

3. Load Analysis and Forecasting

Highlights

- Ameren Missouri expects energy consumption for its non-large load tariff class customers to grow 1.2% annually and peak demand for those customers to grow 0.6% annually for the planning case over the next 20 years including potential impacts from electrification and behind the meter solar generation and including economic development additions. For the large load tariff class, the base case annual energy and peak demand compounded average growth rates are forecasted to be 20.0% and 13.1%, respectively.*
- Economic growth, naturally occurring energy efficiency and customer adoption of distributed energy resources such as solar and efficient electrification of end-uses are key drivers of future growth in our base case forecast.*



Ameren Missouri has developed a range of load forecasts consistent with the scenarios outlined in Chapter 2. These load forecasts provide the basis for estimating Ameren Missouri's future resource needs and provide hourly load information used in the modeling and analysis discussed in Chapter 9. Additionally, the Statistically Adjusted End-use (SAE) forecasting tools and methods that used to develop the forecasts provide a solid analytical basis for testing and refining the assumptions used in the development of the potential demand-side resource portfolios discussed in Chapter 8.¹ The energy intensity of the future economy and the inherent energy efficiency of the stock of energy using goods are explored throughout the analysis to arrive at reasonable estimates of high, base, and low load growth.²

3.1 Energy Forecast

This chapter describes the forecast of Ameren Missouri's energy, peak demand, and customers that underlies the analysis of resources undertaken in this IRP. In order to account for a number of combinations of possible economic and policy outcomes, three different forecast scenarios, high, low, and base load growth scenarios were prepared.

¹ 20 CSR 4240-22.030(1)(A)

² Unless otherwise stated, references to load or peak demand growth EXCLUDE large load customers.

Based on the subjective probabilities of these scenarios identified by Ameren Missouri, a fourth case was developed to represent the planning case for the study. Excluding large load tariff customers, the planning case forecast projects Ameren Missouri's retail sales to grow by 1.2% annually between 2027 and 2046 and retail peak demand to grow by 0.6% per year.

As with any forecast of energy, there are several underlying assumptions. Expectations for economic growth underlying the load forecast are based on Moody's Analytics' forecast of economic conditions in the Ameren Missouri service territory. Expectations about future energy market conditions, such as fuel prices and the impact on electricity prices of different environmental policy regimes, are based on interviews with internal Ameren subject matter experts.

Since the last IRP filing, Ameren Missouri has implemented significant energy efficiency programs, which has significantly reduced overall energy consumption year over year. This forecast assumes significant savings from company-sponsored energy efficiency programs under the Missouri Energy Efficiency Investment Act (MEEIA). Savings from MEEIA Cycle 3 programs, and MEEIA Cycle 4 programs are forecasted through 2046. This IRP forecast assumes 2046 will cumulatively have implemented 179 GWh of energy savings.

As mandated by SB 564, Ameren Missouri provided \$23 million in incentives between 2018 and 2024, resulting in approximately 100 MW of customer owned renewables. The base case scenario assumes that the customer-owned renewable generation capacity would increase during the planning years, reaching 640 MW by 2046. Customer-owned renewable generation capacity is assumed to reach as high as 1,533 MW by 2046 in the low load growth scenario and 309 MW by 2046 in the high load growth scenario.

Compared to Ameren Missouri's previous triennial IRP, filed in 2023, the new forecasted growth rates, excluding large load tariff customers, are higher for high and base scenarios. This increase is largely due to the increases from efficient electrification. Excluding data centers, the forecasted growth rate is higher for the base, high, and planning scenario, but lower for the low scenario. The higher growth rate can be attributed to additional adoption of electric vehicles and lower expected solar capacity by 2046. Ameren Missouri's current initiatives on efficient electrification programs are expected to increase total consumption by 682 GWh between 2025 and 2030. Extending this forecast to 2046, we incorporate an efficient electrification study conducted by the Electric Power Research Institute (EPRI) that concludes significant potential for adoption of electric vehicles and other efficient electrification technologies, raising the overall electric consumption by approximately 9,533 GWh in the base case scenario. Forecasts for the high and low load growth scenarios respectively assume approximately 16,505 GWh and 1,880 GWh of additional load from efficient electrification.

It should be noted that in the development of this forecast, expectations of improving energy efficiency of end use equipment and appliances are reflected only to the extent that it is due to market conditions, federal standards, or past and current cycles of energy efficiency programs Ameren Missouri has implemented under the MEEIA program. The fourth cycle of MEEIA programs is included in the load forecast because it is already planned, approved, and being implemented by the Company. Future energy efficiency programs are the subject of Chapter 8, and the impacts of those programs will be included according to their role in the various candidate resource plans discussed in Chapter 9.

3.1.1 Historical Database³

Ameren Missouri tracks its historical sales⁴ and customer counts by revenue class (Residential, Commercial, and Industrial), and also by rate class (Small General Service, Large General Service, Small Primary Service, and Large Primary Service).⁵ Ameren Missouri uses these rate classes as the sub-classes for forecasting, both because the data is readily accessible from the billing system and because it provides relatively homogeneous groups of customers in terms of size. Historical billed sales are available for all rate and revenue classes dating back to January 1995, and calendar month sales and class demand data⁶ are available beginning July 2003. At the time of the preparation of the load forecast for this IRP, historical sales were known through March 2025.⁷ Except as noted later in this chapter, any data presented for 2025 or beyond is forecasted data and data from 2024 and earlier is actual metered or weather-normalized sales data. Historical energy consumption and customer count data are provided in the electronic workpapers.

Ameren Missouri routinely weather-normalizes the observed energy consumption of its customers to remove the impact of weather variations. The process for weather-normalizing sales is described in section 3.3, and weather-normalized historical consumption from 2010 forward will also be provided in the electronic workpapers. Appendix A includes weather normalization model statistics for various rate-revenue classes. Workpapers that include energy usage per unit sales and demand data for all classes are provided in the electronic workpapers. For each class, the unit chosen in the analysis is the customer count of that class⁸ because it is a measurable value for each class that is accessible and meaningful for all cases.

³ 20 CSR 4240-22.030(1)(B)

⁴ 20 CSR 4240-22.030(2)(B)1

⁵ 20 CSR 4240-22.030(2)(A)

⁶ 20 CSR 4240-22.030(2)(B)2

⁷ 20 CSR 4240-22.030(2)(F)

⁸ 20 CSR 4240-22.030(2)(C)1

3.1.2 Forecast Vintage Comparison

Independent variables⁹

Missouri IRP rule 20 CSR 4240-22.030(6)(C)3 requires a comparison of prior projections of all independent variables used in the energy usage and peak load forecasts from the last 10 years to actual historical values and to projected values in the current IRP filing. Actual historical values for each independent variable for a period of at least the last 20 and up to 40 or more years are acquired by Ameren Missouri from Moody's Analytics, along with forecasts of each variable for the entire planning horizon.¹⁰

The following discusses only the independent variables used in the energy usage forecasts. The peak forecast is derived from using the output from the energy forecast and modeling historical peaks as the Y variable. The growth rates in peak demand are driven by the energy forecasts for each class and end use as described later in this chapter, so the same economic variables used in the energy forecast are also being used to forecast the peak loads.

The prior projections involved in addressing this requirement are from - the 2011 IRP, the 2014 IRP, the 2017 IRP, the 2020 IRP, and the 2023 IRP. Besides prior projections, projections for this 2026 IRP are included. Sales volume shown for the 2026 IRP includes the actual volumes for years up to 2024 and projections starting from 2025.

In some cases, the data vendor may have changed the 'base year' for the independent variables' values. In addition, between certain IRPs, Ameren Missouri has changed its methodology for weighting county level variables into a service territory indicator, so the absolute level of the values for the same year among various vintages may be significantly different. However, the key is the growth rate or trend in these values, so each table is expressed in terms of the year over year growth rate and is accompanied by a chart showing the same, which overcomes the problem of sometimes relying on different bases for some of the variables.

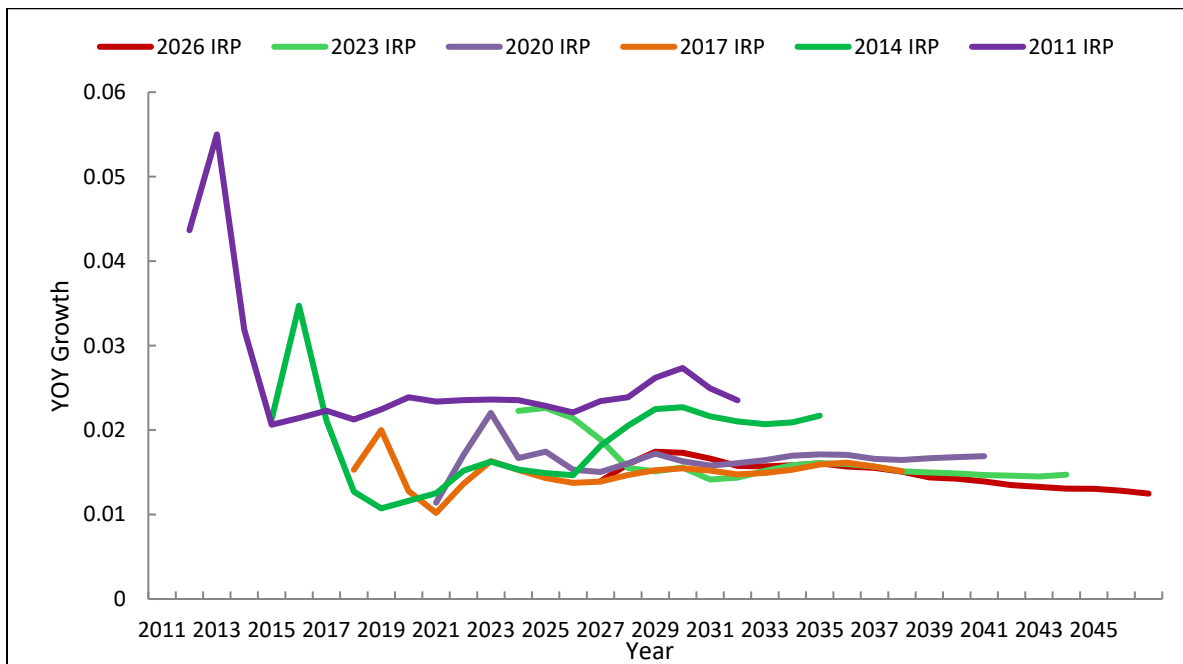
For the residential energy forecast, independent variables used in these forecasts were Households, Population, and Personal Income. For the commercial energy forecast, the independent variables used in the forecasts were total GDP and GDP for several sectors of the economy, including Retail Trade, Miscellaneous Services, Education/Health Services, Information Services, Financial Services, and Transportation. For the industrial energy forecast, the independent variables used in this forecast include Manufacturing GDP and Manufacturing Employment. Service territory GDP variables from each archived

⁹ 20 CSR 4240-22.030(6)(C)3

¹⁰ 20 CSR 4240-22.030(6)(C)1

forecast are shown below in Figure 3.1. The growth rates for each of the variables discussed above will be shown in the chart and tabular form in the final filing.

Figure 3.1: Ameren Missouri Service Territory GDP Forecasts from Prior IRPs

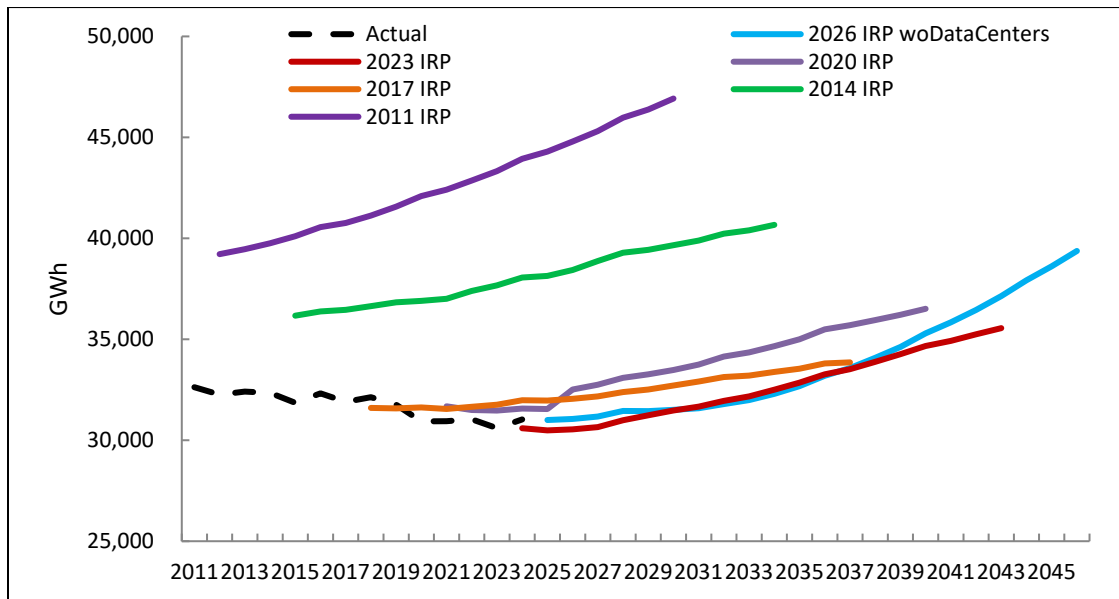
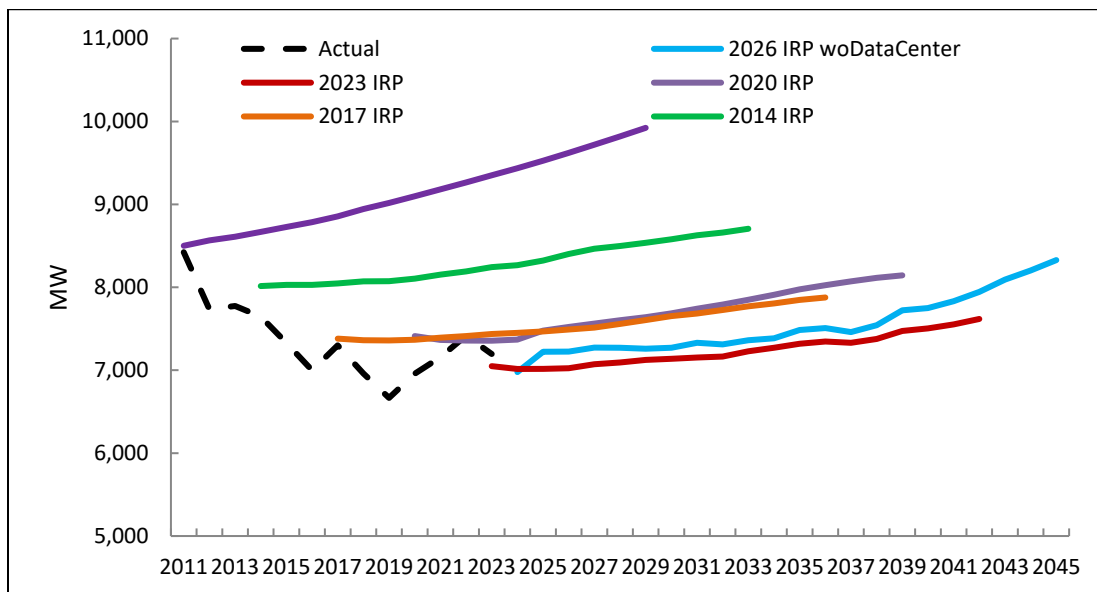


Forecasts¹¹

IRP rule 20 CSR 4240-22.030(6)(C)4 requires a comparison of prior projections of energy and peak demand made in at least the last 10 years to the actual historical energy and peak demands and to projected values in the current IRP filing.

Figures 3.2 and 3.3 below show previous and current forecasts of energy and peak demand, including those for 2026 IRP with and without data centers, 2023 IRP, 2020 IRP, 2017 IRP, 2014 IRP, 2011 IRP, and actual historical values. The data from these charts are provided in tabular form in the work papers.

¹¹ 20 CSR 4240-22.030(6)(C)4

Figure 3.2: Ameren Missouri Actual Historical Energy Sales and Past IRP Energy Forecasts**Figure 3.3: Ameren Missouri Actual Historical Peak Demand and Past IRP Peak Demand Forecasts**

As is evident from the forecasts in the tables, the projections of both energy consumption and peak demand have decreased quite significantly over time due to energy efficiency

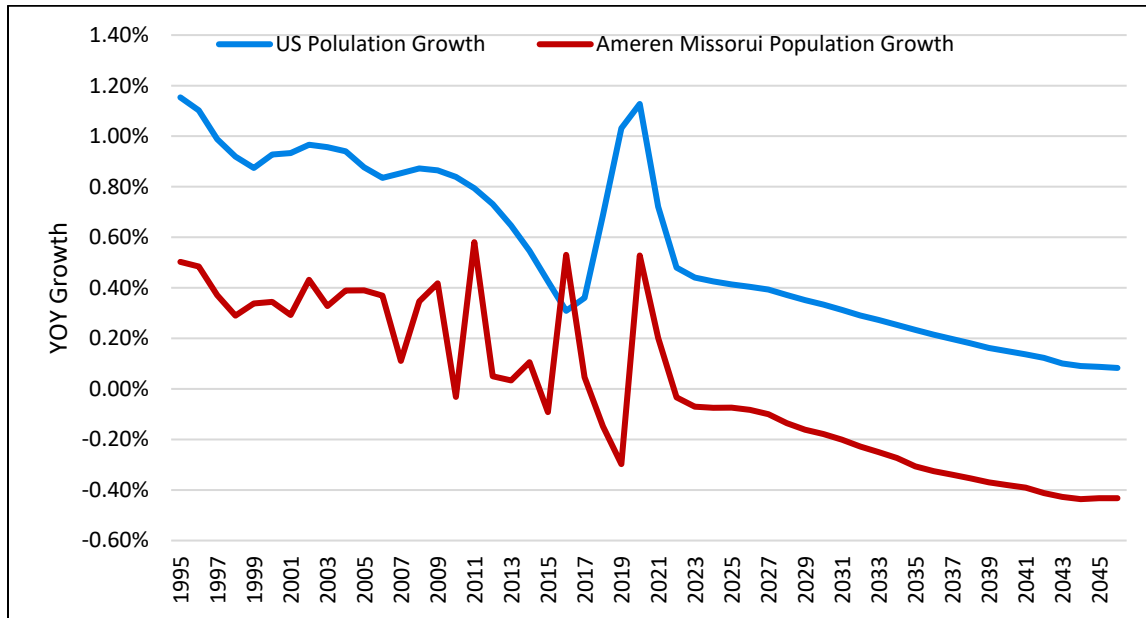
and solar. However, a significant increase is predicted over the next 20 years. Much of this growth in efficient electrification can be attributed to greater penetration of electric vehicles. Excluding data centers, the base case predicts a 0.7% demand increase from 2027 to 2046, primarily due to electrification. Compared to the 2023 IRP, the current Ameren Missouri base case predicts a lower growth of solar installation in its service territory over the next 20 years. The base case from the 2023 IRP predicted solar installations up to 700 MW by 2043. The updated forecast assumes installations reach 640 MW by 2046. The effect of solar installations on total load, all else equal, is expected to account for a 7.0% reduction by 2046. This is less impactful than the prior IRP projection which assumed a 9.0% reduction from 2024 to 2043.

Based on a state wide study conducted by EPRI, Ameren Missouri has also assumed a significant increase in the adoption of electric vehicles and efficient electrification of end uses in its territory over the next 20 years. Adoption of efficient electrification technologies are assumed to increase at an annual rate of approximately 22% over the planning horizon.

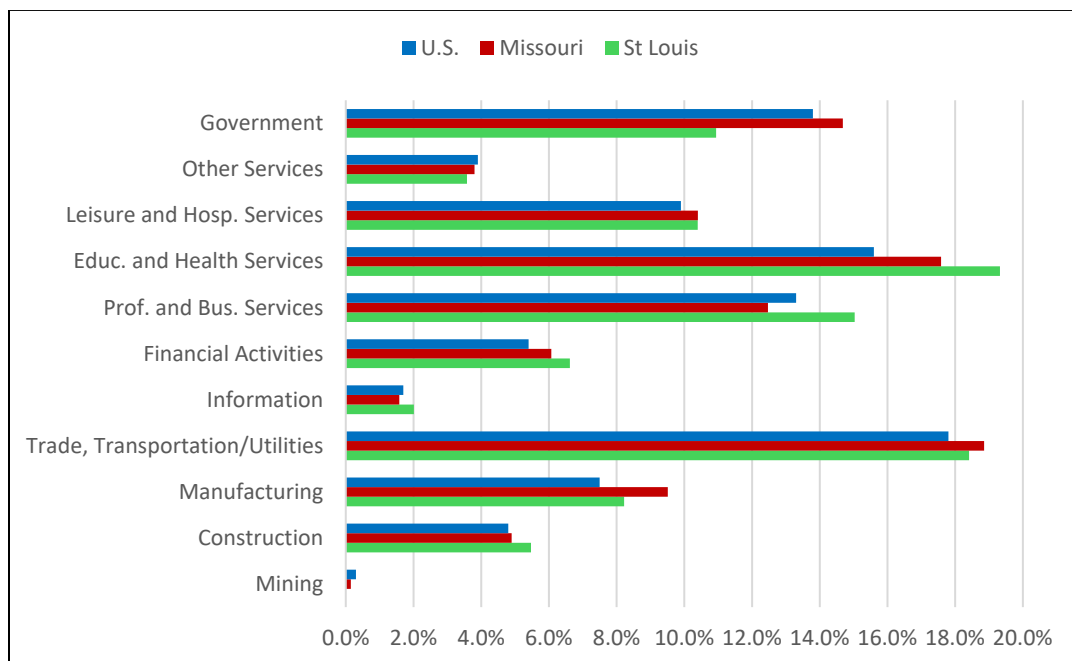
3.1.3 Service Territory Economy

The Ameren Missouri electric service territory is comprised of approximately 60 counties primarily in eastern and central Missouri. It should be noted, however, that although Ameren Missouri serves customers in each of these counties, it does not necessarily serve every electric customer within each of them as Coop or Municipal providers serve many. The level of sales is highly correlated with the health of the economy in the service territory.

Historically, the Ameren Missouri service territory has been characterized by slower population growth than the U.S. as a whole due to demographic and migration factors (Figure 3.4). In that respect, the service territory's economy is like most other Midwestern states and metropolitan areas. Another commonality is that the region's economy was based on manufacturing for many years, but over the past several decades the share of the territory's employment in manufacturing has been declining while employment in services, particularly health care, has grown. So, although the service territory still has a higher-than-average share of employment in manufacturing, it is no longer the employment growth engine it once was. The allocation of service territory employment by NAICS sector is shown in Figure 3.5; a list of some of the largest employers in the service territory is shown in Table 3.1.

Figure 3.4: U.S. and Missouri Population Change

Source: Moody's Analytics

Figure 3.5: U.S. and Ameren Missouri Service Territory Employment by Industry

Source: BLS, Moody's Analytics

Table 3.1: Major Employers in Ameren Missouri Service Territory

Rank	Employer	Industry	Number of Employees
1	BJC Healthcare	Education or Health Services	33,797
2	Washington University in St. Louis	Education or Health Services	21,278
3	Walmart Inc.	Retail Trade	17,000
4	Boeing Defense, Space & Security	Boeing Defense, Space & Security	16,681
5	SSM Health Care System	Education or Health Services	15,631
6	Mercy Health Care	Education or Health Services	15,342
7	Scott Air Force Base	Federal Government	13,100
8	Schnuck Markets Inc.	Retail Trade	8,496
9	McDonald's Corporation	Retail Trade	8,415
10	Archdiocese of St Louis	Other Services	7,000
11	Amazon	Transportation and Warehousing	6,800
12	Spectrum	Information	6,230
13	Edward Jones	Financial Activities	5,446
14	Ameren Corp.	Utility	5,244
15	Enterprise Mobility	Trans./Warehouse/Utilities	5,000
16	Worldwide Technology Inc.	Wholesale Trade	4,929
17	St. Luke's Hospital	Education or Health Services	4,709
18	Centene Corp.	Finance and Insurance	4,530
19	Anheuser-Busch Cos.	Manufacturing	4,500
20	General Motors Corp.	Manufacturing	4,038

Source: Moody's Analytics

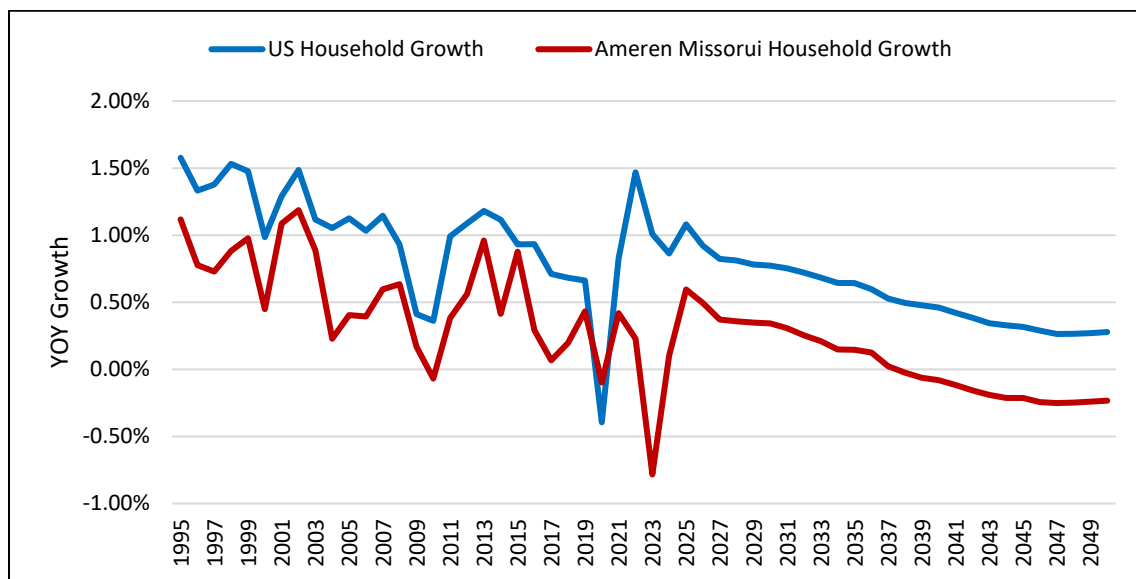
The territory's major employers are spread across a number of different industries, but the region's single biggest employer is a hospital system, BJC Healthcare. Two other healthcare systems and three universities are among the largest employers in the territory, highlighting the importance of health and education services to both the growth and level of employment, as well as to electricity sales.

As noted above, the service territory economy has grown at a slightly slower pace than the U.S. as a whole because of slower population growth. In addition to the trend of slower population growth, the St. Louis region did not experience the boost from the housing bubble that some other markets did.

The service territory economy also contains several nationally known financial firms, including Wells Fargo and Edward Jones.

Since the great recession, Ameren Missouri's service territory economy continued to recover in a manner like the U.S. economy's recovery, although at a slower pace than that of the U.S. recovery. This is evident from the chart of the U.S. and Service Territory GDP Growth shown in Figure 3.7, in which the red line for Ameren Missouri growth follows a pattern like that of the U.S. but is below the blue line for the U.S. GDP growth.¹² During 2020, GDP saw a decrease due to the COVID-19 Pandemic, but GDP saw a recovery in 2021 after the government started lifting COVID-19 restrictions.

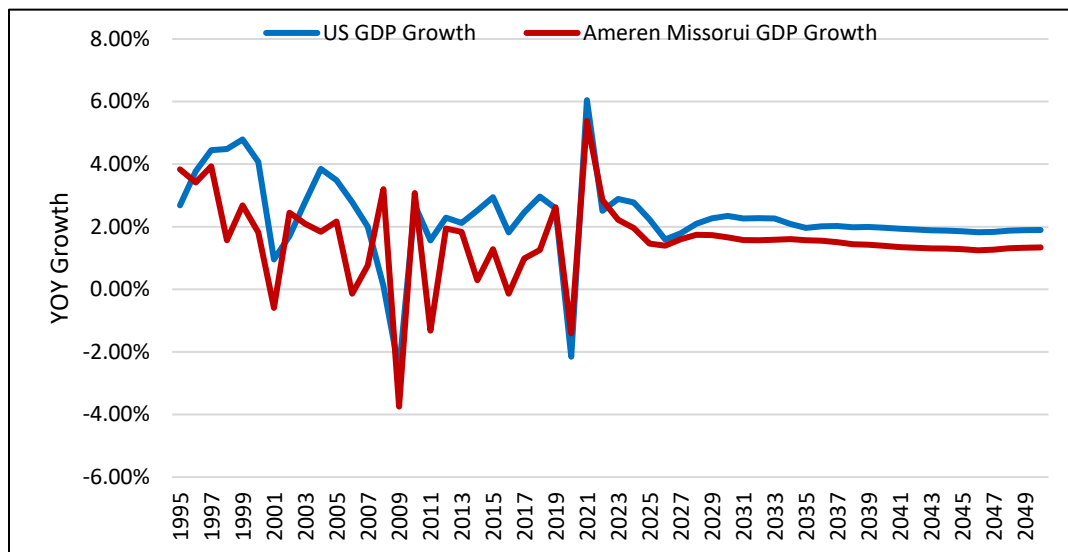
Figure 3.6: Growth in U.S. and Ameren Missouri Households¹³



Source: Moody's Analytics

¹² 20 CSR 4240-22.030(7)(B)3

¹³ 20 CSR 4240-22.030(2)(D)3

Figure 3.7: U.S. and Service Territory GDP Growth¹⁴

Source: Moody's Analytics

3.1.4 Economic Drivers

Several economic indicators were used as independent variables (independent variables in the forecasting models are often referred to as "drivers") in our energy forecasting process. [OBJ]

- For the residential class, income, population, and the number of households in the service territory were used as drivers. These drivers are consistent with drivers used in prior IRP forecasts.¹⁵
- For the four classes of commercial sales (small/large general/primary service), GDP for one or more of eight sectors (Retail Trade, Information Services, Financial Services, Education/Health forecasts), Leisure, Other Services, Government, and Transportation Utilities) were identified as drivers. These eight sectors account for almost all the non-manufacturing and non-government entries in the top employers list in Table 3.1 shown above. These drivers are consistent with those used in all recent IRP forecasts except to the extent that a different sector may have been included for a particular rate class as compared with a previous forecast, but only if the analysis of historical correlation of that driver to the historical loads indicated a better relationship between the two.¹⁶

¹⁴ 20 CSR 4240-22.030(2)(D)3

¹⁵ 20 CSR 4240-22.030(6)(A)1A

¹⁶ 20 CSR 4240-22.030(6)(A)1B

- For the four classes of industrial sales (same classes as in commercial listed above), one or more of the following drivers were used: GDP, Manufacturing GDP, Employment, and Manufacturing Employment. These variables are consistent with past load forecast drivers for industrial class. Table 3.2 illustrates these drivers and their expected growth over the IRP planning horizon.
- As in prior IRPs and IRP Annual Updates, the economic forecasting firm Moody's Analytics was the source for the forecasts of these economic drivers. Moody's Analytics is a highly reputable firm in the macroeconomic forecasting arena with a specialized competency in doing this work, and Ameren Missouri has extensive history using its forecasts and has consistently found them to be credible. Moody's Analytics' forecasts are done for individual counties, and Ameren Missouri aggregates those counties that make up its service territory. The forecasting models used by Moody's are proprietary and not available to Ameren Missouri.¹⁷

Table 3.2 Growth Rates of Selected Economic Drivers

	2027-2046 Compound Growth Rate
Households	0.05%
Population	-0.24%
Real Personal Income	4.15%
GDP Retail	1.69%
GDP Info	2.23%
GDP Financial	1.33%
GDP Education /Health	0.89%
GDP Leisure	1.26%
GDP Other Services	-0.33%
GDP Govt	0.33%
GDP Trans Utilities	1.29%
GDP Total	1.48%
GDP Manufacturing	1.54%
Employment Total	-0.21%
Manufacturing Employment	-0.81%

Source: Moody's Analytics

¹⁷ 20 CSR 4240-22.030(7)(B)1; 20 CSR 4240-22.030(7)(B)2

3.1.5 Energy Forecasting

The Ameren Missouri energy sales forecast was developed with traditional econometric forecasting techniques, including a functional form called the Statistically Adjusted End-Use (SAE) model. In the SAE framework, variables of interest related to economic growth, the price of electricity, energy efficiency, and intensity of end-use appliances, are combined into a small number of independent variables, which are used to predict the dependent variable (typically energy sales or sales per customer by class). The SAE framework was used to forecast energy sales in the company's residential general service rate class, and for all four of its commercial rate classes. The discussion below details the process followed for developing the models, inputs, assumptions, and parameters used in forecasting.

Statistically Adjusted End-Use (SAE)

The advantage of the SAE approach is that it combines the benefits of engineering models and econometric models. Engineering models, such as REEPS, COMMEND, and INFORM model energy sales with a bottom-up approach by building up estimates of end use energy consumption by appliance type, appliance penetration, and housing unit or business type. These models are good at forecasting energy because they can be used to estimate the effects of future changes in saturations or efficiency levels of equipment and appliances, which may be driven by policy, economics, or consumer preferences,¹⁸ even if the changes are not present in observable history. In a traditional econometric model, it can be difficult to model precisely how the changing appliance efficiency standards will affect sales if the standards have been unchanged during the estimation period.

Econometric models, however, are estimated against a relatively long period of time rather than calibrated to sales from a single year, and it is therefore easier to detect and correct any systematic errors or biases in the forecasting model. For that reason, a system that combines the bottom-up approach of engineering models with an econometric approach should produce more accurate forecasts.¹⁹ The SAE approach allows us to do that for our residential and commercial-class sales. For the industrial classes, we used an econometric approach that was influenced by the SAE approach.

The SAE framework used in this load analysis and forecasting work²⁰ was developed by Itron, a consulting firm Ameren Missouri has worked with for many years and implemented by Ameren Missouri forecasting personnel.²¹ The SAE framework contains specific end uses for which saturation and efficiency must be estimated, as well as a miscellaneous category. The residential end uses are heating, cooling, water heating, cooking, primary

¹⁸ 20 CSR 4240-22.030(5)(C)

¹⁹ 20 CSR 4240-22.030(5)(B)

²⁰ 20 CSR 4240-22.030(6)(B)

²¹ 20 CSR 4240-22.030(6)(A)3

and secondary refrigeration, freezers, dishwashing, clothes washing, clothes drying, television, lighting, and miscellaneous.²² Furnace fans are consolidated with the space heating end use due to the fact that in the SAE regression, they are analyzed using a common driver: heating degree days. Personal computers, plug loads and other loads from various forms of electrification are also consolidated due to the availability of data from the U.S. Energy Information Administration (EIA) as packaged by Itron, and due to the fact that these end uses constitute many small devices for which gathering accurate historical appliance stock data (beyond what Itron has analyzed) from the EIA would be challenging at best.²³ Also, as discussed later in this chapter, self-generation resulting from solar photovoltaic systems is treated essentially as a negative end use and modeled explicitly in the load for each class.²⁴ Similarly, electric vehicle charging and other types of efficient electrification were considered as an end use, contributing additional load. For the commercial class, the end uses are heating, cooling, ventilation, water heating, cooking, refrigeration, lighting, office equipment, and miscellaneous.²⁵ The combination of Itron's analysis and past and future Market Potential Studies provide a framework for maintaining the appropriate end use data for future IRPs.²⁶

To predict future changes in the efficiency of the various end uses for the residential class, Ameren Missouri relied on analysis of EIA's Annual Energy Outlook forecast performed by Itron and past Market Potential Studies. Both of these sources rely on stock accounting logic that projects appliance efficiency trends based on appliance life and past and future efficiency standards. These models account for the impacts of all currently effective laws and regulations regarding appliance efficiency, along with life cycle models of each appliance.²⁷ The life cycle models are based on the decay and replacement rates, which are necessary to estimate how fast the existing stock of any given appliance turns over, and newer, more efficient equipment replaces older, less efficient equipment. The underlying efficiency data is based on estimates of energy efficiency from the EIA, or other primary market research data and secondary sources determined to be relevant to Ameren Missouri's service territory. The EIA estimates the efficiency of appliance stocks and the saturation of appliances at the national level and for the Census Regions, while Ameren's market potential study focuses specifically on Ameren Missouri's service territory.

The saturation trends for the end use appliances from EIA for the Census Region were generally discarded in the residential analysis in favor of more locally relevant information. The primary source for up-to-date saturation information was the Ameren Missouri Market

²² 20 CSR 4240-22.030(4)(A)1A

²³ 20 CSR 4240-22.030(4)(A)2A

²⁴ 20 CSR 4240-22.030(4)(A)2B

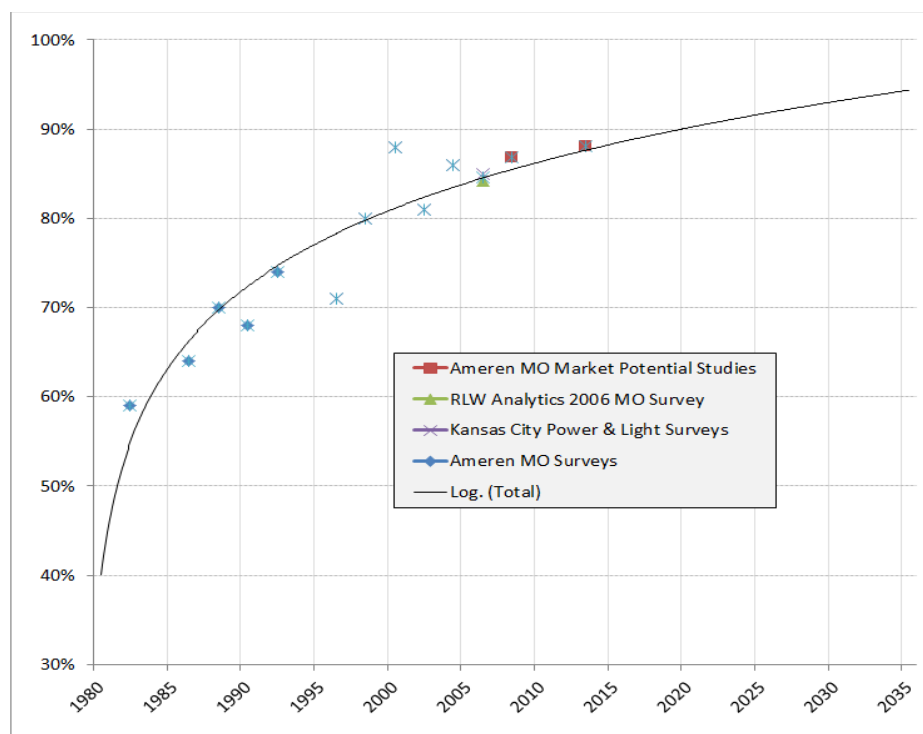
²⁵ 20 CSR 4240-22.030(4)(A)1B

²⁶ 20 CSR 4240-22.030(4)(A)2C

²⁷ 20 CSR 4240-22.030(7)(A)2

Potential Study surveys.²⁸ These studies were conducted in order to provide primary data for Ameren Missouri's energy efficiency and demand side management programs. A historical and forecasted time series of appliance saturations are necessary for the SAE forecasting models that capture long term trends and changes in appliance and equipment ownership. The two surveys done in conjunction with the market potential studies provide a good starting point for developing these trends. Additional information was utilized to fully develop them across more years.

Figure 3.8: Air Conditioning Saturation, Survey Data Points and Fitted Curve²⁹



Ameren Missouri's market potential study surveys provide a more detailed saturation trend based on Ameren Missouri's actual service territory. Therefore, it is a preferable source of secondary data to the EIA information, which is provided on a regional basis. In the example above for central air conditioning, this methodology predicted a saturation of 93.1% in 2030 and at least 95.5% in 2046.

At the time of this forecast work, Ameren Missouri's market potential study was being conducted. After successful implementation of energy efficiency programs under MEEIA since 2012, it is expected to have higher saturation of certain end use stocks such as air

²⁸ 20 CSR 4240-22.030(4)(B)1

²⁹ 20 CSR 4240-22.030(2)(D)3

conditioners. Since the study results were not available at the time of this forecast work, this forecast partially relied on the previous market potential studies.

Appliance saturation and efficiency data is an obvious and important explanatory variable in modeling electricity sales, but there are other important variables that need to be included. Other logical predictors of electricity sales include the number of households in the service territory, income, and weather. Although this sales forecast is based on 30-year normal weather, actual historical weather and actual observed loads are used to estimate model coefficients.

In the SAE framework, elasticities with respect to price and income are determined exogenously and included in the calculation of the independent variables.³⁰ The estimation of price and income elasticities is a complicated subject, and especially with regard to price elasticity, there is a great deal of literature on the subject. One paper that was reviewed identified 36 different studies with 123 estimates of short run residential price elasticity, and those estimates ranged from -2.01 to -0.004.³¹

Ameren Missouri's approach to estimating elasticity parameters for each model was to start with a figure that was close to a central tendency from the literature reviewed where possible while incorporating recommendations from the consultant firm Itron where necessary to supplement the available information. After determining an appropriate starting point, the elasticity parameters were then adjusted up or down by small amounts to determine whether model statistics improved from the change. The elasticities used in the base case load forecast models were values that minimized the model mean absolute percent error (MAPE) over the estimation period.³² The price elasticity in the base case load growth residential model is -0.2.

Each model used a different economic driver, or a set of economic drivers. In the SAE model framework for residential sales, household income and the number of people per household in the service territory act as drivers for use per customer.

The functional framework of the SAE model is:³³

Use per customer

$$= B1 * ((cooling\ use) * (cooling\ index)) + B2 * ((heating\ use) * (heating\ index)) + B3 * ((other\ use) * (other\ index))^{34}$$

³⁰ 20 CSR 4240-22.030(7)(A)1; 20 CSR 4240-22.060(4)(D)

³¹ Espey, James A. and Molly Espey. "Turning on the Lights: A Meta-Analysis of Residential Electricity Demand Elasticities." *Journal of Agricultural and Applied Economics*, 36, 1 (April 2004):65-81.

³² Differences between the base, high, and low load growth scenarios are discussed in section 3.1.6

³³ 20 CSR 4240-22.030(6)(A)2

³⁴ 20 CSR 4240-22.030(4)(A)4

In each term the “index” variable captures past and future trends in appliance saturation and efficiency. This variable characterizes changes over time in the stock of end use appliances within the service territory. The “use” variable is a combination of variables that characterize the utilization of those appliances, including household income, the number of people per household, heating and cooling degree days, and the relevant elasticities. As would be expected, income has a positive correlation with consumption (i.e. as people have more money they tend to consume more), price has a negative correlation (the higher the price of electricity the less people tend to use) and heating and cooling degree days have a positive correlation with usage (as the weather gets more extreme, more energy is required to condition the space in the home to a comfortable level). The specific form of cooling use, for example, is:

Cooling use

$$= (\text{persons per household} \wedge \text{persons per household elasticity of use per customer}) \\ * (\text{household income} \wedge \text{household income elasticity of use per customer}) \\ * (\text{electricity price} \wedge \text{price elasticity of use per customer}) \\ * (\text{index of cooling degree days})$$

The heating and other use variables are similar, except that the heating use variable includes heating degree days instead of cooling degree days, and the other use variable does not include a weather term.

The coefficients B1, B2, and B3 are estimated with ordinary least squares (OLS) regression. One advantage of the SAE approach is that it produces very high t-statistics for each variable relative to most econometric models. In the base case residential model, for example, the t-statistics for the heating, cooling, and other variables are 50.91, 61.08, and 40.35, respectively. The adjusted R-squared for that model is 0.97 with Mean Absolute Percentage Error (MAPE) of 2.73%.

For this IRP iteration, a "COVID-19" variable was added to the SAE equation for the Residential and Commercial classes. In essence, the variable is intended to capture the temporary dynamics of the time, where Residential load increased at least in some respect at the expense of Commercial load. The variable was constructed as a weighted binary variable ranging in value from 0 to 2. The variable is applied to the Heat, Cool, and Other End Uses to account for changes in occupancy during the period in question. A unit greater than 1 indicates load increased due to COVID-19, and a unit less than 1 indicates load decreased due to COVID-19. The variable has a positive impact on Residential load due to increased occupancy from lockdowns and increased work from home during the period. Conversely the variable shows a negative impact on Commercial load caused by lockdowns, increased work from home, and capacity limitations at Commercial establishments. The Covid variable is only applicable for the period March 2020 to

December 2022. B The dynamics driving the “Covid-19” variable are intended to capture began to diminish after 2022, and as such, the COVID-19 variable has no impact on load after that point. It should be noted that in the prior IRP in 2023, a similar weighted dummy was used but where the effect persisted, at a diminishing rate, out to roughly 2028. This modelling was done at a time relatively close to the events being accounted for, with some uncertainty about the prolonged impact they might have. The additional three years of actual data means the post pandemic dynamics, most notably a world of hybrid work, is captured in the additional training data and the weighting no longer needs to persist to capture that effect moving forward.

The SAE framework was also used for the four classes of commercial electricity sales: small general service (SGS), large general service (LGS), small primary service (SPS), and large primary service (LPS).

The functional form of the commercial SAE model is:

$$\text{Use} = B1 * ((\text{cooling use}) * (\text{cooling index})) + B2 * ((\text{heating use}) * (\text{heating index})) \\ + B3 * ((\text{other use}) * (\text{other index}))$$

The coefficients B1, B2, and B3 were estimated with OLS regression.

The SAE approach used to forecast sales for the commercial rate classes is very similar to that used in the residential model. As with the residential class, the “index” variable includes past and forecasted data on appliance efficiency and saturation, while the “use” variable includes an economic driver, electricity prices, weather, and the appropriate elasticities. The end use index variables in the commercial SAE model also include consideration of the mix of building types in the rate class and associated estimates of electric intensity that we matched to our customer base with data from the Ameren Missouri Market Potential Study.

One difference between the commercial class SAE models and the residential SAE model is that in the residential model the SAE function is used to forecast use per customer, and a separate regression model predicts the number of customers. Total MWh sales in the residential class are the product of the result of the customer model and the SAE model. In the case of the commercial class, we are forecasting MWh sales with the SAE models rather than use per customer.

Econometric

The four industrial rate classes were forecasted without including estimates of appliance saturation or efficiency that distinguish the SAE models from more traditional econometric models. The four industrial rate classes, SGS, LGS, SPS, and LPS lack the homogeneity necessary to make the SAE approach useful without having a robust history of primary customer information. A significant degree of homogeneity exists across residential data

for households and the use and saturation of appliances, and even within the commercial class there is some homogeneity, especially within building types. However, industrial customers are much less homogenous. The way that a brewery, for example, uses electricity is likely to be quite different from the way that an aircraft manufacturer uses electricity, and the way an aircraft manufacturer uses electricity is likely to be quite different from a cement factory. Additionally, the SAE framework which has been utilized for the residential and commercial classes requires a significant history of end use information to identify end use trends, and such history is not readily available from any internal studies or external sources that have been identified. Ameren Missouri has collected a significant amount of primary data on these customers as a part of DSM market potential studies in 2020 and 2023, but has not used that data to perform end use forecasting for the reasons described above.³⁵ As additional studies are done, enough history may be developed to consider an end use approach, but the heterogeneous nature of the large industrial customers may still be an overriding factor in determining that econometric forecasts are preferable.

In order to produce a forecast of energy that is reasonable and is able to incorporate future changes in the economic environment and electricity prices, it is necessary to include a price term, a price elasticity parameter, an economic driver, and some elasticity with respect to the economic driver in a sales model. The SAE framework does this very well, but as noted above that form is not currently appropriate for Ameren Missouri's industrial class sales. In a typical econometric model, this would be done by including price and an economic driver in the model as independent variables. The regression estimated coefficients would then serve as de facto elasticities.

In the case of Ameren Missouri's industrial sales data, however, that approach does not always work, so a slightly different approach was used. Price in particular is problematic because real prices trended flat to down over much of the historical estimation period of the sales models, and the period of time with price increases is largely overshadowed by the significant economic disruptions of the 2007-2009 recession and more recent pandemic period. The result is that models with each factor input as standalone independent variables tend to produce coefficients for the price term that are either statistically insignificant, practically insignificant (i.e., a positive sign on the price coefficient), or both. A modification was chosen that combined price, output, and their respective elasticities into one composite independent variable.

The functional form was different from, but inspired by, the SAE framework:

³⁵ 20 CSR 4240-22.030(4)(A)1C; 20 CSR 4240-22.030(4)(A)3

$$\begin{aligned} \text{Sales} = & B1 * (\text{economic driver}^{\text{economic driver elasticity}}) * (\text{price}^{\text{price elasticity}}) \\ & * \text{index of billing/calendar days in the month} + B2 * (\text{CDD index}) + B3 \\ & * (\text{HDD Index}) \end{aligned}$$

Price, output, and their elasticities were combined into one term. As was the case with the SAE residential and commercial models, estimating elasticity was a challenge because estimates of elasticity in electricity consumption vary widely. Initial elasticities were chosen that reflected a mid-point of estimates from the literature. Through an iterative process, elasticities were chosen that minimized the MAPE over the sample period. A measure of billing or calendar days was added to the variable, to better reflect the changes in the volume of energy used in a month driven simply by the varying number of days of consumption that each month includes.

The composite independent variable did not include a weather term. In each rate class, an index of CDD and HDD were added as separate independent variables. In each of the four cases, the weather terms remained in the model if they were both practically and statistically significant.

Other Forecasting Considerations – Historical DSM Impacts

It should also be noted that the anticipated savings of Ameren Missouri's 4th cycle of energy efficiency programs through 2026 under the MEEIA programs are also subtracted from the load forecast projections. These programs are already being implemented and are not the subject of any decision making resulting from this IRP, and therefore these savings are considered as a given that they will occur. All future DSM impacts beyond MEEIA cycles 2,3 and 4 (i.e., programs approved for implementation through December 2026) are excluded from the base forecast and are the subject of the DSM chapter of this IRP study.

Other Forecasting Considerations – Weather³⁶

As in past IRP forecasts, SAE models are typically built using three explanatory variables representing cooling, heating and other loads. However, for some classes, an additional explanatory variable was added to some of the models to reflect the fact that the customers in that class either use their heating or cooling equipment differently during different times of the year, or that there is a non-linearity in their weather response. This additional explanatory variable is constructed as interaction between month/season and one of the three primary variables in SAE model construction. This is especially applicable in a class where some subsets of customers start cooling at one temperature, but another subset does so at a higher temperature. This additional term in the forecast equation captures these seasonal and non-linear weather effects. Additionally, the degree-day break points are evaluated to ensure the best model fits the weather and load relationships. Table 3.3

³⁶ 20 CSR 4240-22.030(5)(A); 20 CSR 4240-22.030(2)(D)2

below shows the degree day breakpoints used for heating and cooling for each class. To the extent that there are two values in the table, a non-linear response was detected and there will be an extra term in the forecasting equation. For the 2026 IRP, Ameren Missouri used a normal weather definition based on the years 1995-2024.

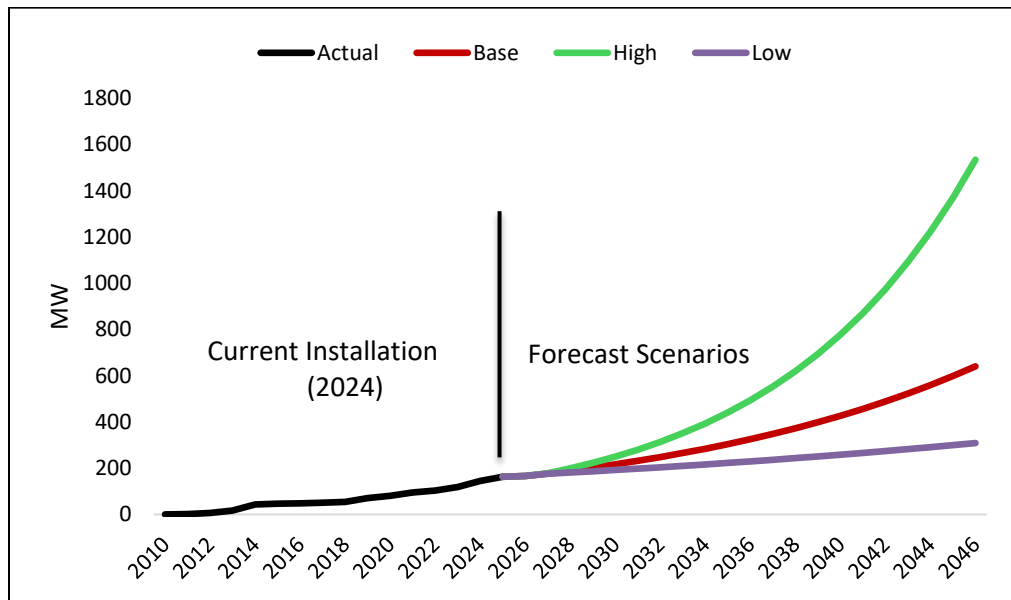
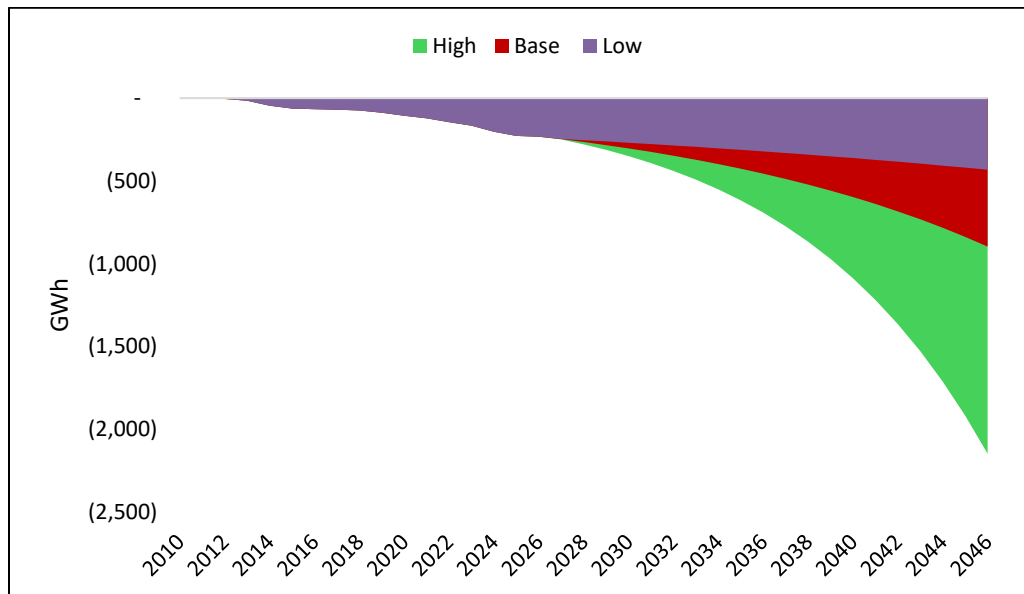
Table 3.3 Degree Day Break Points Used in Energy Modeling

Class	HDD	CDD
Residential	65	65
ComSGS	65	60
ComLGS	65	60
ComSPS	65	65
ComLPS	N/A	50

Other Forecasting Considerations – Customer Owned Solar PV

Over the past couple of years, there has been an increasing penetration of customer owned solar photovoltaic generating systems in Ameren Missouri's service territory. Generation from these systems appears to the utility as a reduction in demand for electricity. To capture the impact on demand for power supplied by the utility, we have incorporated an offset of load by using a projection of customer-owned generation in this forecast.

The rebate that Ameren Missouri offered to customers pursuant to applicable Missouri law drove a rapid increase in solar installations in recent years. The total amount paid for rebates was subsequently capped by regulatory agreement. A slower growth rate compared to 2023 IRP was expected over the next 20 years when Ameren Missouri solar incentive expired by the end of 2023. Ameren Missouri expects the customer-owned solar to increase at a compound annual growth rate of approximately 7.0% between 2027 and 2046 (base case scenario). In this case, the cumulative installed customer-owned solar capacity is expected to reach approximately 177 MW in 2027, and 640 MW by 2046 in Ameren Missouri's territory. The high load growth scenario assumes low adoption of customer owned solar (approximately 309 MW of cumulative installed customer owned solar capacity by 2046), and the low load growth scenario assumes high adoption of customer owned solar (approximately 1,533 MW of cumulative installed customer owned solar capacity by 2046) (Figure 3.9).

Figure 3.9: Cumulative Installed Private Solar (MW)**Figure 3.10: Cumulative Energy Reduction due to Solar Adoption (GWh)**

Other Forecasting Considerations – Efficient Electrification³⁷

At the time of the IRP 2020 publication, Ameren Missouri worked with EPRI to identify cost-effective and resilient strategies to produce and use clean energy. The two-year work plan laid out research to identify efficient electrification opportunities in Missouri and specifically in Ameren Missouri's service territory. Based on this detailed statewide study, EPRI provided an initial estimation of potential impacts of efficient electrification on various end uses. This forecast includes projections of additional energy consumption from efficient electrification during the planning horizon. After discussions with internal EPRI members, it was concluded that the 2020 study was still valid for the 2026 IRP. Ameren Missouri's load forecast for the 2026 IRP incorporates the results from the 2020 study for the base and low load growth assumptions along with its current business targets for the years 2026 to 2030. For the High load Growth Scenario, the EPRI forecast was modified to include a larger EV adoption rate. The High load scenario now assumes by 2050 all 2.5 million vehicles in Ameren Missouri's service territory will be Electric. A brief description of the scope of the 2020 EPRI study has been provided below.

The EPRI study consisted of four tasks: Energy System Assessment, Environmental Assessment, High-level Transmission Assessment, and Electrification Potential and Implementation Plan. Additional details for each task are provided below.

- ***Task 1: Energy System Assessment (2020-2050)***

The U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) modeling system has been adapted in this task to conduct an integrated analysis of potential development paths for the energy system in Missouri.³⁸ US-REGEN has a national scope with flexible regional disaggregation based on state or sub-state-level data. US-REGEN combines a detailed capacity expansion and dispatch model of the electric sector with a detailed end-use model that includes a high resolution of economy-wide energy use, as well as a representation of upstream non-electric energy activities. For each scenario evaluated, the electric model is solved out to 2050, in five-year time steps, to meet electric load at lowest economic costs. The end-use model is solved over the same time horizon, with iteratively updated electricity prices and hourly load shapes based on the changing end-use mix. A version of the model that evaluates Missouri as one of the 16 regions is being used to evaluate a series of Ameren-specified scenarios.

- ***Task 2: Environmental Assessment (2020-2050)***

US-REGEN outputs include projections of greenhouse gas (GHG) emissions namely carbon dioxide (CO₂) and methane (CH₄) and air pollution from the energy system.

³⁷ 20 CSR 4240-22.030(7)(A)5

³⁸ US-REGEN Model documentation: <http://eea.epri.com/models.html>

Estimated energy system CO₂ and CH₄ emissions changes include emissions associated with fossil resource energy development, extraction, distribution, and use. Changes in air emissions will be estimated for each scenario broken down by sector and geography to illustrate how electrification strategies could impact emissions over time and space.

Detailed air quality modeling is being conducted for the U.S. lower-48 to explore the implications of a set of high electrification and low electrification scenarios. The air quality analysis includes economy-wide emissions of air pollutants, including SO₂, NO_x, VOC, NH₃, CO and primary particulate matter—which are calculated by the US-REGEN model and examines the implications for ozone, PM_{2.5} and other air quality measures.

- ***Task 3: High Level Transmission Assessment (2020-2050)***

The results from Task 1, Energy System Assessment (supply side), details on the electric sector power generation mix and capacity, and demand side changes to overall energy demand and load shapes across the end-use sector of buildings, industry, and transportation form the basis of the high-level transmission assessment in Task 3. The transmission assessment will focus on enhancing the safety, reliability, and resiliency of bulk power and distribution system infrastructure consistent with the achieving the goals defined in the analysis scenarios.

The assessment in this task was conducted to understand the qualitative impacts on transmission needs in the state with particular attention to the following:

- a) Assessment of potential ability of the system to incorporate increased loads based on knowledge of existing system
- b) Description of operational implications of new loads and the new system resources required to meet those loads
- c) Guidance for utility internal follow-up study of these issues

- ***Task 4: Electrification Potential and Implementation Plan***

Incorporate the state-level results from Tasks 1, 2, and 3 into strategic, utility-specific guidance for the implementation of electrification programs to realize the economic and environmental benefits projected in the state-level analyses. This included energy technology assessments in the industrial, commercial, residential, and transportation sectors covering both energy-efficiency achievable potentials and opportunities for electrification. The final analysis includes: a utility-specific assessment of electric technologies, location-specific and across all customer classes, and a strategic vision and assessment for near- and long-term emerging technologies and their benefits and impacts. The resulting Customer Electrification Potential Model is used to guide near term program design as well as long-term strategic planning. The model is designed to incorporate other relevant data from prior analyses conducted by Ameren Missouri.

Ameren Missouri's Customer Electrification Potential Model incorporates the best available data, organized by:

- Technology categories within the four customer classes
- Locational distribution of key technologies within the utility service territory
- Projected adoption of both current and emerging technologies from present day to 2050

The Technology Pipeline will be updated over time to include detailed analysis for technologies with high impact and high potential to deliver customer and societal benefits across the timeframe of the project, including:

- Evaluation of Electric Technology Characteristics: Changes in cost and performance over time; identification of energy and non-energy benefits
- Detailed analysis for high-impact, high-potential technologies, including:
 - Electric transportation (light, medium, and heavy-duty), material handling, airports, and rail and other transit terminals.
 - Residential and commercial space and water heating.
 - High impact industrial electrification opportunities.
 - High impact emerging technologies: Indoor agriculture, additive manufacturing, and others.
- Strategic vision and assessment for near and long-term emerging technologies and their benefits and impact.
- Detailed System Impact: Hourly load shapes developed for each technology. Assessment of customer and grid flexibility for each technology.

Implementation scenarios will be prioritized for utility specific opportunities and customer requirements, and will continue to leverage existing EPRI tools, including the Electrification Knowledge Base and the Technology Readiness Guide.

Projected increases in load from electrification for Ameren Missouri were estimated using the US Regional Economy, Greenhouse Gas, and Energy Model, an energy-economy model developed and maintained by the Electric Power Research Institute. US-REGEN analyses were the basis of the EPRI's U.S. National Electrification Assessment (USNEA), which explored the potential for efficient electrification across the U.S. for four core scenarios – two with and two without federal climate policy. Utilities in 14 states are conducting electrification assessments with the model. A central feature in the USNEA and in the runs made for Missouri is the assumption that customers have free choice to choose the technologies – electric or non-electric that make the most sense to them.

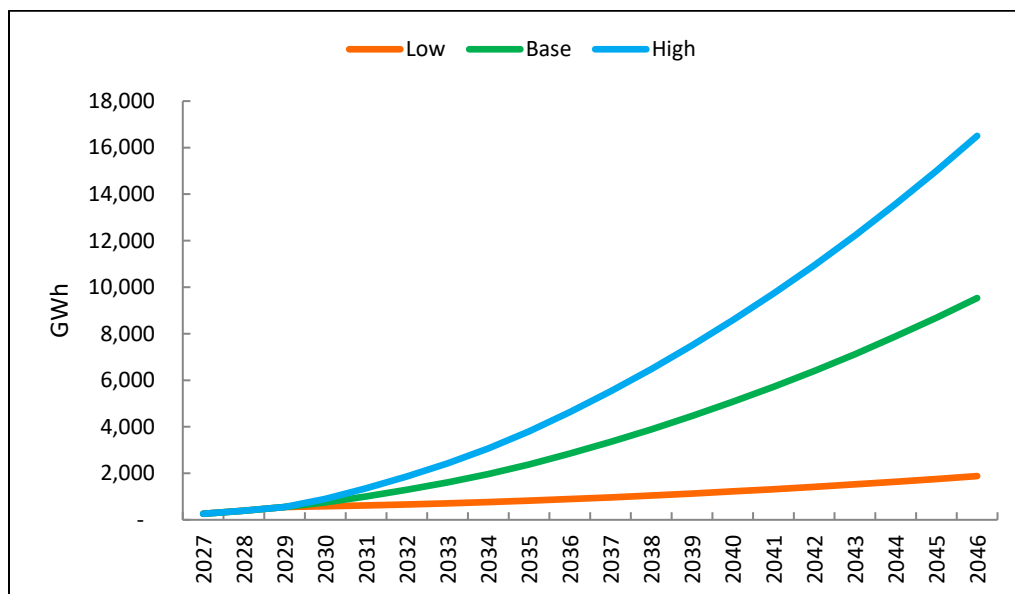
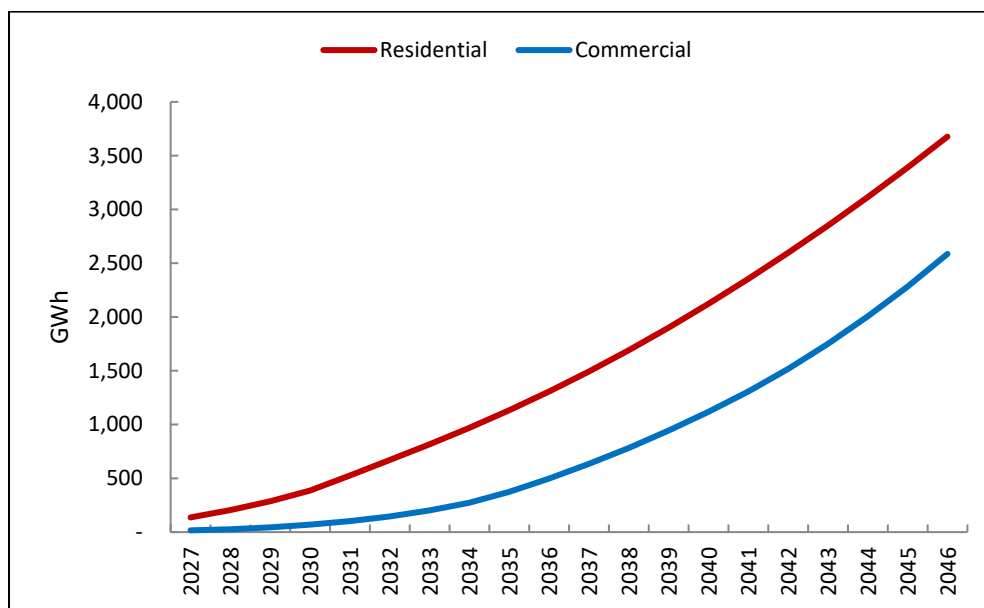
There are three cases defined for the Ameren Missouri IRP: The Low, Base and High Electrification scenarios. All use the same basic structure for the models as discussed

earlier but make changes to the input assumptions. The Low and Base case scenarios assume a low forecast of natural gas prices (developed by Ameren Missouri) and zero carbon prices. In the High Electrification case, the high natural gas price is used, as well as a countrywide, economy-wide carbon price. Additionally, for the Low Electrification case, the share of electric vehicle (EV) and other electrification is restricted to grow at a constant rate. In the base case, a \$5,000 cost adder is added to the estimated future cost of electric vehicles, to account for the fact that battery prices may not fall as fast as EPRI projections. In addition, the study had assumed that autonomous vehicles are not developed. Finally, the High Electrification case uses the default assumptions from the EPRI NEA (except for Ameren Missouri's gas and CO₂ prices). The imposition of an economy-wide carbon tax tends to increase electrification, however, in some sectors, electrification decreases between the Base and High cases, because the much higher deployment of electric vehicles, fueled by the relative decrease in EV costs between the two scenarios as well as the economy-wide carbon price increases the cost of electricity, which reduces the incentive to electrify in other sectors. In order to ensure that the High Electrification case represents a true maximum potential for electrification, each sector's maximum load from across all the scenarios is used to construct the electric load in the High Electrification case. For the 2026 IRP, the team further increased EV adoption in the High Electrification case to show expected electrification if the region were on track to fully electrify on-road vehicles by 2050.

Other Forecasting Considerations – Electric Vehicle Adoption³⁹

The 2026 IRP electrification forecast combines the current business plan and long-term efficient electrification potential estimates from EPRI. All three scenarios utilize Ameren Missouri's internal five-year budget electrification projections through 2027. Beyond 2027, the low adoption scenario bypasses the economic choice mechanism in US-REGEN and assumes that the share of electric vehicles continues to increase at recent historical rates. The medium adoption scenario assumes that the purchase price of electric vehicles does not decline as rapidly as in the default assumptions, and the high electrification scenario has default assumptions and also assumes the Ameren Missouri service territory is on track to see full electrification of all 2.5 million on road vehicles by 2050. Figure 3.12 shows long-term electrification projections used in different load forecasting scenarios. Figure 3.13 shows long-term load growth projection from light duty electric vehicles adopted for residential and commercial classes.

³⁹ 20 CSR 4240-22.030(7)(A)5

Figure 3.12: Long-term Electrification Projection**Figure 3.13: Long-term Load Growth from Electric Vehicle Adoption in Base Case Scenario**

Other Customer Class Forecasts

There are two other classes of energy sales which fell into neither the SAE nor econometric form of forecasting. Those two were Street Lighting and Public Authority (SLPA), and Dusk to Dawn lighting (DTD). SLPA and DTD sales are both functions of the light in a day and other seasonal factors such as time of the year. With the adoption of LED technologies,

sales in the lighting categories are expected to decline. Hence, the projected sales in lighting categories are modeled as a function of light bulb replacement with LED technologies along with a seasonal shape. This forecast assumes that all the streetlights will be replaced with LED by 2027.

Ameren Missouri's current business plan dictates to replace lightbulbs once they stop functioning and therefore, there is no pre-determined schedule for the LED installations. It is assumed that the annual kWh reduction due to LEDs will be similar year over year. Therefore, this forecast utilizes the kWh reduction in annual kWh sales in lighting classes from April 2024 to March 2025. After the annual reduction in lighting load was established, a monthly shape was applied to derive the monthly energy for the lighting classes.

Customer History and Forecasts

Forecasts of customer counts were produced at the rate class level; however, those forecasts were aggregated to revenue class for documentation purposes. In each case, an econometric approach was used with customers modeled as a function of an appropriate driver for that customer class, such as households, employment, or GDP.⁴⁰ The customer models may include dummy variables, end shift variables, or trends to capture the fact that customer growth and driver growth diverged over that part of the historical model estimation period to incorporate unusual effects of economic recession in 2008-2009 into the customer count growth. The models may also include auto-regressive and moving average terms as well as combinations of multiple of the aforementioned modeling approaches to smooth out the customer forecast in some cases.

3.1.6 Sensitivities and Scenarios⁴¹

The nature of the forecasting models used in this IRP forecast is such that the dependent variable (energy sales) is sensitive to changes in the independent variables as well as to the parameter estimates used to represent elasticity. This is a feature of econometric and SAE models, but it is worth mentioning here because it means that the forecast of energy sales is sensitive to changes in any one of the driver variables. The forecast of residential sales is sensitive to changes in households, electricity prices, income, population, and changes in appliance saturation and efficiency. Commercial and industrial sales are sensitive to changes in service territory GDP, employment, and electricity prices.

In this IRP, three different scenarios were modeled that stemmed from the combinations of assumptions about load growth, economic factors, customer owned renewable generation, electric vehicles and electrification of end uses. While the renewable generation forecasts were based on discussions with Ameren subject matter experts, the electrification

⁴⁰ 20 CSR 4240-22.030(3)(A)

⁴¹ 20 CSR 4240-22.030(8); 20 CSR 4240-22.030(8)(A)

projections were developed in consultation with EPRI. The scenario development process is discussed in Chapter 2.

In order to forecast high, base and low load growth scenarios, Ameren Missouri forecast team first developed energy forecast for various classes without including long-term projections of customer owned renewables and efficient electrification of end uses as described in previous sections. This added with various levels of customer owned renewables and efficient electrification provided base, high and low load growth forecast scenarios. Table 3.4 summarizes the key assumptions used to develop base, high and low load growth scenarios. In all cases, the forecasts remain the same until 2027, and changes after that due to changing assumptions on solar and electrification to create different scenarios.

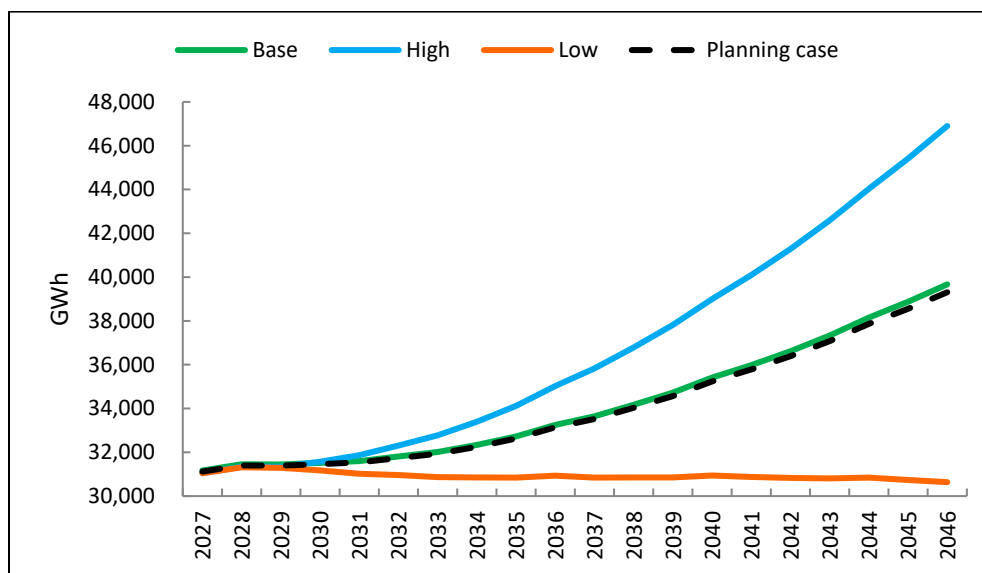
Table 3.4: Scenario Driver and Parameter Differences*

	High Load Growth Assumptions (Low Solar and High Electrification)	Base Load Growth Assumptions	Low Load Growth Assumptions (High Solar and Low Electrification)
Res	- Solar adoption (CAGR): 9.2% - EV adoption (CAGR): 22.4%	- Price elasticity: -0.2 - Household size elasticity: 0.20 (Cool and Heat) and 0.25 (Other) - Income elasticity: 0.13 (Cool and Heat) and 0.15 (Other) - Solar adoption (CAGR): 15.5% - Electrification (CAGR): 18.9%	- Solar adoption (CAGR): 21.8% - EV adoption (CAGR): 9.7%
Com	- Solar adoption (CAGR): 9.2% - Electrification (CAGR): 26.1%	- SGS Output 0.10, Price -0.02 - LGS Output 0.10, Price -0.05 - SPS Output 0.10, Price -0.05 - LPS Output 0.10, Price -0.05 - Solar adoption (CAGR): 15.5% - Electrification (CAGR): 22.5%	- Solar adoption (CAGR): 21.8% - Electrification (CAGR): 12.1%
Ind	Solar adoption (CAGR): 9.2%	- SGS Output 0.75, Price -0.22, Output Weight 0.15 - LGS Output 0.60, Price -0.10, Output Weight 0.70 - SPS Output 0.25, Price -0.10, Output Weight 0.30 - LPS Output 0.05, Price -0.04, Output Weight 0.90 - Solar adoption (CAGR): 15.5%	Solar adoption (CAGR): 21.8%

*: CAGR in the table indicates 20-year compound annual growth rate

Statistical models built with assumptions provide us with energy forecasts for the corresponding scenarios. System energy forecasts are obtained by adding all individual class level energy forecasts. Comparisons of annual system energy forecasts associated with three scenarios are shown below in Figure 3.14.

Figure 3.14: Total Energy Sales Forecast by Scenario



3.1.7 Planning Case Forecast

The three scenarios described in section 3.1.6 describe the range of likely outcomes for load growth over the planning horizon. The single forecast that represents the expected value of load growth over the planning horizon is referred to as the planning case. This forecast is needed in order to have a base expectation against which candidate resource plans can be developed, as discussed in Chapter 9. The integration modeling is actually performed using each forecast scenario, but the plans were created in order to maintain an appropriate amount of capacity given expectations in the planning case.

The calculation of the planning case forecast is a fairly simple exercise. The subjective probabilities of each scenario, as determined by the subject matter experts for the various uncertain factors, were used to weigh the different scenarios and thus determine a probability weighted average load. The planning case does not have its own set of forecast models with case specific drivers but instead is derived from the modeling results for the three independently generated scenarios.

For this IRP analysis, 60% probability was assigned to the base case scenario, and 20% probability was assigned to each of the high and low growth scenarios. The planning case forecast was developed using these probability weights.

3.1.8 Forecast Results

For the planning case, total retail energy sales, excluding the large load tariff class, are expected to grow at 1.2% compound annual rate between 2027 and 2046. In the last decade, total retail sales declined primarily due to the naturally occurring and company sponsored energy efficiency programs and a decline in consumption by the aluminum smelter. Sales dipped sharply in 2009 and went through an uneven period of recovery following the recession. Post-recession recovery was also offset by naturally occurring and company sponsored energy efficiency programs. Between 2020 and 2022, COVID-19 had a positive impact on Residential sales but was offset by a negative impact on both Commercial and Industrial sales. For the 2026 IRP, loads are forecasted to increase 1.2% excluding Large Load Tariff customers by 2046, due largely to Efficient Electrification, especially increasing Electric Vehicle adoption. As mentioned earlier, the load forecast scenarios only incorporate savings from MEEIA 4 cycles through the program year ending in December 2026 for energy efficiency programs and 2027 for demand response program.⁴²

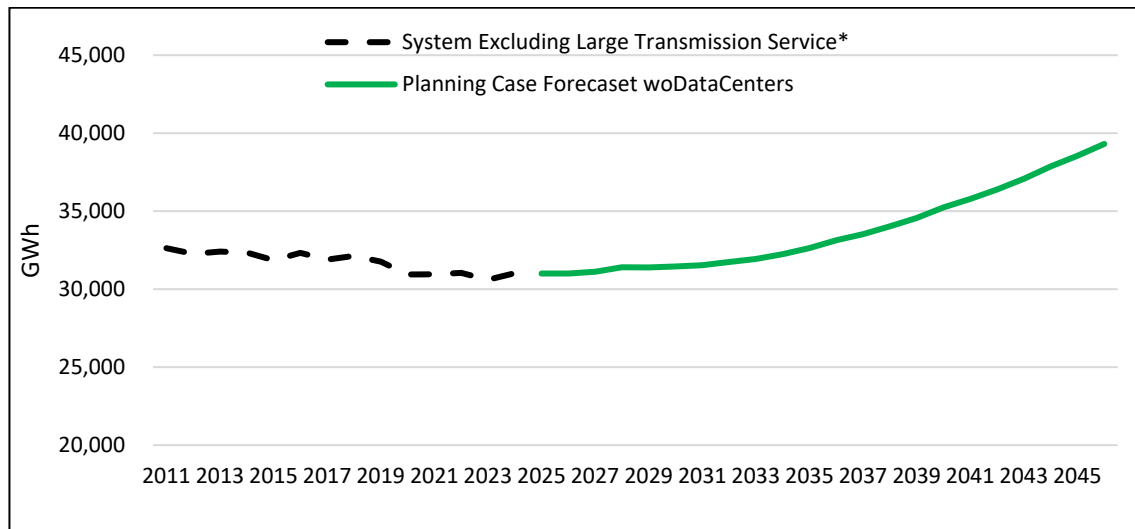
Energy efficiency programs under MEEIA (Cycle 1, 2, 3 and 4) have incrementally reduced sales by ~1% in each of its program years. As the economy recovered from the severe recession, Ameren Missouri's residential and commercial customer count began growing at a historically slow, yet steady pace. Over the past three years, Ameren Missouri's customer counts in the residential class have grown steadily between 0.5 and 1% year over year, while commercial customer counts have seen a decline between 0.2 and 0.4% over the past two years. Savings from energy efficiency programs have diminished any sales growth achieved as a result of the residential customer growth, while it has caused commercial sales to remain flat or slightly decrease. Also, in line with steadiness in overall sales and economic growth over the past several years, Ameren Missouri's economic projections expect this trend to hold steady over the next few years. Additionally, the implementation of LED technologies in the lighting classes has reduced sales to the lighting categories significantly over the past number of years. (Figure 3.15).

One seemingly trivial feature of our sales modeling affecting sales growth is leap day. In each of our models, the number of calendar days in the month is included as an explanatory variable; either on its own or combined with another. Each leap year is one day, or 0.27% longer than normal, and that extra day is in a month when we typically experience meaningful heating load. That causes sales growth in every leap year to be slightly higher than it otherwise would be, and growth in each year that follows a leap year to be slightly lower. This is not noticeable in Figure 3.15 but is noticeable in Table 3.5. The impact of

⁴² 20 CSR 4240-22.030(7)(A)3

leap years on sales is in one sense trivial, and does not meaningfully affect capacity planning, which is of course the central goal of the IRP. It is; however, a logical and observable result of the detailed modeling used in the forecasting process.

Figure 3.15: Planning Case Energy Sales Forecast



*Historical sales have been adjusted to reflect that Ameren Missouri does not serve any customer in Large Transmission rate class at this time.

Table 3.5: Planning Case (2027-2046) Annual Sales Growth by Class

Year	Residential	Commercial	Industrial	Lighting	Total_w/o LL
2027	0.0%	0.3%	1.7%	-1.7%	0.4%
2028	1.1%	0.3%	2.3%	-0.1%	0.9%
2029	0.0%	0.0%	-0.2%	0.0%	0.0%
2030	0.4%	0.1%	0.0%	0.2%	0.2%
2031	0.3%	0.3%	0.0%	0.2%	0.2%
2032	1.0%	0.5%	-0.1%	-0.4%	0.6%
2033	0.7%	0.8%	0.0%	0.2%	0.6%
2034	1.1%	1.2%	0.0%	0.0%	1.0%
2035	1.2%	1.5%	0.0%	0.1%	1.2%
2036	1.7%	1.9%	0.2%	0.0%	1.6%
2037	0.8%	1.9%	0.0%	0.4%	1.1%
2038	1.4%	2.1%	0.1%	0.3%	1.5%

Year	Residential	Commercial	Industrial	Lighting	Total_w/o LL
2039	1.4%	2.2%	0.1%	0.3%	1.6%
2040	2.1%	2.4%	0.0%	-0.3%	1.9%
2041	1.2%	2.4%	0.0%	0.4%	1.6%
2042	1.3%	2.6%	0.1%	0.2%	1.7%
2043	1.6%	2.7%	0.0%	0.0%	1.9%
2044	2.0%	2.8%	0.1%	0.0%	2.1%
2045	1.2%	2.9%	-0.2%	0.0%	1.8%
2046	1.5%	2.9%	0.0%	-0.1%	2.0%

Residential

Between 2011 and 2019, although the customer count increased at a compound annual growth rate of 0.4%, residential weather normalized sales decreased by 0.6%. Ameren Missouri started the first cycle of MEEIA programs in 2013, which had incrementally reduced energy sales by approximately 1% during each of its program years. Customer count in residential class has been growing modestly in the past years. Sales growth due to customer growth between 2011 and 2019 was diminished by naturally occurring and company sponsored energy efficiency programs. Residential sales grew in 2020 by 4.0% due to the COVID-19 pandemic and an increase in telework. This trend is like the trends seen in other utilities and nationwide. As pandemic-related remote work practices gradually eased and more employees returned to the office, residential sales declined after 2021. Between 2020 and 2024, residential sales decreased by 0.3%, yet with a 0.5% increase in customer count.

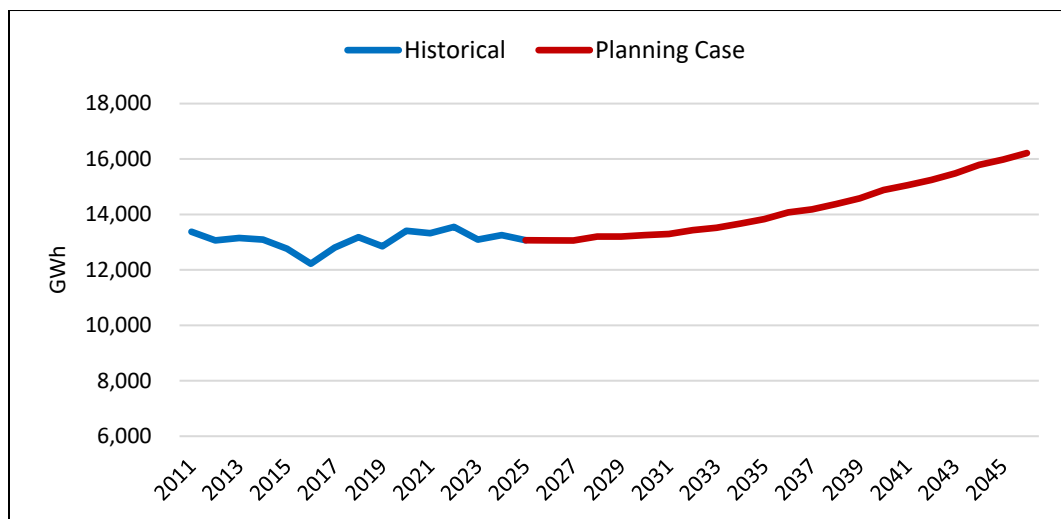
In the planning case forecast, residential load is anticipated to grow at a compound annual rate of 1.1% between 2027 and 2046.

The number of residential customers is expected to grow at a compound average rate of -0.05% between 2027 and 2046. Compared to historical standards, customer growth has been rather modest since the recovery from the recession years 2008-2009. Ameren Missouri's residential customer count grew at a compound annual rate of 0.4% between 2010 and 2024. The forecast assumes that the residential customer count will continue the slow, yet steady growth over the next 10 years and reach the peak by 2036. A growth rate of 0.2% is predicted from 2027 to 2036. Then the customer count is expected to be steady and decrease. The growth rate from 2037 to 2046 is forecasted to be -0.1%.

Usage per customer growth in the residential class is expected to remain modestly declining for the first few years of the forecast horizon. Again, customer owned distributed

energy resources, efficiency standards of appliances and MEEIA programs hold average customer consumption down during this time. An increase rate of 1.3% for usage per customer is predicted from 2030 to 2046 mainly due to EV adoption. In average, per household could add 3,000 kWh per year because of charging at home.

Figure 3.16: Planning Case Forecast of Residential Energy Sales



Commercial

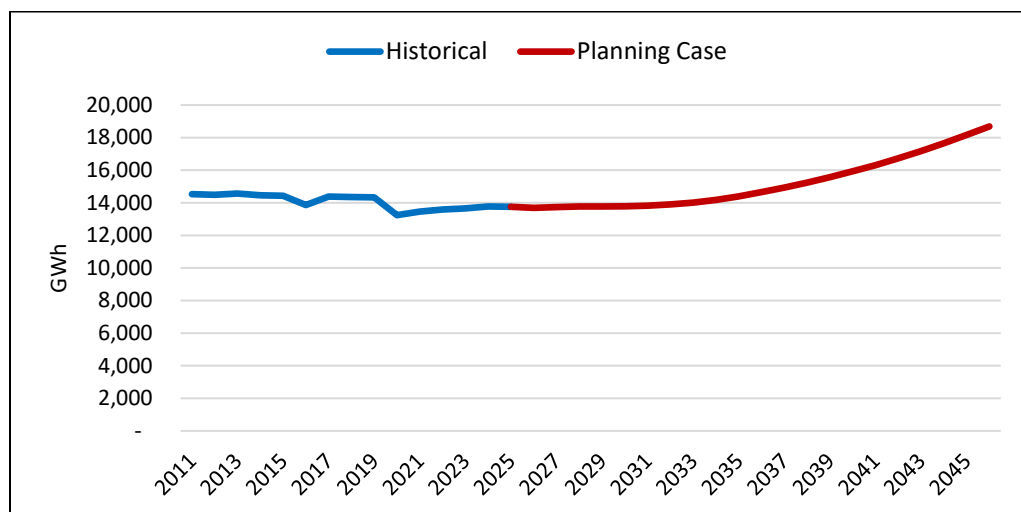
Prior to the COVID-19 pandemic, Ameren Missouri commercial class sales have been the fastest growing segment of sales over the period of historical review for this IRP, partially reflecting the shift away from manufacturing toward health and education services in the service territory economy, and partially because of the growth of new types of commercial load such as data centers. Between 2004 and 2012, weather-normalized sales grew at a compound annual rate of 1.0%. Like residential sales, commercial sales were impacted by the recession and have grown more slowly than the previous historical trend since 2009 due to naturally occurring and company sponsored energy efficiency programs. During 2020, Ameren Missouri Commercial Sales decreased 6.6% due to remote work, government lockdowns, and capacity restrictions on businesses. Since 2020, Commercial sales have seen a recovery, as 2025 sales are up 3.7% compared to 2020. However, these are still below 2019 levels, as 2025 sales are down 3.1% compared to 2019.

Three different factors contributed to load growth prior to 2020. From 2006 through 2008, commercial load grew at a robust pace of around 1.1%. The recession between 2007 and 2009 combined with Ameren Missouri's energy efficiency programs flattened the trajectory of commercial load considerably. The economic impacts of the recession and post-recession recovery coincided with increases in energy efficiency savings during this time period.

Customer count grew at a year over year rate slightly below 1% from 2012 through 2022, with that growth rate slowing down to even slightly decreasing (less than -0.5% Y/Y) by 2025. However, this decline in customer count is expected to flatten out Y/Y starting in 2026 and through the end of the planning period of 2046.

However, Ameren Missouri also started the first cycle of MEEIA programs in 2013, which has incrementally reduced energy sales by little less than 1% in most of its program years. However, the MEEIA program has seen a decline in recent years, as noted by 2025 MEEIA incrementally reducing sales by only 0.5%. As savings from MEEIA programs are fully realized, Ameren Missouri expects customer owned distributed energy resources will increase which will further impact the growth in sales to commercial customers. However, positive impacts from electrification of end uses may stabilize the decline in the sales. Ameren Missouri anticipates commercial sales to grow at a compound annual rate of between 0-1% through 2033, and then steadily increasing to 3.0% by 2046. This is largely due to anticipated heavy increases in electrification energy usage, especially towards the end of the planning period.

Figure 3.17: Planning Case Forecast of Commercial Class Energy Sales



Industrial

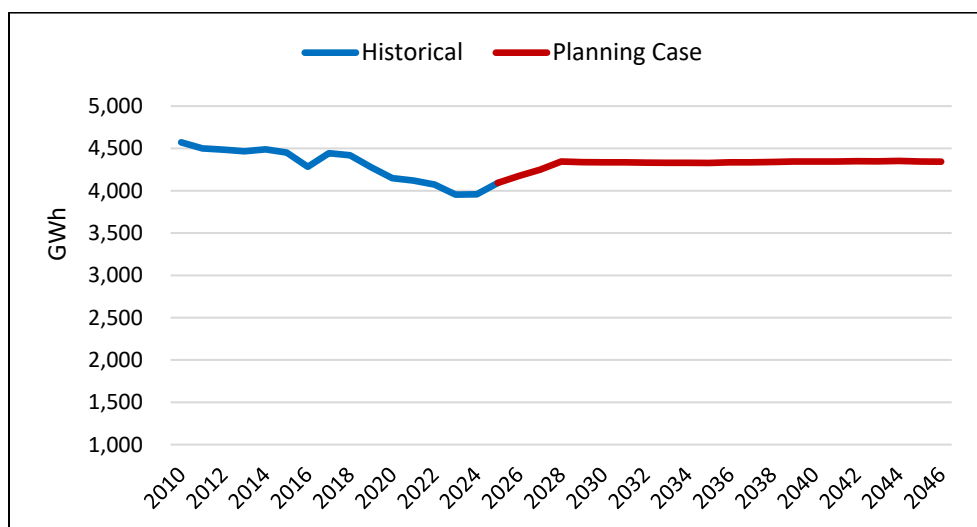
Ameren Missouri industrial class sales have been experiencing a structural decline for more than a decade. Compounding this decline was the significant toll the 2007-2009 recession took on the service territory manufacturing base. The decline in manufacturing activity was not one confined to the Ameren Missouri service territory; national manufacturing severely contracted during the recession as well. However, industrial loads elsewhere recovered at least a significant portion of their losses in the years of slow recovery since the recession.

Ameren Missouri's industrial load remained relatively flat to modestly declining in those years.

Casualties contributing to this decline in the service territory manufacturing base include the Ford Assembly plant in Hazelwood, Missouri, which closed in 2003, and the Chrysler plant in Fenton Missouri, which closed in 2010. Between 2010 and 2024, Ameren Missouri's industrial sales declined at a compound annual rate of 1.0%. Note that Ameren Missouri's largest single customer by far in the past, the aluminum smelter in New Madrid, Missouri, is not included in these industrial load statistics, as this customer is no longer an Ameren Missouri customer.

The planning case forecast for industrial sales reflects a predicted compound annual rate of 0.1% between 2027 and 2046. The forecast does not anticipate that the industrial sales will reach pre-recession levels at all during the planning horizon.

Figure 3.18: Planning Case Forecast of Industrial Class Energy Sales



Customer Forecast

The forecasts of customers for the residential, commercial and industrial classes are reasonable given the performance of customer growth over the prior decade. Table 3.6 showed the historical as well as predicted customer growth rate. Residential customer count was expected to increase for the next 10 years, and then decrease, with a compound annual growth rate of 0.05%. This is consistent with the growth rate of households that under Ameren Missouri service territory. Commercial customer count was forecasted to be flat year over year. Industrial customer count would continue to decrease with a slower rate compared to 2010 to 2024.

Table 3.6: Customer Compound Annual Growth Rates

Year	Residential	Commercial	Industrial
2010-2024	0.4%	0.6%	-1.7%
2027-2046	0.0%	0.0%	-0.3%

Lighting and Other

We anticipate reduction in energy consumption in the Dusk-to-Dawn lighting classes due to expected conversion to LED technologies. Once all the light bulbs are converted into LEDs by 2027, there is no anticipated change in the consumption level during the planning horizon. Overall compound annual growth rate (CAGR) is -0.1% in lighting classes during the planning horizon.

3.3 Peak and Hourly System Load Forecast

The peak demand forecast is of critical importance to the IRP. The demand on the system at the peak hour drives the need for generating capacity. While the need for energy influences the optimal mix of generation resources, the timing and amount of capacity additions are most directly tied to peak demand.

The system load forecast, as in years past, is done on a bottom-up basis. This means that the load is forecasted by aggregating customer class loads and their associated transmission and distribution losses in order to represent all energy consumed on the system. As in prior IRP forecasts, there is an additional level of granularity in this forecast stemming from the fact that the bottom-up forecast is being built from the level of the end-use load when possible, rather than just the customer class load. The energy forecast is prepared on an end-use basis for the residential and commercial classes as described previously. Each end use that has an energy forecast also has an accompanying load profile to shape it into an hourly forecast. These individual end-use forecasts are aggregated to the class level. Where end-use energy forecasts are not available, particularly in the industrial class, class level profile models based off of load research data are used to shape the hourly forecast. Class level forecasts based on the aggregated end uses or class level models have appropriate loss factors applied to them and are then added to create the system level forecast. The maximum load hour from the system load forecast for each year becomes the annual forecast peak load.

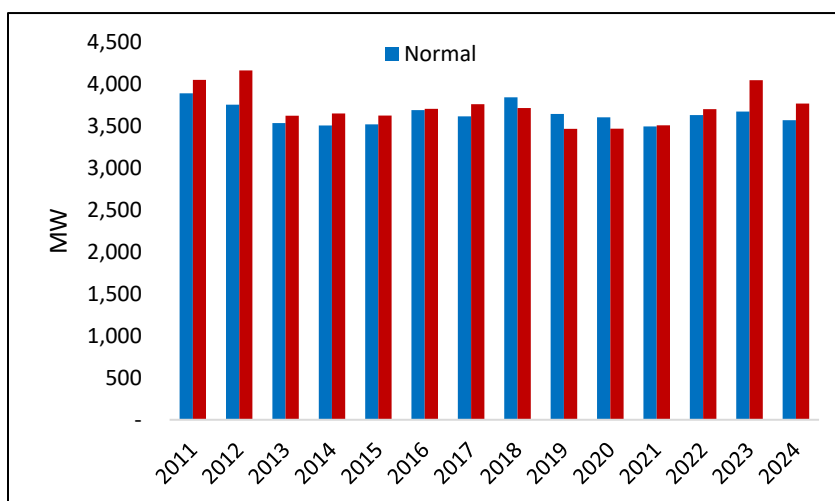
3.3.1 Historical Peak and System Load

Ameren Missouri's historical database of actual and weather-normalized class and system demands is maintained back to July 2003.⁴³ Actual hourly system data is available back to the beginning of January 2001. Earlier data for both class demands and system loads does exist but is not applicable to the Missouri jurisdiction only. Prior to 2005, Ameren Missouri served the Metro East load in Illinois. For the periods described above, the data was able to be disaggregated into its Missouri and Illinois components. For earlier data, the detail needed to perform this disaggregation was no longer available at the time of the Metro East transfer.

All class demand data is based on Ameren Missouri's load research program. As a part of the load research process, hourly class demands are calibrated to the observed system load to ensure that all energy consumed on the system is attributed to classes appropriately.

The annual coincident peak demand, on a weather-normalized basis, for the residential class from the year 2015 to 2024 increased at a compound annual rate of 0.2%. The class load increased from a weather-normalized 3,522 MW in 2015 to 3,571 MW in 2024 (at generation, i.e., inclusive of transmission and distribution losses). On an actual basis (not weather-normalized), the residential class load reached its highest level on August 15, 2007, when the temperature in St. Louis reached 105 degrees Fahrenheit. On that day, the highest hourly integrated residential demand at the time of system peak was 4,174 MW.

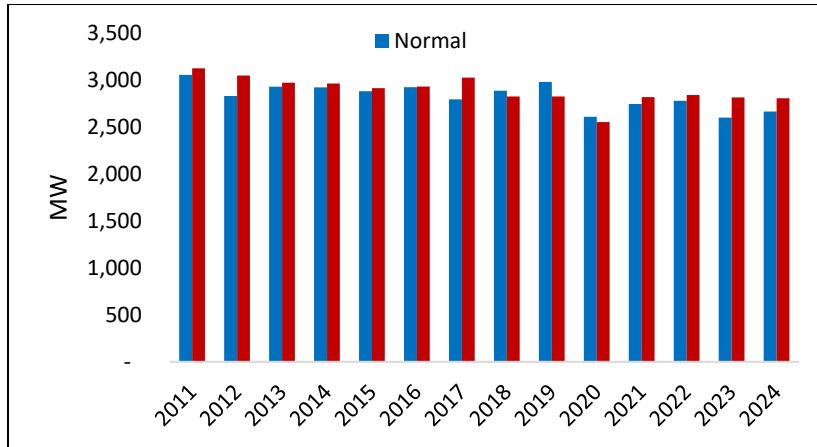
Figure 3.19: Residential Coincident Peak Demand (MW)



⁴³ 20 CSR 4240-22.030(2)(B)3

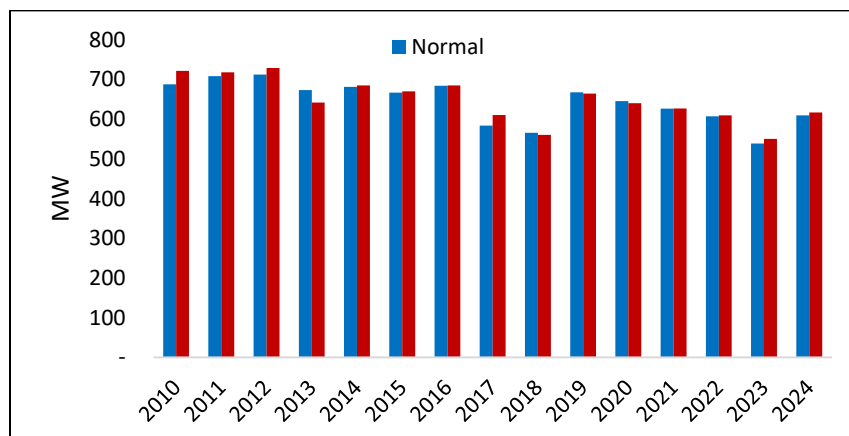
For the commercial class, the annual coincident peak demand declined at 0.9% per year, from a weather-normalized 2,884 MW in 2015 to 2,666 MW in 2024 (at generation, i.e., inclusive of transmission and distribution losses). On an actual basis, the commercial class load reached its highest level in 2011, with an hourly integrated demand of 3,127 MW.

Figure 3.20: Commercial Coincident Peak Demand (MW)



The industrial class annual coincident peak demand declined on a weather-normalized basis since 2008. The normalized class demand decreased rapidly through the recession of 2007-2009, then continue dropping with a slower rate. The weather-normalized peak decreased from 667 MW in 2015 to 609 MW in 2024 at a compound annual rate of 1.0%. There was broad based weakness across this class, but a couple of specific large customer closures coupled with energy efficiency programs had a significant impact on such reduction over last decade. For the industrial class, 2007 saw the highest actual coincident peak demand at 940 MW.

Figure 3.21: Industrial Coincident Peak Demand (MW)



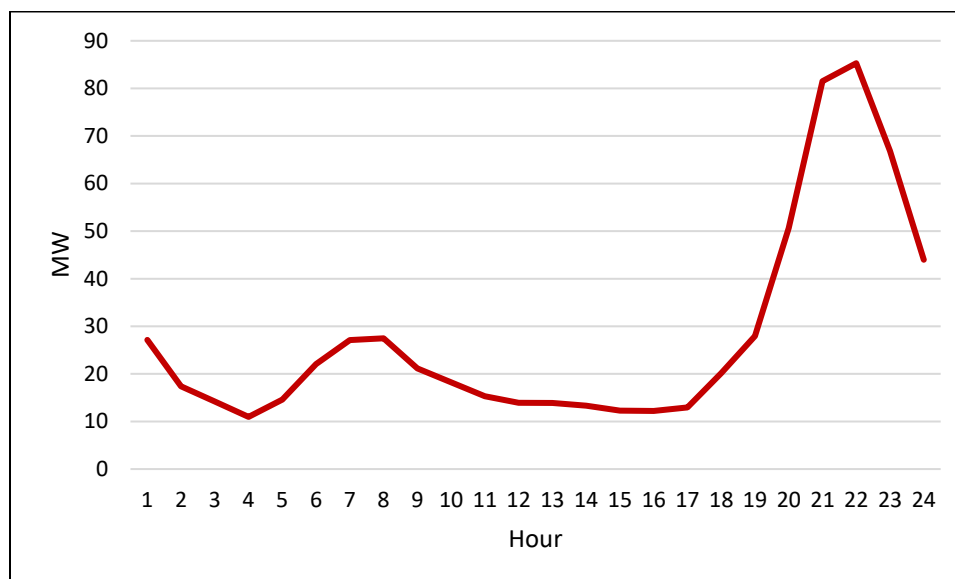
3.3.2 Profile Shapes

The energy forecast provides a view of how much energy is expected to be used by each category of end use for each customer class where applicable and for each total class where end uses are not contemplated in the energy forecast. The challenge of developing a system peak and hourly forecast comes down to determining when that usage will occur. This problem is well-suited to the application of load research data. For the industrial classes that were forecasted using econometric models (no end-use detail), Ameren Missouri specific load research data is used to determine that pattern of usage.

For the residential and commercial classes, the energy forecast from the SAE models can be disaggregated into its end-use components relatively easily. Because of various changes in energy efficiency standards for different end uses as well as differences in the natural growth of the stock of each end-use appliance in the service territory, it was hypothesized that a more accurate peak and hourly forecast could be generated by applying specific end-use shapes to this end-use energy forecast.

To illustrate the point, consider the lighting end use. Lighting is most prominently used by residential customers after sunset to illuminate homes in the evening. The summer peak load, which is arguably the most critical component of this forecast, will almost certainly occur late in the afternoon on a summer weekday. At this time, the sun is shining brightly, and lighting use is relatively low for residential customers compared to the evening. A typical lighting load shape is shown in Figure 3.22, note the peak at hour 21 and the fact that hour 17 (likely the summer system peak hour) energy is only 23% of the peak.

Figure 3.22: Residential Lighting Load Shape



Because the Energy Independence and Security Act (issued in 2007) included standards to increase the efficiency of most light bulbs used by residential customers, the energy forecast associated with lighting has declined fairly significantly relative to other end uses over the planning horizon. If a class level model were used to forecast the residential summer peak, the decline in lighting load would produce a 1 for 1 decline in the summer peak. In other words, if lighting load hypothetically represented 10% of the residential energy usage, and the forecast included a 10% decrease in lighting energy, then the peak load forecast would be 1% lower ($10\% \text{ lighting share} \times 10\% \text{ decline in lighting load} = 1\% \text{ decline in total load}$). However, under the end-use profile framework, lighting may still hypothetically represent 10% of the residential energy consumption, and it may still decline by 10% in a forecast year, but because the lighting profile is at a relatively lower level during the summer peak hours (23% of the peak lighting usage and 63% of the average lighting usage), the lighting contribution to peak will cause something less than a 1% decline in peak load. More of the decline induced by the lighting efficiency gains will be associated with energy usage that occurs later in the evening, not affecting the peak. As this example highlights, by assigning specific end-use profiles to the end-use energy forecast, more realistic load impacts on the peak should result.

Unfortunately, neither Ameren Missouri nor any other utility of which we are aware, currently collects load research data at the end use level. So, for developing load shapes that are applicable to the end use energy forecast, secondary data must be acquired.

Itron's eShapes Database

End-use load research can be a very costly activity. Whereas traditional load research utilizes the existing meter and meter reading infrastructure, end-use load research typically requires the utility to install additional equipment within the premises of the customer and develop a new infrastructure for collecting this data. The cost of it is generally prohibitive, and end-use load research programs are not common today as a result. However, in the 1990's a number of utilities did engage in end-use load research, and the data collected was shared through EPRI.

Itron, an industry leading forecasting and load analysis consulting company, has a product called eShapes, a database of load shapes that apply to loads from various combinations of end use, customer class, and geographic location. The data underlying Itron's eShapes database is proprietary, but the shapes themselves have been publicly available for years and are relied upon widely as a high quality set of end-use load shapes. Ameren Missouri has acquired the Itron eShapes database and utilized its load shapes in its peak and hourly load forecasting process.

Load Shape Calibration⁴⁴

Because the data in Itron's eShapes database is secondary data and probably more than a decade old, and more recent and geographically similar data is nearly impossible to come by, Ameren Missouri worked with this data to ensure that it was as applicable to the Ameren Missouri load as possible. For a three-year period (2010-2012), the Itron data was utilized to construct Ameren Missouri class level data from the bottom-up. Historical energy sales for 2010-2012 were divided into end uses based on information from the SAE forecasting models. The eShapes profiles for each end use were then scaled so that they represented the estimated energy from those years. The scaled end-use shapes were then aggregated to create a "synthetic" class level load shape. That synthetic load shape was then compared to the Ameren Missouri load research data for the same class to determine whether the resultant bottom-up shape was an accurate representation of the relevant load. The eShapes profiles were then calibrated to ensure that the load shapes utilized in the final forecast were a good representation of the load for the class.

For the weather sensitive end uses (heating and cooling), it was necessary to build a regression model of the load temperature relationship of the end use in order to make the load shapes applicable to the historical period in question given the weather that occurred. The data used in the model in the case of these end uses did not come directly from the eShapes database but instead was based on the end-use data simulated for Ameren Missouri by Itron for its 2008 IRP filing. The actual weather from the study years was applied to the model coefficients to produce weather sensitive heating and cooling shapes that are based of the weather experienced in that year.

The synthetic class load shapes were plotted on graphs against the load research data to allow for visual inspection of the loads side by side. Also, an hourly error series was developed by subtracting the load research from the synthetic class load. This error series was examined by averaging it across several time dimensions (hour of the day, day of the week, month) to determine whether there were systematic ways in which the synthetic load profile was varying from the load research data. It quickly became apparent that the average hourly class load shape that had been generated from the end-use data was not consistent with the load shape observed from the load research data. This is not surprising, as again, the end-use load research is secondary data and is removed from its original source in both time and geography. Figure 3.24 shows the average hourly error pattern that was generated in this process for the residential class.

As is apparent in Figure 3.24, the synthetic class load shape was too high during the late morning and evening hours (generating a positive error pattern) and too low in the mid-

⁴⁴ 20 CSR 4240-22.030(4)(B)2; 20 CSR 4240-22.030(1)(C); 20 CSR 4240-22.030(1)(D)

afternoon hours (generating a negative error pattern). In order to improve the fit of the build-up load, the individual end-use load shapes were adjusted slightly. The overall characteristic of the shape was respected, as the eShapes data is the best information available to discern the usage patterns of these end uses. However, the load factor of each shape was adjusted up or down using the unitized load calculation. An algorithm was set up to vary each end-use load shape within certain parameters judged by the forecasting staff to be reasonable, with the goal of minimizing the sum of the hourly absolute errors in the calculation represented by the chart above. Through this process, using the adjusted end-use load shapes, the hourly pattern in the error was reduced significantly. Below is an example of an end-use load shape both before and after load factor adjustment.

Figure 3.23: Average Hourly Difference-End Use Build Up vs. Load Research

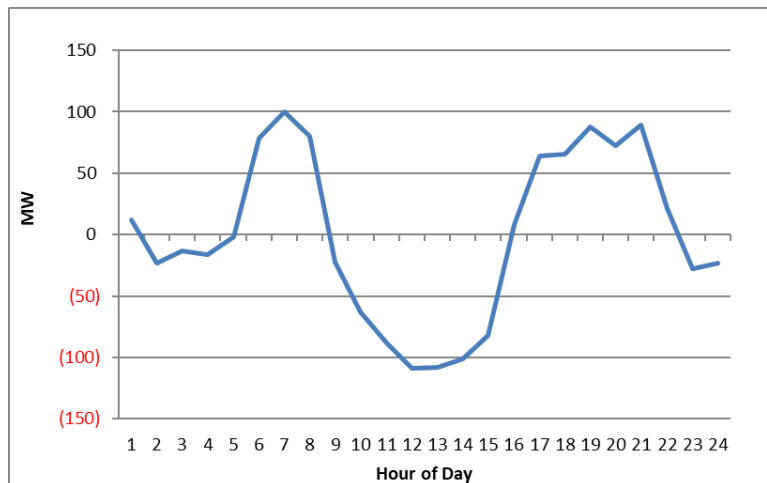
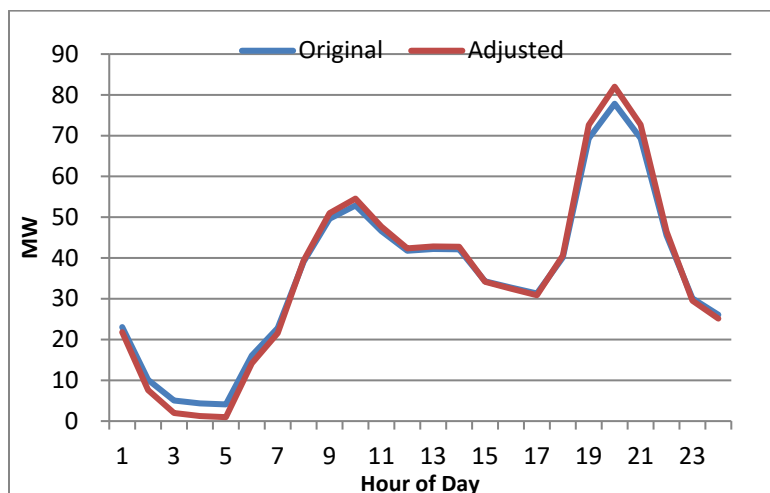


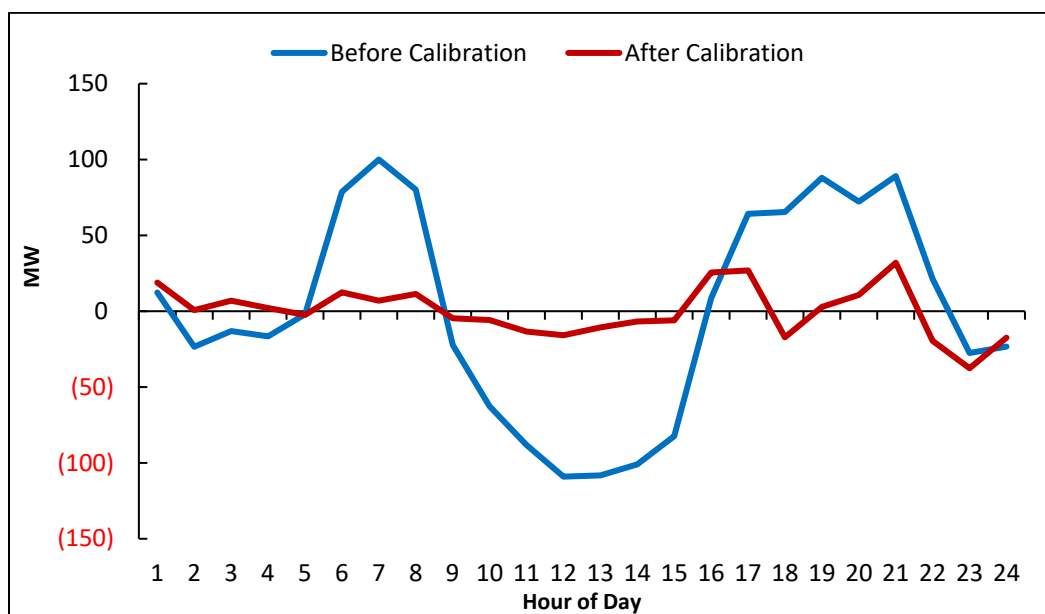
Figure 3.24: Dishwasher Load Shapes



As is visible in the chart of the dishwasher shape, the basic characteristic is retained, but the load factor is reduced in this instance (the peak of the adjusted shape is higher relative to the total energy). Each end use was reviewed and a similar adjustment process applied until the error pattern in the difference series was minimized. The final load shapes for each end use will be included in a chart in the final filing. The pattern of the hourly differences before and after adjustment is shown in Figure 3.25.

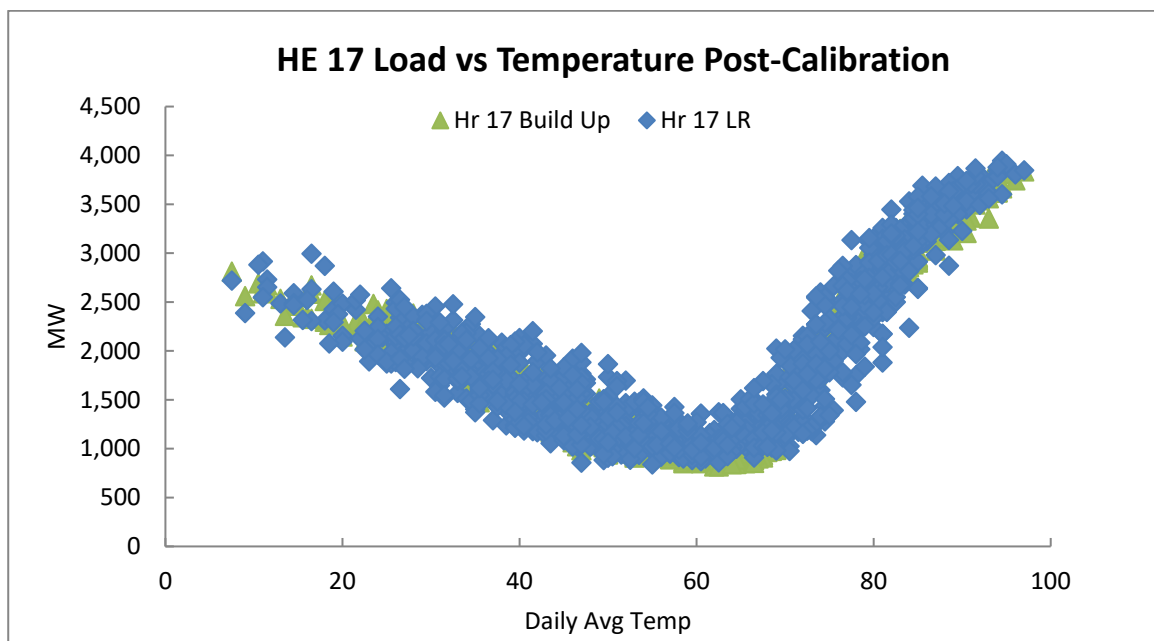
While the adjusted load shape still exhibits some differences from the class actual load shape, the magnitude of the differences is clearly reduced by a substantial amount. It would be impossible to make the synthetic load shape have a perfect fit with the load research data while respecting the characteristic shape of each end use. But with reasonable adjustments, the fit was dramatically improved. Where the original load shape had absolute differences that exceeded 100 MW at times, now no hour's difference exceeds 35 MW as shown in Figure 3.25. This innovative process helped bring the secondary data much more in line with the specific characteristics of the Ameren Missouri service territory loads. The forecasting staff reviewed the adjusted load shape for each individual end use to confirm that it was reasonable.

Figure 3.25: Avg. Hourly Difference-End Use Build Up vs. Load Research



The process described above was replicated for the four commercial rate classes to provide end-use load shapes for all classes for which the energy forecast contemplated this level of detail.

Figure 3.26: Cooling End Use Shape Calibration



An additional level of scrutiny was given to the heating and cooling end use loads, as these are significant contributors to the peak load hours and hence the peak forecast to which Ameren Missouri will plan its capacity needs. Since the system peak typically occurs at hour ended 17 (the hour from 4:00 pm to 5:00 pm) in the summer, we created a scatter plot of HE 17 loads vs. temperature using both the load research data and the synthetic load data. After further adjustment of the cooling load shape, still respecting its basic shape, a high level of agreement between the observed loads and the calculated loads was achieved. The chart shown in Figure 3.26 shows a comparison of the two scatter plots.

3.3.3 Peak Load Forecast

Once the load shapes, both end-use, and class level have been developed, the process of forecasting the peak system loads is straightforward. The most complicated part is developing a planning calendar to base the forecast period profile shapes on and later substituting the actual calendar for this.

Planning Calendar Profile Development

While the forecast is based on normal weather, for future years we cannot know the actual pattern in which the weather will occur. So, a reference historical year is selected for forecasting purposes. For this forecast, 2011 was used as the reference year. The historical year (2011) becomes the base year for the ordering of the daily normal temperatures across the calendar year. The normal weather will follow the pattern that the actual weather

followed within each month of 2011. For example, the hottest day of 2011 fell on the 2nd of August. In our planning calendar case, the hottest weather of August will also fall on the 2nd. However, when applying normal weather to the planning calendar, if the most extreme weather in the historical year fell on a weekend day, the most extreme normal temperature will be shifted down to the next most extreme day, until it lands on a weekday. Weekdays tend to have the highest loads to begin with due to the business cycles of the commercial and industrial customers. It is therefore important to have peak temperatures on a weekday so that the peak is not under-forecasted by matching the highest residential load with lower levels of commercial and industrial load.

In the planning calendar forecast run both the weather and the days of the week are forced to follow the pattern of the reference year. For example, August 2nd (2011) was a Tuesday. So, for the planning calendar (which will be applied to forecast all future years), August 2nd will remain a Tuesday for modeling purposes in all years. This prevents the peak load from changing simply due to changing combinations of weather and weekday over the forecast horizon. If our peak temperatures were allowed to float to different weekdays over the forecast horizon, the load forecast would change from year to year based on nothing more than the assumed day of the week on which the peak fell. Again, as industrial and commercial load patterns follow those customers' weekly business cycles, it is important to reflect a consistent match between the point in the weekly business cycle and the peak load.

The profile shapes must then be extended over the forecast horizon using the planning calendar assumptions. For the non-weather sensitive end-uses, this is a very easy exercise. The shapes from eShapes are generally comprised of just a weekday and weekend shape for each month of the year. To extend the shapes to the forecast horizon, the weekday shapes and the weekend shapes (as adjusted using the calibration process described previously) are applied to the appropriate days given the month and day of week in the planning calendar.

For the weather sensitive end-uses and classes, the statistical profile models and the reference year weather and calendar patterns are used to project the planning case load shape. For classes that are not modeled with end use detail, the models are based on Ameren Missouri load research data for the class consistent with the weather normalization modeling. For the weather sensitive end-uses, the models are based on the Itron simulated heating and cooling shapes consistent with the load shape calibration process mentioned previously. In the case of both the end use and class level profiles, the daily peak load and daily energy are modeled as a function of temperature and calendar (day of week, month, and season) variables. The models are then simulated using the planning calendar for normal temperatures and weekdays

Once both the end-use and class level profiles have been simulated for the planning calendar year, that year is replicated exactly in order to represent the load shape for each year in the forecast horizon for peak modeling purposes.

Actual Calendar Profile Development

While the planning calendar shapes are utilized, as will be discussed further below, to generate a consistent peak forecast from year to year, the final net system hourly load shape will be developed by load shapes based on the actual calendar. In the actual calendar, the temperatures are still mapped to the historical reference year (2011). But in this case, the days of the week are allowed to fall as they actually will in the years in question. For example, in 2017, August 2nd would be a Wednesday as opposed to the Tuesday from the 2011 reference year. This way the final hourly loads are realistic relative to that actual calendar that will be used in the forecast. To ensure consistent peaks that do not vary due to changes in the day of the week on which they fall, the peak hour's load for each month is calibrated to the peak forecast from the planning calendar case.

Monthly System Peak Model Development

For this 2026 IRP update, Ameren Missouri developed an end use-based model to forecast the monthly system peak. Ameren Missouri's peak demand forecast methodology adopted for this work captures the underlying end use trends and economic trends. The peak demand forecast model was built based on the historical relationship between the system peak load and end use energy for peak weather conditions. The methodology is a derivation of the SAE energy forecasting techniques where the monthly class level energy forecasts are decomposed into three primary components for most customer classes: heating, cooling, and base load. The basis for the heating, cooling and base load variables extended to the forecast year are derived from the energy forecast models as discussed in section 3.1.5. The cooling and heating variables for peak load were constructed using the weather conditions on the peak day. The base load contribution to the peak demand, which is not influenced by weather conditions, was derived using the share of each end use in the base load at the time of system peak. The system peak model variables, coefficients, and other model statistics are shown in appendix A. The peak forecasting methodology also incorporates impacts of solar and projected electrification described in the respective sections in 3.1.5.

The monthly peak forecast from this process is then combined with the hourly load profiles in the previous section to produce a class level peak forecast and hourly load forecast.

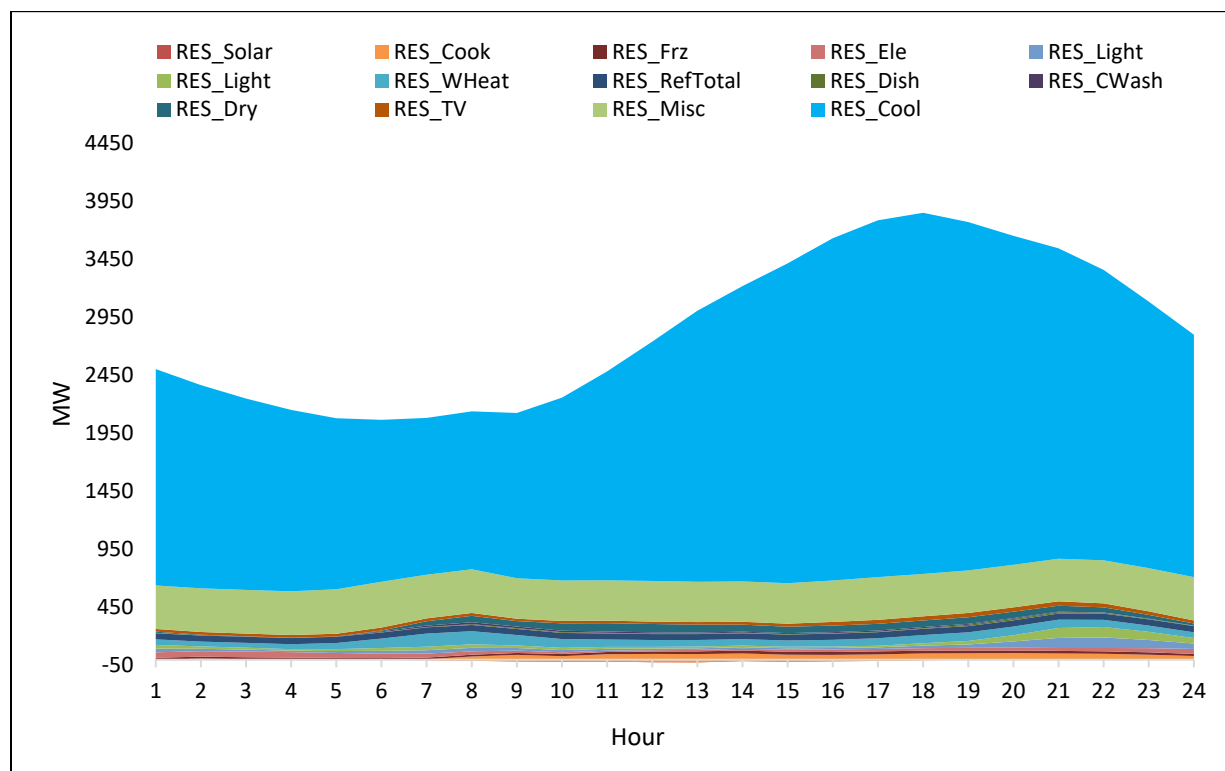
In order account for reductions in load due to Time of Use (TOU) rate programs, adjustments were made to the hourly load based upon the methodology from Dr. Ahmad Faruqui, of the Brattle Group prior to his retirement, as reflected in his workpapers from the

Company's previous rate cases. These TOU options include Evening/Morning Savers, Overnight Savers, Smart Savers and Ultimate Savers. Definitions of the hours reduced, reduction rate, and participation rate can be found in the TOU section in Appendix A.

Bottom-Up Forecasting

From earlier steps in the forecast process, we have developed class level or end-use energy forecasts, profile models that will generate load shapes for each class and end use, and a monthly system peak forecast from a model. Developing the final peak and hourly forecast is a relatively simple process of bringing these three inputs together. The profile shape for each class and end-use is scaled to the monthly energy from the energy forecast and the monthly system peak forecast. This is a simple mathematical exercise, where a ratio is developed between the energy forecast for each class or end-use and the sum of the hourly profile for that class or end-use within each month of the forecast horizon. That ratio is applied to each hour in the profile so that the hourly load retains the profile shape but sums across the hours of the month to the forecasted energy level. Figure 3.28 shows an example (2029 summer, base scenario) of the buildup of the residential load for a summer day from the end-use components.

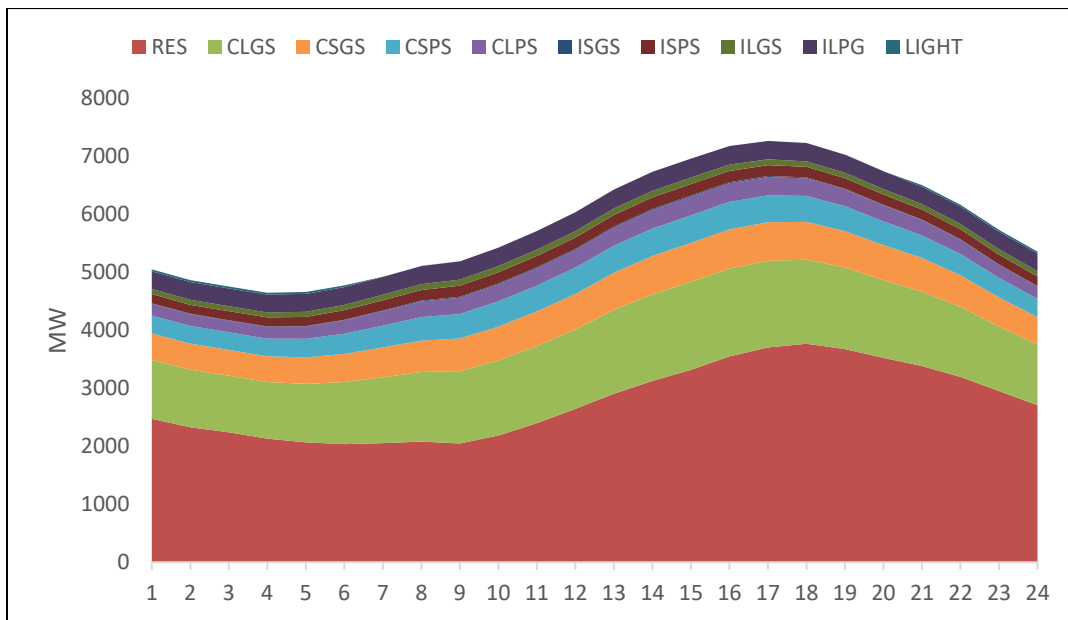
Figure 3.27: Residential Summer Day Usage Built-Up by End Use



Once each class load has been constructed on an hourly basis (either through direct application of the class profile to the class energy forecast or through the aggregation of the end-use scaled load shapes), transmission and distribution losses are applied. The transmission and distribution losses are based on the Ameren Missouri 2024 loss study performed by its distribution engineers. For purposes of calculating the load for the peak forecast, demand loss rates are utilized. Demand loss rates are the loss rates determined by the study to apply to loads at times of peak demand. Typically, this loss rate is higher than average or energy loss rates due to the properties of the system that cause losses to increase both under high load conditions and high temperatures.

The demand loss rates are applied to the profiled loads based on the planning calendar. This is done because the planning calendar was created specifically to develop a consistent peak forecast across time and the demand loss rates are designed specifically for application to peak periods. Each class has the applicable loss rate applied to it based on the voltage level at which its customers are served. When each class's hourly load has been grossed-up to represent the amount of energy that must be generated to serve them inclusive of applicable losses, the class loads are summed for each hour. This results in a forecast of the hourly load from which the maximum value for each month can be isolated as the forecasted peak load for that month. Like the build-up of the residential class from end-use data, a graphical representation (2030 summer) of the build-up of the system load by class, exclude large load tariff customers, can be seen in Figure 3.28.

Figure 3.28: Summer System Peak Day Usages Built-Up by Class*



**Exclude Large Load Tariff customers*

3.3.4 Hourly System Load Forecast⁴⁵

After the bottom-up forecast has been generated using the planning calendar, demand loss rate, and the system level peak model that was used to determine the class level peak load forecast, the same process is replicated using the actual calendar information described above and energy loss rates. This hourly system load data is what is actually passed on to the integration analysis.

The actual calendar data as described above is used to make the hourly load forecast apply correctly to dates in the future. Since the energy for the forecast horizon is an input to this process and not determined by this process, and since we will use the peak forecast from the planning calendar run, it is no longer necessary to force the days of the week to fall in the same order each year for the sake of consistency. The days can now fall as they will when the years actually occur so that the modeling results are calendar correct.

Also because the peak forecast has been determined in the previous step, energy loss rates can now be utilized instead of demand loss rates. Recall that the demand loss rates were created to determine the level of losses that are occurring on the system at the time of peak. Energy loss rates determine the losses that are incurred across the entire year. These are used to gross-up meter level sales to reflect the level of energy that will actually need to be generated in order to meet the demand of Ameren Missouri's customers. The energy loss factors were based on the 2024 loss study mentioned previously.

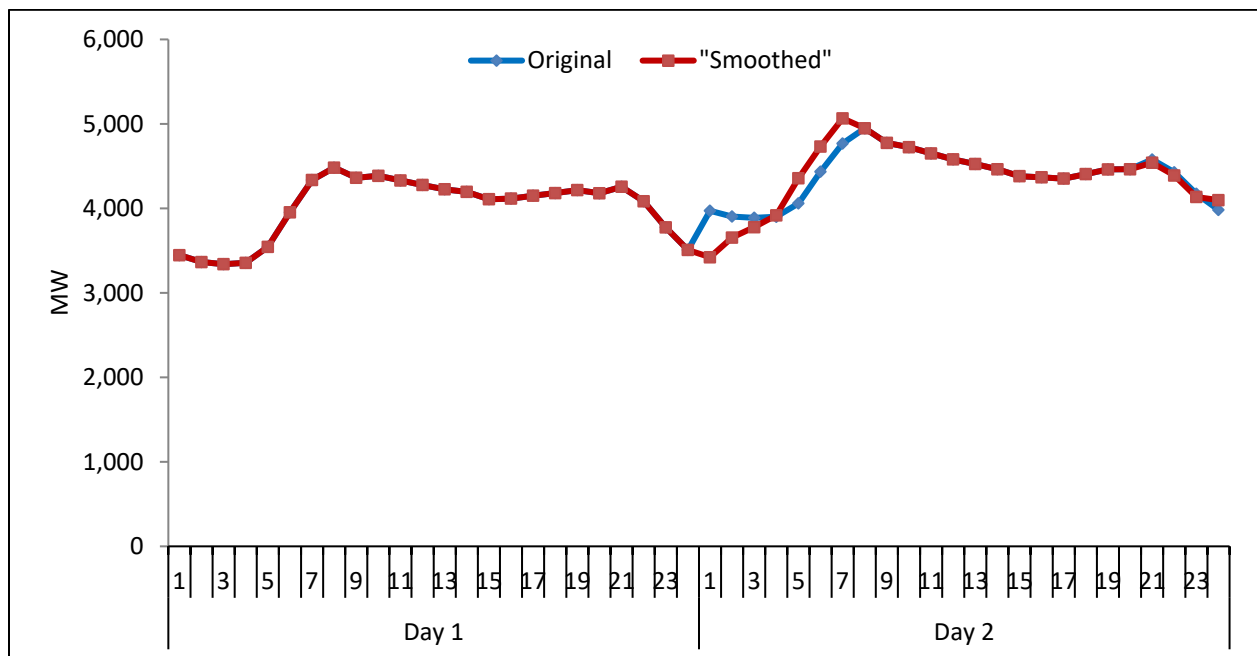
The process of generating the hourly system forecast begins in exactly the same way as the bottom-up forecasting of the peak does, with the exception of the use of the actual calendar and the energy loss rates. The profile shape for each class and end use where applicable is scaled to the energy forecast, grossed up for losses, and aggregated to the system level. After that has been completed, there are only a couple more steps involved in the creation of the hourly system forecast. First, the annual peak load is calibrated to the peak forecast developed in the planning case (as adjusted per the back-calibration routine). Next, transmission losses are deducted from the forecasted loads. Remember that energy loss rates were used to gross-up the sales up to the level of load that will have to be generated. The transmission losses are then deducted because of the way that the company interacts with the Midcontinent Independent System Operator's (MISO) energy markets. Ameren Missouri sells its generation to MISO and buys power and energy to serve its load from MISO. The difference between generation and load is the volume of off-system sales (net of power purchases) made by the company. However, the load that is purchased from MISO does not include transmission losses. In MISO's market, there is a financial charge for transmission losses, but the physical energy is not purchased by the load serving

⁴⁵ 20 CSR 4240-22.030(7)(C)

entity. To reflect this reality, a loss rate is used to back the energy forecast down from the level of energy required to meet customer demand at the generation level to the level of energy needed at the interface between the transmission and distribution system. A series of seasonal loss rates between 1.8-2.8% was used to perform this calculation. This rate was based on the actual rate of losses observed on the Ameren Missouri control area based on MISO settlements.

The final step in the process of developing the hourly system loads involves checking for, and if necessary, correcting discontinuities in the load pattern during the overnight hours. Because each day is modeled independently, there are occasions when the transition from hour 24 of one day to hour 1 of the next day exhibits a significant “jump”. In the cases where this issue is detected, Ameren Missouri has corrected the situation with a smoothing algorithm. This algorithm maintains the total energy for each day from the original forecast but reorganizes certain hours so that the load pattern is more realistic. This is important so that the dispatch algorithms in the integration analysis will not be forced to commit units overnight for an artificial jump in load. An example of before and after “smoothed” load can be seen in Figure 3.29.

Figure 3.29: Example of Smoothed Load Shape



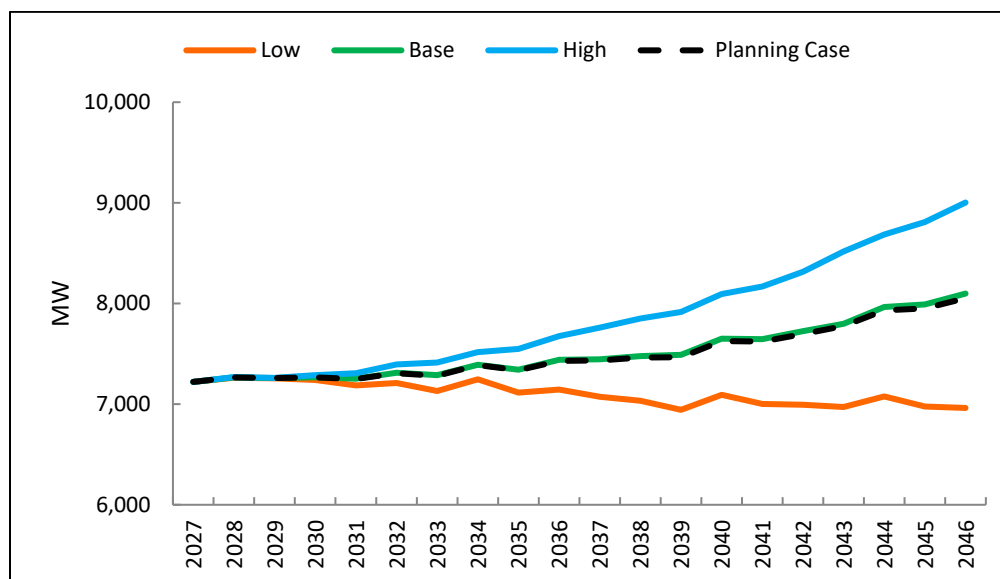
Scenarios and Planning Case Forecasts

The energy forecast described in Section 3.1 was modeled under three different scenarios. Each of these scenarios was based on a certain combination of the critical uncertain factors identified in this IRP. The peak and hourly system forecast was also run for each of these scenarios. This was simply a matter of running the class and end-use level energy forecast results from each scenario through the process detailed above. When this process was complete, again similar to the energy forecast, a planning case peak forecast was developed. This forecast was calculated by taking the subjective probabilities assigned to each scenario and using those as weighting factors to average the scenario load forecasts. Again, this mirrors the process for the planning case energy forecast. The planning case peak forecast was passed to integration analysis to develop the capacity position for the IRP. The scenario-based load forecasts were also passed to integration so that the candidate resource plans could be evaluated under all scenarios identified in the IRP.

3.3.5 Forecast Results

Excluding the data centers, the planning case forecasted an annual peak load growth rate from 2027 through 2046 of 0.6%. For the planning case, the peak load in 2027 is projected to be 7,221 MW, growing to 8,052 MW by 2046. The compound annual growth rates in the various scenarios range from a low of -0.2% (low growth scenario), to 1.2% (high growth scenario).

Figure 3.30: IRP Annual Peak Forecast—Planning Case and Scenarios

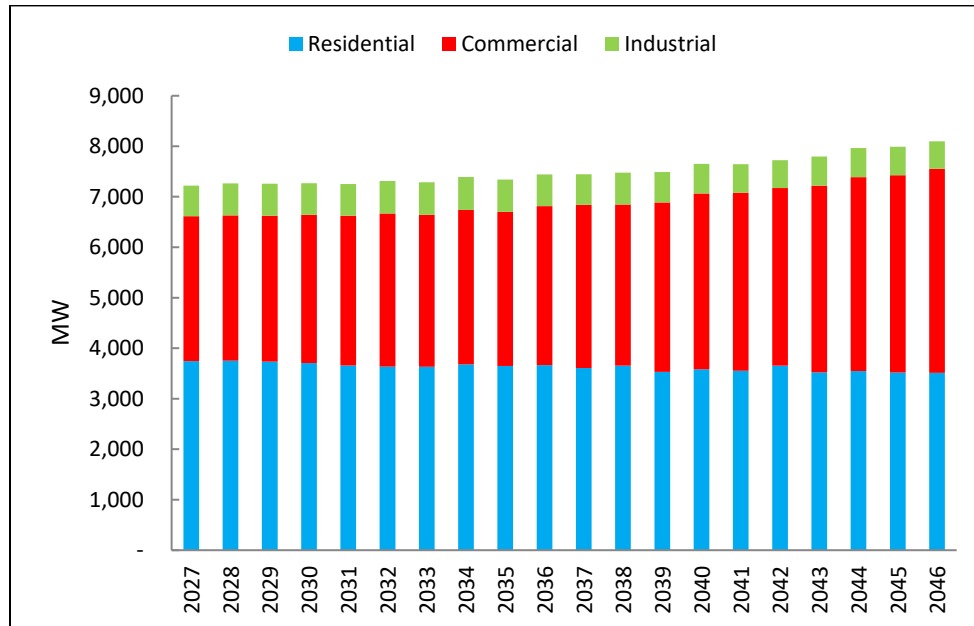


3.3.6 Base Case Peak Demand Forecast

Class and End-Use Peak Demands

The commercial class is forecasted to grow at a compound annual rate of 1.9% from 2027 to 2046, while residential and industrial are expected to decrease at 0.3% and 0.5% respectively. Industrial class energy consumption has been declining over the last decade.

Figure 3.31: Class Contribution to Annual Peak Forecast



The end use contributions to the peak load growth within each class varied fairly significantly. For the residential class, the fastest growing end use in the forecast in percentage terms is electric vehicle load. This end use CAGR is projected to be 17.5% from 2027 to 2046. The tables and charts below indicate the end uses that contribute to the peak load for both the residential and commercial classes. The end-use make-up of the peak load is shown for both the first full year of the forecast (2027) and the last year of the forecast (2046).

Table 3.7: Residential End-Use Contribution to Peak

	2027 Peak Contribution (MW)	% of Peak Load (2027)	2046 Peak Contribution (MW)	% of Peak Load (2046)	CAGR
Cooking	29	0.8%	14	0.4%	-3.7%
Cooling	3,120	82.1%	2,711	77.2%	-1.6%
Clothes Washer	9	0.2%	8	0.2%	-0.6%
Dish Washer	6	0.2%	4	0.1%	-1.8%
Electric Dryer	57	1.5%	54	1.5%	-0.3%
Electrification	11	0.3%	240	6.8%	17.5%
Freezer	25	0.6%	21	0.6%	-0.9%
Heating	-	0.0%	-	0.0%	NA
Lighting	21	0.6%	10	0.3%	-3.9%
Misc	363	9.6%	357	10.2%	-0.1%
Refrigerator	55	1.5%	45	1.3%	-1.0%
Solar	(2)	-0.1%	(27)	-0.8%	13.8%
TV	38	1.0%	22	0.6%	-2.9%
Water Heater	70	1.8%	51	1.5%	-1.6%

Figure 3.32: Residential Peak Load Composition 2027

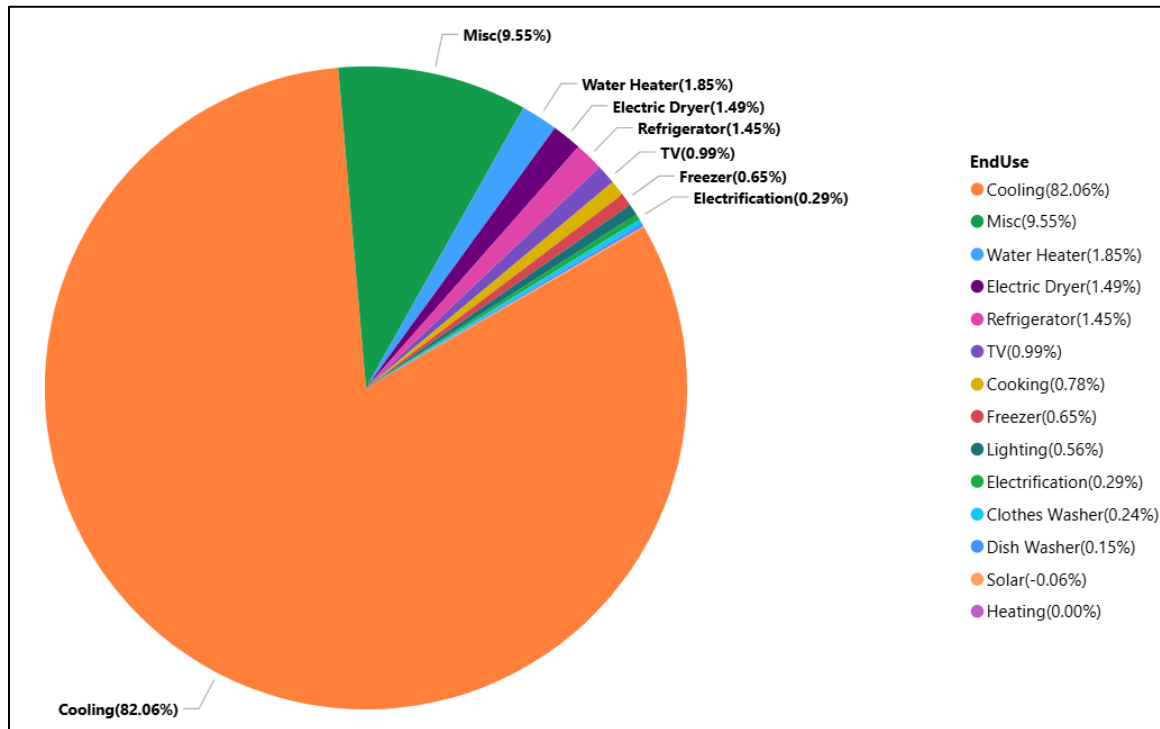


Figure 3.33: Residential Peak Load Composition 2046

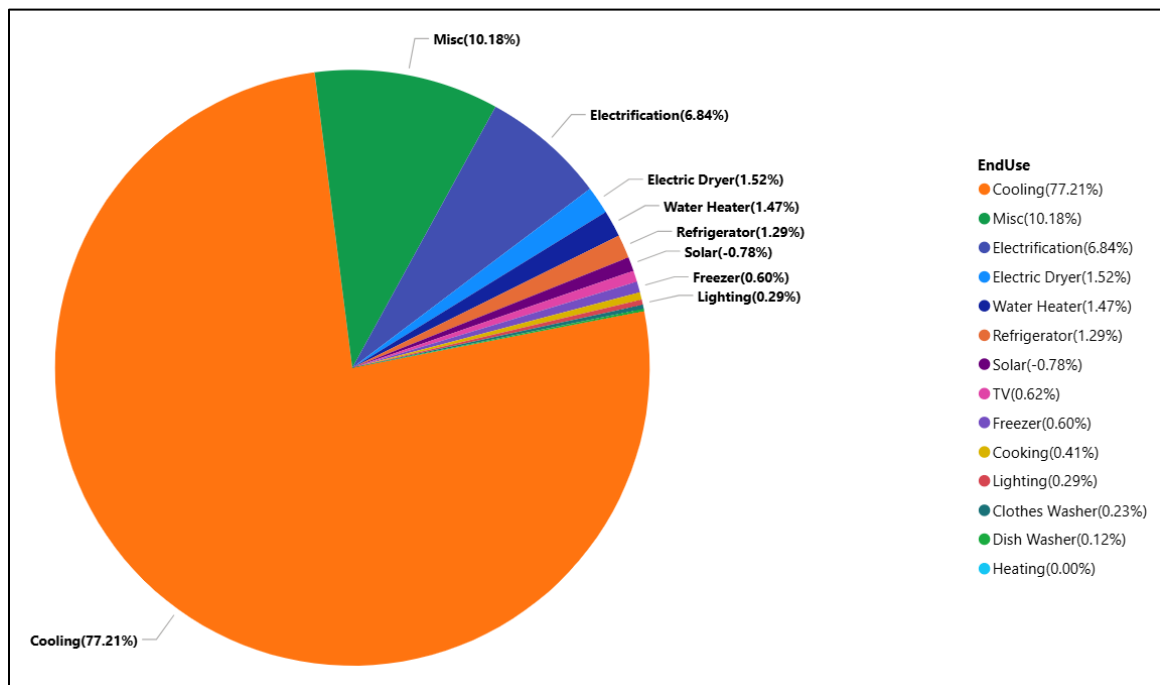


Table 3.8: Commercial End-Use Contribution to Peak

End Use	2027 Peak Contribution (MW)	% of Peak Load	2046 Peak Contribution (MW)	% of Peak Load	CAGR
Cooking	62	2.2%	40	1.0%	-2.2%
Cooling	1,305	46.5%	1,126	27.8%	-0.8%
Electrification	19	0.7%	1,556	38.4%	26.2%
Water Heating	11	0.4%	5	0.1%	-3.8%
Heating	-	0.0%	-	0.0%	NA
Indoor Lighting	216	7.7%	169	4.2%	-1.3%
Miscellaneous	647	23.0%	665	16.4%	0.1%
Office	175	6.2%	203	5.0%	0.8%
Refrigeration	188	6.7%	161	4.0%	-0.8%
Solar	(3)	-0.1%	(16)	-0.4%	9.9%
Ventilation	188	6.7%	143	3.5%	-1.4%

Figure 3.34: Commercial Peak Load Composition 2027

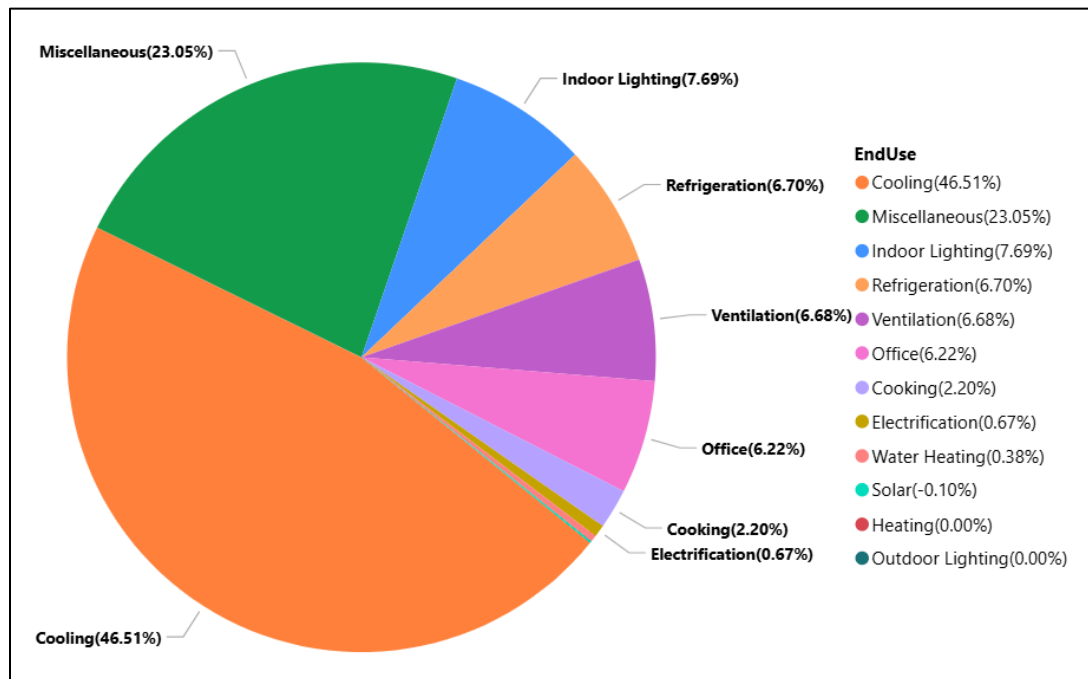
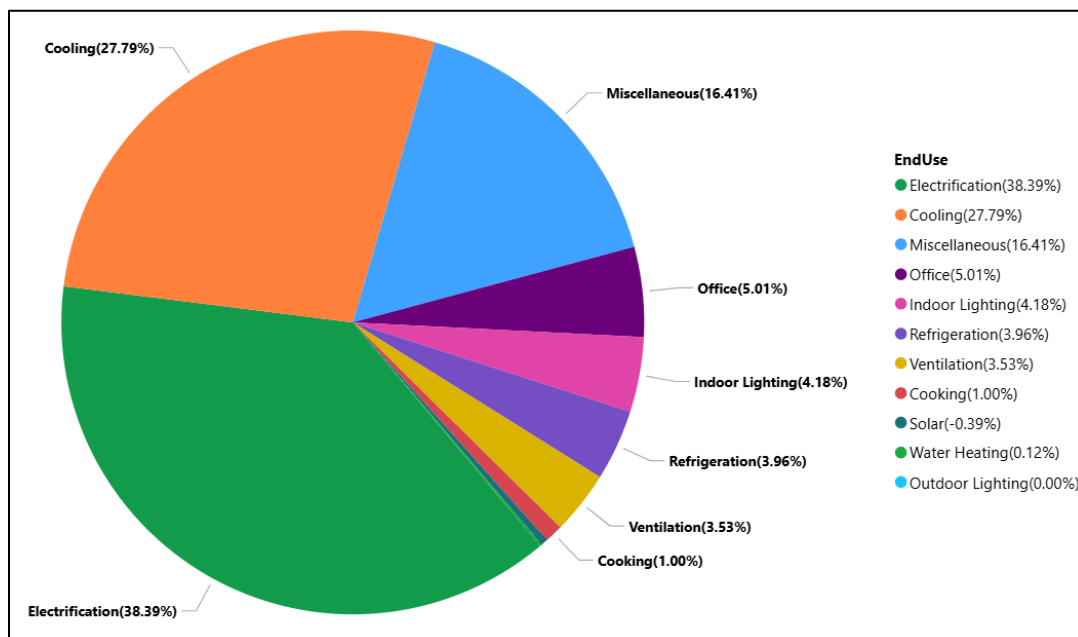


Figure 3.35: Commercial Peak Load Composition 2046



3.3.7 Peak Demand – Extreme Weather Sensitivity⁴⁶

The peak demand forecast described above is based on the expectation of normal weather conditions. However, Ameren Missouri must plan its system to provide reliability even under more extreme weather conditions. An analysis was undertaken to determine the range of effects on peak demand due to extreme weather events as they have been observed historically.

In this process, Ameren Missouri identified the highest 10 weekday peak load projections from the month in which the annual peak is forecasted to occur (July) for 2027, as well as the lowest 10 weekday peak load projections from the month in which the winter peak is forecasted to occur (January) for 2027. From these days, a MW per degree statistic was calculated that indicates the incremental demand on the system for each degree increase/decrease in the daily temperature. Using the summer data, this process resulted in an estimate of 136.9 MW of increased system demand per increased degree, while using the winter data resulted in an estimate of 69.4 MW of increased system demand per decreased degree.

The summer estimate was tested using 2027 summer peak data. The 2027 summer peak forecast (from the base case modeling) called for normal weather (at a two-day weighted

⁴⁶ 20 CSR 4240-22.030(8)(B); 20 CSR 4240-22.070(1)(D)

average temperature of 89.18 degrees) load of 7,172 MW. Next, Ameren Missouri calculated the expected peak load given two day weighted average temperatures equaling the 90th percentile of summer peak temperatures from 1995-2024 and at the absolute maximum temperature observed in that time frame. Additionally, Ameren Missouri tested against a temperature that occurred outside of the 1995-2024 period. Outside this period, the maximum (two day weighted) temperature was 88.17 degrees, which occurred in 2025. The peak load corresponding to this temperature was forecasted to reach 7,033 MW, or 1.9% lower than the normal weather forecast. At the 90th percentile temperature, i.e., 92.68 degrees, the load was estimated to reach 7,652 MW, or 6.7% higher than the normal weather peak. In 2012, when Ameren Missouri's service territory experienced historically record-high temperatures (a two-day weighted average temperature of 96.67), the corresponding peak load is estimated to be 8,197 MW, or 14.3% higher than the normal weather forecast.

The winter estimate was tested using 2027 winter peak data. The 2027 winter peak forecast (from the base case modeling) called for normal weather (at a two-day weighted average temperature of 11.82 degrees) load of 6,268 MW. Next, Ameren Missouri calculated the expected peak load given two day weighted average temperatures equaling the 10th percentile of winter minimum temperatures from 1995-2024 and at the absolute minimum temperature observed in that time frame. Additionally, Ameren Missouri tested against a temperature that occurred outside of the 1995-2024 period. Outside this period, the minimum (two day weighted) temperature was 8.17 degrees, which occurred in 2025. The peak load corresponding to this temperature was forecasted to reach 6,521 MW, or 4.0% higher than the normal weather forecast. At the 10th percentile temperature, i.e., 2.54 degrees, the load was estimated to reach 6,912 MW, or 10.3% higher than the normal weather peak. In 1996, when Ameren Missouri's service territory experienced historically record low temperatures (two day weighted average temperature of -3.31), the corresponding peak load is estimated to be 7,318 MW, or 16.7% higher than the normal weather forecast.

Weather Normalization⁴⁷

Weather normalization is an important aspect of load analysis that allows the utility to determine the level of sales that it should be expected to make on an ongoing basis under normal weather conditions. It also allows the utility to quantify the impact of unusual weather on actual sales. Ameren Missouri has developed weather normalization models for various business reasons including support for rate case filings.

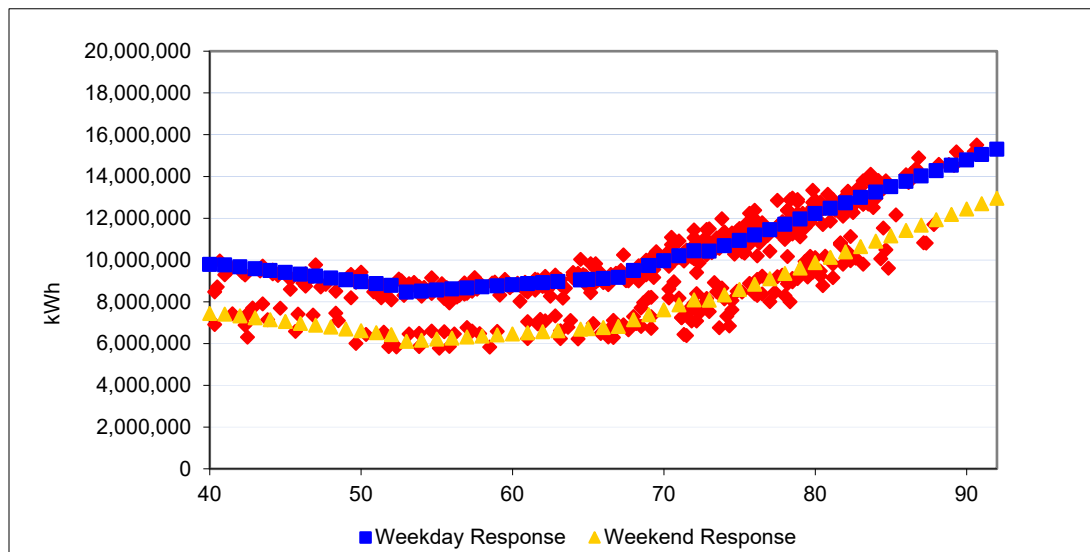
⁴⁷ 20 CSR 4240-22.030(2)(C)2

The weather normalization process involves the normalization of monthly sales, as well as hourly class level load research. The normalized class level load research also becomes the basis of a “bottom up” approach in weather normalizing net system output. The models used in the current IRP filing are consistent with the models supporting rate case filings that are relevant to the historical period in question. Historical data for 2023 and 2024 has been normalized with the same normal weather used for Ameren Missouri's rate case (ER-2024-0319). Historical data for 2021 and 2022 has been normalized with the same normal weather used for Ameren Missouri's rate case (ER-2022-0337). Historical data for 2020 has been normalized with the same normal weather used to settle Ameren Missouri's rate case (ER-2021-0240). For historical periods covered by Ameren Missouri's 2023 IRP and earlier, the weather-normalized information prepared for and reported in that filing is utilized in this filing as is.

The weather normalization process starts by defining normal weather. As referenced above, Ameren Missouri currently uses actual temperature readings for St. Louis Lambert Airport from the period 1995-2024 to develop its normal weather conditions, as adjusted for certain changes in the recording equipment at Lambert. Ameren Missouri creates normal temperatures by applying the “rank and average” methodology to temperatures from this time period to accommodate the unique nature of the problem of normalizing energy usage. Application of this procedure is necessary in order to produce realistic levels of normal energy and peak demand later in the process. It is used to ensure that normal temperatures also exhibit a normal amount of variability that would be expected to occur within a year. This method has been utilized routinely in electric rate cases by the Missouri Public Service Commission Staff (Staff) and was used by both Ameren Missouri and Staff in the Company's most recent rate cases.

The next step in the weather normalization process is to develop load-temperature relationships. Using a software package called MetrixND, daily peak and average loads at the rate and revenue class level are both modeled statistically as a function of calendar and weather variables. These statistical relationships are the basis for the weather adjustments which produce the normalized sales and hourly load research for a given period. These models are developed using various statistically significant weather variables along with various time and economic trend variables if needed as explanatory variables to create a piecewise linear temperature response function.⁴⁸ A graphical representation of this modeling approach can be seen in Figure 3.36.

⁴⁸ 20 CSR 4240-22.030(2)(D)2

Figure 3.36: MetrixND COMSGS Non-Winter Weather Response

The models are first built using actual weather variables along with other explanatory variables. Then the model coefficients are applied to the normal weather variable to generate a normalized version of loads. The difference between the model's estimate of actual and normal loads is the weather impact for the time period in question. This weather impact is applied to the original load value to generate a normalized version of the load in question. The actual model variables and corresponding coefficients are presented in Appendix A.⁴⁹ The weather-normalized sales results will also be provided in the final filing. For the purposes of normalization of hourly load research, the peak and average energy for each day are normalized as described above. The hourly normal values are then derived using the unitized load calculation described in Section 3.2.2.

3.4 Future Research Projects⁵⁰

Ameren Missouri continually works to improve its load analysis processes to produce more accurate forecasts that provide increasing depth to our analytical capabilities. The load analysis function is of increasing importance in this era of increasing energy efficiency, both through company sponsored programs and non-utility efforts. To that end we continue to explore additional data sources, and enhanced forecasting and analytical techniques.

Much of this effort is focused on increasing the ways we can segment our data. Whether it be analyzing our commercial class by segmenting the business types or analyzing our

⁴⁹ 20 CSR 4240-22.030(2)(C)3

⁵⁰ 20 CSR 4240-22.070(6)(A)

residential and commercial classes by the end use appliances and equipment they operate, our analysis is continually increasing in its level of detail.

NAICS Codes

To facilitate that increasingly detailed analysis, Ameren Missouri recently worked with a vendor to append North American Industrial Classification System (NAICS) codes to its commercial and industrial accounts. Going forward, this data will help us to monitor trends in usage by different types of businesses and therefore give insights into the causes of changes in the energy intensity of our service territory economy.

Hourly Energy End-Use Profile

Energy End-Use profile reflected the evolution of energy consumption patterns, technologies and customer behaviors. For Residential, it is predicted that EV adoption, smart home devices, and dynamic pricing would influence the net load profile. The Ameren Missouri load analysis team has partnered with different business functions to revise the end-use profiles in order to improve accuracy of predictions.

End-Use Load Research

Ameren Missouri has been monitoring industry efforts to develop new end use load shape data. We have participated in workshops and discussions within the industry focused on evaluating the ability of Non-Intrusive Load Monitoring devices to disaggregate whole premise load data into its end use components and will continue to monitor efforts to increase data availability from industry sources in this area. Additionally, the Ameren Missouri load analysis function is working to make sure that we are able to leverage any end use metering data collected by evaluation, measurement, and verification contractors for purposes of energy efficiency program impact evaluation. This data can be a valuable tool to further enhance the processes described in this chapter for assessing and improving the applicability of end use load shape data to our customers' loads.

Load Research Sample Design

Ameren Missouri's load research sample was designed in the early 2000s. Although the existing sample has continued to perform well in all measurable ways, it will benefit from a refresh as the sample has been in place for a number of years. Ameren Missouri, as of this writing, has completed its implementation of smart meter infrastructure, or AMI meters, which will collect interval reading for every customer in the system unless opted out. As this smart meter infrastructure is now in place and interval data is collected for every customer in the system, Ameren Missouri will conduct load research based on the data collected from every customer in the smart metering system, going from the previous sample-based method to a full population method that includes every customer, which will be taking place in the Cloud. This transition is expected to be fully completed sometime in the first half of

2026. This will reduce much of the statistical uncertainty of the sampled load research process and provide a better in depth understanding of true load profile of Ameren Missouri customers.

3.5 Large Load Tariff⁵¹

The artificial intelligence (AI) revolution, cloud computing and advanced manufacturing have become key drivers for Ameren Missouri sales growth in the planning horizon. Due to the unique requirements of large load customers, Ameren Missouri applied for approval of a large load tariff from the Missouri Public Service Commission, and the MPSC approved the tariff as modified by agreement with stakeholders in November 2025. It defines any new or expanding customer who reasonably expects a monthly peak demand of 75 MW or greater as a Large Load Customer for purposes of service under the new tariff. The load for Large Load Tariff customers is forecasted separately from the traditional residential, commercial, and industrial classes. The current pipeline of prospective Large Load Customers, including data centers, indicates potential for considerable growth. Load additions for these customers depend in part on successful negotiation of new Electric Service Agreements (ESAs). The base case scenario forecast for Large Load Tariff class consumption represents approximately 1,400 GWh in 2027, increasing to 44,676 GWh by 2046, with a compound annual growth rate of 20%.⁵² The low and high load growth scenarios reflect approximately 30,000 GWh and 67,000 GWh by 2046, respectively. The growth rates are forecast to be 18% and 22.6% for the low and high cases, respectively, from 2027 to 2046.

Besides base, low and high scenarios, Ameren has profiled two other scenarios: base-to-low and high-to-base scenarios. These two scenarios include load loss cases for base and high scenarios through the planning horizon. For the *base-to-low* scenario, the growth rate was assumed to follow the base case through 2036 and then decline to the low case levels beginning in 2037. For the *High-to-Base* scenario, the load was assumed to follow the high case through 2038 and then decline to the base case levels beginning in 2039. The compound annual growth rates are forecasted to be 17.5% and 20.0% for the base-to-low and high-to-base scenarios, respectively, from 2027 to 2046. The low, base, high, base-to-low and high-to-base scenarios for Large Load Tariff sales are shown in Figure 3.37.

The base case peak demand is forecasted to be 591 MW in 2027 and 6,168 MW by 2046, with a compound annual growth rate of 13.1% across the planning horizon. By 2046, the demand is forecasted to be 4,112 MW and 9,252 MW for low and high cases, respectively.

⁵¹ EO-2026-0037 1.B

⁵² These incorporate the growth under already-executed ESAs reflecting contract demand totaling 2.8 GW plus forecasts of additional loads.

The compound annual growth rates are forecasted to be 11.6%, 15.6%, 10.8% and 13.1% for low, high, base-to-low and high-to-base scenarios from 2027 to 2046, respectively. The peak forecasts of all scenarios for Large Load Tariff customers are shown in Figure 3.38.

Figure 3.37: Large Load Tariff Energy Sales Forecast

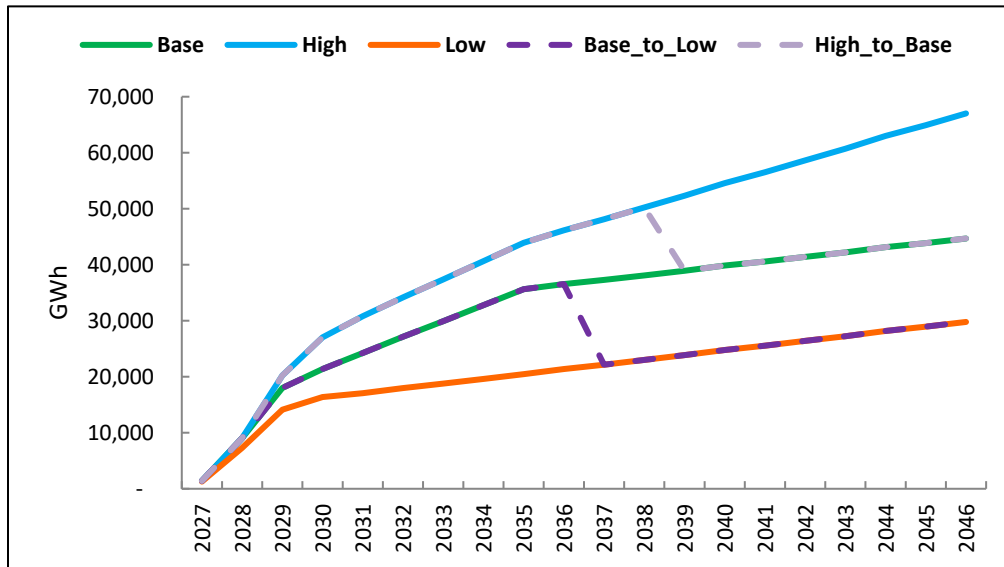
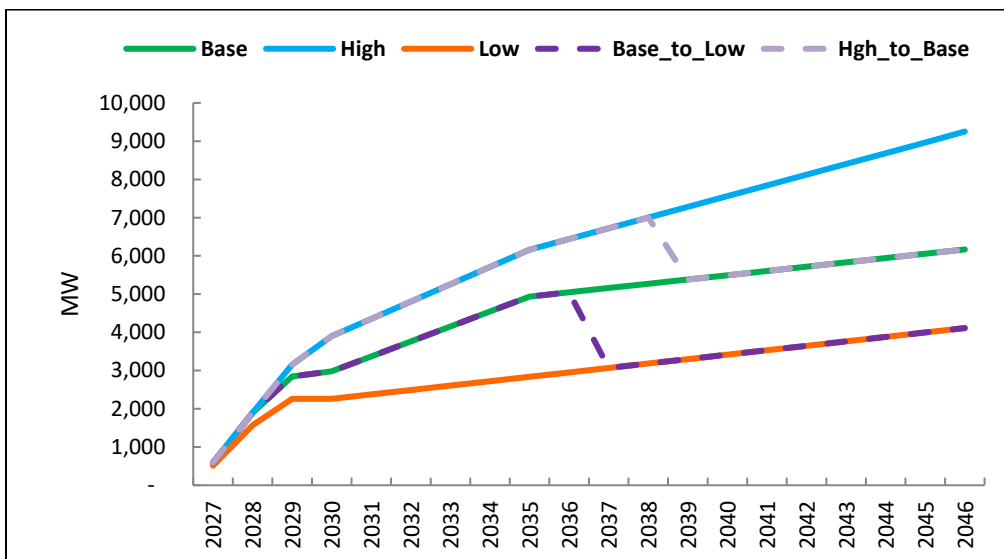


Figure 3.38: Large Load Tariff Annual Peak Demand Forecast



Current Pipeline of Large Load Customers

There are currently 40 active data center opportunities within the Ameren Missouri footprint, representing significant future load potential. This pipeline of prospective customer interest highlights the region's attractiveness for large-scale development and continued expansion in the data center sector.

To date, multiple ESAs have been successfully negotiated and signed, representing a combined load of ~2.8 GW. This level of commitment underscores meaningful progress in converting interest into secured demand.

In addition, multiple construction agreements have been executed, totaling 620 MW of potential additional load. One of these projects is actively engaged in ongoing ESA negotiations, while the other project has been temporarily paused due to a moratorium in St. Charles, Missouri.

Interconnection Queue Overview & Challenges

The Large Load Customer interconnection queue currently includes 24 load requests totaling 15,935 MW, reflecting strong demand for system access. Of these, 16 projects (10,000 MW) are still awaiting formal study, while 8 projects (5,935 MW) have completed studies and are pending construction agreements.

Challenges

Timing: Completing interconnection studies remains a key challenge due to the number of requests received. Additionally, projects with completed interconnection studies are impacting timing for projects in the queue due to ongoing construction agreement negotiations.

Ongoing Negotiations: Developers of several projects in the pipeline are actively negotiating construction agreement terms, but progress is impacted by the ability to identify and secure energy supply as part of the electric service agreement.

Public Impact: Recent moratoriums and project development public hearings have slowed progress, particularly for projects awaiting final agreements or seeking regulatory certainty.

Financial Backstops

The approved Large Load Customer Rate Plan includes tariff- and contract-based protections and penalties intended to address fixed cost recovery associated with accelerated or incremental generation investment if a forecasted large-load customer is delayed, materially downsizes, or does not ultimately materialize over the 5/10/15-year horizons described above, including:

Minimum contract term / long-run commitment: Electric Service Agreement (ESA) includes a minimum **12-year** term, with an optional **5-year load ramp** period (potentially extending the commitment to **17 years**).

“Take-or-pay” minimum billing demand: Minimum demand charge set at 80% of contracted capacity, supporting revenue stability if actual usage is below forecast.

Credit support / collateral: Customer must provide collateral equal to two years of minimum monthly bills, providing a backstop against default or non-performance.

Automatic renewal unless long notice: ESA automatically extends in 5-year increments unless the customer provides at least 36 months’ written notice of non-renewal.

Exit and early termination fees: A customer that does not extend service is subject to an exit fee and an early termination fee; an additional fee applies if termination is sought with less than 24 months’ notice.

Full cost recovery principle: Program design is intended to ensure that all costs incurred to serve large-load rate plan customers are fully recovered, limiting the risk of cost shifting to other customers.

3.6 Compliance References

20 CSR 4240-22.030(1)(A)	1
20 CSR 4240-22.030(1)(B)	3
20 CSR 4240-22.030(1)(C)	43
20 CSR 4240-22.030(1)(D)	43
20 CSR 4240-22.030(2)(A)	3
20 CSR 4240-22.030(2)(B)1	3
20 CSR 4240-22.030(2)(B)2	3
20 CSR 4240-22.030(2)(B)3	39
20 CSR 4240-22.030(2)(C)1	3
20 CSR 4240-22.030(2)(C)2	59
20 CSR 4240-22.030(2)(C)3	61
20 CSR 4240-22.030(2)(D)2	20, 60
20 CSR 4240-22.030(2)(D)3	10, 11, 15
20 CSR 4240-22.030(2)(F)	3
20 CSR 4240-22.030(3)(A)	28
20 CSR 4240-22.030(4)(A)1A	14
20 CSR 4240-22.030(4)(A)1B	14
20 CSR 4240-22.030(4)(A)1C	19
20 CSR 4240-22.030(4)(A)2A	14
20 CSR 4240-22.030(4)(A)2B	14
20 CSR 4240-22.030(4)(A)2C	14
20 CSR 4240-22.030(4)(A)3	19
20 CSR 4240-22.030(4)(A)4	16
20 CSR 4240-22.030(4)(B)1	15
20 CSR 4240-22.030(4)(B)2	43
20 CSR 4240-22.030(5)(A)	20
20 CSR 4240-22.030(5)(B)	13
20 CSR 4240-22.030(5)(C)	13
20 CSR 4240-22.030(6)(A)1A	11
20 CSR 4240-22.030(6)(A)1B	11
20 CSR 4240-22.030(6)(A)2	16
20 CSR 4240-22.030(6)(A)3	13
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20 CSR 4240-22.030(6)(C)1	4
20 CSR 4240-22.030(6)(C)3	4
20 CSR 4240-22.030(6)(C)4	5
20 CSR 4240-22.030(7)(A)1	16
20 CSR 4240-22.030(7)(A)2	14
20 CSR 4240-22.030(7)(A)3	32
20 CSR 4240-22.030(7)(A)5	22, 26
20 CSR 4240-22.030(7)(B)1	12
20 CSR 4240-22.030(7)(B)2	12

20 CSR 4240-22.030(7)(B)3	10
20 CSR 4240-22.030(7)(C)	51
20 CSR 4240-22.030(8)	28
20 CSR 4240-22.030(8)(A)	28
20 CSR 4240-22.030(8)(B)	58
20 CSR 4240-22.060(4)(D)	16
20 CSR 4240-22.070(1)(D)	58
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