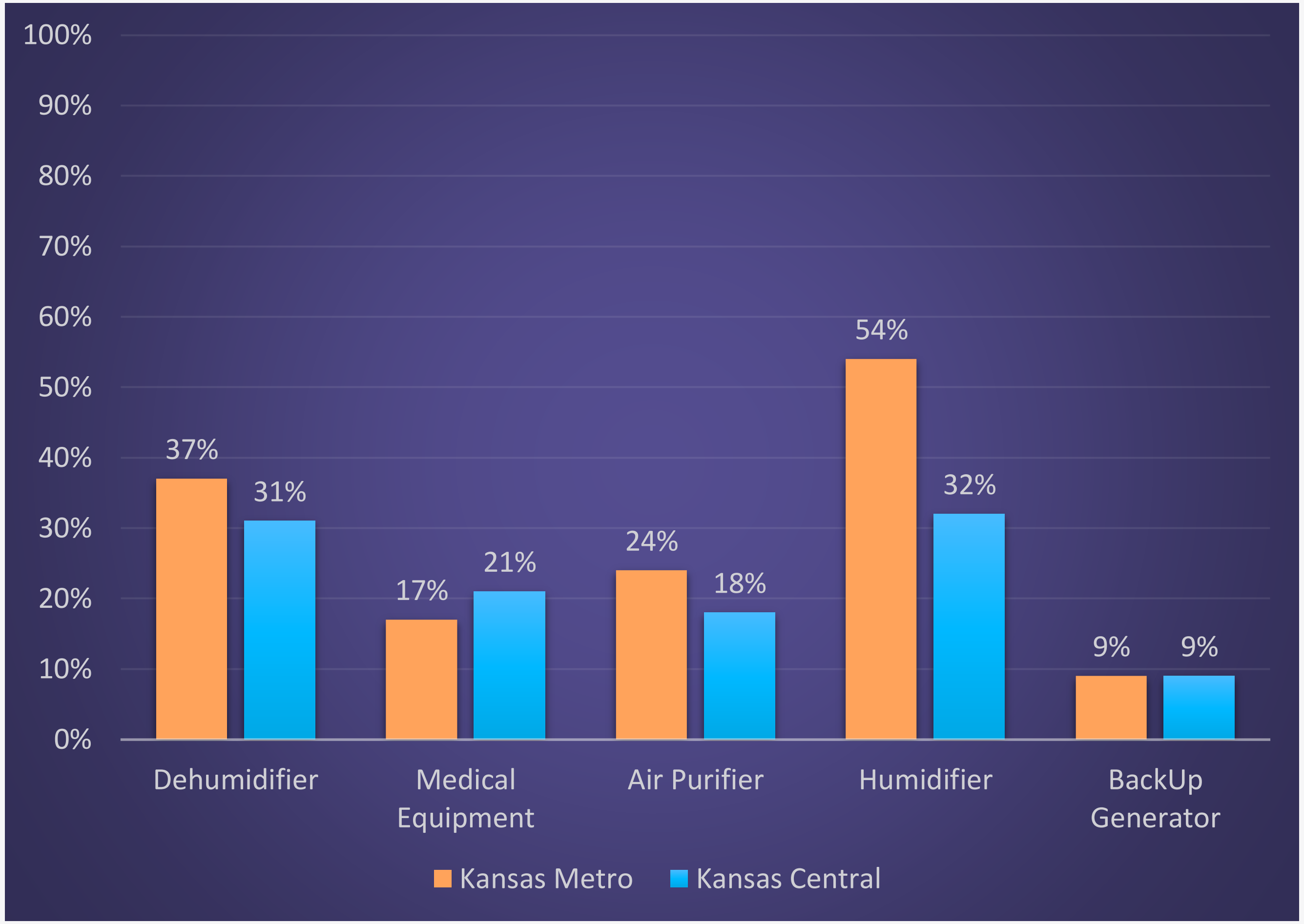
In 2019, 46% of Kansas Central and 53% of Kansas Metro customers had monitors.



Other Types of Equipment

Over half of Kansas Metro customers have a humidifier, while 37% have a dehumidifier.

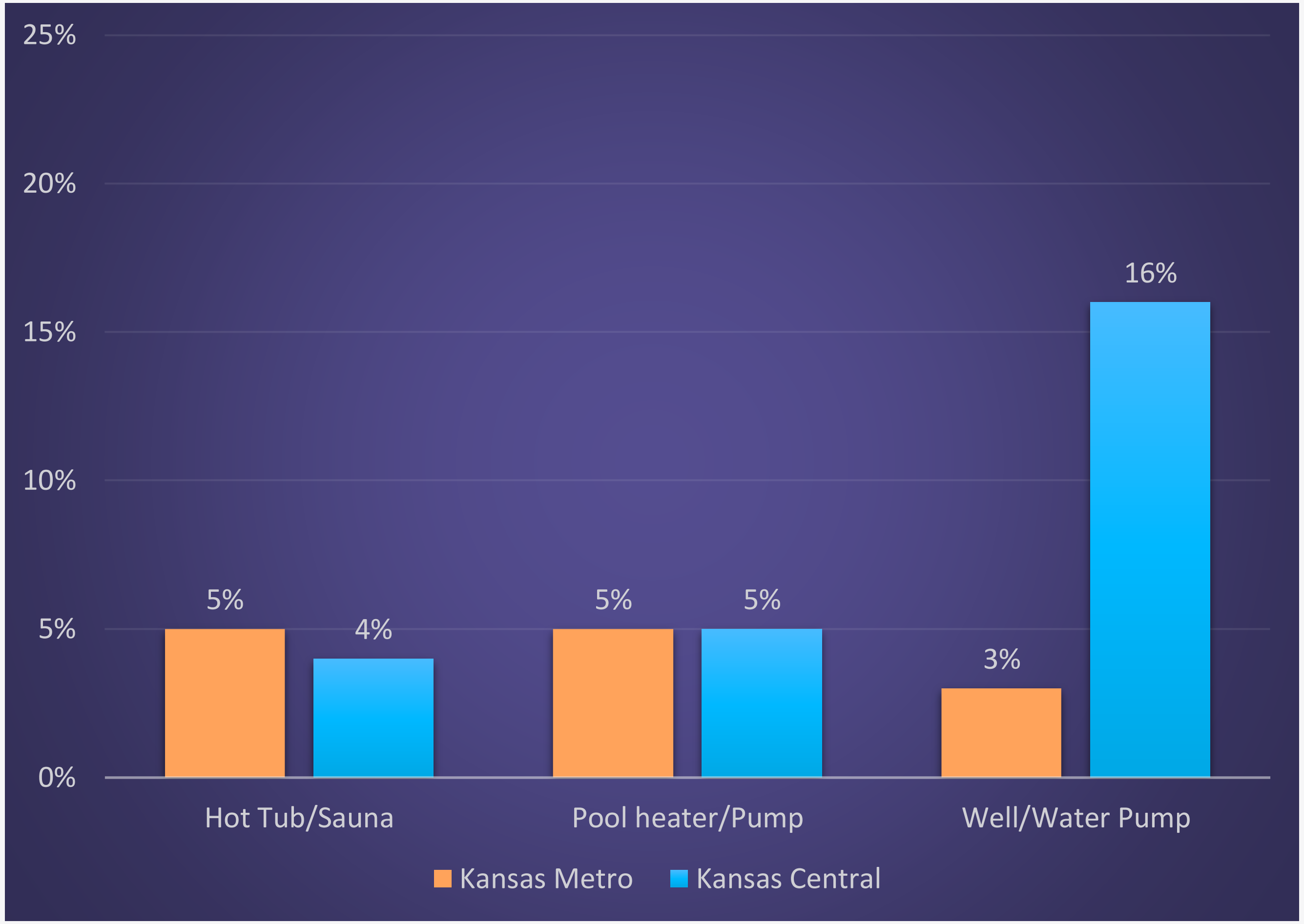
A little under a third of Kansas Central customers have humidifiers and/or dehumidifiers.



Pools, Pumps and Spas

16% of Kansas Central customers have a well/water pump.

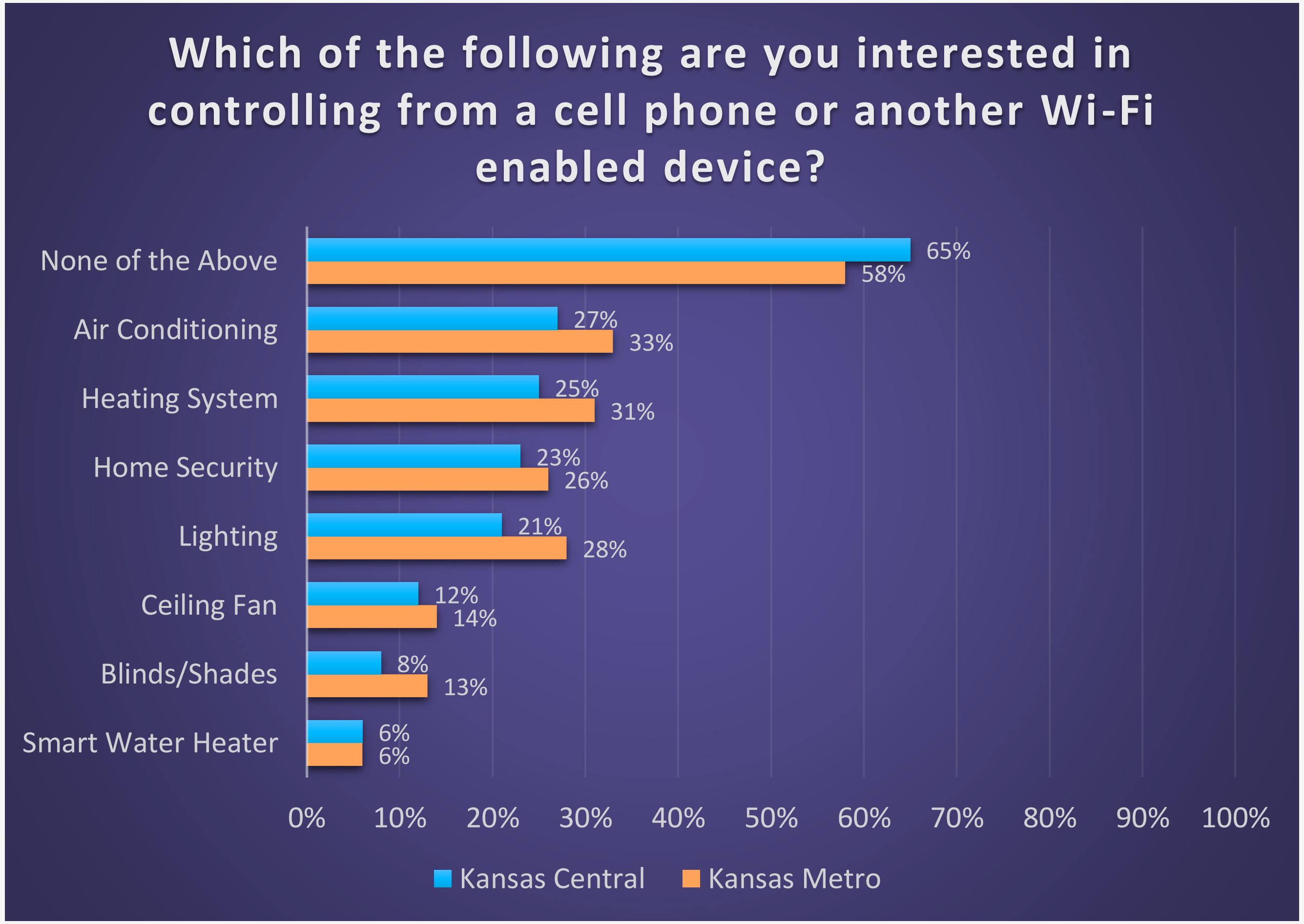
5% or fewer customers in Kansas have hot tubs, saunas or pools.



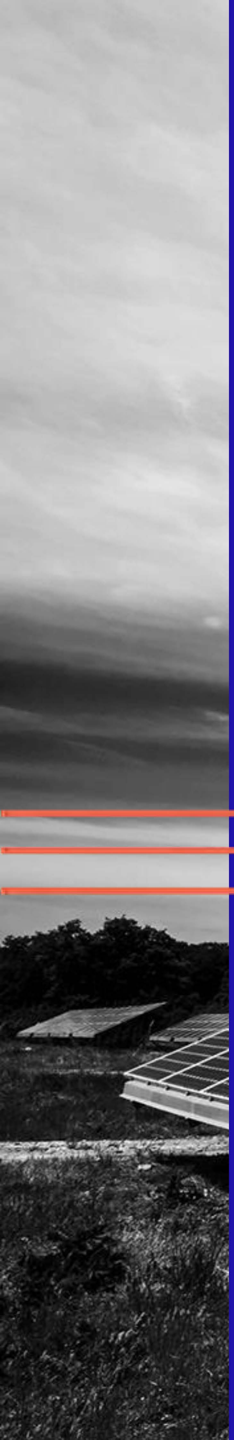
Interest in Smart Controls

The majority of Kansas customers are not interested in smart controls.

Customers who are interested want to control their HVAC, home security and lighting.

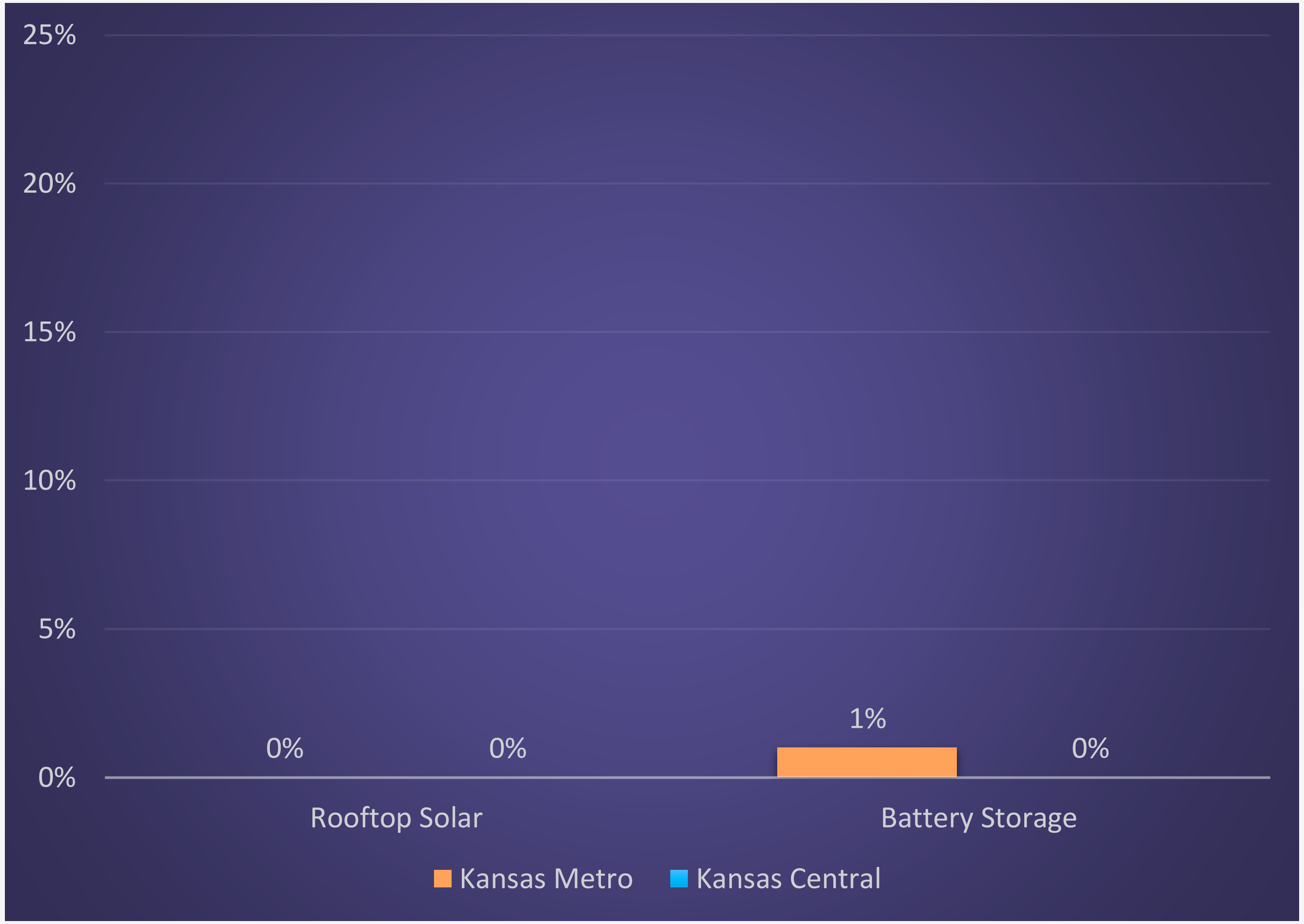


Solar and Electric Vehicles



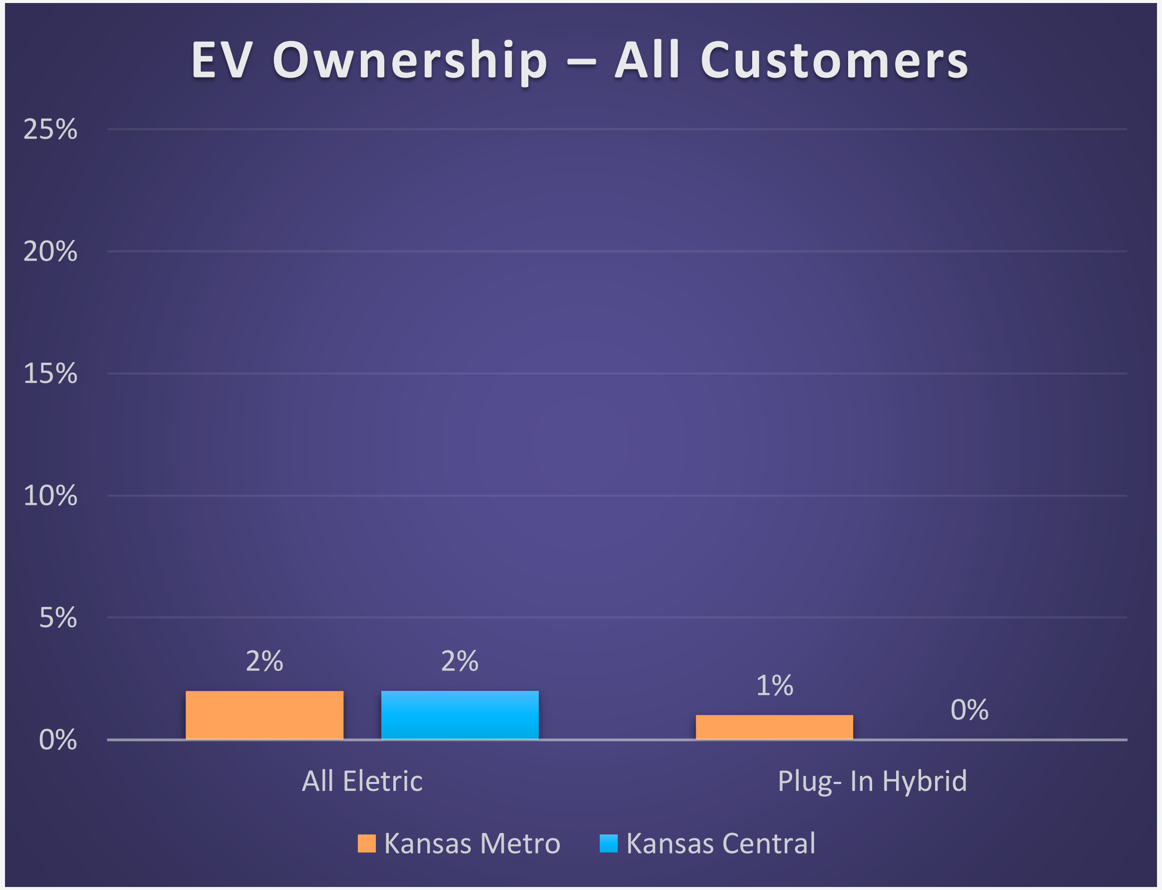
Rooftop Solar and Battery Storage

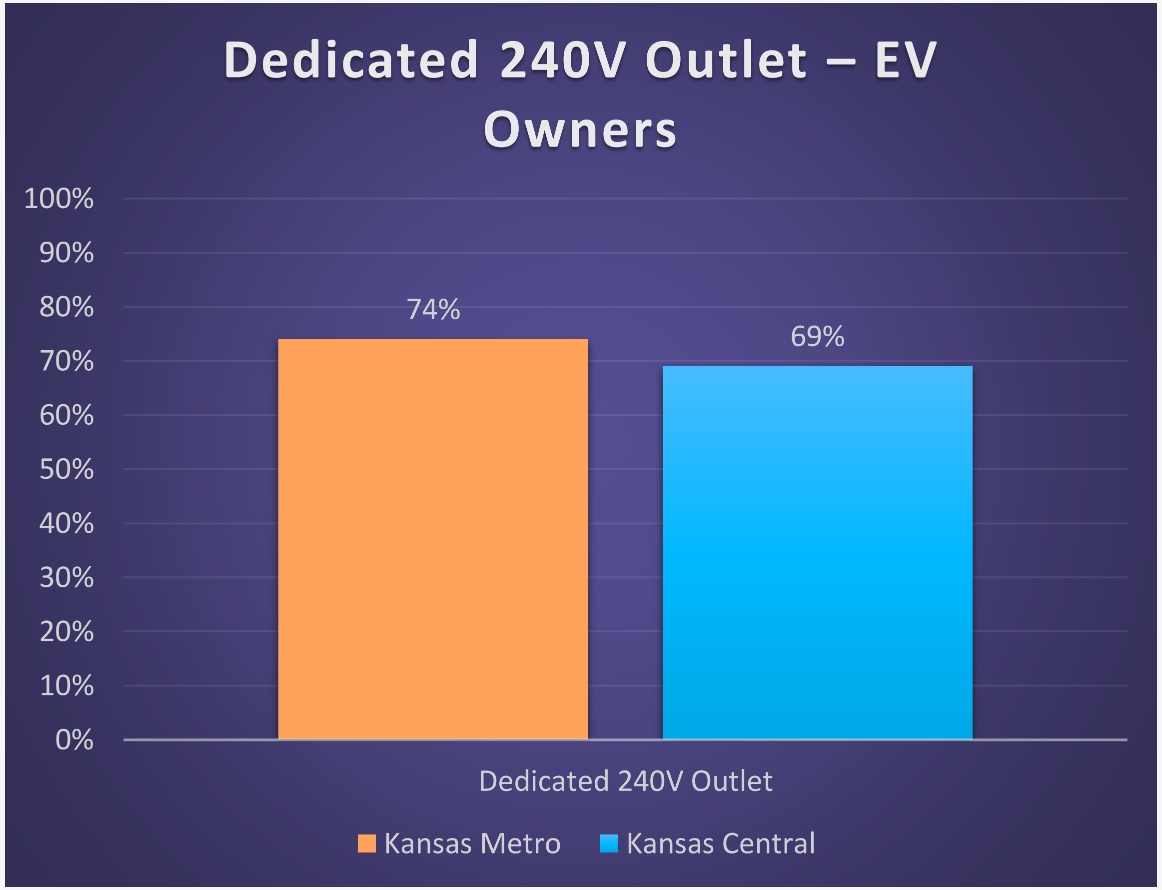
Almost no customers in Kansas have rooftop solar or battery storage.



Electric Vehicles

Very few customers in Kansas have all electric or plug-in hybrid vehicles. The majority of those that do, however, have a dedicated 240V outlet.





Thank You.

AEG

APPLIED ENERGY GROUP

DSM Market Potential Study Results – Evergy West

Prepared for: evergy

Date: May 9, 2023

Table of Contents

Reporting Format

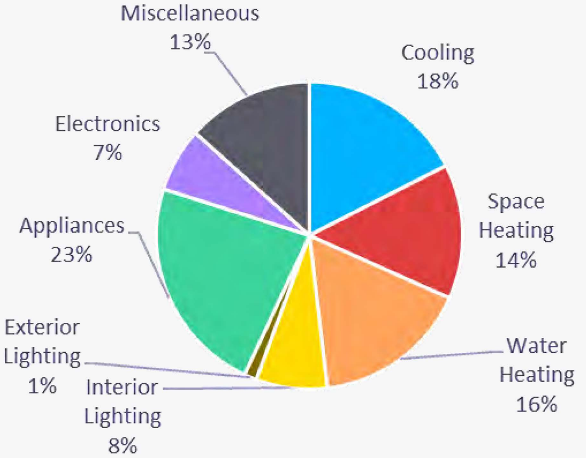
- In support of Evergy's Missouri Integrated Resource Plan (IRP) and Missouri Energy Efficiency Investment Act (MEEIA) Cycle 4 regulations, this presentation summarizes assumptions, methods, inputs and results of the Evergy Demand Side Management (DSM) Market Potential Study.
- Along with this presentation, we provide:
  - A workbook including detailed study inputs and results.
  - A comprehensive report.
- Consistent with 4 CSR 240-22.050, the potential study provides a credible estimation of technical, economic, and achievable potential over the next 20 years.

Energy Efficiency Potential Analysis

Energy Efficiency Potential Approach

Market Characterization

- Customer Segmentation
- Utility Data
- Residential Survey
- Secondary Data

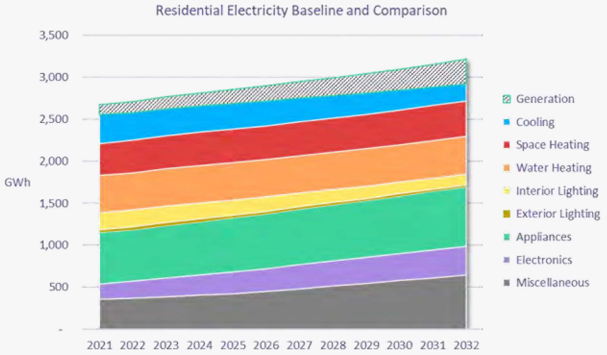


Identify and Characterize Measures

- Efficient Equipment
- Retrofit Opportunities
- Emerging Technologies

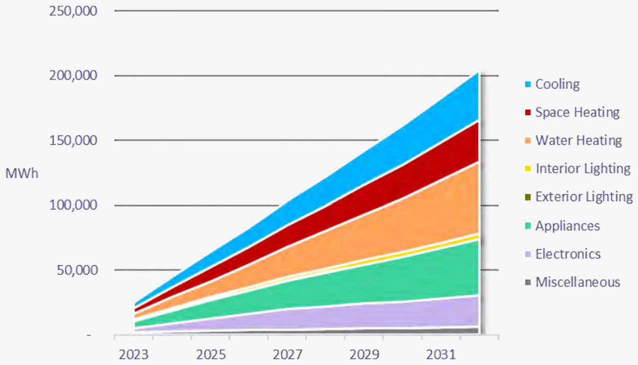
Baseline Projection

- Utility Forecasts
- Stock Turnover
- Codes and Standards



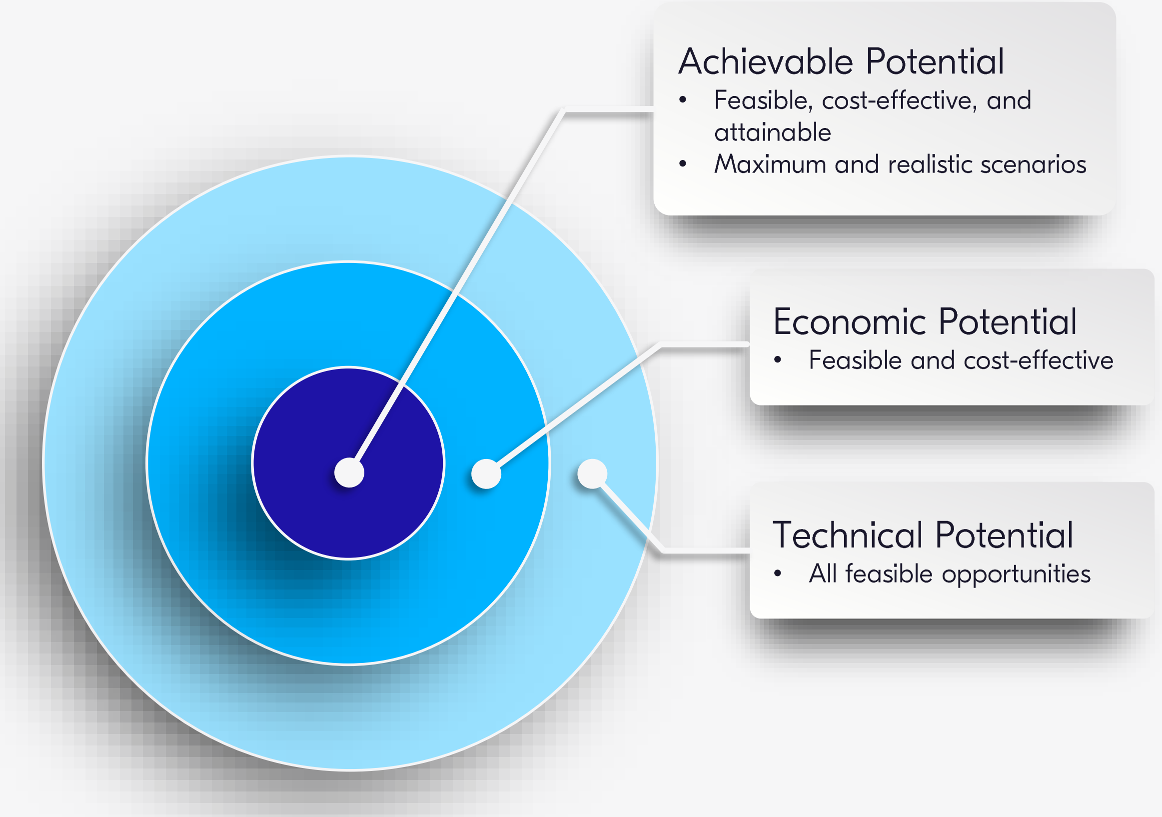
Potential Estimation

- Technical, Economic, and Achievable (MAP and RAP)
- Benchmarked against recent program history



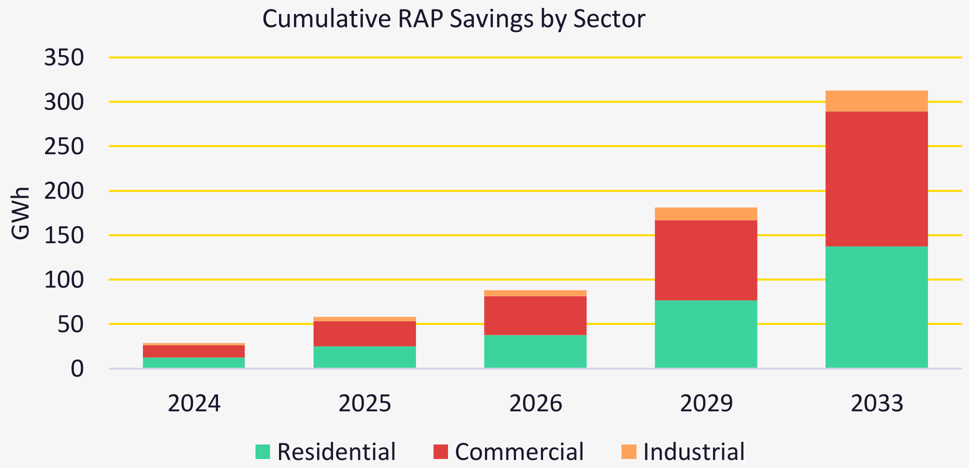
Estimating Energy Efficiency Potential

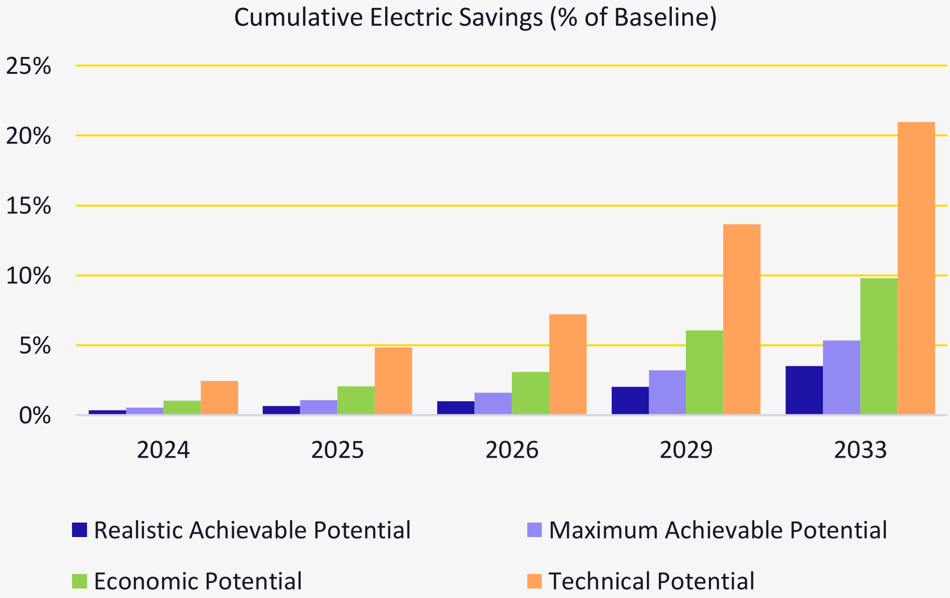
- Potential was estimated by creating an alternate sales forecast incorporating efficient measure adoption and calculating the change from the baseline
- AEG calculated three distinct levels of potential: Technical, Economic, and Achievable
- Achievable potential was assessed under two scenarios:
  - Realistic Achievable Potential (RAP)
  - Maximum Achievable Potential (MAP)

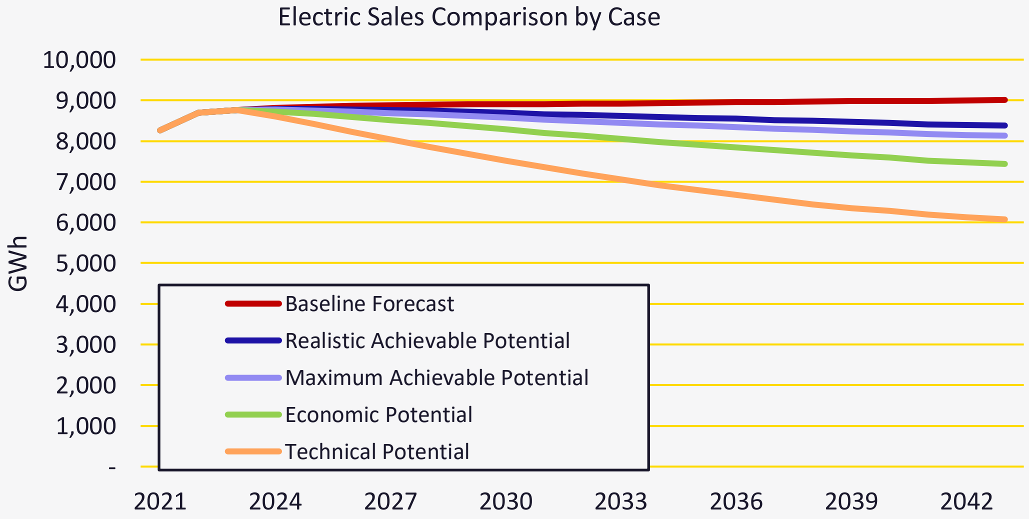


EE Potential Results – Evergy West Summary

- Cumulative RAP is 88.3 GWh by 2026 and 312.8 GWh by 2033, an average of 0.4% of the baseline per year.
- The Commercial sector contributes the most savings, with Residential a close second.
- Cooling and Space Heating savings dominate, with a notable contribution from C&I Lighting.

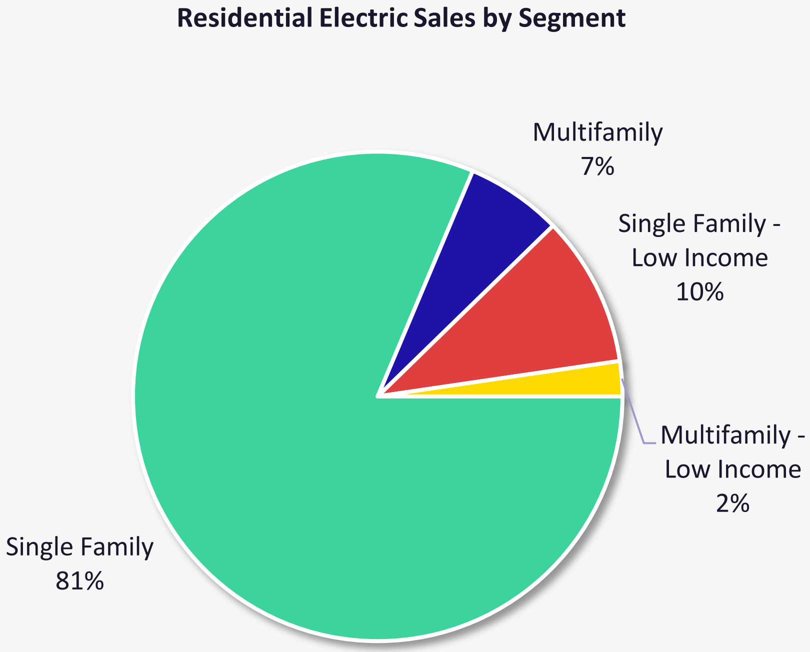






Residential Potential

Residential Market Characterization

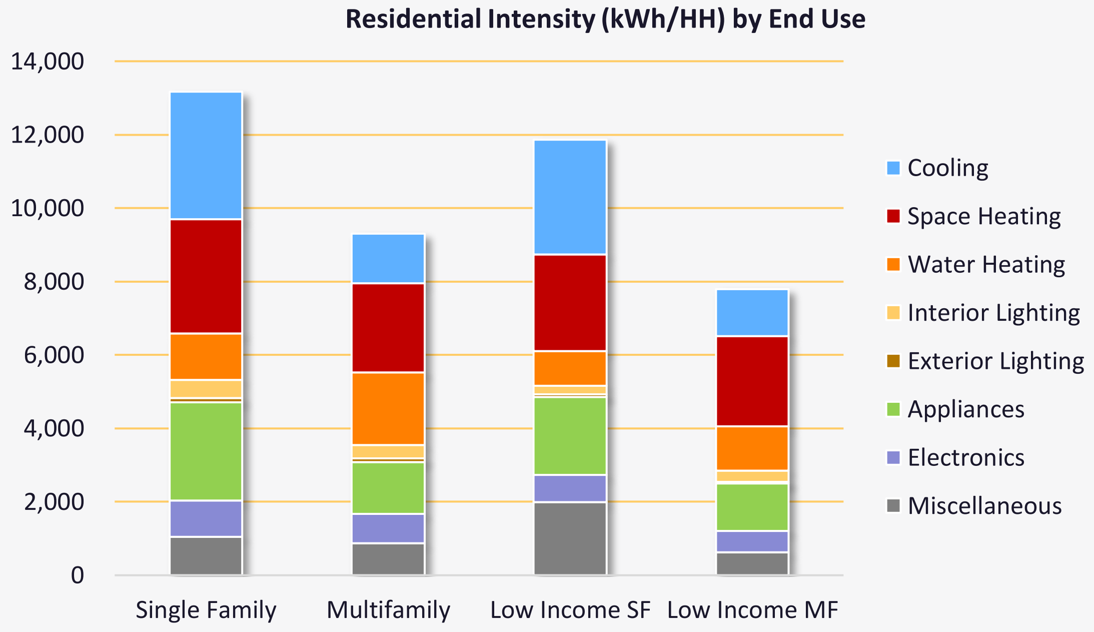


Segment	2021 Electric Use (GWh)	Households	Avg. Use/HH (kWh)	% of Electric Use
Single Family	2,969.8	229,429	12,944	81%
Multifamily	232.2	24,948	9,308	6%
Single Family - Low Income	363.9	30,662	11,868	10%
Multifamily - Low Income	84.6	10,856	7,790	2%
Total	**3,650.5**	**295,895**	**12,337**	**100%**

- Total customers and energy load are taken directly from Evergy's 2021 data and disaggregated into housing types and income groups using a combination of Evergy's system data and demographic information from the US Census
- The majority of homes in Evergy's West territory are single family dwellings, which use 91% of the Residential electricity in the West region.

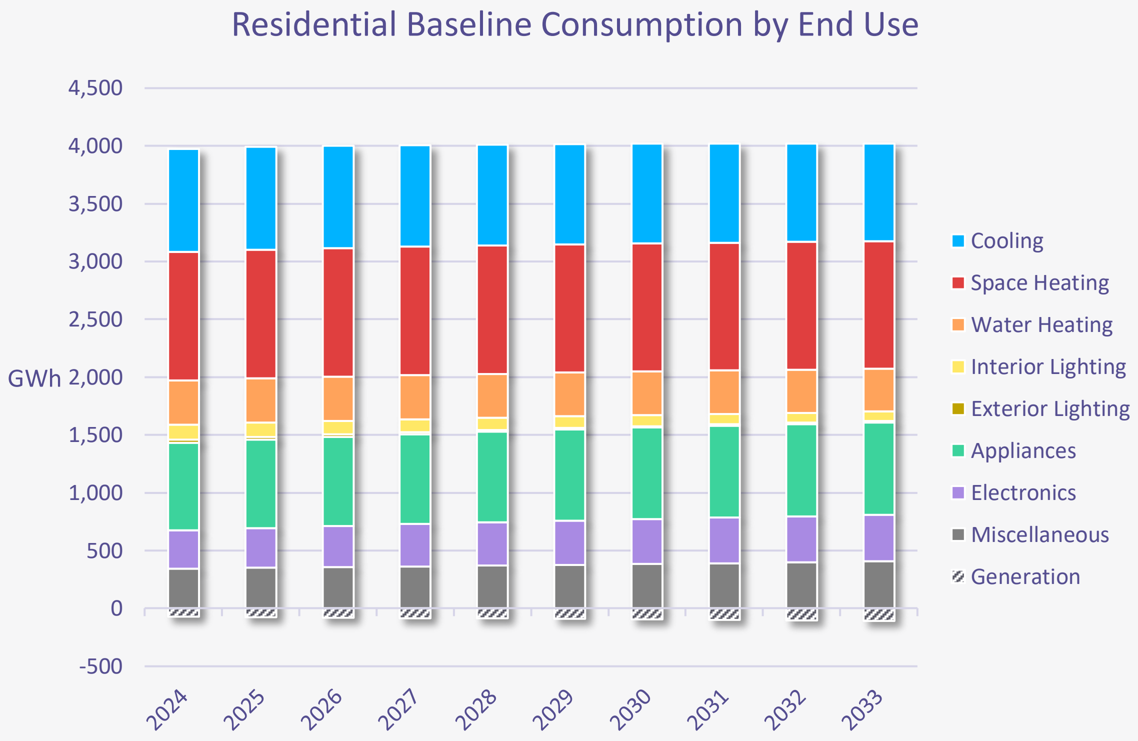
Residential Market Profiles

- The market profile disaggregates energy load per household into specific end uses and technologies.
- Total household **intensity** (kWh per HH) is calibrated to values shown on the previous slide. It is a function of:
  - Saturation – the percentage of homes where equipment is present
  - Unit Energy Consumption – the average annual energy use of a given technology where it is present.
  - Values are taken from well-vetted sources as close to Evergy West's territory as possible
- Key Data Sources
  - Evergy Data
  - Residential Appliance Saturation Survey (RASS)
  - EIA Annual Energy Outlook



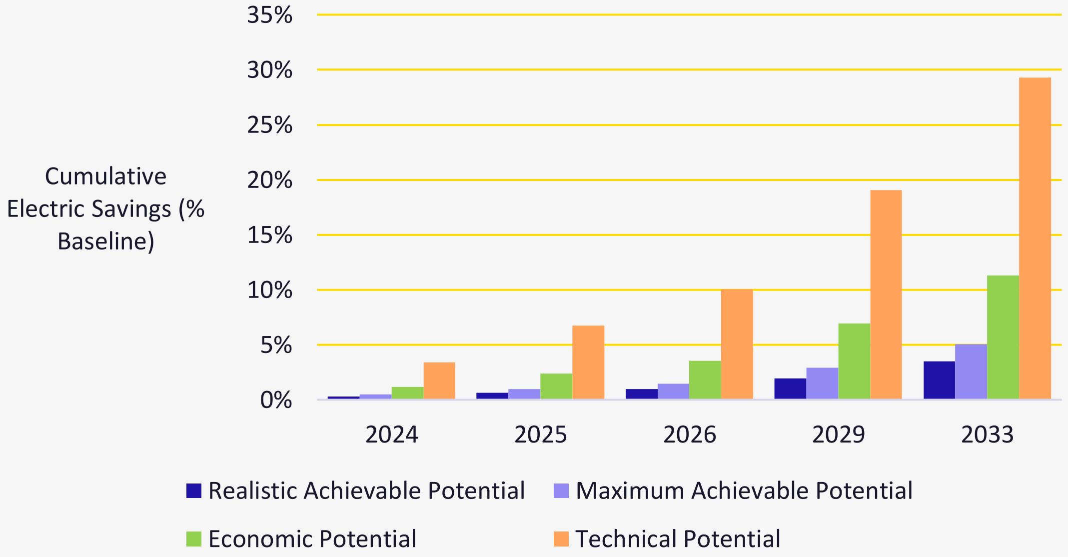
Residential Baseline Projection

- Project a reference baseline for potential that **excludes** future DSM efforts
- Accounts for:
  - Differences in sector and segment
  - Base-year market characterization
  - Customer growth
  - Codes and standards
  - Equipment turnover rates
  - Efficient measure penetration
  - Trends in equipment saturations
  - Weather (CDD, HDD) and other forecast drivers provided by Evergy



Residential Potential Results

- By 2026, cumulative Realistic Achievable Potential (RAP) is 37.5 GWh, or 1.0% of the reference baseline. By 2033, this increases to 137 GWh, or 3.5% of baseline.
  - This is an average of 0.3% per year.
- Maximum Achievable Potential (MAP) reaches 57.4 GWh by 2026, and 196.9 GWh by 2033.



	2024	2025	2026	2029	2033
Baseline Projection (GWh)	3,901	3,912	3,919	3,924	3,912
Cumulative Savings (GWh)					
Realistic Achievable Potential	12	25	38	77	137
Maximum Achievable Potential	19	38	57	114	197
Economic Potential	46	93	140	271	443
Technical Potential	133	265	393	747	1,147
Cumulative as % of Baseline					
Realistic Achievable Potential	0.3%	0.6%	1.0%	1.9%	3.5%
Maximum Achievable Potential	0.5%	1.0%	1.5%	2.9%	5.0%
Economic Potential	1.2%	2.4%	3.6%	6.9%	11.3%
Technical Potential	3.4%	6.8%	10.0%	19.0%	29.3%

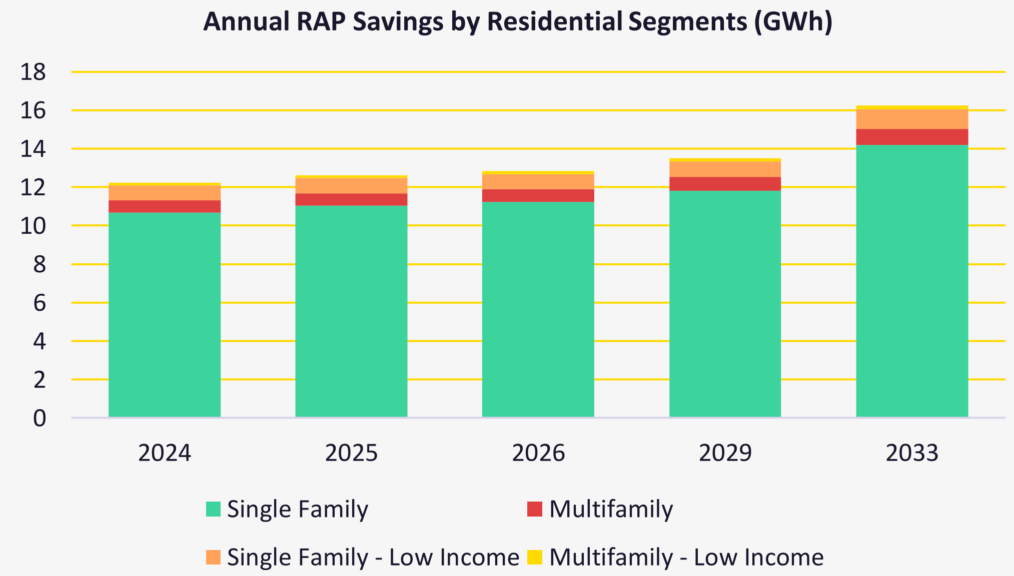
Residential Top Measures - RAP

- HVAC measures provide the bulk of savings:
  - Central Air Conditioner upgrades are the top measure.
  - Converting electric resistance heat to heat pumps is #3.
  - Building shell improvements and controls (e.g., smart thermostats) lower HVAC use.
- LED Lighting is assumed as a baseline condition based on market trends and DOE assumptions, and does not provide program potential.

Rank	Measure Name	Cumulative Savings (MWh) 2026	% of Total
1	Central AC (SEER 18.0 (CEE Tier 2))	4,210	11.2%
2	Ducting - Repair and Sealing (Sealed)	3,818	10.2%
3	Furnace - Conversion to Air-Source Heat Pump	3,496	9.3%
4	Connected Thermostat - ENERGY STAR (1.0) (Networked Installed)	3,199	8.5%
5	Insulation - Floor Upgrade (R-30)	3,162	8.4%
6	Air-Source Heat Pump (SEER 16.0 / HSPF 9.2 (ENERGY STAR 6.1))	2,809	7.5%
7	Ducting - Repair and Sealing - Aerosol (G.17 Aerosol Duct Sealing)	2,489	6.6%
8	Central Heat Pump - Controls and Commissioning (Central Heat Pump with auxiliary heat control strategy, lockout settings, and other parameters)	1,949	5.2%
9	Building Shell - Liquid-Applied Weather-Resistive Barrier (Liquid-Applied Weather-Resistant Barrier)	1,659	4.4%
10	Water Heater - Drainwater Heat Recovery (Installed)	1,438	3.8%
11	Insulation - Ducting (R-8)	1,185	3.2%
12	Refrigerator (CEE Tier 3 (20% above standard))	1,026	2.7%
13	Insulation - Basement Sidewall (R-11)	848	2.3%
14	Exempted Lighting (LED 2020 (95 lm/W))	532	1.4%
15	Insulation - Radiant Barrier (Installed)	527	1.4%
16	Room AC - Recycling (Unit Removed)	513	1.4%
17	Advanced Power Strips - Load or Occupancy (Tier 1 - Load Sensing)	496	1.3%
18	Building Shell - Whole-Home Aerosol Sealing (Building Sealed)	467	1.2%
19	Insulation - Floor Installation (R-30)	449	1.2%
20	Geothermal Heat Pump (EER 17.1 / COP 3.6 (ENERGY STAR 3.2))	439	1.2%
	Total of Top 20 Measures	**34,712**	**92.6%**
	Total Savings - All Measures	**37,495**	**100.0%**

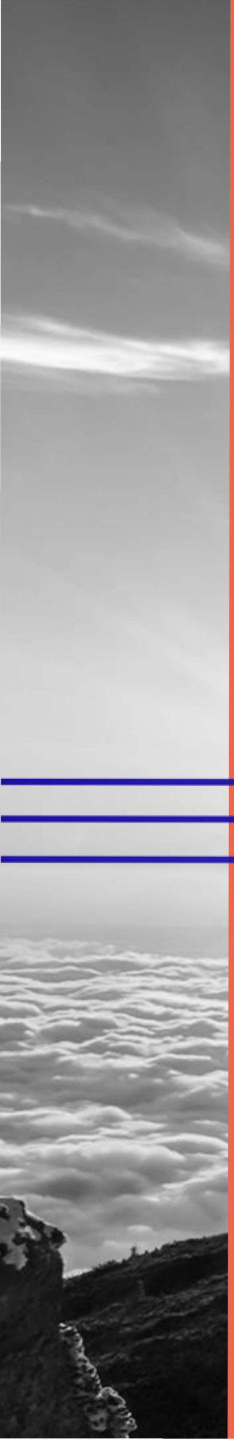
Residential Potential by Segment

- This slide shows incremental (annual) savings by housing type and income group.
- Savings are a function of consumption, so most savings are in the largest segment — single family homes that are not low-income.
- Low-income segments show potential proportionate to their loads

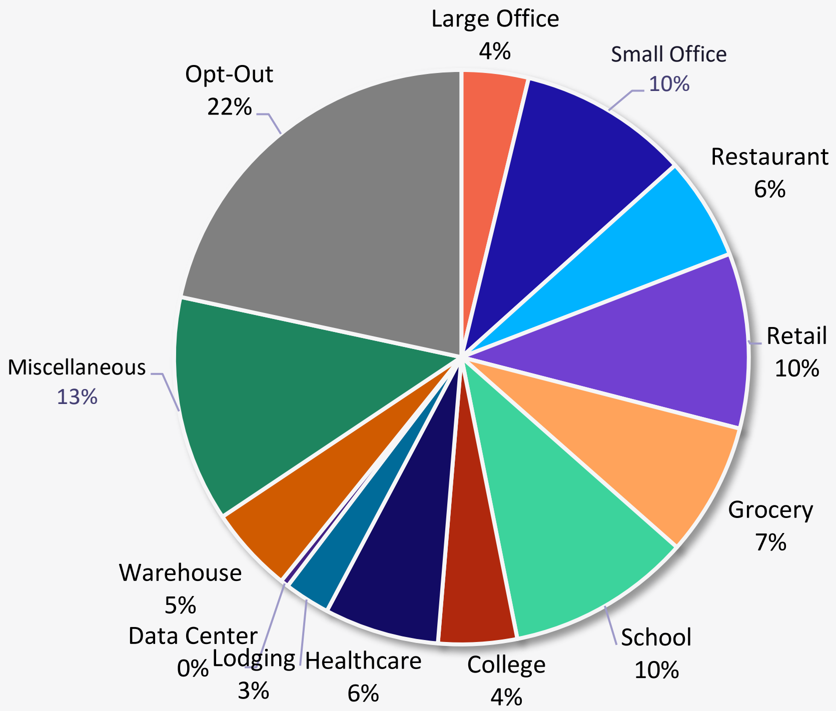


Cumulative GWh	2024	2025	2026	2029	2033
Realistic Achievable Potential					
Single Family	10.7	11.0	11.2	11.8	14.2
Multifamily	0.6	0.6	0.7	0.7	0.8
Single Family - Low Income	0.8	0.8	0.8	0.8	1.0
Multifamily - Low Income	0.2	0.2	0.2	0.2	0.2
Total	**12.2**	**12.6**	**12.8**	**13.5**	**16.3**
Total Low-Income	***0.9***	***0.9***	***0.9***	***1.0***	***1.2***
Maximum Achievable Potential					
Single Family	16.8	17.1	17.0	17.0	19.3
Multifamily	1.0	1.0	1.0	1.0	1.2
Single Family - Low-Income	1.1	1.1	1.1	1.1	1.3
Multifamily - Low-Income	0.2	0.2	0.2	0.2	0.3
Total	**19.1**	**19.4**	**19.3**	**19.3**	**22.0**
Total Low-Income	***1.3***	***1.3***	***1.3***	***1.3***	***1.6***

Commercial Potential



Commercial Market Characterization

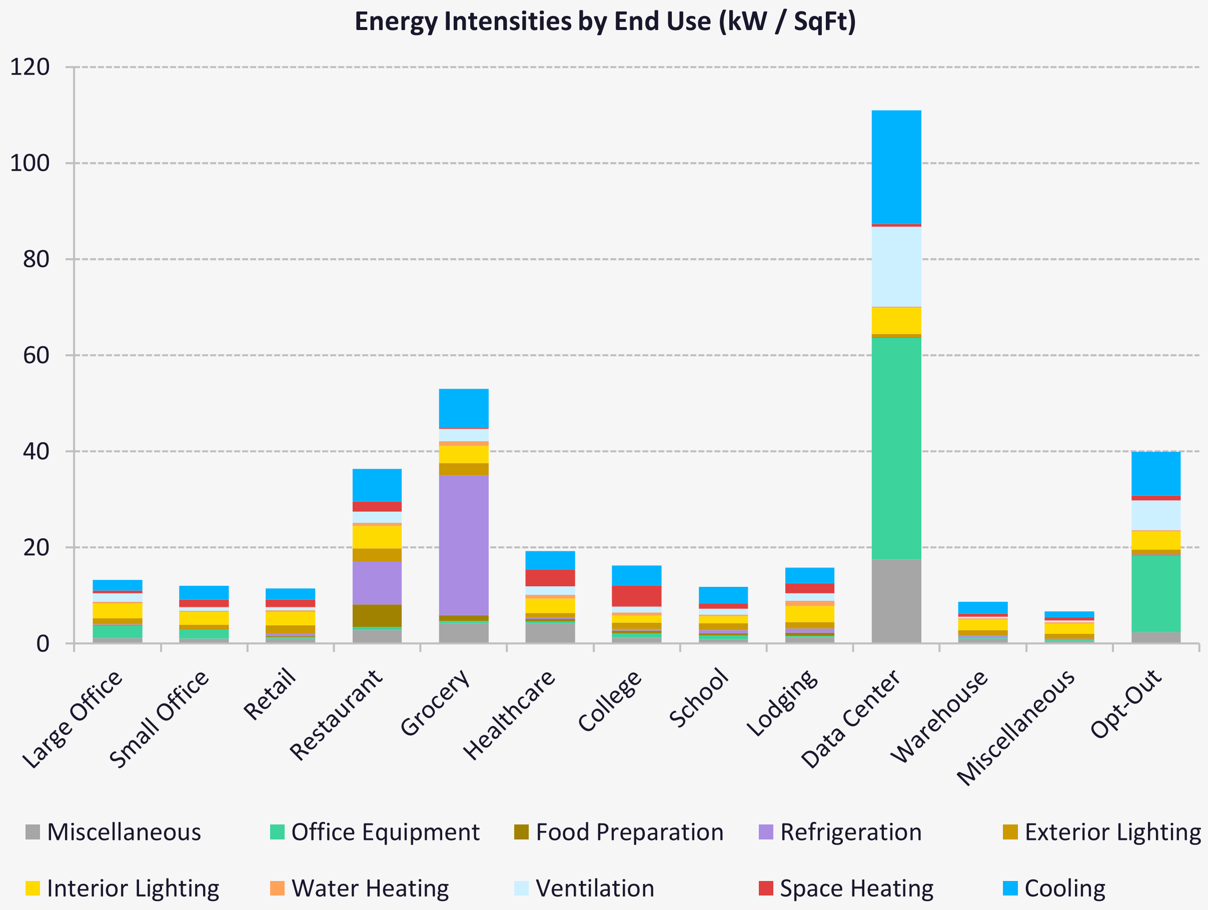


Segment	Electric Use (GWh)	% of Total	Floor Space (Million sqft)	Intensity (kWh/sqft)
Large Office	121.6	4%	9.21	13.20
Small Office	309.5	10%	25.79	12.00
Retail	318.2	10%	5.16	36.36
Restaurant	187.4	6%	27.85	11.42
Grocery	242.5	8%	4.58	52.99
School	335.0	10%	28.48	11.76
College	143.0	4%	8.85	16.16
Healthcare	208.3	6%	10.83	19.24
Lodging	83.3	3%	5.28	15.78
Data Center	14.5	0%	0.13	110.92
Warehouse	156.5	5%	18.05	8.67
Miscellaneous	411.5	13%	62.30	6.60
Opt-Out	698.8	22%	17.54	39.85
Commercial Total	**3,230.0**	**100%**	**224**	**14.42**

- AEG categorized commercial accounts into segments using customer SIC and business data from Evergy.
- Miscellaneous, Small Office, Retail, and School segments dominate the commercial load.
  - The Miscellaneous segment includes nonresidential/non-manufacturing spaces not elsewhere classified or difficult to classify.
- Customers opting out of Evergy programs are separated into their own segment to avoid overstating program potential.

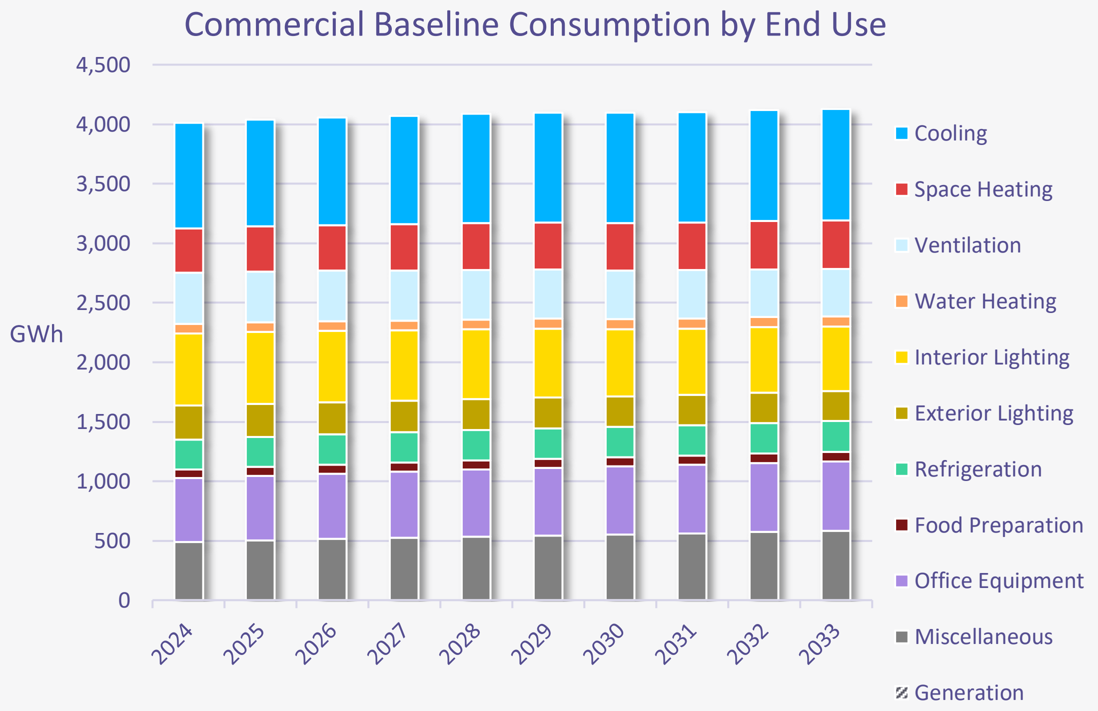
Commercial Market Profiles

- Just like residential, the commercial market profile disaggregates the nonresidential loads into end uses and technologies, calibrating to the appropriate total intensity.
- Key Data Sources
  - Evergy Billing and Load Research Data
  - EIA Commercial Buildings Energy Consumption Survey
  - U.S. DOE Solid State Lighting Forecast Report
  - EIA Annual Energy Outlook
  - AEG Data and Energy Market Profiles



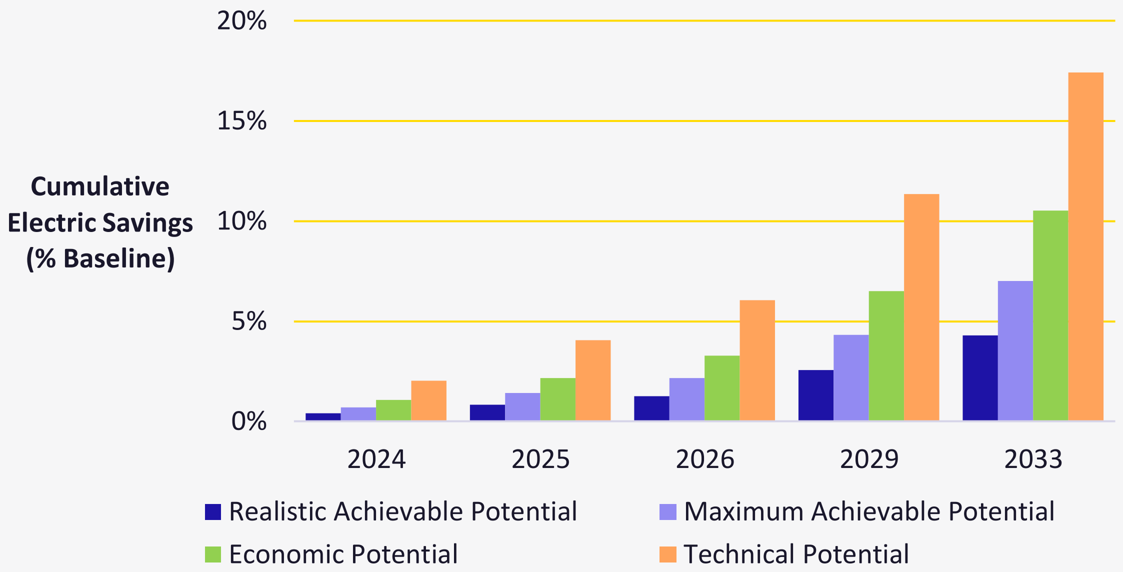
Commercial Baseline Projection

- Project a reference baseline for potential that **excludes** future DSM efforts.
- Accounts for:
  - Differences in sector and segment
  - Base-year market characterization
  - Customer growth
  - Codes and standards
  - Equipment turnover rates
  - Efficient measure penetration
  - Trends in equipment saturations
  - Weather (CDD, HDD) and other forecast drivers provided by Evergy



Commercial Potential Results

- By 2026, cumulative RAP is 43.9 GWh, or 1.3% of the reference baseline. By 2033, this increases to 152.4 GWh, or 4.3% of the baseline.
  - This is an average of 0.4% per year.
- MAP reaches 75.9 GWh by 2026, and 248.5 GWh by 2033.



	2024	2025	2026	2029	2033
Baseline Projection (GWh)	3,460	3,482	3,497	3,525	3,549
Cumulative Savings (GWh)					
Realistic Achievable Potential	14	29	44	90	152
Maximum Achievable Potential	25	50	76	152	249
Economic Potential	37	76	115	230	374
Technical Potential	71	141	212	401	618
Cumulative as % of Baseline					
Realistic Achievable Potential	0.4%	0.8%	1.3%	2.6%	4.3%
Maximum Achievable Potential	0.7%	1.4%	2.2%	4.3%	7.0%
Economic Potential	1.1%	2.2%	3.3%	6.5%	10.5%
Technical Potential	2.0%	4.1%	6.1%	11.4%	17.4%

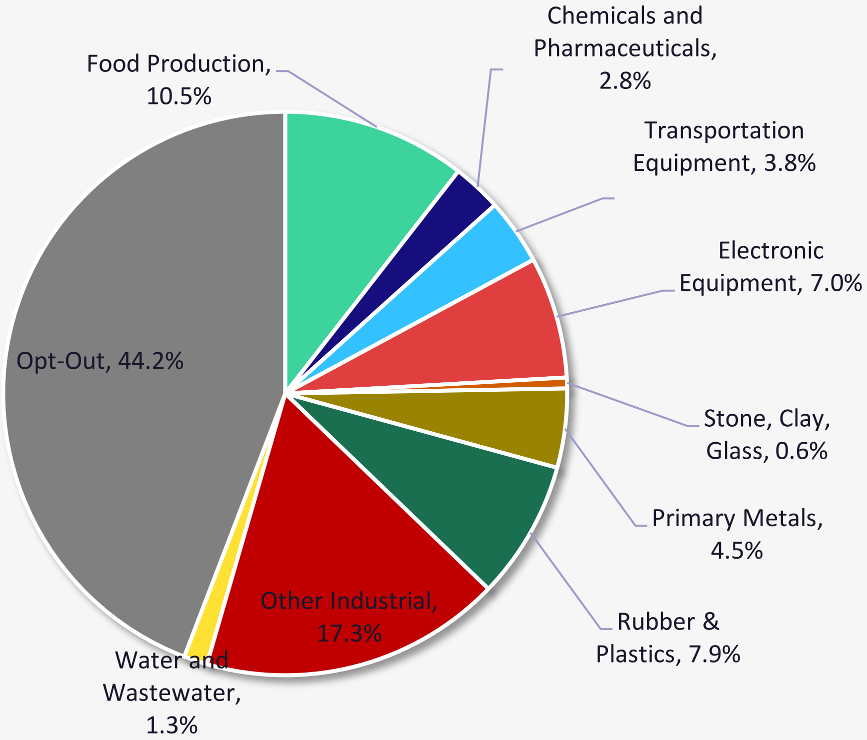
Commercial Top Measures - RAP

- Linear Lighting, Retrocommissioning, and Rooftop Unit (RTU) upgrades have the most significant potential savings.
  - There is significant LED penetration in the baseline for linear and high bay, but this measure is a bundle with embedded controls at the time of fixture replacement, which gives savings above a simple LED.
- Because not all electronics (computers, servers, desktop monitors, etc.) purchased are ENERGY STAR certified, these measures have significant savings potential.
  - However, it can be difficult to incentivize this behavior due to the low/no cost difference between ENERGY STAR and non-certified units.

Rank	Measure Name	Cumulative Savings (MWh) 2026	% of Total
1	Linear Lighting (LED 2020 (109 lm/W system) w/ Controls)	11,743	27.1%
2	Retrocommissioning	5,224	12.1%
3	RTU (IEER 18.0 - ENERGY STAR (4.0))	5,010	11.6%
4	Ventilation - Demand Controlled (Outdoor air controlled based on occupancy to meet ASHRAE 62.1)	3,016	7.0%
5	Exempted Lighting (LED 2020 (95 lm/W))	2,790	6.5%
6	High-Bay Lighting (LED 2020 (132 lm/W) w/ Controls)	2,729	6.3%
7	Server (ENERGY STAR (3.0))	1,384	3.2%
8	Water-Cooled Chiller (COP 12.13 (0.29 kW/ton))	1,098	2.5%
9	Ventilation - Variable Speed Control (VSD on fan motor)	844	2.0%
10	RTU - Advanced Controls (Advanced controls on roof top unit)	788	1.8%
11	HVAC - Maintenance (Tune-up of unitary HVAC systems)	776	1.8%
12	Griddle (ENERGY STAR (1.2))	704	1.6%
13	POS Terminal (ENERGY STAR (7.1))	661	1.5%
14	Ducting - Repair and Sealing (Sealed)	621	1.4%
15	Advanced New Construction Designs (exceeding ASHRAE 90.1 requirements)	616	1.4%
16	Refrigeration - High Efficiency Compressor	586	1.4%
17	Refrigeration - Floating Head Pressure (Wetbulb Reset Controls)	473	1.1%
18	Oven (ENERGY STAR (2.2))	382	0.9%
19	Area Lighting (LED 2020 (120 lm/W) w/ Controls)	365	0.8%
20	Connected Thermostat - ENERGY STAR (1.0) (Thermostat connected to building management control system)	333	0.8%
	Total of Top 20 Measures	**40,142**	**92.8%**
	Total Savings - All Measures	**43,871**	**100.0%**

Industrial Potential

Industrial Market Characterization

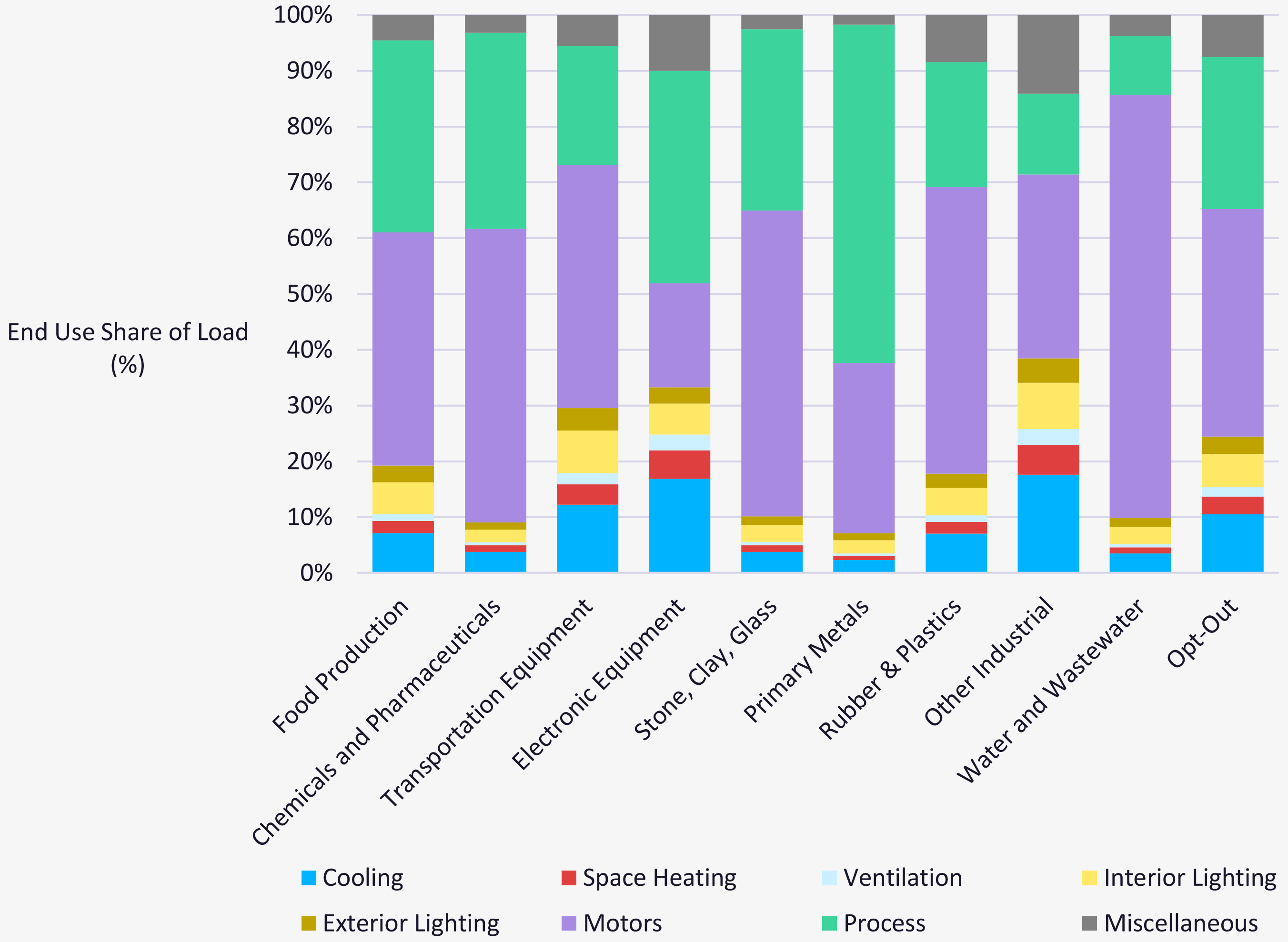


Segment	Electric Use (GWh)	% of Total
Food Production	145.6	11%
Chemicals & Pharmaceuticals	38.9	3%
Electronic Equipment	96.4	7%
Primary Metals	62.7	5%
Stone, Clay, Glass	8.6	1%
Transportation Equipment	52.4	4%
Rubber & Plastics	109.9	8%
Water & Wastewater	18.6	1%
Other Industrial	239.2	17%
Opt-Out	611.0	44%
Industrial Total	**1,383.3**	**100%**

- AEG categorized industrial accounts into segments using SIC codes and customer data from Evergy.
- A greater portion of Industrial facilities are eligible to opt out of programs compared to non-manufacturing commercial.
- The largest non-opt-out characterized segments are Other Industrial, Food Production, Electronic Equipment, and Rubber & Plastics.
- The Other Industrial segment includes the NAICS "Misc. Manufacturing" class and the tail of load in categories not elsewhere classified.

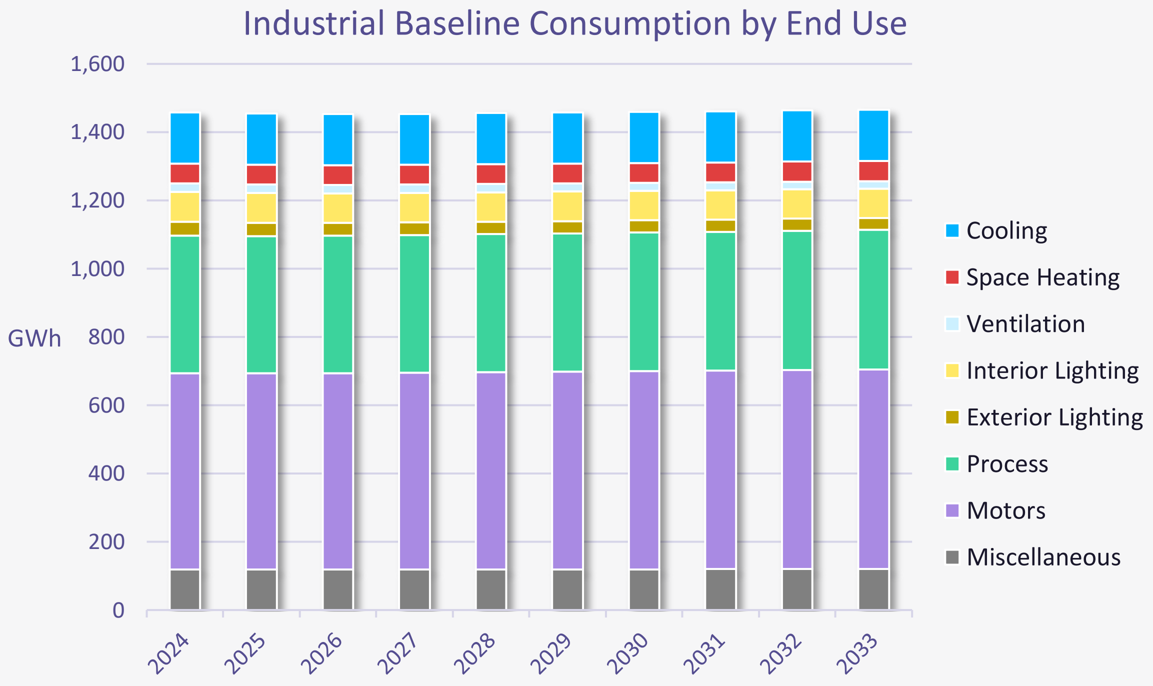
Industrial Market Profiles

- The industrial market profile disaggregates the loads into segments and intensity, calibrating to the appropriate total intensity.
- Key Data Sources
  - SIC codes by customer
  - U.S. DOE Manufacturing Energy Consumption Survey



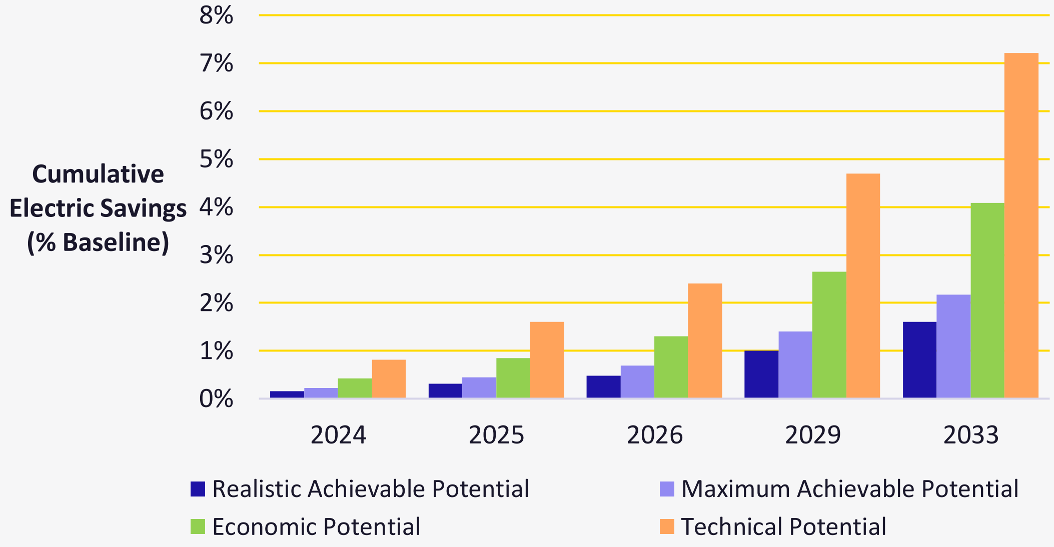
Industrial Baseline Projection

- Project a reference baseline for potential that **excludes** future DSM efforts.
- Accounts for:
  - Differences in sector and segment
  - Base-year market characterization
  - Customer growth
  - Codes and standards
  - Equipment turnover rates
  - Efficient measure penetration
  - Trends in equipment saturations
  - Weather (CDD, HDD) and other forecast drivers provided by Evergy



Industrial Potential Results

- By 2026, cumulative RAP is 7 GWh, or 0.5% of the reference baseline. By 2033, this increases to 23.4 GWh, or 1.6% of the baseline.
  - This is an average of 0.16% per year.
- MAP reaches 10 GWh by 2026, and 31.8 GWh by 2033.



	2024	2025	2026	2029	2033
Baseline Projection (GWh)	1,457	1,454	1,452	1,458	1,465
Cumulative Savings (GWh)					
Realistic Achievable Potential	2	5	7	15	23
Maximum Achievable Potential	3	7	10	21	32
Economic Potential	6	12	19	39	60
Technical Potential	12	23	35	69	106
Cumulative as % of Baseline					
Realistic Achievable Potential	0.2%	0.3%	0.5%	1.0%	1.6%
Maximum Achievable Potential	0.2%	0.5%	0.7%	1.4%	2.2%
Economic Potential	0.4%	0.9%	1.3%	2.7%	4.1%
Technical Potential	0.8%	1.6%	2.4%	4.7%	7.2%

Industrial Top Measures - RAP

- As in commercial, LED fixture replacements including bundles with controls provide savings opportunities, contributing more than half of Industrial potential.
- Ventilation and HVAC chillers have some savings, though HVAC is not the largest portion of Industrial load.
- System upgrades and optimizations for various processes and motor systems make up a long tail of smaller measures in the top 20.

Rank	Measure Name	Cumulative Savings (MWh) 2026	% of Total
1	High-Bay Lighting (LED 2020 (132 lm/W) w/ Controls)	2,437	36.1%
2	Linear Lighting (LED 2020 (109 lm/W system))	1,532	22.7%
3	Indoor Agriculture - LED Lighting	454	6.7%
4	Ventilation (Variable Air Volume)	392	5.8%
5	Water-Cooled Chiller (COP 12.13 (0.29 kW/ton))	272	4.0%
6	Advanced Industrial Motors	208	3.1%
7	Pumping System - System Optimization	182	2.7%
8	Compressed Air - End Use Optimization	167	2.5%
9	Paper - Efficient Agitator	159	2.4%
10	Fan System - Equipment Upgrade	135	2.0%
11	Compressed Air - Variable Speed Drive	114	1.7%
12	Air-Cooled Chiller (COP 4.10 (IPLV 14.0))	105	1.6%
13	Pumping System - Variable Speed Drive	98	1.4%
14	Pumping System - Equipment Upgrade	74	1.1%
15	Refrigeration - System Maintenance	70	1.0%
16	Refrigeration - System Upgrade	70	1.0%
17	Material Handling - Variable Speed Drive	66	1.0%
18	Compressed Air - Equipment Upgrade	47	0.7%
19	Fan System - Variable Speed Drive	44	0.7%
20	Compressed Air - System Controls	36	0.5%
	Total of Top 20 Measures	**6,664**	**98.8%**
	Total Savings - All Measures	**6,954**	**100.0%**

DR/DSR Potential Analysis

DR and DSR Potential Approach

- General methodology for estimating DR and DSR potential is similar to energy efficiency
- Our approach accounts for two key differences:
  - **Neither exists outside of a programmatic structure (i.e., there is no naturally occurring DR)**
  - **Focus on Maximum Achievable and Realistic Achievable Potential**

Market Characterization
- Leverage EE Analysis Alignment
- Segment by Sector, Geography and Size vs. Building Type

Identify and Characterize Measures
- DLC Measure Options
- DR Economic Options
- DSR Options

Baseline Projection
- Leverage EE Analysis for alignment
- Use DR Segmentation
- Account for Interactions

Potential Estimation
- Technical Achievable
- Maximum Achievable
- Realistic Achievable

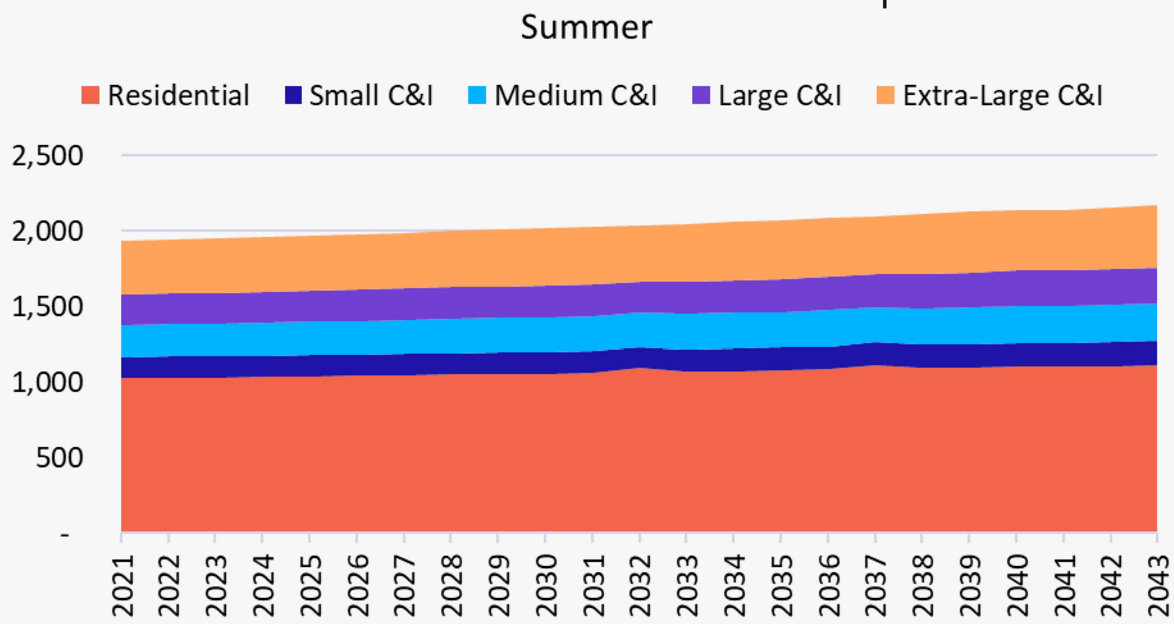
Market Characterization

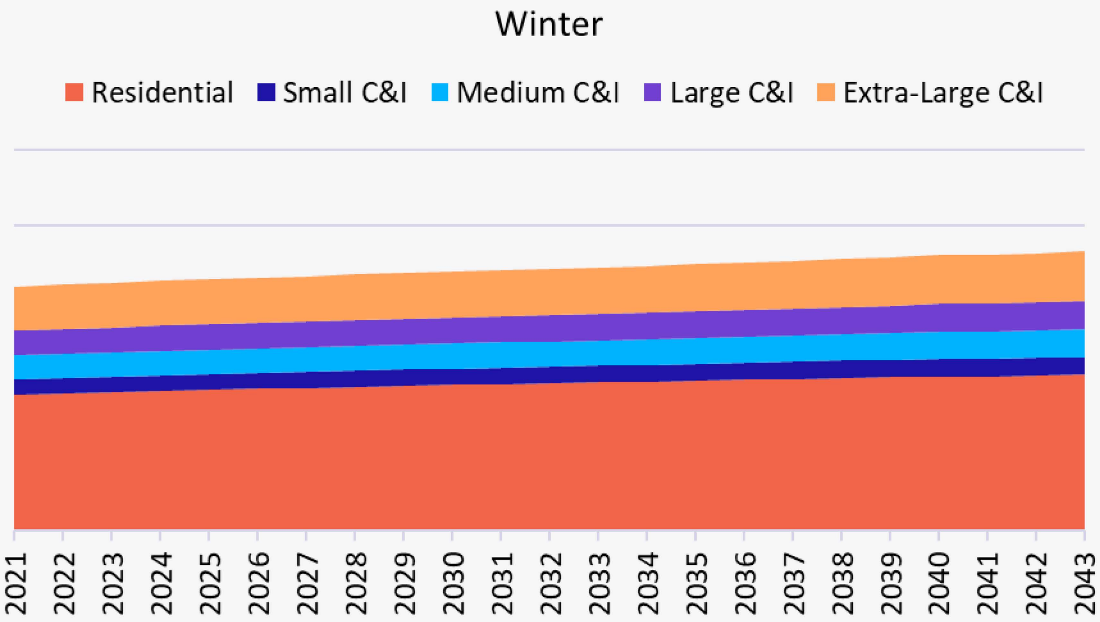
Used billing data to segment C&I customers into size bins (max annual peak)

Small C&I	< 30 kW
Medium C&I	≥ 30 kW, < 150 kW
Large C&I	≥ 150 kW, < 1,000 kW
Extra-Large C&I	> 1,000 kW

Residential consumption accounts for ~50% of Evergy West peak demand in both summer and winter.

C&I winter peak demand is 20%-35% less than winter peak across size bins. Residential winter peak demand reaches ~10% of summer peak demand.





Program Characterization

DR Options	DSR Options
DLC – End Use • Connected Thermostats – Res and C&I • Switches (heating/cooling) • Smart Homes • Electric Vehicles • Water Heating (including grid-interactive models) • Smart Solar PV Inverter • Battery Storage • Thermal Energy Storage **Economic – Whole Facility** • Firm Curtailment/Tariff • C&I Automatic DR (ADR) • Residential Behavioral Demand Response	**Rate-Based** • Critical Peak Pricing • Time-Related Pricing • Time-of-Use Rates • TOU Rate for EV Owners

Participation rates

- Define eligible customers for each given option and reflect appliance saturation rates, customer segmentation, and the hierarchy

Customer impacts

- Percentages or kW values that reflect the total load reduction during an event

Participant/program costs

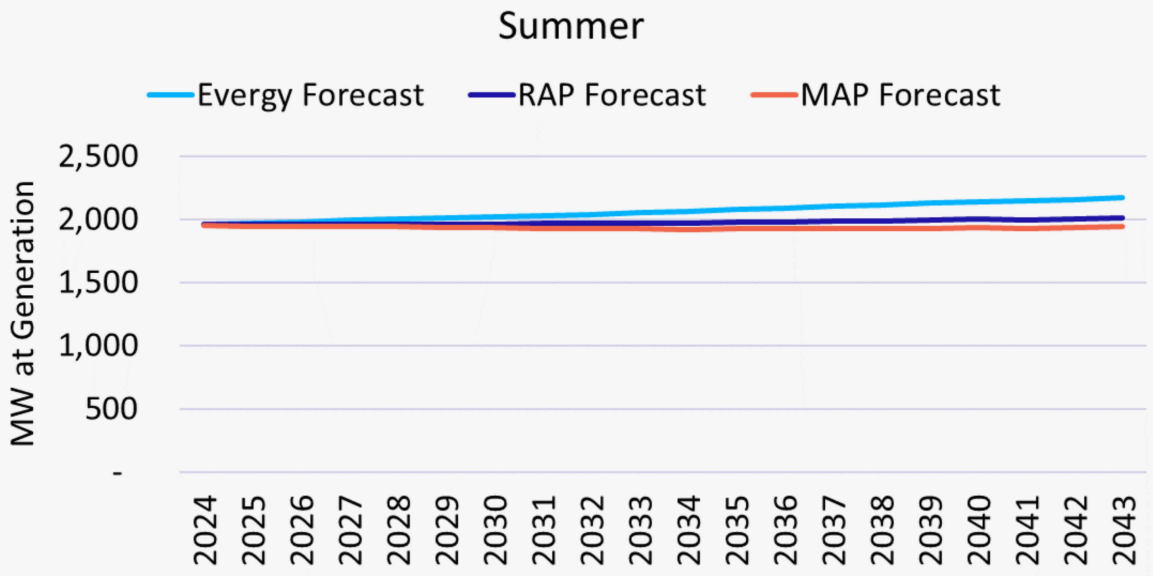
- Incentives and enabling technology costs, program development and administration costs, marketing and recruitment costs, O&M costs

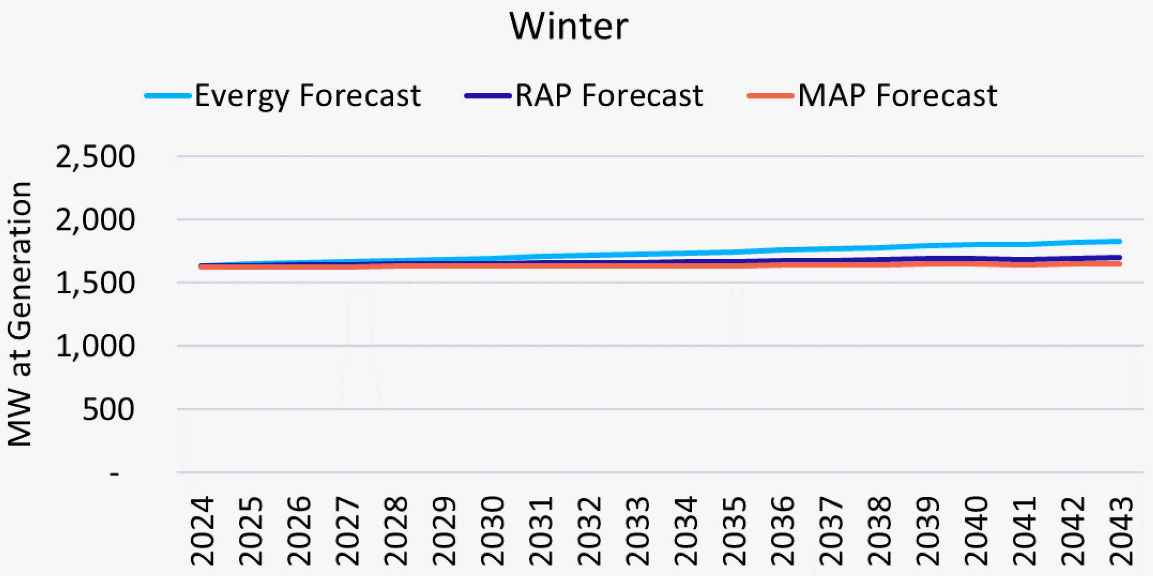
Per customer coincident peak load × % impact × # of eligible customers = MW Impact

Baseline Projection

AEG developed the baseline peak demand forecasts by:

- Using the Evergy peak demand forecast by sector and territory
- Removing the peak demand savings potential generated through energy efficiency adoption forecasted in the MAP and RAP scenarios
- Summer baseline dropped by 8% (RAP) and 11% (MAP) by 2043





MAP Scenario

MAP Scenario

The Maximum Achievable Potential (MAP) scenario:

- Included all cost-effective programs
- Incorporated growth in Evergy's existing programs to benchmarked participation levels
- Lowered baseline projection for the peak demand savings generated through MAP-forecasted energy efficiency adoption.

MAP Sensitivity Analysis:

The Missouri PSC ordered Evergy to transition all residential customers to mandatory TOU rates by October 1, 2023.

In response, AEG and Evergy focused the MAP analysis on how the mandatory TOU rates would affect the baseline projection.

Customer response to pricing signals will reduce the demand available for other DR programs to impact during peak hours.

MAP Sensitivity Analysis

Evergy plans to offer four residential TOU rates:

All residential customers will be transitioned to the TOU Standard Rate by October 2023.

TOU Standard (4:1)

Customers will opt-out within the first year

- **TOU for EV Owners (10-12:1)** — EV owners will opt into the EV TOU rate (20%, 50%, and 100%)
- **Peak Adjustment Rate (~1:1)** — 95% of non-EV owner opt-outs will move to the Peak Adjustment Rate
- **TOU 3-Period (6:1)** — Remaining opt-outs will move to the 3P rate

How the TOU rate order affects residential peak demand depends on (1) TOU Standard customer retention and (2) the TOU rate that opt-out customers move onto instead.

MAP Sensitivity Analysis

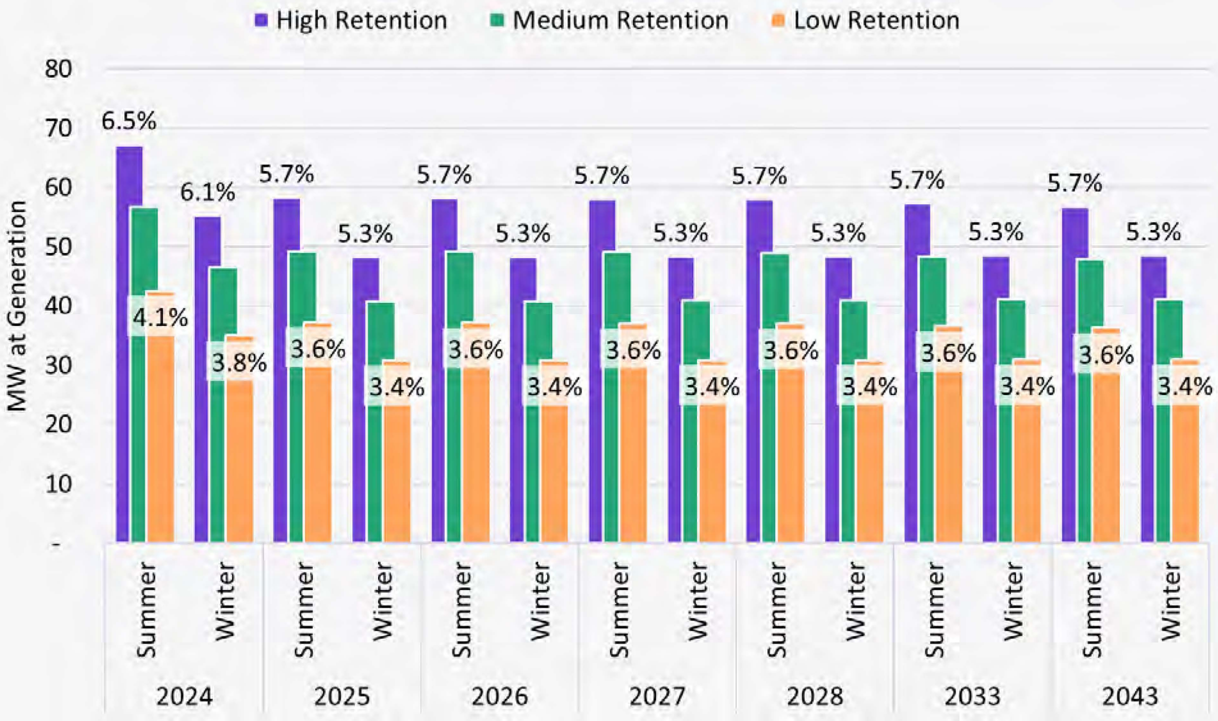
AEG analyzed two sensitivities in addition to the MAP scenario (which is based on a low retention rate of 50%).

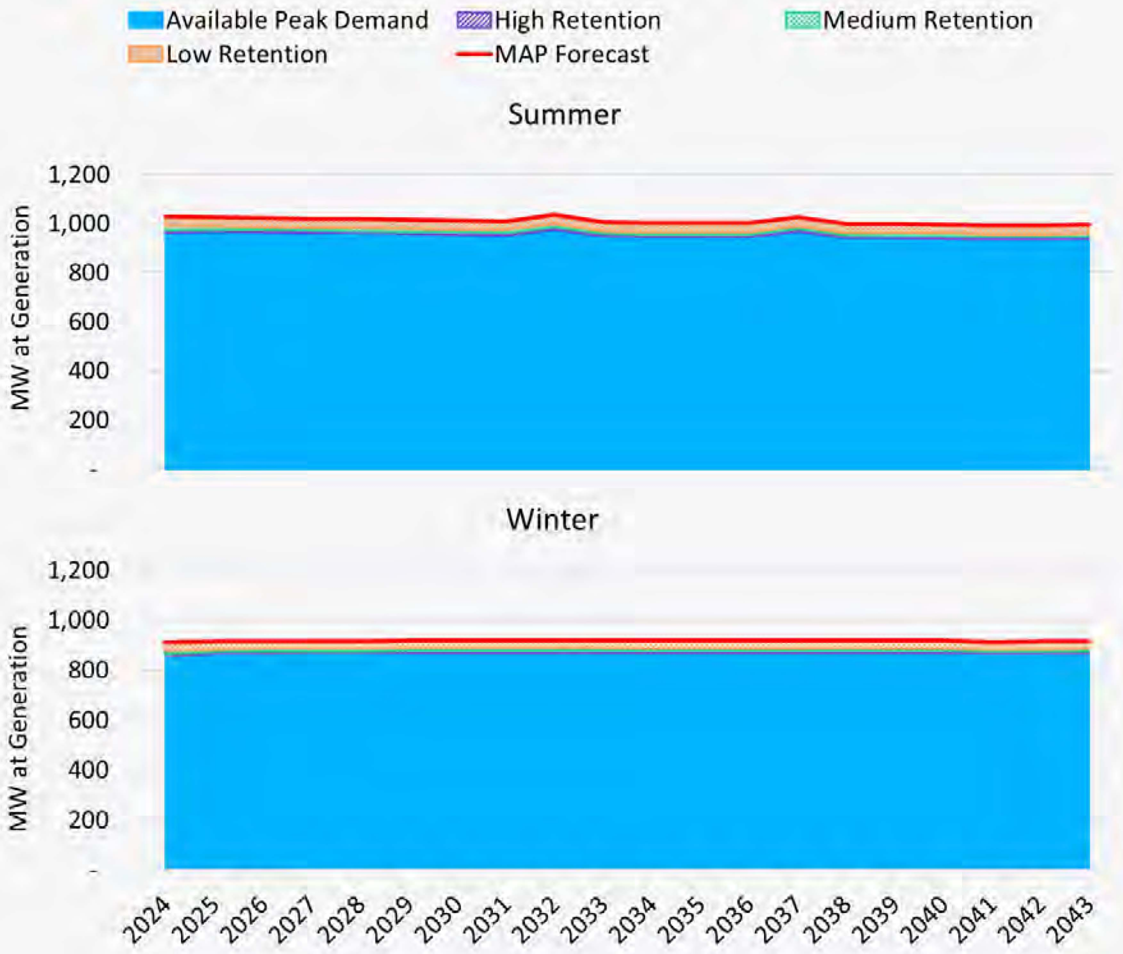
- The Medium- and Low-Retention sensitivities increase the impacts from the mandatory TOU rates and reduce the demand available for other DR program options.

Sensitivity	TOU Standard	TOU for EV Owners	Peak Adjustment Rate	3-Period TOU
MAP	50% of all residential customers	20% of EV owners who opt out of TOU Standard	95% of remaining TOU Standard opt-outs	Other TOU Standard opt-outs
MAP Medium-Retention	70% of all residential customers	50% of EV owners who opt out of TOU Standard	95% of remaining TOU Standard opt-outs	Other TOU Standard opt-outs
MAP High - Retention	85% of all residential customers	100% of EV owners who opt out of TOU standard	95% of remaining TOU Standard opt-outs	Other TOU Standard opt-outs

MAP Sensitivity Analysis

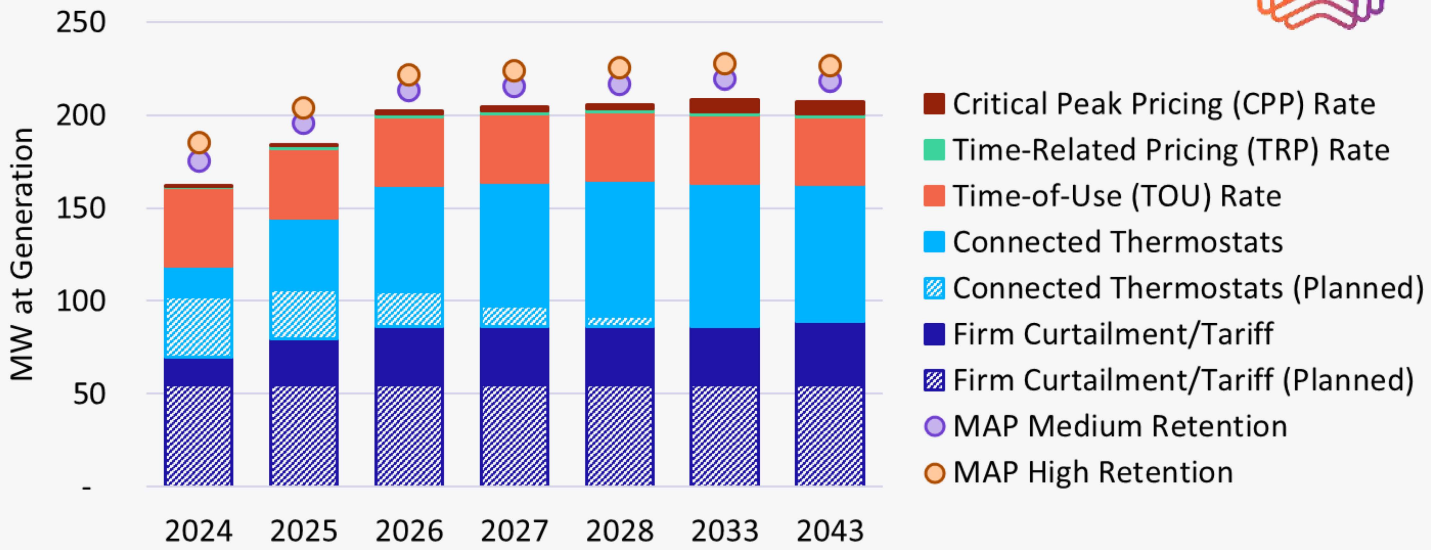
By 2043, the TOU rates reduce the summer residential peak demand baseline by 3.6%-5.7% (3.4%-5.3% in winter). While impacts are not insignificant (36 MW-57 MW in summer), the adjustments relative to the MAP baseline are small.





MAP Summer Potential Results

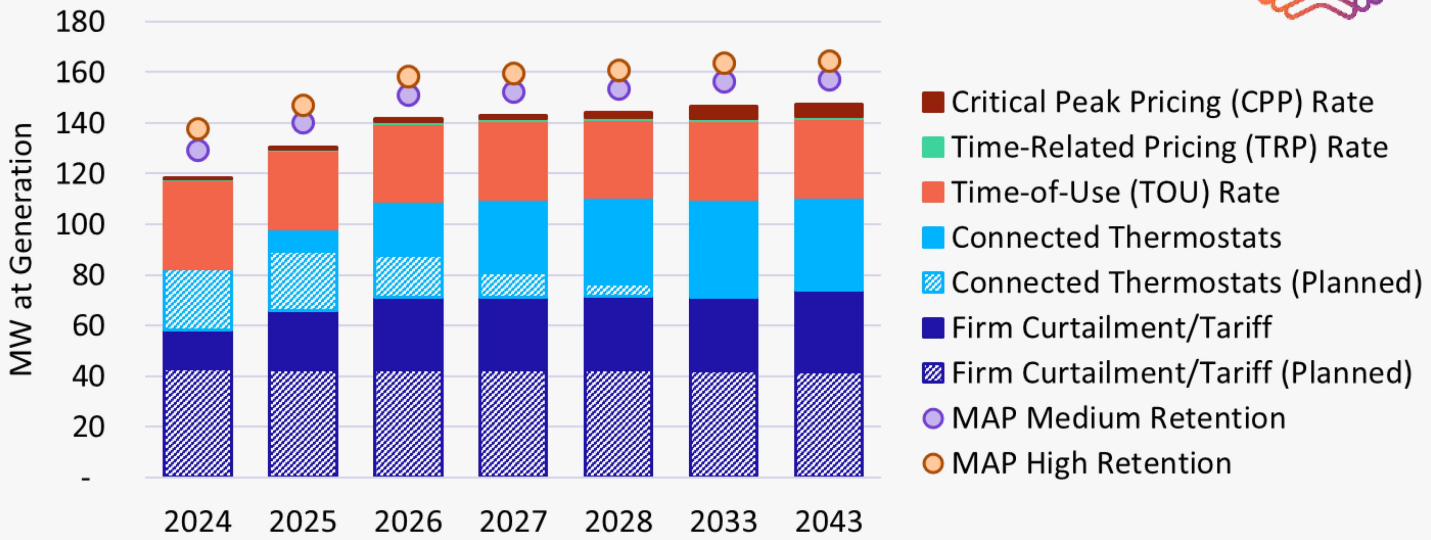
- By 2043, DR/DSR potential is estimated to reduce the summer peak demand baseline by 10%.
  - Firm Curtailment and Connected Thermostats generate over 7% of this reduction and account for nearly 80% of the 2043 DR/DSR potential.
  - TOU rates contribute another 17% to total potential in 2043 and reduce the baseline by another 2%.
  - Over 40% of the potential comes from planned (and existing) programs.
- MAP Medium- and High-Retention analyses increase total summer potential by 11 MW-19 MW.
  - As TOU impacts increase, impacts from other DR resources decrease, netting out some of the mandatory rate effects.



Program Option	MW at Generation (% of Baseline)						
	2024	2025	2026	2027	2028	2033	2043
Firm Curtailment/Tariff (Planned)	55 (3%)	55 (3%)	55 (3%)	55 (3%)	55 (3%)	55 (3%)	55 (3%)
Firm Curtailment/Tariff	15 (1%)	25 (1%)	31 (2%)	31 (2%)	31 (2%)	31 (2%)	34 (2%)
Connected Thermostats (Planned)	33 (2%)	26 (1%)	18 (1%)	11 (1%)	6 (0%)	0 (0%)	0 (0%)
Connected Thermostats	16 (1%)	39 (2%)	57 (3%)	66 (3%)	73 (4%)	77 (4%)	74 (3%)
Time-of-Use (TOU) Rate	43 (2%)	37 (2%)	37 (2%)	37 (2%)	37 (2%)	37 (2%)	36 (2%)
Time-Related Pricing (TRP) Rate	1 (0%)	2 (0%)	2 (0%)	2 (0%)	2 (0%)	2 (0%)	2 (0%)
Critical Peak Pricing (CPP) Rate	0 (0%)	1 (0%)	1 (0%)	2 (0%)	2 (0%)	7 (0%)	7 (0%)
MAP Total	162 (8%)	184 (9%)	202 (10%)	204 (10%)	206 (10%)	208 (10%)	207 (10%)
MAP Medium Retention	175 (9%)	195 (10%)	213 (11%)	215 (11%)	217 (11%)	219 (11%)	218 (10%)
MAP High Retention	185 (9%)	204 (10%)	222 (11%)	224 (11%)	225 (11%)	227 (11%)	226 (10%)

MAP Winter Potential Results

- By 2043, DR/DSR potential is estimated to reduce the winter peak demand baseline by 7%.
  - Firm Curtailment and Connected Thermostats generate over 5% of this reduction and account for over 75% of the 2043 DR/DSR potential.
  - TOU rates contribute another 21% to total potential in 2043 and reduce the baseline by another 1.4%.
  - Almost 30% of the potential comes from planned (and existing) programs.
- MAP Medium- and High-Retention analyses increase total summer potential by 10 MW-17 MW.
  - As TOU impacts increase, impacts from other DR resources decrease, netting out some of the mandatory rate effects.



Program Option	MW at Generation (% of Baseline)						
	2024	2025	2026	2027	2028	2033	2043
Firm Curtailment/Tariff (Planned)	43 (2%)	43 (2%)	43 (2%)	43 (2%)	43 (2%)	42 (2%)	42 (2%)
Firm Curtailment/Tariff	15 (1%)	23 (1%)	29 (1%)	29 (1%)	29 (1%)	29 (1%)	32 (1%)
Connected Thermostats (Planned)	25 (1%)	23 (1%)	16 (1%)	10 (0%)	5 (0%)	0 (0%)	0 (0%)
Connected Thermostats	0 (0%)	9 (0%)	22 (1%)	29 (1%)	34 (2%)	39 (2%)	37 (2%)
Time-of-Use (TOU) Rate	35 (2%)	31 (2%)	31 (2%)	31 (2%)	31 (2%)	31 (2%)	31 (1%)
Time-Related Pricing (TRP) Rate	0 (0%)	1 (0%)	1 (0%)	1 (0%)	1 (0%)	1 (0%)	1 (0%)
Critical Peak Pricing (CPP) Rate	0 (0%)	1 (0%)	1 (0%)	1 (0%)	2 (0%)	5 (0%)	5 (0%)
MAP Total	118 (6%)	130 (7%)	142 (7%)	143 (7%)	144 (7%)	147 (7%)	148 (7%)
MAP Medium Retention	129 (7%)	140 (7%)	151 (8%)	152 (8%)	154 (8%)	156 (8%)	157 (7%)
MAP High Retention	138 (7%)	147 (7%)	158 (8%)	160 (8%)	161 (8%)	163 (8%)	164 (8%)

RAP Scenario

RAP Scenario

The Realistic Achievable Potential (RAP) scenario:

- Included all cost-effective programs
- Restricted growth in Evergy's existing programs to current achieved participation levels
- Lowered baseline projection for the peak demand savings generated through RAP-forecasted energy efficiency adoption
- Used the TOU Low-Retention rate of 50% and dampened TOU impacts for the first few years to simulate a learning curve (i.e., assuming customers become more effective at responding appropriately to pricing signals over time)

RAP Sensitivity Analysis:	Tested the sensitivity of DR/DSR potential to changes in participation rates in all program options.

RAP Sensitivity Analysis

AEG analyzed two sensitivities in addition to the RAP scenario.

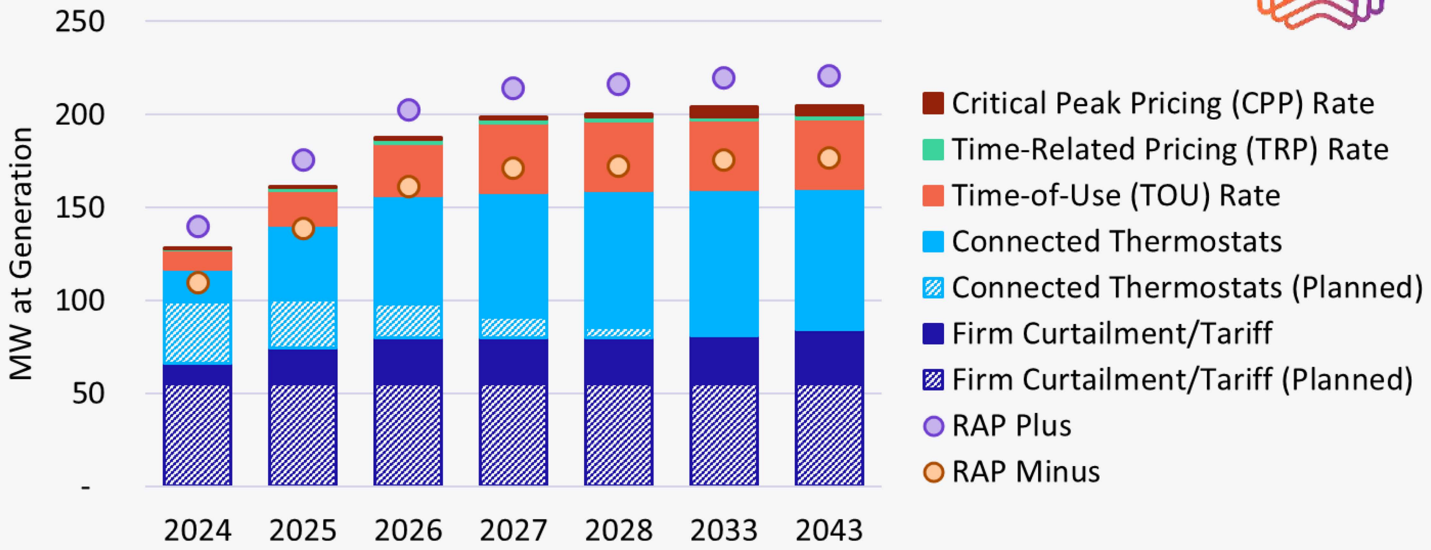
- The RAP Plus scenario increases participation in DR/DSR program options, providing an upper bound around potential under RAP circumstances.
- The RAP Minus scenario provided a lower bound around potential.

Sensitivity	Participation Adjustments	Cost Adjustments	TOU Standard Retention	TOU Impacts
RAP	N/A	N/A	50% of all residential customers	4-year learning curve
RAP Plus[1]	10% increase from RAP	No cost adjustment	50% of all residential customers	4-year learning curve
RAP Minus	15% decrease from RAP	No cost adjustment	43% of all residential customers (15% decrease from RAP)	4-year learning curve

[1]AEG did not increase the TOU retention rate (i.e., TOU Standard participation) in this sensitivity.

RAP Summer Potential Results

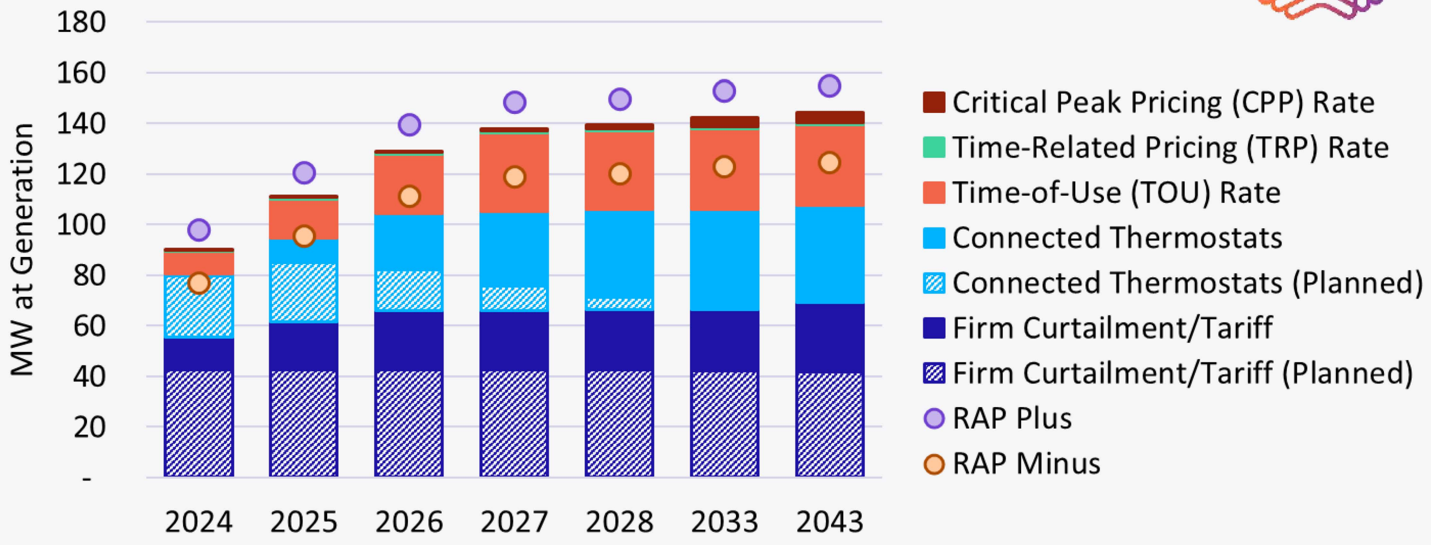
- By 2043, DR/DSR potential is estimated to reduce the summer peak demand baseline by 9%.
  - Firm Curtailment and Connected Thermostats generate over 7% of this reduction and account for nearly 80% of the 2043 DR/DSR potential.
  - TOU rates contribute another 18% to total potential in 2043 and reduce the baseline by another 2%.
  - Over 40% of the potential comes from planned (and existing) programs.
- RAP Plus increased potential by 16 MW
  RAP Minus decreased potential 28 MW



Program Option	MW at Generation (% of Baseline)						
	2024	2025	2026	2027	2028	2033	2043
Firm Curtailment/Tariff (Planned)	55 (3%)	55 (3%)	55 (3%)	55 (3%)	55 (3%)	55 (3%)	55 (3%)
Firm Curtailment/Tariff	11 (1%)	19 (1%)	25 (1%)	25 (1%)	25 (1%)	26 (1%)	29 (1%)
Connected Thermostats (Planned)	33 (2%)	26 (1%)	18 (1%)	11 (1%)	6 (0%)	0 (0%)	0 (0%)
Connected Thermostats	18 (1%)	40 (2%)	58 (3%)	67 (3%)	74 (4%)	79 (4%)	76 (4%)
Time-of-Use (TOU) Rate	11 (1%)	19 (1%)	28 (1%)	37 (2%)	37 (2%)	37 (2%)	37 (2%)
Time-Related Pricing (TRP) Rate	1 (0%)	2 (0%)	2 (0%)	2 (0%)	2 (0%)	2 (0%)	2 (0%)
Critical Peak Pricing (CPP) Rate	0 (0%)	1 (0%)	1 (0%)	1 (0%)	2 (0%)	5 (0%)	5 (0%)
RAP Total	128 (7%)	161 (8%)	187 (9%)	199 (10%)	200 (10%)	204 (10%)	205 (9%)
RAP Plus	140 (7%)	175 (9%)	203 (10%)	214 (11%)	216 (11%)	220 (11%)	221 (10%)
RAP Minus	110 (6%)	138 (7%)	161 (8%)	171 (9%)	172 (9%)	176 (9%)	177 (8%)

RAP Winter Potential Results

- By 2043, DR/DSR potential is estimated to reduce the winter peak demand baseline by 7%.
  - Firm Curtailment and Connected Thermostats generate 5% of this reduction and account for 75% of the 2043 DR/DSR potential.
  - TOU rates contribute another 22% to total potential in 2043 and reduce the baseline by another 1.5%.
  - Almost 30% of the potential comes from planned (and existing) programs.
- RAP Plus increased potential by 11 MW RAP Minus decreased potential 20 MW



Program Option	MW at Generation (% of Baseline)						
	2024	2025	2026	2027	2028	2033	2043
Firm Curtailment/Tariff (Planned)	43 (2%)	43 (2%)	43 (2%)	43 (2%)	43 (2%)	42 (2%)	42 (2%)
Firm Curtailment/Tariff	13 (1%)	19 (1%)	23 (1%)	23 (1%)	24 (1%)	24 (1%)	28 (1%)
Connected Thermostats (Planned)	25 (1%)	23 (1%)	16 (1%)	10 (0%)	5 (0%)	0 (0%)	0 (0%)
Connected Thermostats	1 (0%)	10 (1%)	22 (1%)	29 (1%)	35 (2%)	40 (2%)	38 (2%)
Time-of-Use (TOU) Rate	9 (0%)	15 (1%)	23 (1%)	31 (2%)	31 (2%)	32 (2%)	32 (1%)
Time-Related Pricing (TRP) Rate	0 (0%)	1 (0%)	1 (0%)	1 (0%)	1 (0%)	1 (0%)	1 (0%)
Critical Peak Pricing (CPP) Rate	0 (0%)	0 (0%)	1 (0%)	1 (0%)	1 (0%)	4 (0%)	4 (0%)
RAP Total	90 (5%)	111 (6%)	129 (7%)	138 (7%)	139 (7%)	142 (7%)	144 (7%)
RAP Plus	98 (5%)	121 (6%)	139 (7%)	148 (7%)	150 (7%)	153 (7%)	155 (7%)
RAP Minus	77 (4%)	96 (5%)	111 (6%)	119 (6%)	120 (6%)	123 (6%)	124 (6%)

Standalone Potential

Key Assumptions

Standalone potential provides a view of each program option in isolation, before accounting for any competition between DR/DSR resources.

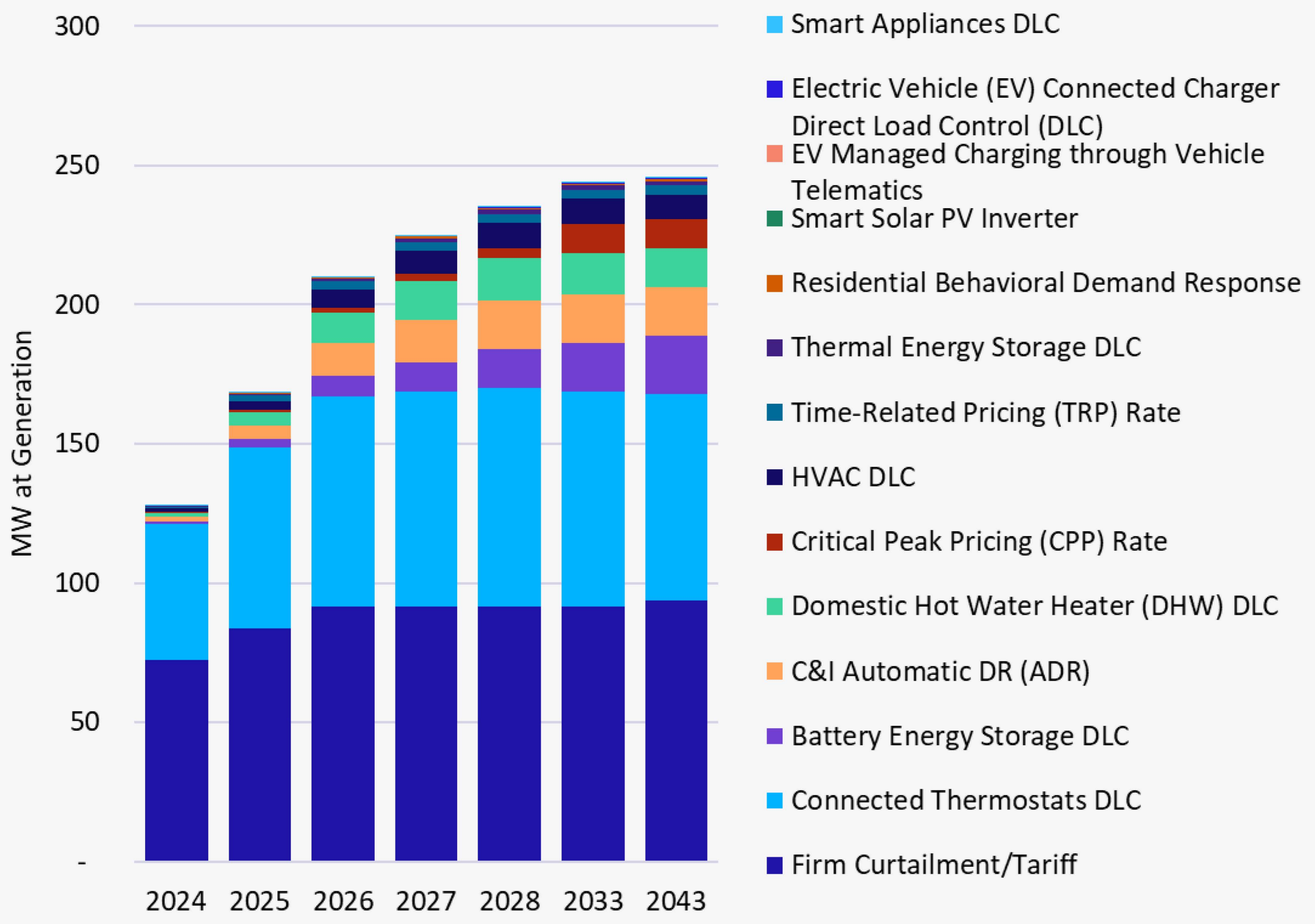
- Maximizes the potential each DR/DSR could provide if no other programs were offered that targeted the same demand during peak hours.
- The economic screen uses standalone potential, because programs will only become less cost-effective once program competition reduces the available capacity to target.

The economic screen identified cost-effective programs for inclusion in the MAP and RAP scenarios.

- Economic screening based on cumulative potential, i.e., including existing resources
- Only considered summer benefits
- Screen based on the Utility Cost Test, i.e., including incentive costs
- Modeled potential at the sector/segment level but screened for cost-effectiveness at the whole-program level
- If a program passed in one region, we included it in both.

Standalone Potential Results

- Existing programs contribute nearly double the summer potential generated by the remaining DR/DSR programs combined, even in 2043.
- After accounting for resource competition:
  - Participation in C&I programs like C&I Automatic DR and Thermal Energy Storage goes down because the Firm Curtailment program option targets these same customers
  - Participation in residential programs like Domestic Hot Water Heater DLC and EV Managed Charging decreases because the Connected Thermostats program targets the same customers



Economic Screen

- Evergy's existing programs and both C&I DSR options passed the economic screen.
- The C&I ADR program was on the edge of being cost-effective, but many of these customers will be captured through the Firm Curtailment program.
- Many programs fell short of the threshold because of installation costs (e.g., switches), equipment and O&M costs (e.g., Battery and Smart Solar PV DLC), and overhead costs.
- Residential Behavioral DR was saddled with full development and administrative costs, i.e., independent of an HER program.

Program Option	UCT
Firm Curtailment/Tariff	3.17
Connected Thermostats DLC	3.14
Time-Related Pricing (TRP) Rate	3.08
Critical Peak Pricing (CPP) Rate	2.10
C&I Automatic DR (ADR)	0.93
HVAC DLC	0.86
Domestic Hot Water Heater (DHW) DLC	0.52
Residential Behavioral Demand Response	0.19
Battery Energy Storage DLC	0.12
Electric Vehicle (EV) Connected Charger Direct Load Control (DLC)	0.12
Smart Solar PV Inverter	0.08
Smart Appliances DLC	0.04
EV Managed Charging through Vehicle Telematics	0.04
Thermal Energy Storage DLC	0.00

Thank You.

AEG
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DSM Market Potential Study Results – Evergy Metro

Prepared for: evergy

Date: May 9, 2023

Table of Contents

Reporting Format

- In support of Evergy's Missouri Integrated Resource Plan (IRP) and Missouri Energy Efficiency Investment Act (MEEIA) Cycle 4 regulations, this presentation summarizes assumptions, methods, inputs, and results of the Evergy Demand Side Management (DSM) Market Potential Study.
- Along with this presentation, we provide:
  - A workbook including detailed study inputs and results.
  - A comprehensive report.
- Consistent with 4 CSR 240-22.050, the potential study provides a credible estimation of technical, economic, and achievable potential over the next 20 years.

Energy Efficiency Potential Analysis

Energy Efficiency Potential Approach

Market Characterization

- Customer Segmentation
- Utility Data
- Residential Survey
- Secondary Data

Identify and Characterize Measures

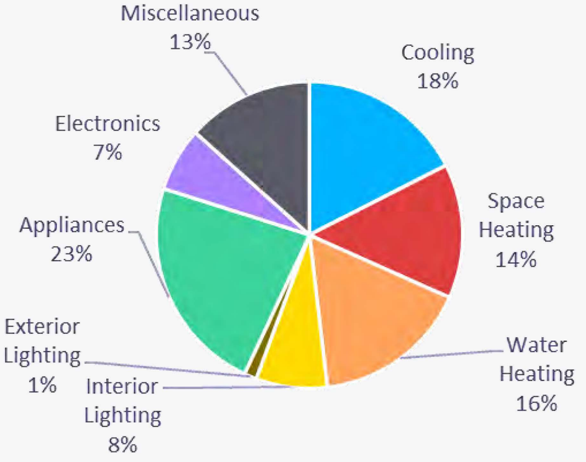
- Efficient Equipment
- Retrofit Opportunities
- Emerging Technologies

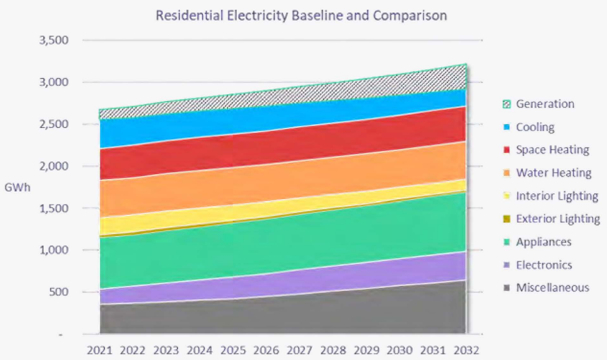
Baseline Projection

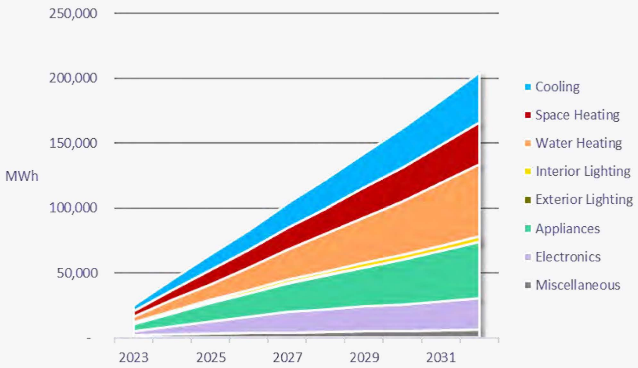
- Utility Forecasts
- Stock Turnover
- Codes and Standards

Potential Estimation

- Technical, Economic, and Achievable (MAP and RAP)
- Benchmarked against recent program history

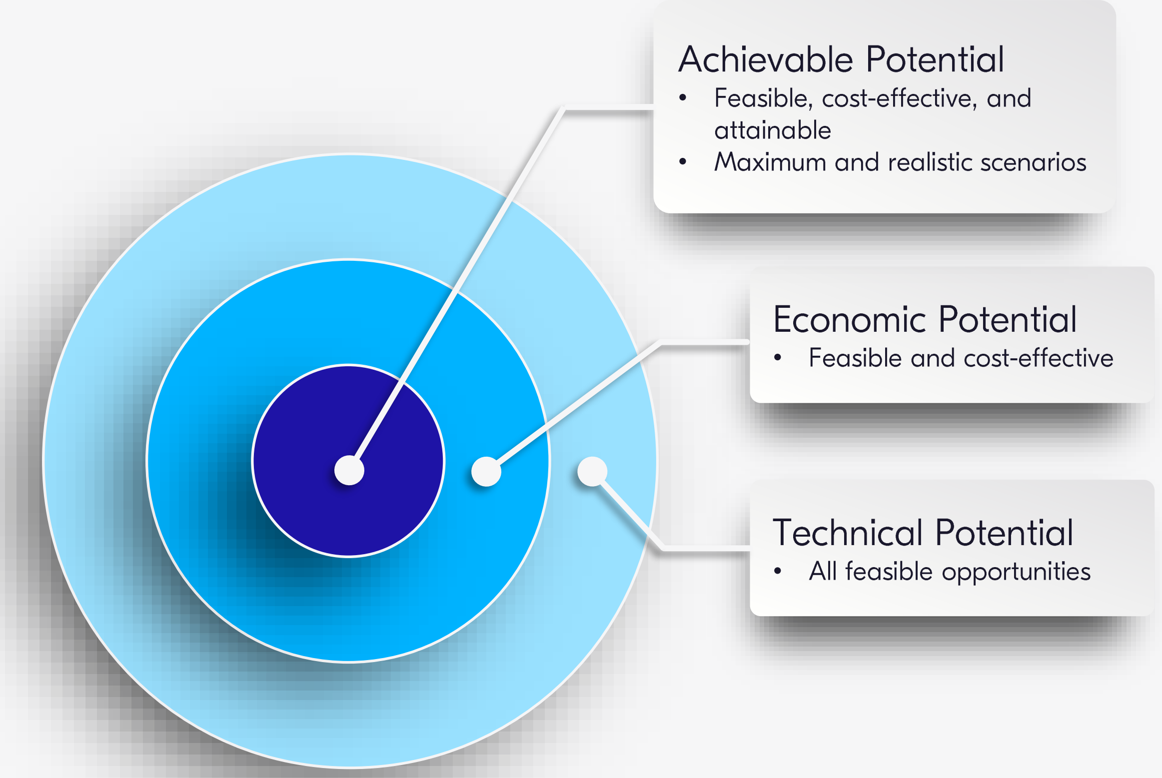






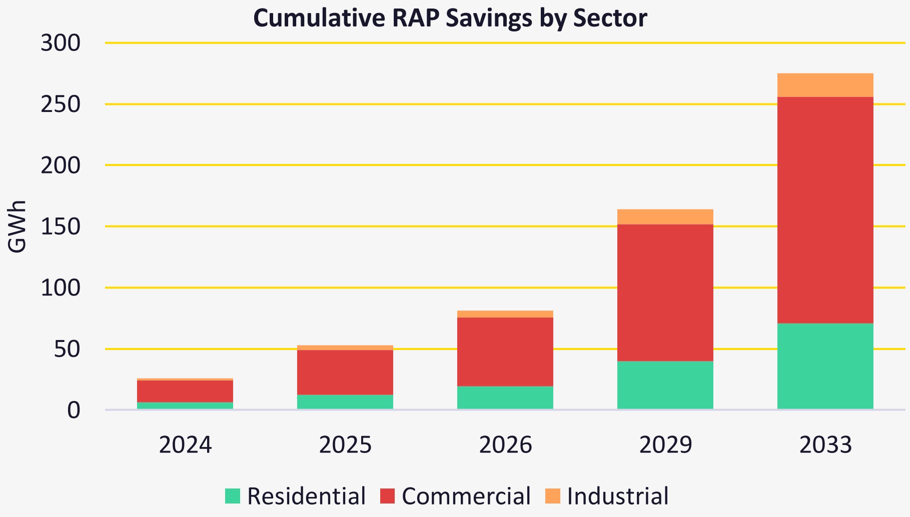
Estimating Energy Efficiency Potential

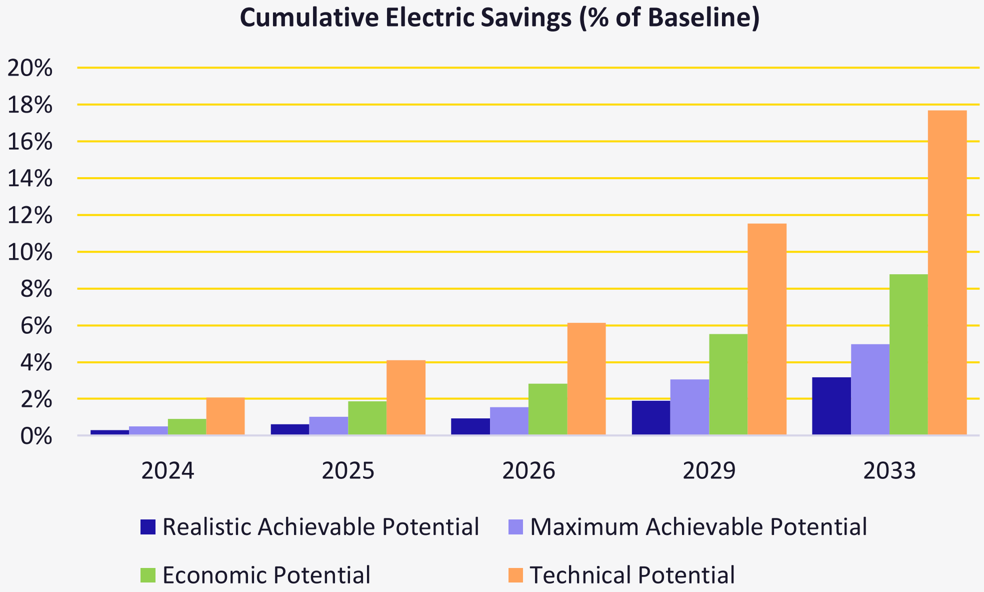
- Potential was estimated by creating an alternate sales forecast incorporating efficient measure adoption and calculating the change from the baseline
- AEG calculated three distinct levels of potential: Technical, Economic, and Achievable
- Achievable potential was assessed under two scenarios:
  - Realistic Achievable Potential (RAP)
  - Maximum Achievable Potential (MAP)

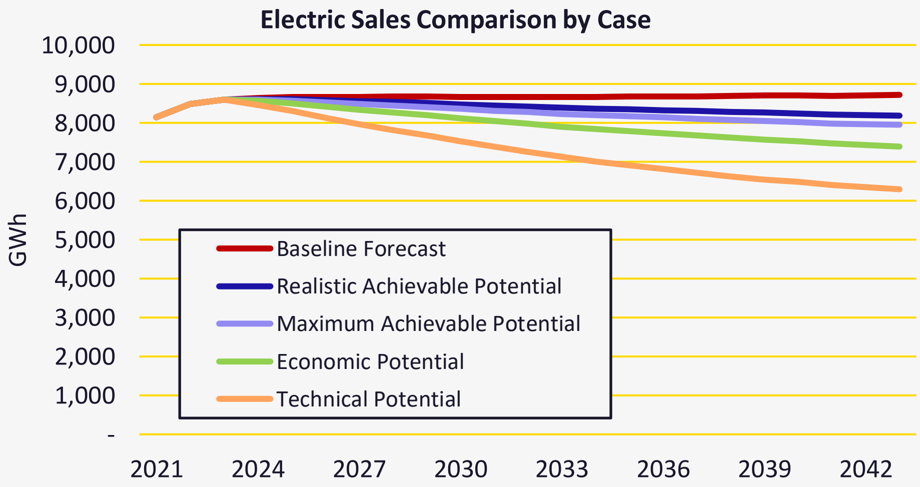


EE Potential Results – Evergy Metro Summary

- Cumulative RAP savings are 81.2 GWh by 2026 and 275.3 GWh by 2033, an average of 0.3% of the baseline per year.
- The Commercial sector contributes the most savings.
- Cooling contributes the most to savings, followed by Commercial Lighting and Space Heating.

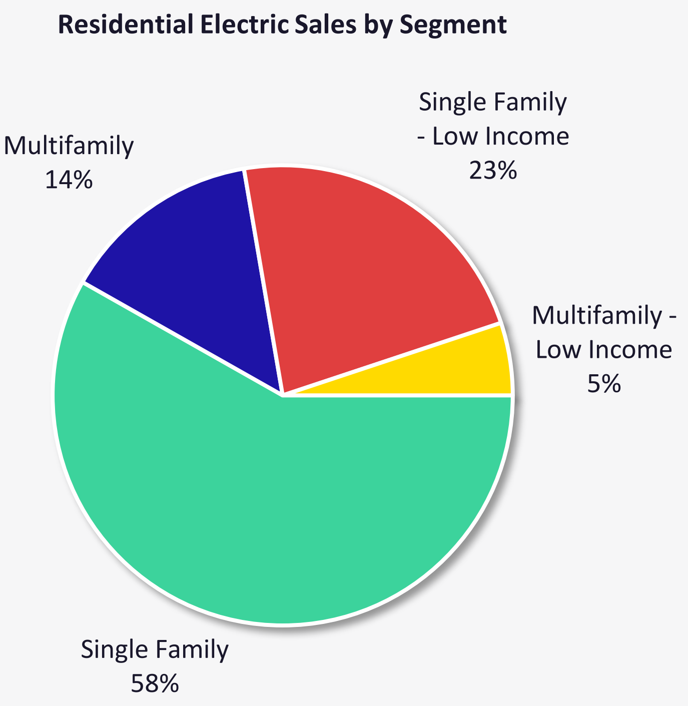






Residential Potential

Residential Market Characterization

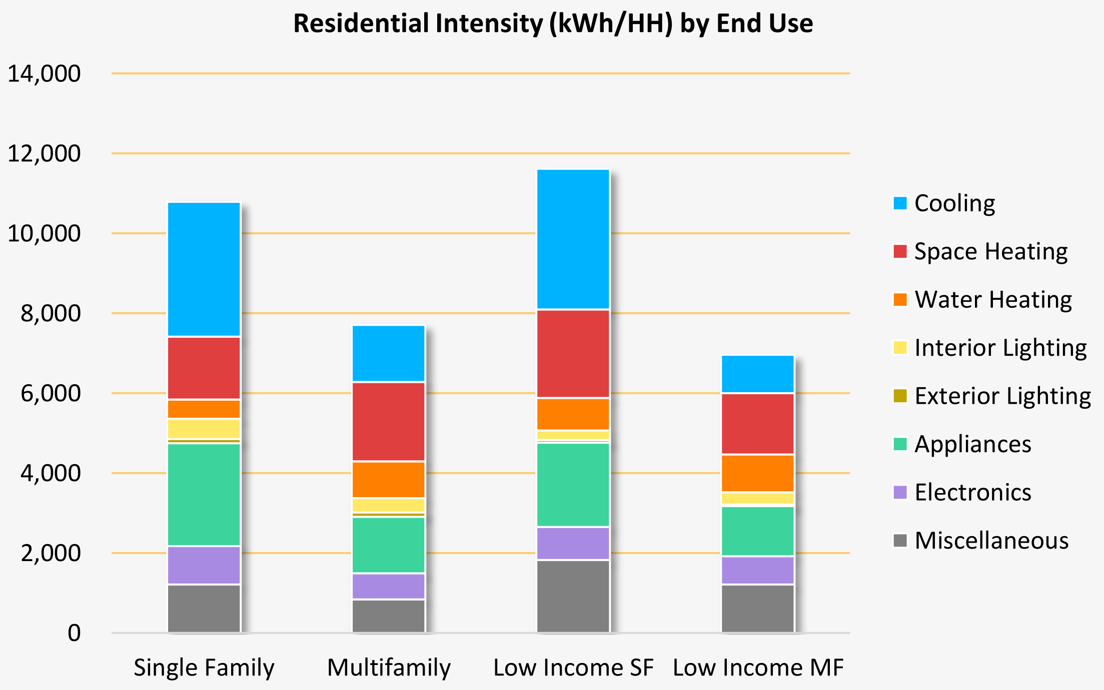


Segment	Electric Use (GWh)	Households	Avg. Use/HH (kWh)	% of Electric Use
Single Family	1,552.3	146,443	10,600	58%
Multifamily	376.3	48,822	7,707	14%
Single Family - Low Income	602.7	51,858	11,621	23%
Multifamily - Low Income	136.1	19,539	6,965	5%
Total	**2,667.3**	**266,662**	**10,003**	**100%**

- Total customers and energy load are taken directly from Evergy's 2021 data and disaggregated into housing types and income groups using a combination of Evergy's system data and demographic information from the US Census.
- The majority of homes in Evergy's Metro territory are single family dwellings, which use 81% of the Residential electricity in the Metro region.

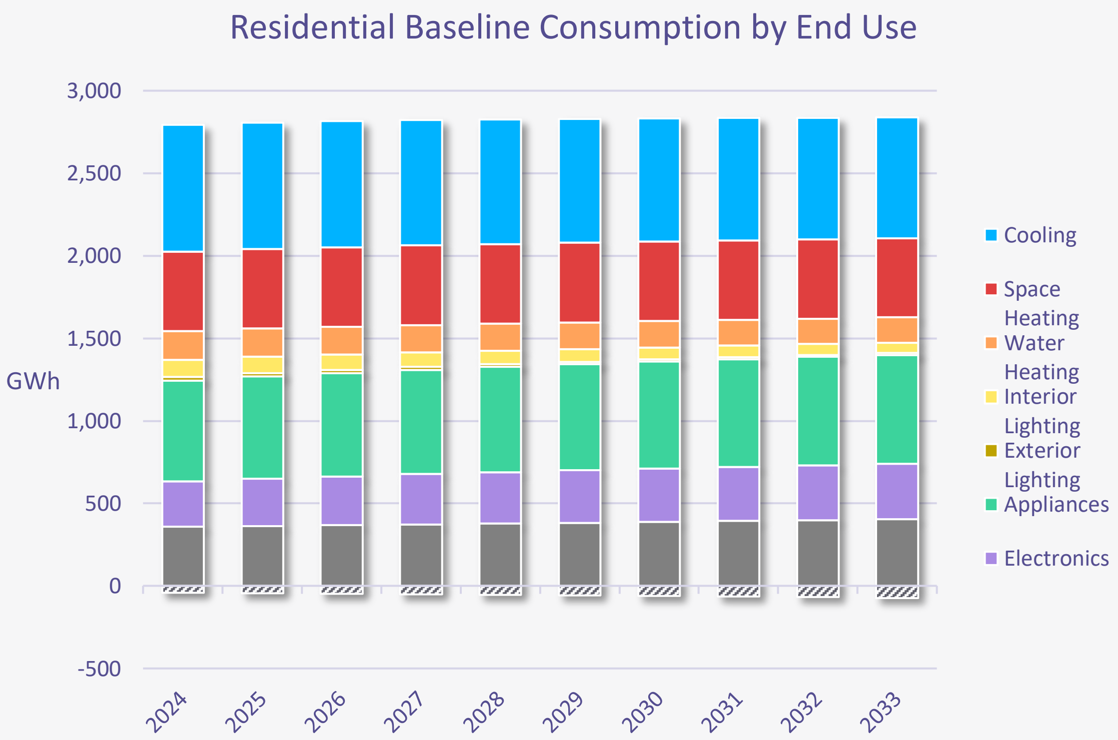
Residential Market Profiles

- The market profile disaggregates energy load per household into specific end uses and technologies.
- Total household **intensity** (kWh per HH) is calibrated to values shown on the previous slide. It is a function of:
  - Saturation – the percentage of homes where equipment is present
  - Unit Energy Consumption – the average annual energy use of a given technology where it is present.
  - Values are taken from well-vetted sources as close to Evergy Metro's territory as possible
- Key Data Sources
  - Evergy Metro Data
  - Residential Appliance Saturation Survey (RASS)
  - EIA Annual Energy Outlook



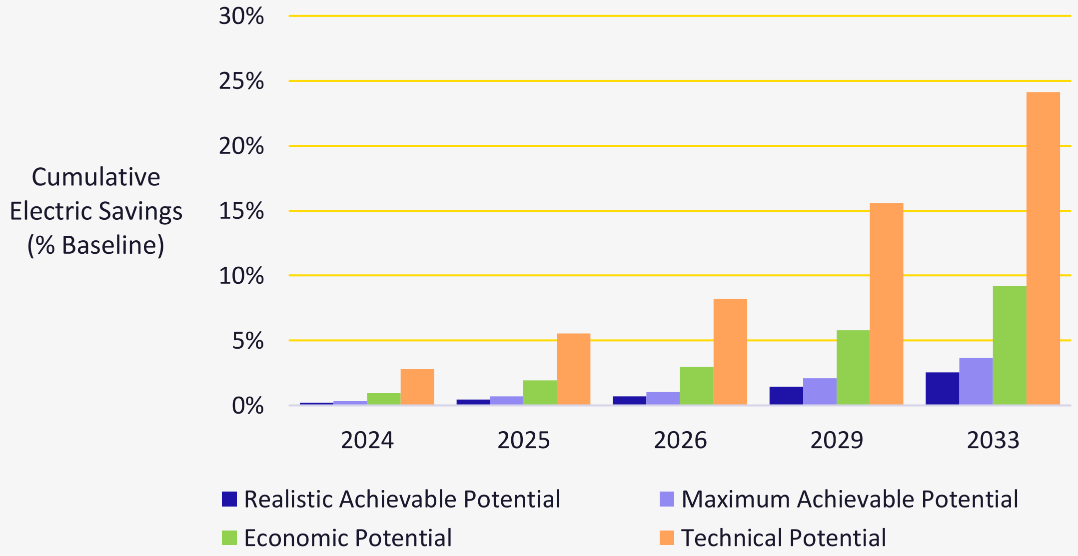
Residential Baseline Projection

- Project a reference baseline for potential that **excludes** future DSM efforts
- Accounts for:
  - Differences in sector and segment
  - Base-year market characterization
  - Customer growth
  - Codes and standards
  - Equipment turnover rates
  - Efficient measure penetration
  - Trends in equipment saturations
  - Weather (CDD, HDD) and other forecast drivers provided by Evergy



Residential Potential Results

- By 2026, cumulative Realistic Achievable Potential (RAP) is 19.1 GWh, or 0.7% of the reference baseline. By 2033, this increases to 70.8 GWh, or 2.6% of the baseline.
  - This is an average of 0.26% per year.
- Maximum Achievable Potential (MAP) reaches 28.9 GWh by 2026, and 101.2 GWh by 2033.



	2024	2025	2026	2029	2033
Baseline Projection (GWh)	2,755	2,765	2,771	2,773	2,766
Cumulative Savings (GWh)					
Realistic Achievable Potential	6	12	19	40	71
Maximum Achievable Potential	9	19	29	59	101
Economic Potential	27	54	82	160	255
Technical Potential	77	153	227	433	668
Cumulative as % of Baseline					
Realistic Achievable Potential	0.2%	0.4%	0.7%	1.4%	2.6%
Maximum Achievable Potential	0.3%	0.7%	1.0%	2.1%	3.7%
Economic Potential	1.0%	1.9%	3.0%	5.8%	9.2%
Technical Potential	2.8%	5.5%	8.2%	15.6%	24.1%

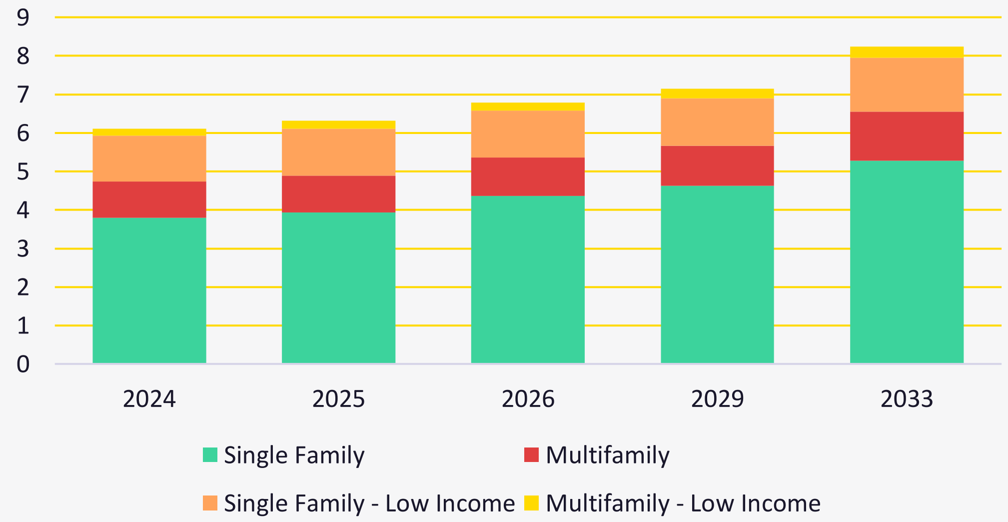
Residential Top Measures - RAP

- Central AC upgrades are the top measure.
- Thermostats and duct/building shell sealing to reduce HVAC use round out the top 5.
  - Collectively, the top 5 measures are half the achievable savings.
- LED Lighting is assumed as a baseline condition based on market trends and DOE assumptions, and does not provide program potential here aside from some small savings in EISA-exempt lighting

Rank	Measure Name	Cumulative Savings (MWh) 2026	% of Total
1	Central AC (SEER 18.0 (CEE Tier 2))	3,653	19.1%
2	Connected Thermostat - ENERGY STAR (1.0) (Networked Thermostat Installed)	2,118	11.1%
3	Ducting - Repair and Sealing (Sealed)	2,070	10.8%
4	Ducting - Repair and Sealing - Aerosol (G.17 Aerosol Duct Sealing)	1,276	6.7%
5	Building Shell - Liquid-Applied Weather-Resistive Barrier (Liquid-Applied Weather-Resistant Barrier)	958	5.0%
6	Room AC - Recycling (Unit Removed)	948	5.0%
7	Refrigerator (CEE Tier 3 (20% above standard))	915	4.8%
8	Water Heater (> 55 Gal) (Heat Pump (UEF 3.9))	807	4.2%
9	Furnace - Conversion to Air-Source Heat Pump	622	3.3%
10	Insulation - Basement Sidewall (R-11)	621	3.3%
11	Air-Source Heat Pump (SEER 16.0 / HSPF 9.2 (ENERGY STAR 6.1))	578	3.0%
12	Insulation - Ducting (R-8)	550	2.9%
13	Room AC (CEER 13.9)	490	2.6%
14	Advanced Power Strips - Load or Occupancy (Tier 1 - Load Sensing)	436	2.3%
15	Exempted Lighting (LED 2020 (95 lm/W))	400	2.1%
16	Central Heat Pump - Controls and Commissioning (Central Heat Pump with auxiliary heat control strategy, lockout settings, and other operational parameters)	387	2.0%
17	Insulation - Radiant Barrier (Installed)	369	1.9%
18	Water Heater - Drainwater Heat Recovery (Installed)	278	1.5%
19	Second Refrigerator (CEE Tier 3 (20% above standard))	233	1.2%
20	Air Purifier (ENERGY STAR (2.0) (2.7 CADR/W))	179	0.9%
	Total of Top 20 Measures	**17,889**	**93.6%**
	Total Savings - All Measures	**19,115**	**100.0%**

Residential Potential by Segment

- This slide shows incremental (annual) savings by housing type and income group.

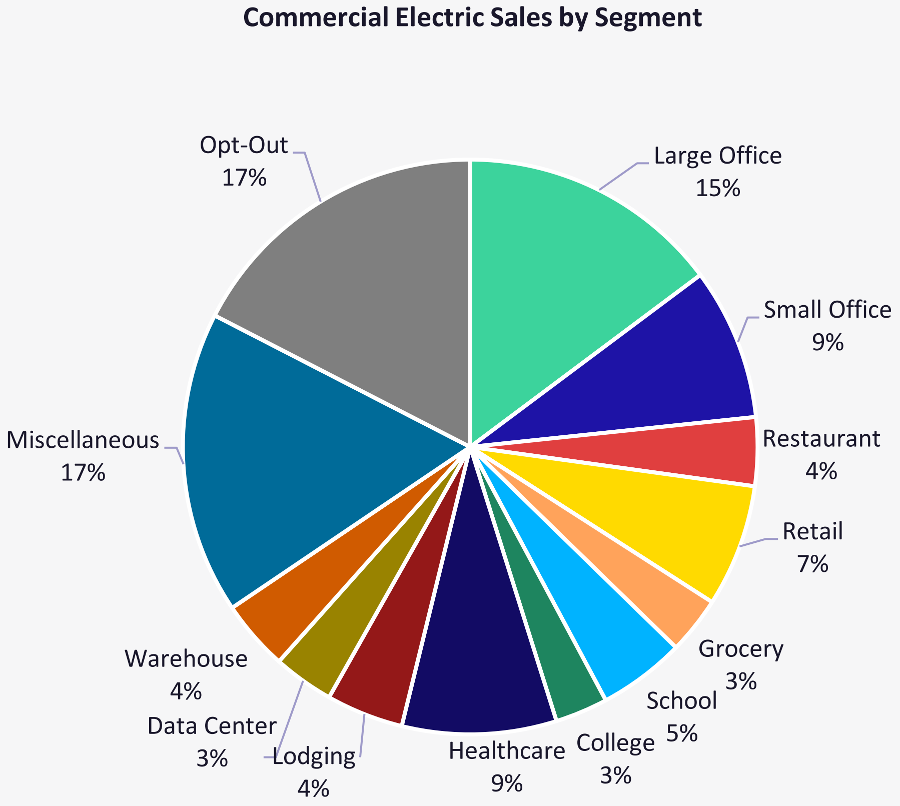


- Savings are a function of consumption, so most savings are coming from the largest segment – single family homes that are not low-income.
- Low-income segments show potential proportionate to their loads

Cumulative GWh	2024	2025	2026	2029	2033
Realistic Achievable Potential					
Single Family	3.8	3.9	4.4	4.6	5.3
Multifamily	0.9	1.0	1.0	1.0	1.3
Single Family - Low Income	1.2	1.2	1.2	1.2	1.4
Multifamily - Low Income	0.2	0.2	0.2	0.2	0.3
Total	**6.1**	**6.3**	**6.8**	**7.1**	**8.2**
Total Low-Income	***1.4***	***1.4***	***1.4***	***1.5***	***1.7***
Maximum Achievable Potential					
Single Family	6.0	6.1	6.7	6.7	7.2
Multifamily	1.5	1.5	1.5	1.5	1.7
Single Family - Low-Income	1.7	1.7	1.7	1.6	1.8
Multifamily - Low-Income	0.2	0.3	0.3	0.3	0.4
Total	**9.4**	**9.6**	**10.1**	**10.2**	**11.1**
Total Low-Income	***1.9***	***2.0***	***2.0***	***2.0***	***2.2***

Commercial Potential

Commercial Market Characterization

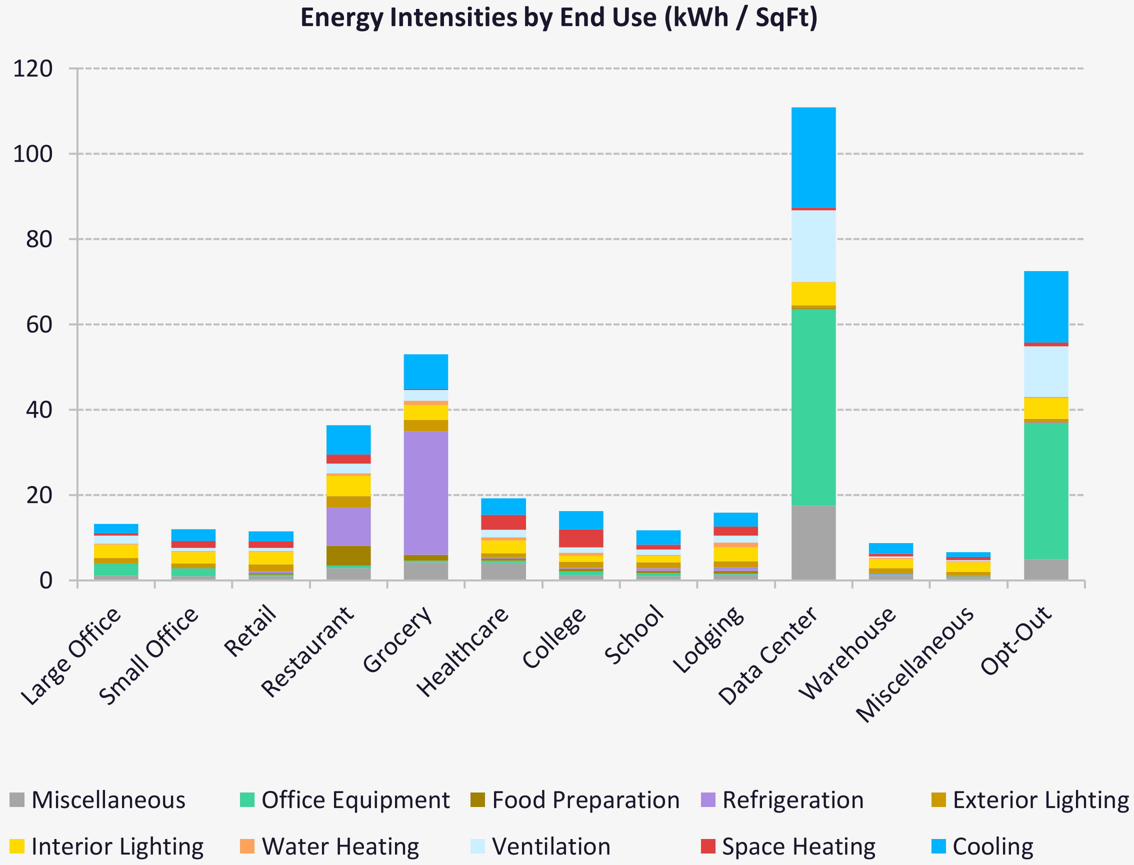


Segment	Electric Use (GWh)	% of Total	Floor Space (Million sqft)	Intensity (kWh/sqft)
Large Office	602.2	15%	45.63	13.20
Small Office	348.1	9%	29.01	12.00
Retail	280.7	7%	4.32	36.36
Restaurant	157.0	4%	24.57	11.42
Grocery	131.1	3%	2.47	52.99
School	198.9	5%	16.91	11.76
College	120.8	3%	7.47	16.16
Healthcare	353.8	9%	18.39	19.24
Lodging	176.8	4%	11.21	15.78
Data Center	139.2	3%	1.26	110.92
Warehouse	161.0	4%	18.57	8.67
Miscellaneous	693.3	17%	104.97	6.60
Opt-Out	710.1	17%	9.79	72.56
Commercial Total	**4,073.1**	**100%**	**294.57**	**13.83**

- AEG categorized commercial accounts into segments using customer SIC and business data from Evergy.
- Miscellaneous and Large Office segments dominate the commercial load.
  - The Miscellaneous segment includes nonresidential/non-manufacturing spaces not elsewhere classified or difficult to classify.
- Customers opting out of Evergy programs are separated into their own segment to avoid overstating program potential.

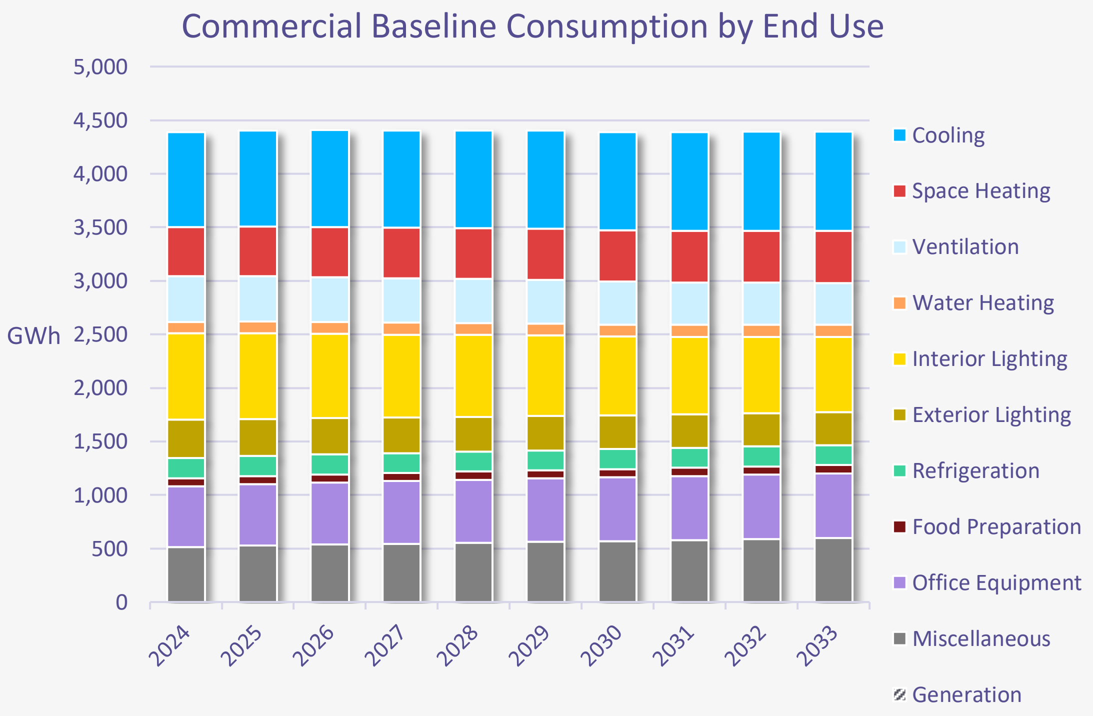
Commercial Market Profiles

- Just like residential, the commercial market profile disaggregates the nonresidential loads into end uses and technologies, calibrating to the appropriate total intensity.
- Key Data Sources
  - Evergy Billing and Load Research Data
  - 2012 EIA Commercial Buildings Energy Consumption Survey (CBECS)
  - U.S. DOE Solid State Lighting Forecast Report (2019)
  - EIA Annual Energy Outlook (AEO)
  - AEG Data and Energy Market Profiles



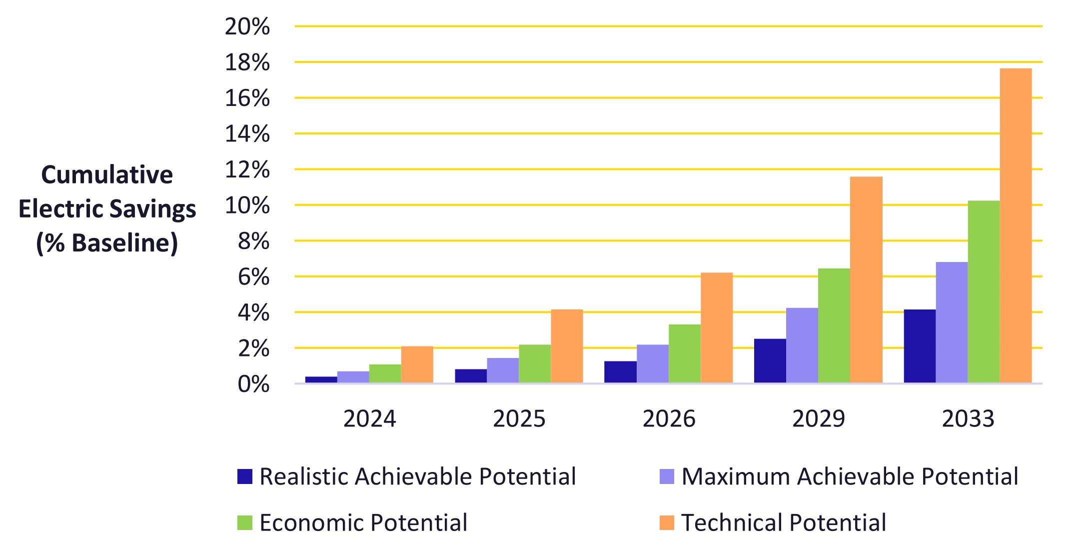
Commercial Baseline Projection

- Project a reference baseline for potential that **excludes** future DSM efforts.
- Accounts for:
  - Differences in sector and segment
  - Base-year market characterization
  - Customer growth
  - Codes and standards
  - Equipment turnover rates
  - Efficient measure penetration
  - Trends in equipment saturations
  - Weather (CDD, HDD) and other forecast drivers provided by Evergy



Commercial Potential Results

- By 2026, cumulative RAP is 56.3 GWh, or 1.3% of the reference baseline. By 2033, this increases to 185.3 GWh, or 4.2% of the baseline.
  - This is an average of 0.4% per year.
- MAP reaches 97.1 GWh by 2026, and 303 GWh by 2033.



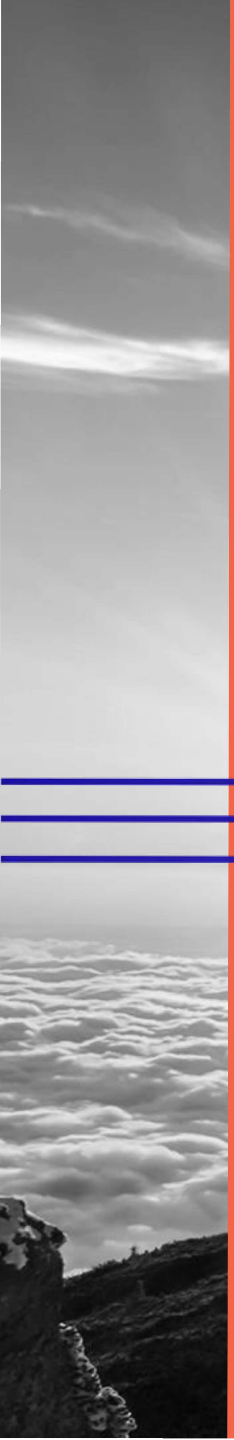
	2024	2025	2026	2029	2033
Baseline Projection (GWh)	4,419	4,434	4,440	4,444	4,438
Cumulative Net Savings (GWh)					
Realistic Achievable Potential	18	37	56	112	185
Maximum Achievable Potential	31	64	97	189	303
Economic Potential	48	97	148	287	455
Technical Potential	92	185	276	515	783
Cumulative as % of Baseline					
Realistic Achievable Potential	0.4%	0.8%	1.3%	2.5%	4.2%
Maximum Achievable Potential	0.7%	1.4%	2.2%	4.3%	6.8%
Economic Potential	1.1%	2.2%	3.3%	6.5%	10.3%
Technical Potential	2.1%	4.2%	6.2%	11.6%	17.6%

Commercial Top Measures - RAP

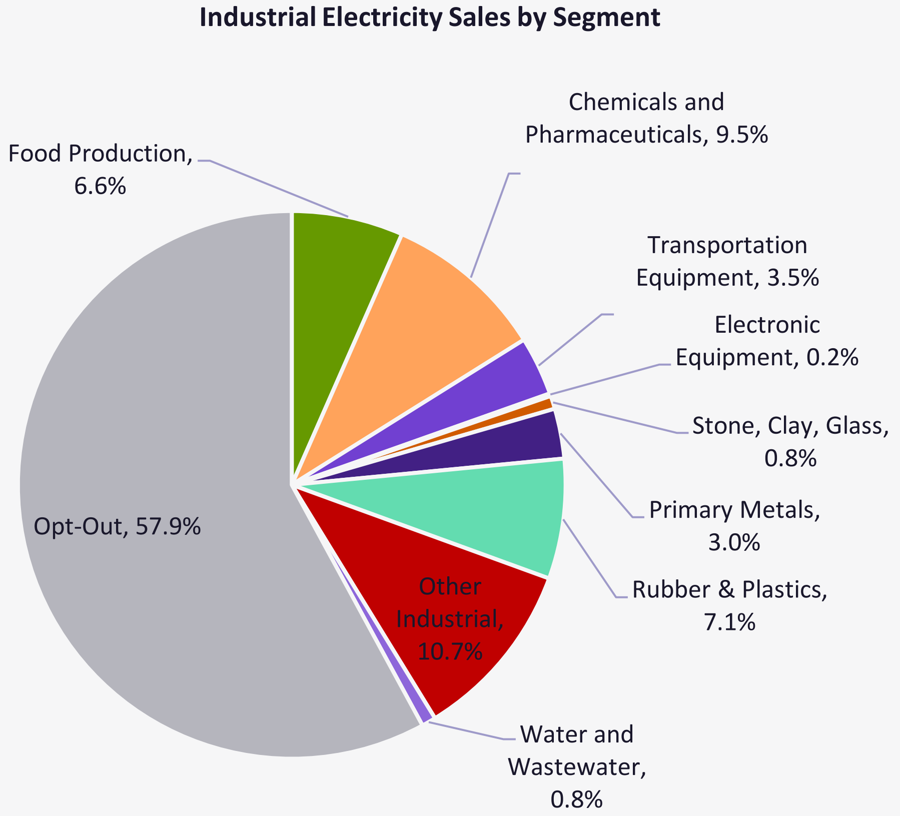
- Linear Lighting, Retrocommissioning, and Rooftop Unit (RTU) upgrades have the most significant potential savings.
  - There is significant LED penetration in the baseline for linear and high bay, but this measure is a bundle with embedded controls at the time of fixture replacement, which gives savings above a simple LED.
- Because not all electronics (computers, servers, desktop monitors, etc.) purchased are ENERGY STAR certified, these measures have significant savings potential.
  - However, it can be difficult to incentivize this behavior due to the low/no cost difference between ENERGY STAR and non-certified units.

Rank	Measure Name	Cumulative Savings (MWh) 2026	% of Total
1	Linear Lighting (LED 2020 (109 lm/W system) w/ Controls)	16,233	28.8%
2	Retrocommissioning	6,455	11.5%
3	RTU (IEER 18.0 - ENERGY STAR (4.0))	5,917	10.5%
4	Exempted Lighting (LED 2020 (95 lm/W))	4,296	7.6%
5	Ventilation - Demand Controlled (Outdoor air controlled based on occupancy to meet ASHRAE 62.1)	4,082	7.3%
6	High-Bay Lighting (LED 2020 (132 lm/W) w/ Controls)	3,200	5.7%
7	Server (ENERGY STAR (3.0))	2,656	4.7%
8	Ventilation - Variable Speed Control (VSD on fan motor)	1,297	2.3%
9	Water-Cooled Chiller (COP 12.13 (0.29 kW/ton))	1,086	1.9%
10	POS Terminal (ENERGY STAR (7.1))	1,057	1.9%
11	HVAC - Maintenance (Tune-up of unitary HVAC systems.)	986	1.8%
12	RTU - Advanced Controls (Advanced controls on roof top unit.)	901	1.6%
13	Griddle (ENERGY STAR (1.2))	734	1.3%
14	Ducting - Repair and Sealing (Sealed)	681	1.2%
15	Data Center - Best Practice Measures	642	1.1%
16	Area Lighting (LED 2020 (120 lm/W) w/ Controls)	616	1.1%
17	Advanced New Construction Designs (exceeding ASHRAE 90.1 requirements)	410	0.7%
18	Oven (ENERGY STAR (2.2))	409	0.7%
19	Chiller - Variable Speed Fans (VSD on fan motors)	409	0.7%
20	Connected Thermostat - ENERGY STAR (1.0) (Thermostat connected to building management control system)	363	0.6%
	Total of Top 20 Measures	**52,429**	**93.2%**
	Total Savings - All Measures	**56,281**	**100.0%**

Industrial Potential



Industrial Market Characterization

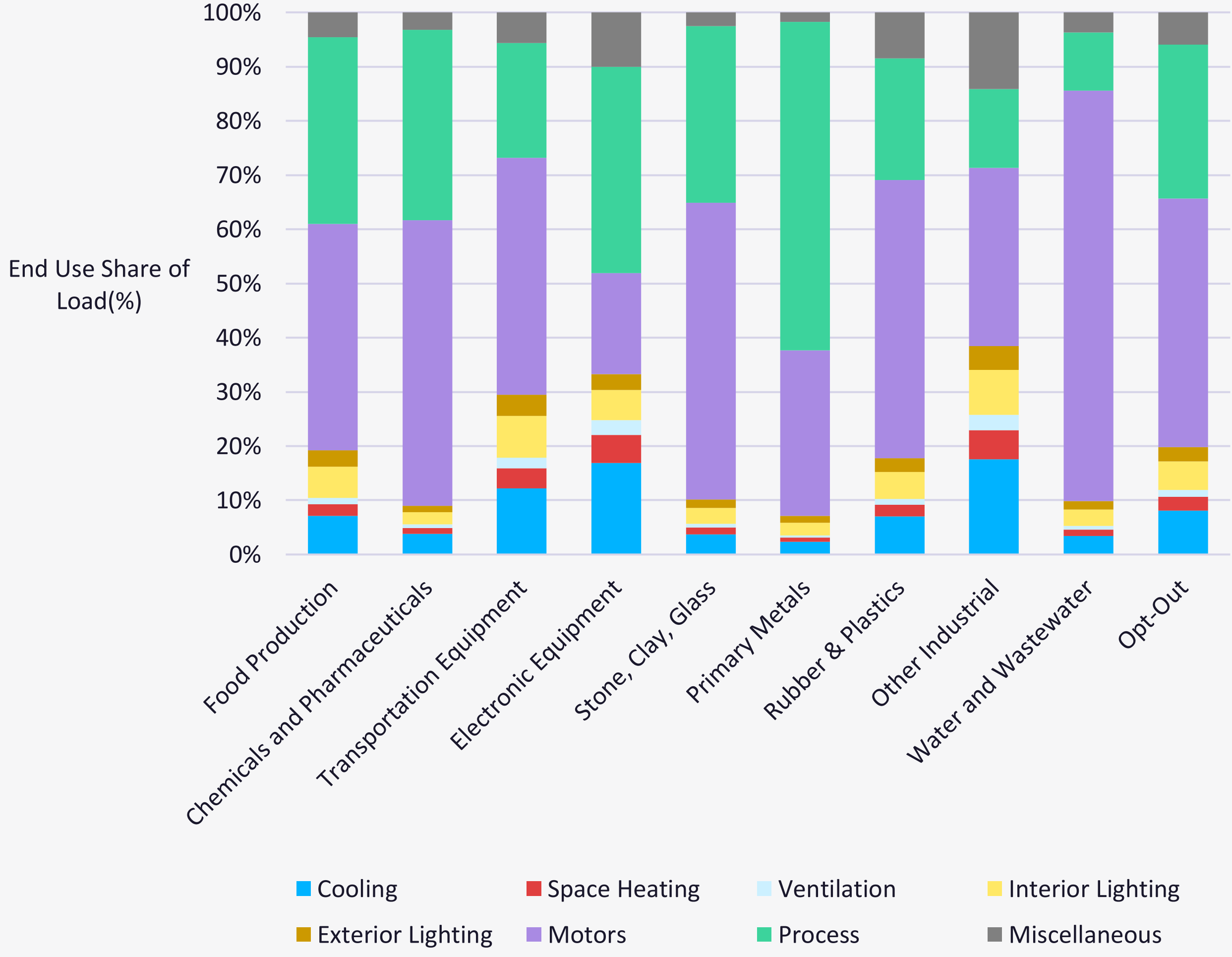


Segment	Electric Use (GWh)	% of Total
Food Production	93.0	7%
Chemicals & Pharmaceuticals	134.3	10%
Electronic Equipment	2.2	0%
Primary Metals	41.7	3%
Stone, Clay, Glass	10.9	1%
Transportation Equipment	49.1	3%
Rubber & Plastics	100.0	7%
Water & Wastewater	11.9	1%
Other Industrial	150.8	11%
Opt-Out	817.5	58%
Industrial Total	**1,411.4**	**100%**

- AEG categorized industrial accounts into segments using SIC codes and customer data from Evergy.
- A greater portion of Industrial facilities are eligible to opt out of programs compared to non-manufacturing commercial.
- The largest non-opt-out characterized segments are Other Industrial, Chemicals & Pharmaceuticals, Food Production, and Rubber & Plastics.
- The Other Industrial segment includes the NAICS “Misc. Manufacturing” class and the tail of load in categories not elsewhere classified.

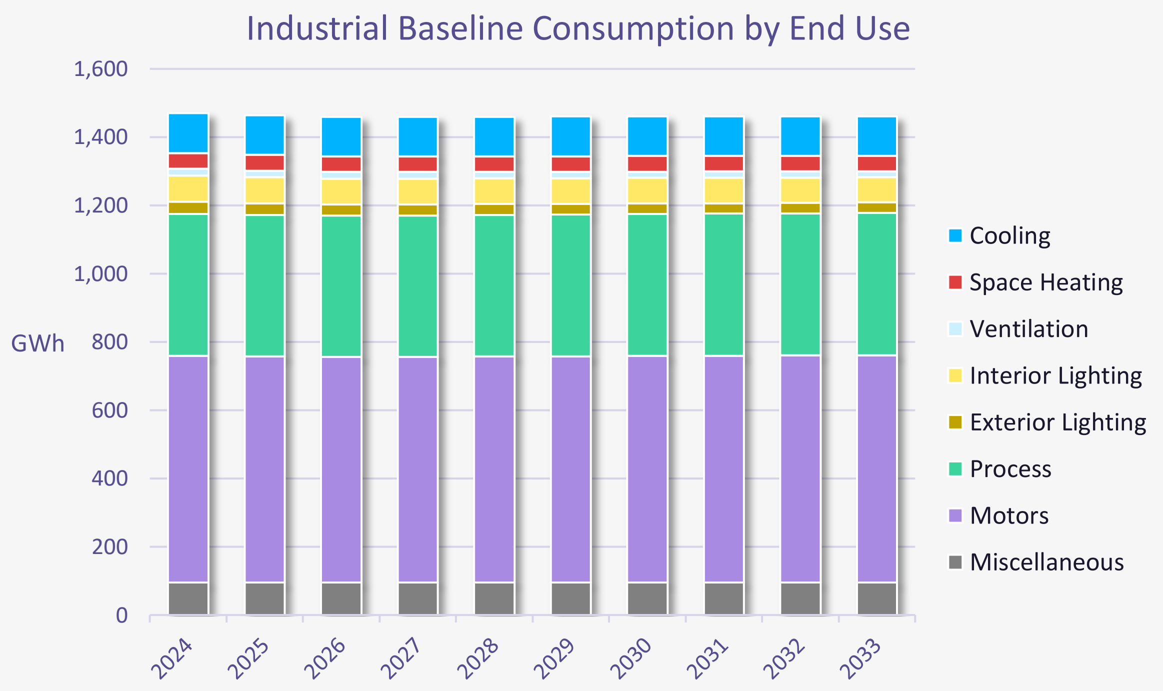
Industrial Market Profiles

- The industrial market profile disaggregates the loads into segments and intensity, calibrating to the appropriate total intensity.
- Key Data Sources
  - SIC codes by customer
  - U.S. DOE Manufacturing Energy Consumption Survey



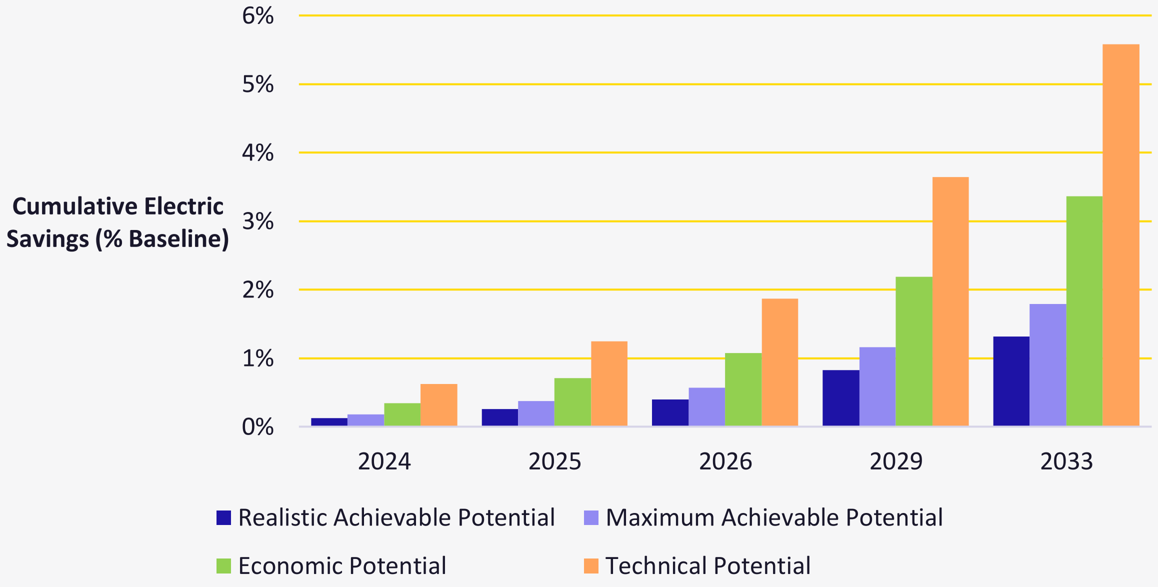
Industrial Baseline Projection

- Project a reference baseline for potential that **excludes** future DSM efforts.
- Accounts for:
  - Differences in sector and segment
  - Base-year market characterization
  - Customer growth
  - Codes and standards
  - Equipment turnover rates
  - Efficient measure penetration
  - Trends in equipment saturations
  - Weather (CDD, HDD) and other forecast drivers provided by Evergy



Industrial Potential Results

- By 2026, cumulative RAP is 5.8 GWh, or 0.4% of the reference baseline. By 2033, this increases to 19.2 GWh, or 1.3% of the baseline.
  - This is an average of 0.13% per year.
- MAP reaches 8.3 GWh by 2026, and 26.1 GWh by 2033.



	2024	2025	2026	2029	2033
Baseline Projection (GWh)	1,471	1,464	1,459	1,460	1,461
Cumulative Net Savings (GWh)					
Realistic Achievable Potential	1.8	3.8	5.8	12.0	19.2
Maximum Achievable Potential	2.7	5.5	8.3	16.9	26.1
Economic Potential	5.1	10.3	15.7	31.9	49.2
Technical Potential	9.2	18.2	27.3	53.2	81.6
Cumulative as % of Baseline					
Realistic Achievable Potential	0.1%	0.3%	0.4%	0.8%	1.3%
Maximum Achievable Potential	0.2%	0.4%	0.6%	1.2%	1.8%
Economic Potential	0.3%	0.7%	1.1%	2.2%	3.4%
Technical Potential	0.6%	1.2%	1.9%	3.6%	5.6%

Industrial Top Measures - RAP

- As in commercial, LED fixture replacements, including bundles with controls, provide savings opportunities, contributing more than half of Industrial potential.
- Ventilation and HVAC chillers have some savings, though HVAC is not the largest portion of Industrial load.
- System upgrades and optimizations for various processes and motor systems make up a long tail of smaller measures in the top 20.

Rank	Measure Name	Cumulative Savings (MWh) 2026	% of Total
1	High-Bay Lighting (LED 2020 (132 lm/W) w/ Controls)	2,066	35.7%
2	Linear Lighting (LED 2020 (109 lm/W system))	1,334	23.0%
3	Indoor Agriculture - LED Lighting (TBD)	353	6.1%
4	Ventilation (Variable Air Volume)	311	5.4%
5	Water-Cooled Chiller (COP 12.13 (0.29 kW/ton))	182	3.1%
6	Advanced Industrial Motors (TBD)	181	3.1%
7	Pumping System - System Optimization (TBD)	164	2.8%
8	Compressed Air - End Use Optimization (TBD)	156	2.7%
9	Fan System - Equipment Upgrade (TBD)	117	2.0%
10	Compressed Air - Variable Speed Drive (TBD)	101	1.7%
11	Paper - Efficient Agitator (TBD)	99	1.7%
12	Pumping System - Variable Speed Drive (TBD)	88	1.5%
13	Compressed Air - Equipment Upgrade (TBD)	79	1.4%
14	Air-Cooled Chiller (COP 4.10 (IPLV 14.0))	70	1.2%
15	Pumping System - Equipment Upgrade (TBD)	67	1.2%
16	Material Handling - Variable Speed Drive (TBD)	57	1.0%
17	Refrigeration - System Upgrade (TBD)	49	0.8%
18	Refrigeration - System Maintenance (TBD)	47	0.8%
19	Fan System - Variable Speed Drive (TBD)	38	0.7%
20	Compressed Air - System Controls (TBD)	32	0.5%
	Total of Top 20 Measures	**5,592**	**96.6%**
	Total Savings - All Measures	**5,788**	**100.0%**

DR/DSR
Potential Analysis

DR and DSR Potential Approach

- General methodology for estimating DR and DSR potential is similar to energy efficiency
- Our approach accounts for two key differences:
  - **Neither exist outside of a programmatic structure (i.e., there is no naturally occurring DR)**
  - **Focus on Maximum Achievable and Realistic Achievable Potential**

Market Characterization

- Leverage EE Analysis Alignment
- Segment by Sector, Geography and Size vs. Building Type

→

Identify and Characterize Measures

- DLC Measure Options
- DR Economic Options
- DSR Options

→

Baseline Projection

- Leverage EE Analysis for alignment
- Use DR Segmentation
- Account for Interactions

→

Potential Estimation

- Technical Achievable
- Maximum Achievable
- Realistic Achievable

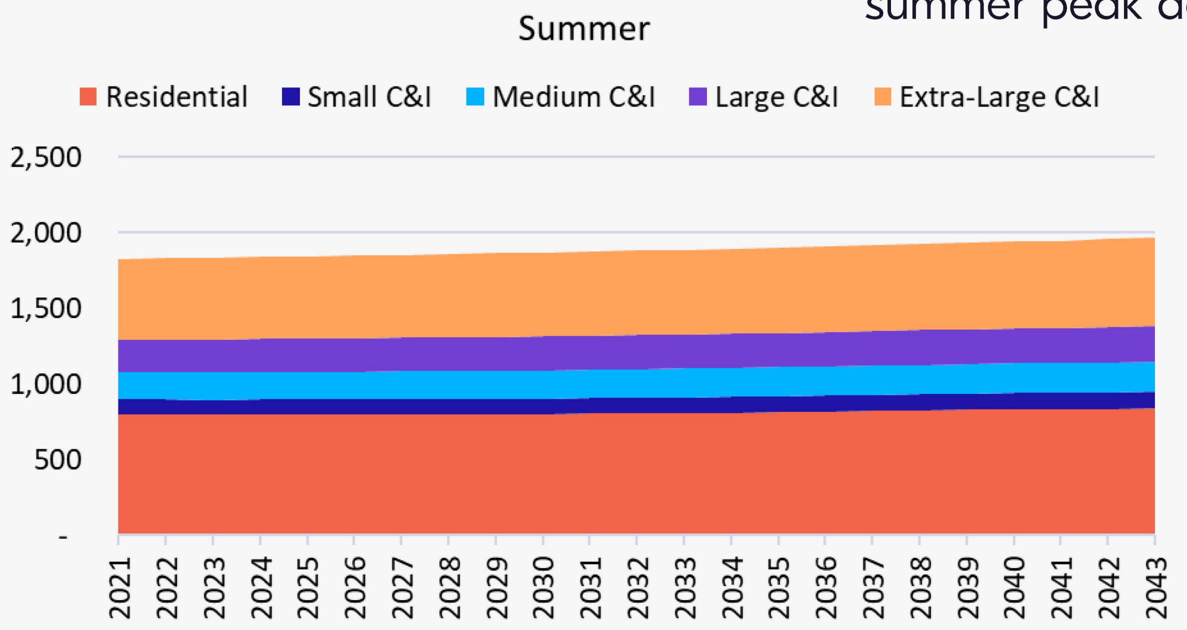
Market Characterization

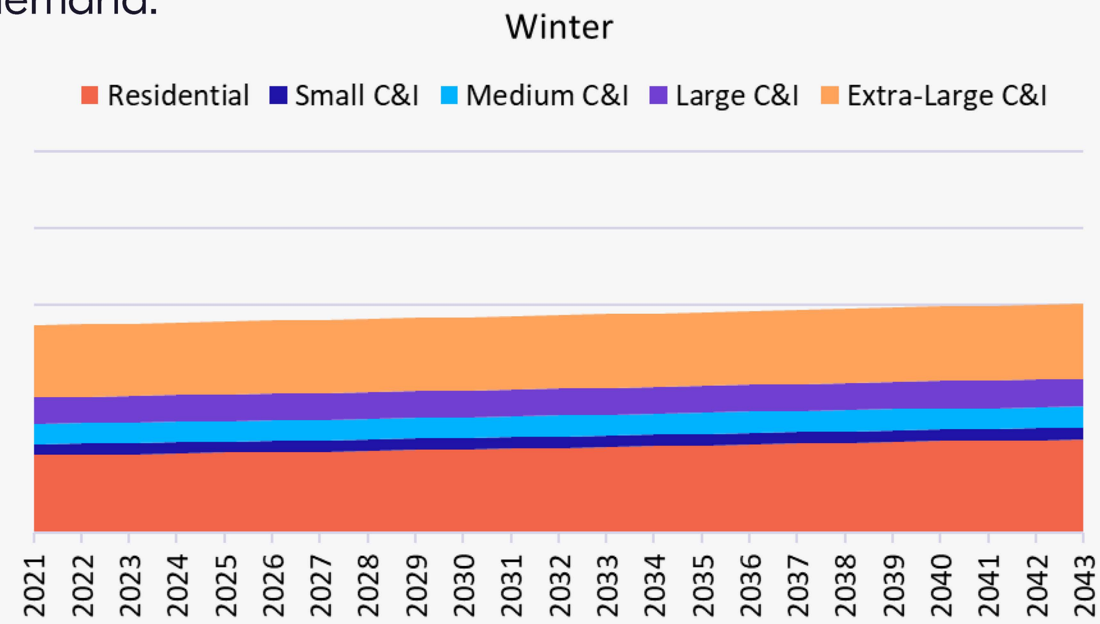
Used billing data to segment C&I customers into size bins (max annual peak)

Small C&I	< 30 kW
Medium C&I	≥ 30 kW, < 150 kW
Large C&I	≥ 150 kW, < 1,000 kW
Extra-Large C&I	> 1,000 kW

Residential consumption accounts for ~45% of Evergy Metro peak demand in summer (38% in winter).

C&I winter peak demand is 20%-35% less than winter peak across size bins. Residential winter peak demand reaches only ~65% of summer peak demand.





Program Characterization

DR Options	DSR Options
DLC – End Use • Connected Thermostats – Res and C&I • Switches (heating/cooling) • Smart Homes • Electric Vehicles • Water Heating (including grid-interactive models) • Smart Solar PV Inverter • Battery Storage • Thermal Energy Storage **Economic – Whole Facility** • Firm Curtailment/Tariff • C&I Automatic DR (ADR) • Residential Behavioral Demand Response	**Rate-Based** • Critical Peak Pricing • Time-Related Pricing • Time-of-Use Rates • TOU Rate for EV Owners

Participation rates

- Define eligible customers for each given option and reflect appliance saturation rates, customer segmentation, and the hierarchy

Customer impacts

- Percentages or kW values that reflect the total load reduction during an event

Participant/program costs

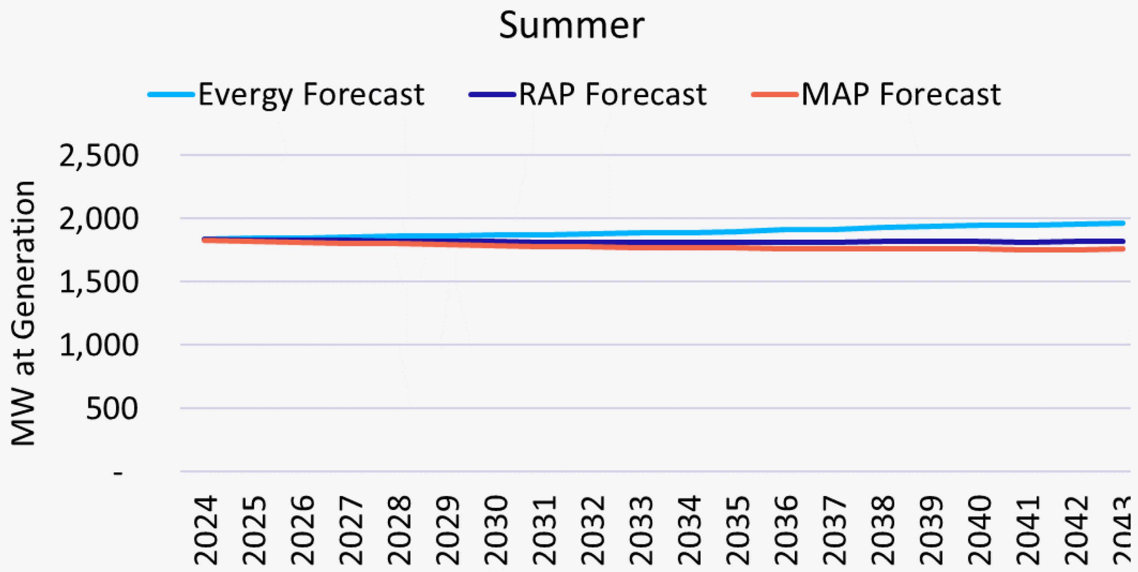
- Incentives and enabling technology costs, program development and administration costs, marketing and recruitment costs, O&M costs

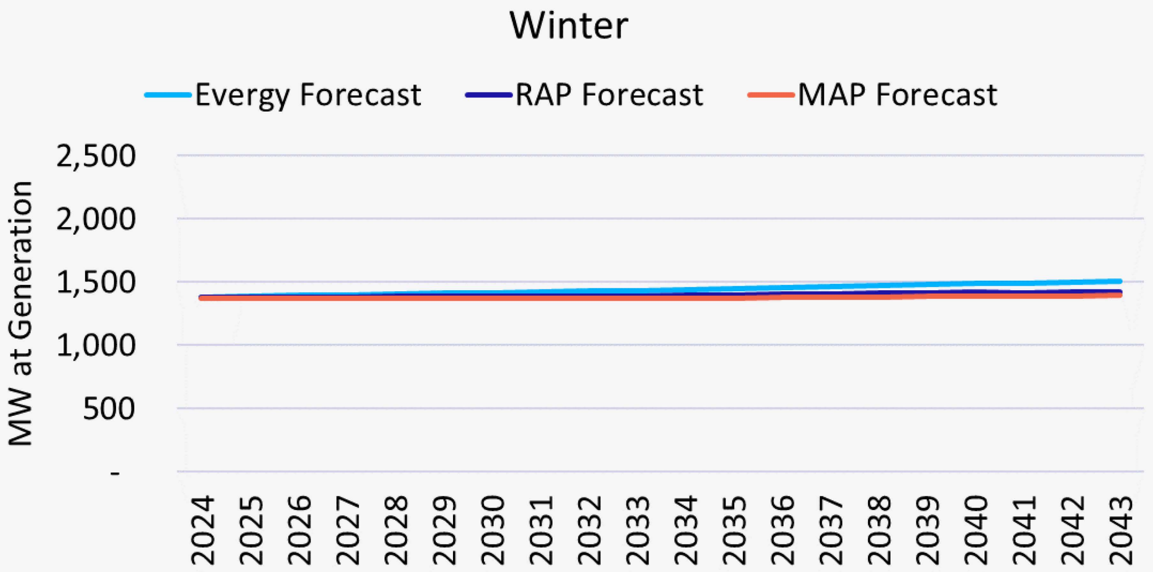
Per customer coincident peak load × % impact × # of eligible customers = MW Impact

Baseline Projection

AEG developed the baseline peak demand forecasts by:

- Using the Evergy peak demand forecast by sector and territory
- Removing the peak demand savings potential generated through energy efficiency adoption forecasted in the MAP and RAP scenarios
- Summer baseline dropped by 7% (RAP) and 11% (MAP) by 2043





MAP Scenario

MAP Scenario

The Maximum Achievable Potential (MAP) scenario:

- Included all cost-effective programs
- Incorporated growth in Evergy's existing programs to benchmarked participation levels
- Lowered baseline projection for the peak demand savings generated through MAP-forecasted energy efficiency adoption.

MAP Sensitivity Analysis:

The Missouri PSC ordered Evergy to transition all residential customers to mandatory TOU rates by October 1, 2023.

In response, AEG and Evergy focused the MAP analysis on how the mandatory TOU rates would affect the baseline projection.

Customer response to pricing signals will reduce the demand available for other DR programs to impact during peak hours.

MAP Sensitivity Analysis

Evergy plans to offer four residential TOU rates:

All residential customers will be transitioned to the TOU Standard Rate by October 2023.

TOU Standard (4:1)

Customers will opt-out within the first year

TOU for EV Owners (10-12:1)	EV owners will opt into the EV TOU rate (20%, 50%, and 100%)
Peak Adjustment Rate (~1:1)	95% of non-EV owner opt-outs will move to the Peak Adjustment Rate
TOU 3-Period (6:1)	Remaining opt-outs will move to the 3P rate

How the TOU rate order affects residential peak demand depends on (1) TOU Standard customer retention and (2) the TOU rate that opt-out customers move onto instead.

MAP Sensitivity Analysis

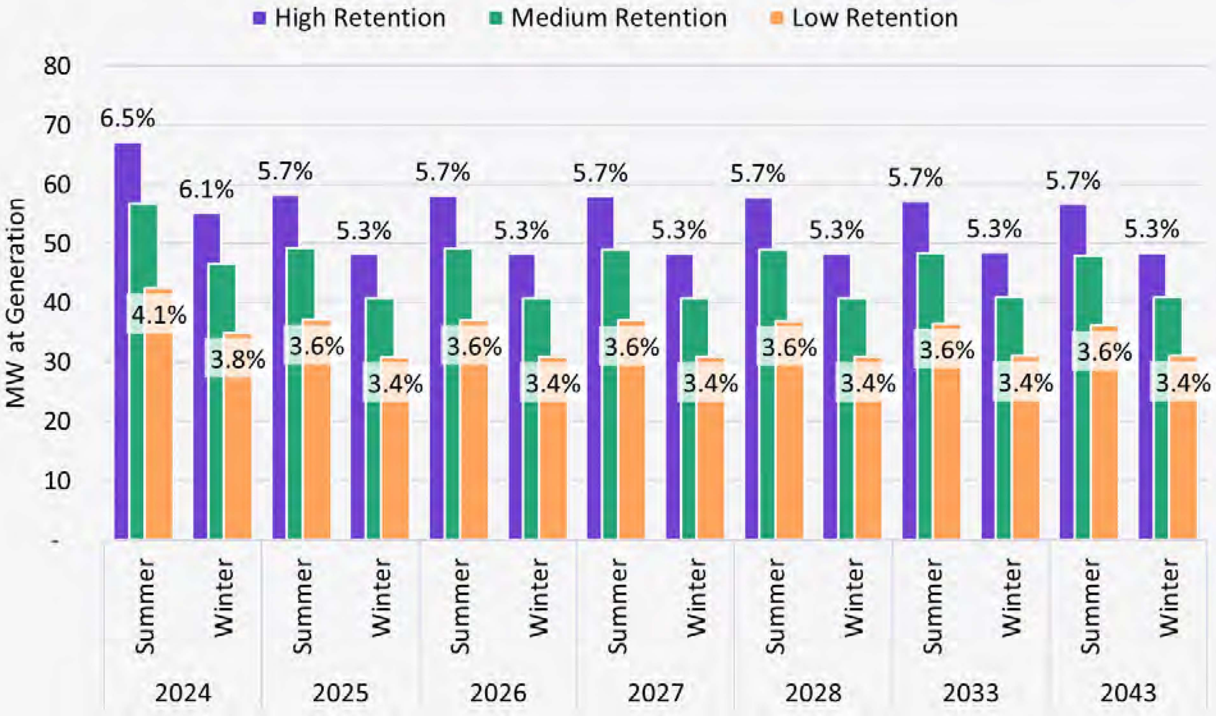
AEG analyzed two sensitivities in addition to the MAP scenario (which is based on a low retention rate of 50%).

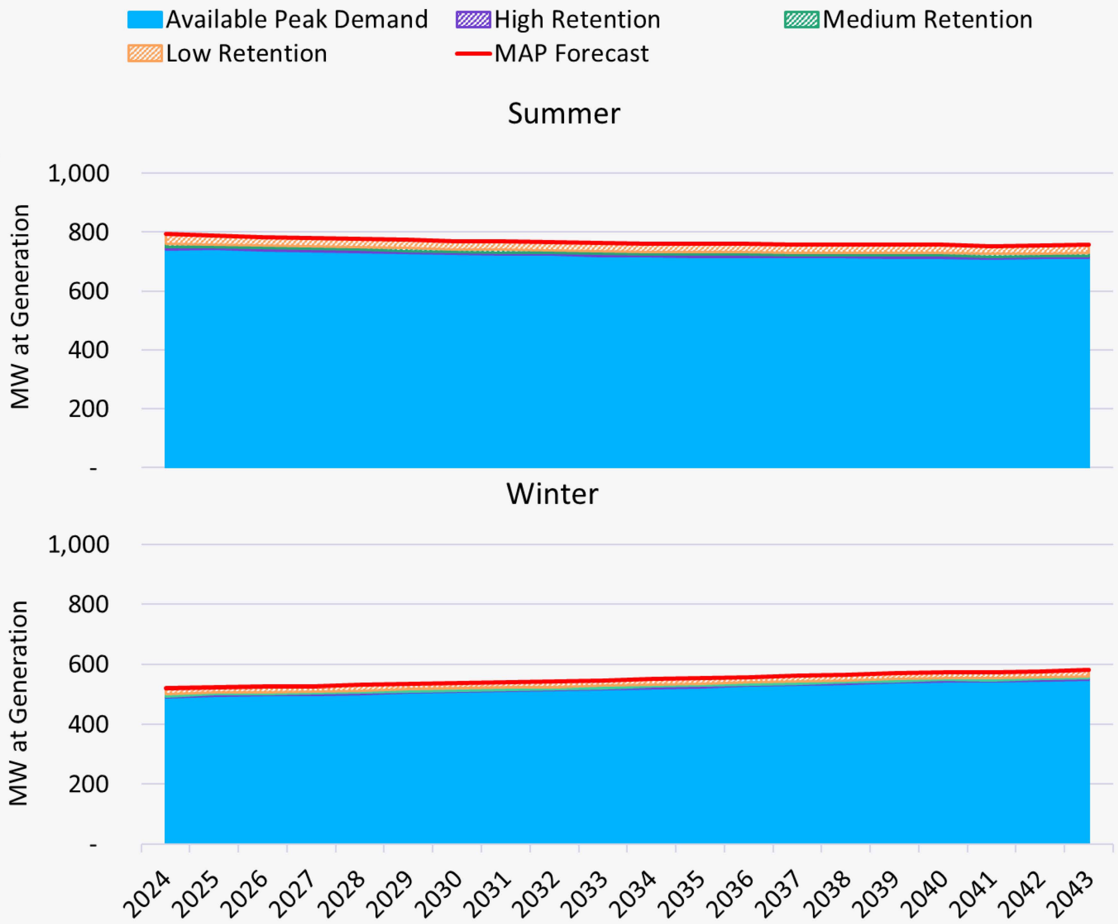
- The Medium- and Low-Retention sensitivities increase the impacts from the mandatory TOU rates and reduce the demand available for other DR program options.

Sensitivity	TOU Standard	TOU for EV Owners	Peak Adjustment Rate	3-Period TOU
MAP	50% of all residential customers	20% of EV owners who opt out of TOU Standard	95% of remaining TOU Standard opt-outs	Other TOU Standard opt-outs
MAP Medium-Retention	70% of all residential customers	50% of EV owners who opt out of TOU Standard	95% of remaining TOU Standard opt-outs	Other TOU Standard opt-outs
MAP High - Retention	85% of all residential customers	100% of EV owners who opt out of TOU standard	95% of remaining TOU Standard opt-outs	Other TOU Standard opt-outs

MAP Sensitivity Analysis

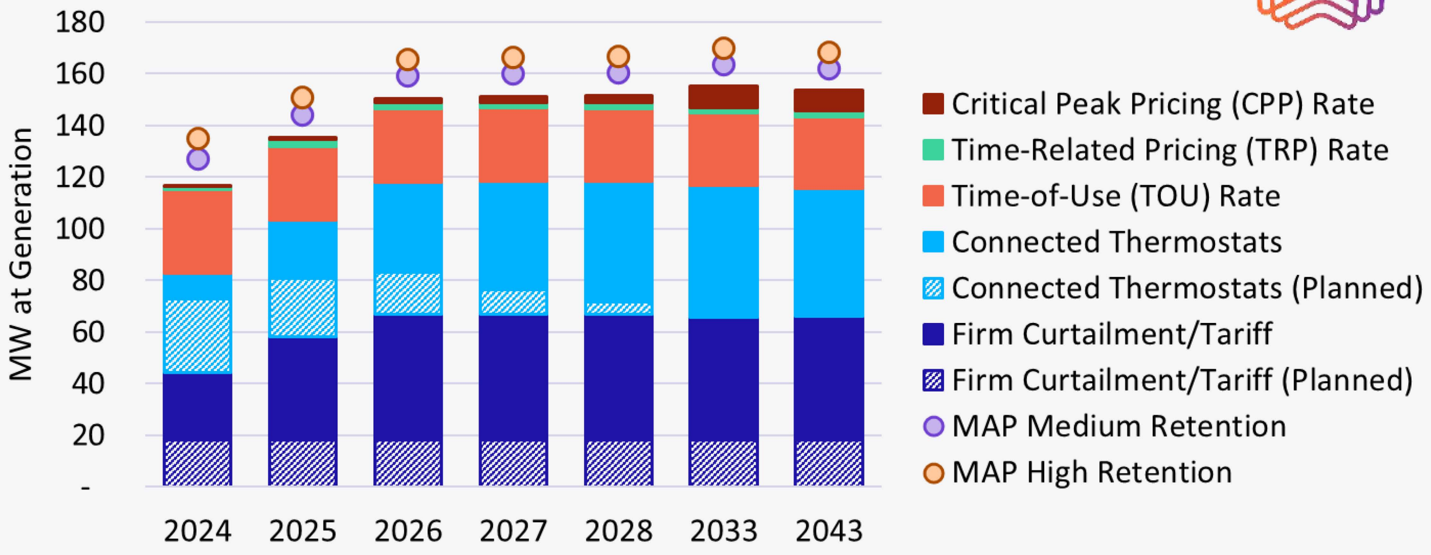
By 2043, the TOU rates reduce the summer residential peak demand baseline by 3.6%-5.7% (3.4%-5.3% in winter). While impacts are not insignificant (28 MW-43 MW in summer), the adjustments relative to the MAP baseline are small.





MAP Summer Potential Results

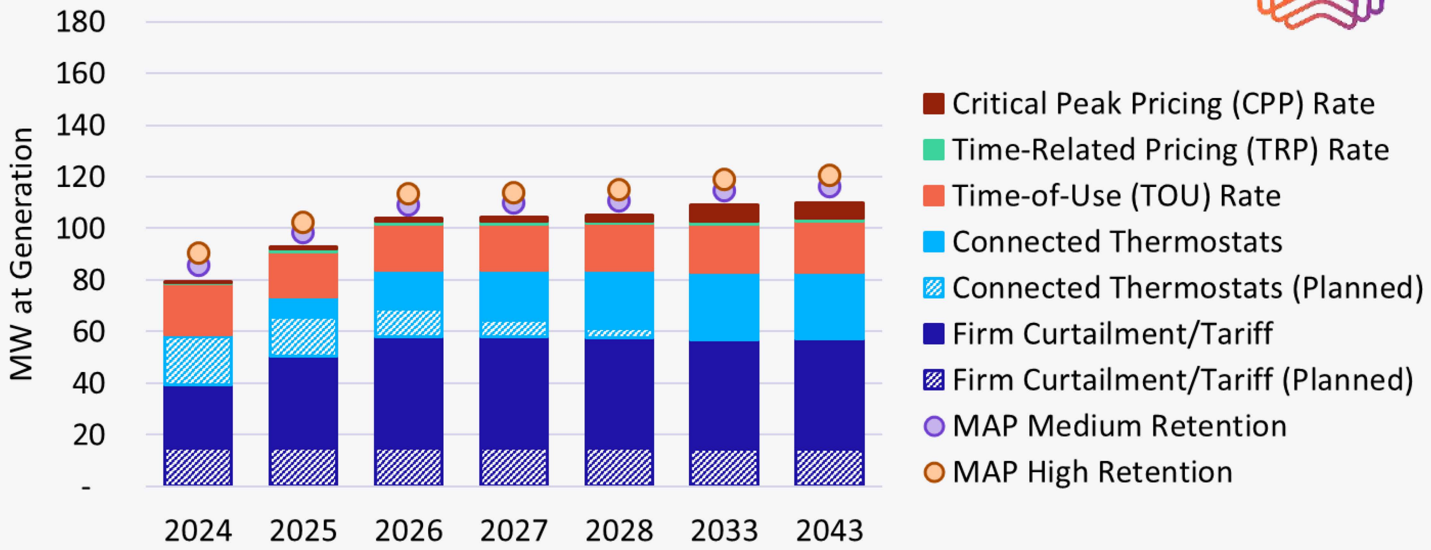
- By 2043, DR/DSR potential is estimated to reduce the summer peak demand baseline by 8%.
  - Firm Curtailment and Connected Thermostats generate over 6% of this reduction and account for 56% of the 2043 DR/DSR potential.
  - TOU rates contribute another 13% to total potential in 2043 and reduce the baseline by another 1.5%.
  - 12% of the potential comes from planned (and existing) programs.
- MAP Medium- and High-Retention analyses increase total summer potential by 8 MW-15 MW.
  - As TOU impacts increase, impacts from other DR resources decrease, netting out some of the mandatory rate effects.



Program Option	MW at Generation (% of Baseline)						
	2024	2025	2026	2027	2028	2033	2043
Firm Curtailment/Tariff (Planned)	18 (1%)	18 (1%)	18 (1%)	18 (1%)	18 (1%)	18 (1%)	18 (1%)
Firm Curtailment/Tariff	26 (1%)	40 (2%)	49 (3%)	49 (3%)	49 (3%)	48 (3%)	48 (3%)
Connected Thermostats (Planned)	28 (2%)	23 (1%)	16 (1%)	10 (1%)	5 (0%)	0 (0%)	0 (0%)
Connected Thermostats	10 (1%)	22 (1%)	35 (2%)	42 (2%)	47 (3%)	51 (3%)	50 (3%)
Time-of-Use (TOU) Rate	33 (2%)	29 (2%)	29 (2%)	28 (2%)	28 (2%)	28 (2%)	28 (2%)
Time-Related Pricing (TRP) Rate	1 (0%)	3 (0%)	2 (0%)	2 (0%)	2 (0%)	2 (0%)	2 (0%)
Critical Peak Pricing (CPP) Rate	0 (0%)	1 (0%)	2 (0%)	2 (0%)	3 (0%)	8 (0%)	8 (0%)
MAP Total	117 (6%)	135 (7%)	150 (8%)	151 (8%)	152 (8%)	155 (9%)	154 (8%)
MAP Medium Retention	127 (7%)	144 (8%)	159 (9%)	160 (9%)	160 (9%)	163 (9%)	162 (9%)
MAP High Retention	135 (7%)	151 (8%)	165 (9%)	166 (9%)	167 (9%)	170 (9%)	168 (9%)

MAP Winter Potential Results

- By 2043, DR/DSR potential is estimated to reduce the winter peak demand baseline by 6%.
  - Firm Curtailment and Connected Thermostats generate almost 5% of this reduction and account for 40% of the 2043 DR/DSR potential.
  - TOU rates contribute another 10% to total potential in 2043 and reduce the baseline by another 1.1%.
  - 13% of the potential comes from planned (and existing) programs.
- MAP Medium- and High-Retention analyses increase total summer potential by 6 MW-11 MW.
  - As TOU impacts increase, impacts from other DR resources decrease, netting out some of the mandatory rate effects.



Program Option	MW at Generation (% of Baseline)						
	2024	2025	2026	2027	2028	2033	2043
Firm Curtailment/Tariff (Planned)	15 (1%)	15 (1%)	15 (1%)	15 (1%)	15 (1%)	15 (1%)	14 (1%)
Firm Curtailment/Tariff	25 (1%)	36 (2%)	43 (2%)	43 (2%)	43 (2%)	42 (2%)	43 (2%)
Connected Thermostats (Planned)	19 (1%)	15 (1%)	11 (1%)	6 (0%)	3 (0%)	0 (0%)	0 (0%)
Connected Thermostats	1 (0%)	8 (0%)	15 (1%)	20 (1%)	23 (1%)	26 (1%)	26 (1%)
Time-of-Use (TOU) Rate	20 (1%)	18 (1%)	18 (1%)	18 (1%)	18 (1%)	19 (1%)	20 (1%)
Time-Related Pricing (TRP) Rate	0 (0%)	1 (0%)	1 (0%)	1 (0%)	1 (0%)	1 (0%)	1 (0%)
Critical Peak Pricing (CPP) Rate	0 (0%)	1 (0%)	1 (0%)	2 (0%)	2 (0%)	6 (0%)	6 (0%)
MAP Total	79 (4%)	93 (5%)	104 (6%)	104 (6%)	105 (6%)	109 (6%)	110 (6%)
MAP Medium Retention	86 (5%)	98 (5%)	109 (6%)	110 (6%)	111 (6%)	115 (6%)	116 (6%)
MAP High Retention	91 (5%)	102 (6%)	113 (6%)	114 (6%)	115 (6%)	119 (7%)	121 (7%)

RAP Scenario

RAP Scenario

The Realistic Achievable Potential (RAP) scenario:

- Included all cost-effective programs
- Restricted growth in Evergy's existing programs to current achieved participation levels
- Lowered baseline projection for the peak demand savings generated through RAP-forecasted energy efficiency adoption
- Used the TOU Low-Retention rate of 50% and dampened TOU impacts for the first few years to simulate a learning curve (i.e., assuming customers become more effective at responding appropriately to pricing signals over time)

RAP Sensitivity Analysis:

Tested the sensitivity of DR/DSR potential to changes in participation rates in all program options.

RAP Sensitivity Analysis

AEG analyzed two sensitivities in addition to the RAP scenario.

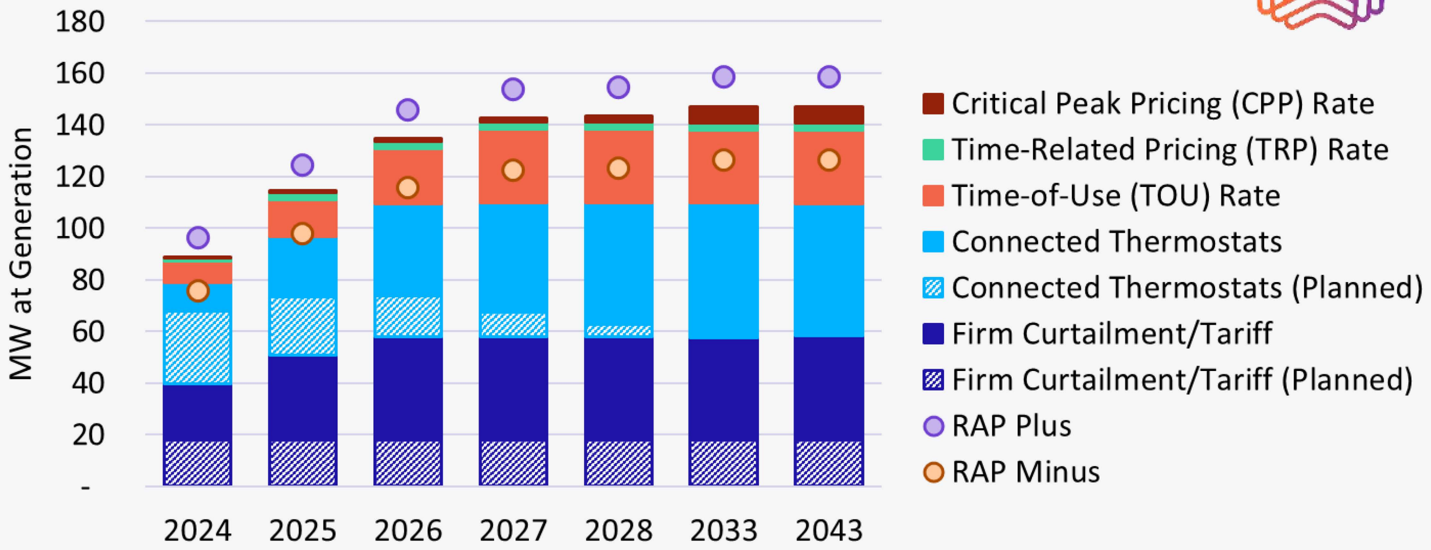
- The RAP Plus scenario increases participation in DR/DSR program options, providing an upper bound around potential under RAP circumstances.
- The RAP Minus scenario provided a lower bound around potential.

Sensitivity	Participation Adjustments	Cost Adjustments	TOU Standard Retention	TOU Impacts
RAP	N/A	N/A	50% of all residential customers	4-year learning curve
RAP Plus[1]	10% increase from RAP	No cost adjustment	50% of all residential customers	4-year learning curve
RAP Minus	15% decrease from RAP	No cost adjustment	43% of all residential customers (15% decrease from RAP)	4-year learning curve

[1]AEG did not increase the TOU retention rate (i.e., TOU Standard participation) in this sensitivity.

RAP Summer Potential Results

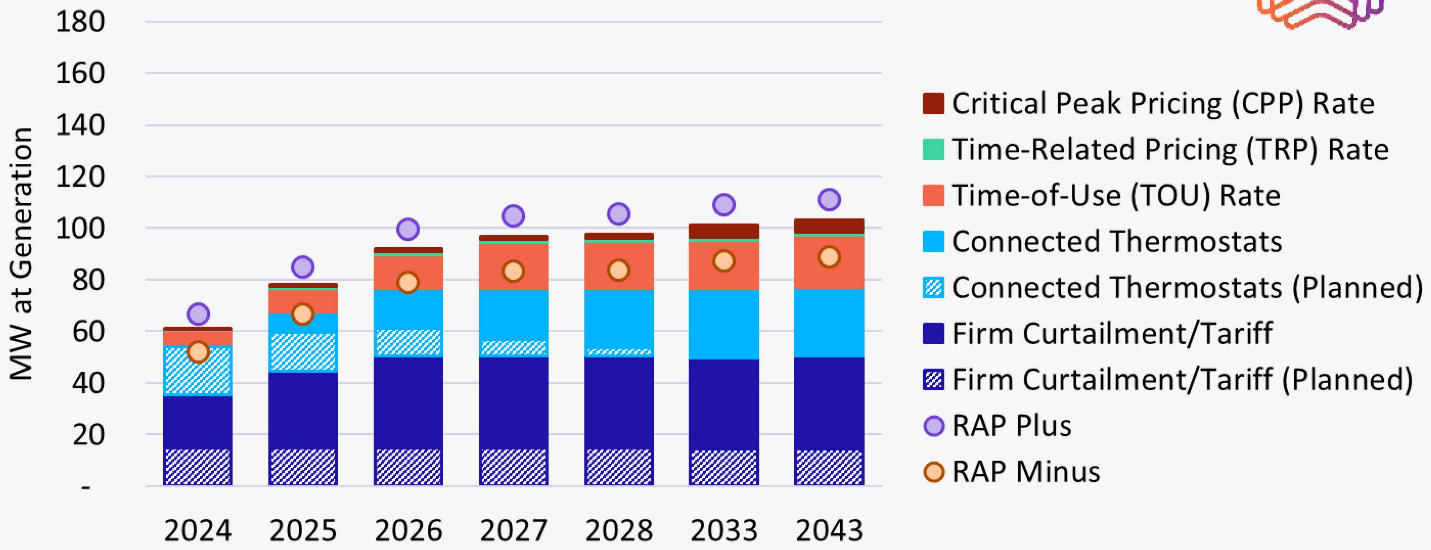
- By 2043, DR/DSR potential is estimated to reduce the summer peak demand baseline by 8%.
  - Firm Curtailment and Connected Thermostats generate 6% of this reduction and account for over 50% of the 2043 DR/DSR potential.
  - TOU rates contribute another 14% to total potential in 2043 and reduce the baseline by another 1.6%.
  - 12% of the potential comes from planned (and existing) programs.
- RAP Plus increased potential by 11 MW
  RAP Minus decreased potential 20 MW



Program Option	MW at Generation (% of Baseline)						
	2024	2025	2026	2027	2028	2033	2043
Firm Curtailment/Tariff (Planned)	18 (1%)	18 (1%)	18 (1%)	18 (1%)	18 (1%)	18 (1%)	18 (1%)
Firm Curtailment/Tariff	22 (1%)	33 (2%)	40 (2%)	40 (2%)	40 (2%)	40 (2%)	40 (2%)
Connected Thermostats (Planned)	28 (2%)	23 (1%)	16 (1%)	10 (1%)	5 (0%)	0 (0%)	0 (0%)
Connected Thermostats	11 (1%)	23 (1%)	36 (2%)	42 (2%)	47 (3%)	52 (3%)	51 (3%)
Time-of-Use (TOU) Rate	8 (0%)	14 (1%)	22 (1%)	29 (2%)	29 (2%)	28 (2%)	28 (2%)
Time-Related Pricing (TRP) Rate	1 (0%)	3 (0%)	3 (0%)	3 (0%)	3 (0%)	3 (0%)	3 (0%)
Critical Peak Pricing (CPP) Rate	0 (0%)	1 (0%)	1 (0%)	2 (0%)	2 (0%)	6 (0%)	6 (0%)
RAP Total	89 (5%)	115 (6%)	135 (7%)	143 (8%)	143 (8%)	147 (8%)	147 (8%)
RAP Plus	97 (5%)	124 (7%)	146 (8%)	154 (8%)	155 (8%)	159 (9%)	159 (9%)
RAP Minus	76 (4%)	98 (5%)	116 (6%)	123 (7%)	123 (7%)	127 (7%)	127 (7%)

RAP Winter Potential Results

- By 2043, DR/DSR potential is estimated to reduce the winter peak demand baseline by 6%.
  - **Firm Curtailment and Connected Thermostats generate over 4% of this reduction and account for almost 40% of the 2043 DR/DSR potential.**
  - **TOU rates contribute another 22% to total potential in 2043 and reduce the baseline by another 1.1%.**
  - **14% of the potential comes from planned (and existing) programs.**
- RAP Plus increased potential by 8 MW
  RAP Minus decreased potential 14 MW



Program Option	MW at Generation (% of Baseline)						
	2024	2025	2026	2027	2028	2033	2043
Firm Curtailment/Tariff (Planned)	15 (1%)	15 (1%)	15 (1%)	15 (1%)	15 (1%)	15 (1%)	14 (1%)
Firm Curtailment/Tariff	21 (1%)	30 (2%)	36 (2%)	36 (2%)	36 (2%)	35 (2%)	36 (2%)
Connected Thermostats (Planned)	19 (1%)	15 (1%)	11 (1%)	6 (0%)	3 (0%)	0 (0%)	0 (0%)
Connected Thermostats	1 (0%)	8 (0%)	15 (1%)	20 (1%)	23 (1%)	27 (1%)	26 (1%)
Time-of-Use (TOU) Rate	5 (0%)	9 (0%)	13 (1%)	18 (1%)	18 (1%)	19 (1%)	20 (1%)
Time-Related Pricing (TRP) Rate	0 (0%)	1 (0%)	1 (0%)	1 (0%)	1 (0%)	1 (0%)	1 (0%)
Critical Peak Pricing (CPP) Rate	0 (0%)	1 (0%)	1 (0%)	1 (0%)	2 (0%)	5 (0%)	5 (0%)
RAP Total	61 (3%)	78 (4%)	92 (5%)	97 (5%)	98 (5%)	101 (6%)	103 (6%)
RAP Plus	67 (4%)	85 (5%)	100 (5%)	105 (6%)	105 (6%)	109 (6%)	111 (6%)
RAP Minus	52 (3%)	67 (4%)	79 (4%)	83 (5%)	84 (5%)	87 (5%)	89 (5%)

Standalone Potential

Key Assumptions

Standalone potential provides a view of each program option in isolation, before accounting for any competition between DR/DSR resources.

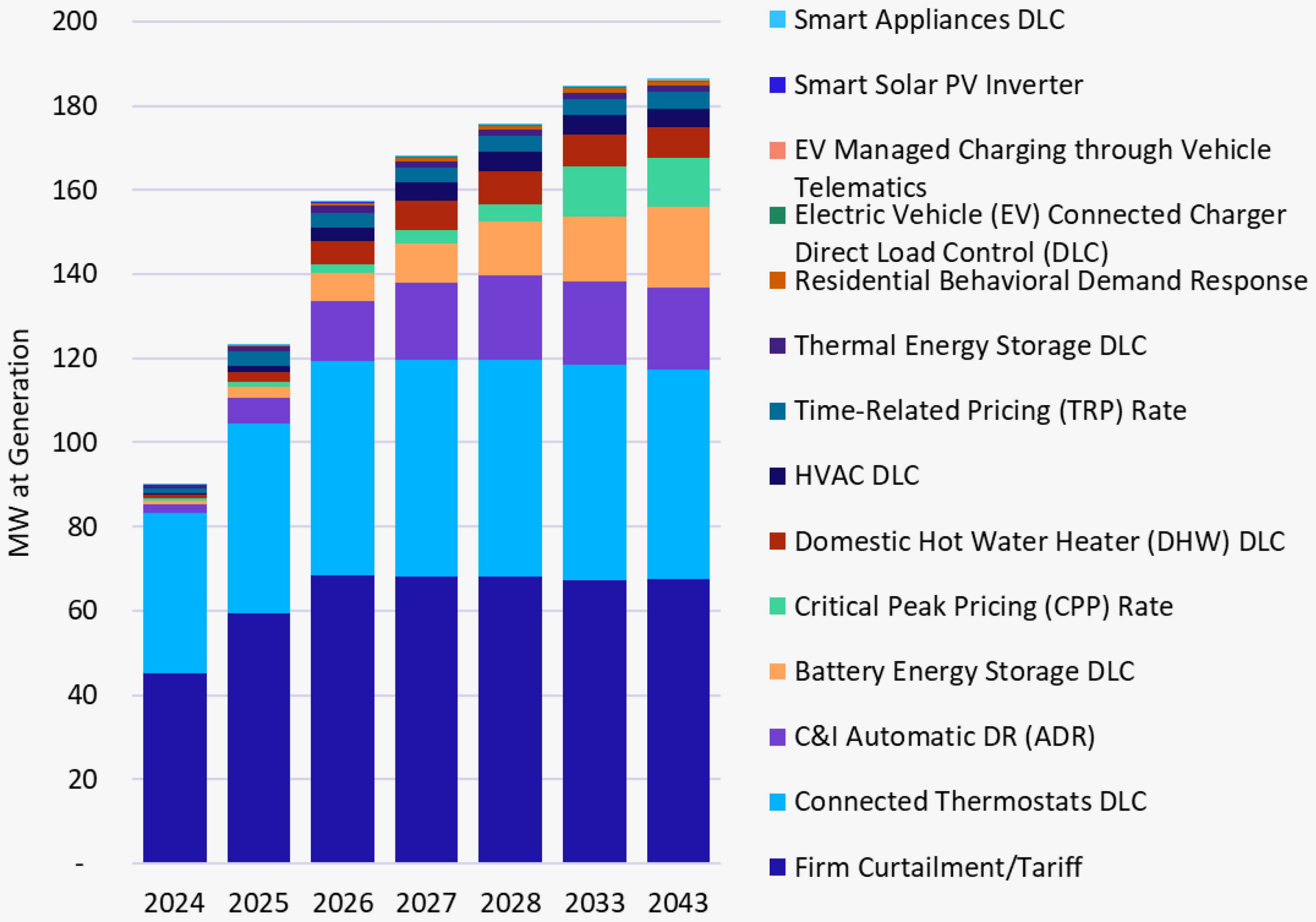
- Maximizes the potential each DR/DSR could provide if no other programs were offered that targeted the same demand during peak hours.
- The economic screen uses standalone potential, because programs will only become less cost-effective once program competition reduces the available capacity to target.

The economic screen identified cost-effective programs for inclusion in the MAP and RAP scenarios.

- Economic screening based on cumulative potential, i.e., including existing resources
- Only considered summer benefits
- Screen based on the Utility Cost Test, i.e., including incentive costs
- Used the MAP scenario to run the cost-effectiveness screen

Standalone Potential Results

- Existing programs contribute more summer potential than all remaining DR/DSR programs combined, even in 2043.
- After accounting for resource competition:
  - Participation in C&I programs like C&I Automatic DR and Thermal Energy Storage goes down because the Firm Curtailment program option targets these same customers
  - Participation in residential programs like Domestic Hot Water Heater DLC and EV Managed Charging decreases because the Connected Thermostats program targets the same customers



Economic Screen

- Evergy's existing programs and both C&I DSR options passed the economic screen.
- The C&I ADR program was on the edge of being cost-effective, but many of these customers will be captured through the Firm Curtailment program.
- Many programs fell short of the threshold because of installation costs (e.g., switches), equipment and O&M costs (e.g., Battery and Smart Solar PV DLC), and overhead costs.
- Residential Behavioral DR was saddled with full development and administrative costs, i.e., independent of an HER program.

Program Option	UCT
Time-Related Pricing (TRP) Rate	3.17
Firm Curtailment/Tariff	3.08
Connected Thermostats DLC	2.51
Critical Peak Pricing (CPP) Rate	2.50
C&I Automatic DR (ADR)	0.92
HVAC DLC	0.59
Domestic Hot Water Heater (DHW) DLC	0.53
Residential Behavioral Demand Response	0.26
Battery Energy Storage DLC	0.13
Electric Vehicle (EV) Connected Charger Direct Load Control (DLC)	0.12
Smart Solar PV Inverter	0.07
EV Managed Charging through Vehicle Telematics	0.04
Smart Appliances DLC	0.04
Thermal Energy Storage DLC	0.00

Thank You.

AEG

APPLIED ENERGY GROUP

Exhibit D_Evergy_Utility Program Review

Sector	Program Name	Program Description	Pros	Cons	Example Utilities	Sources
Residential	Residential New Construction	Rebates/incentives for newly constructed homes that install energy efficient equipment. Criteria for receiving incentives can vary by either a defined set of measures or certain building ratings.	- Evergy is exploring a Zero Energy Ready - New Homes pilot. - Several examples of program types from other utilities with different delivery options/incentive structures. Allows Evergy flexibility on program design to help participation. -New contruction programs avoid lost oppurtunity with installtion of many long-life measures.	- Current Evergy pilot has not launched fully. -Contractor engagement can be difficult	- Black Hills CO (Prescriptive & Performance paths) - Consumers (All-Electric New Homes) - ComEd Illinois (IE New Construction) - CenterPoint	- **Black Hills CO**: https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=976735&p_session_id= - **Consumers**: https://insights.esource.com/documents/Consumers%20Energy%20-%208.1.2021%20-%202022-2025%20Plan%20-%20U-20875.pdf#page=173 - **ComEd**: https://www.icc.illinois.gov/docket/P2021-0155/documents/321073/files/558684.pdf - **CenterPoint**: https://visionelements.programprocessing.com/framework/CenterPointTX/382022120411.2022_CenterPoint_HEH_-_Program_Guide.pdf
Residential	Smart Home Energy Management	Residential customers control connected devices through a central system. Possibility to reduce usage during times of high usage (higher rates). The majority of similar offerings from other utilities were pilot programs that supplied kits to participants and incentivized them to participate in other programs, such as demand response events.	- Program would include new offerings that may attract more residential customers to participate in MEEIA. - Measures could be linked to other offerings (i.e. reducing usage during DR events or times of high usage). -Potential for program expansion with new technology introductions.	- No exact 1 for 1 measure comparison from Evergy TRM. Evergy TRM has "SMART Home Product" (Alexa, Google Home, etc.). - Potential Study includes a Home Energy Management System (HEMS) measure, but the measure does not have any potential in the study. - There is uncertainty on demand or interest for such offerings. May not have enough participation to be a standalone program or offering in an existing program. - There is uncertainty related to program characterization such as attribution, applicable net-to-gross factors, and savings levels.	- JCP&L - CenterPoint Texas (New Homes) - Pepco (kit = hub with sensors/plugs) - Consumers	- **JCP&L**: https://insights.esource.com/documents/Jersey%20Central%20Power%20&%20Light%20-%209.28.2020%20-%202021-2024%20Energy%20Efficiency%20Plan%20-%20EO20090620.pdf#page=133 - **Pepco**: https://homeenergysavings.pepco.com/md/residential/smart-home-pilot-program - **Consumers**: https://insights.esource.com/documents/Consumers%20Energy%20-%208.1.2021%20-%202022-2025%20Plan%20-%20U-20875.pdf#page=173
Residential	Mobile/Manufactured Home Program	Offer either free installation or rebates for energy efficiency measures (HVAC, Wx) for mobile home customers.	- Adding mobile/manufactured home offerings could expand participation Evergy sees for its MEEIA offerings. -Typically underserved market	- Uncertainty on amount of participation offerings would get. Potential study shows 1-3% of homes in Evergy service territory are mobile or manufactured homes. - May not necessarily be a full program, may have to expand eligibility to include mobile homes for other offerings instead.	- Georgia Power - Ameren Illinois	- **Georgia Power**: https://services.psc.ga.gov/api/v1/External/Public/Get/Document/DownloadFile/190693/72407 - **Ameren Illinois**: https://www.icc.illinois.gov/docket/P2021-0158/documents/322773/files/561841.pdf

Sector	Program Name	Program Description	Pros	Cons	Example Utilities	Sources
Community	School Kits	Supply free energy efficiency kits and education materials to schools.	- Evergy already offers similar product in Income Eligible kits. - Several examples of offering from other utilities.	- Uncertainty related to demand/interest for such offerings. May not have enough participation to be a standalone program or offering in existing program. - Savings claimed from this type of offering would be limited. This could mean spending in this program that does not necessarily lead to large savings for the portfolio.	- Black Hills CO - Ameren Illinois	- **Black Hills CO**: https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=976735&p_session_id= - **Ameren Illinois**: https://www.icc.illinois.gov/docket/P2021-0158/documents/322773/files/561841.pdf
Community	UHI Mitigation	Offer rebates for UHI mitigation measures such as cool/reflective roofs. Also offer events for shade tree giveaways (either free or rebated) with education materials.	- Evergy has an existing Shade Tree pilot program. - Strong stakeholder support for this offering. - Including UHI mitigation offerings helps to address the portfolio goal of decarbonization opportunities. -Long measure life for some measures that could offer generational benefits.	- Tree measures not included in Potential Study. No estimation of potential for measures or existing characterization to go off of for design in MEEIA. - No existing policy for claiming savings on these type of projects. - Limited number of utilities have cool roof/shade trees as standalone offering. Most utilities include these measures as offerings in a larger program. - Uncertainty surrounding cost-effectiveness for program, especially for cool roof measures.	- CPS Energy Texas (Cool Roofs) - SRP Arizona (Shade Tree) - UNS Arizona (Shade Tree)	- **CPS Energy**: https://insights.esource.com/documents/CPS%20Energy%20-%205.20.2021%20-%20FY2021%20Annual%20Report.pdf#page=58 - **SRP**: https://insights.esource.com/documents/SRP%20-%208.1.2021%20-%20FY2020%20Energy%20Efficiency%20Report.pdf#page=24 - **UNS**: https://insights.esource.com/documents/UNS%20-%203.1.2022%20-%202021%20DSM%20Annual%20Report%20-%20E-00000U-18-0055.pdf#page=28
Community	Non-Profit	Rebates for purchase and installation of energy efficient measures for nonprofit organizations. Offering would include energy audits, customized reports, and concierge style assistance for each participant.	- Evergy has done a non-profit pilot that has seen moderate success. - Program addresses portfolio goal of equity and providing energy efficiency opportunities for customer types that have had limited access historically. -Hard to reach market where a dedicated program could offer needed benefits.	- Participants will need higher incentive levels and one on one assistance due to knowledge gaps and sensitive customer segments, leading to higher incentive and administrative costs. - Market participants can have competing priorities and limited capital for building improvements. This could hinder participation.	- Ameren Illinois - ComEd Illinois - Xcel MN - Xcel CO	- **Ameren Illinois**: https://www.icc.illinois.gov/docket/P2021-0158/documents/322773/files/561840.pdf - **ComEd**: https://insights.esource.com/documents/ComEd%20-%202.20.2020%20-%202019%20Q4%20Report%20-%2017-0312.pdf#page=15 - **Xcel MN**: https://insights.esource.com/documents/Xcel%20MN%20-%203.31.2022%20-%202021%20CIP%20Annual%20Report%20-%2020-473.pdf#page=70 - **Xcel CO**: https://insights.esource.com/documents/Xcel%20CO%20-%207.1.2020%20-%202021-2022%20DSM%20Plan%20-%2020A-00287EG.pdf#page=165
Community	Local Building Energy Benchmarking	Provide free energy benchmarking to local business customers to assist in tracking energy usage and year over year results.	- Program could address customer types in service territory that have not participated in MEEIA programs in the past. - Offering could encourage these types of customers to participate in other MEEIA programs. - Program could include a behavioral aspect if Evergy chooses to make results public and introduce a competitive piece to the program.	- Uncertainty on ability to claim savings from this type of program. - Uncertainty on Evergy's existing infrastructure and ability to offer benchmarking services.	- Consumers - Xcel CO - Energy Star Program	- **Consumers**: https://insights.esource.com/documents/Consumers%20Energy%20-%208.1.2021%20-%202022-2025%20Plan%20-%20U-20875.pdf#page=173 - **Xcel CO**: https://co.my.xcelenergy.com/s/business/cost-savings/energy-benchmarking - **Energy Star Program**: https://aceee2022.conferencespot.org/event-data/pdf/catalyst_activity_32410/catalyst_activity_paper_20220810190508991_a33aec2d_e47c_4c76_928d_744b0d0621e0

Sector	Program Name	Program Description	Pros	Cons	Example Utilities	Sources
Community	LED Street Lighting	Incentivize municipal customers to install LED lighting for their streetlight fixtures.	- Addressing new area that Evergy has not necessarily focused on before. - Could reach more customers that have not participated in MEEIA programs in the past. -Additional public safety benefits beyond energy efficiency.	- Uncertainty surrounding LED standards and opportunities for upcoming MEEIA. - Streetlighting measures not included in Evergy TRM or Potential Study. No estimation of potential for measures or existing characterization to go off of for design in MEEIA. -Free ridership a concern given high street lighting baseline.	- Ameren Illinois - ComEd Illinois - Otter Tail Power Co. (MN)	- **Ameren Illinois**: https://www.icc.illinois.gov/docket/P2021-0158/documents/322773/files/561840.pdf - **ComEd**: https://www.comed.com/WaysToSave/ForYourBusiness/Pages/StreetLights.aspx - **Otter Tail**: https://insights.esource.com/documents/Otter%20Tail%20Power%20-%207.1.2020%20-%202021-2023%20Plan%20-%2020-475.pdf#page=80
Business	Indoor Agriculture	Incentives for purchase and installation of specialized energy efficient equipment used by indoor agricultural facilities.	- Addressing new area that Evergy has not necessarily focused on before. - Could reach more customers that have not participated in MEEIA programs in the past.	- Uncertainty related to demand/interest for such offerings. May not have enough participation to be a standalone program or offering in existing program. -Program could take customers from Custom projects.	- Efficiency Maine - Black Hills CO	- **Efficiency Maine**: https://www.efficiencymaine.com/at-work/agricultural-solutions/ **- Black Hills CO:** https://www.blackhillsenergy.com/sites/blackhillsenergy.com/files/coe-ee-indoor-ag-program.pdf
Business	Business Marketplace	Discounts for business customers on C&I energy efficient equipment sold through an online marketplace.	- Evergy has existing infrastructure to deliver this type of program. - Measures included in this program could be used to incentivize participation in other programs.	- Further discussion on which commercial measures would be available on the marketplace. - Limited examples from other utilities of this type of offering for business customers. Most examples only include smart thermostats to be used in other offerings.	- NIPSCO - Ameren Illinois	- **NIPSCO**: https://www.nipsco.com/business-online-marketplace **- Ameren Illinois:** https://amerenillinoissavings.com/business/industry-solutions/small-business/
Business	SBDI	Small business participants receive an on-site assessment and incentives for installation of any energy efficiency equipment recommended from the assessment.	- Evergy has experience running this type of program. - Several examples of other utilities offering this type of program. - Evergy could focus program on disadvantaged business owners to further emphasize the goal of an equitable portfolio of offerings.	- Evergy discontinued historical offering due to cost concerns. -Offerings can be duplicative of other programs.	- Ameren Illinois - ComEd Illinois - Indianapolis Power & Light - Ameren MO - National Grid RI	- **Ameren Illinois**: https://www.icc.illinois.gov/docket/P2021-0158/documents/322773/files/561840.pdf - **ComEd**: https://www.icc.illinois.gov/docket/P2021-0155/documents/321073/files/558684.pdf - **Indianapolis Power & Light**: https://insights.esource.com/documents/IPL%20-%204.23.2020%20-%202021-2023%20DSM%20Plan%20-%2045370.pdf#page=66 - **Ameren MO**: https://insights.esource.com/documents/Ameren%20-%20MO%20-%202.8.2018%20-%202019-2024%20Plan%20-%20EO-2018-0211.pdf#page=144 - **National Grid RI**: https://insights.esource.com/documents/National%20Grid%20-%20RI%20-%209.30.2022%20-%202023%20DSM%20Plan%20-%2022-23-EE.pdf#page=193
Business	Virtual Energy Management	Provide free energy management platform for Small Business participants. A subscription to the energy management tool includes installation of various measures.	- Evergy has an existing pilot offering and existing infrastructure to deliver this type of program. - Evergy could focus program on disadvantaged business owners to further emphasize the goal of an equitable portfolio of offerings. -Low barrier to entry for certain	- Could overlap with advanced technology offerings on the demand response side. -Certain customer segments could be excluded based on building and technology limitations.	- ComEd Illinois	- **ComEd**: https://www.comed.com/WaysToSave/ForYourBusiness/Pages/BusinessEnergyAnalyzer.aspx

Sector	Program Name	Program Description	Pros	Cons	Example Utilities	Sources
Business	Food Service	Provide free on-site assessments and/or rebates to restaurants in the area for the purchase and installation of recommended energy efficient food service equipment.	- Assortment of food service measures had potential in the Potential Study. - Addressing new area that Evergy has not necessarily focused on before. -Long life measures where lost oppurtunity if efficient measures not installed.	- Concerns with cost-effectiveness for this offering as AEG has seen cost-effectiveness be an issue for these types of measures in other models. - Uncertainty related to demand/interest and participation for such offerings.May not warrant a stand alone offering. -Secondary market for food service equipment limits the new efficient measure market.	- Consumers - CenterPoint MN - Xcel MN - DTE Electric - Peoples/North Shore Gas	- **Consumers**: https://insights.esource.com/documents/Consumers%20Energy%20-%208.1.2021%20-%202022-2025%20Plan%20-%20U-20875.pdf#page=173 - **CenterPoint MN**: https://insights.esource.com/documents/CenterPoint%20MN%20-%207.1.2020%20-%202021-2023%20Plan%20-%2020-478.pdf#page=120 - **Xcel MN**: https://insights.esource.com/documents/Xcel%20Energy%20-%20MN%20-%207.1.2020%20-%202021-2023%20Plan%20-%2020-473.pdf#page=60 - **DTE Electric**: https://insights.esource.com/documents/DTE%20Electric%20-%206.30.2021%20-%202022-23%20Energy%20Waste%20Reduction%20Plan%20-%20U-20876.pdf#page=176 - **Peoples/NSG**: https://insights.esource.com/documents/Peoples%20Gas%20-%203.1.2021%20-%202022-2025%20EE%20Plan%20-
Business	Data Center Program	Rebates for purchase and installation of energy efficient equipment related to data centers.	- Addressing new area that Evergy has not necessarily focused on before. - Assortment of data center measures from the Potential Study had potential attached to them. -Each project can offer large savings.	- There are few examples of standalone programs for this specific area from other utilities. Most utility examples include data center measures as part of a larger offering such as a standard rebate program. - Uncertainty related to demand/interest for such offerings. May not have enough participation to be a standalone program or offering in existing program.	- Xcel CO - Xcel MN	- **Xcel CO**: https://www.xcelenergy.com/staticfiles/xe-responsive/co-business-programs-summary.pdf - **Xcel MN**: https://insights.esource.com/documents/Xcel%20Energy%20-%20MN%20-%207.1.2020%20-%202021-2023%20Plan%20-%2020-473.pdf#page=54

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Evergy 2023 IRP DSM Analysis – Exhibit E_Program Descriptions

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1 | Evergy 2023 IRP Program Bundle Descriptions

This chapter details the key elements of each program in the portfolio, specifically the energy efficiency and demand response RAP scenario (demand side rates are not included). The years highlighted are the nearest program implementation cycle of 2024-2027, as well as 2036 and 2043, the final year of the study. Data for all years and scenarios are available in Exhibits E and F.

1.1 Residential

1.1.1 Energy Saving Products

Objective	The Energy Saving Products program will feature point-of-purchase rebates and online discounts for energy-efficient measures, including but not limited to: smart thermostats, appliances, advanced power strips, air purifiers, dehumidifiers and water-saving devices.
Target Market	All residential customers, manufacturers, and local retailers.
Description	Customers will receive an instant incentive for the purchase of qualified high-efficiency products – either through an online marketplace or a retail brick & mortar store. Incentives will vary depending upon the measures.
Implementation	Evergy will engage a third-party implementation contractor to: • Establish relationships with manufacturers and retailers throughout service territories. • Provide in-store promotional materials and retail sales staff training. • Maintain comprehensive online customer portal where customers will be able to browse the marketplace through the offered energy efficient equipment and appliances, and purchase qualifying measures through an online marketplace that will offer instant rebates. • Provide online support for customer website troubleshooting • Track program performance, including tracking sales data, reviewing sales data for accuracy, and payment to retailers. • Periodically report progress towards program goals and opportunities for improvement. Evergy will work with the implementation contractor to market the program to customers and educate retailer sales staff. Marketing efforts to increase customer awareness may include, but not be limited to, bill inserts, newspaper advertisements, internet placement, and Point-of-Purchase materials (hang tags, posters). Energy Saving Products will be cross-marketed with Evergy's other Residential DSM programs and be used to increase awareness of DSM rebates will reduce spillover. The program will be implemented upstream from retailers; therefore, incentives will be provided at the manufacturer- and distributor-level. Upstream options simplify the participation process, eliminating the need for customers to complete and submit a rebate application. However, upstream options typically have higher free ridership and leakage outside the service territory. Several steps will be taken to reduce free ridership and leakage while increasing spillover, including: • Evergy will work with the implementation contractor to select retailers located well within the service territory to reduce leakage. • Incentives will be modified as needed to respond to the market price of the qualifying measure, with a goal of the incentive being no higher than 50% of the incremental cost.

Eligible Measures	Residential customers will be eligible for instant, point-of-purchase rebates on products. Incentives may be modified to respond to the market. Eligible measure include, but not limited to: • Advanced Power Strips • Air Purifiers • ENERGY STAR Clothes Washers • ENERGY STAR Connected Thermostats • Dehumidifiers • LED Linear Lighting Measures • ENERGY STAR Refrigerators • Faucet Aerators • Low Flow Showerheads • Pipe Insulation • Thermostatic Shower Restriction Valves (TSRV)
Estimated Savings	(see tables below)
Estimated Budget	(see table below)
Cost-Effectiveness	(see table below)

Estimated Savings

Territory	Net MWh Savings					
	2024	2025	2026	2027	2036	2043
Metro	1,543	1,689	1,730	1,779	2,039	1,248
West	2,654	2,885	2,951	3,041	3,415	2,098
Total	4,197	4,575	4,681	4,820	5,453	3,346

Territory	Net MW Savings					
	2024	2025	2026	2027	2036	2043
Metro	0.50	0.53	0.55	0.58	0.61	0.39
West	0.77	0.82	0.86	0.90	0.96	0.58
Total	1.26	1.35	1.41	1.47	1.56	0.97

Estimated Budget

Territory	Annual Budget					
	2024	2025	2026	2027	2036	2043
Metro	$540,274	$583,631	$624,331	$659,157	$763,921	$528,944
West	$820,909	$886,154	$943,824	$997,937	$1,137,182	$722,267
Total	$1,361,184	$1,469,785	$1,568,155	$1,657,095	$1,901,103	$1,251,211

Cost-Effectiveness

Territory	TRC Ratio					
	2024	2025	2026	2027	2036	2043
Metro	1.63	1.89	1.98	2.09	2.99	2.69
West	1.78	2.09	2.19	2.32	3.36	3.24
Total	1.72	2.01	2.11	2.23	3.21	3.00

1.1.2 Heating, Cooling & Weatherization

Objective	Encourage whole-house improvements to existing homes by promoting home energy audits and comprehensive retrofit services. This includes: • Encourage energy-saving behavior and whole house improvements. • Help residential customers reduce their electricity bills. • Educate customers about the benefits of installing high-efficiency equipment. • Develop partnerships with contractors to bring efficient systems to market.
Target Market	The program targets high energy-use residential customers in single family, duplex and “4-plex or less” multi-family buildings. Other groups with high interest in achieving optimum delivery are builders, HVAC contractors, energy auditors, realtors, financing agents, etc.
Description	The program encourages home improvements that increase operational energy efficiency and home comfort. It consists of two primary components: • *Audit and Weatherization*, provides incentives for installing home envelope/weatherization measures, such as insulation and air sealing. This component also offers a free direct installed energy saving kit by energy auditor trade allies, with a requirement to have an Energy Audit performed. • *HVAC,* which incentivizes energy efficiency improvements to a homes’ HVAC. It offers equipment rebates for qualifying installed HVAC equipment, duct efficiency improvements and tune-ups performed by an authorized trade ally. Customers that rent a residence must receive the written approval of the homeowner/landlord to participate in the option.
Implementation	We will continue to co-deliver this program with the local gas utility, where service jurisdictions overlap and shared cost benefits exist. Due to the unpredictable and changing nature of the marketplace, Evergy and its contractors will maintain flexibility within the program. Various market factors — including new codes and standards, energy legislation and consumer value shifts — will affect the measure mix and program delivery strategy. Evergy will engage a third-party contractor to implement the option. An implementation contractor will: • Hire staff/engage local contractors to conduct audits and direct measure installation. • Engage customers and schedule home energy audit appointments. • Provide customer service support. • Establish relationships with local HVAC contractors to work with the option installing energy efficient HVAC equipment and insulation measures. • Process rebate applications, including review and verification of applications and payment of customer rebates. • Track option performance, including customer and contractor participation as well as quality assurance/quality control (QA/QC). • Periodically report option progress. Customer marketing activities may include, but not be limited to bill inserts, newspaper advertisements, email blasts, bill messaging, and community events. It is important that the measures are properly installed and customer satisfaction is high. Evergy and/or the implementation contractor should conduct QA/QC of a random group of completed projects by project type and contractor. The QA/QC process should include verifying the installed equipment and customer satisfaction with the contractor and the option.

Eligible Measures	The measures may be modified to reflect market conditions.

Weatherization Measures
Liquid-Applied Weather-Resistive Barrier
Whole-Home Aerosol Sealing
Duct Repair and Sealing
Duct Insulation
Basement Sidewall Insulation
Floor Insulation
Radiant Barrier Insulation

Equipment Rebate Measures
Air Source Heat Pump
Central Air Conditioner
Central Heat Pump Controls
Heat Pump Ductless Mini-Split
Geothermal Heat Pump
Room Air Conditioner
Water Heater Drain Water Heat Recovery
Heat Pump Water Heater

Estimated Savings

Territory	Net MWh Savings					
	2024	2025	2026	2027	2036	2043
Metro	2,879	3,018	3,523	3,665	4,114	3,006
West	6,984	7,209	7,468	7,670	8,597	7,155
Total	9,863	10,227	10,991	11,335	12,711	10,161

Territory	Net MW Savings					
	2024	2025	2026	2027	2036	2043
Metro	1.58	1.67	1.77	1.85	2.08	1.37
West	2.55	2.67	2.80	2.91	3.33	2.27
Total	4.14	4.34	4.57	4.76	5.41	3.64

Estimated Budget

Territory	Annual Budget					
	2024	2025	2026	2027	2036	2043
Metro	$1,920,943	$2,031,953	$2,264,194	$2,368,702	$2,989,520	$2,074,965
West	$4,290,412	$4,470,686	$4,657,843	$4,825,946	$5,929,648	$4,964,283
Total	$6,211,355	$6,502,639	$6,922,037	$7,194,648	$8,919,169	$7,039,249

Cost-Effectiveness

Territory	TRC Ratio					
	2024	2025	2026	2027	2036	2043
Metro	1.43	1.52	1.58	1.68	2.17	2.12
West	1.25	1.33	1.42	1.50	1.94	1.74
Total	1.31	1.39	1.47	1.56	2.02	1.85

1.1.3 Research and Pilot – Appliance Recycling

Objective	Promote the removal and retirement of inefficient appliances.
Target Market	Residential customers disposing of their primary or secondary inefficient refrigerators, freezers, dehumidifier, or room air conditioners.
Description	Residential customers are encouraged to turn in their old inefficient refrigerators, freezers, and room air conditioners, removing them from the electric system and disposing of them in an environmentally safe and responsible manner. Program requirements to recycle a refrigerator or freezer include: • The unit must be between 10 and 30 cubic feet in size and in working condition. • At the time of pick-up, the unit must be empty, plugged into an electrical outlet, and there must be a clear path for removal. • Units using ammonia or SO2 refrigerant are excluded from participation. • The unit can be primary or secondary. Customers may recycle their old room air conditioners free of charge during a scheduled pick-up for a qualifying refrigerator/freezer. The recycled unit must be working at the time of pick-up. Customers are limited to two (2) refrigerator and freezer rebates and three (3) room air conditioners per household per year.
Implementation	The start year of this program will be 2028, when the program becomes cost effective. Implementation activities will include: • Schedule pick-ups from customer homes, verify customer eligibility and appliance qualification, remove appliances from customer homes, and recycle / responsibly dispose of appliances. • Rebate processing. • Program tracking. • Periodically report progress towards program goals and opportunities for improvement. • Marketing plan to achieve program goals. Marketing may include, but not be limited to, bill inserts, newspaper/community newsletter advertisements, community events, billboards, and Evergy's website. The program consists of an educational component informing customers about the benefits of recycling their inefficient appliances and environmentally responsible disposal. Actual energy and demand savings could be lowered if a customer recycles a secondary appliance and begins utilizing their former primary unit as a secondary unit. Appliance recycling programs typically have higher free ridership rates than other programs, primarily due to: • Customers planning to replace their appliance before participating in the program. • Customers that were not using their appliance prior to participating in the program. In an effort to reduce free ridership, the program should emphasize and enforce the requirement that the appliance is plugged in and in operating condition at the time of pick-up. In an effort to increase spillover, the program should be cross-marketed with other residential programs.
Eligible Measures	Incentives will be offered for refrigerators and freezers only. **Measure**: Refrigerator; Freezer; Room Air Conditioner; Dehumidifier

Estimated Savings

Territory	Net MWh Savings					
	2024	2025	2026	2027	2036	2043
Metro	n/a	n/a	n/a	n/a	621	610
West	n/a	n/a	n/a	n/a	800	795
Total	n/a	n/a	n/a	n/a	1,421	1,405

Territory	Net MW Savings					
	2024	2025	2026	2027	2036	2043
Metro	n/a	n/a	n/a	n/a	0.27	0.26
West	n/a	n/a	n/a	n/a	0.21	0.20
Total	n/a	n/a	n/a	n/a	0.48	0.46

Estimated Budget

Territory	Annual Budget					
	2024	2025	2026	2027	2036	2043
Metro	n/a	n/a	n/a	n/a	$157,220	$170,559
West	n/a	n/a	n/a	n/a	$299,245	$326,183
Total	n/a	n/a	n/a	n/a	$456,465	$496,743

Cost-Effectiveness

Territory	TRC Ratio					
	2024	2025	2026	2027	2036	2043
Metro	n/a	n/a	n/a	n/a	2.08	2.02
West	n/a	n/a	n/a	n/a	1.15	1.12
Total	n/a	n/a	n/a	n/a	1.47	1.43

1.1.4 Residential New Construction

Objective	Encourage energy efficiency achievements in the new construction of residential homes.
Target Market	Homeowners, home builders/developers, and raters. Single-family homes and duplexes qualify for rebates.
Description	Residential customers and builders put together a customized new construction package by selecting any combination of eligible measures to receive the incentive. Customers must relect an HVAC unit and a shell measure in order to qualify for the incentive. Customers are encouraged to move forward with a suite of measurs to secure a higher incentive.
Implementation	Implementation activities will include: • Engage and establish relationships with builders, developers, and raters to participate in the program. • Provide customer service support. • Process rebate applications, including review and verification of applications and payment of rebates. • Track program performance. • Quality assurance/quality control (QA/QC) activities will include application reviews and random site visits to verify measure installation. • Periodically report program progress. Evergy will market the program to residential customers and builders/developers. Partnerships with builders, developers, and raters will be developed via education and training seminars, presentations at Home Builder Association meetings, and other informational events. Customer marketing activities may include, but not be limited to bill inserts, email blasts, bill messaging, and community events. The key barriers for many new construction offerings is the administrative burden to locate raters and receive HERs rating. This offering is designed to be a prescriptive offering to reduce barriers encountered with the location and training of HERS raters. A HERS rating will not be required for this program. Instead, the implementation contractor will work with interested customers to ensure they are selecting the right products for their new construction home. It is important that the measures are properly installed and customer satisfaction is high. Evergy and/or the implementation contractor should conduct QA/QC of a random group of completed projects by project type and contractor. The QA/QC process should include verifying the installed equipment and customer satisfaction with the contractor and the option. In an effort to increase spillover, the program should be cross-marketed with other residential programs.

Eligible Measures

Eligible measures include:

Measure
Advanced Power Strip
Air-Source Heat Pump
Liquid-Applied Weather-Resistive Barrier
Central AC
Central Heat Pump Controls and Commissioning
Connected Thermostat
Floor Insulation
Radiant Barrier Insulation
Refrigerator
Drain Water Heat Recovery
Water Heater
High-Efficiency Windows

Estimated Savings

Territory	Net MWh Savings					
	2024	2025	2026	2027	2036	2043
Metro	741	664	602	539	363	85
West	874	863	828	777	584	199
Total	1,615	1,526	1,430	1,316	947	284

Territory	Net MW Savings					
	2024	2025	2026	2027	2036	2043
Metro	0.38	0.34	0.31	0.28	0.17	0.03
West	0.43	0.42	0.40	0.37	0.24	0.06
Total	0.81	0.76	0.71	0.64	0.41	0.09

Estimated Budget

Territory	Annual Budget					
	2024	2025	2026	2027	2036	2043
Metro	$333,229	$299,771	$272,743	$245,544	$168,012	$36,577
West	$352,642	$349,733	$337,545	$318,323	$250,708	$105,452
Total	$685,871	$649,504	$610,289	$563,866	$418,719	$142,029

Cost-Effectiveness

Territory	TRC Ratio					
	2024	2025	2026	2027	2036	2043
Metro	1.64	1.74	1.84	1.95	2.58	2.44
West	1.79	1.89	2.00	2.10	2.58	1.90
Total	1.72	1.82	1.93	2.03	2.58	2.04

1.1.5 Income Eligible Multi-Family

Description	The program aims to provide direct install measures in housing units and common area measures in multi-family buildings. This includes the following characteristics: ***Multi-Family DI.*** Direct installation of low-cost measures for income-eligible homeowners and renters in multi-family housing, at no cost to the participant. The low-cost measures to be installed include: low-flow faucet aerator, low-flow showerhead, advanced power strip, water heater tank wrap, hot water pipe insulation and LEDs. ***Multi-Family Common Areas.*** Installation of prescriptive lighting measures in multi-family common areas, at no cost to the participating building owner, and custom measure rebates at $/kWh saved.
Objectives	Deliver long-term energy savings and bill reductions to income-eligible customers in multi-family housing and common area energy savings.
Target Market	Income-eligible residential homeowners and renters that are below 200% of the Federal poverty level and reside in multi-family housing. Multi-family buildings with income-eligible residents.
Implementation Strategy	Evergy will engage a third-party implementation contractor to: • Identify and establish relationships with multi-family building owners that have a number of income-eligible residents. • Engage customers and schedule appointments. • Track program performance. • Periodically report progress toward program goals. The implementation contractor framework could include providing owners of multi-family buildings with a single point of contact or Coordinator for in-unit and common area/building system measures. The Coordinator's duties could include: • Determining eligibility and ensuring eligible customers are aware of the available incentives from all utilities. • Assisting in the application process for the residential and business improvements. In addition, where other utilities are participating, assisting with those applications. • Providing a seamless point of contact for navigating the various incentive offers provided by the Company and other utilities. • Maintaining a relationship with the existing business trade ally network and providing information and guidance to assist them with the bid process for installation work. • Understanding and maintaining a network of assistance agencies and making referrals for financing and repairs, seeking to remove barriers to participation. • Providing case studies and education, and working with business development teams to ensure proper outreach is occurring. • Coordinating marketing materials to provide an easy to understand process for participation. • Maintaining working relationships with and providing outreach and education to stakeholders such as lenders, government agencies, and other identified parties. The program targets an underserved market that may not participate in other DSM programs due a lack of funds or awareness. The program will encourage building managers and owners to continue improving building energy efficiency via the Business DSM Programs. The program focuses on providing energy efficiency services to income-eligible residents to ensure reduced consumption. There is little risk associated with this product.
Measures	The multi-family unit kits and common area lighting measures are installed free of charge. The DI include: low-flow faucet aerator, low-flow showerhead, advanced power strip, water heater tank wrap, hot water pipe insulation and LEDs. Major measures and custom common area incentives are provided at 100% of the incremental cost.

Estimated Savings

Territory	Net MWh Savings					
	2024	2025	2026	2027	2036	2043
Metro	211	249	282	300	350	256
West	164	169	205	212	219	167
Total	375	419	486	513	569	424

Territory	Net MW Savings					
	2024	2025	2026	2027	2036	2043
Metro	0.06	0.07	0.08	0.09	0.09	0.07
West	0.05	0.05	0.06	0.06	0.05	0.04
Total	0.10	0.12	0.14	0.16	0.14	0.10

Estimated Budget

Territory	Annual Budget					
	2024	2025	2026	2027	2036	2043
Metro	$100,844	$133,325	$149,542	$216,556	$266,730	$229,714
West	$99,332	$103,720	$122,254	$128,000	$146,286	$97,792
Total	$200,176	$237,046	$271,796	$344,556	$413,016	$327,506

Cost-Effectiveness

Territory	TRC Ratio					
	2024	2025	2026	2027	2036	2043
Metro	1.56	1.49	1.53	1.29	1.62	1.38
West	1.21	1.30	1.33	1.42	1.79	1.87
Total	1.39	1.40	1.44	1.34	1.68	1.53

1.1.6 Income Eligible Single Family

	The program leverages the Weatherization Assistance Program to provide qualifying customers with approved energy efficiency measures and equipment.
Objectives	Deliver long-term energy savings and bill reductions to income-eligible customers.
Target Market	Income-eligible residential homeowners and renters below 200% of the Federal poverty level.
Implementation Strategy	Evergy will work with local Weatherization Assistance Program agencies to implement the program. The agencies will utilize the Evergy funding to provide weatherization to additional homes and will be responsible for the following activities: • Market the program and engage customers. • Schedule appointments. • Install measures. • Track program performance. • Periodically report progress towards program goals. The program targets an underserved market that may not participate in other DSM programs due a lack of funds. The program focuses on providing energy efficiency services to income-eligible residents to ensure reduced consumption. There is little risk associated with this product.
Eligible Measures	Measures are provided at no cost to the customer and include, but not limited to:

Eligible Measures
Advanced Power Strip
Air Purifier
Air Source Heat Pump
Liquid-Applied Weather-Resistive Barrier
Whole-Home Aerosol Sealing
Central AC
Central Heat Pump Controls and Commissioning
Connected Thermostat
Dehumidifier
Duct Insulation & Sealing
Basement Sidewall Insulation
Floor Insulation
Radiant Barrier Insulation
Refrigerator
Room AC
Faucet Aerator
Low Flow Showerhead
Pipe Insulation
Thermostatic Shower Restriction Valve
Water Heater

Estimated Savings

Territory	Net MWh Savings					
	2024	2025	2026	2027	2036	2043
Metro	1,308	1,381	1,428	1,466	1,140	786
West	908	951	975	998	935	724
Total	2,216	2,332	2,403	2,464	2,075	1,510

Territory	Net MW Savings					
	2024	2025	2026	2027	2036	2043
Metro	0.64	0.67	0.70	0.73	0.43	0.32
West	0.38	0.40	0.42	0.43	0.27	0.20
Total	1.02	1.07	1.12	1.16	0.70	0.53

Estimated Budget

Territory	Annual Budget					
	2024	2025	2026	2027	2036	2043
Metro	$708,630	$740,499	$771,791	$796,949	$825,995	$507,293
West	$567,433	$586,448	$602,807	$617,608	$693,593	$515,873
Total	$1,276,063	$1,326,947	$1,374,598	$1,414,557	$1,519,588	$1,023,166

Cost-Effectiveness

Territory	TRC Ratio					
	2024	2025	2026	2027	2036	2043
Metro	1.72	1.91	2.05	2.21	2.29	2.51
West	1.40	1.55	1.68	1.82	1.89	1.81
Total	1.58	1.75	1.89	2.04	2.11	2.16

1.1.7 Residential Smart Thermostat

Description	The Residential Smart Thermostat with Direct Load Control (DLC) Program pays an incentive to participants to reduce peak demand by controlling their cooling equipment during periods of system peak demand and when there may be delivery constraints within certain load zones. This is done by way of a remotely communicating, wifi thermostat. During a program event, the program operations center sends a signal to the thermostat to adjust its set-point by a few degrees such that the system will consume less energy and run less frequently throughout the max 4-hour event duration. Bring Your Own (BYO) Customers enroll in the program with a thermostat of their choosing and receive an annual incentive for their participation in demand response events.
Objectives	Primarily decrease peak demand usage to provide system and grid relief during particularly high-load, high-congestion peak hours. Also provide annual energy savings.
Target Market	Individually metered residential customers. Target primarily single family homeowners, expanding into multi-family as the single family market opportunities begin to saturate.
Implementation Strategy	Evergy will engage a third-party implementation contractor to: • Hire/sub-contract local staff to install the programmable thermostats. • Engage customers, schedule installation appointments and process customer incentives. • Provide customer service support. • Track program performance and event data. • Periodically report progress towards program goals and opportunities for improvement. Events typically occur between June 1 and September 30, Monday to Friday. Event duration is max 4 hours per day Customers may opt-out twice a year. The program will be marketed through direct contact with consumers using bill inserts, newsletters, website, broadcast and print media, and direct mail. The program will be cross marketed with Evergy's Residential DSM programs. In particular, it will be marketed and positioned to customers as a seamless bundle with other demand response programs that are similar in delivery mechanism and nature. The primary benefit of demand response programs is to mitigate the risks and costs associated with system peak loads. From a planning perspective, using demand response resources in the most valuable way would imply that system planners would include the peak impacts in the load forecast nominated to the RTO (regional transmission organization), thereby reducing the utility system peak, required capacity, and the reserve requirements. This also implies that events would primarily be called when the day-ahead forecast projects a load in excess of that nominated peak, rather than using another event trigger mechanism, such as energy market prices above a certain threshold or weather above a certain temperature. Having the thermostats available as a resource year-round is potentially of value to system operations in the event of plant maintenance or other grid events. Curtailment in participating homes with electric heat could provide additional risk management capabilities during winter months in the future. Providing the opportunity for customers to opt-out or override a limited number of events provides choice and control to the customer, minimizing the risk of attrition and lost participants.
Eligible Measures	Customers enroll their existing device or one purchase through the Evergy energy efficiency programs.

Estimated Savings

Territory	Net MWh Savings					
	2024	2025	2026	2027	2036	2043
Metro	5,689	6,396	7,084	7,054	7,144	7,075
West	7,420	9,500	10,490	10,417	10,333	10,045
Total	13,109	15,896	17,574	17,471	17,477	17,120

Territory	Net MW Savings					
	2024	2025	2026	2027	2036	2043
Metro	35.51	39.88	44.11	43.87	44.07	43.39
West	46.36	59.33	65.48	65.00	64.47	62.74
Total	81.87	99.21	109.59	108.87	108.54	106.13

Note that incremental demand savings for DR programs represents the annual number of participants in the entire population that roll over from year to year. This makes the incremental savings equal to the cumulative savings.

Estimated Budget

Territory	Annual Budget					
	2024	2025	2026	2027	2036	2043
Metro	$1,755,687	$1,894,672	$1,988,415	$1,516,272	$1,527,312	$1,535,440
West	$2,135,480	$2,636,667	$2,341,723	$1,768,008	$1,729,510	$1,721,124
Total	$3,891,167	$4,531,339	$4,330,138	$3,284,280	$3,256,822	$3,256,564

Cost-Effectiveness

Demand Response resources were screened using the utility cost test (UCT) as the primary test for cost effectiveness.

Territory	TRC Ratio					
	2024	2025	2026	2027	2036	2043
Metro	1.76	1.85	1.91	2.07	2.97	3.20
West	1.84	1.93	2.15	2.40	3.70	4.03
Total	1.81	1.90	2.04	2.26	3.37	3.65

1.2 Non-Residential

1.2.1 Commercial Prescriptive

Description	The Business Energy Efficiency Rebate – Standard is a pre-qualified list of measures designed to help commercial and industrial customers save energy through a broad range of energy efficiency options that address all major end uses and processes. The program will offer standard rebates as well as mid-stream incentives. The measures incentivized, including lighting, HVAC equipment, and motors, are proven technologies readily available with known performance characteristics. Participants select energy efficient equipment from a pre-qualified list. Rebates are issued to participants upon completion of the project and submission of the rebate application.
Objectives	Encourage the purchase and installation of energy efficient equipment.
Target Market	All commercial and industrial customers as well as Trade Allies.
Implementation Strategy	Evergy will engage a third-party implementation contractor to: • Process customer applications, verify eligibility and process customer rebates. • Conduct QA/QC to verify equipment installation. • Provide customer service support. • Track program performance. • Periodically report progress towards program goals and opportunities for improvement. Key pillars of the marketing strategy will include Trade Allies and direct customer marketing, including direct mail, newspaper advertisements, email blasts, bill inserts, and HVAC trade publications. Additional marketing tactics will include: • **Education.** Train and educate Trade Allies on the programs and how to effectively sell the program to customers. • **Incentives.** Provide incentives to Trade Allies that successfully increase the sale of qualifying measures to customers within the Evergy service territory. • **Trade Associations.** Businesses rely on trade associations to represent the industry's best interests in lobbying, growth, and identification of business opportunities. Evergy will coordinate with specific associations to highlight suitable program offerings. • **Highlight successfully completed projects.** Evergy will select projects to display the process and benefits of the program. This type of marketing will spur the customer's competitors to improve building performance and increase business process efficiency. The program will be cross-marketed with Evergy's Business DSM programs, particularly the Business Energy Efficiency Rebate – Custom Program. The key barriers are return on investment, decision timing, customer internal funding, and approval processes. Many customers have internal return on investment hurdles that are quite aggressive, sometimes as short as a one-year payback. Another barrier is ensuring enough vendors are properly educated to actively engage customers by explaining the benefits of efficiency improvements. Measure savings are expected to be updated annually. Potential changes to measure savings, costs, and other key assumptions could affect the measure's ability to pass cost-effectiveness tests. Therefore, the mix of measures offered could change from year to year to reflect changes made to the original measure attributes. Incentives will be modified as needed to respond to market prices, with a goal of the incentive being no higher than 50% of the incremental cost. Proper incentives can reduce free ridership while still encouraging customers to participate in the program.

Measures

The consolidated measure list below is set for planning purposes and may be modified to reflect market conditions. Additional measures included in the Company TRM may also be offered.

Measure	
Air Cooled Chiller	Floating Head Pressure
Air Source Heat Pump	Linear Lighting
Area Lighting	Oven
Connected Thermostat	Packaged Terminal AC
Efficient Hand Dryer	Pool Heater
Griddle	Automatic High-Speed Doors
Display Case Anti-Sweat Heater Controls	Floating Head Pressure
Display Case Door Retrofit	Linear Lighting
Display Case LED Lighting	High-Efficiency Evaporator Fan Motors
Display Case Low-Heat/No-Heat Doors	Strip Curtain
Display Case Motion Sensors	RTU
High Bay Lighting	Steamer
Hot Food Container	Demand Controlled Ventilation
Icemaker	Variable Speed Control
Interior Fluorescent Delamping	Faucet Aerators/Low Flow Nozzles
Kitchen Ventilation Advanced Controls	Low-Flow Showerheads
Linear Lighting	Pipe Insulation
Oven	Pre-Rinse Spray Valve
Packaged Terminal AC	Water-Cooled Chiller
Pool Heater	Water Heater

Estimated Savings

Territory	Net MWh Savings					
	2024	2025	2026	2027	2036	2043
Metro	13,146	15,313	14,797	14,478	15,817	10,918
West	10,500	11,961	11,836	11,962	14,959	9,542
Total	23,645	27,275	26,632	26,440	30,776	20,461

Territory	Net MW Savings					
	2024	2025	2026	2027	2036	2043
Metro	2.61	3.08	3.02	2.98	3.17	2.10
West	2.37	2.67	2.68	2.76	3.09	1.92
Total	4.98	5.75	5.70	5.74	6.26	4.01

Estimated Budget

Territory	Annual Budget					
	2024	2025	2026	2027	2036	2043
Metro	$4,527,627	$5,273,386	$5,641,997	$5,992,398	$7,249,523	$5,556,174
West	$3,595,094	$3,980,201	$4,271,068	$4,806,158	$5,755,431	$4,356,716
Total	$8,122,721	$9,253,587	$9,913,065	$10,798,555	$13,004,954	$9,912,890

Cost-Effectiveness

Territory	TRC Ratio					
	2024	2025	2026	2027	2036	2043
Metro	1.14	1.39	1.40	1.41	1.86	1.73
West	1.24	1.51	1.54	1.50	2.18	1.92
Total	1.18	1.44	1.46	1.45	2.01	1.81

1.2.1 Commercial and Industrial Custom

Description	The program is designed to provide customers incentives for installing energy efficient measures not explicitly identified in the Standard program. It helps commercial and industrial customers save energy through a broad range of energy efficiency options that address all major end uses and processes. Applications must be pre-approved by Evergy before equipment is purchased and installed and must have a Total Resource Cost Test benefit-cost ratio of at least 1.0. Incentives, up to 50% of the project cost, were included as a $ per first-year-kWh saved. Participant rebates per program year are limited to the annual cap outlined in the tariff on the company website and applications. Multiple rebate applications for different measures may be submitted. Rebates will be issued upon completion of the project.
Objectives	Encourage the purchase and installation of energy efficient equipment by providing incentives to lower the cost of purchasing efficient equipment for commercial and industrial facilities.
Target Market	All commercial and industrial customers.
Implementation Strategy	Evergy will engage a third-party implementation contractor to: • Process customer applications, verify eligibility, review pre-approval applications, and process customer rebates. • Conduct QA/QC to verify equipment installation. Randomly inspect 10% of projects and all projects over a threshold determined by Evergy (e.g., $10,000). • Provide customer service support. • Track program performance. • Periodically report progress towards program goals and opportunities for improvement. Key pillars of the marketing strategy will include Trade Allies and direct customer marketing, including direct mail, newspaper advertisements, email blasts, bill inserts and HVAC trade publications. Additional marketing tactics will include: • Education. Train and educate Trade Allies on the programs and how to effectively sell the program to customers. • Trade Associations. Businesses rely on trade associations to represent industry's best interests in lobbying, growth, and identification of business opportunities. Evergy will coordinate with specific associations to highlight suitable program offerings. • Highlight successfully completed projects. Evergy will select projects to display the process and benefits of the program. This type of marketing will spur the customer's competitors to improve building performance and increase business process efficiency. The program will be cross marketed with Evergy's Business DSM programs, particularly the Business Energy Efficiency Rebate – Standard Program. The key barriers are return on investment, decision timing, and customer internal funding and approval processes. Many customers have internal return on investment hurdles that are quite aggressive, sometimes as short as a one year payback. Another barrier is ensuring that enough vendors are properly educated to allow them to actively engage customers by explaining the myriad benefits of efficiency improvements.
Eligiblity Measures	Incentives were set for planning purposes and may be modified to reflect market conditions. Incentives, up to 50% of the project cost and up to a maximum annual cap, are $0.08-0.18 per first-year kWh saved for all incentives.

Estimated Savings

Territory	Net MWh Savings					
	2024	2025	2026	2027	2036	2043
Metro	7,883	8,370	8,364	8,485	8,958	10,101
West	6,281	6,604	6,664	6,813	7,859	8,880
Total	14,164	14,975	15,028	15,299	16,817	18,981

Territory	Net MW Savings					
	2024	2025	2026	2027	2036	2043
Metro	1.56	1.69	1.69	1.70	1.90	2.06
West	1.38	1.45	1.47	1.50	1.89	1.95
Total	2.94	3.14	3.16	3.20	3.79	4.01

Estimated Budget

Territory	Annual Budget					
	2024	2025	2026	2027	2036	2043
Metro	$2,506,082	$2,691,106	$2,708,993	$2,808,024	$3,569,488	$4,573,981
West	$1,955,542	$2,038,609	$2,079,543	$2,192,107	$2,976,702	$3,723,761
Total	$4,461,624	$4,729,715	$4,788,536	$5,000,131	$6,546,190	$8,297,741

Cost-Effectiveness

Territory	TRC Ratio					
	2024	2025	2026	2027	2036	2043
Metro	1.10	1.33	1.41	1.48	1.92	1.90
West	1.23	1.47	1.55	1.61	2.11	2.09
Total	1.16	1.39	1.47	1.54	2.01	1.99

1.2.2 Business Curtailment Agreements

Description	The Demand Response Incentive Program provides firm contractual arrangements with customers for periodic curtailments at times of system peak demand. Customers enter into a contract for a one, three, or five-year term and receive a payment/bill credit based upon the curtailable load, the contract term and number of consecutive years under contract. Participants receive notification of an event at least 4 hours prior to the start time.
Objectives	Decrease peak demand usage to provide system and grid relief during particularly high-load, high-congestion peak hours.
Target Market	Large commercial and industrial customers with load curtailment capability of at least 200 kW.
Implementation Strategy	Evergy key account executives will be vital to coordinating with the largest customers and gaining their participation and collaboration. The program will also be marketed through direct customer outreach as well as newsletters and direct mail. The program will promote Evergy's Business DSM programs to participating customers. The primary benefit of demand response programs is to mitigate the risks and costs associated with system peak loads. From a planning perspective, using demand response resources in the most valuable way would imply that system planners would include the peak impacts in the load forecast nominated to the RTO, thereby reducing the utility system peak, required capacity, and the reserve requirements. This also implies that events would primarily be called when the day-ahead forecast projects a load in excess of that nominated peak, rather than using another event trigger mechanism, such as energy market prices above a certain threshold or weather above a certain temperature. Providing the opportunity for customers to opt-out or override a limited number of events provides choice and control to the customer, minimizing the risk of attrition and lost participants.
Eligible Measures	Customers receive a fixed, capacity-reserve payment in terms of $/kW, based on the number of curtailable kW, the contract term, and number of consecutive years under contract. The fixed payment is supplemented by a performance payment on a $/kWh basis, calculated from the customer's actual load curtailment relative to their baseline load, as calculated by program management.
Estimated Savings	See tables below.
Estimated Budget	See table below.

Estimated Savings

Territory	Net MWh Savings					
	2024	2025	2026	2027	2036	2043
Metro	2,826	3,570	4,069	4,064	4,048	4,093
West	4,529	5,063	5,431	5,438	5,566	5,732
Total	7,355	8,633	9,500	9,502	9,614	9,825

Territory	Net MW Savings					
	2024	2025	2026	2027	2036	2043
Metro	37.24	47.55	54.29	54.26	54.24	54.87
West	61.61	69.24	74.35	74.49	76.19	78.57
Total	98.85	116.79	128.64	128.75	130.43	133.44

Note that incremental demand savings for DR programs represents the annual number of participants in the entire population that roll over from year to year. This makes the incremental savings equal to the cumulative savings.

Estimated Budget

Territory	Annual Budget					
	2024	2025	2026	2027	2036	2043
Metro	$1,063,991	$1,352,765	$1,541,315	$1,540,560	$1,539,854	$1,557,381
West	$1,778,208	$1,991,761	$2,134,991	$2,138,790	$2,186,371	$2,252,950
Total	$2,842,199	$3,344,526	$3,676,306	$3,679,350	$3,726,225	$3,810,331

Cost-Effectiveness

Demand Response resources were screened using the utility cost test (UCT) as the primary test for cost effectiveness.

Territory	UCT Ratio					
	2024	2025	2026	2027	2036	2043
Metro	2.96	3.02	3.07	3.12	3.91	4.15
West	2.95	3.00	3.05	3.10	3.88	4.12
Total	2.95	3.01	3.06	3.11	3.89	4.14

1.2.3 Business Smart Thermostat

Description	The Business Smart Thermostat with Direct Load Control (DLC) Program pays an incentive to participants to reduce peak demand by controlling their cooling equipment during periods of system peak demand and when there may be delivery constraints within certain load zones. This is done by way of a remotely communicating, programmable thermostat. During a program event, the program operations center sends a signal to the thermostat to adjust its set-point by a few degrees such that the system will consume less energy and run less frequently throughout the max 4-hour event duration. One method of participation will be for customers to receive the thermostat and professional installation for free upon qualification and enrollment in the program. Smart thermostats also achieve energy savings by using occupancy sensors and setback schedules with learning algorithms.
Objectives	Primarily decrease peak demand usage to provide system and grid relief during particularly high-load, high-congestion peak hours. Also provide annual energy savings.
Target Market	Small & medium Commercial customers who control their heating and cooling with traditional wall-mounted thermostats.
Implementation Strategy	Evergy will engage a third-party implementation contractor to: • Hire/sub-contract local staff to install the programmable thermostats. • Engage customers, schedule installation appointments and process customer incentives. • Provide customer service support. • Track program performance and event data. • Periodically report progress towards program goals and opportunities for improvement. Events will typically occur between June 1 and September 30, Monday to Friday. Event duration is max 4 hours per day. Customers may opt-out twice a year. The program will be marketed through direct contact with consumers using newsletters, website, broadcast and print media, and direct mail. The program will be cross marketed with Evergy's Business DSM programs. The primary benefit of demand response programs is to mitigate the risks and costs associated with system peak loads. From a planning perspective, using demand response resources in the most valuable way would imply that system planners would include the peak impacts in the load forecast nominated to the RTO (regional transmission organization), thereby reducing the utility system peak, required capacity, and the reserve requirements. This also implies that events would primarily be called when the day-ahead forecast projects a load in excess of that nominated peak, rather than using another event trigger mechanism, such as energy market prices above a certain threshold or weather above a certain temperature. Having the thermostats available as a resource year-round is potentially of value to system operations in the event of plant maintenance or other grid events. Curtailment in participating homes with electric heat could provide additional risk management capabilities during winter months in the future. Providing the opportunity for customers to opt-out or override a limited number of events provides choice and control to the customer, minimizing the risk of attrition and lost participants.
Eligible Measures	Customers enroll their existing device or one purchased through the Evergy energy efficiency programs.

Estimated Savings

Territory	Net MWh Savings					
	2024	2025	2026	2027	2036	2043
Metro	233	544	699	776	758	731
West	141	423	986	1,268	1,376	1,327
Total	374	967	1,685	2,044	374	967

Territory	Net MW Savings					
	2024	2025	2026	2027	2036	2043
Metro	1.46	3.40	4.37	4.85	4.72	4.54
West	0.88	2.64	6.16	7.92	8.56	8.24
Total	2.34	6.04	10.53	12.77	2.34	6.04

Note that incremental demand savings for DR programs represents the annual number of participants in the entire population that roll over from year to year. This makes the incremental savings equal to the cumulative savings.

Estimated Budget

Territory	Annual Budget					
	2024	2025	2026	2027	2036	2043
Metro	$52,669	$117,252	$141,700	$119,528	$116,746	$115,007
West	$26,326	$75,666	$140,802	$136,377	$145,579	$143,072
Total	$78,995	$192,918	$282,502	$255,905	$78,995	$192,918

Cost-Effectiveness

Demand Response resources were screened using the utility cost test (UCT) as the primary test for cost effectiveness.

Territory	UCT Ratio					
	2024	2025	2026	2027	2036	2043
Metro	1.22	1.36	1.70	1.99	3.71	4.12
West	3.09	2.15	2.21	2.67	5.50	6.12
Total	1.58	1.61	1.92	2.32	4.66	5.19

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APPENDICES C1 and D CONTAIN CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC.

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