SOUTHWESTERN ELECTRIC POWER COMPANY

An AEP Company

DRAFT

2023 Integrated Resource Plan Report
to the
Louisiana Public Service Commission

March 28, 2023

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Executive Summary

The Company has prepared this draft IRP in accordance with the LPSC IRP Process Schedule, Event #5. In this report, the Company has not included a Preferred Plan as it intends to consider feedback to this draft report from Staff and Stakeholders. It is anticipated for the Company's submission of a Final IRP with a Preferred Plan and Action Plan, some assumptions and inputs might be updated.

This Integrated Resource Plan ("IRP" or "Report") is submitted by Southwestern Electric Power Company ("SWEPCO" or "Company") based upon the best information available at the time of preparation. However, changes that affect this Plan can occur without notice. Therefore, this Plan is not a commitment to specific resource additions or other courses of action, as the future is highly uncertain. Accordingly, this IRP and the action items described herein are subject to change as new information becomes available or as circumstances warrant.

To meet its customers' future energy requirements, SWEPCO will continue the operation of, and ongoing investment in, its existing fleet of generation resources including its efficient base-load coal plants, its newer combined cycle and combustion turbine plants, its growing renewable resources and certain older gas-steam plants. In addition, SWEPCO must consider the impact of the ongoing promulgation of environmental rules as well as the emergence of new technologies and renewable energy resources, both large-scale and distributed.

Keeping all of the various considerations discussed above in mind, SWEPCO has analyzed various Portfolios that would provide adequate supply and demand resources to meet its peak load obligations, and reduce or minimize costs to its customers, including energy costs, for the next twenty years.

For this IRP, SWEPCO identified four objectives aligning to customer and corporate priorities including: customer affordability, rate stability, maintaining reliability, and sustainability. The candidate resource portfolios are evaluated against these four objectives using the IRP Scorecard to considered merits between each portfolio.

Louisiana IRP Stakeholder Process

As part of the IRP Process, the Company held a stakeholder meeting as outlined in the LPSC IRP Process Schedule of Events #3 on March 29, 2022. In this meeting the Company discussed initial data assumptions and expected Scenarios and Portfolios to be modeled. A 2nd Stakeholder meeting was held on July 20, 2022 to provide an update of assumptions and inputs planned for the IRP. Stakeholders provided feedback that the Company considered in this IRP. Additional written questions provided outside of the Stakeholder meetings were submitted to the Company that were also considered as part of this IRP and are included in Appendix Exhibit G.

Key dates as defined by the LPSC IRP Process Schedule of Events are shown in Table 1:

Table 1 LPSC IRP Process Schedule of Events

Event	Description	Number of Months from IRP Filing Date	Date
1	Utility submits its request to initiate the IRP process, which should specify dates in accordance with this schedule of events, and a non-disclosure agreement.	At filing date (IRP Cycle Date)	December 29, 2021
2	Utility files data assumptions to be used in the IRP and a description of studies to be performed.	1	January 31, 2022
3	Utility holds first Stakeholder Meeting.	2	March 29, 2022
4	Stakeholders may file written comments.	4	April 28, 2022
	SWEPCO provided Optional 2nd Stakeholder Meeting		July 2022
5	Draft IRP Report published.	15	March 2023
6	Utility holds second (third) Stakeholder Meeting.	16	April 2023
7	Stakeholders may file comments about the draft IRP Report.	18	June 2023
8	Staff files comments about draft IRP Report.	19	July 2023
9	Final IRP Report filed by the utility.	22	October 2023
10	Stakeholders submit list of disputed issues and alternative recommendations.	24	December 2023
11	Staff submits recommendations to the Commission including whether or not a proceeding is necessary for the resolution of disputed issues.	25	January 2024
12	Commission Order acknowledging the IRP or setting disputed issues for hearing.	27	March 2024

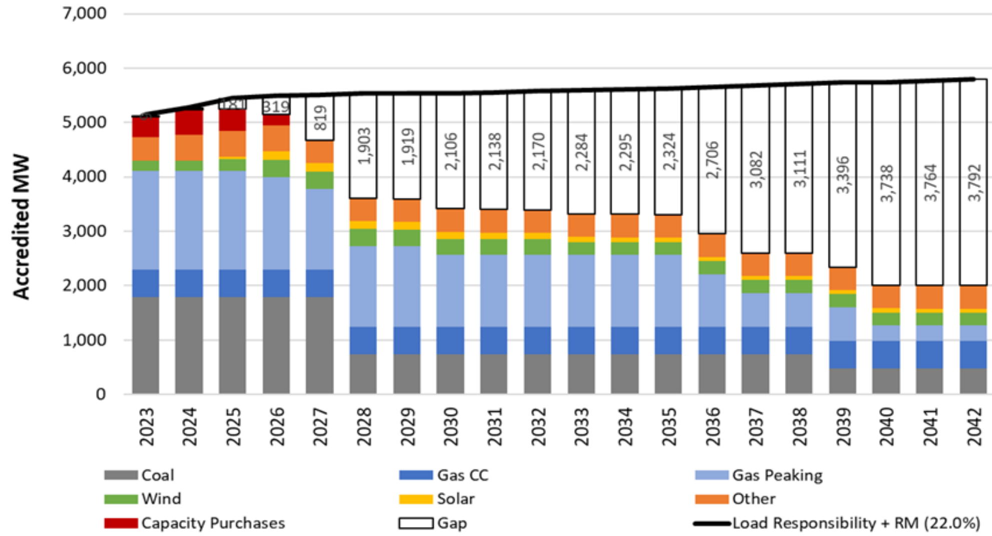
Reliable and Affordable Power

The Company's customers have come to expect reliable and affordable power and this IRP outlines how the Company intends to deliver on customers' needs. In this IRP, SWEPCO started from evaluating a known "going-in" capacity position that shows current expectations about existing and planned owned resources and contracts. This going-in position, while including recently approved solar and wind resources,[1] reveals a need for new capacity beginning in 2025, reflecting the currently planned retirements of Arsenal Hill unit 5 in December 2025 and Lieberman gas steam units 3 & 4 in December 2026. The needs further widen in 2028 when SWEPCO's Welsh 1 & 3 units cease burning coal and are removed from the going-in assumptions and the planned retirement of the Wilkes 1 gas-steam unit in 2030.While the assumptions in this IRP include these planned retirements, the retirement assumptions may be further considered as the Company obtains more clarity in the availability and

[1] Planned resources include company owned resources of the Diversion Wind project planned in 2025 (201MW), Wagon Wheel Wind Project planned in 2026 (598MW) and the Mooringsport Solar project planned in 2026 (200MW) along with the Rocking R Solar PPA project planned in 2025 (73MW)

timing of new resources and the Southwest Power Pool (SPP) resource adequacy requirements evolve.

Figure 1 SWEPCO Summer Going - In Position



SWEPCO used the AURORA model to select a set of resources that provided the lowest expected costs to customers subject to certain constraints and balanced against non-cost factors of the scorecard. The list of candidate resources considered in this IRP includes Energy Efficiency ("EE") options that can be selected alongside, or as an alternative to, new utility-scale resources when meeting customer needs.

Furthermore, the Company explicitly considers a scenario where a winter reserve requirement is enforced to analyze the winter reliability of electricity supply to customers. This is discussed further in Section 8.3.

Responsive to Changing Customers' Needs

SWEPCO considered how customer's needs could change under five different market scenarios that consider different outcomes of fundamental factors that drive the demand for electricity, including changes in customer preferences and end-use technologies that affect SWEPCO customer load patterns. SWEPCO developed forecasts of customer load that were used as inputs into the portfolio model, as well as forecasts of EE and other demand-side resources in the service territory. The result is a set of load assumptions that describe a base, high, and low outlook of the energy and capacity requirements to serve SWEPCO's customers over the 20-year IRP forecast period.

Over the next 20 years, under reference case conditions, SWEPCO is projected to see customer count grow at a rate of 0.2% per year. Retail sales are also expected to grow at 0.3% over this period as stronger growth from the residential and industrial classes offsets a modest decline in commercial sales. SWEPCO's peak demand is also expected to increase at an average rate of 0.3% per year through 2042.

SWEPCO considered advanced and innovative supply options alongside demand-side resources to evaluate the best way to meet future customer needs. SWEPCO considered emerging supply-side technologies such as hydrogen and small modular nuclear reactors, as well as long-duration storage technologies as solutions to meet customer requirements under different market conditions.

Empowering Customers with Choices

SWEPCO's customers already benefit from existing demand-side programs that include DSM and EE measures. Nonetheless, SWEPCO continues to explore the potential to further implement demand-side programs to the benefit of its customers. This IRP considers EE measures that could be selected alongside new utility-scale resources.

Planning for Uncertain Futures

SWEPCO knows the importance of reliability to its customers and set an objective to the extent practicable, to mitigate risks of high costs during unexpected or adverse market conditions. This IRP includes two methods for evaluating cost risks:

- The first approach is a scenario analysis where SWEPCO tested candidate portfolios over a set of five market scenarios that test plausible but materially different long-term views of fundamental external market conditions such as commodity prices, customer load and preferences, policy requirements, resource costs, and transmission availability.
- The second approach is a stochastic analysis where SWEPCO subjected the candidate portfolios to a large number of randomly drawn market simulations that combined volatility in power prices and natural gas prices with volatility in resource output to observe how the candidate portfolio performed from a cost perspective.

Five-Year Action Plan (2024 to 2028)

Steps to be taken by SWEPCO in the near future as part of its Five-Year Action Plan include:

- Action plan to be developed with the Final IRP report.

1. Introduction

This Report presents the 2023 Integrated Resource Plan ("IRP") for Southwestern Electric Power Company ("SWEPCO" or "Company") including descriptions of assumptions, study parameters, and methodologies. The IRP identifies the amount, timing, and type of supply- and demand-side resources required to ensure affordable and reliable energy to customers.

For this IRP, SWEPCO engaged Charles River Associates ("CRA") to assist in the development and analyses. CRA is a leading global consulting firm that offers economic, financial, and business management consulting expertise and applies advanced analytic techniques and in-depth industry knowledge to complex engagements for a broad range of clients. The energy practice of CRA has staff based in Washington DC, Boston, New York, London, and Toronto. CRA advises a range of clients on a range of issues including resources planning, asset valuation, auction design and implementation, policy development, and procurement and planning strategies. Recently CRA has supported numerous investor- and publicly-owned utilities to develop long-term generation, transmission, and distribution plans that meet the evolving needs of customers, regulators, and other stakeholders.

1.1. Integrated Resource Plan Process

The Company defined a set of performance objectives and metrics and arranged them into a scorecard to provide a structured approach to comparing the tradeoffs between different resource alternatives relative to the objectives defined by SWEPCO.

These objectives and performance indicators were used to inform the assumptions and steps taken in the IRP analysis to create and evaluate candidate resource plans.

This IRP is developed to align with SWEPCO's objectives as follows:

- **Customer affordability** by considering a broad range of resource options including renewables to take advantage of tax credits for the Company's customers, and demand-side measures including EE;
- **Rate stability** by considering renewable resources to reduce uncertainties around future fuel prices and carbon policies, and using comprehensive scenario and stochastic analyses to inform portfolio choices to minimize rate risks to customers;
- **Maintaining reliability** by considering SWEPCO's portfolio performance against seasonal reserve margins and adverse system events and,
- **Local impact & sustainability** through inclusion of renewable and advanced generation technologies as resource options to enable a greener future for all as well as considering economic impacts for new resources to SWEPCO communities.

The details of the 2023 IRP portfolio analysis framework and the scorecard elements are discussed below in Section 8.

This Report covers the processes, assumptions, results, and recommendations required to develop the Company's IRP. It uses the best available information at the time of preparation, but changes that may affect its results can, and do, occur without notice. Therefore, commitments to specific resources and actions remain subject to further review and consideration.

Included in this draft IRP are assumptions related to the Company's Load Forecast, Commodity Forecast and Technology costs. These are subject to potential changes and will be considered further with respect to the final IRP.

1.2. IRP Process

The IRP process for SWEPCO includes the following components/steps:

- Describe the Company and the resource planning process;

- Describe future customer needs and evaluate how those needs are likely to change over the 20-year period forecast in the 2023 IRP (see Chapter 2);
- Assess the adequacy of current resources, both demand- and supply-side, in meeting future customers' needs taking into account near term changes in the portfolio and the potential impact of future legislations on the resource performance (see Chapter 3);
- Discuss transmission and distribution system integration in meeting future customer needs (see Chapter 4);
- Identify a list of resources that could be selected by the portfolio model to meet future customer needs. Resources include both supply-side (see Chapter 5) and demand-side options (see Chapter 6);
- Assess sources of future risks and uncertainties, and devise market scenarios and stochastic analysis to represent those risks as part of portfolio optimization (See Chapter 7)
- Define the objectives or targets that the preferred resource plan should achieve, and evaluate all resource options to identify the portfolio options (see Chapter 8);
- Engage with stakeholders and consider feedback; and
- Utilize resource modeling results in formulating the preferred resource plan and the associated five-year action plan (See Chapter 0).

1.3. Introduction to SWEPCO

SWEPCO is an affiliate company of American Electric Power (AEP). With more than five million customers and serving parts of 11 states, AEP is one of the country's largest investor-owned utilities. AEP's service territory covers 197,500 square miles in Louisiana, Arkansas, Texas, Oklahoma, Indiana, Michigan, Kentucky, Ohio, Tennessee, Virginia and West Virginia.

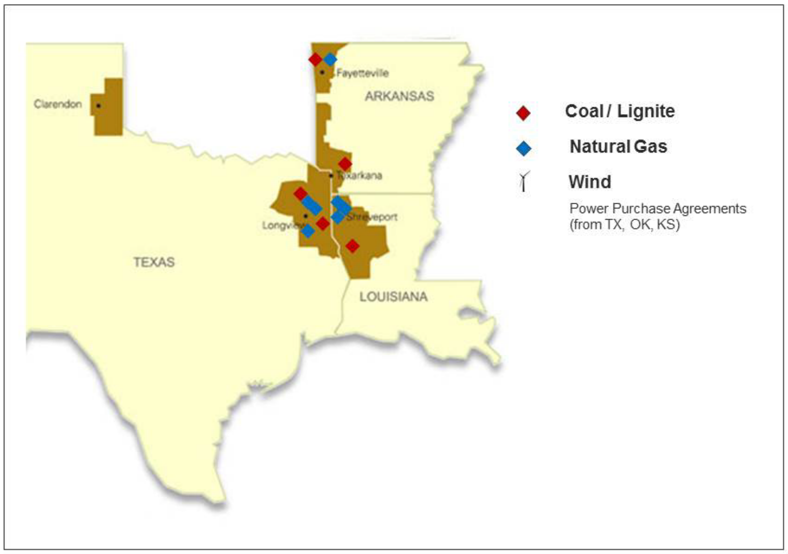
AEP owns and/or operates one of the largest generation portfolios in the United States, with approximately 26,000 megawatts of generating capacity in three RTOs. AEP's customers are served by one of the world's largest transmission and distribution systems. System-wide there are approximately 40,000 circuit miles of transmission lines and more than 222,000 miles of distribution lines.

The two AEP operating companies in the Southwest Power Pool (SPP), SWEPCO and Public Service Company of Oklahoma (PSO) collectively serve a population of about 4.25 million, which includes over 1 million retail customers in a 36,000 square mile area in parts of Arkansas, Louisiana, Oklahoma, and Texas.

SWEPCO's customers consist of both retail and sales-for-resale ("wholesale") customers located in the states of Arkansas, Louisiana, and Texas (see Figure 2). Currently, SWEPCO serves approximately 550,000 retail customers in those states; including approximately 124,000, 233,000 and 189,000 in the states of Arkansas, Louisiana and Texas, respectively. The peak load requirement of SWEPCO's total retail and wholesale customers is seasonal in nature, with distinctive peaks occurring in the summer and winter seasons. SWEPCO's historical all-time highest recorded peak demand was 5,554MW, which occurred in August 2011; and the highest recorded winter peak was 4,919MW, which occurred in January 2014. The most recent 2022 actual SWEPCO summer peak demand was 4,838MW occurring on July 20th. SWEPCO's annual peak demand for 2022 occurred on December 23, 2022, with a value of 4,918 MW.

SWEPCO service territory is highlighted in Figure 2.

Figure 2 SWEPCO's Service Territory



2. Load Forecast and Forecasting Methodology

2.1. Overview

The SWEPCO load forecast was developed by AEP's Economic Forecasting organization and completed in June 2022.[2] The final load forecast is the culmination of a series of underlying forecasts that build on each other. In other words, the economic forecast provided by Moody's Analytics is used to develop the customer forecast which is then used to develop the sales forecast which is ultimately used to develop the peak load and internal energy requirements forecast.

Over the next 20-year period (2023-2042)[3], SWEPCO's service territory is expected to see population and non-farm employment experience similar growth of 0.5% and 0.4% per year, respectively. Not surprisingly, SWEPCO is projected to see customer count growth at a rate of 0.2% per year. Over the same forecast period, SWEPCO's retail sales are projected to grow at 0.3% per year with stronger growth expected from the residential class (0.4% per year) while the commercial class experiences a modest decrease (0.1% per year) and the industrial class experiences modest increases (0.6% per year) over the forecast horizon. The projected change in SWEPCO's internal energy over the next 20 years is for requirements to increase by 0.3% per year. Finally, SWEPCO's peak demand is also expected to increase at an average rate of 0.3% per year through 2042.

2.2. Forecast Assumptions

2.2.1. Economic Assumptions

The load forecasts for SWEPCO and the other operating companies in the AEP System incorporate a forecast of U.S. and regional economic growth provided by Moody's Analytics. The load forecasts utilized Moody's Analytics economic forecast issued in December 2021. Moody's Analytics projects moderate growth in the U.S. economy during the 2023-2042 forecast period, characterized by a 2.1% annual rise in real Gross Domestic Product ("GDP"), and moderate inflation as well, with the implicit GDP price deflator expected to rise by 1.9% per year. Industrial output, as measured by the Federal Reserve Board's index of industrial production, is expected to grow at 1.6% per year during the same period. Moody's projected regional employment growth of 0.4% per year during the forecast period and real regional income per-capita annual growth of 1.6% for the SWEPCO service area.

2.2.2. Energy Price Assumptions

The Company utilizes an internally developed service area electricity price forecast. This forecast incorporates information from the Company's financial plan for the near term and the U.S. Department of Energy ("DOE") Energy Information Administration ("EIA") outlook for the West South Central Census Region for the longer term. These price forecasts are incorporated into the Company's energy sales models, where appropriate.

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[2] The load forecasts (as well as the historical loads) presented in this report reflect the traditional concept of internal load, i.e., the load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission service by the utility. Such load serves as the starting point for the load forecasts used for generation planning. Internal load is a subset of connected load, which also includes directly connected load for which the utility serves only as a transmission provider. Connected load serves as the starting point for the load forecasts used for transmission planning

[3] 20 year forecast periods begin with the first full forecast year, 2023

2.2.3. Specific Large Customer Assumptions

SWEPCO's customer service engineers are in frequent touch with industrial and commercial customers about their needs and activities. From these discussions, expected load additions or reductions are relayed to the Company.

2.2.4. Weather Assumptions

Where appropriate, the Company includes weather as an explanatory variable in its energy sales models. These models reflect historical weather for the model estimation period and normal weather for the forecast period.

2.2.5. Energy Efficiency (EE) and Demand-Side Management (DSM) Assumptions

The Company's long term load forecast models account for trends in EE both in the historical data as well as the forecasted trends in appliance saturations as the result of various legislated appliance efficiency standards (Energy Policy Act of 2005 [EPAct], Energy Independence and Security Act [EISA] of 2007, etc.) modeled by the EIA. In addition to general trends in appliance efficiencies, the Company also administers Demand-Side Management (DSM) programs approved by the Commission as part of its DSM portfolio. The load forecast utilizes the most current DSM programs, which either have been previously approved by or are pending currently before the Commission, at the time the load forecast is created to adjust the forecast for the impact of these programs. For this IRP, EE Resources through 2022 are in the load forecast.

2.3. Overview of Forecast Methodology

SWEPCO's load forecasts are based mostly on econometric, state-of-the-art statistically adjusted end-use and analyses of time-series data. This is helpful when analyzing future scenarios and developing confidence bands in addition to objective model verification by using standard statistical criteria.

SWEPCO utilizes two sets of econometric models: 1) a set of monthly short-term models, which extend for approximately 24 months and 2) a set of monthly long-term models, which extend for approximately 30 years. The forecast methodology leverages the relative analytical strengths of both the short- and long-term methods to produce a reasonable and reliable forecast that is used for various planning purposes.

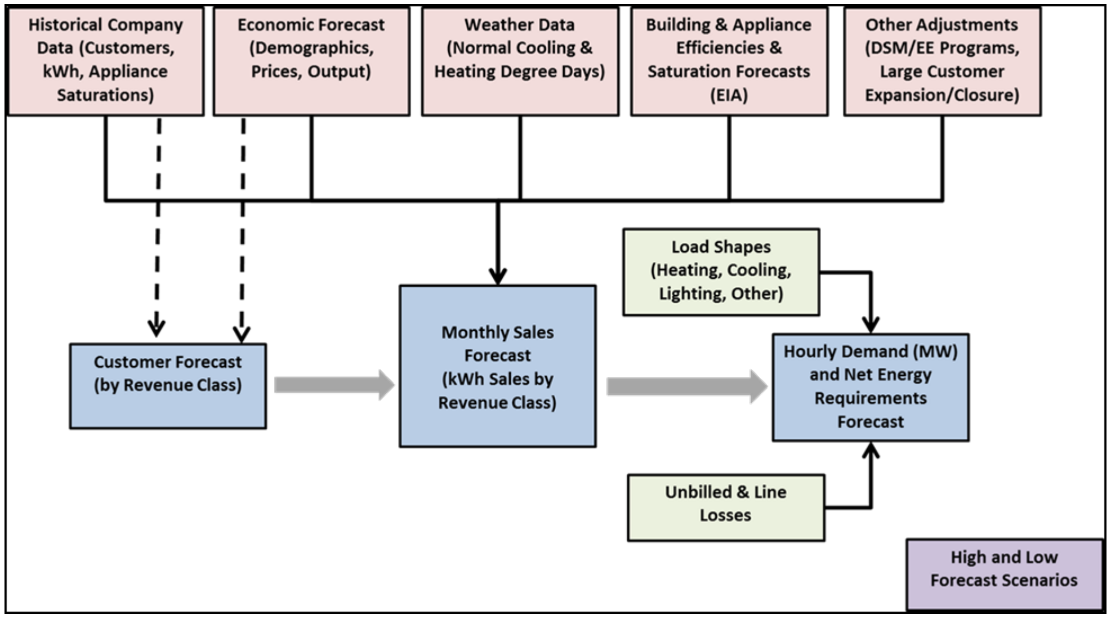
For the first full year of the forecast, the forecast values are generally governed by the short-term models. The short-term models are regression models with time series errors which analyze the latest sales and weather data to better capture the monthly variation in energy sales for short-term applications like capital budgeting and resource allocation. While these models produce extremely accurate forecasts in the short run, without logical ties to economic factors, they are less capable of capturing structural trends in electricity consumption that are more important for longer term resource planning applications.

The long-term models are econometric, and statistically adjusted end-use models which are specifically equipped to account for structural changes in the economy as well as changes in customer consumption due to increased energy efficiency. The long-term forecast models incorporate regional economic forecast data for income, employment, households, output, and population.

The short-term and long-term forecasts are then blended to ensure a smooth transition from the short-term to the long-term forecast horizon for each major revenue class. There are some instances when the short-term and long-term forecasts diverge, especially when the long-term models are incorporating a structural shift in the underlying economy that is expected to occur within the first 24 months of the forecast horizon. In these instances, professional judgment is used to ensure that the final forecast that will be used in the peak models is reasonable. The class level sales are then summed and adjusted for losses to produce monthly net internal energy sales for the system. The demand forecast model utilizes a series of algorithms to allocate the monthly net internal energy to hourly demand. The inputs into forecasting hourly demand are internal energy, weather, 24-hour load profiles and calendar information.

A flow chart depicting the sequence of models used in projecting SWEPCO's electric load requirements as well as the major inputs and assumptions that are used in the development of the load forecast is shown in Figure 3.

Figure 3 SWEPCO Internal Energy Requirements & Peak Demand Forecasting Method



2.4. Detailed Explanation of Load Forecast

This section provides a more detailed description of the short-term and long-term models employed in producing the forecasts of SWEPCO's energy consumption, by customer class. Conceptually, the difference between short and long-term energy consumption relates to changes in the stock of electricity-using equipment and economic influences, rather than the passage of time. In the short term, electric energy consumption is considered to be a function of an essentially fixed stock of equipment. For residential and commercial customers, the most significant factor influencing the short term is weather. For industrial customers, economic forces that determine inventory levels and factory orders also influence short-term utilization rates. The short-term models recognize these relationships and use weather and recent load growth trends as the primary variables in forecasting monthly energy sales.

Over time, demographic and economic factors such as population, employment, income, and technology influence the nature of the stock of electricity-using equipment, both in size and composition. Long-term forecasting models recognize the importance of these variables and include all or most of them in the formulation of long-term energy forecasts.

Relative energy prices also have an impact on electricity consumption. One important difference between the short-term and long-term forecasting models is their treatment of energy prices, which are only included in long-term forecasts. This approach makes sense because although consumers may suffer sticker shock from energy price fluctuations, there is little they can do to affect them in the short-term. They already own a refrigerator, furnace or industrial equipment that may not be the most energy-efficient model available. In the long term, however, these constraints are lessened as durable equipment is replaced and as price expectations come to fully reflect price changes.

2.4.1. Customer Forecast Models

The Company also utilizes both short-term and long-term models to develop the final customer count forecast. The short-term customer forecast models are time series models with intervention (when needed) using Autoregressive Integrated Moving Average (“ARIMA”) methods of estimation. These models typically extend for 24 months into the forecast horizon.

The long-term residential customer forecasting models are also monthly but extend for 30 years. The explanatory jurisdictional economic and demographic variables may include gross regional product, employment, population, real personal income and households used in various combinations. In addition to the economic explanatory variables, the long-term customer models employ a lagged dependent variable to capture the adjustment of customer growth to changes in the economy. There are also binary variables to capture monthly variations in customers, unusual data points and special occurrences.

The short-term and long-term customer forecasts are blended as was described earlier to arrive at the final customer forecast that will be used as a primary input into both short-term and long-term usage forecast models.

2.4.2. **Short-term Forecasting Models**

The goal of SWEPCO's short-term forecasting models is to produce an accurate load forecast for the first full year into the future. To that end, the short-term forecasting models generally employ a combination of monthly and seasonal binaries, time trends, and monthly heating cooling degree-days in their formulation. The heating and cooling degree-days are measured at weather stations in the Company's service area. The forecasts relied on ARIMA models.

There are separate models for the Arkansas, Louisiana, and Texas Jurisdictions of the Company. The estimation period for the short-term models was January 2012 through January 2022.

Residential and Commercial Energy Sales

Residential and commercial energy sales are developed using ARIMA models to forecast usage per customer and number of customers. The usage models relate usage to lagged usage, lagged error terms, heating and cooling degree-days and binary variables. The customer models relate customers to lagged customers, lagged error terms and binary variables. The energy sales forecasts are a product of the usage and customer forecasts.

Industrial Energy Sales

Short-term industrial energy sales are forecast separately for 22 large industrial customers in SWEPCO and for the remainder of industrial energy. These short-term industrial energy sales models relate energy sales to lagged energy sales, lagged error terms and binary variables for each of the Company’s jurisdictions. The industrial models are estimated using ARIMA models. The short-term industrial energy sales forecast is a sum of the forecasts for the 20 large industrial customers and the forecasts for the remainder of the manufacturing customers. Customer service engineers also provide input into the forecast for specific large customers.

All Other Energy Sales

The “All Other Energy Sales” category for SWEPCO includes public street and highway lighting (or other retail sales) and sales to municipalities. Current SWEPCO wholesale requirements customers include the cities of Bentonville, Hope and Prescott in Arkansas, City of Minden in Louisiana, and Northeast Texas Electric Cooperative. Wholesale loads are generally longer term, full requirements, and cost-of-service based contracts, although SWEPCO does have a partial requirements wholesale customer due to the ownership of generation resources by this customer.

Both the other retail and municipal models are estimated using ARIMA models. SWEPCO's short-term forecasting model for Public Street and highway lighting energy sales includes binaries, and lagged energy sales. The sales-for-resale model includes binaries, heating and cooling degree-days, lagged error terms and lagged energy sales.

Off-system sales and/or sales of opportunity are not relevant to the net energy requirements forecast, as they are not requirements load or part of the IRP process.

2.4.3. Long-term Forecasting Models

The goal of the long-term forecasting models is to produce a reasonable load outlook for up to 30 years in the future. Given that goal, the long-term forecasting models employ a full range of structural economic and demographic variables, electricity and natural gas prices, weather as measured by monthly heating and cooling degree-days, and binary variables to produce load forecasts conditioned on the outlook for the U.S. economy, for the SWEPCO service-area economy, and for relative energy prices.

Most of the explanatory variables enter the long-term forecasting models in a straightforward, untransformed manner. In the case of energy prices, however, it is assumed, consistent with economic theory, that the consumption of electricity responds to changes in the price of electricity or substitute fuels with a lag, rather than instantaneously. This lag occurs for reasons having to do with the technical feasibility of quickly changing the level of electricity use even after its relative price has changed, or with the widely accepted belief that consumers make their consumption decisions on the basis of expected prices, which may be perceived as functions of both past and current prices.

There are several techniques, including the use of lagged price or a moving average of price that can be used to introduce the concept of lagged response to price change into an econometric model. Each of these techniques incorporates price information from previous periods to estimate demand in the current period.

The general estimation period for the long-term load forecasting models was 1995-2020, with some variation in the estimation period for the various models. The long-term energy sales forecast is developed by blending of the short-term forecast with the long-term forecast. The energy sales forecast is developed by making a billed/unbilled adjustment to derive billed and accrued values, which are consistent with monthly generation.

2.4.4. Supporting Model

In order to produce forecasts of certain independent variables used in the internal energy requirements forecasting models, several supporting models are used, including a natural gas price model for SWEPCO’s Arkansas, Louisiana, and Texas service areas. These models are discussed below.

Consumed Natural Gas Pricing Model

The forecast price of natural gas used in the Company's energy models comes from a model of natural gas prices for each state’s three primary consuming sectors: residential, commercial, and industrial. In the state natural gas price models, sectoral prices are related to West South Central Census region’s sectoral prices, with the forecast being obtained from EIA’s “2022 Annual Energy Outlook.” The natural gas price model is based upon 1980-2021 historical data.

Residential Energy Sales

Residential energy sales for SWEPCO are forecasted using two models, the first of which projects the number of residential customers, and the second of which projects kWh usage per customer. The residential energy sales forecast is calculated as the product of the corresponding customer and usage forecasts.

The residential usage model is estimated using a Statistically Adjusted End-Use model (“SAE”), which was developed by Itron, a consulting firm with expertise in energy modeling. This model assumes that use will fall into one of three categories: heat, cool and other. The SAE model constructs variables to be used in an econometric equation where residential usage is a function of Xheat, Xcool and Xother variables.

The Xheat variable is derived by multiplying a heating index variable by a heating use variable. The heating index incorporates information about heating equipment saturation; heating equipment efficiency standards and trends; and thermal integrity and size of homes. The heating use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices and electricity prices.

The Xcool variable is derived by multiplying a cooling index variable by a cooling use variable. The cooling index incorporates information about cooling equipment saturation; cooling equipment efficiency standards and trends; and thermal integrity and size of homes. The cooling use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices and electricity prices.

The Xother variable estimates the non-weather sensitive sales and is similar to the Xheat and Xcool variables. This variable incorporates information on appliance and equipment saturation levels; average number of days in the billing cycle each month; average household size; real personal income; gas prices and electricity prices.

The appliance saturations are based on historical trends from SWEPCO's residential customer survey. The saturation forecasts are based on EIA forecasts and analysis by Itron. The efficiency trends are based on DOE forecasts and Itron analysis. The thermal integrity and size of homes are for the West South Central Census Region and are based on DOE and Itron data.

The number of billing days is from internal data. Economic and demographic forecasts are from Moody's Analytics and the electricity price forecast is developed internally.

The SAE residential models are estimated using linear regression models. These monthly models are typically for the period January 1995 through January 2022. It is important to note, as will be discussed later in this document, that this modeling has incorporated the reductive effects of the Energy Policy Act of 2005 (EPAct), the Energy Independence and Security Act of 2007 (EISA), American Recovery and Reinvestment Act of 2009 (ARRA) and Energy Improvement and Extension Act of 2008 (EIEA2008) on the residential (and commercial) energy usage.

The long-term residential energy sales forecast is derived by multiplying the "blended" customer forecast by the usage forecast from the SAE model.

Separate residential SAE models are estimated for the Company's Arkansas, Louisiana, and Texas jurisdictions.

Commercial Energy Sales

Long-term commercial energy sales are forecast using a SAE model. These models are similar to the residential SAE models, where commercial usage is a function of Xheat, Xcool and Xother variables.

As with the residential model, Xheat is determined by multiplying a heating index by a heat use variable. The variables incorporate information on heating degree-days, heating equipment saturation, heating equipment operating efficiencies, square footage, average number of days in a billing cycle, commercial output and electricity price.

The Xcool variable uses measures similar to the Xheat variable, except it uses information on cooling degree-days and cooling equipment, rather than those items related to heating load.

The Xother variable measures the non-weather sensitive commercial load. It uses non-weather sensitive equipment saturations and efficiencies, as well as billing days, commercial output and electricity price information.

The saturation, square footage and efficiencies are from the Itron base of DOE data and forecasts. The saturations and related items are from EIA's 2021 Annual Energy Outlook. Billing days and electricity prices are developed internally. The commercial output measure is either service gross regional product, service area real personal income per capita or service area commercial employment from Moody's Analytics. The equipment stock and square footage information are for the West South Central Census Region.

The SAE is a linear regression for the period, which is typically January 2000 through January 2022. As with the residential SAE model, the effects of EPAct, EISA, ARRA and EIEA2008 are captured in this model. Separate commercial SAE models are estimated for the Company's Arkansas, Louisiana, and Texas jurisdictions.

Industrial Energy Sales

The Company uses some combination of the following economic and pricing explanatory variables: service area gross regional product manufacturing, service area manufacturing employment, FRB industrial production indexes, service area industrial electricity prices and state industrial natural gas price. In addition, binary variables for months are special occurrences and are incorporated into the models. Based on information from customer service engineers, there may be load added or subtracted from the model results to reflect plant openings, closures or load adjustments. Separate models are estimated for the Company's Arkansas, Louisiana, and Texas jurisdiction. The last actual data point for the industrial energy sales models is January 2022.

All Other Energy Sales

The forecast of public-street and highway lighting relates energy sales to either service area employment or service area population and binary variables.

The municipal energy sales model is specified linear with the dependent and independent variables in linear form. Wholesale energy sales are modeled relating energy sales to economic variables such as service area gross regional product, heating and cooling degree-days and binary variables. Binary variables are necessary to account for discrete changes in energy sales that result from events such as the addition of new customers.

Blending Short and Long-Term Sales

Forecast values for 2022 and 2023 are taken from the short-term process. Forecast values for 2024 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by July of 2024, the entire forecast is from the long-term models. The goal of the blending process is to leverage the relative strengths of the short-term and long-term models to produce the most reliable forecast possible. However, at times the short-term models may not capture structural changes in the economy as well as the long-term models, which may result in the long-term forecast being used for the entire forecast horizon.

Large Customer Changes

The Company's customer service engineers are in continual contact with the Company's large commercial and industrial customers about their needs for electric service. These customers relay information about load additions and reductions. This information will be compared with the load forecast to determine if the industrial or commercial models are adequately reflecting these changes. If the changes are different from the model results, then add factors may be used to reflect those large changes that are different from those from the forecast models' output.

Losses and Unaccounted-For Energy

Energy is lost in the transmission and distribution of the product. This loss of energy from the source of production to consumption at the premise is measured as the average ratio of all FERC revenue class energy sales measured at the premise meter to the net internal energy requirements metered at the source. In modeling, Company loss study results are applied to the final blended sales forecast by revenue class and summed to arrive at the final internal energy requirements forecast.

2.4.5. Forecast Methodology for Seasonal Peak Internal Demand

The demand forecast model is a series of algorithms for allocating the monthly internal energy sales forecast to hourly demands. The inputs into forecasting hourly demand are blended revenue class sales, energy loss multipliers, weather, 24-hour load profiles and calendar information.

The weather profiles are developed from representative weather stations in the service area. Twelve monthly profiles of average daily temperature that best represent the cooling and heating degree-days of the specific geography are taken from the last 30 years of historical values. The consistency of these profiles ensures the appropriate diversity of the Company loads.

The 24-hour load profiles are developed from historical hourly Company or jurisdictional load and end-use or revenue class hourly load profiles. The load profiles were developed from segregating, indexing and averaging hourly profiles by season, day types (weekend, midweek and Monday/Friday) and average daily temperature ranges.

In the end, the profiles are benchmarked to the aggregate energy and seasonal peaks through the adjustments to the hourly load duration curves of the annual 8,760 hourly values. These 8,760 hourly values per year are the forecast load of SWEPCO and the individual companies of AEP that can be aggregated by hour to represent load across the spectrum from end-use or revenue classes to total AEP-East, AEP-West (SPP), or total AEP system. Net internal energy requirements are the sum of these hourly values to a total Company energy need basis. Company peak demand is the maximum of the hourly values from a stated period (month, season or year).

2.5. Load Forecast Results and Issues

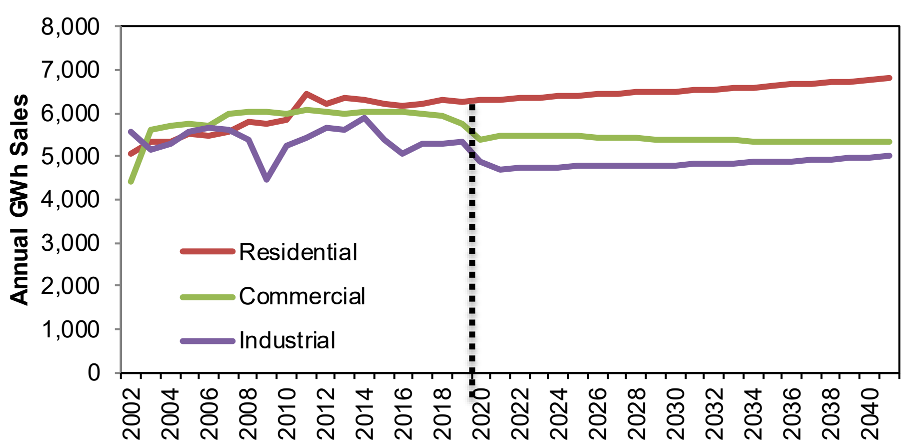
All tables referenced in this section can be found in the Appendix of this Report in Exhibit A.

2.5.1. Load Forecast

Exhibit A-1 presents SWEPCO's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial, other retail and wholesale sales, as well as losses) on an actual basis for the years 2012-2021. 2022 data are six months actual and six months forecast and on a forecast basis for the years 2023-2042. The exhibit also shows annual growth rates for both the historical and forecast periods. Corresponding retail sales information for the Company's Arkansas, Louisiana and Texas retail service areas are given in Table A-2.

Figure 4 provides a graphical depiction of weather normal and forecast Company residential, commercial, and industrial sales for 2002 through 2042.

Figure 4 Weather Normalized History and Forecast of SWEPCO's Sales by Category

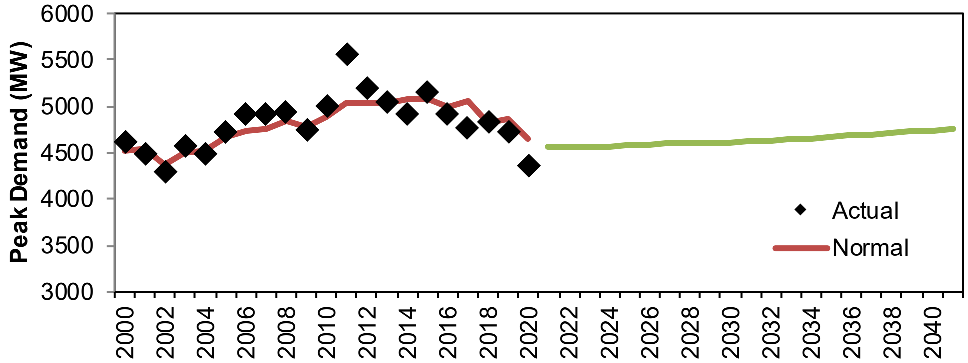


2.5.2. Peak Demand and Load Factor

Table A-3 provides SWEPCO's seasonal peak demands, annual peak demand, internal energy requirements and annual load factor on an actual basis for the years 2012-2021. 2022 data are six months actual and six months forecast and on a forecast basis for the year 2023-2042. The table also shows annual growth rates for both the historical and forecast periods.

Figure 5 presents actual, weather normal and forecast SWEPCO peak demand for the period 2000 through 2042.

Figure 5 SWEPCO's Peak Demand Between 2000 and 2042



2.5.3. Monthly Data

Table A-4 provides historical monthly sales data for SWEPCO by customer class (residential, commercial, industrial, other retail and wholesale) for the period January 2012 through June 2022. Table A-5 provides forecast SWEPCO monthly sales data by customer class for July 2022 through December 2042.

2.5.4. Prior Load Forecast Evaluation

Table A-6 presents a comparison of SWEPCO's energy sales and peak demand forecasts in the 2019 IRP with the actual and weather normal data for 2019, 2020 and 2021. The major source of forecast error was the impacts of the COVID-19 Pandemic. As explained in more detail below, the commercial and industrial sectors were most affected by the economic shutdown, resulting in decreased load across those classes. Otherwise, load forecast performed well. For example, the 2019 retail sales were over forecast by only 0.7%. However, there is a constant monitoring of the modeling process to seek improvement in forecast accuracies. Table A-7 provides the impact of demand-side management on the 2019 IRP.

2.5.5. Weather Normalization

The load forecast presented in this report assumes normal weather. To the extent that weather is included as an explanatory variable in various short- and long-term models, the weather drivers are assumed to be normal for the forecast period.

2.5.6. Significant Determinant Variables

Table A-8 provides significant economic and demographic variables incorporated in the various residential long-term energy sales models for the Company. Table A-9 provides significant economic variables utilized in the various SWEPCO jurisdictional commercial energy sales models. Table A-10 presents significant economic variables that the Company employed in its jurisdictional industrial models. Table A-11 depicts the significant economic variables the Company incorporated in its other retail and wholesale energy sales models.

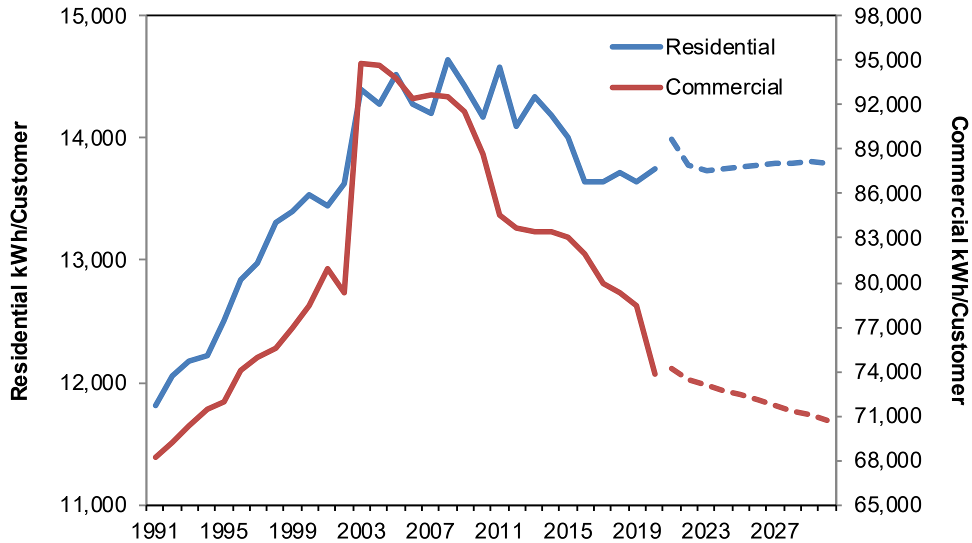
2.6. Load Forecast Trends & Issues

2.6.1. Changing Usage Patterns

Over the past decade, there has been a significant change in the trend for electricity usage from prior decades. Figure 6 presents SWEPCO's historical and forecasted residential and commercial usage per customer between 1991 and 2030. During the first decade shown (1991-2000), Residential usage per customer grew at an average rate of 1.4% per year while the Commercial usage grew by 2.1% per year. Over the next decade (2001-2010), growth in Residential usage slowed to 0.5% per year while the Commercial class usage increased by

0.9% per year. For the most recent decade (2011-2020) Residential usage declined at a rate of 0.6% per year while the Commercial usage also fell by an average of 1.4% per year. The COVID-19 Pandemic had a significant impact on commercial usage. With more people at home, Residential usage increased by 0.7% in 2020. Meanwhile, with the economy shutdown, Commercial usage declined by 5.8% in 2020. Efficiency gains are expected to continue over the next ten years (2022-2030), with residential usage declining at a rate of 0.1% per year while commercial usage falls by 0.4%.

Figure 6 SWEPCO's Normalized Usage Per Customer by Customer Type



The SAE models are designed to account for changes in the saturations and efficiencies of the various end-use appliances. Every 3-4 years, the Company conducts a Residential Appliance Saturation Survey to monitor the saturation and age of the various appliances in the residential home. This information is then matched up with the saturation and efficiency projections from the EIA, which includes the projected impacts from the various enacted federal policy mentioned earlier.

The result of this is a base load forecast that already includes some significant reductions in usage as a result of projected EE. For example, Figure 7 below shows the assumed cooling efficiencies embedded in the statistically adjusted end-use models for cooling loads. It shows that the average Seasonal Energy Efficiency Ratio (SEER) for central air conditioning is projected to increase from 11.78 in 2010 to nearly 15.0 by 2030. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units as well. Figure 8 shows similar improvements in the efficiencies of lighting and refrigerators over the same period. However, there are not many additional efficiency gains expected from lighting for residential customers, as consumers have adopted the newer technologies and moved away from incandescent lighting.

Figure 7 Projected Changes in Cooling Efficiencies, 2010 - 2030

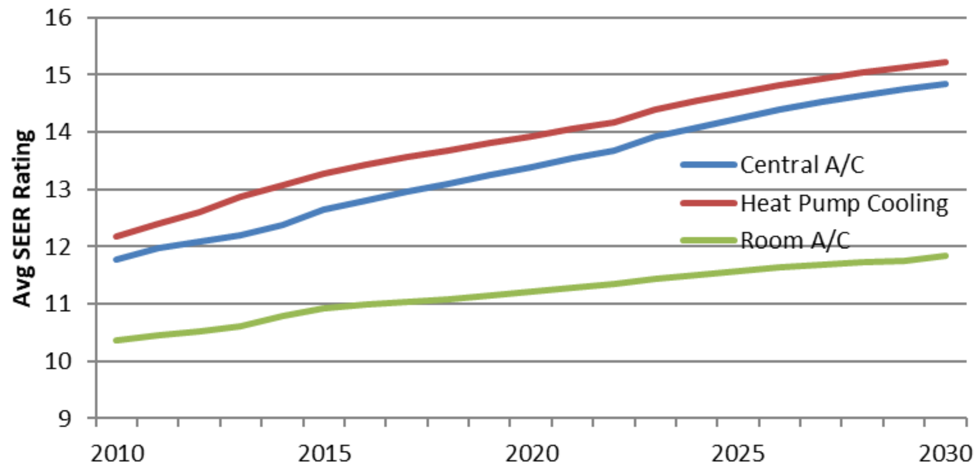


Figure 8 Projected Changes in Lighting & Clothes Washer Efficiencies, 2010-2030

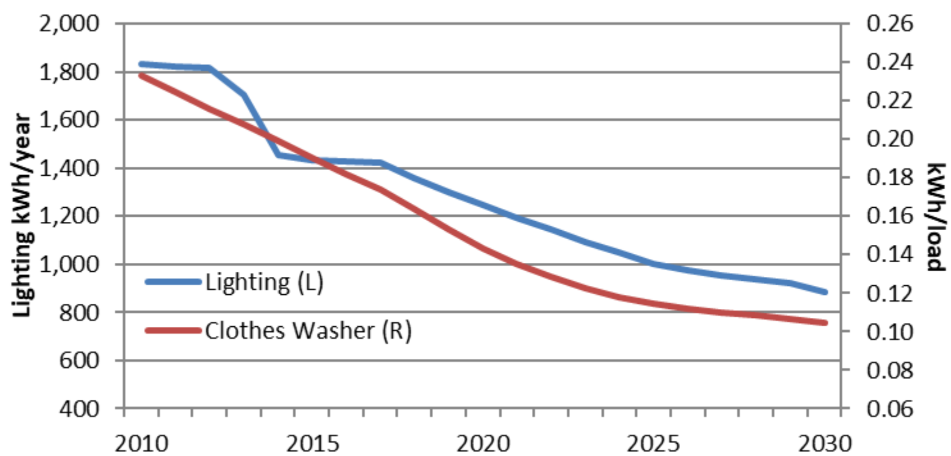
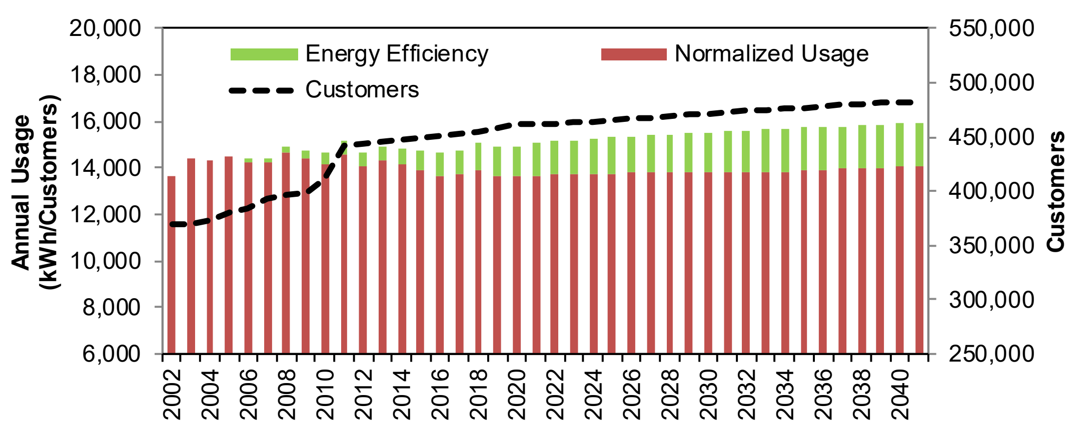


Figure 9 shows the impact of appliance, equipment, and lighting efficiencies on the Company's weather normal residential usage per customer. This graph provides weather normalized residential energy per customer and an estimate of the effects of efficiencies on usage. In addition, historical and forecast of SWEPCO residential customers are provided.

Figure 9 Residential Usage and Customer Growth, 2002 - 2042



2.6.2. Demand-Side Management (DSM) Impacts on the Load Forecast

Table A-12 provides the DSM/EE impacts incorporated in SWEPCO's load forecast provided in this report. Annual energy and seasonal peak demand impacts are provided for the Company and its Louisiana jurisdiction.

2.6.3. Losses and Unaccounted for Energy

Actual and forecast losses and unaccounted for energy are provided in Table A-13. See Section for a discussion of loss estimation. At this time, the Company does not have any planned loss reduction programs

2.6.4. Interruptible Load

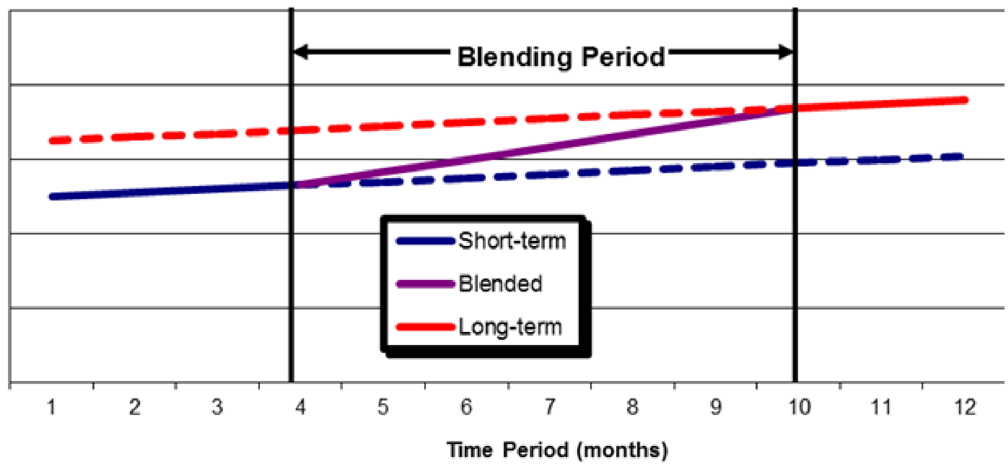
The Company has 21 customers with interruptible provisions in their contracts. The aggregate on-peak capacity available for interruptions is 54.7MW. The load forecast does not reflect any load reductions for these customers. Rather, the interruptible load is seen as a resource when the Company's load is peaking, or during system emergencies, such as the 2021 winter storm. As such, estimates for "demand response" impacts are reflected by SWEPCO in determination of SPP-required resource adequacy (i.e., SWEPCO's projected capacity position).

2.6.5. Blended Load Forecast

As noted above, at times the short-term models may not capture structural changes in the economy as well as the long-term models, which may result in the long-term forecast being used for the entire forecast horizon. Table A-14 provides an indication of which retail models are blended and which strictly use the long-term model results. In addition, seven of the nine wholesale forecasts utilize the long-term forecast model results and the other two uses the blended model results.

In general, forecast values for 2022 and 2023 were typically taken from the short-term process. Forecast values for 2023 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by July 2024 the entire forecast is from the long-term models. This blending allows for a smooth transition between the two separate processes, minimizing the impact of any differences in the results. Figure 10 illustrates a hypothetical example of the blending process (details of this illustration are shown in Table A-15). However, in the final review of the blended forecast, there may be instances where the short-term and long-term forecasts diverge especially when the long-term forecast incorporates a structural shift in the economy that is not included in the short-term models. In these instances, professional judgment is used to develop the most reasonable forecast.

Figure 10 Load Forecast Blending



2.6.6. Large Customer Changes

The Company's customer service engineers are in continual contact with the Company's large commercial and industrial customers about their needs for electric service. These customers will relay information about load additions and reductions. This information will be compared with the load forecast to determine if the industrial or commercial models are adequately reflecting these changes. If the changes are different from the model results, then additional factors may be used to reflect those large changes that differ from the forecast models' output.

2.6.7. Wholesale Customer Contracts

Company representatives are in continual contact with wholesale customer representatives about their contractual needs. If a wholesale customer intends to seek bids for the supply of power, they typically would need to give the Company a five-year notice of such intentions, although there may be stipulations within a contract that permits the customer to do so earlier. Concurrently, any self-generation provided by those wholesale customers that is appropriately "assumed" by SWEPCO for purposes of its long-term resource planning has been likewise removed.

2.7. Load Forecast Scenarios

The base case load forecast is the expected path for load growth that the Company uses for planning. There are a number of known and unknown potentials that could drive load growth different from the base case. While potential scenarios could be quantified at varying levels of assumptions and preciseness, the Company has chosen to frame the possible outcomes around the base case. The Company recognizes the potential desire for a more exact quantification of outcomes, but the reality is if all possible outcomes were known with a degree of certainty, then they would become part of the base case.

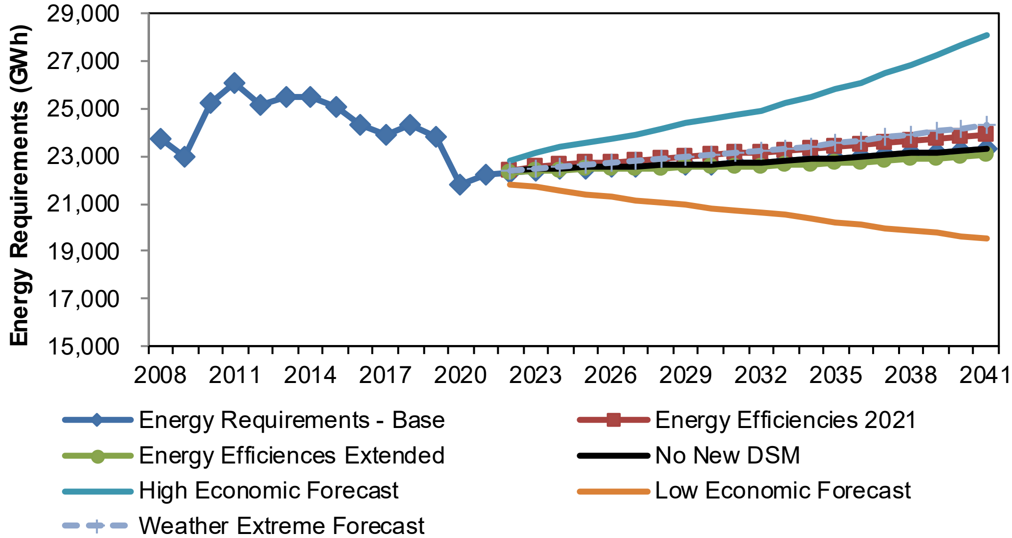
Forecast sensitivity scenarios have been established which are tied to respective high and low economic growth cases. The high and low economic growth scenarios are consistent with scenarios laid out in the EIA's 2022 Annual Outlook. While other factors may affect load growth, this analysis only considered high and low economic growth. The economy is seen as a crucial factor affecting future load growth.

The low-case, base-case and high-case forecasts of summer and winter peak demands and total internal energy requirements for SWEPCO are tabulated in Exhibit A-16.

For SWEPCO, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2042, represent deviations of about 9.1% below and 13.1% above, respectively, the base-case forecast.

During the load forecasting process, the Company developed various other scenarios. Figure 11 provides a graphical depiction of the scenarios developed in conjunction with the load provided in this report.

Figure 11 SWEPCO's Load Forecast Scenarios



The no new DSM scenario extracts the DSM included in the load forecast and provides what load would be without the increased DSM activity. The energy efficiencies 2021 scenario keeps energy efficiencies at 2021 levels for the residential and commercial equipment. Both scenarios result in a load forecast greater than the base forecast.

The energy efficiencies extended scenario has energy efficiencies developing at a faster pace than is represented in the base forecast. This scenario is based on analysis developed by the Energy Information Administration. This forecast is lower than the base forecast due to enhanced energy efficiency for residential and commercial equipment.

The weather extreme forecast assumes increased average daily temperatures for both the winter and summer seasons, which results in diminished heating degree-days in the winter and increased cooling degree-days in the summer. This analysis is based on a potential impact of climate change developed by Purdue University. This scenario results in increased load in the summer and diminished load in the winter, with the net result being a higher energy requirement forecast. Exhibit A-17 provides graphical displays of the range of forecasts of summer and winter peak demand for SWEPCO along with the impacts of the weather scenario for each season.

All of these alternative scenarios fall within the boundary of the Company's high and low economic scenario forecasts. The Company's expectations are that any reasonable scenario developed will fall within this range of forecasts.

Although the Company does not explicitly account for enhanced adoption of electric vehicles and distributed generation in the load forecast, it does continually monitor the adoption rate and will address the issue as it becomes more significant. At this time, SWEPCO has not seen a high penetration of electric vehicles in its service territory or an excessive percentage of DER penetration relative to its peak load; however, the Company anticipates that these activities will grow in the coming years. For EV growth, the Company has developed high, low, and base scenarios on adoption in the service area through 2030. These scenarios a presented graphically in Figure 12 and in Appendix Exhibit A-18 for SWEPCO's three state jurisdictions. Figure 13 illustrates the Company's projections for DG growth for the Company's three state jurisdictions as well as in Appendix Exhibit A-19.

Figure 12 Electric Vehicle Growth Projections

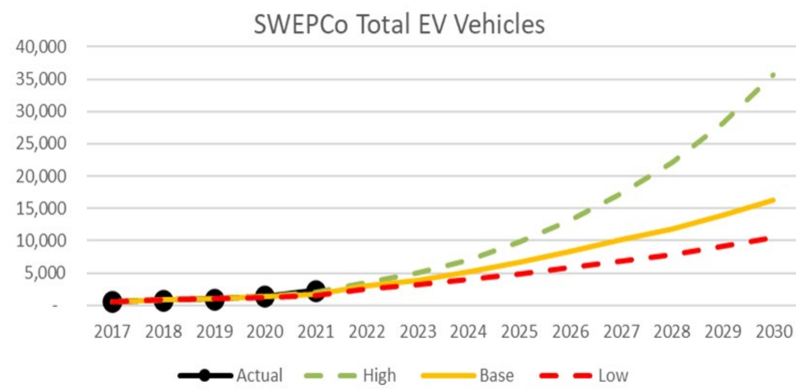
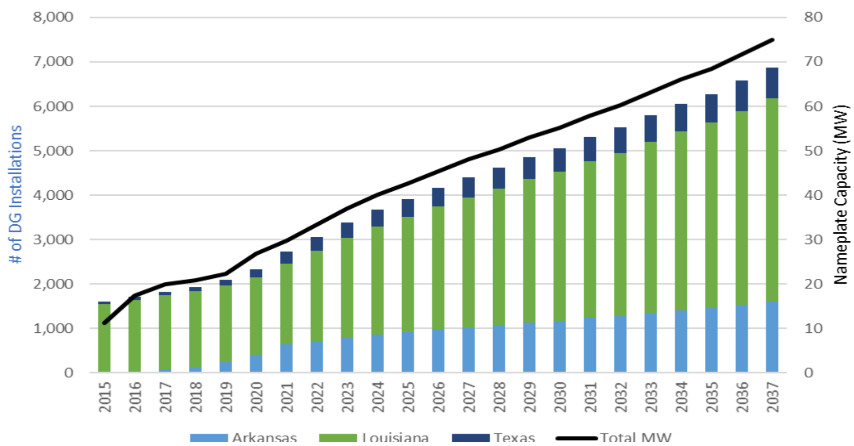


Figure 13 Distributed Generation Projections



2.8. Price Elasticity

The long-term load forecast models include electricity price as one of many explanatory variables. The coefficient of the electricity price variable is an estimate of the price elasticity, which is simply a measure of how responsive customers are to changes in price. The formula for price elasticity is simply the percentage change in the quantity demanded divided by the percentage change in price. If the change in demand is greater than the change in price, the elasticity estimate would be greater than 1 and it would be described as elastic demand. If the change in demand is less than the change in price, the elasticity estimate would be less than 1 and it would be classified as inelastic demand. The demand for electricity is very inelastic. For the Residential class, the long-term elasticity estimate is approximately 0.1. For the Commercial class, the modeled price elasticity is 0.15 and the elasticity estimate for the Industrial class is 0.18. For comparison, the estimated long-term elasticity for gasoline is 0.6 while the elasticity for restaurant meals is 2.3[4]. (Note: technically each of these elasticity estimates are negative values based on the inverse relationship between price and quantity demanded. The convention by economists when describing the elasticity is to report the absolute value of these elasticity estimates.)

[4] O'Sullivan, Arthur, Steven M. Sheffrin, & Stephen J. Perez Survey of Economics: Principles, Applications, and Tools. Prentice Hall © 2012 Table 4.2 'Price Elasticities of Demand for Selected Products' pg. 86.

3. Current Resource Evaluation

3.1. Introduction

SWEPCO's resource portfolio comprises a diverse set of supply- and demand-side resources that serve the Company's capacity, energy, and other reliability requirements. The supply-side resources include a mix of wind and fossil-fired resources. The demand-side resources include active demand response ("DR") and EE programs. Customers wishing to generate their own energy can also participate in SWEPCO's distributed generation ("DG") program.

3.2. Existing SWEPCO Generation Resources

Table 2 identifies the current SWEPCO generating resources.

Table 2 SWEPCO's Generation Assets as of March 2023

Unit Name	Primary Fuel Type	C.O.D.[1]	Rating (MW) [2]	Location	Retirement Date
Arsenal Hill 5	Gas Steam	1960	108	LA	1/1/2026
Flint Creek 1	Coal	1978	258	AR	1/1/2039
Harry D. Mattison 1	Gas (CT)	2007	70	AR	1/1/2053
Harry D. Mattison 2	Gas (CT)	2007	71	AR	1/1/2053
Harry D. Mattison 3	Gas (CT)	2007	71	AR	1/1/2053
Harry D. Mattison 4	Gas (CT)	2007	71	AR	1/1/2053
Pirkey	Coal	1985	580 (3)	TX	3/31/2023
J Lamar Stall	Gas (CC)	2010	511	LA	1/1/2051
John W. Turk, Jr. 1	Coal	2012	477	AR	1/1/2068
Knox Lee 5	Gas Steam	1974	335	TX	1/1/2040
Lieberman 3	Gas Steam	1957	109	LA	1/1/2027
Lieberman 4	Gas Steam	1959	108	LA	1/1/2027
Welsh 1	Coal	1977	525	TX	3/1/2028
Welsh 3	Coal	1982	528	TX	3/1/2028
Wilkes 1	Gas Steam	1964	162	TX	1/1/2030
Wilkes 2	Gas Steam	1964	352	TX	1/1/2036
Wilkes 3	Gas Steam	1964	350	TX	1/1/2037
Sundance	Wind	2021	109 (A)	OK	2051
Maverick	Wind	2021	156 (A)	OK	2051
Traverse	Wind	2022	544 (A)	OK	2051
Majestic	Wind	Wind (PPA)	80	TX	2029
High Majestic	Wind	Wind (PPA)	80	TX	2032
Flat Ridge	Wind	Wind (PPA)	109	KS	2032
Canadian Hills	Wind	Wind (PPA)	201	OK	2032

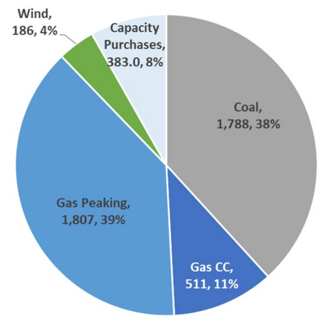
(1) Commercial operation date
(2) Peak net dependable capability (Summer) as of filing.
(3) Pirkey retires 3/31/2023
(A) Installed capacity; Represents SWEPCO's 54,5% ownership stake

In addition to these long-term resources, SWEPCO currently has short-term contracts with two gas-fired resources to provide capacity during the period between June 1, 2023 and May 31, 2027. The amounts currently under contract are 383 MW for the 2023/2024 delivery year (DY), 469 MW for DY 2024/2025, 483 MW for DY 2025/2026, and 200 MW for DY 2026/2027.

Based on the assessment of the current resources, planned retirements and peak demand projections, a capacity needs assessment can be established that will determine the amount and timing of capacity resources for this IRP. This is discussed further in Section 3.5.

Figure 14 shows SWEPCO's owned and contracted generation summer accredited capacity contribution to peak load.

Figure 14 SWEPCO 2023 Generation Asset Accredited Summer Capacity (MW) Contribution by Type



For the Company's existing resources, a supplemental analysis was conducted at Staff's request as captured in the Stakeholder feedback summarized in Appendix, Exhibit G. This analysis is included in Confidential Appendix Volume 2, Exhibit J.

3.2.1. Fuel Inventory and Procurement Practices

SWEPCO plans to have adequate fuel supplies at its generating units to meet burn requirements in both the short-term and the long-term. SWEPCO's primary objective is to assure the availability of an adequate, reliable supply of fuel at the lowest reasonable delivered cost.

Procurement Process - Coal

American Electric Power Service Corporation (AEPSC), acting as agent for SWEPCO, is responsible for the procurement and delivery of coal to SWEPCO's coal generating stations, Flint Creek, Turk and Welsh. AEPSC is also responsible for establishing each plant's coal inventory targets and managing those levels.

Coal delivery requirements are determined by taking into account existing coal inventory, forecasted coal consumption, and adjustments for contingencies that necessitate an increase or decrease in coal inventory levels. SWEPCO's total coal requirements are met using a portfolio of long-term arrangements and spot-market purchases that are primarily made through a competitive Request for Proposal process. Long-term contracts (>1 year) support a relatively stable and consistent supply of coal, but often do not provide the required flexibility to meet changes in demand for coal fired generation in a low gas price and/or low power demand scenario. Spot purchases are used to provide additional flexibility to accommodate changing market conditions.

All coal purchased for Flint Creek, Turk and Welsh, originate from the Powder River Basin in Wyoming. The coal is transported via rail to the plants in railcars owned and/or leased by SWEPCO and the other AEP Operating companies as part of the AEP System Railcar Use Agreement. As of January 1, 2023, SWEPCO has six long-term coal supply agreements with three suppliers. Additionally, SWEPCO has three spot agreements several committed spot contracts with two suppliers that contribute to fulfilling the supply requirements. Any remaining supply requirements will be met with purchases that are not yet committed.

Procurement Process – Natural Gas

Given the variable and uncertain operation of SWEPCO's natural gas power plants, spot market purchases continue to be an integral part of the supply portfolio. However, SWEPCO does have a long-term supply agreement, which supplies a nominal percentage of daily requirements. Additionally, SWEPCO purchases monthly and seasonal baseload natural gas supply to further mitigate price volatility that may be experienced in the spot market. SWEPCO relies on both firm and interruptible transportation agreements to optimize the delivery of natural gas.

Forecasted Fuel Prices

SWEPCO specific forecasted annual fuel prices, by unit, for the period 2023 through 2052 are displayed in Confidential Appendix Volume 2, Exhibit H.

3.3. Current Demand-Side Programs

Demand-Side programs, also known as Demand-side Management (DSM) collectively includes utility programs aimed at influencing both the level of, and timing of, customer use of grid supplied electricity. These types of programs are structured to counter the ongoing need for increased supply resources through customer energy conservation or direct intervention in how customers use electricity. Typically, customer influence is achieved through some form of monetary or product enticement either through utility rebates or electric bill credit payments. Several demand-side programs typically available including Energy Efficiency (EE), Demand Reduction (DR), and Distributed Generation (DG).

Generally, EE programs pay rebates directly to customers that are designed to encourage either end-use conservation or energy use reduction through the installation of or upgrade to more efficient end-use technologies. Some EE programs do not pay a cash rebate but instead encourage customers to reduce their annual energy consumption, or better manage their cost of electricity. Other types of EE programs seek to influence the manufacture and supply of more efficient end-use technologies through upstream rebate payments to end-use technology providers that reduce the technology cost to end-use customers. EE programs provide both energy and demand savings. Energy savings are accounted for as an around-the-clock energy reduction impact while demand savings are accounted for in terms of their point-in-time, peak coincident use reduction on an hourly basis. SWEPCO currently has EE programs in place in its Arkansas, Louisiana, and Texas service territories. SWEPCO forecasts EE measures will reduce peak demand in 2023 by 7.1 MW and reduce 2023 energy consumption by approximately 32 GWh.

Generally, DR programs offer electric bill credits through tariff pricing mechanisms to elicit point-in-time energy use reductions (also known as demand, or coincident peak demand reductions). DR programs require specific action to monitor and control electricity use during periods of peak usage. Direct load control (DLC) programs allow utility control over customers' end use loads to achieve the specific peak period use reduction. Other types of DR programs allow customers to reduce use during peak periods on their own accord and pay bill credits based on the actual level of usage during peak period events. Demand response programs primarily provide peak coincident demand impacts but can provide energy impacts as well depending upon the extent of use reduction that occurs. For this IRP, incremental DR programs were not modeled however, the Company will continue to review opportunities to offer a program for its customers.

DG typically refers to small-scale customer-sited generation behind the customer meter. Common examples are Combined Heat and Power (CHP), residential and small commercial solar applications, and even wind. Currently, these sources represent a small component of demand-side resources, even with available federal tax credits and tariffs favorable to such applications. Two of SWEPCO's retail jurisdictions have "net metering" tariffs in place which currently allow excess generation to be credited to customers at a full or reduced retail rate. For this IRP, incremental DG resources were assumed to be captured within the Company's load forecast as discussed in section 2.6.1.

3.4. Environmental Compliance

It should be noted that the following discussion of environmental regulations is based on the requirements currently in effect and those compliance options viewed as most likely to be implemented by the Company and incorporated into its analysis within this IRP. Activity including but not limited to Presidential Executive Orders, litigation, petitions for review, and Federal

Environmental Protection Agency (EPA) proposals may delay the implementation of these rules, or alter the requirements set forth by these regulations. While such activities have the potential to materially change the compliance options available to the Company in the future, all potential outcomes cannot be reasonably foreseen or estimated and the assumptions made within the IRP represent the Company's best estimation of outcomes as of the filing date. The Company is committed to closely following developments related to environmental regulations and will update its analysis of compliance options and timelines when sufficient information becomes available to make such judgments.

3.4.1. Clean Air Act (CAA) Requirements

The Clean Air Act (CAA) establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements. The primary regulatory programs that continue to drive investments in AEP's existing generating units include: (a) periodic revisions to National Ambient Air Quality Standards (NAAQS) and the development of State Implementation Plans (SIPs) to achieve any more stringent standards, (b) implementation of the regional haze program by the states and the Federal EPA, (c) regulation of hazardous air pollutant emissions under the Mercury and Air Toxics Standard (MATS) rule, (d) implementation and review of Cross-State Air Pollution Rule (CSAPR), a Federal Implementation Plan (FIP) designed to eliminate significant contributions from sources in upwind states to non-attainment or maintenance areas in downwind states and (e) the Federal EPA's regulation of greenhouse gas emissions from fossil fueled electric generating units under Section 111 of the CAA.

Notable developments in significant CAA regulatory requirements affecting the Company's operations are discussed in the following sections

3.4.2. National Ambient Air Quality Standards (NAAQS)

The CAA requires the EPA to establish and periodically review NAAQS designed to protect public health and welfare. Revisions tend to increase the stringency of the standards, which in turn may require the Company to make investments in pollution control equipment at existing generating units, or, since most units are already well controlled, to make changes in how units are dispatched and operated. In January 2023, the EPA announced its proposed decision to strengthen the primary (health-based) annual PM2.5 standard. The Biden administration has previously indicated that it is likely to revisit the NAAQS for ozone, which were left unchanged by the prior administration following its review. Management cannot currently predict if any changes to either standard are likely to be finalized or what such changes may be, but will continue to monitor this issue and any future rulemakings.

3.4.3. Regional Haze Rule (RHR)

The RHR requires affected states to develop regional haze SIPs that contain enforceable measures and strategies for reducing emissions of pollutants that can impair visibility in certain federally protected areas. Each initial SIP required certain eligible facilities to conduct an emission control analysis, known as a Best Available Retrofit Technology (BART) analysis, to evaluate emissions control technologies for NOx, SO2 and particulate matter (PM), and determine whether such controls should be deployed to improve visibility based on five factors set forth in the regulations. BART is applicable to EGUs greater than 250 megawatts and built between 1962 and 1977. If SIPs are not adequate or are not developed on schedule, regional haze requirements will be implemented through FIPs. In January 2017, the Federal EPA revised the rules governing submission of SIPs to implement the visibility programs, including a provision that postpones the due date for the next comprehensive SIP revisions until 2021. The Federal EPA announced in 2019 it would reconsider the visibility program revisions in response to petitions for reconsideration. Petitions for review of the final rule revisions have been filed in the U.S. Court of Appeals for the District of Columbia Circuit.

In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO2 and NOx emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. The rule was challenged in the U.S. Court of Appeals for the District of Columbia Circuit. In March 2018, the U.S. Court of Appeals for the District of Columbia Circuit affirmed the Federal EPA rule.

In October of 2022, EPA announced its decision to revisit aspects of the 2017 Regional Haze Rule revisions. EPA intends to commence a notice-and-comment rulemaking which will address portions of the rule, including but not limited to the Reasonably Attributable Visibility Impairment (RAVI) provisions and the provisions regarding Federal Land Manager (FLM) consultation.

3.4.4. Arkansas Regional Haze

The State of Arkansas and the Arkansas Department of Environmental Quality (ADEQ) submitted a regional haze SIP to the Federal EPA in 2008, including emission limits necessary to meet its BART obligations.

On November 16, 2011, the Federal EPA issued its proposed decision on Arkansas' regional haze SIP. The Federal EPA proposed to disapprove the regional haze SIP, in part, including the emission limitations based on ADEQ's BART analysis.

After the Federal EPA's proposed decision was issued, SWEPCO coordinated with ADEQ and Federal EPA to conduct a more detailed BART analysis for Flint Creek.

SWEPCO proposed to meet the NOx requirements at Flint Creek through participation in the CSAPR program. The Federal EPA had determined that, on a parameter-by-parameter basis, compliance with CSAPR is sufficient to meet the regional haze obligations for facilities covered by that program. SWEPCO proposed to meet the SO2 Regional Haze requirements through the installation of a dry scrubber (NIDTM technology).

In 2015, the Federal EPA proposed a FIP that accepted the SO2 controls presented in Flint Creek's BART analysis. However, the proposed Federal EPA FIP included the installation of Low NOx Burner with Over-Fire-Air (LNB/OFA) and an emission limitation of 0.23 lb. NOx/mmBtu. The Federal EPA did not address CSAPR at all in their FIP and SWEPCO submitted comments specifically seeking that CSAPR be approved as meeting the NOx obligations at Flint Creek.

In a final rule that became effective on October 27, 2016, the Federal EPA established a final SO2 emission limitation of 0.06 lb./mmBtu, and a final NOx limitation of 0.23 lb./mmBtu for the Flint Creek Plant and accelerated the deadline for compliance. Both of these limitations were required to be met by April 27, 2018 and were consistent with the already-installed dry FGD system for SO2 reductions and the planned installation of LNB/OFA for NOx emission reduction. The final rule is being challenged in the U.S. Court of Appeals for the Eighth Circuit and the case is currently held in abeyance while the parties work on a settlement.

On February 12, 2018, the Federal EPA issued two final rules related to the Arkansas Regional Haze requirements and settlement that affect NOx control for Flint Creek. The Federal EPA approved a SIP revision submitted by Arkansas on July 12, 2017 that proposed CSAPR participation as an alternative to BART for satisfying the Regional Haze NOx requirements. The Federal EPA also withdrew the NOx FIP requirements that would have required the installation of LNB/OFA and a NOx limit of 0.23 lb/mmBtu by April 27, 2018. Installation of the LNB/OFA continued in order to enhance compliance with EPA's MATS. On August 9, 2018, ADEQ finalized and submitted to Federal EPA for approval a second SIP revision to address SO2 requirements for BART sources. In this SIP revision, ADEQ determined that equipment already installed at Flint Creek Plant satisfies the requirements for the SO2 Regional Haze requirements. Federal EPA approved this SIP revision on September 27, 2019.

On August 2, 2022, ADEQ submitted the state's Regional Haze Plan for Planning Period II to EPA for approval on August 8, 2022

3.4.5. Louisiana Regional Haze

Louisiana submitted a regional haze SIP to the Federal EPA in June of 2008. All SWEPCO units were determined not to be “BART-eligible” and, therefore, no BART analysis or emission reductions were required for BART. The Federal EPA partially approved and partially disapproved Louisiana’s SIP in July 2012. The Federal EPA approved the BART determinations but required additional evaluation to be done to meet the Reasonable Progress Goals and Long-Term Strategy to improve visibility in one Class I area in Louisiana. The impact evaluation did not include any of the SWEPCO units and no additional emission controls are expected for those facilities as a result of the RHR at this time. States are required to reevaluate their Reasonable Progress Goals and Long-Term Strategy every five years.

The Federal EPA issued a final rule approving the Louisiana SIP on December 21, 2017. No requirements were included that specifically impact SWEPCO facilities. Petitions for review of the final approved Louisiana SIP were filed in the U.S. Court of Appeals for the Fifth Circuit; The court upheld the Louisiana SIP in October 2019. Louisiana has proposed rules that would constitute the state’s Regional Haze Plan for Planning Period II. Those rules have not been finalized.

3.4.6. Texas Regional Haze

Texas submitted its initial Regional Haze state implementation plan (SIP) to the Federal EPA in March 2009, and the 5-year update in March 2014. Both submittals state that Best Available Retrofit Technology (BART)-eligible facilities in Texas do not impact Class I areas, which means they are not subject to BART emissions control requirements. Federal EPA issued a proposed federal implementation plan (FIP) in November 2014. Federal EPA proposed to take no action on the portions of the Texas SIP that relate to BART-eligible facilities, but determined that the Reasonable Further Progress (RFP) Goals and Long-Term Strategy were inadequate. Federal EPA identified cost-effective controls to achieve visibility improvements that did not include any SWEPCO units. In January 2016, Federal EPA issued a Final Rule partially disapproving portions of the Texas Regional Haze SIP and issuing an RFP, but taking no action on the portions of the Texas SIP that relate to BART-eligible facilities due to issues with the Cross-State Air Pollution Rule (CSAPR) relative to those facilities. The FIP was challenged in the U.S. Court of Appeals for the Fifth Circuit, which issued a stay of the FIP and sent it back to Federal EPA to revise.

In January 2017, Federal EPA proposed a clean air plan for Texas to meet the Regional Haze BART and interstate visibility transport requirements. The proposal included SO2 and NOx emission reductions for 14 coal and natural gas-fired power plants in Texas. The proposed rule recommended an emission limit of 0.04 lb/MMBTU SO2 for Welsh Unit 1 based on the retrofit of wet FGD technology. In September 2017, Federal EPA finalized a rule:

1. Withdrawing Texas from participation in the Phase 2 CSAPR program; and
2. Determining that Texas has no further interstate transport obligations with respect to particulate matter (PM).

In October 2017, Federal EPA finalized a BART FIP for EGUs that established a federal intrastate trading program to address SO2 emissions as an alternative to source specific SO2 controls, a determination that Texas’s participation in the CSAPR NOx ozone season trading program satisfied Texas’ Regional Haze NOx requirements, and a determination that the BART alternatives satisfied many of Texas’ interstate transport requirements for all pollutants. A petition for review of this final BART FIP was filed in the Fifth Circuit in December 2017. Upon motion by Petitioners and Federal EPA, the court held the case in abeyance pending resolution of a petition for reconsideration. In August 2018, in response to that petition for reconsideration, Federal EPA proposed to affirm its October 2017 Rule and re-open it for public comment. In November 2019, Federal EPA issued a supplemental notice of proposed rulemaking and proposed revisions to the SO2 intrastate trading program. In August 2020, the Federal EPA affirmed portions of its October 2017 Rule and revised the SO2 intrastate trading program. That action has been challenged in the U.S. Court of Appeals for the Fifth Circuit, as well as in the U.S. Court of Appeals for the District of Columbia Circuit. The Fifth Circuit ordered the challenges to the 2017 Texas BART Rule and the 2020 Texas BART Rule to be consolidated and transferred to the D.C. Circuit; and in March 2021, denied a motion for reconsideration of that decision. Meanwhile, the D.C. Circuit has granted Federal EPA's motion to hold these matters in abeyance, to permit Federal EPA to provide requested updates to the new administration on a variety of matters. The Federal EPA may change its position on some or all of these matters because of the change in administration.

In a separate case, environmental groups challenged the September 2017 rule in the U.S. Court of Appeals for the District of Columbia Circuit. In April 2018, the court granted a motion to hold the case in abeyance pending Federal EPA's review of a petition for reconsideration of the Rule. In July 2020, the Federal EPA denied that petition for reconsideration. That denial has been challenged in the D.C. Circuit. The D.C. Circuit ordered the challenges to the September 2017 Rule and the July 2020 denial that were filed in the D.C. Circuit to be consolidated in November of 2020. Further consolidation of the combined D.C. Circuit cases with the combined 2017 and 2020 Texas BART Rule cases that were transferred from the Fifth Circuit is now pending.

SWEPCO is currently complying with the SO2 intrastate trading program.

On June 30, 2021, TCEQ adopted the 2021 Regional Haze SIP Revision to meet the Regional Haze Rule's requirements for the second planning period. TCEQ has submitted its rules to Federal EPA for approval.

3.4.7. Cross-State Air Pollution Rule (CSAPR)

CSAPR is a regional trading program designed to address interstate transport of emissions that contribute significantly to non-attainment and maintenance of the 1997 ozone and PM NAAQS in downwind states. CSAPR relies on SO2 and NOx allowances and individual state budgets to compel further emission reductions from electric utility generating units. Interstate trading of allowances is allowed on a restricted basis.

In January 2021, the EPA finalized a revised CSAPR rule, which substantially reduces the ozone season NOx budgets in 2021-2024. Several utilities and other entities potentially subject to the Federal EPA's NOx regulations have challenged that final rule in the U.S. Court of Appeals for the District of Columbia Circuit and oral arguments were held in September 2022. This rule has subsequently been upheld. Management believes it can meet the requirements of the rule in the near term, and is evaluating its compliance options for later years, when the budgets are further reduced. In addition, in February 2023, the EPA Administrator finalized the denial of 2015 Ozone NAAQS SIPs for 19 states. A FIP (also known as the Good Neighbor Plan) that further revises the ozone season NOx budgets under the existing CSAPR program in those states, including Louisiana, was finalized on March 15, 2023 and will take effect for the 2023 ozone season. Management is evaluating the impact of changes in that rulemaking.

Collectively, the installed SCR and FGD systems' respective emission reductions of NOx and SO2, the use of allocated NOx and SO2 emission allowances in conjunction with adjusted banked allowances, and the purchase of additional allowances as needed through the open market position SWEPCO well moving forward for compliance with CSAPR.

3.4.8. Climate Change, CO_2 Regulation and Energy Policy

In 2019, the Affordable Clean Energy (ACE) rule established a framework for states to adopt standards of performance for utility boilers based on heat rate improvements for such boilers. However, in January 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the ACE rule and remanded it to the EPA. In October 2021, the United States Supreme Court granted certiorari and combined four separate petitions seeking review of the District of Columbia Circuit Court decisions. Oral arguments were held in February 2022 and on June 30, 2022, the United States Supreme Court reversed the District of Columbia Circuit Court's decision and remanded for further proceedings. The EPA has announced it expects to propose a new rule in 2023 to apply to both new and existing sources.

In 2018, the EPA filed a proposed rule revising the standards for new sources and determined that partial carbon capture and storage is not the best system of emission reduction because it is not available throughout the U.S. and is not cost-effective. That rule has not been finalized. The EPA has indicated that it intends to conduct a comprehensive review of the existing standards and, if appropriate, amend the emission standards for new fossil fuel-fired generating units. A proposed rule is expected in 2023. Management continues to actively monitor these rulemaking activities.

The Company has taken action to reduce CO_2 emissions from its generating fleet and expects CO_2 emissions from its operations to continue to decline over the next decade due to the retirement of coal-fired generation units, and actions taken to diversify the generation fleet and increase energy efficiency where cost effective and there is regulatory support for such activities.

3.4.9. Coal Combustion Residuals (CCR) Rule

The EPA's CCR rule regulates the disposal and beneficial re-use of CCR, including fly ash and bottom ash created from coal-fired generating units and FGD gypsum generated at some coal-fired plants. The rule applies to active and inactive CCR landfills and surface impoundments at facilities of active electric utility or independent power producers.

In 2020, the EPA revised the CCR rule to include a requirement that unlined CCR storage ponds cease operations and initiate closure by April 11, 2021. The revised rule provides two options that allow facilities to extend the date by which they must cease receipt of coal ash and close the ponds.

The first option provides an extension to cease receipt of CCR no later than October 15, 2023 for most units, and October 15, 2024 for a narrow subset of units; however, the Federal EPA's grant of such an extension will be based upon a satisfactory demonstration of the need for additional time to develop alternative ash disposal capacity and will be limited to the soonest timeframe technically feasible to cease receipt of CCR.

The second option is a retirement option, which provides a generating facility an extended operating time without developing alternative CCR disposal. Under the retirement option, a generating facility would have until October 17, 2023 to cease operation and to close CCR storage ponds 40 acres or less in size, or through October 17, 2028 for facilities with CCR storage ponds greater than 40 acres in size.

Under both the first and second options, each request must undergo formal review, including public comments, and be approved by the EPA. In late 2020, SWEPCO filed two applications under the second option, committing to cease coal combustion at the Pirkey plant by October 17, 2023 and at the Welsh Plant by October 17, 2028. Those applications remain pending before EPA.

The Company retired the Pirkey plant in March of 2023 and ceased coal combustion as a component of its plan for compliance with the CCR rule. Physical closure of Pirkey's west bottom ash pond was certified in December 2022. The east bottom pond will be closed by October 2023.

At Flint Creek, as of March of 2023 the company has completed the plant modifications required for compliance with the CCR rule and is no longer using water to handle the ash produced by coal combustion. The work to close Flint Creek's ash impoundments is underway and is expected to be completed by in June 2023.

The Turk plant does not use water to transport or store coal combustion byproducts, and there is not subject to CCR compliance investments.

Because SWEPCO currently use surface impoundments and landfills to manage CCR materials at generating facilities, significant costs will be incurred to upgrade or close and replace these existing facilities and conduct any required remedial actions. Closure and post-closure costs have been included in Asset Retirement Obligation (ARO) in accordance with the requirements in the final rule. Additional ARO revisions will occur on a site-by-site basis if groundwater monitoring activities conclude that corrective actions are required to mitigate groundwater impacts, which could include costs to remove ash from some unlined units.

In January 2022, the EPA proposed to deny several extension requests filed by the other utilities based on allegations that those utilities are not in compliance with the CCR Rule (the January Actions). In November 2022, the Federal EPA finalized one of these denials. The Federal EPA's allegations of noncompliance rely on new interpretations of the CCR Rule requirements. The January Actions of the Federal EPA have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit as unlawful rulemaking that revises the existing CCR Rule requirements without proper notice and without opportunity for comment. Management is unable to predict the outcome of that litigation.

3.4.10. Clean Water Act Regulations

The EPA's ELG rule for generating facilities establishes limits for FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater, which are to be implemented through each facility's wastewater discharge permit. In 2020, EPA revised the ELG rule to establish additional options for reusing and discharging small volumes of bottom ash transport water, an exception for retiring units and an extension the compliance deadline to a date as soon as possible beginning one year after the rule was published but no later than December 2025. SWEPCO is in the process of implementing those 2020 ELG Rule requirements. The Company has assessed technology additions and retrofits to comply with the 2020 rule and in January 2021, permit modifications to incorporate the 2020 ELG Rule's requirements were filed for affected facilities. The Pirkey and Welsh Plants opted to comply with the 2020 ELG Rule by committing to cease coal combustion by 2023 and 2028, respectively.

On March 7, 2023, the Federal EPA proposed further revisions to the ELG Rule which, if finalized, would establish a zero-discharge standard for flue gas desulfurization wastewater and bottom ash transport water, and more stringent discharge limits for combustion residual leachate. SWEPCO is evaluating the impacts of the proposed rule to operations at its Flint Creek and Turk plants. The Flint Creek plant does not generate flue gas desulfurization wastewater and already meets the zero discharge requirements proposed for bottom ash transport water but will be subject to the new leachate limits. The Turk Plant will also only be subject to the leachate requirements as it was designed and built with a dry scrubber and dry ash handling systems. SWEPCO is still evaluating how the proposed combustion residual leachate limits will impact these plants.

In January 2023, the EPA finalized a new rule revising the definition of "waters of the United States," which will become effective in March 2023. The new rule expands the scope of the definition, which means that permits may be necessary where none were previously required and issued permits may need to be reopened to impose additional obligations. Management is evaluating what impacts the revised rule will have on operations.

In October 2022, the United States Supreme Court heard an appeal related to the scope of "waters of the United States," specifically which wetlands can be regulated as waters of the United States. Management cannot predict the outcome of that litigation.

In April 2020, the U.S. District Court for the District of Montana issued a decision vacating the U.S. Army Corps of Engineers' ("Corps") General Nationwide Permit 12 ("NWP 12"), which provides standard conditions governing linear utility projects in streams, wetlands and other waters of the United States having minimal adverse environmental impacts. The Court found that in reissuing NWP 12 in 2017, the Corps failed to comply with Section 7 of the Endangered Species Act ("ESA"), which requires the Corps to consult with the U.S. Fish and Wildlife Service regarding potential impacts on endangered species. The Court remanded the permit back to the Corps to complete its ESA consultation, and also enjoined the Corps from authorizing any dredge or fill activities under NWP 12 pending completion of the consultation process. The Department of Justice filed a motion to stay the injunction and tailor the remedy imposed by the Court. In May 2020, the Court revised its order lifting the injunction for non-oil and gas pipeline construction activities and routine maintenance, inspection, and repair activities on existing NWP 12 projects. The Department of Justice appealed the Court's decision to the Court of Appeals for the Ninth Circuit and moved for stay pending appeal, which was denied. In June 2020, the Department of Justice submitted an application to the U.S. Supreme Court requesting a stay of the District Court's Order, and the Court granted the request with respect to all oil and gas pipelines except the Keystone Pipeline. The Company is monitoring the litigation and evaluating other permitting alternatives but is currently unable to predict the impact of future proceedings on current and planned projects.

In September 2020, the Corps issued for public comment the proposed renewal of all General Nationwide Permits. As part of that proposal the Corps narrowed the focus of NWP 12 to only oil and natural gas pipeline activities. The Corps proposed two new Nationwide Permits governing electric utility line and telecommunications activities, and other utility lines (e.g., conveyance of potable water, sewage, other substances), respectively. In January 2021, the Corps issued 16 final Nationwide Permits, including NWP 12 and the two new utility line permits, NWP 57 and NWP 58. The Corps chose not to reissue or modify the remaining Nationwide Permits at this time. The 2017 versions of those permits remain in effect. Management is currently assessing impacts of the rulemaking on current and planned projects.

3.5. Capacity Needs Assessment

As a member of SPP, SWEPCO (together with PSO) and other member utilities have an obligation to maintain a minimum level of generating capacity under SPP's Resource Adequacy construct. If a utility falls short of these obligations, SPP may assess expensive penalties. The current *minimum* SPP Planning Reserve Margin (PRM) beginning on June 1,2023 requires a reserve capacity of 15% above SWEPCO's coincident summer peak load. This was increased from the prior 12% summer requirement in 2022.

There are currently numerous initiatives under consideration at SPP which could increase these requirements. These include potential further increases to the current summer PRM requirement, the addition of a winter seasonal requirement in response to recent extreme winter events, and Performance-Based Accreditation (PBA) methodology for thermal resources.

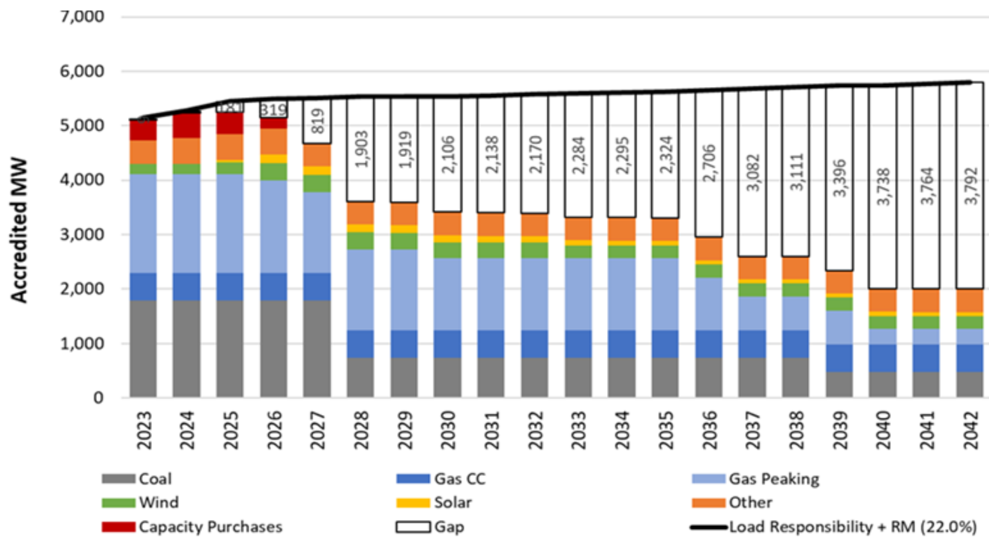
For this IRP, the Company planned to an SPP PRM of 22%. The PRM provides an appropriate confidence level for SWEPCO to comply with SPP's 15% PRM given increasingly stringent and still evolving SPP resource adequacy requirements, as well as further scrutiny at the state regulatory commissions following the aftermath of Winter Storm Uri.

Figure 15 illustrates the starting capacity needs of SWEPCO through 2042. As of March 2023, the Company has obtained what it projects to be sufficient resources to meet SPP's minimum 15% summer PRM requirement for the capacity years beginning June 1, 2023, and June 1, 2024. Beginning with the delivery year which starts on June 1, 2025, additional capacity will be required due to planned retirement of aging existing units. This includes the currently planned retirements of Arsenal Hill unit 5 in December 2025 and Lieberman gas-steam units 3 & 4 in December 2026. The needs further widen in 2028 when SWEPCO's Welsh 1 & 3 units cease burning coal and are removed from the going-in resource assumptions along with planned retirement of the Wilkes 1 gas-steam unit in 2030.[5]

Note also that SWEPCO utilizes several Power Purchase Agreements ("PPA") to meet the minimum SPP reserve margin requirement and customers' energy needs. The first PPA, expiring at the end of 2028, is a 79.5 MW contract with NextEra Energy Resources LLC from the Majestic Wind Farm located in Carson County, Texas. Additional agreements expire in 2032 and constitute a 79.6 MW contract with the High Majestic II wind plant in Texas, a 201 MW contract with the Canadian Hills wind plant in Oklahoma and a 108.8 MW contract with the Flat Ridge 2 wind plant in Kansas. Also included as part of the Going-In assumptions, are the planned resource additions of the Diversion Wind project planned in 2025 (201MW), Wagon Wheel Wind Project planned in 2026 (598MW) and the Mooringsport Solar project planned in 2026 (200MW) along with the Rocking R Solar PPA project planned in 2025 (73MW).

[5] While the Going-In assumptions in this IRP include the removal of the aforementioned units at Arsenal Hill, Lieberman, Welsh and Wilkes, the Company may re-evaluate these assumptions as the Company obtains more clarity in the availability and timing of new resources, impacts of any new environmental regulations, and SPP resource adequacy requirements evolve.

Figure 15 SWEPCO "Going-In" SPP Capacity Position and Obligation



Additionally, SWEPCO considered winter seasonal requirements as part of the 2023 IRP. One scenario, Focus on Resiliency (discussed in Section 7), enforces a 26% PRM in winter and changes to the resource accredited capacity of different technologies. This winter PRM was informed by an April 2022 SPP Supply Adequacy Working Group (SAWG) study[6]. Seasonal capacity needs are filled by supply- and demand-side resources using the AURORA model. DSM resource options are discussed in Section 6 and new utility-scale resources are covered in Section 5.

6 https://www.spp.org/Documents/66966/sawg%20agenda%20and%20background%20materials%2020220422%20(2).zip , 06a_WWE RPA 2.6 Preliminary Winter LOLE Study and Generation Sensitivity Results.pdf

4. Transmission and Distribution Evaluation

4.1. Transmission System Overview

The portion of the AEP Transmission System operating in SPP (AEP-SPP zone, or AEP-SPP) consists of approximately 1,500 miles of 345 kV, approximately 3,750 miles of 138 kV, approximately 2,300 miles of 69 kV, and approximately 390 miles at other voltages above 100 kV. The AEP-SPP zone is also integrated with and directly connected to thirteen other companies at over 90 interconnection points, of which over 70 are at or above 69 kV and to Electric Reliability Council of Texas (ERCOT) via two high voltage direct current (HVDC) ties. These interconnections provide an electric pathway to provide access to off-system resources, as well as a delivery mechanism to neighboring systems.

4.2. Current AEP-SPP Transmission System Issues

The limited capacity of interconnections between SPP and neighboring systems, as well as the electrical topology of the SPP footprint transmission system, influences the ability to deliver non-affiliate generation, both within and external to the SPP footprint, to AEP-SPP loads and from sources within AEP-SPP balancing authority to serve AEP-SPP loads. Moreover, a lack of seams agreements between SPP and its neighbors has significantly slowed down the process of developing new interconnections. Despite the robust nature of the AEP-SPP transmission system as originally designed, its current use is in a different manner than originally designed, in order to meet SPP requirements, which can stress the system. In addition, factors such as outages, extreme weather, and power transfers also stress the system. This has resulted in a transmission system in the AEP-SPP zone that is sometimes constrained when generation is dispatched in a manner substantially different from the original design of utilizing local generation to serve local load. However, since becoming an RTO in 2004, many bulk transmission upgrades within SPP have greatly improved SPP's ability to dispatch generation in a more economic and flexible manner while maintaining reliability, and more such upgrades continue each year.

SPP has made efforts to solve seams issues, and SPP and MISO have engaged in a coordinated study process to identify transmission improvement projects which are mutually beneficial. Projects deemed beneficial by both RTOs will be pursued with joint funding, but no such projects have yet been deemed beneficial by both RTOs.

Additional background on SPP's Interregional Relations, including the Regional Review Methodology and SPP's Joint Operating Agreements with MISO and AECI may be found at: http://www.spp.org/engineering/interregional-relations/

4.3. The SPP Transmission Planning Process

Currently, SPP produces an annual SPP Transmission Expansion Plan ("STEP"). The STEP is a comprehensive listing of all transmission projects in SPP for the 20-year planning horizon. The STEP is developed through an open stakeholder process with AEP participation. SPP studies the transmission system, checking for base case and contingency overload and voltage violations in SPP base case load flow models, plus models which include power transfers.

The 2023 STEP summarizes 2022 activities, including expansion planning and long-term SPP Open Access Transmission Tariff ("OATT") studies ("Tariff Studies") that impact future development of the SPP transmission grid. Key topics included in the STEP are:

1. Transmission Services
2. Generator Interconnection
3. Requests pursuant to Attachment AQ
4. Integrated Transmission Planning (ITP)
5. Balanced Portfolio

6. High Priority Studies
7. Sponsored Upgrades
8. Interregional Coordination
9. Integrated Transmission Planning 20-Year Assessment, and
10. Generation Retirement

These topics are critical to meeting mandates of either the SPP strategic plan or the nine planning principles in FERC Order 890. As an RTO under the domain of the FERC, SPP must meet FERC requirements and the SPP OATT, or Tariff. The SPP RTO acts independently of any single market participant or class of participants. It has sufficient scope and configuration to maintain electric reliability, effectively perform its functions, and support efficient and non-discriminatory power markets. Regarding short-term reliability, the SPP RTO has the capability and exclusive authority to receive, confirm, and implement all interchange schedules. It also has operational authority for all transmission facilities under its control. The 10-year RTO regional reliability assessment continues to be a primary focus.

STEP projects are categorized by the following designations:

- Generation Interconnect – Projects associated with a FERC-filed Interconnection Agreement
- High Priority – Projects identified in the high priority process
- Interregional – Projects identified in SPP's joint planning and coordination processes
- ITP – Projects needed to meet regional reliability, economic, or policy needs in the ITP study process
- Transmission service – Projects associated with a FERC-filed Service Agreement
- Zonal Reliability – Projects identified to meet more stringent local Transmission Owner criteria
- Zonal-Sponsored – Projects sponsored by facility owner with no Project Sponsor Agreement.

The 2023 STEP[7] identified 343 transmission network upgrades with a total cost of approximately $3.28 billion. At the heart of SPP's STEP process is its ITP process, which represented approximately 71% of the total cost in the 2023 STEP. The ITP process was designed to maintain reliability and provide economic benefits to the SPP region in both the near and long-term. The ITP resulted in a recommended portfolio of transmission projects for comprehensive regional solutions, local reliability upgrades, and the expected reliability and economic needs of a 10-year horizon. Upgrades that require a financial commitment within the next four years receive Notification to Construct ("NTC") letters issued by SPP

4.4. Recent AEP-SPP Bulk Transmission Improvements

Currently the capability of the transmission system to accommodate large incremental firm imports to the AEP-SPP area is limited. Generally, the transfers are limited by the facilities of neighboring systems rather than by transmission lines or equipment owned by AEP.

4.4.1. AEP-SPP Import Capability

Increasing the import capabilities with AEP-SPP's neighboring companies could require a large capital investment for new transmission facilities by the neighboring systems or through

[7] The 2023 STEP is available at:
https://www.spp.org/Documents/56611/2023%20SPP%20Transmission%20Expansion%20Plan%20Report.pdf

sponsored upgrades by SPP transmission owners. An analysis of the cost of the upgrades cannot be performed until the capacity resources are determined. For identified resources, the cost of any transmission upgrades necessary on AEP's transmission system can be estimated by AEP once SPP has identified the upgrade. AEP's West Transmission Planning group can identify constraints on third-party systems through ad hoc power flow modeling studies, but West Transmission Planning does not have information to provide estimates of the costs to alleviate those third-party constraints.

4.4.2. SPP Studies that may Provide Import Capability

Some projects that may lead to improved transfer capability between AEP-SPP and neighboring companies include:

- Chisholm – Woodward/Border tie 345 kV line. This project will increase bulk transfer capability from west to east across the west Texas/Oklahoma area.
- Sooner to Wekiwa 345 kV line build. This project was a FERC 1000 competitive transmission project awarded to Transource, a partnership between AEP and Evergy. and relieves congestion west of the Tulsa area for the outage of the Cleveland to Tulsa North 345 kV line. This project will relieve bottlenecks on the electric grid, improve reliability and open access to low-cost electricity. SPP estimates that customers in Oklahoma and parts of Arkansas, Missouri, Texas, and Louisiana will save millions of dollars in coming years because of this project, which is projected to provide $16.8 million in congestion savings during the first year and $465.6 million over the next forty years. Extra-high voltage projects, like Sooner-Wekiwa, were approved to enable the delivery of low-cost renewable resources, while reducing price separation in the SPP marketplace that is driven by congestion on the transmission grid.
- South Shreveport – Wallace Lake 138 kV line rebuild. This project will improve reliability in the Shreveport / Bossier City area and will strengthen the transmission system between SPP and the Cleco area of MISO.

4.4.3. Recent AEP-SPP Bulk Transmission Improvements

Over the past several years, there have been several major transmission enhancements initiated to reinforce the AEP-SPP transmission system. These enhancements include:

- **Northwest Arkansas**: The Siloam Springs (GRDA)-Siloam Springs (SWEPCO) 161 kV line has been upgraded to a larger conductor with improved thermal capacity. Another ITP project is expected to further upgrade terminal equipment on this line. These upgrades relieve constraints for west to east flow and improve reliability.
- **Tulsa Metro, Oklahoma area:** The Tulsa area upgrades include Tulsa Southeast to E. 61st St, 138 kV line, Riverside Station Upgrade, Tulsa Southeast to S. Hudson 138 kV line, Tulsa Southeast to 21st Street Tap 138 kV line. These projects improve the capacity in the area with larger conductor and new breakers for the Riverside station.

These major enhancements are in addition to several completed or initiated upgrades to 138 kV and 69 kV transmission lines to reinforce the AEP-SPP transmission system.

4.5. SWEPCO Distribution System Overview

SWEPCO serves approximately 550,000 customers across 20,701 square miles of Arkansas, Louisiana, and Texas. This includes approximately 466,100 residential, 74,300 commercial, 6,800 industrial, and 600 "other" customers. SWEPCO's Distribution Operations organization includes five districts: Longview, Fayetteville, Texarkana, Shreveport, and Valley. SWEPCO's distribution system includes approximately 21,717 overhead circuit miles and approximately 3,580 underground circuit miles. SWEPCO's distribution system includes approximately 19,999 primary miles and 5,297 secondary miles.

4.5.1. Distribution Investments

SWEPCO's Distribution Operations organization includes five functional support departments: Engineering, Region Operations, Vegetation Management, Distribution Systems and Continuous Improvement. These departments are responsible for distribution system engineering and design activities, resource planning and contracting activities, vegetation management, construction and maintenance, and the operation of the distribution electrical system for the entire SWEPCO service territory.

In SWEPCO's most recent rate case filings, SWEPCO has proposed a significant investment to revitalize and transform its distribution grid. Successful implementation of the proposed plan would require approximately $301.96M in capital investment in SWEPCO's distribution grid over the next five years.

Table 3 provides an overview of this plan.

Table 3 SWEPCO Grid Transformation and Infrastructure Program

Project Type	Estimated Spend (Millions $)
Capacity Assurance	92.79
Grid Modernization	39.91
Reliability Enhancements	62.43
Asset Renewal	106.83
Total	301.96

The Company is also pursuing the development of a Community Solar project with storage. At this time, the project is still under development although it is anticipated to be brought online in 2023. The Company looks forward to the addition and the opportunity to learn how the operation will impact the Company's peak load.

5. Supply-Side Resource Options

5.1. Introduction

The future landscape of generation technologies has become increasingly uncertain. The roles of traditional technologies in providing baseload and intermediate-load electricity are being challenged by zero marginal cost renewable technologies. The emergence of advanced generation technologies could significantly change the future economics of generation rendering certain technologies obsolete leading to a risk of premature retirements. The evolving electricity generation mix may also require a more diverse set of resources that can provide different system needs at different times to maintain system reliability particularly under extreme weather conditions.

The supply-side resource options considered by SWEPCO in this IRP fall into six categories: base / intermediate alternatives, peaking alternatives, renewable alternatives, advanced generation alternatives, long-duration storage alternatives, and short-term market purchases.

Unless stated otherwise, SWEPCO relied on EIA's 2022 AEO as the starting point for the technology cost and performance assumptions for new utility scale generation in the SPP footprint. Reference case changes to technology cost and performance over time are based on the medium case of the 2022 National Renewable Energy Laboratory's ("NREL") annual technology baseline ("NREL ATB 2022") report.[8] Cost assumptions for advanced technologies are generally based on a compilation of estimates from different external sources, reflecting uncertainties associated with cost estimates for technologies under development. Capital Costs shown are in nominal dollars starting from a base year of 2021, reflecting the Producers Price Index for Energy (PPI).

All new resources also included an assumption for additional transmission network and interconnection upgrade costs. For this IRP, a proxy cost of $20/kW was included in the cost of thermal resources. Wind resources included a capital cost of $90/kW and solar resources included a capital cost of $115/kW.

5.2. Base / Intermediate Alternatives

Baseload electricity is the minimum level of electricity demand in the system. Traditionally, baseload electricity demand is met by baseload power plants optimized for continuous running. Baseload plants include coal and nuclear plants which generally cannot vary their outputs quickly. However, the electricity supply mix is changing with increased intermittent renewable generation. Furthermore, regulations and changing customers' needs have made new coal and nuclear plants economically infeasible. As such, coal without carbon capture and storage and traditional nuclear are not part of supply-side resource options in this IRP.

Intermediate power plants adjust outputs as electricity demand fluctuates. This role has been traditionally met by older and relatively less efficient power plants. But as these power plants retire, new capacity will be needed. For this IRP, natural gas combined cycle is considered as a resource option for intermediate power plants.

5.2.1. Natural Gas Combined Cycle (NGCC)

Natural gas combined cycle units combine a steam and a gas turbine cycle to generate electricity. In the gas turbine cycle, atmospheric air is pressurized using a compressor, injected with fuel and ignited to generate high-temperature pressurized gas that expands to drive the turbine and generate electricity. The waste heat from the gas turbine is then used to generate steam to drive a steam turbine to generate additional electricity, increasing generation efficiency.

[8] NREL Electricity Annual Technology Baseline (ATB)

Modern NGCCs have moderate capital costs, high generating efficiency, relatively low carbon emissions (per MWh) compared to older fossil fuel units, and the ability to load follow. These characteristics make the technology desirable for baseload and intermediate applications.

NGCCs are modeled in AURORA as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. Two NGCC configurations in the model are available for selection, including the H-class turbine single shaft configuration with 418 MW capacity and the H-class turbine multi-shaft configuration with 1,100 MW capacity. These resources are made available in the model with a first operating year of 2031, reflective of the anticipated period required for SPP interconnection request approvals, regulatory approvals, permitting siting, engineering, and construction.

Overnight capital cost assumptions for NGCC options are shown Figure 16. The first operating year variable operations and maintenance cost ("VOM"), the fixed operations and maintenance cost ("FOM") and heat rate assumptions are shown in Table 4.

Figure 16 Capital Cost Assumptions for NGCC

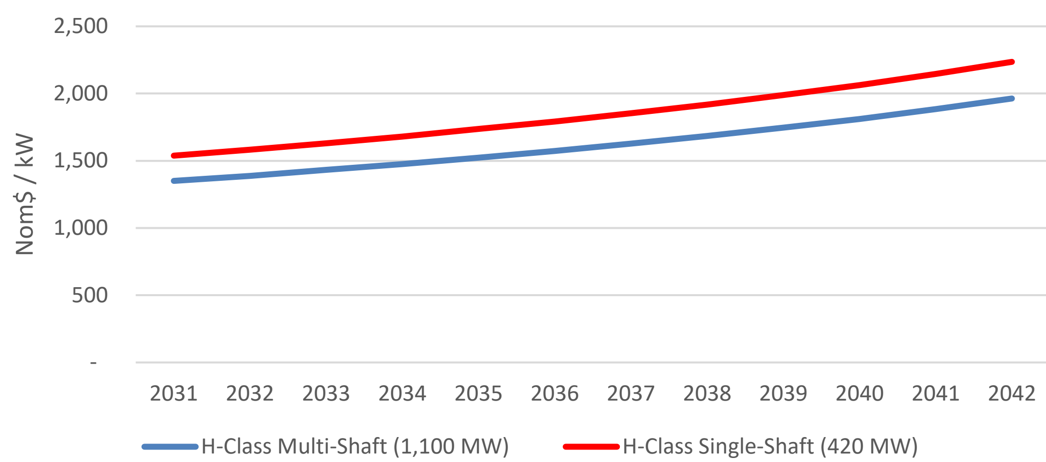


Table 4 Operating Cost and Heat Rate Assumptions for NGCC

		H-Class Multi-Shaft (1,100 MW)	H-Class Single Shaft (420 MW)
VOM	$ / MWh	2.41	3.29
FOM	$ / kW-yr	15.72	18.17
Heat Rate	Btu / kWh	6,370	6,431

5.3. Peaking Alternatives

Peaking sources have traditionally provided top-up generating capacity during demand peaks that typically occur a few hours each year. Given the low utilization of peaking generators, focus in the past has been on minimizing capital and fixed costs instead of fuel efficiency and other variable costs. In this IRP, four peaking sources considered are simple cycle combustion turbines, aeroderivatives, reciprocating engines, and lithium-ion batteries.

5.3.1. Simple Cycle Combustion Turbines (NGCT)

A combustion turbine system uses a compressor to pressurize atmospheric air, which is injected with fuel and ignited to generate high-temperature pressurized gas that expands to drive the turbine and generate electricity. Unlike NGCCs, unused energy is released as exhaust gases into the atmosphere instead of being recovered. NGCTs are usually expected to start up once a day and operate at full capacity during peak demand hours in the day, making them well suited for a power system with predictable peak patterns.

In addition, turbine manufacturers are developing the ability of new gas turbines to burn increasing volumes of hydrogen in the gas stream. Recent turbines can burn up to 30% hydrogen by volume[9] in the gas stream and can potentially be retrofitted to burn 100% hydrogen when the hydrogen supply chain is sufficiently developed. Section 5.5.3 provides further detailed on the modeling assumptions associated with retrofitting NGCT units to burn hydrogen exclusively.

NGCTs are modeled in AURORA as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. One NGCT configuration is available for AURORA to select, i.e. the 240 MW F-Class unit. These resources are made available in the model with a first operating year of 2031, reflective of the anticipated period required for SPP interconnection request approvals, regulatory approvals, permitting, siting, engineering, and construction. The maximum annual capacity addition is 480 MW.

The NGCT overnight capital cost assumptions are shown in Figure 17. The first operating year FOM, VOM, and heat rate assumptions are shown in

Table 5.

Figure 17 Capital Cost Assumptions for NGCT

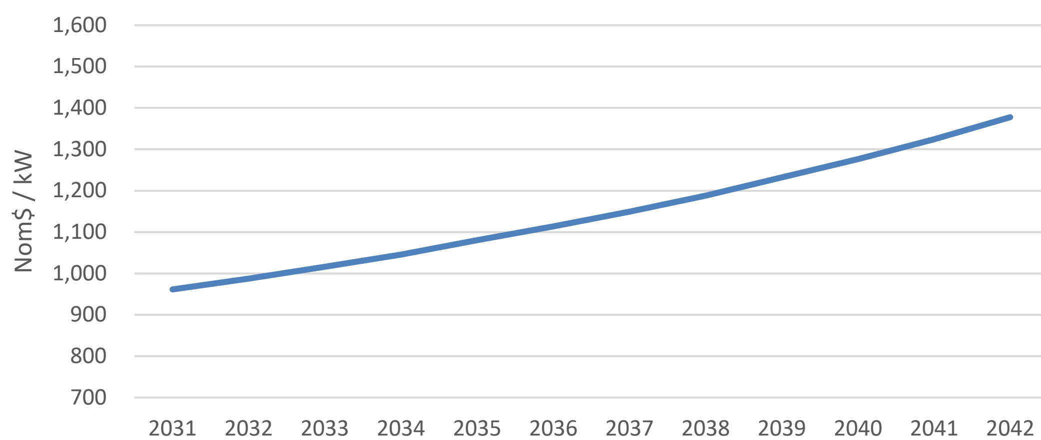


Table 5 Operating and Heat Rate Assumptions for NGCT

		F-Class CT (240 MW)
VOM	$ / MWh	5.80
FOM	$ / kW-yr	9.02
Heat Rate	Btu / kWh	9,905

5.3.2. Aeroderivatives (AD)

Aeroderivative units are aircraft jet engines used for power generation. Their operating characteristics make them well suited for high renewable penetration as they can quickly respond to significant shifts in supply and demand conditions in the power system. For example, the GE 9E series NGCT requires 30 minutes to start up whereas the GE LM6000 AD unit requires only 5 minutes. This allows AD units to operate at full load even for a small amount of

[9] Gas turbines in the US are being prepped for a hydrogen-fueled future (2021). Retrieved from https://www.nsenergybusiness.com/features/gas-turbines-hydrogen-us/

time. In addition, AD units are more efficient in a simple cycle operation than NGCTs for capacity less than 100 MW. However, AD units are relatively more expensive than NGCTs.

AD units are modeled in AURORA in 105 MW units as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. These resources are made available in the model with a first operating year of 2031, reflective of the anticipated period required for approval, siting, engineering, and construction. The maximum annual capacity addition is 210 MW.

The AD overnight capital cost assumptions are shown in Figure 18. The first operating year FOM, VOM, and heat rate assumptions are shown in Table 6.

Figure 18 Capital Cost Assumptions for AD

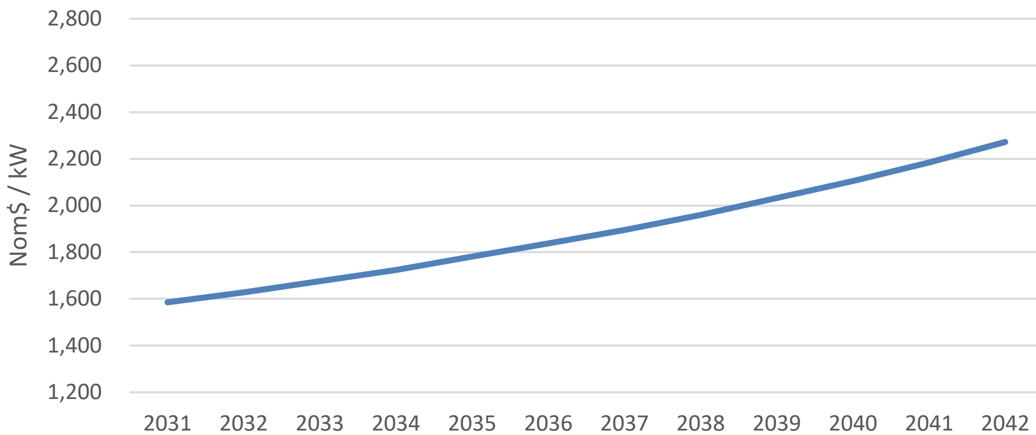


Table 6 Operating and Heat Rate Assumptions for AD

		AD (100 MW)
VOM	$ / MWh	6.06
FOM	$ / kW-yr	21.00
Heat Rate	Btu / kWh	9,124

5.3.3. Reciprocating Engines (RE)

Like NGCTs, REs rely on the combustion of air mixed with fuel to generate hot pressurized gases. Unlike NGCT, the expansion of these gases creates pressure which is used to drive a rotating motion to generate electricity. Multiple RE units are usually incorporated into a larger generating set for main grid applications.

RE generating sets can usually start and reach full load in less than five minutes, making them even faster than AD units in responding to system needs. RE generating sets can also run more efficiently at partial load as individual RE units within the generating set can be shut down to reduce output while allowing remaining units to run at full load. Unlike NGCTs or ADs, RE units can be started multiple times in a day without incurring substantial additional maintenance costs. These characteristics make RE units well suited for power systems that require frequent but short-duration dispatches.

REs are modeled in AURORA in 21 MW units as a standard dispatch resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. These resources are made available in the model with a first operating year of 2031, reflective of the anticipated period required for approval, siting, engineering, and construction.

The RE overnight capital cost assumptions are shown in Figure 19.The first operating year FOM, VOM, and heat rate assumptions are shown in Table 7.

Figure 19 Capital Cost Assumptions for RE

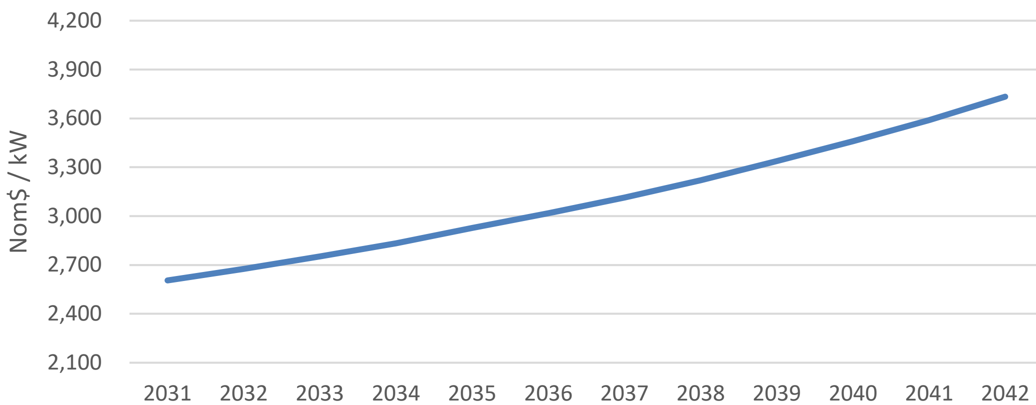


Table 7 Operating and Heat Rate Assumptions for RE

		RE (20 MW)
VOM	$ / MWh	7.34
FOM	$ / kW-yr	45.31
Heat Rate	Btu / kWh	8,295

5.3.4. Lithium-Ion Battery (Li-ion)

Li-ion batteries store and discharge energy through the movement of lithium ions between a negative and positive electrode, separated by an electrolyte. Unlike other peaking technologies considered, Li-ion batteries do not provide additional energy. Instead, they provide additional capacity during periods of peak energy demand through discharging of energy stored generally during periods of low energy demand. Accordingly, increased deployment of Li-ion in the system can smooth out energy price volatility.

Li-ion batteries are experiencing rapid growth in deployment in utility-scale storage applications. This reflects advantageous operating characteristics that include high round-trip efficiency, high energy density, and lower self-discharge. The batteries can also respond to systems within a second, making them well suited for primary frequency regulations, i.e., providing initial immediate response to deviations in grid frequency driven by sudden demand spikes or supply losses. However, Li-ion batteries have limited cycle life due to degradation; battery augmentation is required during the project lifetime to maintain performance.

Li-ion batteries are first made available in AURORA from 2026 and are modeled as an energy storage option with a duration of four hours. AURORA optimizes charging and discharging of the resource against projected SPP hourly electricity prices, taking into account a round-trip efficiency of 85%, a self-discharge rate of 0.2% per day. As a duration-limited resource, the ability of Li-ion batteries to meet demand peaks will decline as greater amounts of renewable generation widen the length of demand peaks. Therefore, the capacity credit for Li-ion batteries is assumed to decline from 100% today to 25-54% by 2042, depending on the scenario (see section 7.3). Li-ion batteries are made available in a configuration of 50 MW. The maximum annual capacity addition is 200 MW and the cumulative maximum is 3000 MW.

The overnight capital cost assumptions for Li-ion batteries are shown in Figure 20. Investment Tax Credit ("ITC") value is assigned to the project by applying a reduction in modeled upfront capital cost at a rate of 30% for projects entering service before the end of 2032. After 2032, ITC tax credits reduce to 22.5%, 15% and 0% of their value in 2033, 2034, and 2035, respectively.[10]

Figure 21 shows the assumed FOM for a Li-ion battery built in each specific year.

Figure 20 Capital Cost Assumptions for Li-Ion

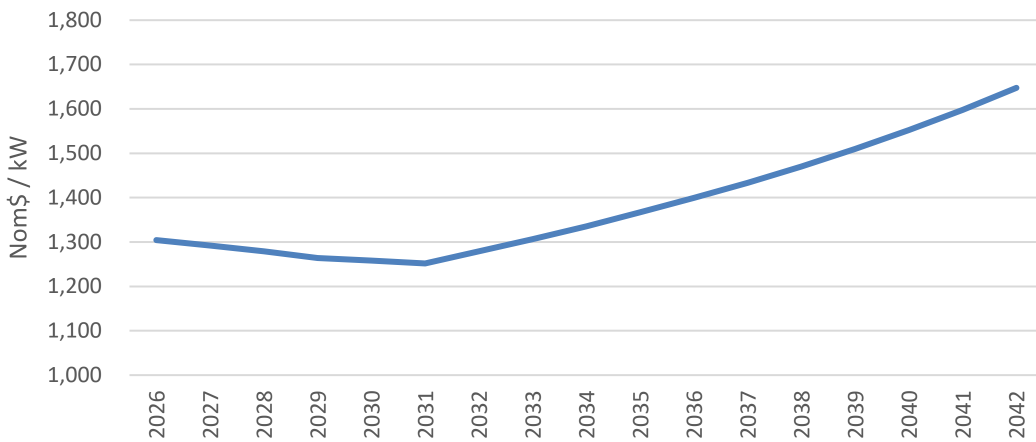
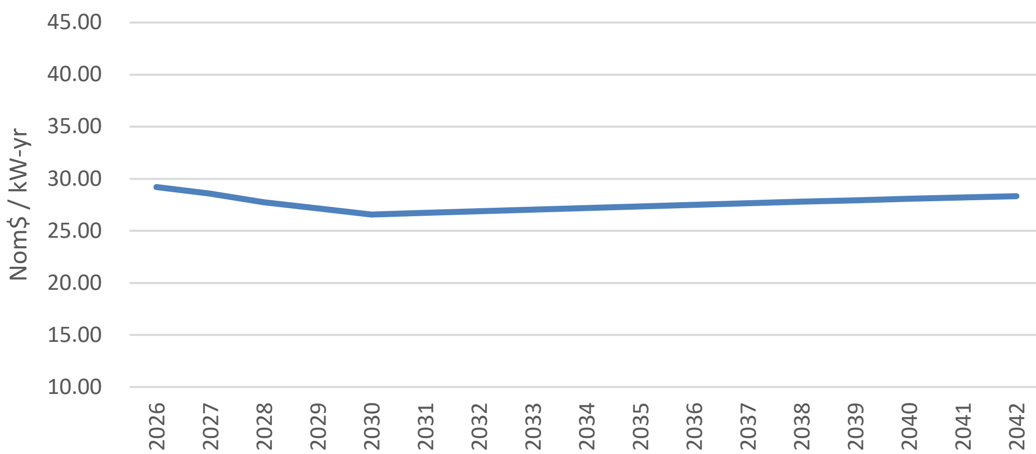


Figure 21 FOM Assumptions for Li-Ion



5.4. Renewable Alternatives

Renewable generation alternatives provide an opportunity to deliver affordable clean energy to address future electricity needs, consistent with SWEPCO's aim of enabling a greener future for all when cost effective. These renewable technologies can provide a hedge against future uncertainties in fuel prices, carbon policies, and technology risks as they have zero carbon emissions and zero marginal costs and as such, they are more likely to remain competitive against other technologies as fuel prices fluctuate and new generation technologies become available, minimizing pricing and stranded cost risk to customers.

In this IRP, two renewable alternatives considered are onshore wind and utility-scale solar photovoltaic. These two technologies are made available as resource options in AURORA. In

[10] For portfolio modeling, a safe harbor provision is assumed which provides a three-year delay in the effects of declining tax credits as long as adequate construction has commenced for new resources.

addition, AURORA can also choose to pair utility-scale solar photovoltaic with lithium-ion battery where a paired solution is economic.

5.4.1. Wind

Wind energy is based on exploiting the air pressure differential across two sides of the blade, causing the rotor blade to spin and generate electricity.

Wind is first made available as a resource option in AURORA in2026. It is modeled as a generation resource dispatching according to a generic production profile representative of the region with an average capacity factor of 45%. The capacity credit for wind is evaluated based on its Effective Load Carrying Capability (ELCC), consistent with SPP's methodology used for accrediting the capacity credit for wind resources. Based on SWEPCO's analysis of wind ELCC, wind resources are credited with 15.4% capacity value in the IRP analyses. This capacity credit is discussed further in Section 7.3.3. Both the hourly production profile and average capacity factor are estimated based on recent market data obtained by AEP through the 2021-22 RFP process and are assumed to be a reasonable representation of the production and performance characteristics of a typical new wind resource in the region.

Wind resources are made available in a configuration of 100 MW. Two pricing tiers, Tier 1 and Tier 2, were modeled to reflect the range of potential pricing for wind resources in the marketplace. Because wind generation resources tend to be located electrically further from load centers, a congestion and loss cost adder were also included. The maximum annual capacity addition is assumed to be 400 MW for lower cost Tier 1 sites and 1,600 MW for Tier 2 sites. The assumed cumulative maximum is 4,400 MW.

The cost reduction projection from NREL ATB 2022 is applied to the capital cost to project the capital costs through the study period and beyond, as shown in Figure 22 below.

Figure 22 Capital Cost Assumptions for Onshore Wind

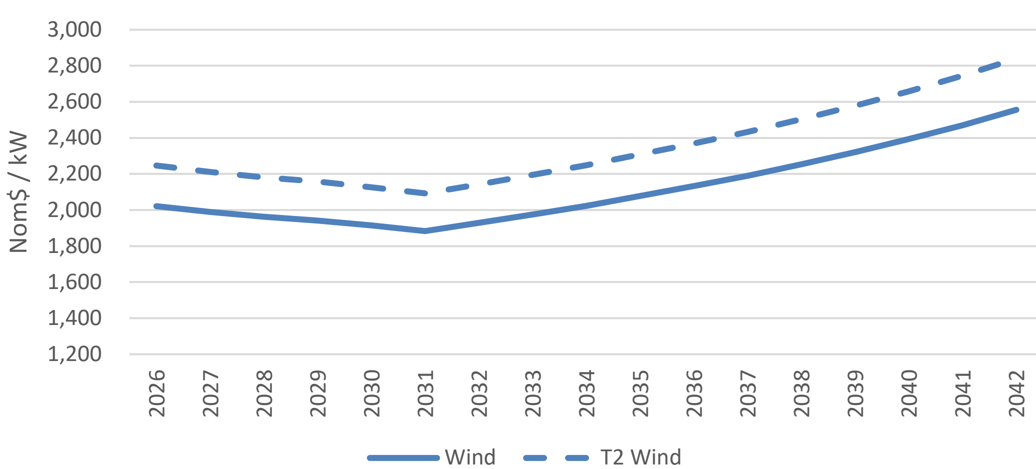
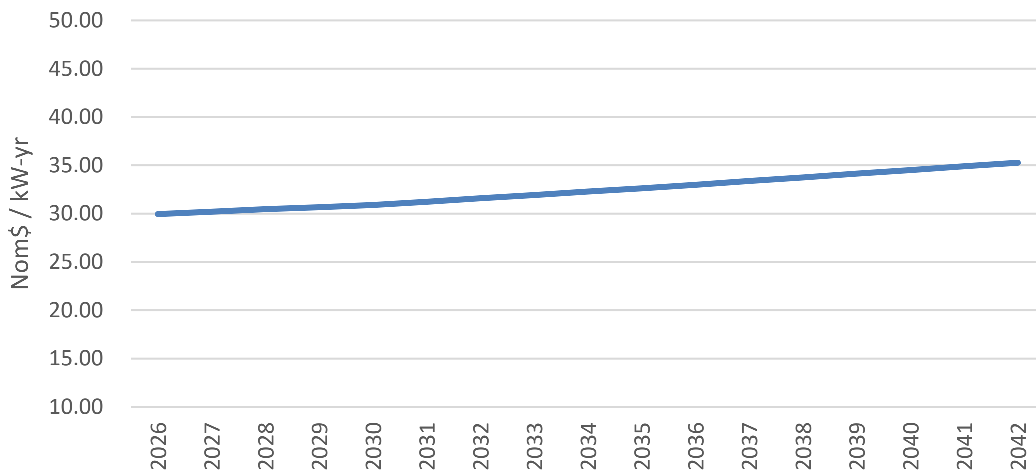


Figure 23 illustrates the FOM cost assumptions for onshore wind.

Figure 23 FOM Assumptions for Onshore Wind



Pursuant to the Inflation Reduction Act (IRA) of 2022, projects whose construction begins by the end of 2032 are eligible for a Production Tax Credit ("PTC"), added to the project value at a rate of 100% of the PTC, or \$25/MWh[11], which is implemented in AURORA as a negative variable cost adder. After 2032, PTC tax credits were assumed to be reduced to 75%, 50% and 0% of their value in 2033, 2034, and 2035, respectively.[12]

5.4.2. Solar

Solar photovoltaic ("solar PV") uses semiconductor materials surrounded by protective layers to convert sunlight into electricity. The system has a modular structure which allows it to be scaled to meet different levels of energy needs, large or small.

Utility-scale solar PV is first made available as a resource option in AURORA from 2026. Like wind, solar generation is modeled as a must-run resource with a generic hourly production profile representative of the region with a capacity factor of around 25%. Solar capacity credit for summer is estimated at a percentage of ICAP. This capacity credit is discussed further in section 7.3.3. The percentage credit is modeled at 60% in 2026 and then declines to 15% by 2042, depending on the scenario (see Section 7.4.2). The hourly production profile and average capacity factor are based on production estimates for solar resources within SPP. Solar is made available in a configuration of 50 MW. The maximum annual capacity addition is 150 MW for lower cost Tier 1 sites and 450 MW for Tier 2 sites. Similar to wind resources, a congestion and loss adder was also included. The cumulative maximum is 4,500 MW.

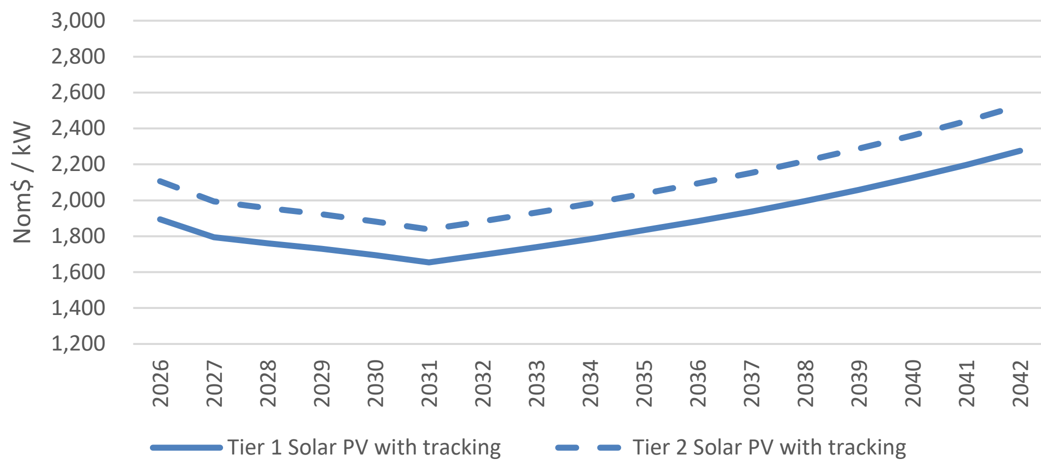
Hybrid 3:1 solar+storage systems are available in 200 MW blocks, up to 400 MW annually, up to a cumulative maximum of 2,000 MW.

The overnight capital cost assumptions for solar PV are shown in Figure 24.

[11] In 2021 dollars; 10 year tax credit; PTC eligibility declines to zero for projects in service for 2035 and beyond. There is potential for several years extension through safe harbor provisions.

[12] For portfolio modeling, a safe harbor provision is assumed which provides a three-year delay in the effects of declining tax credits as long as adequate construction has commenced for new resources.

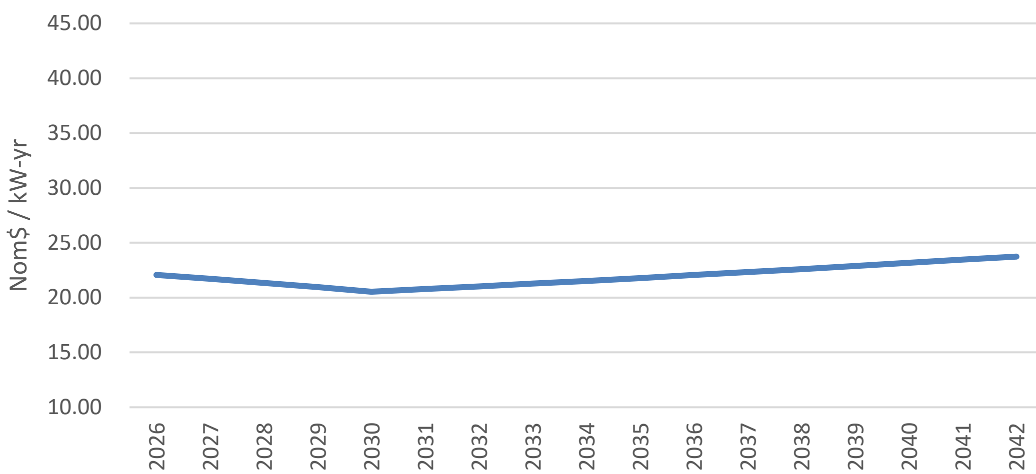
Figure 24 Capital Cost Assumptions for Utility-Scale Solar PV



As with wind resources, under the terms of the IRA, solar projects whose construction begins by the end of 2032 are eligible for a Production Tax Credit ("PTC"), added to the project value at a rate of 100% of the PTC. Solar PTCs were modeled similarly to the wind resource option described is the previous section.

Figure 25 shows the FOM cost assumptions for solar PV.

Figure 25 FOM Assumptions for Utility-Scale Solar PV



5.5. Advanced Generation Alternatives

Advanced generation technologies are low-carbon technologies that are still in the development stage but could be commercially available during the planning horizon of this IRP. When they are available, they could potentially render specific generation technologies obsolete leading to their premature retirement. Including advanced generation technologies in this IRP allows SWEPCO to consider the impact of future technology uncertainties on the Company's generation portfolio and identify technologies that are available today but might be at risk of obsolescence. This informs the selection of the preferred plan that minimizes technology risks and allows SWEPCO to continue to deliver reliable and affordable power to customers.

Based on a survey of literature on generation technologies, three advanced generating technologies are potentially available within the planning horizon of this IRP, namely small modular reactor (“SMR”), carbon capture and storage (“CCS”), and hydrogen.

5.5.1. Small Modular Reactor (SMR)

Small Modular Reactor (SMR) is a new generation of nuclear fission technology utilizing smaller reactor designs, module factory fabrication, and passive safety features. Key features of an SMR include:

- Small physical footprints;
- Limited on-site preparation, leading to faster construction time and scalability;
- Siting flexibility including sites previously occupied by coal-fired plants; and
- Passive safety features, allowing the reactor to safely shutdown in an emergency without requiring human interventions.

SMNR can be a zero-carbon alternative for providing base-load electricity without CO_2 emissions. Its siting flexibility and improved safety features allow it to be sited closer to demand centers, reducing transmission investments. However, it is subject to the same economic challenges facing base-load power plants today, namely the erosion in value of base-load electricity as a result of increased intermittent generation.

SMNR is still in the early stages of development and there remain uncertainties over the cost, performance, and availability of the technology. The cost assumptions for the First-of-a-Kind (“FOAK”) are taken from the EIA AEO 2022. The Nth-of-a-Kind (“NOAK”) cost assumptions in this IRP is based on projecting the FOAK cost forward using a learning rate from a Department of Energy (“DOE”) study on the learning rate for SMR[13]. The DOE study provides a learning rate as cost reduction per each doubling of installed capacity. As such, it is further assumed for the purpose of projecting SMR cost reduction that the first SMR unit with FOAK cost assumptions will be built in 2028 and subsequently one new SMR plant will be built each year in the first five years, two new SMR plants for the next five years, and four new SMR plants for the five years after that. It is assumed that SMR will not be available for commercial deployment until 2035 in a block size of 600MW. Figure 26 below shows the assumed overnight capital cost of SMR cost over time. The first operating year FOM, VOM assumptions are shown in Table 8.

13 Department of Energy (2013), Small Modular Nuclear Reactors: Parametric Modeling of Integrated Reactor Vessel Manufacturing Within a Factory Environment Volume 2, p. 59

Figure 26 Capital Cost Assumptions for SMR

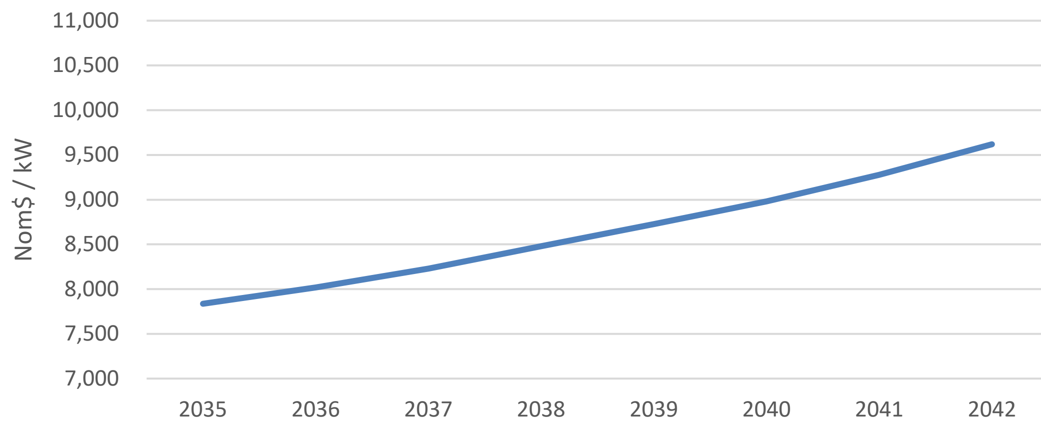


Table 8 Operating and Heat Rate Assumptions for SMR

		SMR
VOM	$/ MWh	4.16
FOM	$ / kW-yr	131.90
Heat Rate	Btu / kWh	10,443

5.5.2. Carbon Capture and Storage Technologies (CCS)

CCS technology provides another alternative for producing reliable low-carbon baseload electricity. Carbon dioxide (“CO_2”) in the flue gas from the combustion of fossil fuels is captured by amine-based solvent in the absorption column and then released from the solvent in a concentrated form in a stripper column. The process requires a significant amount of steam to break the bond between the CO_2 and the solvent, and auxiliary power to run the compressor and other mechanical equipment. As such, CCS-equipped power plants have heat rate and capacity penalties relative to power plants without CCS.

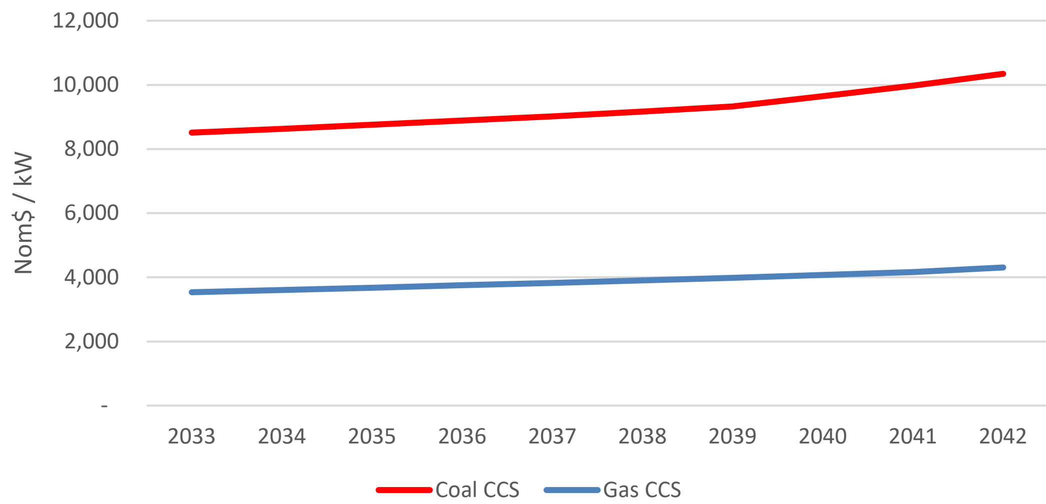
In AURORA, CCS is modeled as new build options and retrofit options. CCS plants are treated as standard dispatch resources in AURORA, which are assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. Section 45Q legislation provides a tax credit of $94/short-ton of CO_2 sequestered. This incentive is implemented in AURORA as a negative variable cost adder, improving dispatch economics.

New build options

Two new build CCS configurations are available for selection in AURORA, including the 650 MW ultra-supercritical coal power plant with 90% carbon capture and the 380 MW H-class combined-cycle natural gas turbine with 90% carbon capture. Coal CCS is assumed available in 2033 and natural gas CCS in 2031.

The assumptions on overnight capital costs for new build CCS are shown in Figure 27. The first operating year FOM, VOM, and heat rate assumptions are shown in Table 9 below.

Figure 27 Capital Cost Assumptions for New Build CCS



Note – Coal CCS represents a 650 MW ultra-supercritical unit with 90% capture rate; Gas CC CCS represents a 380 MW single shaft CCGT with 90% capture rate

Table 9 Operating and Heat Rate Assumptions for New Build CCS

		Coal	Gas
VOM	$ / MWh	14.68	7.52
FOM	$ / kW-yr	76.95	35.56
Heat Rate	Btu / kWh	11,341	6,696

Retrofit Options

It is also possible for AURORA to choose to retrofit existing NGCC units and coal-fired units with CCS. The cost and performance assumptions for retrofitted NGCCs are based on a compilation of assumptions from various sources including the Clean Air Task Force, Global CCS Institute and National Energy Technology Laboratory.

Table 10 Operating and Heat Rate Differentials for Retrofit CCS

		Retrofitted NGCC
Capacity penalty	% of pre-retrofit capacity	13.2%
Heat rate penalty	% of pre-retrofit heat rate	17.2%
Incremental capital cost	$2021 / kW post-retrofit capacity	881
Incremental FOM	$2021 / kW post-retrofit capacity	19.9
Incremental VOM	$ / kWh	1.24

The cost and performance parameters for retrofit coal units are taken from the Environmental Protection Agency's ("EPA") modeling assumptions in its power sector modeling platform[14]. The applied parameters vary based on the capacity and heat rate of the coal unit as shown in Table 11 below. The table shows significant heat rate and capacity penalties on coal units with 400

[14] Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model (2018). Retrieved from https://www.epa.gov/sites/default/files/2018-05/documents/epa_platform_v6_documentation_-_all_chapters_v15_may_31_10-30_am.pdf

MW capacity; coal units with lower than 400 MW capacity are assumed to be ineligible for retrofit due to unfavorable economics.

Table 11 EPA Performance and Unit Cost Assumptions for CC Retrofits on Coal Plants

Capacity (MW)	Heat Rate (Btu/kWh)	Capital Cost ($/kW)	FOM ($/kW-year)	Variable O&M (mills/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)
400	9,000	2,595	36.9	18.2	33.6	50.6
	10,000	2,960	41.2	19.7	37.3	59.5
	11,000	3,373	46.1	21.3	41.0	69.6
700	9,000	1,852	23.7	14.9	19.2	23.7
	10,000	2,071	26.1	15.6	21.3	27.0
	11,000	2,302	28.6	16.4	23.4	30.6
1000	9,000	1,625	19.7	13.9	13.4	15.5
	10,000	1,810	21.6	14.5	14.9	17.5
	11,000	2,001	23.6	15.0	16.4	19.6

Carbon Storage and Transportation Costs

CCS plants also incur costs associated with storing and transporting CO_2. The parameters in Table 12 were derived from EPA National Electric Energy Data System ("NEEDS") v6, representing the cost of transporting and storing CO_2 across potential CO_2 storage. Low cost storage may be depleted over time as more CCS is added to the system, therefore the carbon storage and transportation costs will be higher over time as the storage capacity of the lowest cost option is depleted.

Table 12 Carbon transport and storage schedule ($2021 / t$CO_2$)

	Louisiana	Texas	Oklahoma	Kansas	Arkansas	Missouri
Storage Cost	5.00	5.00	5.00	5.00	5.00	-
Transport Cost	43.44	43.43	27.54	42.09	19.04	34.71
Total Cost	**48.44**	**48.43**	**32.54**	**47.09**	**24.04**	**34.71**

5.5.3. Hydrogen (H_2)

Two key components that make up a "green" hydrogen system[15] are the polymer electrolyte membrane ("PEM") electrolyzer and the hydrogen gas combustion turbine ("H_2 CT").

H_2 CTs operate on the same principle as the NGCT systems but with some differences in operating characteristics including:

- **Energy density**: H_2 is less energy dense than natural gas. Using hydrogen as a fuel will require a fuel accessory system configured to provide three times higher fuel flow rates into the turbine relative to using natural gas;
- **Flame speed:** H_2 has about 4.5 times the flame speed of natural gas. The combustion systems have to be configured specifically for hydrogen to prevent the flame from propagating upstream;
- **Flammability:** H_2 is more flammable than natural gas. The enclosure and ventilation system have to be designed to limit the concentration of hydrogen; and

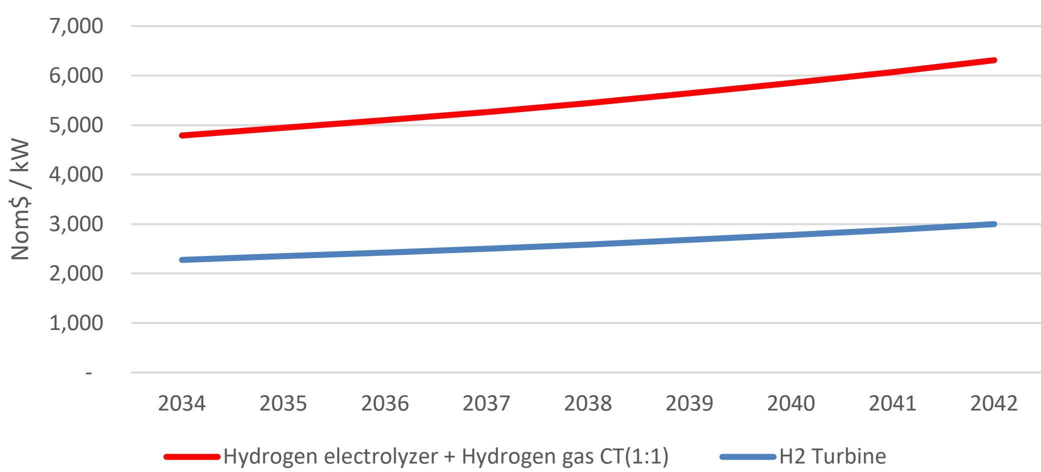
[15] Green hydrogen is made with electrolyzers powered by non-carbon emitting resources. Other types of hydrogen production, for example "blue" hydrogen, is made from reforming methane with CCS of the CO_2 byproduct.

- **Flame temperature:** H_2 burns at a higher temperature than natural gas, resulting in higher NO_x emissions. A selective catalytic reduction system is required to reduce NO_x emissions.

H_2 can play multiple roles within an electricity system. It can provide storage capacity during periods of high renewable generation and, depending on H_2 prices, cycling capabilities for intermediate loads or generation capacity during periods of high electricity demand. As a gas turbine technology, hydrogen can also provide system services such as inertia, frequency response, voltage support, regulating reserves and black start.

The cost, cost reduction curve, and efficiency assumptions for the PEM electrolyzer are developed based on a compilation of various sources including PNNL[16], IEA[17], EPRI[18], DOE[19] and the International Council on Clean Transportation[20]. The capital cost assumption for the PEM electrolyzer component included stack replacement costs. The cost and performance modeling assumptions for H_2 CT is from conversations with power equipment vendors. The capital cost reduction curve is based on NREL for NGCT. Overnight capital cost assumptions are shown in Figure 28, FOM for electrolyzer in Figure 29, efficiency for electrolyzer in Figure 30. Other first operating year parameters shown in Table 13 are VOM and NGCT's FOM and heat rate; these are not expected to improve over time. The fixed operating cost for a H_2 CT is estimated to be the same with the EIA AEO 2022 estimate for NGCT, reflecting additional costs for maintaining a system with high levels of water and steam injection for emission control.

Figure 28 Capital Cost Assumptions for PEM Electrolyzer and H2 CT Components



[16] 2020 Grid Energy Storage Technology Cost and Performance Assessment 2020 (December 2020). Retrieved from https://www.pnnl.gov/sites/default/files/media/file/Hydrogen_Methodology.pdf

[17] The Future of Hydrogen – Assumption Annex (December 2020), Retrieved from https://iea.blob.core.windows.net/assets/29b027e5-fefc-47df-aed0-456b1bb38844/IEA-The-Future-of-Hydrogen-Assumptions-Annex_CORR.pdf

[18] Program on Technology Innovation: Prospects for Large-Scale Production of Hydrogen by Water Electrolysis. Retrieved from https://www.epri.com/research/products/000000003002014766

[19] Hydrogen Production Cost from PEM Electrolysis – 2019 (February 2020). Retrieved from https://www.hydrogen.energy.gov/pdfs/19009_h2_production_cost_pem_electrolysis_2019.pdf

[20] Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe (June 2020). Retrieved from https://theicct.org/sites/default/files/icct2020_assessment_of_hydrogen_production_costs_v1.pdf

Figure 29 FOM Assumptions for PEM Electrolyzer and H2 CT Components

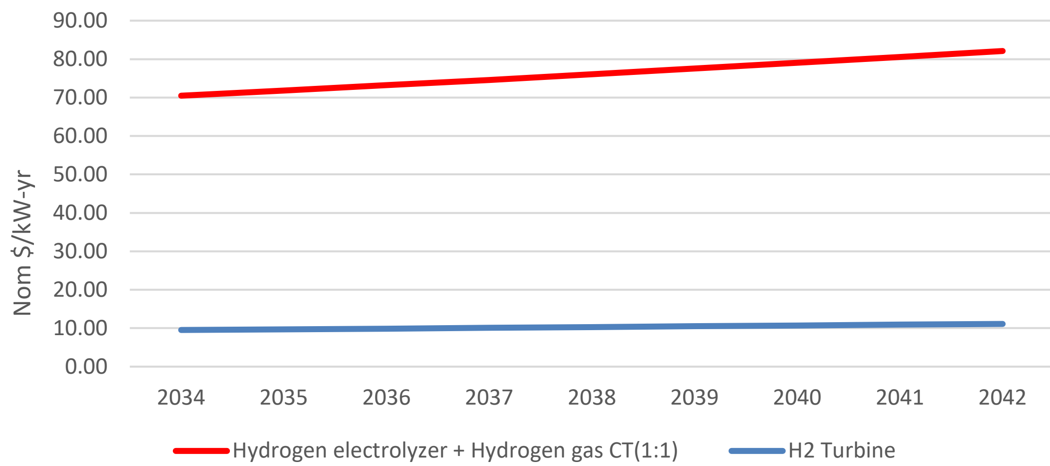


Figure 30 Efficiency Assumptions for PEM Electrolyzer

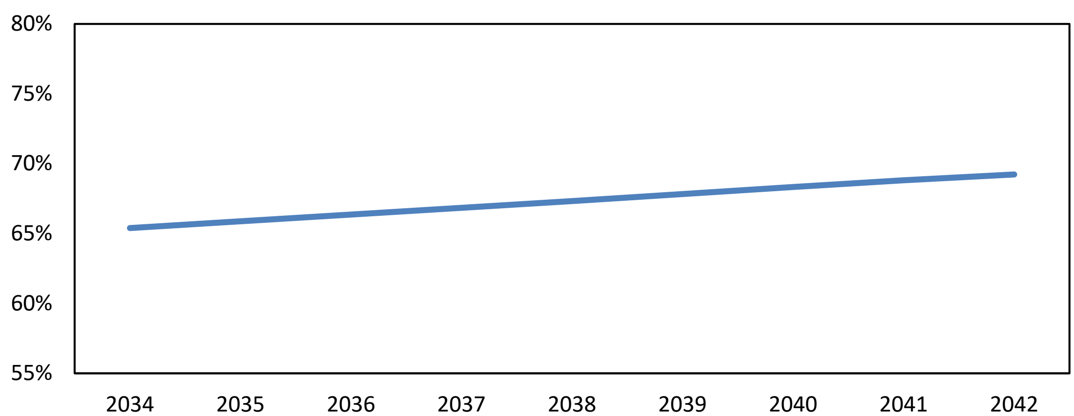


Table 13 Operating and Heat Rate Assumptions for PEM Electrolyzer and H_2 CT

		PEM Electrolyzer	H_2 CT
VOM	$ / MWh	0.65	6.13
FOM	$/ kW-yr	Figure 29	Figure 29
Efficiency/Heat Rate	Btu / kWh	Figure 30	9,655

Projects whose construction begins by the end of 2032 are eligible for a Production Tax Credit ("PTC"). This is applied as a discount to the price of hydrogen fuel in AURORA at a rate of $3/kg[21].

Hydrogen is made available in AURORA starting in 2032, based on statements by various major power equipment providers committing to provide 100% H_2 CTs by 2030 and a best estimate of when market supply of hydrogen could be reliably available.

Hydrogen resources are offered in AURORA assuming third-party H_2 supply, whereby only the H_2 CT is assumed to be utility owned, thus the modelled costs comprise the capital cost, FOM, VOM of H_2 CT only, and fuel prices represented by the levelized cost of hydrogen. The levelized cost of hydrogen is calculated based on the levelized cost of the PEM electrolyzer plus the electricity costs for the SPP region. The supply of H_2 is assumed to be available on demand. The H_2 CT is then modeled as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints.

5.6. Long Duration Storage Alternatives

For the purposes of this IRP, long-duration storage refers to storage that can provide 20 hours' worth of energy. A storage of this duration can be used to balance diurnal variations in renewable energy resources as well as variations in demand from weekends (low demand) to weekdays (high demand). The technology can also provide needed capacity during longer duration weather events, such as cold periods or wind droughts that could last for several days.

The value of long-duration storage is likely to increase as intermittent renewable generation increases within SWEPCO's service territory and extreme weather events become more frequent. In addition to energy arbitrage, some long-duration technologies can also increase system reliability through the provision of frequency, inertia, voltage, short circuit levels, and restoration. Increased deployment of long-duration storage can also dampen price volatility and displace more expensive forms of generation during periods of high electricity demand, contributing to rate stability and customer affordability.

Pumped hydro energy storage is currently the dominant form of long duration storage, however its potential has largely been depleted and is not considered as part of this IRP. Three alternative long-duration technologies are considered, including pumped thermal energy storage, vanadium flow battery storage and compressed air energy storage.

Cost and performance assumptions for the IRP are developed based on a compilation of projections from various sources.

5.6.1. Pumped Thermal Energy Storage (PTES)

PTES refers to a group of technologies that use a heat pump and heat engine to convert electricity into stored heat which is in turn converted back to electricity. The heat is stored in a thermal medium, such as molten salt in an insulated tank to reduce heat leakage. When needed, a heat engine takes the heat from the tank to generate steam to drive a turbine to generate electricity.

Large insulated thermal tanks have already been widely deployed as part of the development of concentrated solar power plants. Whereas concentrated solar power plants use reflected sunlight to heat the thermal medium, PTES uses the heat pump instead.

Key benefits of PTES include relatively low capital costs, siting flexibility, high energy density, ability to provide inertia and avoided use of toxic or hazardous chemicals to store energy. However, it has relatively low round-trip efficiency, slower response time, and high self-discharge.

[21] While the amount of the credit varies based on the CO_2e per kg of emissions of the hydrogen production process, the ten-year hydrogen PTC is for up to $3 per kg (in 2022 dollars and inflated over time).

As a turbine-based technology, PTES can provide various ancillary services including inertia, frequency response, regulating reserve and voltage support. However, the response time of PTES is around 10 seconds, which is slower than other storage technologies such as Lithium-Ion battery or vanadium flow battery.

PTES is modeled in AURORA as an energy storage option. AURORA optimizes charging and discharging of the resource against projected SPP hourly electricity prices, taking into account a round-trip efficiency of 65% and a self-discharge rate of 1% per day. PTES is made available in a configuration of 50 MW. The maximum annual capacity addition is 200 MW and the cumulative maximum of 500 MW.

The forecasted PTES overnight capital cost and FOM assumptions are developed based on averages of values reported in a wide range of sources including reports published by NREL, the UK Department for Business, Energy & Industrial Strategy ("BEIS"), and academic studies. The assumptions are shown in Figure 31 and Figure 32 below.

Figure 31 Capital Cost Assumptions for 20-hour duration PTES

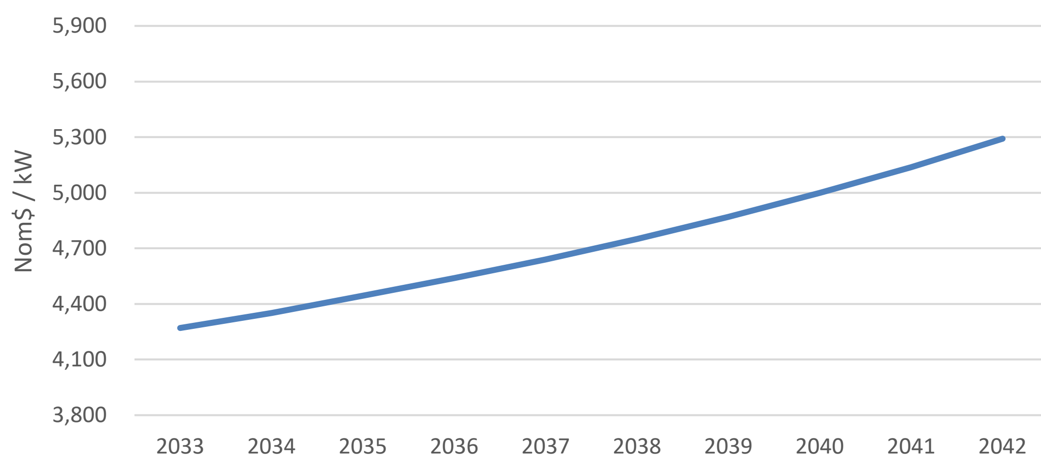
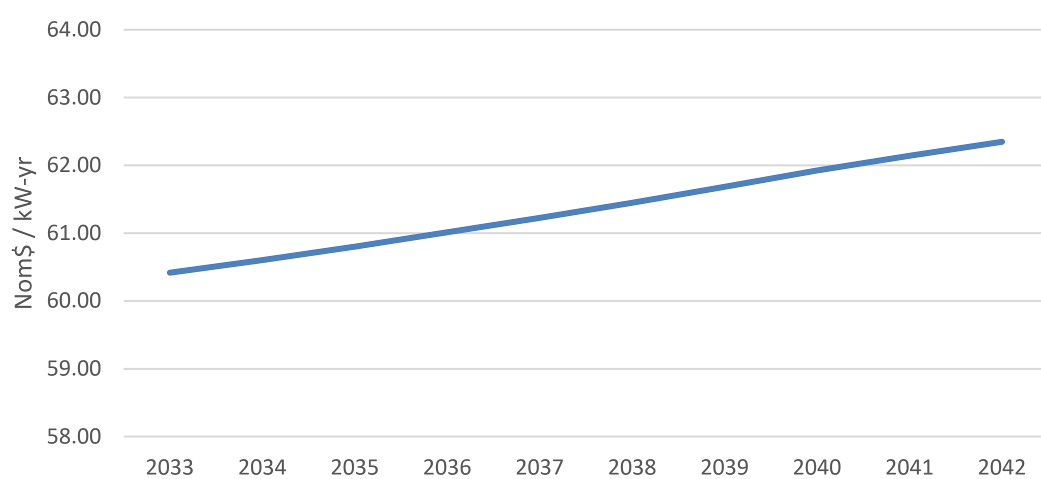


Figure 32 FOM Assumptions for 20-hour duration PTES



Investment Tax Credit ("ITC") value is assigned to the project by applying a reduction in modeled upfront capital cost at a rate of 30% for projects entering service before the end of 2032. After

2032, ITC tax credits reduce to 22.5%, 15% and 0% of their value in 2033, 2034, and 2035, respectively.[22]

5.6.2. Vanadium Flow Battery Storage (VFB)

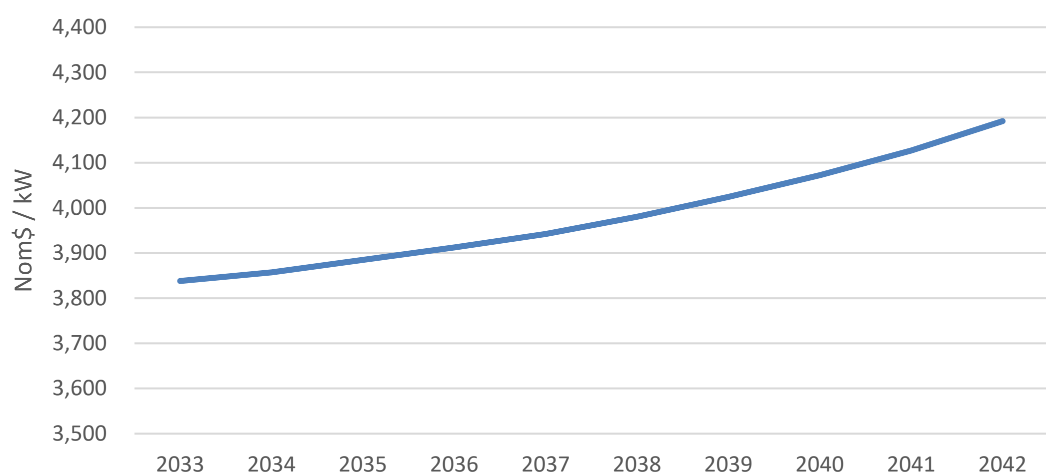
VFB stores energy in vanadium-based electrolytes that can transfer electrons back and forth between four different oxidation states causing charge and discharge. The electrolytes are dissolved in water and stored in two tanks connected by an iron selective membrane. During a discharge, electrolyte is spent producing DC power which is converted to AC power using converters and controllers. Electrolytic fluid is then regenerated using DC power from the converter during a charge. VFB is already being commercially deployed, but the supply chain is not as mature as lithium-ion battery.

Key benefits of VFB include quick response time of less than 1 second, high round-trip efficiency, siting flexibility and no degradation during its lifetime. Disadvantages include high operating costs and the use of corrosive electrolyte.

VFB is modeled in AURORA as an energy storage option. AURORA optimizes charging and discharging of the resource against projected SPP hourly electricity prices, considering a round-trip efficiency of 70% and a self-discharge rate of 1% per day. VFB is made available in a configuration of 50 MW. The maximum annual capacity addition is 200 MW and the cumulative maximum is 500 MW. The first available year for operation is 2033.

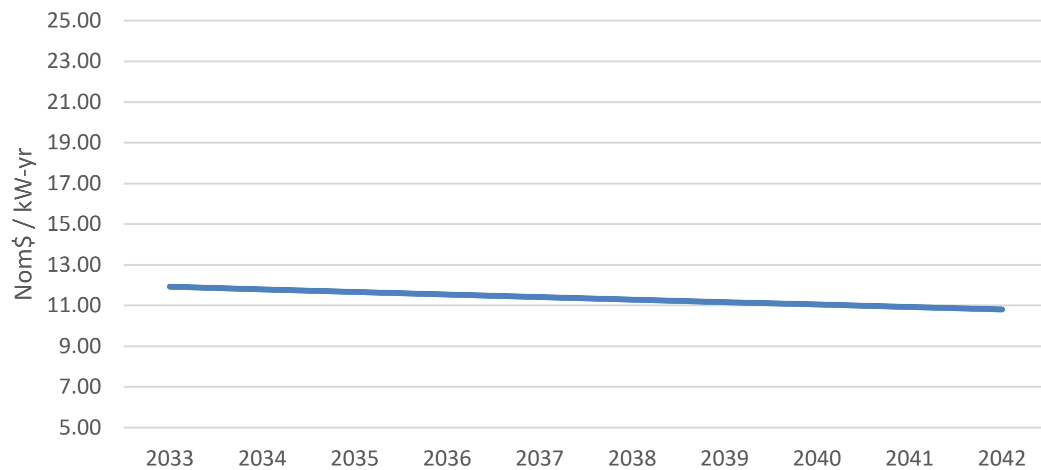
The forecasted VFB overnight capital cost and FOM assumptions are developed based on an average of values reported in wide range of sources including reports published by EIA, PNNL, BEIS and academic studies. These assumptions are shown in Figure 33 and Figure 34 below.

Figure 33 Capital Cost Assumptions for 20-hour duration VFB



[22] For portfolio modeling, a safe harbor provision is assumed which provides a three-year delay in the effects of declining tax credits as long as adequate construction has commenced for new resources.

Figure 34 FOM Assumptions for 20-hour duration VFB



Investment Tax Credit ("ITC") value is assigned to the project by applying a reduction in modeled upfront capital cost at a rate of 30% for projects entering service before the end of 2032. After 2032, ITC tax credits reduce to 22.5%, 15% and 0% of their value in 2033, 2034, and 2035, respectively.[23]

5.6.3. Compressed Air Energy Storage (CAES)

CAES is using compressed air to generate electricity. First, electricity is used to drive a compressor to pump air into a pressurized reservoir, e.g. salt cavern, abandoned natural gas storage facilities or depleted oil and gas fields. The compressor generates heat which is captured by a heat exchanger and stored in a separate thermal energy storage device. To discharge, the compressed air in the reservoir is combined with the stored heat to create hot high-pressure air which expands in a turbine to generate electricity.

Existing CAES projects are based on a diabatic process where the heat generated by the compressor is released into the atmosphere instead of being stored. As a result, an alternative source of heat, often fossil fuel, is required during the expansion stage, leading to a lower round-trip efficiency.

Key advantages of CAES include avoided use of toxic or hazardous chemicals, relatively mature and well understood component parts of the technology, and the opportunity to revive abandoned energy infrastructures such as abandoned natural gas storage facilities. Disadvantages include siting limitations and relatively low round-trip efficiency. CAES also has relatively longer response time of about a minute, which is slower than other technologies in this section.

CAES is modeled in AURORA as an energy storage option with a round trip efficiency of 52% and a self-discharge rate of 0.05% per day. AURORA optimizes charging and discharging of CAES based on projected SPP hourly electricity prices. CAES is made available in a configuration of 50 MW. The maximum annual capacity addition is 200 MW and the cumulative maximum is 500 MW. The first year available for operation is 2033.

The forecasted CAES overnight capital cost is based on a survey of recent project development activity, whereas FOM is based on an average of a wide range of sources including reports from DOE, PNNL, BEIS and academic studies. Investment Tax Credit ("ITC") value is assigned to the

[23] For portfolio modeling, a safe harbor provision is assumed which provides a three-year delay in the effects of declining tax credits as long as adequate construction has commenced for new resources.

project by applying a reduction in modeled upfront capital cost at a rate of 30% for projects entering service before the end of 2032.

5.7. Short-Term Market Purchase (STMP)

Short-Term Market Purchase alternative capacity resources were made available to the model for selection during the development of the optimal plans. This resource is assumed to have no energy associated with it and a contract term of one year. The purpose of adding this resource was to allow the model an option to include a short-term capacity resource as a bridge to mitigate abrupt capacity shortfalls. At this time, due to the Company's understanding of the availability of third-party capacity purchases, it is appropriate to limit the availability of this resource option to the 2027-2028 period to a maximum of 200 MW/year.

6. Demand-side Resource Options

6.1. Introduction

This chapter considers two categories of demand-side resources as alternatives to new generation supply in meeting future capacity needs. The categories include energy efficiency programs and customer-owned distributed generation.

6.2. Energy Efficiency Measures

This IRP considers incremental EE programs as resource options to meet future capacity needs. These incremental EE programs, starting from 2024, are in addition to the existing demand-side programs that run until 2023 and are discussed in Section 2.2.5.

6.2.1. EE Cost and Performance Assumptions

The cost and performance parameters for the incremental EE programs evaluated are based on input from SWEPCO's internal subject matter experts and the Electric Power Research Institute's ("EPRI") "2014 U.S. Energy Efficiency Potential Through 2035" report with updates from the 2019 Technical Update of this same report. The EPRI report and the SWEPCO Energy Efficiency and Consumer Programs team provided information on a multitude of current and anticipated end-use measures including measure costs, energy savings, market acceptance ratios and program implementation factors. Table 14 provides a list of current and anticipated EE measures for both the residential and commercial sectors.

Table 14 Energy Efficiency Measure Categories by Sector

Residential Measures	Ceiling Insulation Dish Washer Television Central AC Water Heating	Wall Insulation Refrigerator Heat Pump Clothes Washer Behavioral	Windows Freezer Lighting Clothes Dryer
Commercial Measures	Heating Measures Water Heating Personal Computers Outdoor Lighting*	Cooling Measures Commercial Ventilation Servers	Chiller Space Cooling Refrigeration Indoor Lighting*

Note: *Indoor and outdoor lighting categories apply to both commercial and industrial sectors to account for potential EE savings in the industrial sector.

The amount of available EE potential can be broken into three categories: technical, economic, and achievable. Technical potential refers to the amount of EE that could be deployed regardless of cost and barriers to deployment. Economic potential refers to the amount of cost-effective EE that could be deployed regardless of deployment barriers. Cost-effectiveness is based on the Total Resource Cost (TRC) test which compares the avoided cost savings over the life of an EE measure with the cost to implement it, regardless of who bears the cost. Achievable potential is a subset of economic potential accounting for market acceptance and implementation barriers.

The achievable potential can further be broken into the amount that would be accomplished if implemented through utility-sponsored programs, and the total amount that would fall under codes and standards. The former is included as part of resource options for capacity expansion while the latter is accounted for as reductions from the load forecast.

6.2.2. Modeling EE measures as resource options

SWEPCO ranked individual EE measures according to their lifetime levelized cost. Residential measures were ranked separately from commercial measures to reflect different operating characteristics between residential and commercial EE programs. Once ranked, EE measures were grouped into bundles based on the following criteria:

- First, the highest cost measure in the bundle cannot exceed twice the average cost of the measures in the bundle. This is to preserve a degree of cost homogeneity among the measures within the same bundle;
- Second, the gross energy savings potential in each bundle is at least 0.5% of the total system load. This is to ensure that each bundle represents a significant energy resource option for AURORA to select when compared against other energy resource options, such as new generating units.

Table 15 lists the EE bundles for the residential and C&I sectors. The high-cost bundle for the commercial and industrial sectors is excluded from resource modeling due to its prohibitively high levelized cost beyond other available supply- and demand-side options in the model.

Table 15 Energy Efficiency Bundles Statistics

	LCOE ($ / MWh)			2024 Gross Total Energy Savings Potential (MWh)	Energy Saving as % of Total 2023 Load
	Min	Mean	Max		
Residential					
Low	3	16	29	248,817	2.1%
Medium	33	45	53	108,858	0.9%
High	72	104	159	213,786	1.8%
Commercial					
Low	3	5	10	59,837	0.5%
Medium	12	21	36	182,509	1.6%
High	54	709	1,274	299,322	2.4%

Table 16 provides incremental gross average yearly energy savings potential for each bundle overtime.

Table 16 Incremental Gross Average Yearly Energy Savings

	Time Period (MWh / Year)		
	2024-2028	2029-2033	2034-2038
Residential			
Low	49,577	4,320	2,008
Medium	25,685	5,606	8,121
High	50,975	9,245	6,303
Commercial			
Low	11,709	0	0
Medium	37,047	0	0

Each EE bundle has a unique 8760 hourly load shape, allowing AURORA to consider the impact of the bundle on energy demand as well as assessing the contribution of the bundle to meeting capacity needs during summer and winter peaks. The load shape reflects the impact on customer load shapes of different electricity end uses and the mix of individual EE measures included in the bundle. For example, Table 17 shows the composition of individual EE measures comprising the low-cost bundle for residential sector for 2024-28 and 2029-33. The individual EE measures are from four electricity end-uses: residential heating, residential cooling, lighting, and other.[24] The load shape for this bundle is the weighted average shape of the four end uses where the weights are the gross energy savings potential of each end use in each time period. The load shapes for each end-use remain the same over time, but the load shape in each bundle will change over time due to the changes in the gross energy savings potential of each underlying measure.

[24] Other includes electric water heating, electric cooking, refrigerator, freezer, dishwasher, clothes washer, clothes dryer, TV sets, furnace fans and miscellaneous

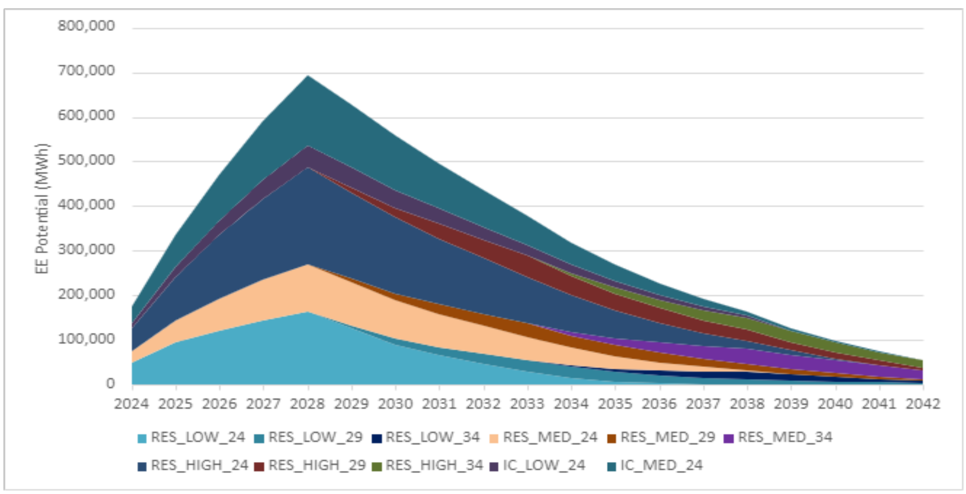
Table 17 Composition of Individual EE measures in Low Residential Bundle by Year

Individual EE measure	Electricity End Use	Gross Incremental Energy Savings Potential (MWh) 2028	2033
Low Flow Showerheads	Other	18,286	1,346
Faucet Aerators	Other	4,360	321
Screw-In – Halogen to LED	Lighting	15,928	1,246
Duct Insulation	Heating + Cooling	9,871	1,976
Pipe Insulation	Other	10,409	766
Energy Star Television	Other	53,097	9,038
Smart Thermostats	Heating + Cooling	59,021	14,506
Behavioral Program	All	66,277	1,344
Energy Star Refrigerator	Other	10,635	1,715
Total		**247,884**	**32,258**

Each bundle is made available in AURORA in any given year during each five-year window. If the bundle is not selected within the selection window, it will not be available for selection in the next selection window. This assumes that the underlying EE measures within each bundle would have been obsolete by the next selection window. Once the bundle is selected, it will remain activated over its life regardless of when in the selection window it is selected.

Figure 35 shows net annual energy savings potential across all EE bundles made available to AURORA. The Figure assumes that all EE bundles would be selected in the first year of each selection period. At its peak in 2028, net annual energy savings potential available to AURORA accounts for 6% of total energy demand in the year.

Figure 35 Net Annual Energy Savings Potential Across EE Bundles



7. Planning Scenarios and Uncertainties

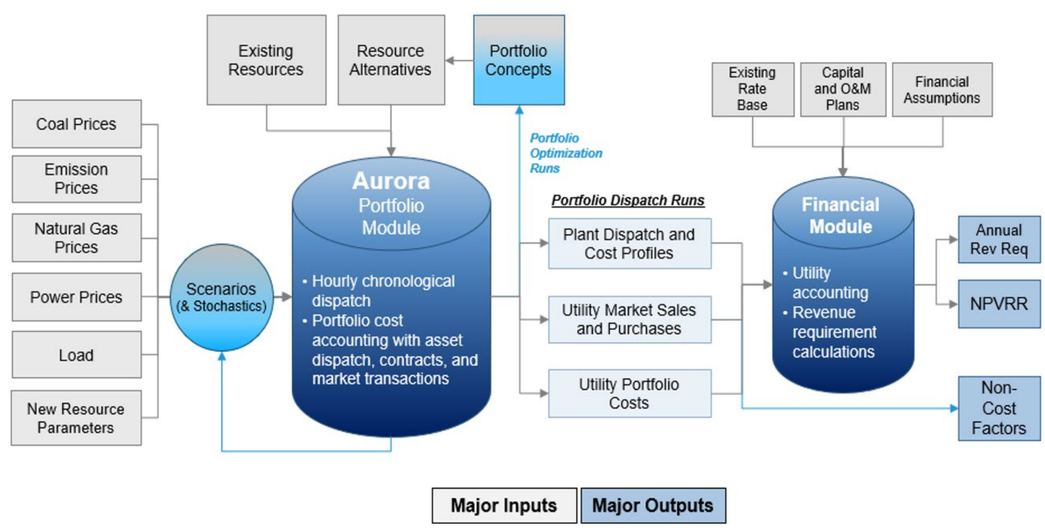
7.1. Introduction

Rate stability and maintaining reliability are two of SWEPCO's objectives for the 2023 IRP. In the context of rising future uncertainties, this section explains how the 2023 IRP analysis captures the key uncertainties and planning risks facing the SWEPCO portfolio that affects system reliability and costs to customers. The analysis informs the selection of candidate resources that balances customer affordability with rate stability, maintaining reliability, and providing positive local impacts to SWEPCO's customers. SWEPCO evaluates uncertainty and risk using two different methods as part of the 2023 IRP.

The first method is based on developing a set of five market scenarios that test plausible but materially different long-term views of fundamental external market conditions such as commodity prices, customer preferences, policy requirements, and transmission availability. In addition to the Reference Scenario, which is intended to reflect a middle-of-the-road outcome, SWEPCO developed four additional market scenarios (CETA, ECR, FOR, and NCR) that test the boundaries of expected long-term outcomes. Each candidate portfolio was then stress-tested under all five market scenarios.

Each of these market scenarios is supported by a set of assumptions describing the fundamental inputs from the Company's Fundamental Forecast described in Section 7.2 that combine to reflect a specific theme or "what-if" narrative. The key categories of assumptions used to develop the 2023 IRP market scenarios include: load, fuel prices (natural gas prices and coal), CO_2 prices, reserve requirements by season, demand- and supply-side technology cost, and technology performance inputs that describe dispatch and reserve characteristics. All five scenarios in the 2023 IRP were modeled using AURORA to evaluate the evolution of generation capacity and prices across SPP under these different sets of fundamental conditions. This process is illustrated in Figure 36.

Figure 36 2023 IRP Modeling Framework



The second method subjected the candidate portfolios to a large number of randomly drawn market simulations in the 2023 IRP as part of the stochastic analysis. This means that each candidate portfolio was dispatched in a high number of market outcomes that combine volatility of power prices and natural gas prices with volatility of generator output to observe the impact on customer costs. In some simulations, these factors combine into severe operating conditions similar to those observed during the extreme weather experienced in February 2021 that disrupted both the SPP and ERCOT markets. SWEPCO analyzes the portfolio costs under these severe outcomes to assess how much higher customers costs are likely to be under adverse or extreme market conditions, and how exposed customers are to higher costs under the candidate resource plan.

7.2. The Fundamentals Forecast

CRA produced a fundamental forecast for key market assumptions including prices for natural gas, coal, and CO_2 based on information from Wood Mackenzie, EIA, and CRA's proprietary market models.

The primary tool used for the development of the North American long-term energy market pricing forecasts is the AURORA energy market simulation model. The AURORA model iteratively generates zonal, but not company-specific, long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions, and capital costs.

The AURORA model is widely used by utilities for integrated resource and transmission planning, power cost analysis and detailed generator evaluation. The database includes approximately 25,000 electric generating facilities in the contiguous United States, Canada, and Baja Mexico. These generating facilities include wind, solar, biomass, nuclear, coal, natural gas, and oil. A licensed online data provider, ABB Velocity Suite, provides up-to-date information on markets, entities, and transactions along with the operating characteristics of each generating facility, which are subsequently exported to the AURORA model. AURORA's vendor Energy Exemplar also incorporates the most recent transmission topology for SPP including flow limits between its zones. These are informed by power flow cases, reliability reports and other ISO Planning documents

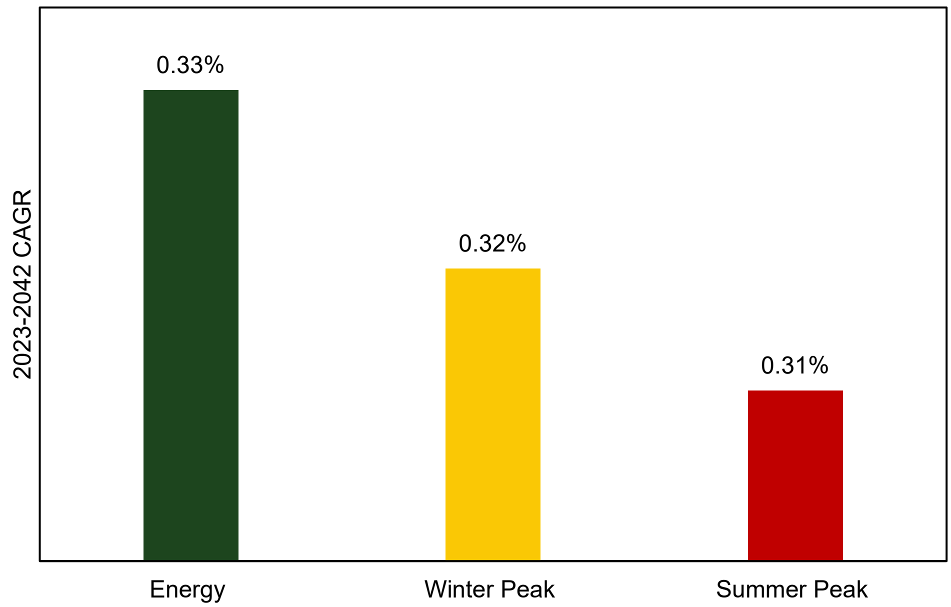
7.2.1. Reference Scenario Market Drivers and Assumptions

The Reference Scenario represents an expected view of how load growth, commodity prices, technology development and policy will evolve over time and contribute to the market conditions under which SWEPCO will operate.

7.2.2. Reference Scenario Load

Under the Reference Scenario provided by AEP Economic Load Forecasting, demand for energy in SPP is expected to grow by 0.33% per year over the 20-year forecast period (2023-2042). Peak summer demand is expected to grow at a rate of 0.31% per year, while peak winter demand grows slightly more quickly at 0.32% per year. These figures are illustrated in Figure 37. The details of the analysis and the assumptions underlying the load forecast are discussed in Section 2 above.

Figure 37 Reference case SPP energy and seasonal peak demand growth rates (2023-2042)



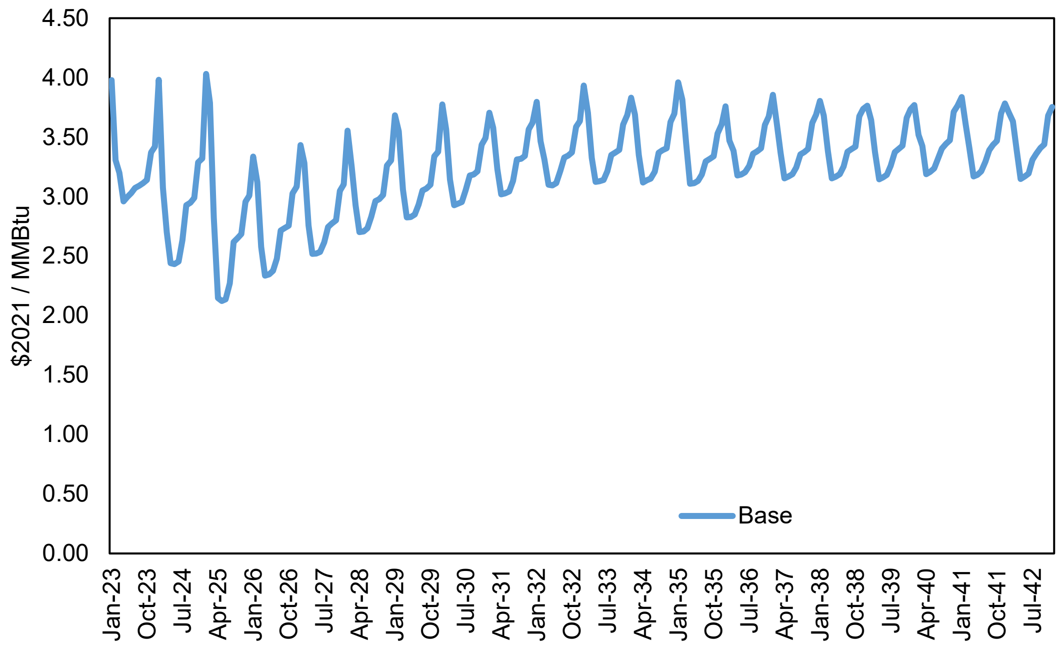
7.2.3. Reference Scenario Fuel & CO_2 Prices

The commodity price inputs to the Reference scenario reflect the "base" view for natural gas, coal, and CO_2 emissions pricing. For the 2023 IRP Reference Scenario, these "base" commodity price outlooks were used to represent the expected conditions for the broader SPP market.

Natural Gas Prices

Figure 38 illustrates the monthly Panhandle Eastern TX-OK natural gas price forecast that was used for the SPP market modeling in the Reference Scenario. This pricing point was selected for the report because it reflects the point used to supply SWEPCO's units and is largely representative of gas prices in the region. Under the Reference Scenario, prices fall from current levels through 2026 in real terms, after which annual growth in prices is modest for the remainder of the forecast period.

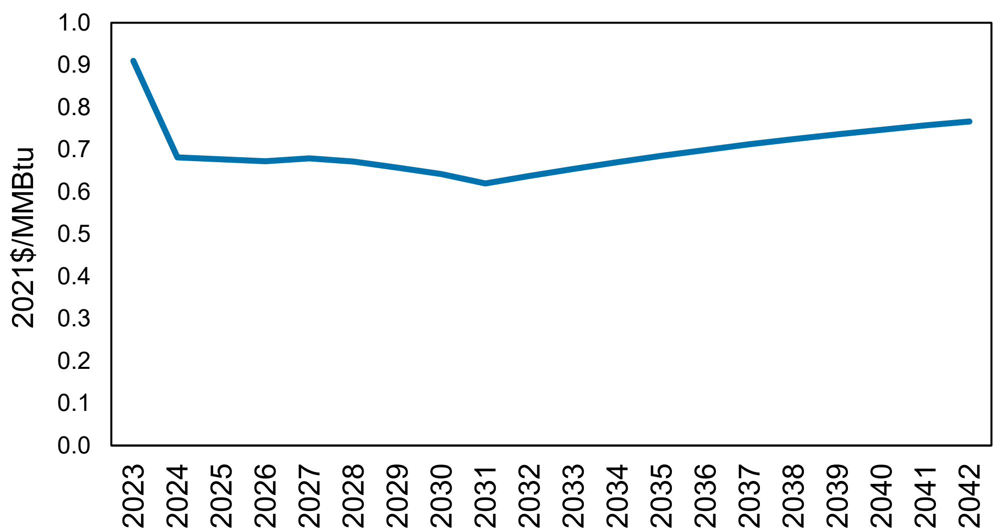
Figure 38 Panhandle Eastern TX-OK Natural Gas Prices (real $ / MMBtu)



Coal Prices

SWEPCO used a coal price forecast from Wood Mackenzie as inputs to the 2023 IRP. Figure 39 below illustrates the monthly forecast of Powder River Basin ("PRB") coal prices at the point of purchase (i.e., exclusive of transportation costs) that were used in the Reference Scenario. While some coal-fired units in SPP burn coals other than PRB, this price reflects the outlook for the type of coal burned at SWEPCO's solid fuel facilities. In the Reference Scenario, similar to natural gas, the PRB forecast exhibits a shorter-term decline in prices from current levels then remains largely consistent through the end of the forecast horizon to 2042.

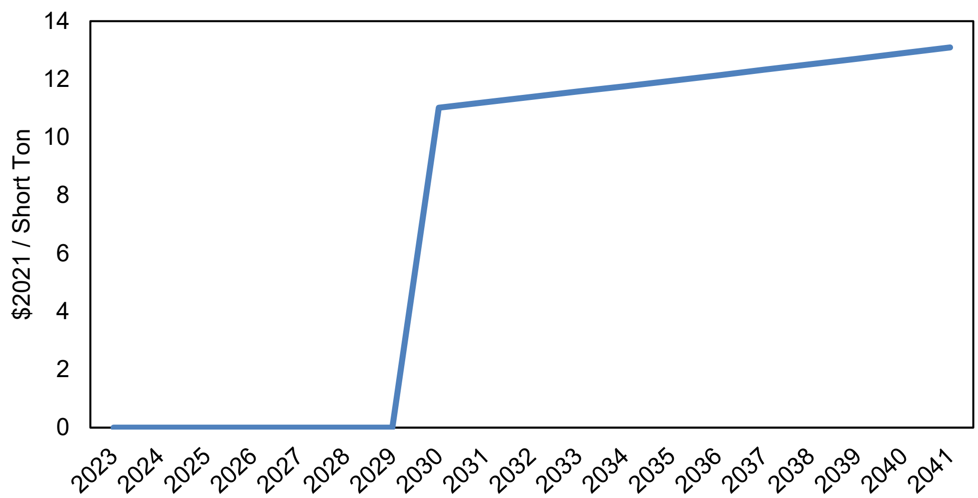
Figure 39 PRB 8,800 Coal Prices (real $ / MMBtu, FOB origin)



CO_2 Prices

SWEPCO assumes that policymakers enact a moderate CO_2 price starting in 2030 as part of the 2023 IRP Reference Scenario. This price is assumed to start around $11 / Ton (in real $2021) and rises modestly throughout the forecast period, as illustrated in Figure 40. The CO_2 price increases the dispatch cost of all fossil-fired units in SPP based on the modeled emissions of the unit that, in turn, is a function of each unit's heat rate and carbon content of the fuel it consumes.

Figure 40 Moderate CO_2 Price Forecast ($2021 / Short Ton)



7.2.4. Reference Scenario Reserve Requirements

SWEPCO assumes that SPP will need to procure sufficient resources to meet expected load plus a summer planning reserve margin of 15%.

While the planning reserve margin percentage is not assumed to change over the course of the forecast period in the Reference Scenario, SWEPCO does assume changes in the capacity contribution of different technology types, namely solar PV and 4-hour battery storage to reflect how incremental additions of these technologies are expected to shift peak load and reduce the Effective Load Carrying Capacity ("ELCC") of these resources. SWEPCO relied upon studies performed by SPP to estimate the change in ELCC over time as penetration of these resources increases in the SPP footprint.[25,26] Section 7.3.3 discusses the assumed reduction in ELCC over time.

7.2.5. Reference Scenario Technology Assumptions

In general, SWEPCO relied on EIA's 2022 AEO as the starting point for the technology cost and performance assumptions for new utility scale generation in the SPP footprint. Reference case changes to technology cost and performance over time are based on the medium case of the 2022 National Renewable Energy Laboratory's ("NREL") annual technology baseline ("ATB") report.[27] SWEPCO assumed federal tax credits for new renewable generation, hydrogen, CCS,

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[25] 2020 SPP Solar & Wind ELCC Accreditation. SPP. November 2022. < https://www.spp.org/documents/68289/2022%20spp%20elcc%20study%20wind%20and%20solar%20report.pdf>

[26] SPP Energy Storage Study Final Report. Astrape Consulting. November 2019. – Appendix Added September 2021<https://spp.org/documents/65977/astrape%20spp%20energy%20storage%20study%20report%20updated%20winter%20results.pdf >

[27] NREL Electricity Annual Technology Baseline (ATB) 2022. <https://atb.nrel.gov/electricity/2022/data>

and grid energy storage under all scenarios to reflect current law and the schedules enacted in the Inflation Reduction Act (IRA) of 2022.

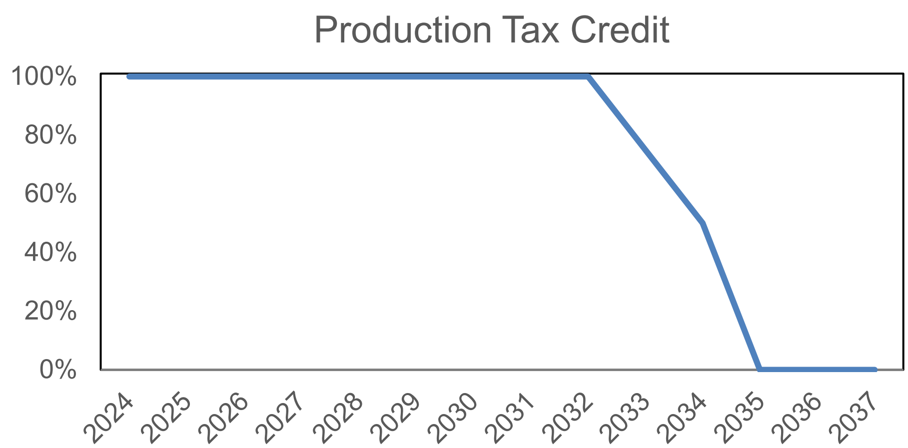
Cost and performance assumptions for demand-side technologies, including EE were developed by AEP staff and the details of the demand-side resource assumptions are discussed in Section 6.

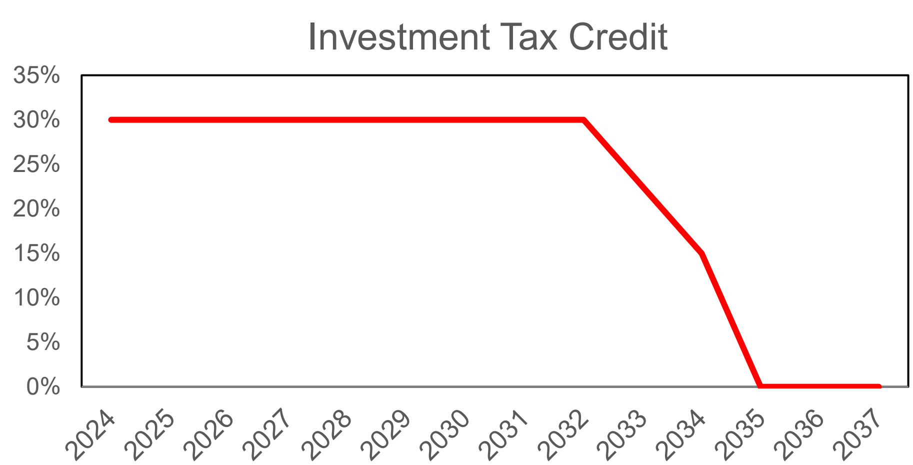
7.2.6. Federal Tax Credits for Renewable Energy

The Inflation Reduction Act of 2022 ("IRA") provides federal tax credits for clean energy, energy storage, clean hydrogen, and CCS. SWEPCO modeled IRA tax benefits as part of the 2023 IRP.

The primary provisions under the IRA are made available through the production tax credit ("PTC") and investment tax credit ("ITC"). These benefits are adopted for all scenarios. Figure 41 below illustrates how these benefits are assumed to decline over time. The PTC value in Figure 41 represents the multiplier applied to the statutorily defined value of the credit (e.g., in 2024 it is assumed that new wind units will receive 100% of the defined credit value). By contrast, the ITC value represents the percent of capital cost that can be recovered through the credit (i.e., in 2024 it is assumed that new solar will receive a 30% rebate on capital costs).

Figure 41 Federal Tax Credit Assumptions Used in the 2023 IRP (2024-2037)





7.3. IRP Scenario Inputs

SWEPCO evaluated four market scenarios, in addition to the Reference Scenario, that describe plausible futures that may develop over time and result in a materially different set of market conditions under which SWEPCO will need to serve customer needs. Each scenario is driven by a set of thematically oriented fundamental market assumptions. These scenarios are used to test the boundaries of future market conditions. SWEPCO dispatched the 2023 IRP candidate portfolios across the scenarios. The themes tested within and across scenarios reflect the priorities and key risks identified by SWEPCO and its stakeholders and support the analysis of a no or least regrets evaluation of options.

Figure 42 summarizes the key drivers of each scenario in a matrix.

Clean Energy Technology Advancement ("CETA")

The CETA scenario is one of two in the 2023 IRP that test how an aggressive policy shift to decarbonize the electric sector could manifest in future market conditions. Under the CETA scenario, GHG reductions are achieved primarily through increased deployment of clean supply- and demand-side technologies. For example, under the CETA scenario SWEPCO assumes that investments in R&D drive cost improvements beyond the Reference Scenario for new wind, solar, and storage units. The CETA case also incorporates more aggressive end-use electrification than the Reference Scenario resulting in greater penetration of EVs and other technologies. This results in a higher load forecast and a shift in customer demand patterns.

Enhanced Carbon Regulation ("ECR")

The ECR case is the other case that tests an aggressive policy shift to decarbonize the electric sector. Unlike the CETA case, reductions under the ECR scenario are achieved through a combination of actions that result in higher costs for emitting generation and restrictions on the future development of fossil fuels. Under the ECR scenario carbon emissions are regulated through a federal cap-and-trade program that results in a significant CO_2 price and higher natural gas costs, relative to the Reference Scenario.

Focus on Resiliency ("FOR")

Under the FOR case, overall pressure on GHG emissions and fuel prices is similar to the Reference Scenario, but regulators are increasingly concerned with the reliability of the electric grid. Under the FOR scenario, SPP is assumed to enforce both winter and summer reserve requirements on participating utilities. For this IRP, SWEPCO assumed a 26% Planning Reserve Margin for winter informed by the SPP study discussed in Section 3.5. Further, the peak credit value of solar and storage resources decreases more quickly over time in the FOR scenario than in the Reference Scenario and additional fully-dispatchable capacity is deployed across SPP.

No Carbon Regulation ("NCR")

Under the NCR case, natural gas prices remain low and no federal limits on carbon emissions are enacted during the forecast period. The resulting market conditions are similar to recent history and tend to be more favorable for natural gas and coal resources relative to the Reference Scenario. The NCR case allows SWEPCO to stress test candidate portfolios that rely more heavily on new renewable generation under conditions that are generally more favorable to gas-fired units and evaluate the impact on expected customer costs.

Figure 42 2023 IRP Scenario Assumption Matrix

Scenario Concept	Load	Natural Gas	Carbon	Reserve Margin	New Resource Cost	Peak Capacity Credit
Reference	Base	Base	Moderate	Base	Base	Base
Clean Energy Technology Advancement (CETA)	High	Base	Moderate	Base	Low	Base
Enhanced Carbon Regulation (ECR)	Low	High	High	Base	Low	Base
Focus on Resiliency (FOR) – Summer	Base	Base	Moderate	Summer Requirements	Base	Low
Focus on Resiliency – (FOR) – Winter	Base	Base	Moderate	Winter Requirements	Base	Low
No Carbon Regulation (NCR)	Base	Low	No Price	Base	Base	Base

7.3.1. Scenario Load

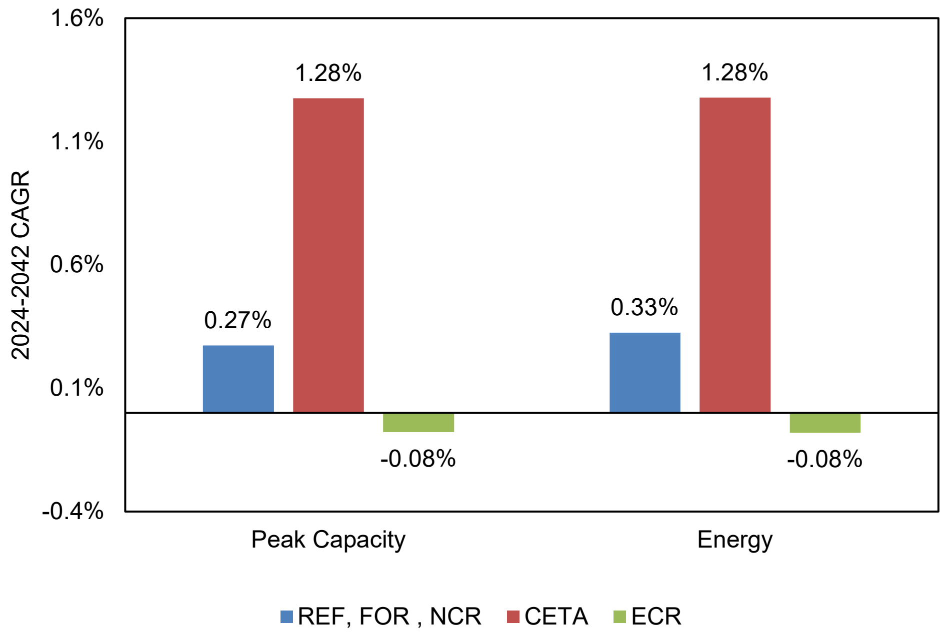
Two of the 2023 IRP scenarios, the FOR and NCR Scenarios, use the same base case load forecast as the reference scenario above (described in Section 2), while the CETA and ECR cases flex customer load higher and lower (respectively) to reflect changes in the broader economy and the expected impact of demand-side technologies.

Under the CETA scenario, load grows more quickly than under the Reference Scenario driven by increased economic growth, deployment of electric vehicles, and greater building electrification. Overall annual load growth for the SPP market in the CETA scenario is 1.28% per year between 2024-2042, or approximately 1% higher than the Reference Scenario. The accelerated adoption of EVs and other end-use electrification applications also impact the load shape.

Under the ECR scenario, overall load levels in SPP fall over time driven by lower economic growth and adoption of distributed technologies by SWEPCO's customers. Under this case, annual load growth in SPP is forecast at -0.08% per year, or approximately 0.35% lower than the forecast of load growth from the Reference Scenario during the 2024-2042 period. SWEPCO relied on the AEP Load Forecast Fundamentals for this estimate.

Changes to annual energy for load across the SPP market are illustrated in Figure 43, below.

Figure 43 SPP Load Growth 2024-2042 CAGR and Comparison with the Reference Scenario



7.3.2. Scenario Fuel & CO_2 Prices

Where the Reference Scenario reflects an expected outlook for commodity prices and other fundamental market drivers, there are a number of factors that may result in market conditions that produce higher or lower prices for natural gas and CO_2 permits.

Natural Gas Prices

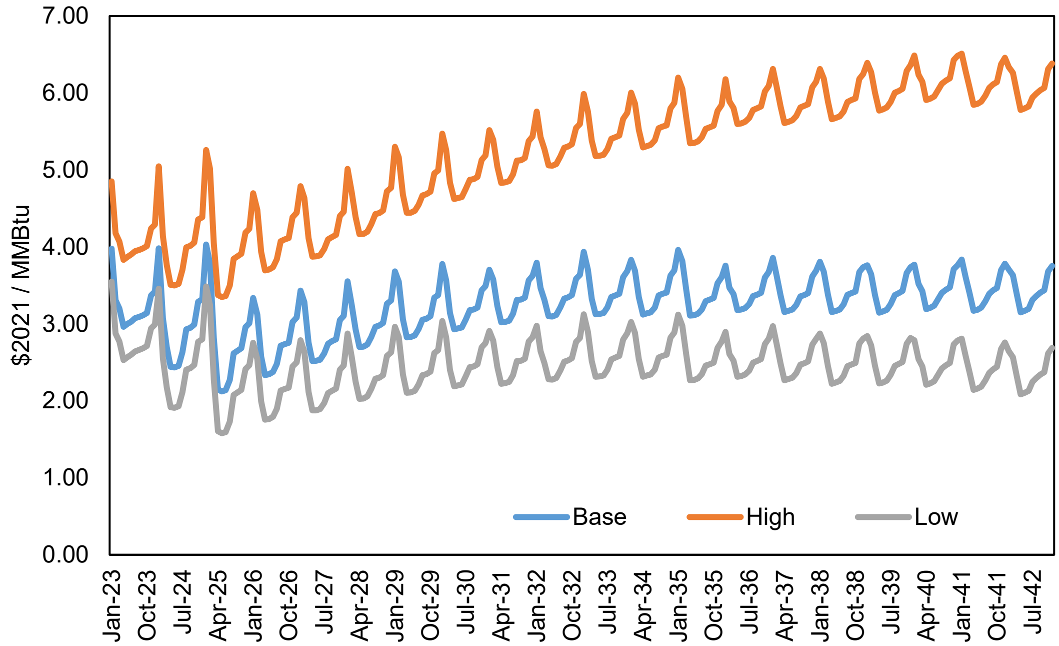
The same natural gas price view relied upon for the Reference Scenario is also used in the CETA and the FOR scenarios when deriving the power price forecast for the SPP market. Under the ECR and NCR Scenarios, natural gas prices are flexed upwards and downwards (respectively) reflecting different views of supply-side conditions for producers.

Under the ECR case, natural gas prices are assumed to be higher than in the Reference Scenario despite lower overall demand. In this scenario, policymakers are enacting stricter federal regulations in an effort to reduce GHG emissions economy-wide. This results in a higher CO_2 price sooner, limits on access to natural gas supply (e.g., drilling bans), and higher production costs due to higher CO_2 prices and stricter environmental requirements. The result is that the natural gas price forecast is approximately $2.00/ MMBtu higher than in the Reference Scenario over the course of the 2024-2042. Under the NCR case, policymakers place less pressure on economy-wide GHG emissions than under the Reference Scenario and natural gas prices are approximately $0.80/ MMBtu lower.

Figure 44 below compares the high and low gas price forecasts relied upon in the ECR and NCR cases to the base view used for the remaining scenarios. All three forecasts benchmark against EIA AEO 2022 forecasts for Henry Hub by using three cases: the AEO 2022 Reference Case, the High Oil and Gas supply and the Low Oil and Gas supply. In the AEO 2022 Reference case for the gas price, U.S, natural gas production increases through 2050 with more than 35% of gross additions exported.

According to the details provided by EIA, the oil and gas supply cases illustrate the relationship between LNG exports and production. The Low Oil and Gas Supply case assumes higher costs with less resource availability resulting in an increase of natural gas prices. In this case, LNG exports begin to decline in the mid-2030s. In the High Oil and Gas Supply case, that assumes lower natural gas prices, LNG exports grow twice as fast compared to the Reference case, leveling off during the mid-2040s.[28]

Figure 44 High, Base and Low Panhandle Eastern TX-OK Natural Gas Price Forecasts (real 2021$ / MMBtu)



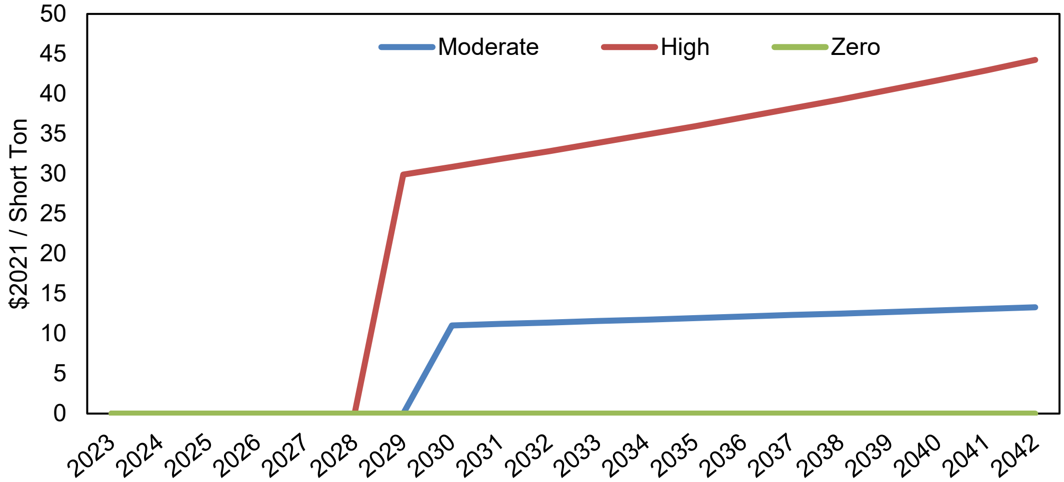
CO_2 Prices

Under the Reference Scenario policymakers enact measures that put moderate pressure on the economy to reduce greenhouse gas emissions in the form of a carbon price starting in 2030. Both the CETA and FOR scenarios use the same trajectory for CO_2 prices. However, there is the potential that future emissions reduction policy could occur sooner than expected and that the level of policy pressure could be materially higher, as represented in the high CO_2 price forecast used in the ECR scenario.

Under this scenario, a national cap on carbon is instituted starting in 2029 with prices starting at approximately $30/Ton (real $2021) and rising to around $45/Ton by 2042. Under the NCR Scenario, policymakers do not enact a price on CO_2, and prices are assumed to be zero throughout the forecast period. Figure 45 below illustrates how the high and zero CO_2 prices in the ECR and NCR Scenarios (respectively) compared to the moderate CO_2 price view used in the remaining three scenarios.

[28] https://www.eia.gov/outlooks/aeo/narrative/production/sub-topic-01.php

Figure 45 High and Zero CO_2 Price Forecasts ($2021 / Ton)



7.3.3. Scenario Reserve Requirements

Summer Capacity Requirements

SPP recently announced it will require LSEs to maintain sufficient firm capacity to meet a 15% planning reserve margin[29] above summer peak demand to maintain system reliability. SPP also continues to review their resource adequacy requirements for LSEs such that the Company considers this a risk.

Increments of certain new resources, including some renewables and various duration battery storage, provide less additional capacity value as more of the resource is added to the system. That is, the amount of solar already installed on the system impacts how much Effective Load Carrying Capability (ELCC) the next increment provides.

Figure 46 summarizes the reference and low ELCC views for select technologies used in the 2023 IRP scenarios. This figure summarizes the relationship between the installed nameplate capacity in the SPP market and the ELCC value received. It does not show the ELCC value awarded by year across scenarios, which is discussed in Section 7.4.2.

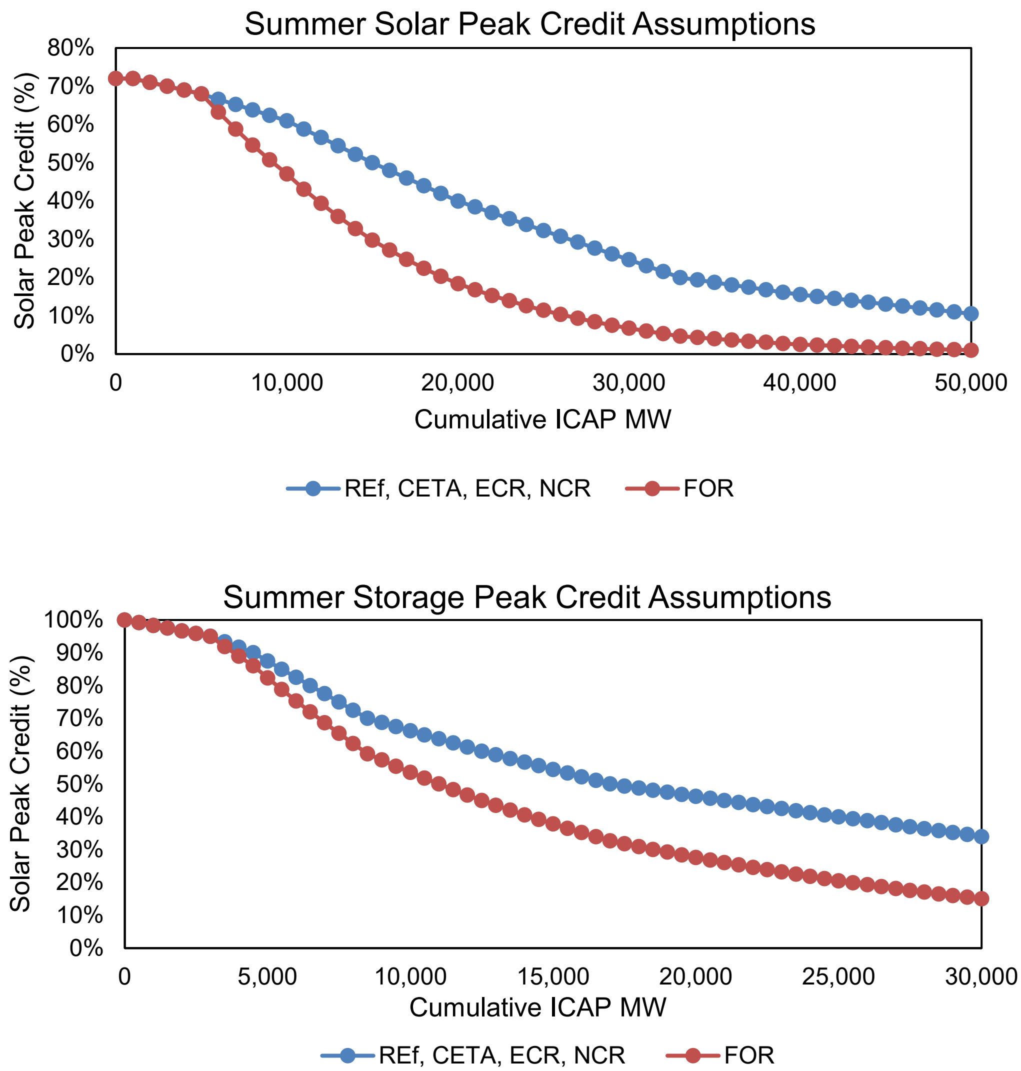
Under the FOR case, a lower outlook is used than in the other scenarios driven by changing SPP market rules for maintaining reliability. Again, the assumed ELCC values were informed by studies performed by or for SPP.[30,31]

29 https://www.rtoinsider.com/articles/30538-spp-board-regulators-side-with-staff-over-reserve-margin

30 https://www.spp.org/documents/65169/2020%20elcc%20wind%20and%20solar%20study%20report.pdf

31 https://spp.org/documents/65977/astrape%20spp%20energy%20storage%20study%20report%20updated%20winter%20results.pdf

Figure 46 ELCC Assumptions for Select Resources by Cumulative ICAP MW [32,33]



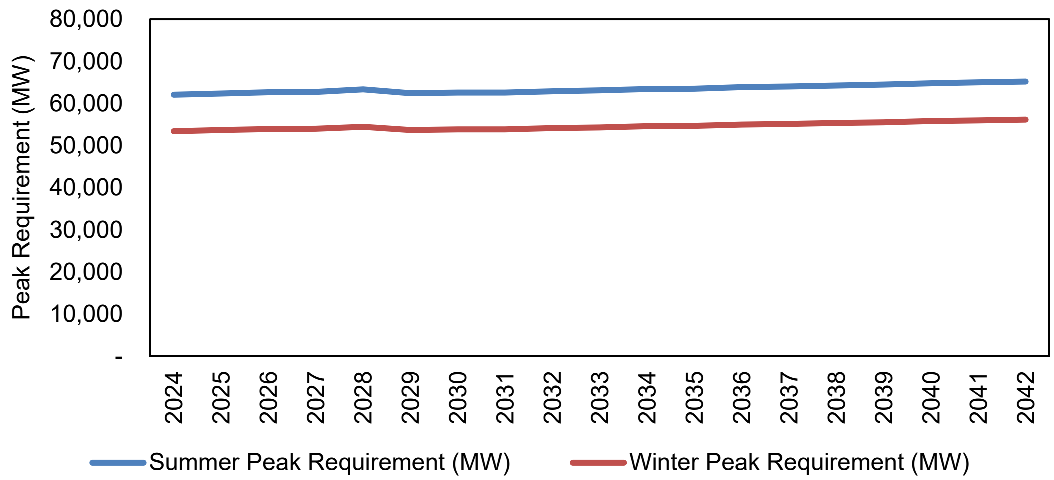
Winter Capacity Requirements

Outside of the summer capacity requirements that are enforced for all five scenarios, in the FOR scenario, SWEPCO modeled a 26% reserve margin requirement for the winter season as well. This scenario posits that the SPP market rules will evolve as the resource mix changes in SPP and maintaining reliability in the winter season becomes more challenging absent a planning requirement. Figure 47 below compares the annual forecast of winter peak requirements with peak summer requirements in the FOR case and shows how winter peak demand is growing similarly to summer peak demand. SWEPCO relied on AEP Load Forecasting Fundamentals for the winter load estimates.

32 2019 SPP Solar & Wind ELCC Accreditation. SPP. August 2019. <https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf>

33 SPP Energy Storage Study Final Report. Astrape Consulting. November 2019. <https://spp.org/documents/61387/astrape%20spp%20energy%20storage%20study%20report.pdf>

Figure 47 Comparison of FOR Scenario SPP Winter and Summer Peak Requirements (2024-2042)



To model winter requirements in the FOR case, it was also necessary to develop assumptions describing the peak contribution of different resource types in the winter season. Peak demand in winter typically occurs early in the morning. Some resources, particularly solar PV, may provide less load carrying capacity during winter peak periods than during summer peaks. Under this scenario solar resources are expected to perform materially different in winter than summer and their peak credits are modeled to decline over time from 19% in 2024 to 1% in 2042. The net load peaks in SPP during the winter are fairly flat across the day. Because of this, batteries are not able to provide as much capacity value as they do during the summer. For winter, it was assumed the capacity peak credits for 4- hour batteries to decline form 80% to around 25% in 2042.

7.3.4. Scenario Technology Assumptions

In general, SWEPCO relied on EIA's 2022 AEO as the starting point for the technology cost and performance assumptions for new utility scale generation in the SPP footprint. Reference case changes to technology cost and performance over time are based on the moderate case of the 2022 National Renewable Energy Laboratory's ("NREL") annual technology baseline ("ATB") report.[34] SWEPCO assumes that under all scenarios, federal tax credits for new renewable generation and grid energy storage reflect current law and the schedules enacted in the Inflation Reduction Act (IRA) of 2022.

SWEPCO's 2023 IRP scenario flexed a number of technology-related assumptions including the expected capital cost and federal tax benefits available to renewable units as part of the 2023 IRP scenarios.

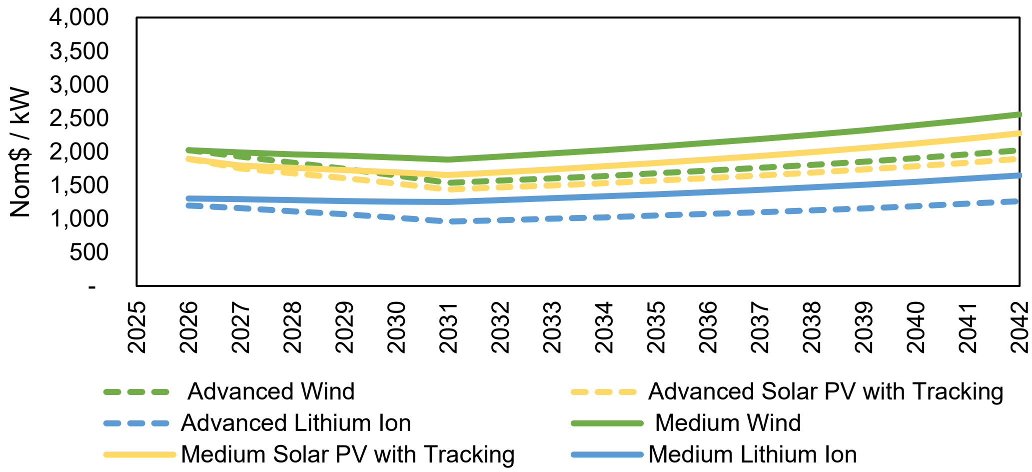
Unit Capital Costs

As described in Section 5, SWEPCO generally relies on technology cost assumptions from EIA's 2022 AEO report to establish the expected capital cost of new utility-scale resources. Those costs change over time based on the medium outlook from the NREL 2022 ATB. This outlook of new unit costs is used for three of the 2023 IRP scenarios: the Reference Scenario, the FOR scenario, and the NCR Scenario. However, under the ECR and CETA Scenarios, rapid deployment of new renewable technologies combines with higher levels of policy support causing the cost of these technologies to decline more quickly. Capital costs follow the "advanced" NREL ATB case learning rates, resulting in costs that are materially lower

[34] NREL Electricity Annual Technology Baseline (ATB) 2022. https://atb.nrel.gov/electricity/2022/data

throughout the forecast period. Figure 48 below compares the forecast of expected capital costs from NREL's advanced case used in the ECR and CETA Scenario to the medium case costs used in the remaining three scenarios.

Figure 48 Comparison of Capital Costs Under Advanced and Medium Outlooks for Select Technologies (2025-2042 | Nom$ / kW)



7.4. Market Scenario Results

The load, technology, policy, and other assumptions for the five scenarios described above served as inputs into the AURORA model. Using the model's long-term capacity expansion ("LTCE") functionality, SWEPCO developed scenario-specific forecasts of the SPP market. In the portfolio modeling stage, described below in Section 8, SWEPCO developed an optimal candidate resource plan for each of the five scenarios.

7.4.1. Capacity Expansion Results

SWEPCO used the AURORA LTCE model to forecast the least-cost combination of resource additions and retirements in SPP using the assumptions for each market scenario. While the SPP market selections do not directly impact the resources that can be selected for the SWEPCO portfolio, they are informative for describing how different resource types are likely to perform under certain conditions. Figure 49 and

Figure 50 below illustrate the 2042 SPP capacity and generation mix (respectively) across all five market scenarios compared with the SPP resource mix in 2022.

Under the Reference Scenario, much of the existing coal fleet is retired over the course of the forecast. Due to the combination of announced retirements and the modest CO_2 price that comes into effect in 2030, only 1 GW of coal are left by the end of the study period. To replace coal plant retirements and meet growing load, a combination of renewables, 4-hour battery storage, and new gas units are added over time. In total, approximately 23 GW of new wind, 26 GW of new solar, 24 GW of new storage units, 6 GW of new gas peakers, and 2 GW of new combined cycles are added by 2042. The gas units are installed primarily to meet firm requirements and mostly enter the market beyond 2030. Under the Reference Scenario, solar and wind generators provide more than 75% of the total SPP generation by 2042. The result is that total CO_2 emissions in the SPP market drops by 80% in the Reference Scenario from 2022 to 2042.

Figure 49 Comparison of 2022 and 2042 Nameplate Capacity by Technology in SPP

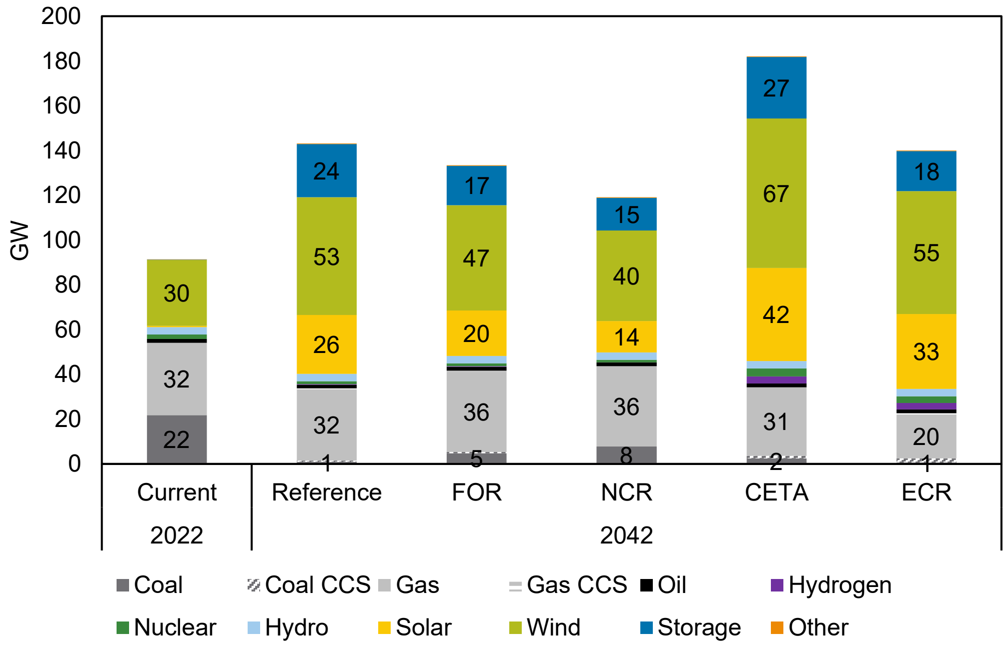
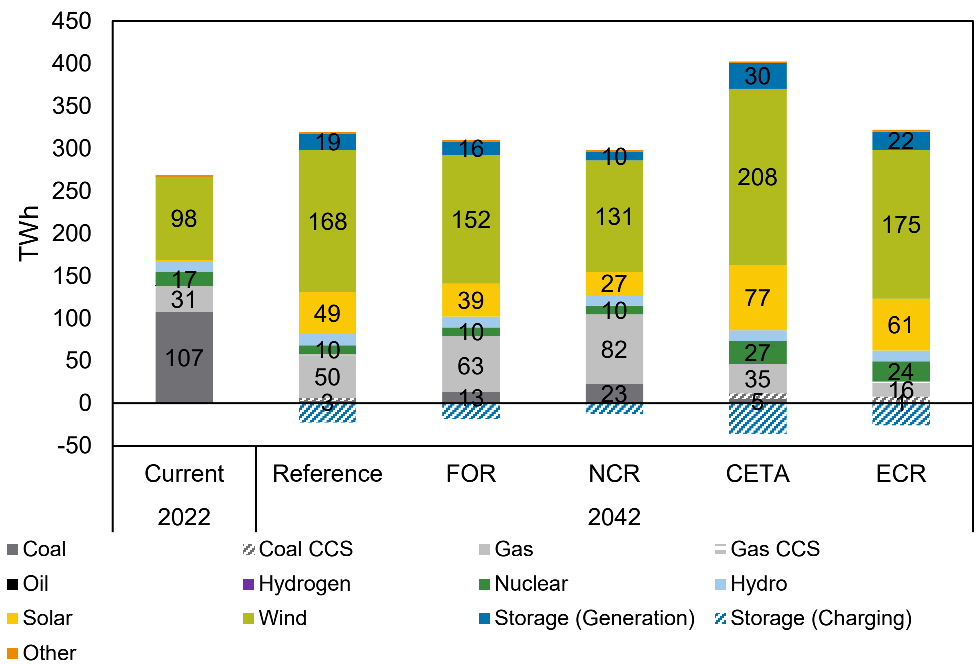


Figure 50 Comparison of 2022 and 2042 Generation by Technology in SPP



Under the NCR Scenario, there is no economy-wide CO_2 price; however, natural gas prices are forecast lower than in the Reference Scenario. The result is that more existing coal is able to remain competitive and approximately 8 GW of coal units are still operating by the end of the forecast period.

The overall build-out of new renewables in the NCR Scenario is lower than in the Reference Scenario with approximately 10 GW of new wind, 14 GW of new solar, and 15 GW of new short and long duration battery storage added by 2042. Compared to the Reference Scenario, there is a similar amount of total gas capacity, though it is weighted more heavily towards combined cycles in the NCR Scenario due to the lower commodity price assumption that makes these units more competitive. The result is that wind and solar resources comprise only about 55% of total SPP generation by 2042 in the NCR Scenario, with natural gas units providing the majority of the remaining energy. Emissions fall in this scenario, but not as far as in the Reference Scenario, down around 53% from 2022 levels by the end of the forecast period.

In the FOR scenario, commodity price conditions are similar to the Reference Scenario, but the addition of the winter reserve margin requirement and the reduction in the peak contribution for wind and solar units result in a larger proportion of thermal dispatchable generation in the SPP market than under Reference Scenario conditions. As a result, by 2042, there is approximately 4 GW more coal capacity remaining in the market and 4 GW of additional gas-fired generation relative to the Reference Scenario by 2042. Deployment of renewable technologies is lower than in the Reference Scenario due to the lower capacity credit value of these units. Approximately 20 GW of new solar, 17 GW of new wind, and 13 GW of new 4-hour battery storage are added by 2042. Renewable sources comprise just under 60% of SPP market generation in this year. SPP CO_2 emissions drop by approximately 68% from 2022 to 2042, compared to around 79% in the Reference Scenario.

Under the CETA Scenario, load growth is higher than in the Reference Scenario and the cost of new renewable generation is lower due to faster learning rates. The combination of higher load and more affordable renewable technology leads to materially greater deployment of solar, wind and 4-hour battery storage than under the Reference Scenario. By 2042, nearly 42 GW of new solar, 37 GW of new wind, and 27 GW of new energy storage of various duration are added in SPP under the CETA Scenario. Furthermore, approximately 1.7 GW of NGCC capacity with carbon capture and storage is installed or retrofitted. Despite higher load and 2 GW more coal retirements, gas generation across SPP under CETA is slightly higher than under the Reference Scenario due to greater penetration of renewables. Solar and wind units comprise more than 76% of total SPP generation by 2042, and CO_2 emissions decline by around 83% SPP-wide relative to 2022 levels.

In the ECR Scenario, a lower load outlook for SPP is combined with a higher outlook for CO_2 and natural gas commodity prices. This results in accelerated coal retirements, relative to the Reference Scenario, and nearly all coal units in SPP are retired by 2042. Natural gas-fired capacity also falls SPP-wide and approximately 2 GW of NGCCs are retrofits with carbon capture and storage over the forecast period. The ECR Scenario also indicates a more favorable environment for existing nuclear resources. Gas units without CCS retrofits run at low capacity factors under the ECR scenario, while CCS-equipped gas units tend to run at higher capacity factors as carbon prices rise over the study period. SPP sees slightly higher amounts of wind and solar deployment as the Reference Scenario (around 54 GW and 33 GW respectively) and lower levels of various duration battery storage (around 17 GW). However, due to lower load growth, these resources make up a large proportion of the overall system, with wind and solar accounting for 79% of total SPP generation by 2042. SPP-wide CO_2 emissions are the lowest in this scenario and decline by 92% relative to 2022 levels by the end of the forecast period. To achieve these levels, renewable generation is supported by additional nuclear and CCS-equipped natural gas capacity relative to the Reference Scenario.

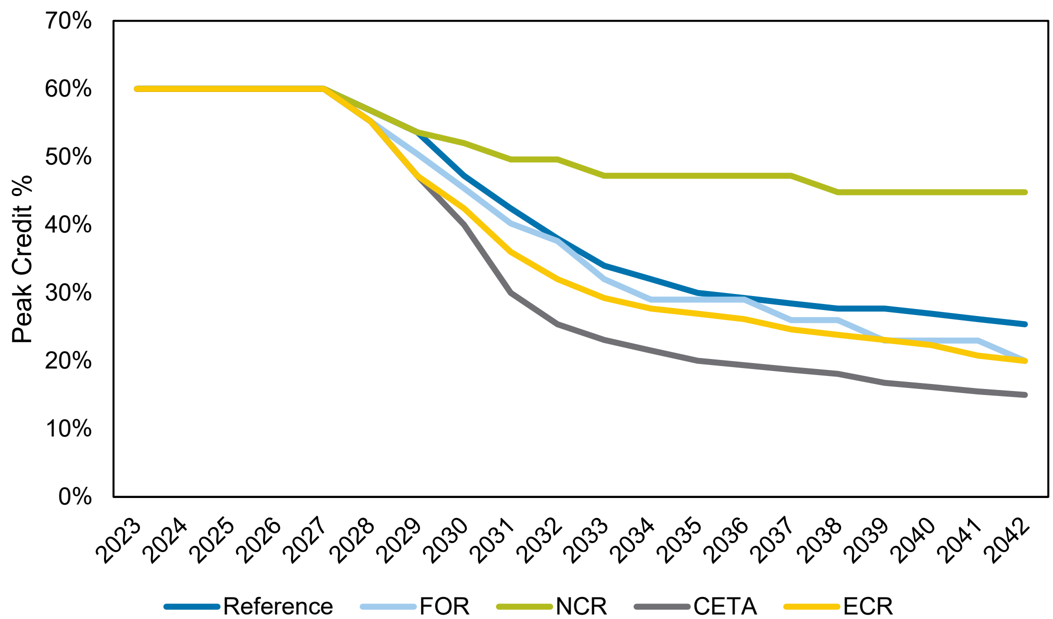
7.4.2. Effective Load Carrying Capability (ELCC) Results

As described in 7.4.1, the SWEPCO scenarios have produced a range of capacity expansion results using the AURORA LTCE model that result in different penetration levels of renewable and 4-hour battery storage. The ELCC value of the renewables and 4-hour battery storage are based on the amounts installed in each scenario. The resulting differences are illustrated by the curves in Figure 46. While solar and storage credits vary by case, wind ELCC is assumed to stay constant at 15.4% informed by a SPP Study.[35]

Under the Reference, FOR, and ECR scenarios, solar ELCC values decline from the current 60% value to levels near 25% by 2042, with the capacity value falling over time in-line with the increments of new solar added in each case. Less solar is added in the NCR case driven by lower natural gas prices and the absence of an economy-wide CO_2 price, and solar ELCC declines to around 45% peak value by 2042. While the NCR Scenario stretches towards an upper bound, the CETA case sets the lower bound. Under the CETA Scenario capital costs are lower for renewable resources leading to more and earlier additions. ELCC of incremental solar and storage falls more quickly in this scenario and settles at value of around 15% in summer during the second half of the forecast. Similar to solar, storage ELCC values vary across scenarios, ranging from 40% to 55% by 2042. The resulting solar and storage summer ELCC values are summarized in Figure 51 and **Error! Reference source not found.**.

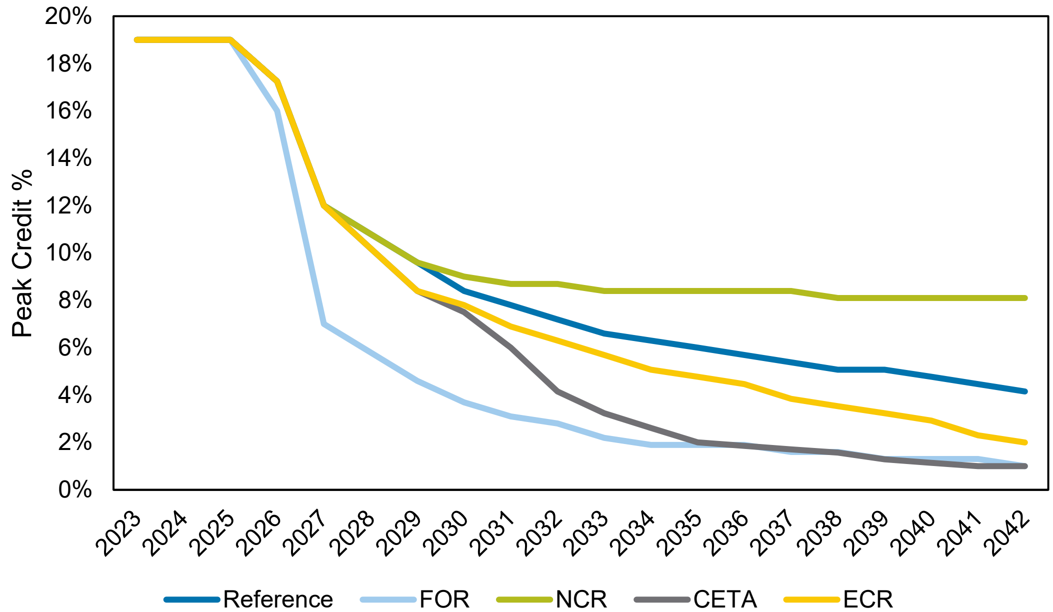
Under the FOR scenarios, solar winter ELCC values are assumed to decline from 19% in 2023 to 1% by 2042. Winter season reserve margin requirements were not enforced in the remaining market scenarios.

Figure 51 Comparison of Solar Summer Peak Credits by Scenario



[35] 2020 SPP Solar & Wind ELCC Accreditation. SPP. November 2022. < https://www.spp.org/documents/68289/2022%20spp%20elcc%20study%20wind%20and%20solar%20report.pdf

Figure 52 Comparison of Storage Summer Peak Credits by Scenario



7.4.3. Market Price Results

The key market outputs from the scenario modeling process are the power prices illustrated below in Figure 53 and Figure 54. Shown are all five market scenarios modeled in the 2023 IRP. These figures illustrate the wide but plausible range of energy prices that emerge from the scenario modeling step.

Figure 53 Annual On-Peak SPP South Hub Electricity Price ($2021 / MWh)

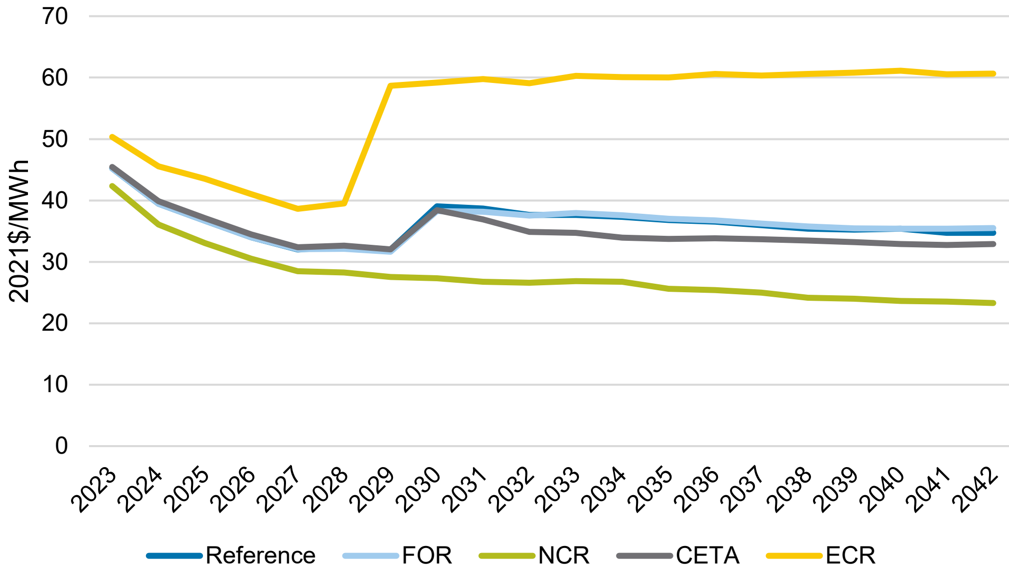
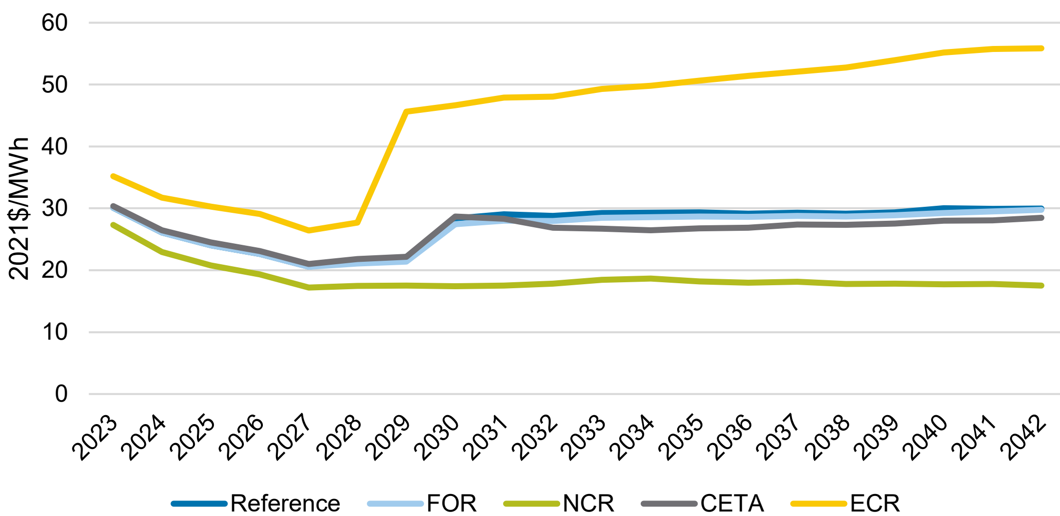


Figure 54 Annual Off-Peak SPP South Hub Electricity Price ($2021 / MWh)



Under the Reference Scenario, on-peak energy prices in SPP South Hub decline gradually from around $45 / MWh ($2021 real) in 2023 to $32 / MWh by 2029 in large part due to the decrease in natural gas prices over the period. There is approximately a $12 / MWh spread between on- and off-peak pricing over this same period, in real dollar terms. Starting in 2030 prices step up in both on- and off-peak periods by approximately $7 / MWh driven by the introduction of the CO_2 price in that year. There is a slight decline in on-peak pricing from 2030 onward even as CO_2 prices continue to rise due to the increasing penetration of renewable generation on the SPP system. Off-peak prices, however, remain relatively flat due to increasing costs of thermal generation in periods of lower renewable output. This contributes to a narrowing of the spread between on- and off-peak prices over the forecast period, which declines to about $4.75 / MWh by 2042. Overall, similar to the rest of the scenarios, the passage of the Inflation Reduction Act enables additional amount of renewable and energy storage generation to enter the SPP market. SWEPCO considered the impacts of the IRA in all scenarios.

Under the FOR and CETA Scenarios, SPP market prices are largely similar, though forecasted to be somewhat lower, especially under the CETA Scenario, than in the Reference Scenario. This outcome is to be expected given that the same commodity prices were used in all three of these scenarios (i.e., base natural gas and moderate CO_2 prices). Under the CETA Scenario, prices are between $2-3 / MWh lower than the Reference Scenario over the long term despite faster load growth due to the high level of renewable penetration in the SPP market.

The ECR scenario sets the upper bound of SPP market prices. During the 2024-2028 period, both on- and off-peak prices are approximately $6-7 / MWh higher than in the Reference Scenario due the higher natural gas price assumed in this scenario. In 2029, the high CO_2 price is introduced and SPP market prices rise by around $19 / MWh in both on- and off-peak periods. From 2029 onward, on-peak prices remain flat (in real terms) due to the lower load growth assumption in this scenario and the high penetration of renewable generation offset the progressively increasing cost of carbon. Conversely, off-peak prices grow slightly from 2029-2042 due to the high cost of running thermal generation during periods of low renewable output. The result is that the spread between on- and off-peak prices falls to around $4.80 /MWh by 2042 in the ECR scenario when viewed on an annual average basis.

The NCR Scenario sets the lower bound of SPP market prices. From 2024-2029, overall market prices are around $3-4 / MWh lower than in the Reference Scenario due to the low natural gas prices forecast that is assumed in this scenario. After 2029, SPP prices in this case are materially lower than in the Reference Scenario due to the lack of federal CO_2 pricing and lower outlook for natural gas prices assumed as part of the scenario. On-peak prices are largely steady from 2029 until the mid-2030s when they begin to decline modestly in real terms as additional renewable generation is added to the system. Off-peak pricing is flat through the early 2030s, after which prices grow slightly due to an increase in the forecasted coal prices and changing capacity mix in the SPP market. The spread between on- and off-peak prices therefore narrows from around $9-10/MWh to between $5-6 / MWh in this scenario on an annual basis by the end of the study period.

7.5. IRP Stochastics Development

SWEPCO's stochastic risk analysis attempts to address volatility and "tail risk" impacts to its generation portfolio that would not be included under "expected" or "weather normal" deterministic forecasts. The selected variables modeled for stochastic realizations – gas prices, power prices, and renewable output – are specifically selected to address portfolio performance under various market dynamics and generation availability outcomes.

As described in Section 8.1, rate stability is one of the key objectives. The scorecard metric "Cost Risk" is defined as the NPVRR increase between the 95^{th} percentile and 50^{th} percentile portfolio cost observed under the set of stochastic distributions of variables. This metric captures the robustness of portfolio cost when subjected to a range of combinations of gas prices, power prices, and renewable output.

This analysis involves developing 250 combinations of stochastic gas prices, power prices, and renewable output, then determining the portfolio costs under each of the 250 iterations through portfolio dispatch in AURORA and the PERFORM financial module. The 95^{th} and 50^{th} percentile NPVRR among the set of portfolio cost realizations are identified to calculate the "Cost Risk" scorecard metric.

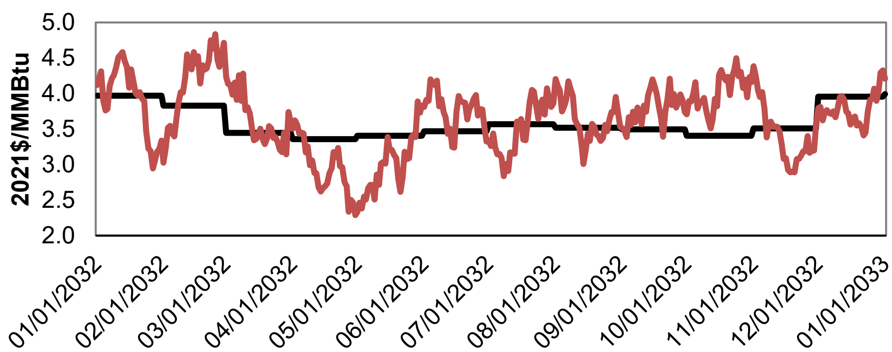
7.5.1. Gas and Power Prices Stochastics

Stochastic price paths for gas and power prices are developed using CRA's Moment Simulation Energy Price ("MOSEP") model. MOSEP is a regime-switching, mean-reverting[36] model that takes as input expected paths for gas and power, based on SWEPCO's Reference Scenario outlined in Section 7.2. MOSEP's Monte Carlo engine simulates random price deviations around the expected paths based on historical volatility and seasonal gas-power correlative relationships to yield "realized" price paths for both gas and power. While price paths are developed for the period 2023-2042, data from 2032 and 2042 are singled out for the portfolio cost analysis.

To reflect realistic market price behavior, historical daily average gas and power price data were gathered to observe key price characteristics and calibrate simulation model parameters. The key seasonal market price characteristics include, but are not limited to, the range of prices around a seasonal median price, standard deviation, magnitude and frequency of sudden price spikes, market heat rate, and correlation between gas and power. The specific pricing points used in this analysis are the daily natural gas spot index at ANR-SW and the day-ahead, around-the-clock SPPS price strip. The historical prices from the period January 1, 2017 to December 31, 2021 were used to summarize the relevant market price behavior and include only the most recent market dynamics.

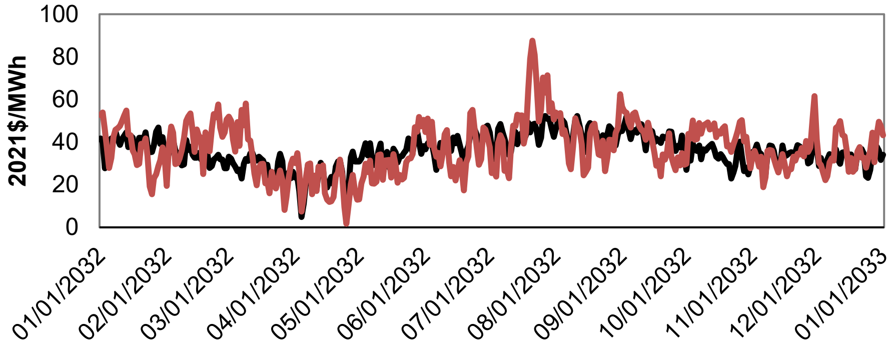
Figure 55 and Figure 56 illustrate one sample iteration of gas and power daily prices in 2032 produced by MOSEP (red lines). The baseline forecasts are included in the same graphic (black lines) for comparison. As illustrated, the stochastic price paths exhibit more daily volatility as well as high-price and low-price risk than the deterministic Reference Scenario forecasts.

Figure 55 Sample Iteration of Daily Natural Gas Price Simulation for 2032 ($2021)



[36] The model simulates price behavior under different price regimes (e.g., normal price regime, spike price regime). Commodity prices have been found to exhibit a mean-reverting behavior after a sudden price jump. The model facilitates switching between different regimes via a Markov transition matrix. Given the current regime, the transition matrix specifies the probabilities of staying in the current regime or moving to a different regime. These probabilities are approximated based on historical data. For references, see the following paper, on which MOSEP is based - Higgs, H. & Worthington, A. "Stochastic price modeling of high volatility, mean-reverting, spike-prone commodities: The Australian wholesale electricity market." Energy Economics, 2008.

Figure 56 Sample Iteration of Daily Power Price Simulation for 2032 ($2021)



7.5.2. Renewable Output Stochastics

Renewable output uncertainty is integrated in SWEPCO's stochastic analysis process to address the risks associated with energy market exposure. To widen the range of modeled renewable availability, historical weather data from NREL was used to proxy wind and solar availability using NREL's System Advisor Model ("SAM").

Historical hourly weather conditions for the years 2008 to 2012 (5 weather years) for counties across Oklahoma[37] were used as inputs into the SAM tool. Proxies for a farm of wind turbines and single-axis tilt solar panels were used in SAM to simulate hourly wind and solar power output, respectively. Adjustments to SAM power estimates were used to align with SWEPCO's capacity factor assumptions for new wind and solar resources.

Given the fact that the weather years sampled had a narrower distribution of average capacity factor over the course of the year, extra variability was induced on certain capacity factor profiles to simulate outcomes from more extreme weather data. To induce such variability, a cumulative distribution function was created using the original data, and multipliers were applied to specific portions of the data to replicate a similar distribution. The multipliers were constrained such that this new distribution maintains the physical constraints of a solar/wind system (i.e. roughly half the hours of the year have no sun). An example of a cumulative distribution function for the original set of hourly capacity factors versus adjusted values is displayed in Figure 57.

[37] Five geographically diverse counties across Oklahoma - Caddo, Cimarron, Dewey, Kay, and Kingfisher – were identified to determine a wind capacity factor shape. SAM simulated wind power output for each weather year, and the combined output across the five counties for a given weather year was used to define a single wind output shape. For solar, Caddo county data was used to define a solar output shape, as one would expect less volatility across geography for hourly solar output than wind.

Figure 57 Example of Capacity Factor Adjustment

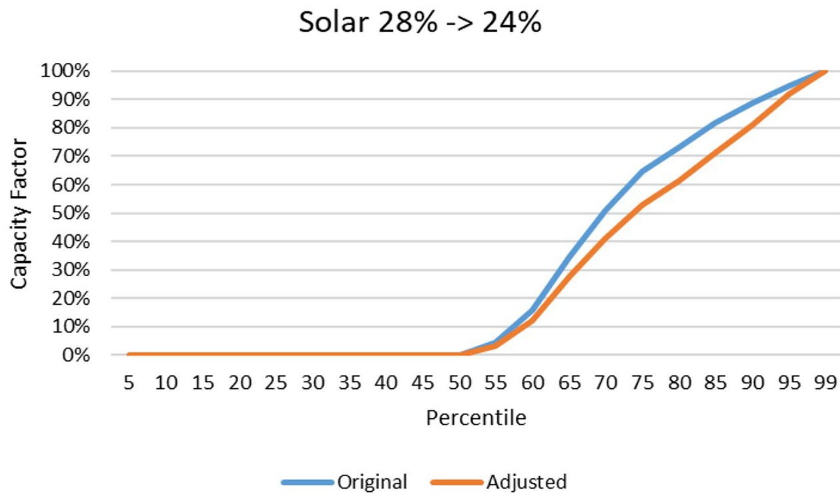


Figure 58 and Figure 59 illustrate hourly capacity factor shapes for wind and solar in the month of July, with the monthly average capacity factor shape depicted in the bolded blue and yellow lines, respectively.

Each of the 250 commodity price paths are combined with renewable output data from one of the five historic weather years. For example, the first 50 iterations of gas and power prices are matched with wind and solar output based on historical weather year 2008 conditions.

Figure 58 Simulated Hourly Wind Capacity Factor for July

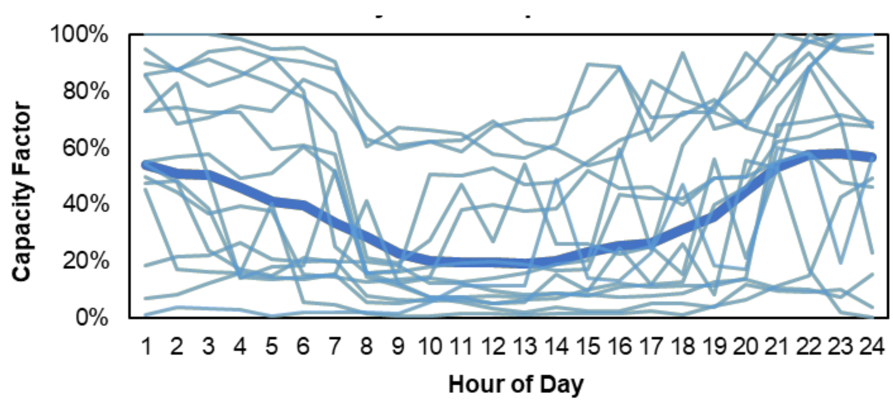
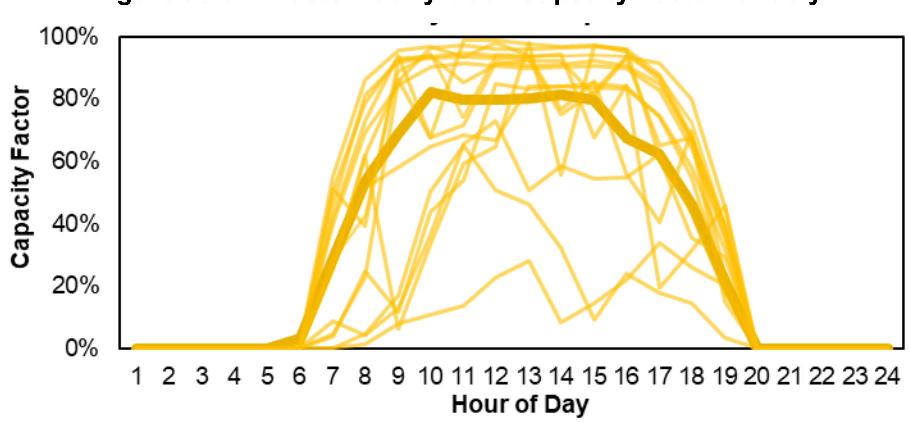
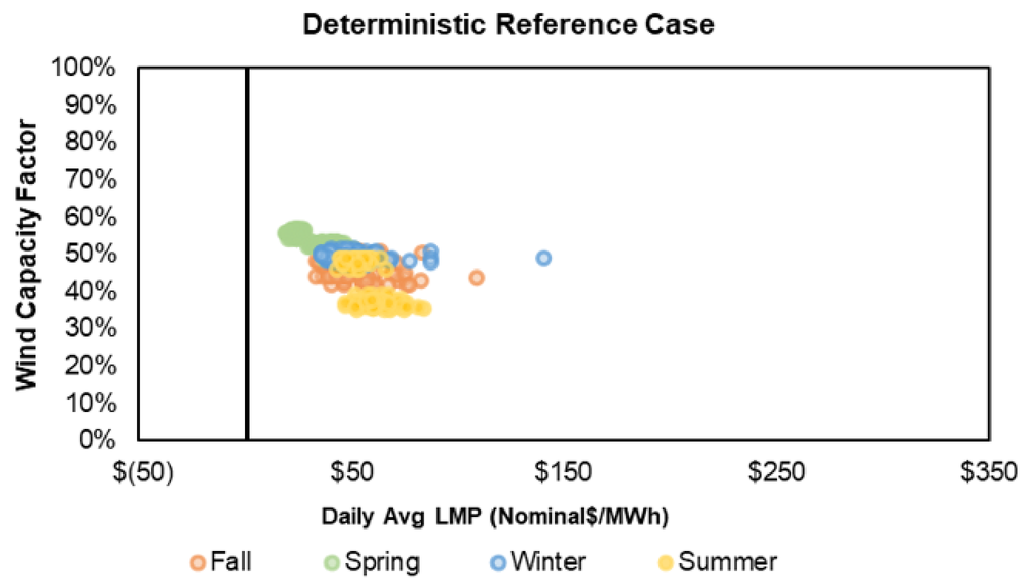


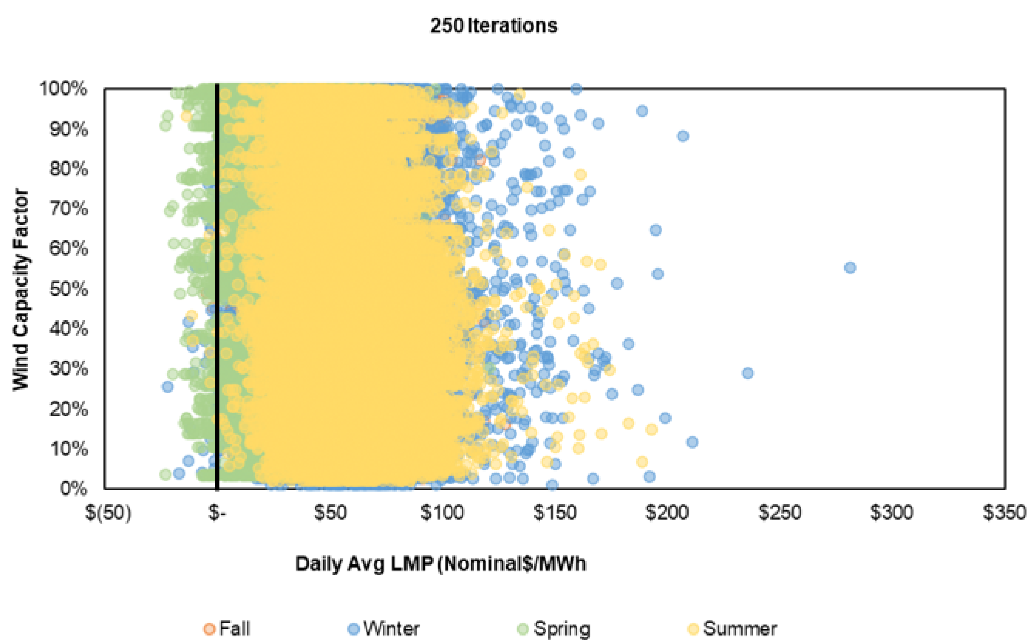
Figure 59 Simulated Hourly Solar Capacity Factor for July



By incorporating stochastic renewable profiles and gas and power prices, the combinations of renewable output and price paths cover a greater range than the Reference Scenario. This is illustrated in Figure 60 that compares combinations of daily average wind capacity factors and the daily average power price across the deterministic Reference Scenario versus the 250 stochastic iterations around the Reference Scenario. From the first graphic, prices vary with renewable output, but there is limited variability in the overall market prices that are reflected. By contrast, the stochastic modeling approach used by SWEPCO tests many more hours and captures periods of high market prices and low renewable output, and vice versa.

Figure 60 Daily Average Wind Capacity Factor and Power Price, Under Deterministic Reference Scenario vs. 250 Stochastic Iterations





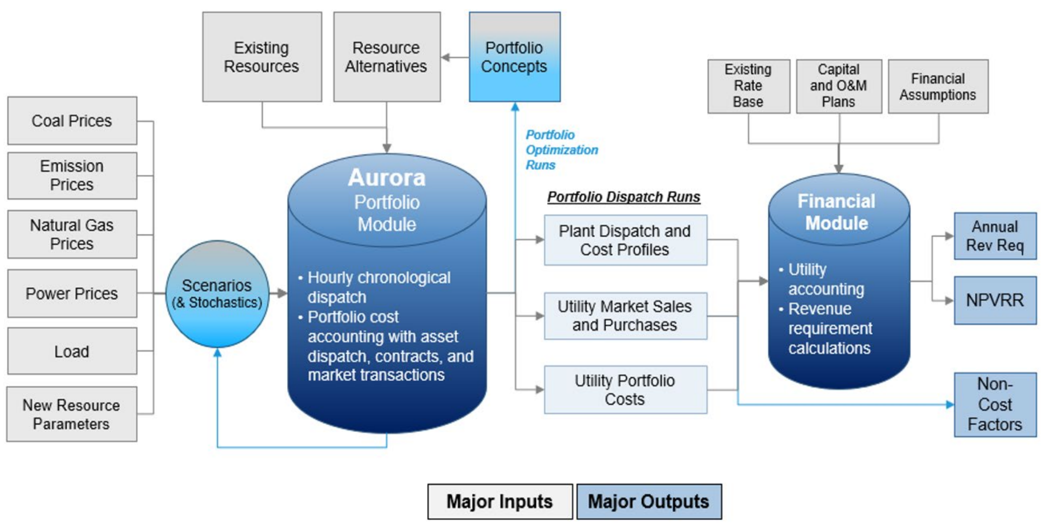
8. Portfolio Analysis

8.1. Introduction

The 2023 Portfolio Analysis began by reviewing the priorities and objectives of SWEPCO and its Stakeholders, as well as key uncertainties and potential futures risks associated with the cost of serving SWEPCO's customers described in the prior section. This process informed the analysis performed and the development of an IRP scorecard. The scorecard is a tool used to evaluate the potential trade-offs between different demand- and supply-side options that SWEPCO may employ to meet customer future needs in the 2023 IRP. The 2023 IRP scorecard and metrics are detailed below in this chapter.

In terms of impact on the IRP analysis, the priorities and objectives informed the 2023 IRP by leading to the creation of five different market scenarios that reflect plausible, but different, combinations of outcomes across key related fundamental market drivers (e.g., load, fuel costs, seasonal requirements, level of environmental pressure, etc.) described in the prior section. These scenarios tested how the prices of energy changed across the SPP market under different combinations of these fundamental conditions. One portfolio was developed under each of the five scenarios (under FOR, both a winter and summer portfolio was developed) using the portfolio optimization feature in AURORA to find "optimal" selections of resources under different market conditions. These five SPP market scenarios were also used to test the riskiness (or not) of the different candidate resource plans by subjecting them to a wide range of market outcomes that are materially different than scenario under which each plan is optimal.

Figure 61 2023 IRP Modeling Framework



SWEPCO set an objective to provide reliable service for customers while also guarding customers from periods of unexpectedly high costs in the winter and summer seasons. The IRP, therefore, seeks to test market volatility and short-term extreme conditions through the stochastic analysis of power, gas, and renewable outcomes. The risk metrics incorporate high cost outcomes to evaluate the potential impacts on total system costs under extreme or adverse SPP market conditions that may occur in both winter and summer for each of the Portfolios.

8.2. Scorecard Metrics

In resource planning, a scorecard can be an effective tool in decision-making. "Scorecard" for resource planning purposes refers to a device that illustrates the performance of alternative resource plans across a set of company-defined objectives, performance indicators, and metrics. A scorecard enables a utility to develop and defend resource decisions on the basis of how different plans score on the factors that matter to the utility and the customers it serves. It provides a simple and structured means of explaining how sometimes objectives align, while other times they can conflict and be traded off as part of reaching a reasonable decision that is in the best interest of customers.

The scorecard has three primary elements, illustrated in Figure 62:

- **Objectives** are overarching goals that align to SWEPCO or stakeholder priorities. The four objectives of the 2023 SWEPCO IRP Scorecard are:
  - Customer Affordability
  - Rate Stability
  - Maintaining Reliability
  - Local Impacts & Sustainability
- **Performance indicators** measure progress towards goals and serve as measurable categories across which portfolios can be compared. There are ten performance indicators on the SWEPCO Scorecard, these align to the four objectives and are detailed below.
- **Metrics** are the units in which the performance indicators are measured, often they include a time element (e.g., net present value, cumulative period, future test year) in addition to numerical value or calculation.

Figure 62 Elements of the 2023 SWEPCO IRP Scorecard

Objective	Performance Indicator	Metric
Customer Affordability	NPVRR	Total long-term Annual Costs paid by ratepayers
	% of Income	Percentage of wallet for residential customers
	Near-Term Rates	Near-term impact of resource decisions
Rate Stability	Scenario Resilience	Range of cost from highest to lowest market scenario
	Cost Risk	95th percentile of shock risk
	Market Exposure	Amount of net purchase or sales from SPP market
Maintaining Reliability	Reserve Margin	Excess capacity position
	Operational Flexibility	Dispatchable capacity included in portfolio
Local Impacts & Sustainability	Local Impacts	New Investment in utility service territory
	Carbon Emissions	Percent carbon reduction

The details of objective, performance indicator, and metrics are described in the following sections. The scorecard is found below as Figure 63.

8.2.1. Objective 1: Customer Affordability

Customer affordability is a primary goal for SWEPCO. This objective aligns with AEP's corporate vision, "We're redefining the future of energy and developing forward-thinking solutions that provide both clean and affordable energy to power the communities we serve."[38] For the SWEPCO 2023 IRP, minimizing the expected cost to customers, to the extent reasonable when evaluated against other objectives, was a clear and obvious objective for the scorecard.

The SWEPCO scorecard includes two performance indicators that track the customer affordability objective across the short- and long-term.

[38] From AEP corporate website on planning for clean energy future: <https://www.aep.com/about/ourstory/cleanenergy>

Short Term: 5-year expected growth in customer rates

Customers need affordable energy over the long term. However, many customers may tend to prefer resource plans that limit expected short term increases in customer rates. Portfolios with similar net present values over the longer term can have significantly different near-term impacts, which may be important to consider, along with long term costs, when selecting a preferred plan. This performance indicator allows SWEPCO to assess that risk across portfolios and weigh short- and long-term cost considerations when selecting the preferred plan.

SWEPCO measures and considers the expected percentage growth in retail rates over five years as the metric for the short-term customer affordability performance indicator. Near-term retail rate impact is measured using a 5-year Compound Annual Growth Rate ("CAGR") of expected system costs for the years 2023-2028

Long Term: 30-year net present value of revenue requirement

Portfolios that perform well in the short- and medium-term may be expensive over the longer term. Further, portfolios that perform similarly in the short- to medium-term may look very different over the long term under varying market conditions.

This performance indicator allows SWEPCO to evaluate the risk of higher costs when viewed further into the future and weigh short- and long-term cost considerations.

NPVRR was selected as the metric for this performance indicator. NPVRR is a representation of the total long-term annual costs paid by SWEPCO's utility customers related to power supply. This includes plant O&M costs, fuel costs, environmental costs, net purchases and sales of energy and capacity, property and income taxes, and the return on and of capital related to power supply. NPVRR will be measured over the long-term using a 30-year period (2023-2052) and is expressed both in terms of total and levelized rate. The levelized rate is the fixed charge per MWh needed to recover the 30-year NPVRR.

8.2.2. **Objective 2: Rate Stability**

Rate stability is a key component of affordability for SWEPCO's customers. A resource plan that performs well under expected conditions may expose ratepayers during periods of volatility, extreme weather events, or extended outages. SWEPCO understands that market fluctuations in electric and fuel commodities and other uncertainties can adversely impact customer rates under a resource plan deemed to be the most affordable. This risk was recently highlighted during the 2021 Texas power crisis where a historic cold weather event led to rolling blackouts, forced generator outages, and high wholesale gas and electricity prices. While SPP was shielded from long-term outages in its service territory during this event, SWEPCO's customers were exposed to high wholesale gas and electricity prices.

The performance indicators of rate stability test how certain and robust the expected costs of each portfolio are by subjecting them to different market scenarios and to random shocks in power and gas prices, and renewable outputs. This assessment evaluates how portfolios perform under a wide range of market conditions, commodity prices, and policy outcomes and allows SWEPCO to balance affordability under expected conditions with resilience to changes in the market.

The three performance indicators for rate stability are described below, they include an assessment of the potential change in rates across a wide range of scenarios, the amount of revenue requirement at risk under adverse or extreme conditions and track the amount of seasonal reliance on the SPP energy market under each candidate plan.

Scenario Resilience: Range of 30-year NPVRRs across the 5 market scenarios

This performance indicator describes the range of total long-term costs for a given portfolio when modeled across all five market scenarios. This allows management to compare the overall variability or consistency of costs for each candidate portfolio under the full range of market conditions considered in the IRP.

The metric for this performance indicator measures the range in cost of each portfolio option between its best and worst performing planning scenario. It is calculated by subtracting the 30-year NPVRR for a single resource plan in the (1) the market scenario under which total costs for the resource plan were the lowest from (2) the market scenario under which the total costs to the resource plan were the highest.

The 30-year NPVRR is selected because SWEPCO's going in position shows a need for replacements in the 2020s and later in the 2030s. Using a long-term metric allows for all of the resource decisions made in the IRP to be fully reflected and maintains consistency in the affordability performance indicators on the scorecard. NPVRR is a representation of the total long-term annual costs paid by SWEPCO's utility customers related to power supply. This includes plant O&M costs, fuel costs, environmental costs, net purchases and sales of energy and capacity, property and income taxes, and the return on and of capital related to power supply. NPVRR will be measured over the long-term using a 30-year period (2023-2052) and is expressed both in terms of total and levelized rate.

Cost Risk: The revenue requirement increase when moving from the 50th to the 95th percentile of portfolio costs in years 2032 and 2042

Portfolios that perform well (or similarly) under expected conditions may perform poorly when exposed to market volatility, extreme weather, or extended unit outages - such as the impacts of extreme weather observed in February 2021. This measure tests the robustness of portfolio costs when exposed to random combinations of gas prices, power prices, and renewable outputs, and allows SWEPCO to compare the cost of the candidate portfolios under adverse market conditions, relative to the expected cost of the option under normal conditions. In other words, this metric measures the increase in the expected cost to serve customers under volatile or extreme conditions, relative to the expected case.

The metric for this performance indicator measures the difference between the (1) total portfolio costs under 95th percentile conditions and (2) portfolio costs under median conditions across the stochastic distribution in the Reference Scenario for years 2032 and 2042. This measure serves as a useful touch point for discussing portfolio risk with stakeholders and evaluating whether renewable-heavy portfolios that engage in market purchases and sales at different times of the day or year increase or decrease its cost risk.

2032 and 2042 are selected as the test dates to align with the reported customer affordability metrics and enables SWEPCO to distinguish between the impact of decisions made in the 2020s and 2030s to meet known capacity gaps. These test years also align to the 10-year and 20-year results presented in the IRP report and appendix, respectively.

Market Exposure: net purchases or sales as a % of summer and winter load in 2032

This performance indicator allows SWEPCO to evaluate the medium- and long-term exposure of different resources options to conditions in the SPP energy markets by indicating the total portion of customer needs served by the market, or conversely, the reliance on market sales in certain periods of excess generation. SWEPCO current purchases significant amounts of energy needed to serve load on an annual basis and there is an opportunity for the utility to supply more of the energy that its customers consume. This indicator allows management to measure progress towards that goal.

The metric for this performance indicator measures the magnitude of net purchases or sales made by each portfolio in model year 2032, distinguishing between market activity occurring during the summer (June, July, Aug) and winter (Dec, Jan, Feb) seasons. It is calculated by subtracting the volume of hourly gross energy sales from hourly gross purchases across the test months for each season, and then dividing the resulting value by total volume of energy demand served over those same months.

2032 is chosen as the test year to illustrate the long-term differences in market exposure across the candidate portfolios. Both winter and summer values are reported for this year.

8.2.3. Objective 3: Maintaining Reliability

“Safe, reliable power” is a key theme of the SWEPCO mission statement and reliability is an important consideration for SWEPCO’s customers that are active in the stakeholder process. Understanding the role that SPP plays in maintaining broader system reliability, SWEPCO has identified maintaining reliability as an important, fundamental objective to be included on the IRP scorecard. Reliability is an essential aspect of a utility’s mission and has taken on even greater importance since the Texas and SPP energy event of winter 2021. SWEPCO also noted the potential benefits to maintaining reliability of distributing a relatively larger number of smaller units across geographies that provide local benefits and relieve system constraints.

Four performance indicators were selected to measure progress towards maintaining reliability. These cover the total capacity reserves, by season, maintained by SWEPCO under each plan, the amount of dispatchable capacity included in each plan, and an indicator of the locational diversity of the resources selected in each candidate portfolio.

Planning Reserves: % of summer and winter capacity requirements served by the resource plan from 2023-2042

SWEPCO seeks to track energy and capacity exposure separately in the 2023 IRP. This performance indicator measures SWEPCO’s expected reliance on the market (or excess capacity) for meeting summer and winter reserve margin requirements. This measure allows SWEPCO to evaluate the seasonal exposure of different candidate resource plans to reliability events measured as the percent of seasonal reserve requirements contributed by owned resources (i.e., excluding any short-term purchases) towards meeting planning reserve margin requirements. This exposure is viewed as the average performance across all five market scenarios to capture the full range of load forecasts included in the 2023 IRP.

The metric for this performance indicator will be SWEPCO’s reserve margin measured as the ratio of firm (i.e., UCAP) supply to expected peak demand for *both* the summer and winter periods. For reporting purposes, the average reserve margin period over the 2023-2042 time period will be included in the scorecard. The period 2023-2042 is used to evaluate SWEPCO’s average exposure across the portfolios over time.

This metric is calculated by dividing the winter UCAP of the resource plan by SWEPCO’s winter peak requirement and the summer UCAP of the resource plan by SWEPCO’s summer peak requirement for years 2023-2042 across all five market scenarios. This results in 100 winter values and 100 summer values. These values are then averaged by season and reported on the scorecard.

Operational Flexibility: Dispatchable capacity in 2031 and 2041

The increase in intermittent renewable resources across SPP may create the need for more flexible resources that can provide a reliability service and balance the system during periods of low output or extreme weather. Understanding each portfolio’s ability to respond to system needs is an important factor for determining the preferred plan and can also be considered as a measure of future ancillary services value, which is highly uncertain.

This performance indicator allows management to evaluate the amount of ramping capacity on its system measured as the cumulative amount of dispatchable capacity selected by the candidate portfolio in 2032 and 2042. Dispatchable resources include new gas peaking units (multiple configurations), new gas combined cycle units (with or without CCS), new energy storage units, and new hydrogen-fired units.

The metrics for this performance indicator represent the total firm capacity (UCAP) provided by fast-ramping technologies in years 2032 and 2042. Multiple blocks of identical scalable technologies (such as battery storage) constructed within a single year will be considered as separate units, since no discount is being providing to represent benefits of collocating projects (i.e., the model does not see lower interconnection or land costs when building many of these units so they could be assumed to be located separately). The 10- and 20-year reporting period is selected to align with the results included in the IRP report and reflect SWEPCO's position after filling the expected capacity gap emerging in the late 2020s and into the 2030s.

Resource Diversity: Generation mix by resource in 2042

SWEPCO is interested in maintaining a diverse set of resources as a method for maintaining reliability for its customers and in evaluating the role that new and innovate technologies can play to help customers reach their goals. This performance indicator will allow management to assess the overall diversity of its long-term resource plan as well as compare the performance of plans that rely on more traditional vs. more advanced technologies.

The metric for this performance indicator is a pie chart displaying the percentage of total generation provided by the different generating technologies selected in each candidate resource plan in model year 2042 and under the Reference Scenario. The metric is measured in 2042 to capture the full range of replacement decisions and because it is expected that many advanced technologies may not become economic until the 2030s and therefore a shorter term (e.g., 10-year) metric may provide little or no information to support SWEPCO's evaluation. Wedges of qualifying advanced technologies are emphasized using the color palette to compare the relative level of new or innovative technologies selected by each resource plan.

8.2.4. Objective 4: Local Impacts & Sustainability

Community partnership and local investment are key themes in the SWEPCO mission statement and sustainability objectives. SWEPCO has repeatedly indicated an interest in having a positive local impact within its service territory and highlighting the opportunities for customer-sited resources as part of the 2023 IRP. Furthermore, this metric integrates awareness to sustainability measures through an assessment of carbon reduction estimates in each portfolio.

SWEPCO indicated interest in measuring the performance of alternative resources against those goals. This objective also allows SWEPCO to evaluate the relative exposure of candidate resource plans under outcomes where significant reductions in GHG emissions are required in the power sector – a plausible outcome with potentially material impacts on the cost to serve SWEPCO's customers.

Two performance indicators were selected to measure progress towards local impacts and sustainability. Local impacts are measured as the amount of new generation located in the SWEPCO service territory and the amount of local investment associated with those projects. Sustainability is measured through portfolio CO_2 emissions and the level of reductions achieved relative to a 2005 baseline.

Local Impacts: Installed MW and capital invested inside SWEPCO's service territory

SWEPCO has a continued interest in being a community partner and recognizes the importance of demonstrating the potential benefits of different candidate resource plans to its stakeholders and customers, including creating opportunities for customers interested in locating new generation on-site. This performance indicator allows management to compare the amount of total new installed resources likely to be constructed in regions that SWEPCO serves and that may be candidates for customer sited projects over the 2023-2032 period. Further, this indicator allows management to evaluate the expected amount of local investment made under each candidate resource plan, which is a fair proxy for evaluating the relative local economic impacts of each plan.

There are two metrics associated with this performance indicator: (1) The cumulative nameplate MW of new capacity likely located within the SWEPCO service territory from 2023-2032; and (2) the cumulative capital invested in the SWEPCO service territory from 2023-2032, calculated as the sum of capital spent over the period in current year (e.g., 2023) US dollars.

The 2023-2032 period was selected to align the scorecard to the portfolio modeling results that are presented in the 2023 IRP and to focus the evaluation on local impacts over the first 10 years of the overall resource plan.

CO_2 Emissions: Percent reduction from 2005 in the Reference Scenario in 2032 & 2042

This performance indicator allows SWEPCO to evaluate progress towards reducing carbon emissions and also serves as a measure of comparing the relative exposure of candidate resource plans under outcomes where significant reductions in GHG emissions are required in the US power sector.

The metric for this performance indicator is the level of carbon emission reductions relative to SWEPCO's total emissions in the year 2005. Carbon emissions are defined as the direct emissions from SWEPCO's owned and contracted generating resources. This metric is calculated by dividing the total SWEPCO portfolio emission in the test year (2032 or 2042) by total SWEPCO portfolio emission from the year 2005 and evaluating the percent reduction. The scorecard uses the test years 2032 and 2042 to maintain consistency with the 10- and 20-year outlooks reflected in the IRP report and appendix.

Figure 63 2023 IRP Scorecard

	Customer Affordability		Rate Stability			Maintaining Reliability				Sustainability
Portfolio	***Short Term:*** *5-yr Rate CAGR, Reference Case*	***Long Term:*** *30-yr NPVRR, Reference Case*	***Scenario Range:*** *High Minus Low Scenario Range, 30-yr NPVRR*	***Cost Risk:*** *RR Increase in Reference Case (95th minus 50th Percentile)*	***Market Exposure:*** *Net Sales as % of Portfolio Load, Scenario Average*	***Planning Reserves:*** *% Reserve Margin, Scenario Average*	***Operational Flexibility:*** *Dispatchable Capacity*	***Resource Diversity:*** *Generation Mix (MWh) by Technology Type - Reference Case*	***Locational Diversity:*** *Nameplate MW Installed Outside SWEPCO Territory*	***CO2 Emissions:*** *Percent Reduction from 2005 Baseline - Reference Case*
Year Ref.	2023-2028	2023-2052	2023-2052	2032| 2042	2032	2023-2042	2032 | 2042	2042	2023-2032	2032 | 2042
Units	%	$MM Levelized Rate	$MM Levelized Rate	$MM Levelized Rate	Summer | Winter	Summer | Winter	MW	%	MW|$MM	% Reduction
Reference Portfolio										
CETA Portfolio										
ECR Portfolio										
FOR – Summer Portfolio										
FOR – Winter Portfolio										
NCR Portfolio										

Coal
Gas CC
Gas CT
Wind
Solar
Other

*Levelized Rates and NPVRR metrics are for generation component only. Metrics are for comparison only and do not represent the final costs which will apply to ratepayers.

8.3. Portfolios Considered

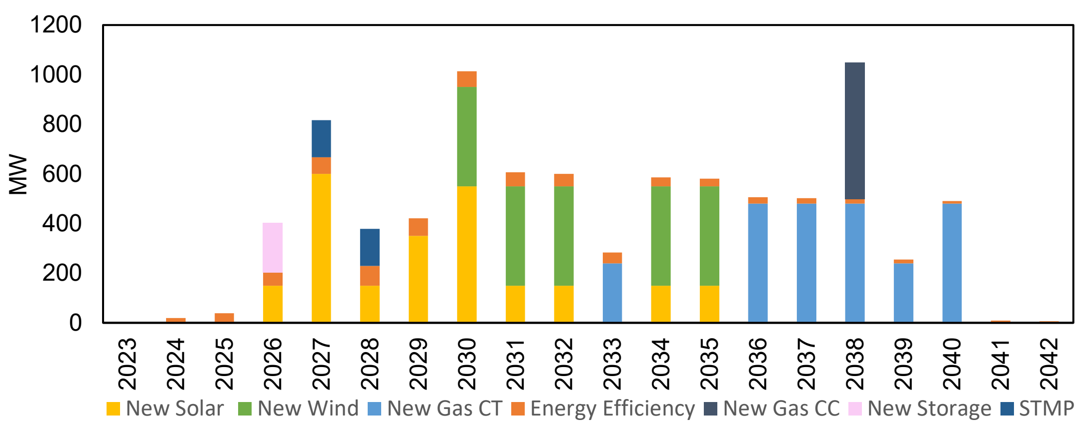
SWEPCO used the AURORA model to select an optimal portfolio of resources to meet expected future customer needs under each of the five SPP market scenarios. The AURORA model uses an optimization technique to select the "least-cost" set of candidate resources that minimizes the net present value of revenue requirements subject to certain constraints and assuming the market scenario conditions including load, fuel and CO_2 prices, reserve requirements and technology capacity accreditation assumptions where relevant (as discussed for each market scenario in Section 7). The candidate resources made available to the model include the conversion of the two Welsh units to natural gas in 2028, supply-side resource and demand-side resource options, the input parameters for the Reference Scenario of which are discussed in Section 5 and Section 6, respectively, and the scenario parameters which are discussed in Section 7.

Each of the six candidate portfolios were stress-tested under all five market scenarios and were also stress tested under stochastic distributions of gas prices, power prices, and renewable outputs (as discussed in Section 7.5) using a suite of resource planning tools, namely AURORA and the PERFORM utility financial model. AURORA produces projections of asset-level dispatch and the total variable costs associated with serving load. The AURORA output is then used by CRA's PERFORM model to build a full annual revenue requirement, inclusive of capital investments, fixed operating and maintenance costs, tax credits, and financial accounting of depreciation, taxes, and utility return on investment. The PERFORM model produces annual and NPV estimates of revenue requirements over the planning horizon. The outputs from AURORA and PERFORM are then used to populate the 2023 IRP Scorecard to inform the Company for the identification of the Preferred Plan.

8.3.1. Resource Additions by Portfolio

Resource additions in each of the six portfolios considered are shown in Figure 64 to Figure **68** below.

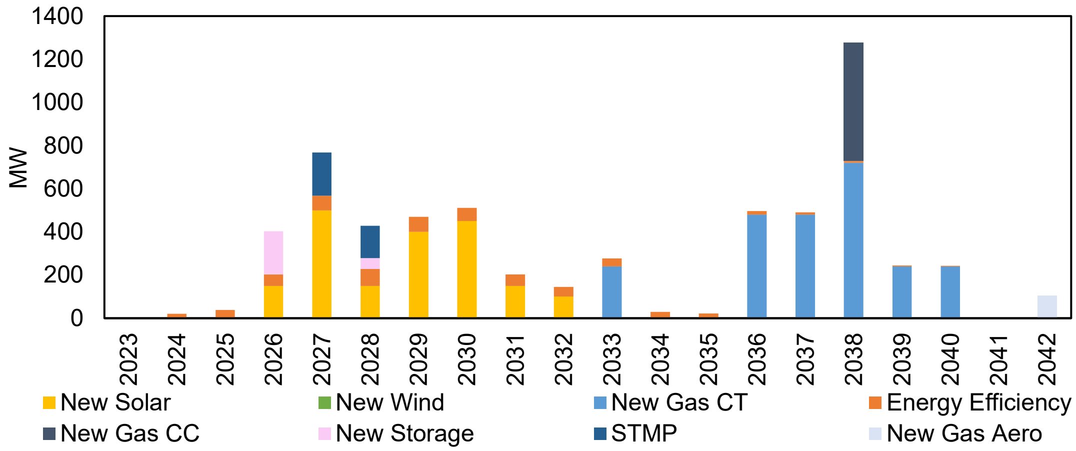
Figure 64 Annual Resource Additions in the Reference Portfolio



For the Reference portfolio, approximately 2.4 GW of new solar, 2.0 GW of new wind, 2.4 GW of new NGCTs, 200 MW of energy storage, and 550 MW of NGCC are added by 2042. All of the new solar, storage, and new wind are added by the end of 2035 to take advantage of the ITC and PTC for customers from the Inflation Reduction Act. New NGCT and NGCC units are installed primarily from 2036 onward, to replace retiring existing units to meet firm requirements. The Welsh 1 & 3 conversions are selected in 2028.

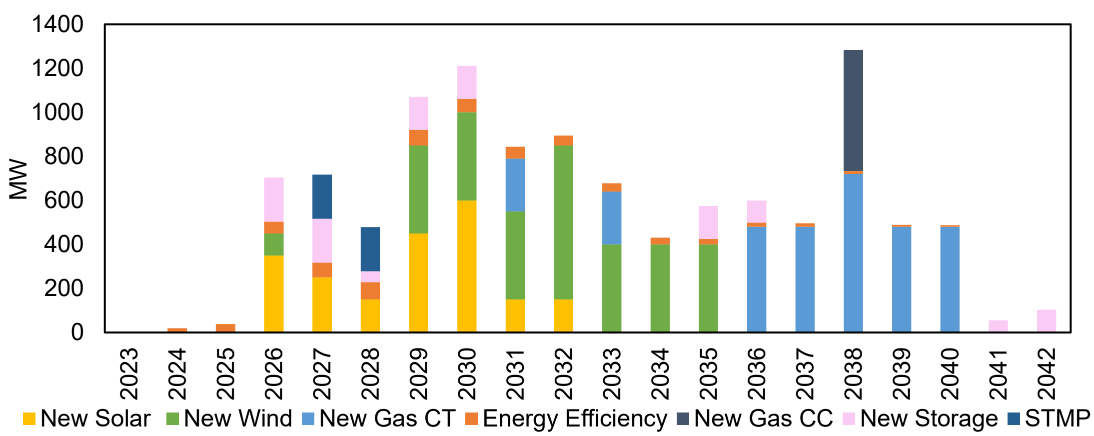
In addition, demand-side resources including incremental EE programs are pursued. The contributions of incremental EE programs occur from 2024 – 2042, with the peak MW contribution of 78.8 MW in 2028.

Figure 65 Annual Resource Additions in the NCR Portfolio



The NCR Scenario has lower natural gas prices and zero carbon prices that generally improve the economics of gas-fired generation relative to other scenarios. However, lower additions of renewables in the SPP region means that solar PV installed in this portfolio has a higher ELCC, given this technology's higher capacity credit relative to other scenarios. The higher capacity credit of solar PV makes this resource more attractive in the NCR Scenario relative to the other SPP market outlooks. As a result, AURORA selects more solar in the NCR portfolio despite low gas and carbon prices. In addition, the lack of carbon program reduces the competitiveness of energy rich resources like wind and this portfolio des not add any new wind during the study period. By 2042, the NCR portfolio adds 1.9 GW of new solar, 250 MW of new storage, 2.4 GW of new NGCTs, and 550 MW of NGCC.

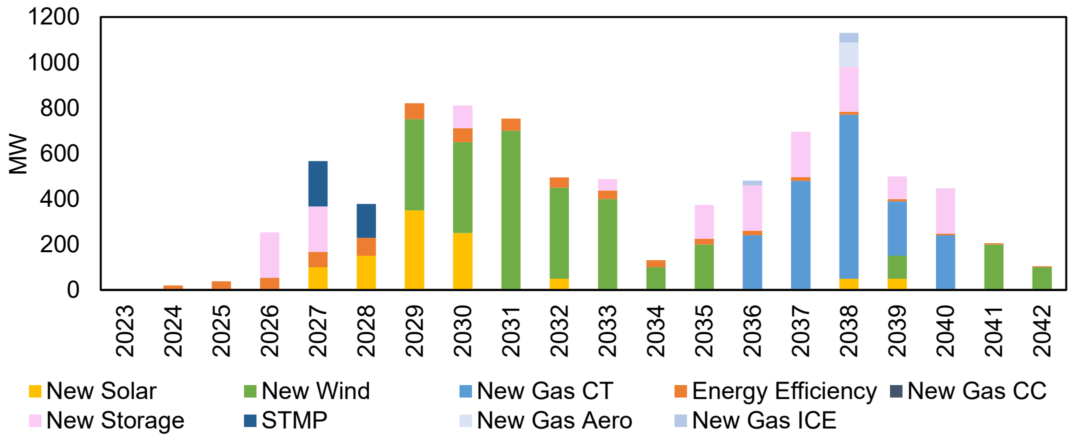
Figure 66 Annual Resource Additions in the CETA Portfolio



The CETA Scenario combines higher load and more affordable renewable technologies that result in faster decline in renewable technology costs. As a result of higher load, the CETA portfolio has larger capacity additions than all summer optimized portfolios. Due to the assumed changes in technology costs, these additions are predominantly renewables. Due to higher additions of solar PV elsewhere in the SPP region, solar PV has the lowest ELCCs compared to other scenarios. In order to meet firm capacity requirements given the low ELCCs for solar PV, the CETA portfolio adds proportionately less solar PV and more new wind and storage units. By 2042, approximately 2.1 GW of solar, 3.2 GW of wind, 3.1 GW of

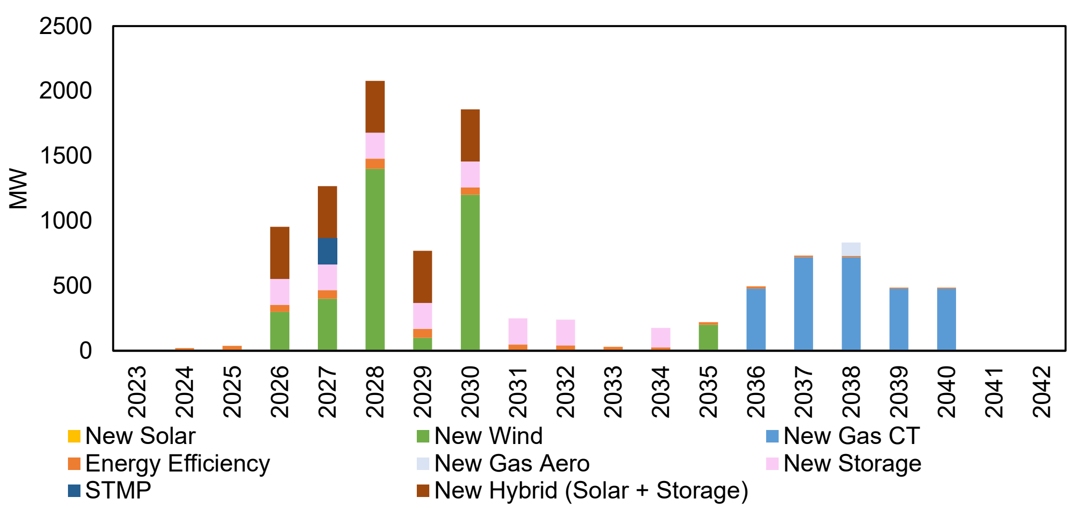
NGCTs, and 1.15 GW of storage units are added. In total, the peak contribution from incremental demand side resources is 78.8 MW in 2028.

Figure 67 Annual Resource Additions in the ECR Portfolio



The ECR Scenario combines lower load growth with high-cost gas and carbon. Due to the lower load forecast, the ECR portfolio adds fewer resources overall relative to the other portfolios. Because of the high gas and carbon prices assumed for the Scenario, the ECR portfolio prefers adding new storage units over NCGTs to meet firm requirements. By 2042, approximately 1 GW of solar, 3 GW of wind, 1.9 GW of NGCTs, and 1.6 GW of storage units are added. The amount of new wind added is about 1 GW higher than the level in the Reference portfolio due to the higher carbon price beyond 2029.The contributions of incremental EE programs occur from 2024 – 2042, with the peak MW contribution of 78.8 MW registered in 2028.

Figure 68 Annual Resource Additions in the FOR Under Winter Requirement



SWEPCO also evaluated an optimized build under FOR conditions to assess a requirement for winter peak adequacy. To model winter requirements in the FOR case, it was also necessary to develop assumptions describing the peak contribution of different resource types in the winter season. Peak demand in winter typically occurs early in the morning. Some resources, particularly solar PV, provide less load carrying capacity during winter peak periods than during summer peaks.

When optimized in the FOR Summer portfolio, AURORA returns almost identical supply-side and demand-side resource selections as in the Reference portfolio. Therefore, for the FOR Scenario, SWEPCO focused on the resource selection required to meet the winter reserve requirement.

Under the FOR Winter scenario, solar resources are expected to perform materially different in winter than summer and their peak credits are modeled with a decline over time from 19% in 2023 to 1% in 2042. The net load peaks in SPP during the winter are fairly flat across the day. Because of this, batteries are not able to provide as much capacity value as they do during the summer. For winter, SWEPCO assumed the capacity peak credits for 4- hour batteries to decline form 80% to around 25% in 2042.

The FOR Winter portfolio adds 3.6 GW of wind, 2.9 GW of NGCT, 1.5 GW of storage and 2.0 GW of solar with storage hybrid. In addition the portfolio adds 200 MW of shorter term market purchases. This portfolio adds significantly more resources than the Reference Portfolio needed to maintain the winter resource adequacy under the FOR-scenario conditions. Similar with the rest of the portfolios, the Welsh 1 & 3 conversions provide valuable firm capacity during the 10-year period until it is mostly replaced by new NGCTs and New Gas Aero in 2038. This portfolio adds about 2 GW of hybrid solar with storage mostly due to the capacity accreditation of storage. On the demand-side, the need for resources results in the procurement of energy efficiency throughout the study period with a peak contribution of around 78.8 MW in 2028.

8.4. Scorecard Results

8.4.1. Customer Affordability

SWEPCO measures customer affordability across two time scales:

- Short-term affordability, measured as the 5-year CAGR of growth in customer rates associated with the new demand- and supply-side resources selected under each portfolio; and
- Long-term affordability, measured as the 30-year NPVRR of new demand- and supply-side resources selected under each portfolio.

Short-Term

Table 18 shows the portfolio performance under the Customer Affordability objective. As discussed in Section 8.2.1, the indicators for this objective include the expected annual growth in customer rates over the next five years, and the revenue requirements over the next 30 years expressed on both an NPVRR basis and a levelized rate basis, all measured under Reference Scenario market conditions.

Table 18 Portfolio Performance under Customer Affordability Metrics

Portfolio	5-Year Rate CAGR, Reference Scenario (%/annum)	30-Year NPVRR, Reference Scenario ($ Millions)	30-Year Levelized Rate, Reference Scenario ($/MWh)
Reference	4.32%	19,217	71.1
CETA	4.97%	20,991	77.5
ECR	3.79%	19,880	73.4
FOR-Summer	4.18%	19,260	71.2
FOR-Winter	12.5%	25,799	95.3
NCR	4.29%	19,439	71.8

Over the next five years, the variation in the expected growth of customer rates is driven by the differences in near-term resource additions across the portfolios. The ECR portfolio has the smallest amount of capacity additions in this period – primarily driven by the low load growth – and this portfolio exhibits the slowest rate of growth at 3.79% per year. Conversely, the FOR Winter portfolio has the highest rate of growth at 12.49% per year, owing to the greater amount of new resources added to the portfolio over this period to meet winter capacity requirements. The remaining portfolios fall in between these two extremes, with the CETA portfolio showing higher costs, with rates growing at 4.97% over the 2023-2028 period relative to the Reference, FOR Summer and NCR portfolios that grow at a rate of 4.18-4.32%.

Long-term

In terms of revenue requirements over the next 30 years, the Reference, ECR, FOR Summer, and NCR portfolios perform similarly on both the NPVRR and the levelized rate basis. Overall, the Reference portfolio has the lowest expected cost to customers due to a combination of lower capex resource types, greater tax credit monetization, and lower O&M. The FOR portfolio is next best and only slightly higher cost compared to the Reference portfolio due to similar build schedules. The next most expensive is the NCR portfolio with $19.4 billion followed by the ECR portfolio with $19.9 billion.

The CETA portfolio and the FOR Winter portfolio have the highest long-term revenue requirements and levelized rates. For the CETA portfolio, the high long-term revenue requirement is driven largely by the amount of new resource additions added by 2042. This portfolio sees nearly 2,500 MW more new capacity than the Reference, ECR, FOR, and NCR Scenarios in order to meet a higher load under the CETA Scenario. For the FOR Winter portfolio, the high costs are driven by a similarly large amount of resource additions in order to meet the 26% winter reserve margin. These portfolios are the most expensive to customers over the longer term and could leave customers at risk of higher rates if the higher load scenario fails to materialize.

8.4.2. Rate Stability

SWEPCO measures rate stability by evaluating:

- Scenario resilience as measured by the range of 30-year NPVRR of the portfolio across the five market scenarios;
- Cost risk as measured by the NPVRR increase when moving from the 50th to the 95th percentile of portfolio costs in years 2032 and 2042; and
- Market exposure as measured by net sales in the summer and winter seasons as a percentage of load in 2042.

Scenario Resilience

Table 19 shows the 30-year NPVRRs across the five market scenarios and the difference between the highest and lowest NPVRRs of each of the six portfolios considered. The difference between the highest and lowest value is used to populate the Scenario Resilience indicator on the IRP scorecard.

Table 19 The 30-Year NPVRRs of the Portfolio Across Market Scenarios ($Million)

	Market Scenarios					
Portfolios	**Reference**	**CETA**	**ECR**	**FOR**	**NCR**	**High/Low Difference**
Reference	19,217	19,211	17,960	19,198	18,645	1,257
CETA	20,991	20,680	18,145	20,984	20,934	2,804
ECR	19,880	19,536	18,145	19,886	19,429	1,742
FOR-Summer	19,260	19,254	17,922	19,247	18,720	1,338
FOR-Winter	25,799	25,688	23,160	25,816	25,838	2,678
NCR	19,439	19,809	20,670	19,428	17,939	2,731

In general, the various portfolio costs under the Reference Scenario and the FOR scenarios produce the highest expected 30-year portfolio NPVRRs, though the portfolio costs under these market scenarios are not significantly higher compared to the others. Both the Reference and FOR scenarios assume base technology costs; compared to the faster technology cost declines assumed under the CETA and ECR scenarios. Base costs in the Reference and FOR scenarios combined with large buildouts of new resources lead to higher overall NPVRR values. The IRP portfolios tend to report the lowest costs under the ECR scenario due to the combination of lower customer loads and lower technology costs in this forecast than under the other outlooks.

The Reference portfolio and FOR Summer portfolio are the most resilient under the five market scenarios with an NPVRR range of approximately $1,257 million and $1,338 million, respectively. The ECR portfolio ranks third with a slightly higher range of $1,742 million. The FOR Winter portfolio produces the next highest range of NPVRRs at $2,678 million.

The NCR and CETA portfolios are least resilient by this measure with an NPVRR range of greater than $2.7 billion when solved under different fundamental conditions. The CETA portfolio was optimized to high customer load and low technology costs, so under market conditions with lower customer loads and higher technology costs, this portfolio performs poorly. As a result, the NPVRR of the CETA portfolio under the Reference and FOR portfolios are the highest. The NCR portfolio was optimized to a market scenario with no carbon regulation and low natural gas costs. As a result, this portfolio sees a large buildout of NGCC and NGCT resources. Under the ECR scenario, this portfolio performs worst due to high carbon taxes and natural gas costs. Under the NCR and CETA portfolios, customers are at highest risk from regulatory changes and fluctuating natural gas prices.

Cost Risk

Figure 69 and Figure 70 present a summary of the stochastic results for each of the six candidate portfolios. This metric compares the distributions of net present revenue requirements in 2032 after applying 250 iterations of natural gas prices, power prices, and renewable production profiles to the candidate portfolios under Reference Scenario market conditions. The cost risk is expressed as the difference between the median portfolio costs (i.e., 50th percentile) relative to portfolio costs under adverse conditions, represented as the 95th percentiles of revenue requirements observed. In the figure below, the median value is represented as the center of each box, with the top of relevant line indicating costs at the 95th percentile. **Error! Reference source not found.** shows a summary of the cost risk across each candidate portfolio. Table 21 highlights the upside cost risk across each portfolio.

Figure 69 Distribution of Revenue Requirements Based on Stochastic Analysis (2032)

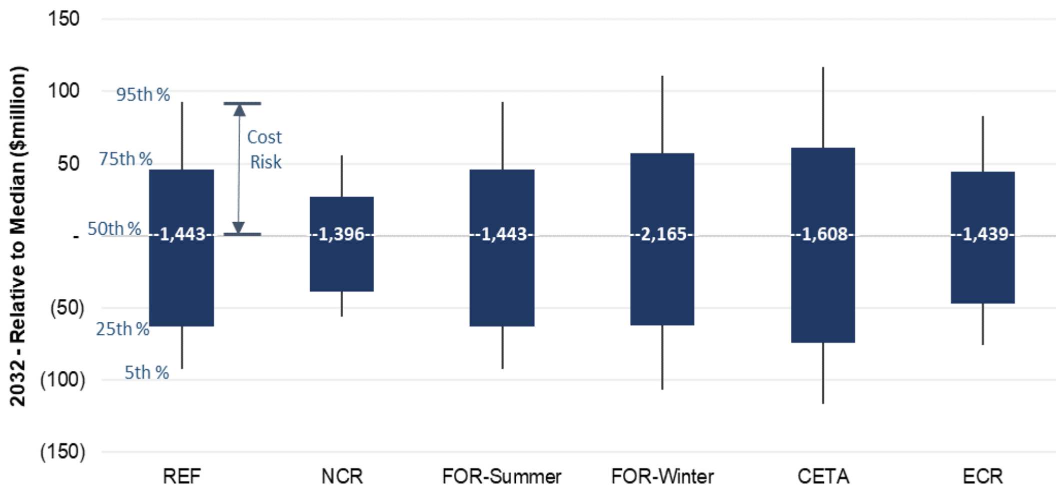


Figure 70 Distribution of Revenue Requirements Based on Stochastic Analysis (2042)

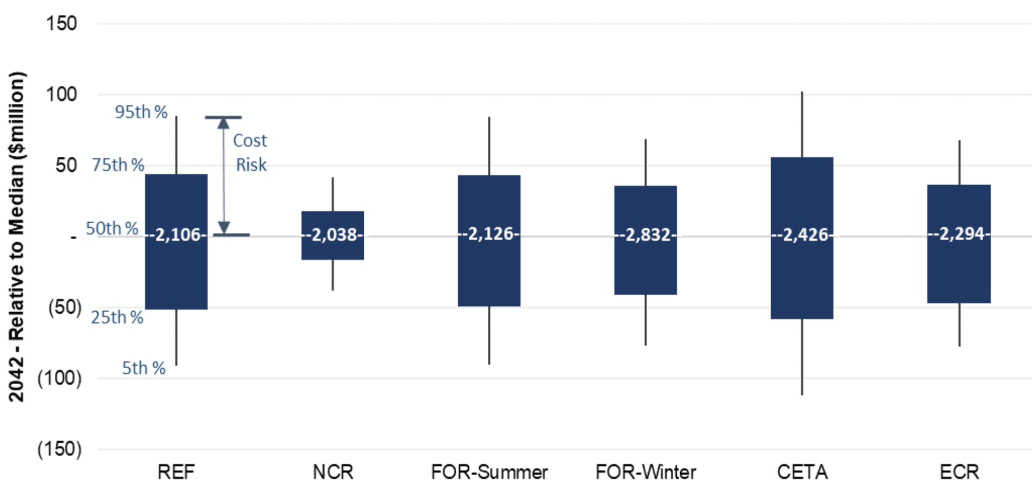


Table 20 Cost Risk - 50th to 95th Percentile Distribution Range ($Million)

Portfolio	2032	2042
Reference	92.5	85.1
CETA	117.3	102.4
ECR	83.1	67.8
FOR Winter	110.6	68.6
FOR Summer	92.5	84.3
NCR	55.9	42.1

Table 21 Upside cost risk as a % of total Revenue Requirement

Portfolio	2032 (%)	2042 (%)
Reference	6.4	4.0
CETA	7.3	4.2
ECR	5.8	3.0
FOR Winter	5.1	2.4
FOR Summer	6.4	4.0
NCR	4.0	2.1

The CETA portfolio in both 2032 and 2042 has the highest cost risk and thus is more exposed to short-term volatility in power prices, gas prices, and renewable output. The NCR portfolio has the lowest cost risk, with a much narrower distribution of outcomes.

Market Exposure

Table 22 shows the net energy sales as a percentage of portfolio load split by summer and winter. The percentages shown are averaged across all market scenarios.

Table 22 Average Net Energy Sales as % of Portfolio Load Across All Scenarios

Portfolio	Summer			Winter		
	2023	2032	2042	*2023*	2032	2042
Reference	34%	15%	21%	31%	12%	31%
CETA	34%	25%	33%	31%	28%	55%
ECR	34%	13%	13%	31%	16%	34%
FOR-Summer	34%	15%	21%	31%	12%	33%
FOR-Winter	34%	30%	18%	31%	50%	42%
NCR	34%	6%	5%	31%	-2%	4%

Generation from SWEPCO's current portfolio is expected to exceed demand in the short-term resulting in a long energy position. This is mainly driven by robust thermal dispatch and a higher market heat rate environment.

By 2032, all portfolios evaluated in the 2023 IRP show a tendency for reduced net sales in summer relative to 2023. In winter, all portfolios except the FOR-Winter portfolio also tend to reduce their share of net sales by 2032 as a percent of customer load, compared with 2023 levels. The FOR-Winter portfolio relies most heavily on market sales to balance customer requirements while the NCR portfolio has the least reliance on market in 2032.

The summer net sales position of most portfolios tends to increase between 2032 and 2042 primarily due to later additions of new solar resources. Net sales in winter tend to grow more between 2032 and 2042 relative to the summer season. This is explained, in part, by the fact that many portfolios include more thermal resources by year 2042 to make up for reduced production from solar in the winter months, leading to higher generation from the portfolio.

8.4.3. Maintaining Reliability

SWEPCO measures each portfolio's contribution to maintaining reliability by evaluating:

- Planning reserves measured as the ratio of firm (i.e., UCAP) supply to expected peak demand for *both* the summer and winter periods, averaged over the period between 2022 and 2042;

- Operational flexibility measured as the total firm capacity (UCAP) provided by fast-ramping technologies in years 2032 and 2042; and
- Resource diversity measured as the percentage of total generation provided by the different generating technologies selected in each candidate resource plan in model year 2042 under the Reference Scenario.

Planning Reserves

Table 23 shows the summer and winter planning reserves, averaged over the period between 2022 and 2042 and across all market scenarios.

Table 23 Planning Reserves Between 2023 and 2042 by Portfolio

Portfolio	Summer	Winter
Reference	21%	19%
CETA	32%	28%
ECR	20%	20%
FOR-Summer	22%	20%
FOR-Winter	33%	27%
NCR	18%	17%

SWEPCO assumed that each candidate portfolio would need to meet a planning reserve margin of 22% above summer peak load by 2025 when optimizing each candidate portfolio in its native market scenario. This approach can result in capacity short-falls or extra capacity when candidate portfolios are evaluated in non-native scenarios due to differences in load forecasts and resource ELCC value. For example, the NCR Scenario solution showed lower overall deployment of solar SPP-wide in response to low gas prices and zero CO_2 price. AURORA then selected the amount of solar needed to balance customer load in the NCR portfolio under NCR Scenario conditions. When run in other scenarios with greater solar penetration and lower solar ELCCs, this portfolio tends to be short capacity and rely on market purchases to meet firm requirements. The opposite is true in the CETA portfolio. Higher deployment of solar SPP-wide in the CETA Scenario results in lower solar ELCCs. As a result, the CETA portfolio tends to have a large surplus when run under market conditions that award more capacity contribution to solar resources.

When viewed as the average across all scenarios, the Reference, NCR and ECR Portfolios fall short of the 22% requirement in the summer. For the ECR portfolio, the result is driven by the fact that it has the smallest capacity additions relatively to all other portfolios as the portfolio is optimized for low load growth. For the Reference and NCR Portfolio, the result is driven by the portfolios adding just enough capacity to meet its load obligations and relying on cheap market purchases to meet energy shortfalls. The CETA portfolio has an average summer reserve margin of 32% by this measure, about 10% higher than the planning reserve margin. This is driven by greater capacity additions in this portfolio in anticipation of high load growth, and the greater ELCC value awarded to solar resources in any of the non-CETA Scenarios.

Operational Flexibility

Table 24 shows the capacity of dispatchable units in 2032 and 2042 in each of the portfolio considered.

Table 24 The Amount of Dispatchable Capacity in 2032 and 2042 by Portfolio

Portfolio	2032 Dispatchable Capacity (MW)	2042 Dispatchable Capacity (MW)
Reference	3,748	4,133
CETA	4,315	5,047
ECR	3,942	3,893
FOR-Summer	3,758	4,365
FOR-Winter	4,034	4,203
NCR	3,769	4,234

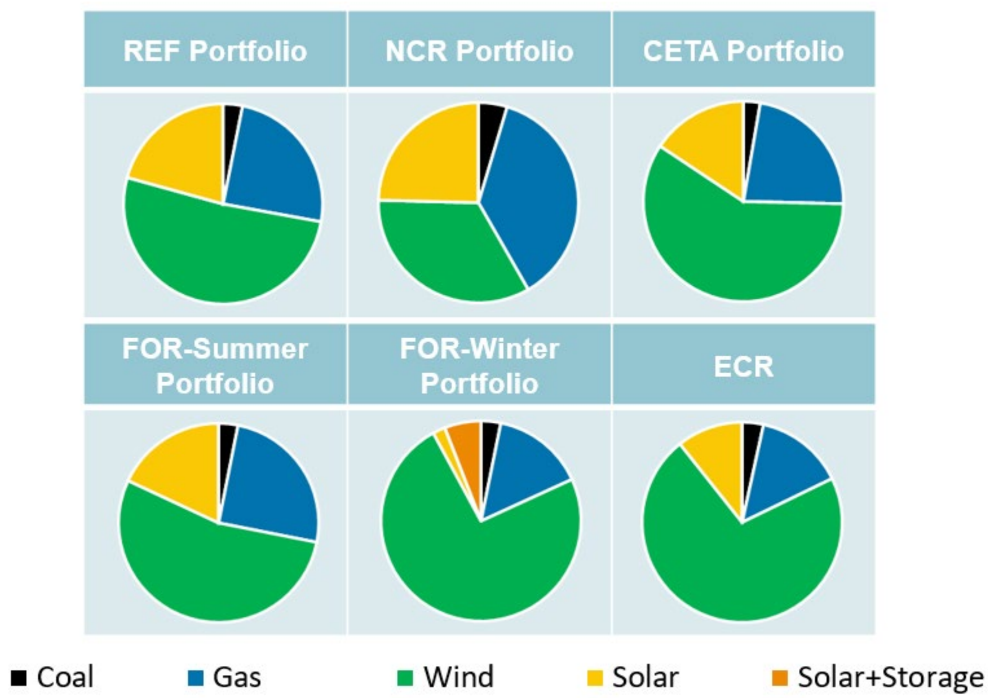
The CETA portfolio tends to score highest on this metric, particularly over the first 10 years, owing to the overall higher amount of new resources constructed in anticipation of higher customer loads resulting in greater operational flexibility. The Reference, FOR-Summer and NCR portfolios tend to score less due to greater reliance on solar.

All portfolios except the ECR tend to have higher amounts of dispatchable capacity in 2042 compared to 2032. This is due to the addition of greater amounts of dispatchable thermal resources including a 550 MW NGCC in the later years which the ECR portfolio doesn't include.

Resource Diversity

Figure 71 shows pie charts displaying the percentage of total generation provided by existing resources as well as the different generating resources selected by each candidate resource plan in model year 2042 under Reference Scenario market conditions.

Figure 71 2042 Generation Mix by Technology and Portfolio (MWh)



All portfolios primarily rely on coal, NGCC, NGCT, wind and solar along with small amounts of demand-side resources and storage. Despite assumed improvements in technology costs over time, no advanced generation technologies are selected across any portfolios.

The NCR portfolio is most diverse, with similar proportions of energy provided by gas, solar and wind units. FOR portfolios score similarly on this metric but are slightly more wind-heavy than the NCR portfolios. Finally, the ECR and CETA portfolios are the least diverse, with wind dominating total portfolio generation in 2042.

8.4.4. Local Impacts & Sustainability

SWEPCO compares portfolio performance across the local impacts and sustainability objective by evaluating:

- Local impacts measured as (1) the total new installed nameplate capacity inside SWEPCO service territory, and (2) the total amount of capital invested inside SWEPCO service territory between 2023 and 2032; and
- The percentage reduction in CO_2 emissions in 2032 and 2042 from owned resources relative to the baseline year 2005 in the Reference Scenario.

Local Impacts

Table 25 compares the total new installed nameplate capacity and total expected CAPEX invested inside SWEPCO service territory between 2023 and 2032 for each candidate portfolio. This includes an assumption of particular assets being located within SWEPCO's territory. For this metric, informed by the current SPP queue, all thermal and storage resources as well as 35% of solar resources are included while all wind resources are excluded. The Company will, however, continue to explore opportunities to locate resources within and outside of SWEPCO's territory if they are beneficial to SWEPCO customers.

Table 25 Local Impacts Metrics by Portfolio

Portfolio	New Nameplate Capacity Between 2023 and 2032 (MW)	Total CAPEX Invested Inside SWEPCO Territory ($ Millions)
Reference	1,988	10,564
CETA	2,778	11,712
ECR	1,868	10,211
FOR-Summer	1,988	10,553
FOR-Winter	2,453	17,088
NCR	1,968	10,360

The CETA portfolio scores best by the MW metric and second by the dollar metric, owing to the greater deployment of new resources under this case to meet faster growth in customer load. The FOR Winter portfolio scores best by the dollar metric and second best by the MW metric due to its greater deployment of new resources to compensate for lower generation in the winter. The Reference portfolio is third-best in capacity metric with 1,988 MW installed in the territory and a total expected investment of approximately $10.5 billion over the 10 years which ranks third across the portfolio options. The ECR and NCR portfolios score similarly by this measure and result in approximately $10.2-$10.3 billion in new investment in the SWEPCO territory over the next 10 years.

CO_2 Emissions

Table 26 shows the levels of carbon emissions in 2032 and 2042 in the Reference Scenario by portfolio and expresses the reduction in carbon emissions relative to the level of emissions to 2005 in percentage terms. Total CO_2 emissions from both SWEPCO owned plants and contracted output was 21.9mt in year 2005. Emissions have since declined and are now forecast to be around 16.5mt in 2022.

Table 26 CO_2 Emission Reductions by Portfolio

Portfolio	Level of Emissions in 2005 ($mtCO_2$)	Level of Emissions in 2032 ($mtCO_2$)	% reduction in 2032 relative to 2005	Level of Emissions in 2042 ($mtCO_2$)	% reduction in 2042 relative to 2005
Reference	21.9	3.5	84%	3.7	83%
CETA	21.9	3.6	83%	3.9	82%
ECR	21.9	3.5	84%	2.5	89%
FOR-Summer	21.9	3.5	84%	3.8	83%
FOR-Winter	21.9	3.5	84%	2.7	87%
NCR	21.9	3.5	84%	3.7	83%

By 2032, all portfolios have similar levels of CO_2 emissions between 3.5 and 3.6mt.

By 2042, all portfolios but the FOR-Winter and ECR portfolios have similar levels of CO_2 emissions between 3.7 and 3.9mt CO_2. The FOR-Winter and ECR portfolios have lower emissions because they don't include the 550MW NGCC resource added in other portfolios.

8.4.5. Evaluating the 2023 IRP Scorecard

The fully populated scorecard is shown in Figure 72. The key results from the scorecard are summarized below:

- The Reference and the FOR-Summer Portfolios perform similarly well across all criteria. However, the FOR-Summer Portfolio has slightly higher revenue requirements due to the slightly higher additions than the Reference Portfolio as a results of slightly lower assumed capacity peak credits.
- The FOR- Winter Portfolio is a clear outlier when measured against the customer affordability objective. While lowest winter capacity credit for renewable and storage resources to reflect winter conditions, the FOR -Winter Portfolio exposes customers to higher costs if the winter reserve requirement is not considered by SPP. However, the greater amount of new resource additions in this portfolio results in the highest levels of planning reserves and operational flexibility.
- The ECR and NCR Portfolios, while relatively affordable, do not perform well on reliability metrics. The summer planning reserves for both portfolios are below the 22% reserve margin requirement assumed for the SPP region. The NCR Portfolio is also capacity short and so it is exposed to market prices in the surrounding markets.
- The Reference and the NCR Portfolios are similar in cost, with the NCR resulting in lower near-term rate increases but a slightly higher 30-year NPVRR by about $222 million or $0.70 per MWh in levelized rates. The ECR Portfolio shows higher scenario range than the Reference Portfolio but lower cost risk.

Figure 72 Populated 2023 IRP Scorecard

	Customer Affordability		Rate Stability			Maintaining Reliability				Sustainability
Portfolio	***Short Term:*** *5-yr Rate CAGR, Reference Case*	***Long Term:*** *30-yr NPVRR, Reference Case*	***Scenario Range:*** *High Minus Low Scenario Range, 30-yr NPVRR*	***Cost Risk:*** *RR Increase in Reference Case (95th minus 50th Percentile)*	***Market Exposure:*** *Net Sales as % of Portfolio Load, Scenario Average*	***Planning Reserves:*** *% Reserve Margin, Scenario Average*	***Operational Flexibility:*** *Dispatchable Capacity*	***Resource Diversity:*** *Generation Mix (MWh) by Technology Type - Reference Case*	***Locational Diversity:*** *Nameplate MW Installed Outside SWEPCO Territory*	***CO2 Emissions:*** *Percent Reduction from 2005 Baseline - Reference Case*
Year Ref.	2023-2028	2023-2052	2023-2052	2032| 2042	2032	2023-2042	2032 | 2042	2042	2023-2032	2032 | 2042
Units	%	$MM Levelized Rate	$MM Levelized Rate	$MM Levelized Rate	Summer | Winter	Summer | Winter	MW	%	MW|$MM	% Reduction
Reference Portfolio	4.32	19,217 $71.1	1,257 $4.51	92.5 | 85.1	15% | 12%	21% | 19%	3,748|4,133		1,988 | 10,564	84% | 83%
CETA Portfolio	4.97	20,991 $77.5	2,804 $6.11	117.3 | 102.4	25% | 28%	32% | 28%	4,315|5,047		2,778 | 11,712	83% | 82%
ECR Portfolio	3.79	19,880 $73.4	1,742 $5.97	83.1 | 67.8	13% | 16%	20% | 20%	3,942|3,893		1,868 | 10,211	84% | 89%
FOR – Summer Portfolio	4.18	19,260 $71.2	1,338 $4.54	92.5| 84.3	15% | 12%	22% | 20%	3,758|4,365		1,988 | 10,553	84% | 83%
FOR – Winter Portfolio	12.49	25,799 $95.3	2,678 $6.84	110.6 | 68.6	30% | 50%	33% | 27%	4,034|4,203		2,453 | 17,088	84% | 87%
NCR Portfolio	4.29	19,439 $71.8	2,731 $15.40	55.9 | 42.1	6% | -2%	18% | 17%	3,769|4,234		1,968 | 10,360	84% | 83%

Coal
Gas CC
Gas CT
Wind
Solar
Other

*Levelized Rates and NPVRR metrics are for generation component only. Metrics are for comparison only and do not represent the final costs which will apply to ratepayers.

8.5. Preferred Plan

An identification and discussion of a Preferred Plan for this IRP is planned to occur following the planned Stakeholder review meeting as identified in the LPSC Process Schedule of Events. This will be completed for the filing of the Company's final IRP report.

9. Conclusion

The Conclusion section and associated 5-year action plan will be included in the Company's filing of the final IRP planned for later in 2023 per the LPSC IRP Process Schedule of Events.

10. Appendix

Exhibit A: Load Forecast

Exhibit B: Detailed Generation Technology Modeling Parameters

Exhibit C: Capability, Demand and Reserve (CDR) – "Going In"

Exhibit D: Long-Term Commodity Price Forecast

Exhibit E: Cost of Capital

Exhibit F: Modeled Portfolio Results

Exhibit G: Stakeholder Comments

CONFIDENTIAL EXHIBITS

Volume 2:

Exhibit H Confidential – Existing Unit Fuel Forecast

Exhibit I Confidential – Existing Unit Performance

Exhibit J Confidential – Supplemental Analysis, Existing Units

Volume 3:

Exhibit K Confidential – SWEPCO Input Data Model Equations and Statistical Results

Exhibit A: Load Forecast

Exhibit A-1

Southwestern Electric Power Company
Actual and Forecast Internal Energy Requirements (GWh)***
By Customer Class

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other** Energy Requirements	Growth Rate	Internal Energy Requirements	Growth Rate
Actual										
2012	6,301	---	6,103	---	5,661	---	7,123	---	25,188	---
2013	6,431	2.1	6,011	-1.5	5,612	-0.9	7,430	4.3	25,484	1.2
2014	6,311	-1.9	5,996	-0.2	5,901	5.1	7,308	-1.6	25,516	0.1
2015	6,336	0.4	6,076	1.3	5,370	-9.0	7,333	0.3	25,115	-1.6
2016	6,148	-3.0	6,064	-0.2	5,074	-5.5	7,074	-3.5	24,360	-3.0
2017	5,903	-4.0	5,824	-4.0	5,339	5.2	6,817	-3.6	23,884	-2.0
2018	6,564	11.2	5,910	1.5	5,391	1.0	6,429	-5.7	24,294	1.7
2019	6,303	-4.0	5,776	-2.3	5,338	-1.0	6,373	-0.9	23,790	-2.1
2020	5,988	-5.0	5,296	-8.3	4,891	-8.4	5,617	-11.9	21,792	-8.4
2021	6,205	3.6	5,489	3.6	4,682	-4.3	5,673	1.0	22,049	1.2
Forecast										
2022*	6,351	2.4	5,632	2.6	5,051	7.9	5,958	5.0	22,991	4.3
2023	6,149	-3.2	5,530	-1.8	5,046	-0.1	5,707	-4.2	22,432	-2.4
2024	6,163	0.2	5,544	0.2	5,078	0.6	5,720	0.2	22,504	0.3
2025	6,162	0.0	5,545	0.0	5,135	1.1	5,780	1.0	22,622	0.5
2026	6,186	0.4	5,546	0.0	5,179	0.9	5,786	0.1	22,697	0.3
2027	6,199	0.2	5,531	-0.3	5,208	0.6	5,809	0.4	22,747	0.2
2028	6,222	0.4	5,513	-0.3	5,224	0.3	5,828	0.3	22,788	0.2
2029	6,251	0.5	5,498	-0.3	5,231	0.1	5,839	0.2	22,818	0.1
2030	6,276	0.4	5,479	-0.3	5,238	0.1	5,854	0.3	22,846	0.1
2031	6,314	0.6	5,465	-0.3	5,255	0.3	5,870	0.3	22,904	0.3
2032	6,349	0.6	5,456	-0.2	5,279	0.5	5,889	0.3	22,975	0.3
2033	6,379	0.5	5,447	-0.2	5,310	0.6	5,909	0.3	23,045	0.3
2034	6,414	0.5	5,440	-0.1	5,339	0.5	5,925	0.3	23,117	0.3
2035	6,448	0.5	5,434	-0.1	5,369	0.6	5,942	0.3	23,193	0.3
2036	6,477	0.5	5,431	-0.1	5,401	0.6	5,961	0.3	23,270	0.3
2037	6,514	0.6	5,431	0.0	5,436	0.7	5,981	0.3	23,362	0.4
2038	6,547	0.5	5,430	0.0	5,474	0.7	6,002	0.4	23,452	0.4
2039	6,579	0.5	5,429	0.0	5,512	0.7	6,021	0.3	23,541	0.4
2040	6,608	0.4	5,427	0.0	5,550	0.7	6,036	0.3	23,621	0.3
2041	6,636	0.4	5,425	0.0	5,584	0.6	6,054	0.3	23,699	0.3
2042	6,669	0.5	5,426	0.0	5,617	0.6	6,070	0.3	23,781	0.3

Note: *2022 data are six months acutal and six months forecast.
**Other energy requirements include other retail sales, wholesale sales and losses.
***Historical and 2022 data are adjusted to reflect reclass of industrial and commercial industry codes, with no revenue or earnings impact.

	Residential	Commercial	Industrial	Other	Internal Energy
Compound Annual Growth Rate 2012-2021					
	-0.2	-1.2	-2.1	-2.5	-1.5
Compound Annual Growth Rate 2023-42					
	0.4	-0.1	0.6	0.3	0.3

Exhibit A-2.1

Southwestern Electric Power Company-Arkansas
Actual and Forecast Retail Sales (GWh)**
By Customer Class

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other Retail	Growth Rate	Retail Sales	Growth Rate
Actual										
2012	1,132	---	1,356	---	1,562	---	12	---	4,062	---
2013	1,135	0.2	1,332	-1.8	1,540	-1.4	12	-1.1	4,018	-1.1
2014	1,121	-1.2	1,343	0.8	1,543	0.2	12	-0.5	4,019	0.0
2015	1,111	-0.9	1,353	0.8	1,442	-6.6	12	-0.2	3,917	-2.5
2016	1,121	0.9	1,332	-1.6	1,426	-1.1	12	0.7	3,890	-0.7
2017	1,087	-3.1	1,309	-1.7	1,367	-4.1	12	0.6	3,775	-3.0
2018	1,207	11.1	1,332	1.8	1,340	-2.0	11	-2.3	3,891	3.1
2019	1,175	-2.6	1,311	-1.6	1,257	-6.2	12	1.5	3,754	-3.5
2020	1,114	-5.2	1,202	-8.3	1,116	-11.2	11	-4.3	3,443	-8.3
2021	1,163	4.4	1,269	5.6	1,081	-3.2	10	-7.8	3,523	2.3
Forecast										
2022*	1,183	1.7	1,291	1.7	1,097	1.5	10	-4.3	3,581	1.6
2023	1,171	-1.1	1,285	-0.4	1,095	-0.2	10	1.1	3,561	-0.5
2024	1,177	0.5	1,288	0.2	1,104	0.8	10	0.0	3,579	0.5
2025	1,181	0.4	1,293	0.4	1,113	0.8	10	-0.3	3,598	0.5
2026	1,188	0.6	1,296	0.2	1,126	1.1	10	0.2	3,620	0.6
2027	1,193	0.4	1,296	0.0	1,134	0.7	10	0.0	3,633	0.4
2028	1,203	0.8	1,295	-0.1	1,139	0.5	10	0.0	3,647	0.4
2029	1,212	0.8	1,295	0.0	1,142	0.3	10	0.0	3,659	0.3
2030	1,221	0.7	1,294	-0.1	1,145	0.3	10	0.0	3,670	0.3
2031	1,233	1.0	1,294	0.0	1,149	0.4	10	0.0	3,686	0.4
2032	1,244	0.9	1,295	0.1	1,155	0.5	10	0.0	3,703	0.5
2033	1,254	0.8	1,295	0.0	1,161	0.5	10	0.0	3,720	0.4
2034	1,264	0.8	1,296	0.1	1,167	0.5	10	0.0	3,737	0.4
2035	1,272	0.6	1,297	0.1	1,173	0.5	10	0.0	3,752	0.4
2036	1,280	0.6	1,299	0.1	1,180	0.6	10	0.0	3,768	0.4
2037	1,288	0.7	1,300	0.1	1,187	0.6	10	0.0	3,786	0.5
2038	1,297	0.6	1,302	0.1	1,194	0.6	10	0.0	3,803	0.5
2039	1,305	0.6	1,304	0.1	1,202	0.6	10	0.0	3,821	0.5
2040	1,313	0.6	1,305	0.1	1,209	0.6	10	0.0	3,837	0.4
2041	1,320	0.6	1,307	0.1	1,216	0.5	10	0.0	3,853	0.4
2042	1,329	0.6	1,309	0.1	1,222	0.5	10	0.0	3,869	0.4

Note: *2022 data are six months acutal and six months forecast.
**Historical and 2022 data are adjusted to reflect reclass of industrial and commercial industry codes, with no revenue or earnings impact.

	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other Retail	Growth Rate	Retail Sales	Growth Rate
Compound Annual Growth Rate 2012-2021										
	0.3		-0.7		-4.0		-1.5		-1.6	
Compound Annual Growth Rate 2023-2042										
	0.7		0.1		0.6		0.0		0.4	

Exhibit A-2.2

Southwestern Electric Power Company-Louisiana
Actual and Forecast Retail Sales (GWh)**
By Customer Class

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other Retail	Growth Rate	Retail Sales	Growth Rate
Actual										
2012	2,990	---	2,453	---	1,080	---	40	---	6,563	---
2013	3,041	1.7	2,428	-1.0	1,020	-5.6	40	-0.9	6,528	-0.5
2014	2,991	-1.6	2,406	-0.9	1,034	1.4	40	0.3	6,472	-0.9
2015	3,032	1.4	2,454	2.0	1,039	0.5	40	0.8	6,565	1.4
2016	2,919	-3.7	2,489	1.4	1,026	-1.2	40	0.6	6,475	-1.4
2017	2,793	-4.3	2,344	-5.8	1,160	13.0	41	1.0	6,337	-2.1
2018	3,081	10.3	2,376	1.4	1,179	1.7	40	-0.9	6,676	5.4
2019	2,945	-4.4	2,310	-2.8	1,213	2.9	41	1.3	6,509	-2.5
2020	2,800	-4.9	2,118	-8.3	1,116	-8.0	41	0.0	6,075	-6.7
2021	2,887	3.1	2,186	3.2	1,051	-5.9	40	-2.5	6,163	1.4
Forecast										
2022*	2,915	1.0	2,241	2.5	1,165	10.9	38	-3.8	6,359	3.2
2023	2,799	-4.0	2,204	-1.7	1,165	0.0	39	0.8	6,206	-2.4
2024	2,798	0.0	2,207	0.2	1,173	0.7	39	0.0	6,217	0.2
2025	2,792	-0.2	2,205	-0.1	1,177	0.4	39	-0.1	6,213	-0.1
2026	2,799	0.2	2,203	-0.1	1,180	0.2	39	0.1	6,221	0.1
2027	2,800	0.0	2,195	-0.4	1,179	-0.1	39	0.0	6,212	-0.1
2028	2,805	0.2	2,185	-0.4	1,175	-0.3	39	0.0	6,205	-0.1
2029	2,813	0.3	2,177	-0.4	1,171	-0.3	39	0.0	6,200	-0.1
2030	2,819	0.2	2,167	-0.5	1,168	-0.3	39	0.0	6,192	-0.1
2031	2,829	0.4	2,159	-0.4	1,165	-0.2	39	0.0	6,191	0.0
2032	2,839	0.3	2,153	-0.3	1,163	-0.2	39	0.0	6,193	0.0
2033	2,846	0.3	2,147	-0.3	1,162	-0.1	39	0.0	6,194	0.0
2034	2,858	0.4	2,142	-0.2	1,161	-0.1	39	0.0	6,200	0.1
2035	2,871	0.4	2,139	-0.2	1,160	0.0	39	0.0	6,208	0.1
2036	2,880	0.3	2,135	-0.1	1,161	0.0	39	0.0	6,215	0.1
2037	2,894	0.5	2,134	-0.1	1,161	0.1	39	0.0	6,228	0.2
2038	2,906	0.4	2,132	-0.1	1,162	0.1	39	0.0	6,238	0.2
2039	2,917	0.4	2,130	-0.1	1,163	0.1	39	0.0	6,249	0.2
2040	2,926	0.3	2,128	-0.1	1,164	0.1	39	0.0	6,256	0.1
2041	2,935	0.3	2,125	-0.1	1,165	0.1	39	0.0	6,264	0.1
2042	2,946	0.4	2,124	-0.1	1,166	0.1	39	0.0	6,274	0.2

Note: *2022 data are six months acutal and six months forecast.
**Historical and 2022 data are adjusted to reflect reclass of industrial and commercial industry codes, with no revenue or earnings impact.

	Residential		Commercial		Industrial		Other Retail		Retail Sales	
Compound Annual Growth Rate 2012-2021										
	-0.4		-1.3		-0.3		0.0		-0.7	
Compound Annual Growth Rate 2023-2042										
	0.3		-0.2		0.0		0.0		0.1	

Exhibit A-2.3

Southwestern Electric Power Company-Texas
Actual and Forecast Retail Sales (GWh)**
By Customer Class

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other Retail	Growth Rate	Retail Sales	Growth Rate
Actual										
2012	2,179	---	2,294	---	3,018	---	30	---	7,521	---
2013	2,256	3.5	2,251	-1.9	3,053	1.1	29	-1.4	7,588	0.9
2014	2,198	-2.5	2,247	-0.2	3,324	8.9	29	-0.6	7,798	2.8
2015	2,193	-0.2	2,270	1.0	2,889	-13.1	29	-1.0	7,381	-5.4
2016	2,108	-3.9	2,244	-1.1	2,622	-9.2	28	-0.8	7,002	-5.1
2017	2,023	-4.0	2,172	-3.2	2,812	7.2	28	-0.7	7,035	0.5
2018	2,276	12.5	2,203	1.4	2,872	2.1	27	-3.3	7,378	4.9
2019	2,182	-4.1	2,156	-2.1	2,868	-0.2	27	-0.1	7,233	-2.0
2020	2,074	-5.0	1,977	-8.3	2,658	-7.3	27	-1.2	6,735	-6.9
2021	2,155	3.9	2,034	2.9	2,551	-4.0	27	-0.5	6,767	0.5
Forecast										
2022*	2,253	4.6	2,101	3.3	2,788	9.3	27	0.6	7,168	5.9
2023	2,179	-3.3	2,042	-2.8	2,786	-0.1	27	0.3	7,033	-1.9
2024	2,188	0.4	2,049	0.4	2,800	0.5	27	0.3	7,065	0.4
2025	2,189	0.0	2,046	-0.1	2,845	1.6	27	-0.1	7,107	0.6
2026	2,199	0.5	2,046	0.0	2,874	1.0	27	0.2	7,146	0.6
2027	2,205	0.3	2,040	-0.3	2,896	0.8	27	0.0	7,168	0.3
2028	2,215	0.4	2,033	-0.4	2,909	0.5	27	0.1	7,184	0.2
2029	2,226	0.5	2,026	-0.3	2,917	0.3	27	0.1	7,196	0.2
2030	2,236	0.5	2,018	-0.4	2,925	0.3	27	0.1	7,207	0.2
2031	2,253	0.7	2,012	-0.3	2,941	0.5	27	0.1	7,233	0.4
2032	2,267	0.6	2,008	-0.2	2,962	0.7	27	0.1	7,264	0.4
2033	2,279	0.5	2,004	-0.2	2,987	0.9	27	0.1	7,298	0.5
2034	2,292	0.6	2,001	-0.2	3,011	0.8	27	0.1	7,331	0.5
2035	2,305	0.6	1,999	-0.1	3,035	0.8	27	0.1	7,366	0.5
2036	2,317	0.5	1,997	-0.1	3,061	0.8	27	0.1	7,402	0.5
2037	2,332	0.6	1,996	0.0	3,088	0.9	27	0.1	7,443	0.6
2038	2,345	0.6	1,996	0.0	3,117	0.9	27	0.1	7,485	0.6
2039	2,358	0.6	1,995	0.0	3,147	1.0	27	0.1	7,527	0.6
2040	2,370	0.5	1,994	-0.1	3,177	0.9	27	0.1	7,568	0.5
2041	2,381	0.5	1,993	0.0	3,203	0.8	27	0.1	7,605	0.5
2042	2,394	0.5	1,993	0.0	3,229	0.8	27	0.1	7,644	0.5

Note: *2022 data are six months acutal and six months forecast.
**Historical and 2022 data are adjusted to reflect reclass of industrial and commercial industry codes, with no revenue or earnings impact.

Compound Annual Growth Rate 2012-2021

	Residential		Commercial		Industrial		Other Retail		Retail Sales	
	-0.1		-1.3		-1.9		-1.1		-1.2	

Compound Annual Growth Rate 2023-2042

	Residential		Commercial		Industrial		Other Retail		Retail Sales	
	0.5		-0.1		0.8		0.1		0.4	

Exhibit A-3

Southwestern Electric Power Company Winter, Summer and Annual Peak Demand (MW) Internal Energy Requirements (GWh) and Load Factor (%)					
Year	Summer Peak Demand	Preceding Winter Peak Demand	Annual Peak Demand	Internal Energy Requirements	Load Factor
Actual					
2012	5,205	4,021	5,205	25,188	55.2
2013	5,048	4,178	5,048	25,484	57.6
2014	4,836	4,919	4,919	25,516	59.2
2015	5,149	4,708	5,149	25,115	55.5
2016	4,921	4,051	4,921	24,360	56.5
2017	4,769	4,419	4,769	23,884	57.2
2018	4,834	4,792	4,834	24,294	57.4
2019	4,727	4,148	4,727	23,790	57.3
2020	4,351	3,900	4,351	21,792	57.2
2021	4,444	4,563	4,563	22,049	55.2
Forecast					
2022*	4,547	3,896	4,547	22,991	57.7
2023	4,557	4,223	4,557	22,432	56.0
2024	4,561	4,230	4,561	22,504	56.3
2025	4,585	4,248	4,585	22,622	56.3
2026	4,598	4,260	4,598	22,697	56.3
2027	4,608	4,268	4,608	22,747	56.2
2028	4,619	4,285	4,619	22,788	56.3
2029	4,617	4,284	4,617	22,818	56.4
2030	4,626	4,288	4,626	22,846	56.4
2031	4,644	4,297	4,644	22,904	56.2
2032	4,661	4,308	4,661	22,975	56.3
2033	4,679	4,321	4,679	23,045	56.2
2034	4,685	4,331	4,685	23,117	56.3
2035	4,706	4,341	4,706	23,193	56.1
2036	4,729	4,362	4,729	23,270	56.2
2037	4,748	4,363	4,748	23,362	56.2
2038	4,770	4,375	4,770	23,452	56.1
2039	4,792	4,391	4,792	23,541	55.9
2040	4,799	4,403	4,799	23,621	56.2
2041	4,820	4,412	4,820	23,699	56.1
2042	4,842	4,423	4,842	23,781	56.1
Note: *2022 data are six months acutal and six months forecast.					
Compound Annual Growth Rate 2012-2021					
	-1.7	1.4	-1.5	-1.5	0.0
Compound Annual Growth Rate 2023-2042					
	0.3	0.2	0.3	0.3	0.0

Exhibit A-4.1

Southwestern Electric Power Company
Actual Internal Energy Requirements (GWh)
By Customer Class

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2012	1	567.8	429.1	402.9	597.0	1,996.7
2012	2	417.4	422.7	420.6	563.5	1,824.2
2012	3	396.9	458.8	494.2	473.0	1,822.9
2012	4	368.8	484.4	474.1	455.8	1,783.2
2012	5	514.8	574.7	526.7	568.5	2,184.8
2012	6	686.5	584.1	512.5	660.1	2,443.2
2012	7	784.0	610.6	484.8	769.7	2,649.1
2012	8	790.3	632.2	486.7	700.1	2,609.3
2012	9	545.3	521.3	476.4	649.2	2,192.2
2012	10	378.2	484.9	473.6	525.5	1,862.1
2012	11	353.4	442.1	455.6	545.2	1,796.3
2012	12	497.7	458.3	452.5	615.2	2,023.7
2013	1	630.1	442.5	409.2	646.6	2,128.4
2013	2	390.8	393.1	398.2	625.7	1,807.7
2013	3	472.8	443.7	451.3	526.9	1,894.7
2013	4	390.3	453.6	465.4	479.5	1,788.9
2013	5	429.8	519.0	501.3	561.6	2,011.6
2013	6	626.6	582.6	498.6	657.2	2,365.0
2013	7	695.3	548.7	467.2	757.5	2,468.6
2013	8	750.2	635.5	513.5	736.1	2,635.3
2013	9	635.5	561.1	461.9	655.7	2,314.3
2013	10	414.8	482.6	456.0	519.8	1,873.2
2013	11	357.0	478.0	525.1	565.2	1,925.3
2013	12	638.2	470.3	464.5	697.9	2,270.8
2014	1	711.6	488.7	454.8	723.5	2,378.6
2014	2	550.0	434.6	437.0	610.9	2,032.5
2014	3	485.4	470.0	485.6	622.3	2,063.3
2014	4	312.2	407.0	563.0	517.2	1,799.5
2014	5	389.6	470.6	502.9	602.7	1,965.7
2014	6	576.0	567.8	498.7	618.5	2,261.0
2014	7	640.8	556.2	477.3	722.4	2,396.7
2014	8	750.8	690.1	590.8	505.5	2,537.2
2014	9	557.6	498.4	442.6	705.1	2,203.8
2014	10	408.3	497.7	487.3	504.6	1,897.9
2014	11	387.2	470.8	505.7	564.2	1,928.0
2014	12	541.6	444.4	455.0	610.7	2,051.8
2015	1	674.7	491.3	433.6	696.3	2,295.8
2015	2	495.4	425.4	403.4	714.5	2,038.7
2015	3	536.1	448.9	408.5	533.5	1,927.1
2015	4	316.0	456.1	455.0	476.2	1,703.3
2015	5	428.9	528.0	491.2	477.0	1,925.2
2015	6	597.1	573.0	468.4	669.8	2,308.3
2015	7	778.8	621.6	483.4	785.9	2,669.6
2015	8	750.9	606.4	442.0	758.9	2,558.2
2015	9	557.1	554.0	493.8	646.4	2,251.3
2015	10	406.6	475.7	442.8	498.7	1,823.8
2015	11	344.8	469.6	448.9	447.3	1,710.7
2015	12	449.4	426.4	399.0	628.4	1,903.1

Exhibit A-4.2

Southwestern Electric Power Company Actual Internal Energy Requirements (GWh) By Customer Class						
Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2016	1	605.3	492.7	444.0	621.7	2,163.7
2016	2	440.3	385.4	399.7	574.9	1,800.3
2016	3	349.1	423.1	404.3	529.9	1,706.5
2016	4	378.9	483.5	443.7	364.4	1,670.5
2016	5	409.2	501.1	433.3	526.4	1,870.0
2016	6	590.9	573.4	451.6	689.8	2,305.6
2016	7	796.5	611.8	402.9	791.2	2,602.4
2016	8	714.6	605.6	433.5	699.2	2,452.9
2016	9	593.9	575.8	417.5	614.4	2,201.5
2016	10	424.7	483.0	423.7	563.9	1,895.2
2016	11	342.9	466.8	400.0	479.8	1,689.6
2016	12	502.0	462.2	419.5	618.3	2,002.1
2017	1	557.7	449.4	397.5	558.6	1,963.2
2017	2	319.4	345.0	366.3	584.0	1,614.8
2017	3	432.6	495.1	474.0	368.1	1,769.8
2017	4	357.5	431.7	416.7	509.3	1,715.1
2017	5	434.1	502.2	464.2	493.1	1,893.7
2017	6	558.7	533.3	469.9	633.0	2,194.9
2017	7	721.8	587.3	463.6	737.9	2,510.7
2017	8	649.6	545.3	437.7	703.6	2,336.2
2017	9	515.5	525.8	456.6	599.8	2,097.7
2017	10	456.1	482.4	485.4	525.5	1,949.4
2017	11	388.8	464.9	451.8	436.5	1,742.0
2017	12	511.2	461.8	455.5	668.0	2,096.5
2018	1	737.4	454.5	389.6	685.9	2,267.5
2018	2	474.2	399.5	385.4	483.9	1,743.0
2018	3	346.7	412.6	445.5	478.7	1,683.5
2018	4	340.5	418.5	444.0	412.2	1,615.2
2018	5	555.2	619.8	551.6	361.1	2,087.8
2018	6	710.0	568.1	450.8	617.9	2,346.8
2018	7	740.1	580.6	453.5	694.5	2,468.7
2018	8	702.6	592.4	475.7	655.7	2,426.4
2018	9	549.4	501.8	436.3	570.5	2,058.0
2018	10	444.7	496.0	471.2	399.2	1,811.0
2018	11	388.6	448.7	469.2	520.7	1,827.2
2018	12	574.6	417.9	418.3	548.5	1,959.3
2019	1	580.5	454.8	428.5	636.8	2,100.7
2019	2	466.0	384.8	387.2	524.2	1,762.2
2019	3	481.2	433.5	434.7	459.8	1,809.2
2019	4	316.7	405.9	439.7	449.8	1,612.2
2019	5	414.6	504.8	479.8	502.4	1,901.6
2019	6	566.2	500.6	436.5	553.9	2,057.2
2019	7	709.1	594.1	492.7	534.0	2,329.8
2019	8	716.1	591.5	483.3	693.0	2,484.0
2019	9	645.4	560.0	437.6	639.0	2,282.0
2019	10	431.8	432.9	432.6	494.9	1,792.1
2019	11	452.0	496.6	495.2	321.9	1,765.8
2019	12	523.1	416.2	389.9	563.7	1,892.9

Exhibit A-4.3

Southwestern Electric Power Company Actual Internal Energy Requirements (GWh) By Customer Class						
Year	**Month**	**Residential**	**Commercial**	**Industrial**	**Other* Energy Requirements**	**Internal Energy Requirements**
2020	1	534.2	432.7	410.8	496.0	1,873.6
2020	2	471.3	399.8	401.3	496.3	1,768.7
2020	3	400.6	395.3	430.3	390.7	1,616.9
2020	4	328.8	346.2	408.3	385.2	1,468.5
2020	5	427.0	393.8	374.1	443.1	1,638.0
2020	6	590.1	496.7	404.5	529.0	2,020.3
2020	7	738.4	554.0	401.1	588.7	2,282.2
2020	8	684.4	534.8	403.9	583.8	2,206.8
2020	9	527.2	462.9	380.0	461.8	1,831.9
2020	10	392.4	463.5	488.3	340.9	1,685.1
2020	11	356.1	386.9	388.2	406.0	1,537.2
2020	12	537.3	429.4	400.5	495.7	1,863.0
2021	1	664.1	427.3	319.5	501.8	1,912.7
2021	2	615.3	444.2	339.8	522.9	1,922.2
2021	3	420.4	337.2	312.0	513.5	1,583.1
2021	4	306.0	411.1	420.3	370.9	1,508.3
2021	5	412.6	460.2	436.0	351.2	1,660.0
2021	6	555.7	524.6	437.5	531.3	2,049.1
2021	7	704.5	537.9	402.6	588.6	2,233.5
2021	8	739.6	600.3	434.9	526.8	2,301.7
2021	9	554.8	478.5	365.4	541.5	1,940.2
2021	10	439.5	479.3	441.7	360.5	1,721.0
2021	11	356.9	403.3	387.2	422.5	1,570.0
2021	12	435.3	384.9	385.3	441.8	1,647.2
2022	1	612.6	480.7	402.8	506.8	2,002.9
2022	2	535.2	357.5	326.5	586.7	1,805.9
2022	3	488.2	428.2	385.4	395.6	1,697.3
2022	4	322.0	398.9	421.9	407.5	1,550.4
2022	5	519.6	544.8	476.9	422.0	1,963.2
2022	6	660.6	543.6	495.5	559.9	2,259.7

Exhibit A-5.1

Southwestern Electric Power Company						
Forecast Internal Energy Requirements (GWh)						
By Customer Class						
Year	**Month**	**Residential**	**Commercial**	**Industrial**	**Other* Energy Requirements**	**Internal Energy Requirements**
2022	7	705.2	553.3	434.6	614.5	2,307.5
2022	8	724.5	584.8	445.5	576.8	2,331.6
2022	9	545.1	493.6	406.2	513.4	1,958.3
2022	10	375.6	429.4	425.1	425.6	1,655.7
2022	11	365.9	425.4	438.2	391.0	1,620.5
2022	12	496.4	391.6	392.1	558.1	1,838.1
2023	1	657.9	456.4	407.4	446.6	1,968.3
2023	2	507.2	389.8	379.6	411.3	1,687.9
2023	3	403.6	388.3	405.1	442.1	1,639.0
2023	4	327.3	392.3	418.3	406.2	1,544.1
2023	5	450.2	495.3	466.8	406.5	1,818.8
2023	6	602.1	537.1	448.0	477.3	2,064.5
2023	7	706.6	554.9	435.1	615.7	2,312.2
2023	8	707.8	573.6	454.6	600.5	2,336.5
2023	9	540.0	490.7	399.2	514.2	1,944.1
2023	10	383.3	437.4	420.9	411.8	1,653.4
2023	11	355.1	413.7	421.5	436.3	1,626.5
2023	12	507.6	401.1	389.7	538.5	1,836.8
2024	1	667.7	461.5	399.9	434.4	1,963.4
2024	2	501.0	383.9	373.3	503.7	1,761.9
2024	3	398.7	383.3	400.4	442.5	1,624.9
2024	4	329.9	393.8	417.3	408.1	1,549.0
2024	5	451.6	496.7	467.0	400.6	1,815.9
2024	6	600.3	536.2	447.0	471.0	2,054.6
2024	7	707.0	556.8	431.2	617.4	2,312.3
2024	8	717.2	582.9	455.0	569.3	2,324.4
2024	9	535.9	489.2	410.8	516.5	1,952.4
2024	10	380.6	435.7	432.5	416.9	1,665.6
2024	11	361.5	420.3	438.4	413.0	1,633.2
2024	12	512.1	403.7	404.8	526.3	1,846.9
2025	1	668.2	460.2	413.5	440.1	1,982.0
2025	2	480.5	367.5	369.9	481.8	1,699.8
2025	3	403.1	384.6	405.3	445.4	1,638.4
2025	4	342.6	404.7	428.3	387.5	1,563.0
2025	5	454.2	499.6	473.4	399.9	1,827.1
2025	6	597.9	534.6	450.1	491.7	2,074.2
2025	7	710.8	561.6	437.6	620.5	2,330.6
2025	8	713.4	581.5	457.9	585.8	2,338.6
2025	9	540.9	494.6	417.1	519.8	1,972.4
2025	10	378.4	434.1	435.2	432.9	1,680.6
2025	11	364.1	422.6	442.5	418.5	1,647.7
2025	12	508.0	399.0	404.6	555.7	1,867.3

Exhibit A-5.2

Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2026	1	670.0	460.0	417.3	438.2	1,985.5
2026	2	499.5	380.2	380.8	444.6	1,705.2
2026	3	403.8	384.7	409.2	447.5	1,645.2
2026	4	334.0	395.3	426.0	413.0	1,568.3
2026	5	456.3	500.1	477.3	395.4	1,829.1
2026	6	601.6	536.6	454.7	491.2	2,084.1
2026	7	712.2	561.5	440.8	622.6	2,337.0
2026	8	710.5	578.3	459.7	597.1	2,345.7
2026	9	541.9	494.4	420.6	521.8	1,978.8
2026	10	381.0	435.0	439.5	428.2	1,683.8
2026	11	362.8	419.2	444.0	434.3	1,660.3
2026	12	512.5	400.6	409.2	551.7	1,874.0
2027	1	673.0	459.8	420.5	433.5	1,986.8
2027	2	496.6	375.9	381.5	454.7	1,708.6
2027	3	410.6	388.6	414.8	450.3	1,664.4
2027	4	333.9	394.0	428.5	414.5	1,570.9
2027	5	454.1	495.6	477.5	405.5	1,832.8
2027	6	601.5	534.6	456.9	494.9	2,087.9
2027	7	711.6	559.2	442.9	623.9	2,337.5
2027	8	714.0	579.4	463.5	597.2	2,354.1
2027	9	543.0	493.2	423.1	523.3	1,982.6
2027	10	380.2	431.9	440.7	432.0	1,684.9
2027	11	366.0	419.9	447.1	421.8	1,654.8
2027	12	514.0	399.0	410.8	557.4	1,881.3
2028	1	675.3	458.1	422.1	430.7	1,986.1
2028	2	497.6	373.6	382.6	530.9	1,784.6
2028	3	409.0	384.0	414.3	451.0	1,658.2
2028	4	337.3	393.7	430.4	401.1	1,562.4
2028	5	459.1	498.0	481.4	400.3	1,838.7
2028	6	603.4	533.0	458.4	490.9	2,085.7
2028	7	710.0	554.3	442.6	624.5	2,331.4
2028	8	719.3	580.1	466.2	589.6	2,355.2
2028	9	541.0	487.8	422.4	523.8	1,975.0
2028	10	386.9	434.5	443.9	420.4	1,685.7
2028	11	368.0	419.0	448.1	420.7	1,655.9
2028	12	515.6	397.2	411.3	544.4	1,868.5
2029	1	677.1	456.1	422.6	445.0	2,000.7
2029	2	501.4	373.4	384.0	456.1	1,714.8
2029	3	410.4	382.3	414.7	452.2	1,659.7
2029	4	339.1	392.6	431.1	410.1	1,572.9
2029	5	461.3	497.2	482.3	405.6	1,846.4
2029	6	606.4	532.2	459.4	492.5	2,090.6
2029	7	717.4	556.3	445.0	626.6	2,345.3
2029	8	717.4	574.3	464.5	609.0	2,365.2
2029	9	544.6	486.8	423.2	525.2	1,979.9
2029	10	388.2	432.6	444.0	432.0	1,696.8
2029	11	369.1	417.4	448.1	431.7	1,666.4
2029	12	518.2	396.5	411.9	552.5	1,879.0

Exhibit A-5.3

Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2030	1	679.7	454.6	423.0	445.8	2,003.1
2030	2	502.0	370.8	383.7	459.6	1,716.2
2030	3	410.1	379.0	413.9	453.0	1,656.0
2030	4	343.4	393.7	433.0	408.2	1,578.4
2030	5	463.0	496.0	482.9	406.0	1,847.9
2030	6	608.6	530.6	459.9	490.7	2,089.8
2030	7	721.9	555.9	446.4	628.2	2,352.5
2030	8	719.1	571.5	464.8	609.3	2,364.7
2030	9	548.8	486.3	424.6	526.8	1,986.4
2030	10	388.0	429.3	443.9	438.2	1,699.4
2030	11	371.2	416.5	449.2	430.6	1,667.6
2030	12	520.0	394.8	412.6	557.1	1,884.6
2031	1	682.3	453.1	424.0	447.9	2,007.4
2031	2	504.8	369.2	384.7	461.0	1,719.7
2031	3	411.8	376.8	414.4	454.2	1,657.2
2031	4	347.4	394.0	435.0	405.4	1,581.8
2031	5	465.9	495.3	484.4	403.1	1,848.7
2031	6	612.1	529.4	461.3	496.6	2,099.3
2031	7	726.6	555.1	448.0	629.9	2,359.8
2031	8	723.4	570.2	466.3	607.9	2,367.7
2031	9	554.2	486.4	426.8	528.7	1,996.1
2031	10	389.6	427.2	445.1	441.8	1,703.6
2031	11	373.2	415.2	450.7	431.4	1,670.5
2031	12	523.0	393.4	414.2	561.7	1,892.3
2032	1	686.9	452.4	426.0	435.7	2,000.9
2032	2	505.7	366.6	385.4	536.0	1,793.7
2032	3	418.7	379.6	418.5	456.6	1,673.4
2032	4	346.8	390.7	435.3	408.5	1,581.3
2032	5	468.6	495.0	486.5	395.7	1,845.8
2032	6	615.2	528.8	463.2	497.1	2,104.4
2032	7	726.1	550.9	448.2	630.8	2,356.1
2032	8	731.6	573.4	470.4	596.5	2,371.8
2032	9	554.7	483.3	427.7	529.8	1,995.5
2032	10	394.3	428.6	448.4	424.0	1,695.4
2032	11	375.5	414.8	453.2	420.0	1,663.7
2032	12	525.3	392.2	416.4	558.7	1,892.7
2033	1	689.0	451.0	428.1	447.4	2,015.6
2033	2	509.6	367.0	388.5	464.1	1,729.1
2033	3	421.9	380.1	421.8	458.5	1,682.3
2033	4	345.7	387.4	436.2	417.7	1,586.9
2033	5	470.7	494.4	489.1	406.2	1,860.5
2033	6	618.3	528.4	466.0	504.7	2,117.4
2033	7	731.3	551.7	451.5	632.9	2,367.3
2033	8	733.7	571.6	472.5	613.3	2,391.0
2033	9	559.9	484.5	431.3	531.9	2,007.7
2033	10	394.2	425.8	450.1	436.9	1,706.9
2033	11	377.4	414.1	455.8	430.3	1,677.6
2033	12	527.3	391.2	418.8	565.4	1,902.7

Exhibit A-5.4

Southwestern Electric Power Company Forecast Internal Energy Requirements (GWh) By Customer Class						
Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2034	1	691.8	450.0	430.6	452.2	2,024.6
2034	2	511.8	365.9	390.8	465.1	1,733.7
2034	3	422.9	378.1	423.5	459.8	1,684.3
2034	4	349.5	388.1	439.5	410.8	1,587.9
2034	5	473.4	493.9	491.6	411.1	1,870.1
2034	6	621.9	528.1	468.6	506.0	2,124.6
2034	7	735.9	551.7	454.1	634.7	2,376.4
2034	8	737.3	570.8	474.7	617.5	2,400.3
2034	9	562.0	482.7	433.0	533.3	2,011.1
2034	10	398.0	426.3	453.0	439.2	1,716.4
2034	11	379.6	413.6	458.1	434.5	1,685.8
2034	12	529.8	390.4	421.1	560.6	1,901.9
2035	1	694.4	448.9	432.8	454.3	2,030.3
2035	2	514.2	365.0	393.0	466.2	1,738.4
2035	3	422.3	374.9	424.2	460.8	1,682.3
2035	4	354.7	390.1	443.4	408.4	1,596.6
2035	5	476.3	493.9	494.4	412.1	1,876.7
2035	6	625.3	528.0	471.3	503.7	2,128.4
2035	7	741.5	553.1	457.5	636.9	2,389.0
2035	8	739.1	569.2	476.5	624.1	2,408.9
2035	9	563.9	481.2	435.0	534.8	2,014.9
2035	10	401.7	427.0	456.2	441.4	1,726.2
2035	11	381.9	413.3	460.8	436.9	1,693.0
2035	12	532.2	389.6	423.6	562.6	1,908.1
2036	1	696.9	448.3	435.4	450.5	2,031.0
2036	2	514.4	362.9	394.6	524.2	1,796.0
2036	3	418.8	369.2	423.6	461.3	1,673.0
2036	4	364.0	396.2	450.1	393.4	1,603.7
2036	5	479.1	494.2	497.4	405.1	1,875.9
2036	6	628.2	527.9	474.0	502.1	2,132.2
2036	7	744.7	553.1	460.2	638.6	2,396.5
2036	8	742.8	569.7	479.6	611.7	2,403.7
2036	9	567.8	482.0	438.2	536.7	2,024.7
2036	10	402.5	425.5	458.4	440.8	1,727.1
2036	11	384.1	413.1	463.6	429.7	1,690.5
2036	12	534.1	388.5	426.0	566.6	1,915.3
2037	1	699.9	447.6	438.1	454.5	2,040.1
2037	2	518.4	363.3	397.8	470.3	1,749.8
2037	3	424.6	371.8	428.3	463.7	1,688.3
2037	4	361.8	391.7	450.3	409.4	1,613.2
2037	5	482.3	494.6	500.5	406.1	1,883.5
2037	6	631.7	528.1	477.0	512.7	2,149.4
2037	7	750.8	555.3	464.1	640.9	2,411.1
2037	8	744.9	568.8	481.8	623.5	2,419.1
2037	9	573.0	483.9	442.0	538.9	2,037.8
2037	10	403.5	424.2	460.8	446.8	1,735.2
2037	11	386.4	412.9	466.5	441.2	1,707.1
2037	12	537.0	388.2	429.0	572.9	1,927.2

Exhibit A-5.4 (continued)

Southwestern Electric Power Company Forecast Internal Energy Requirements (GWh) By Customer Class						
Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2038	1	702.6	447.2	441.2	452.3	2,043.3
2038	2	520.3	362.7	400.6	471.5	1,755.1
2038	3	432.5	376.6	434.5	466.5	1,710.1
2038	4	358.5	386.6	450.3	422.9	1,618.3
2038	5	485.1	495.0	503.9	406.9	1,890.9
2038	6	635.0	528.4	480.2	514.7	2,158.3
2038	7	753.2	554.8	466.7	642.6	2,417.3
2038	8	749.6	570.3	485.6	627.9	2,433.3
2038	9	576.2	484.2	445.2	540.8	2,046.3
2038	10	405.9	424.1	463.9	445.1	1,739.0
2038	11	388.9	412.9	469.8	432.1	1,703.6
2038	12	539.1	387.2	431.7	578.6	1,936.6
2039	1	705.1	446.5	444.1	457.9	2,053.7
2039	2	522.5	362.1	403.5	472.6	1,760.6
2039	3	433.6	375.2	436.9	468.0	1,713.7
2039	4	362.1	387.6	454.2	415.9	1,619.7
2039	5	487.7	495.0	507.2	411.7	1,901.7
2039	6	638.3	528.7	483.6	516.4	2,167.0
2039	7	755.7	554.2	469.5	644.2	2,423.6
2039	8	754.1	571.6	489.4	632.5	2,447.6
2039	9	579.1	484.3	448.5	542.5	2,054.4
2039	10	408.4	424.1	467.4	446.7	1,746.7
2039	11	391.1	412.8	473.1	435.3	1,712.3
2039	12	541.6	386.6	434.9	577.0	1,940.2
2040	1	707.2	445.7	447.3	454.6	2,054.8
2040	2	524.1	361.3	406.4	549.0	1,840.9
2040	3	429.7	369.6	436.9	468.4	1,704.6
2040	4	369.9	392.6	460.6	398.3	1,621.4
2040	5	490.2	495.2	510.6	411.9	1,907.8
2040	6	641.5	529.1	487.1	507.5	2,165.2
2040	7	758.1	553.7	472.2	645.8	2,429.7
2040	8	758.3	572.8	493.1	625.0	2,449.1
2040	9	576.0	479.4	448.9	543.1	2,047.4
2040	10	416.0	428.8	473.0	435.5	1,753.3
2040	11	393.2	412.7	476.1	432.7	1,714.7
2040	12	543.9	386.1	437.8	564.3	1,932.2
2041	1	708.8	444.6	449.8	466.6	2,069.7
2041	2	526.0	360.6	409.1	475.8	1,771.6
2041	3	431.7	369.3	439.8	470.0	1,710.7
2041	4	371.8	392.3	463.4	408.5	1,636.1
2041	5	492.8	495.5	513.8	417.3	1,919.4
2041	6	644.5	529.4	490.1	511.5	2,175.6
2041	7	766.1	558.0	477.2	648.3	2,449.5
2041	8	756.9	569.4	493.9	641.0	2,461.2
2041	9	582.8	483.0	453.5	545.5	2,064.9
2041	10	414.0	425.1	473.9	452.8	1,765.8
2041	11	395.2	412.6	478.9	438.6	1,725.3
2041	12	545.8	385.4	440.3	577.7	1,949.1
2042	1	711.7	444.3	452.6	466.8	2,075.4
2042	2	528.1	360.0	411.6	476.9	1,776.5
2042	3	432.6	367.8	441.8	471.3	1,713.4
2042	4	375.4	393.4	466.9	406.0	1,641.6
2042	5	495.6	496.0	516.8	414.0	1,922.4
2042	6	647.6	529.6	492.9	517.5	2,187.5
2042	7	770.1	558.9	480.2	650.1	2,459.3
2042	8	760.2	569.8	496.7	639.9	2,466.6
2042	9	587.7	484.9	457.1	547.5	2,077.1
2042	10	414.3	423.5	475.8	458.5	1,772.1
2042	11	397.4	412.7	481.7	438.8	1,730.6
2042	12	548.0	384.8	442.8	582.8	1,958.4

Exhibit A-6

Southwestern Electric Power Company Actual and Weather Normal Energy Sales (GWh) And Peak Demand (MW) vs. 2019 IRP Forecast												
	2019 IRP Forecast			Actual			Difference			% Difference		
	2019	2020	2021	2019	2020	2021	2019	2020	2021	2019	2020	2021
Residential	6,126	6,243	6,231	6,303	5,988	6,205	-177	255	26	-2.8%	4.3%	0.4%
Commercial	5,751	5,855	5,845	5,776	5,296	5,489	-25	559	356	-0.4%	10.6%	6.5%
Industrial	5,356	5,473	5,517	5,338	4,891	4,682	18	582	835	0.3%	11.9%	17.8%
Other Retail	79	80	80	80	79	77	-1	1	3	-0.9%	0.8%	3.4%
Wholesale	5,171	4,610	4,648	5,255	4,433	4,523	-84	177	126	-1.6%	4.0%	2.8%
Total Sales	22,483	22,261	22,321	22,751	20,687	20,975	-268	1,574	1,346	-1.2%	7.6%	6.4%
	2019 IRP Forecast			Normal			Difference			% Difference		
	2019	2020	2021	2019	2020	2021	2019	2020	2021	2019	2020	2021
Residential	6,126	6,243	6,231	6,263	6,310	6,176	-137	-67	55	-2.2%	-1.1%	0.9%
Commercial	5,751	5,855	5,845	5,756	5,394	5,445	-5	461	399	-0.1%	8.5%	7.3%
Industrial	5,356	5,473	5,517	5,338	4,891	4,682	18	582	835	0.3%	11.9%	17.8%
Other Retail	79	80	80	80	79	77	-1	1	3	-0.9%	0.8%	3.4%
Wholesale	5,171	4,610	4,648	5,248	4,473	4,522	-77	137	127	-1.5%	3.1%	2.8%
Total Sales	22,483	22,261	22,321	22,685	21,148	20,902	-201	1,113	1,419	-0.9%	5.3%	6.8%
	2019 IRP Forecast			Normal			Difference			% Difference		
	2019	2020	2021	2019	2020	2021	2019	2020	2021	2019	2020	2021
Winter Peak	4,148	4,170	4,200	4,148	3,900	4,563	0	271	-363	0.0%	6.9%	-8.0%
Summer Peak	4,784	4,673	4,696	4,727	4,351	4,444	57	322	252	1.2%	7.4%	5.7%
	2019 IRP Forecast			Normal			Difference			% Difference		
	2019	2020	2021	2019	2020	2021	2019	2020	2021	2019	2020	2021
Winter Peak	4,148	4,170	4,200	4,322	4,272	4,159	-174	-101	41	-4.0%	-2.4%	1.0%
Summer Peak	4,784	4,673	4,696	4,869	4,640	4,595	-85	34	101	-1.7%	0.7%	2.2%

Exhibit A-7

Southwestern Electric Power Company and State Jurisdictions
DSM/Energy Efficiency Included in 2019 IRP Load Forecast
Energy (GWh) and Coincident Peak Demand (MW)

	SWEPCO DSM/EE			SWEPCO - Arkansas DSM/EE			SWEPCO - Louisana DSM/EE			SWEPCO - Texas DSM/EE		
Year	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand
2019	22.2	3.9	4.4	14.5	2.5	2.6	7.6	1.3	1.7	0.1	0.0	0.0
2020	37.5	6.4	7.1	27.2	4.7	4.9	9.6	1.6	2.1	0.7	0.0	0.1
2021	46.8	7.8	8.5	38.3	6.7	6.9	6.6	1.0	1.4	1.9	0.1	0.2
2022	53.0	8.8	9.4	46.6	8.3	8.4	3.5	0.3	0.6	2.9	0.1	0.3
2023	50.6	7.2	8.4	44.4	6.9	7.7	2.2	0.1	0.3	3.9	0.2	0.5
2024	43.2	4.3	6.1	35.8	3.9	5.3	2.4	0.1	0.3	5.0	0.2	0.6
2025	35.5	2.4	4.5	28.3	2.1	3.7	2.3	0.1	0.3	4.8	0.2	0.6
2026	20.2	1.0	2.4	15.3	0.7	1.8	1.6	0.1	0.2	3.4	0.2	0.4
2027	9.4	0.5	1.1	6.5	0.3	0.8	1.0	0.0	0.1	2.0	0.1	0.2
2028	1.1	0.1	0.1	0.0	0.0	0.0	0.4	0.0	0.0	0.7	0.0	0.1
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	4.6	1.5	1.2	1.9	0.6	0.6	1.1	0.4	0.2	1.6	0.5	0.4
2031	11.2	3.7	2.8	4.8	1.5	1.5	2.6	1.0	0.5	3.8	1.3	0.9
2032	12.1	4.0	3.0	4.9	1.5	1.5	2.9	1.1	0.5	4.3	1.4	1.0
2033	9.5	3.2	2.3	3.3	1.0	1.0	2.5	0.9	0.5	3.7	1.2	0.8
2034	7.1	2.4	1.7	1.9	0.6	0.6	2.1	0.8	0.4	3.1	1.1	0.7
2035	4.9	1.7	1.1	0.6	0.2	0.2	1.7	0.6	0.3	2.6	0.9	0.6
2036	3.3	1.2	0.7	0.0	0.0	0.0	1.3	0.5	0.3	2.0	0.7	0.5
2037	2.4	0.8	0.5	0.0	0.0	0.0	0.9	0.3	0.2	1.4	0.5	0.3
2038	1.4	0.5	0.3	0.0	0.0	0.0	0.5	0.2	0.1	0.9	0.3	0.2
2039	0.6	0.2	0.1	0.0	0.0	0.0	0.2	0.1	0.0	0.4	0.1	0.1

***Demand coincident with Company's seasonal peak demand.**

Exhibit A-8

Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Residential Customer and Energy Usage Models

Year	SWEPCO Arkansas Population	SWEPCO Arkansas Real Personal Income	SWEPCO Arkansas Housing Stock	SWEPCO Louisiana Population	SWEPCO Louisiana Real Personal Income	SWEPCO Louisiana Housing Stock	SWEPCO Texas Population	SWEPCO Texas Real Personal Income
1995	566.0	15,338.1	238.5	572.4	15,263.4	245.9	784.8	20,349.1
1996	582.1	16,066.6	245.8	573.6	15,472.1	247.2	796.2	21,264.9
1997	593.8	16,807.2	252.3	574.1	15,797.7	248.5	804.8	22,484.2
1998	602.5	17,932.1	257.7	573.0	16,262.9	249.3	813.4	23,521.2
1999	613.6	18,751.1	262.8	575.5	16,591.8	250.2	819.5	24,072.8
2000	627.3	19,560.6	268.4	577.2	17,098.1	251.6	825.4	25,190.3
2001	636.3	20,081.4	273.6	576.6	18,221.0	253.9	830.1	26,148.8
2002	647.0	20,463.3	279.3	576.7	18,446.5	256.2	837.4	26,394.2
2003	659.7	21,339.3	285.4	575.9	18,685.5	258.5	845.2	26,950.2
2004	672.9	23,135.9	292.5	579.9	19,045.1	262.6	853.1	27,500.9
2005	690.0	24,316.6	300.9	583.4	20,197.6	261.6	861.1	28,808.7
2006	708.5	25,729.7	311.5	589.7	20,831.3	249.0	873.9	30,204.0
2007	722.3	27,045.2	319.0	589.7	20,887.1	258.4	882.2	30,968.6
2008	733.4	28,050.4	324.0	590.3	23,110.2	263.8	890.2	34,350.4
2009	743.7	26,610.8	327.5	596.1	22,262.4	266.9	900.5	32,539.5
2010	755.6	27,551.6	330.8	603.4	23,557.8	268.7	907.8	34,373.0
2011	767.2	29,996.4	333.0	606.9	23,678.8	270.7	912.4	36,460.3
2012	776.3	33,249.3	335.0	611.8	23,794.0	272.9	915.6	36,619.4
2013	784.3	32,741.8	337.5	608.3	23,712.4	275.2	916.9	36,562.9
2014	792.2	36,047.0	340.3	605.8	24,569.1	277.5	921.0	37,657.7
2015	803.3	38,130.5	343.7	603.5	24,102.1	279.9	924.9	36,479.5
2016	814.3	39,573.7	347.8	600.9	23,233.9	282.2	929.4	35,350.8
2017	826.4	40,386.7	352.8	596.6	23,086.4	284.9	933.7	36,818.4
2018	834.9	42,257.7	357.9	591.0	23,675.8	287.1	939.6	37,866.2
2019	844.2	43,051.3	363.4	586.6	23,811.5	289.2	944.9	38,248.1
2020	848.6	44,415.5	369.5	587.2	25,227.2	291.1	958.3	39,530.2
2021	861.6	45,229.2	376.4	584.9	25,494.2	293.2	956.2	41,903.4
2022	870.7	44,476.7	383.6	584.2	24,057.7	295.3	961.6	40,091.6
2023	879.8	46,030.7	390.8	583.7	24,356.4	298.0	967.7	41,062.6
2024	889.0	47,719.0	398.4	583.2	24,814.0	300.9	972.8	42,203.7
2025	898.0	49,312.6	406.0	582.4	25,082.1	303.9	977.4	43,092.5
2026	907.1	50,733.7	413.3	581.4	25,279.4	306.8	981.7	44,020.6
2027	916.0	52,106.5	420.1	580.2	25,525.6	309.6	986.2	45,111.3
2028	924.9	53,583.3	426.3	578.8	25,850.8	312.2	990.8	46,311.7
2029	933.6	55,172.6	432.1	577.4	26,180.2	314.7	995.8	47,526.0
2030	942.3	56,742.0	437.5	576.0	26,481.3	317.1	1,001.0	48,714.1
2031	950.9	58,247.5	442.6	574.6	26,746.1	319.4	1,006.2	49,928.0
2032	959.5	59,806.9	447.5	573.1	26,991.3	321.6	1,011.3	51,040.2
2033	967.9	61,383.2	452.2	571.7	27,225.9	323.8	1,016.4	52,157.4
2034	976.4	62,963.7	456.8	570.3	27,444.5	325.9	1,021.4	53,268.2
2035	984.7	64,545.0	461.2	568.9	27,647.7	328.0	1,026.3	54,360.4
2036	992.9	66,118.5	465.6	567.4	27,824.7	330.2	1,030.8	55,409.0
2037	1,001.1	67,667.8	470.0	566.0	27,983.8	332.3	1,035.2	56,439.3
2038	1,009.2	69,186.6	474.3	564.6	28,114.8	334.5	1,039.5	57,422.3
2039	1,017.1	70,686.0	478.5	563.1	28,224.6	336.6	1,043.6	58,390.5
2040	1,024.8	72,208.4	482.6	561.5	28,342.4	338.7	1,047.6	59,390.1
2041	1,032.2	73,778.5	486.6	559.9	28,470.4	340.8	1,051.5	60,417.1
2042	1,039.5	75,421.8	490.5	558.2	28,611.2	342.9	1,055.3	61,477.5
Units	Thousands	Millions (2012 $)	Thousands	Thousands	Millions (2012 $)	Thousands	Thousands	Millions (2012 $)

Exhibit A-9

Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Commercial Energy Sales Models

Year	SWEPCO Arkansas Gross Regional Product	SWEPCO Louisana Population	SWEPCO Louisana Real Personal Income	SWEPCO Texad Population	SWEPCO Texas Gross Regional Product	SWEPCO Texas Commercial Gross Regional Product
1995	18,775.1	572.4	15,263.4	784.8	27,808.9	17,743.0
1996	19,505.6	573.6	15,472.1	796.2	28,962.7	18,577.3
1997	19,942.2	574.1	15,797.7	804.8	30,947.7	19,608.9
1998	20,345.6	573.0	16,262.9	813.4	31,748.3	20,130.2
1999	22,010.6	575.5	16,591.8	819.5	32,317.1	20,842.7
2000	22,560.8	577.2	17,098.1	825.4	33,240.7	21,287.2
2001	23,291.5	576.6	18,221.0	830.1	33,129.5	21,454.2
2002	24,842.6	576.7	18,446.5	837.4	34,416.0	21,994.1
2003	26,627.5	575.9	18,685.5	845.2	35,042.6	22,405.4
2004	28,392.2	579.9	19,045.1	853.1	38,177.8	23,422.8
2005	29,992.9	583.4	20,197.6	861.1	38,123.8	24,087.5
2006	30,710.8	589.7	20,831.3	873.9	40,569.9	25,026.9
2007	29,855.3	589.7	20,887.1	882.2	42,287.5	25,478.4
2008	29,174.2	590.3	23,110.2	890.2	42,288.1	26,018.9
2009	27,906.2	596.1	22,262.4	900.5	40,727.6	25,774.6
2010	29,076.7	603.4	23,557.8	907.8	42,336.0	26,847.9
2011	29,333.3	606.9	23,678.8	912.4	43,118.7	27,224.6
2012	29,767.5	611.8	23,794.0	915.6	44,295.1	28,271.0
2013	30,851.4	608.3	23,712.4	916.9	45,649.5	28,732.8
2014	31,616.2	605.8	24,569.1	921.0	46,608.3	29,119.3
2015	32,486.6	603.5	24,102.1	924.9	46,695.1	29,245.8
2016	33,131.6	600.9	23,233.9	929.4	44,906.0	28,817.3
2017	34,031.8	596.6	23,086.4	933.7	45,447.4	29,001.6
2018	35,023.2	591.0	23,675.8	939.6	47,498.7	29,760.3
2019	35,898.0	586.6	23,811.5	944.9	47,883.9	30,118.8
2020	35,921.9	587.2	25,227.2	958.3	45,873.7	29,406.6
2021	38,442.1	584.9	25,494.2	956.2	47,555.4	31,241.8
2022	40,145.6	584.2	24,057.7	961.6	49,958.0	32,587.4
2023	41,501.5	583.7	24,356.4	967.7	51,776.8	33,747.0
2024	42,886.5	583.2	24,814.0	972.8	53,469.8	34,939.4
2025	44,303.6	582.4	25,082.1	977.4	55,011.2	36,130.8
2026	45,647.4	581.4	25,279.4	981.7	56,409.2	37,263.4
2027	46,824.7	580.2	25,525.6	986.2	57,671.9	38,272.2
2028	47,975.7	578.8	25,850.8	990.8	59,016.1	39,294.4
2029	49,165.6	577.4	26,180.2	995.8	60,399.1	40,333.0
2030	50,353.7	576.0	26,481.3	1,001.0	61,791.8	41,362.9
2031	51,579.2	574.6	26,746.1	1,006.2	63,224.3	42,422.8
2032	52,868.8	573.1	26,991.3	1,011.3	64,712.3	43,539.8
2033	54,203.6	571.7	27,225.9	1,016.4	66,251.3	44,718.9
2034	55,564.7	570.3	27,444.5	1,021.4	67,819.7	45,932.5
2035	56,954.7	568.9	27,647.7	1,026.3	69,376.1	47,153.6
2036	58,382.3	567.4	27,824.7	1,030.8	70,921.3	48,379.9
2037	59,827.2	566.0	27,983.8	1,035.2	72,464.9	49,608.6
2038	61,288.3	564.6	28,114.8	1,039.5	73,997.7	50,845.0
2039	62,793.8	563.1	28,224.6	1,043.6	75,561.8	52,094.1
2040	64,305.2	561.5	28,342.4	1,047.6	77,166.7	53,375.9
2041	65,861.3	559.9	28,470.4	1,051.5	78,797.0	54,692.4
2042	67,439.4	558.2	28,611.2	1,055.3	80,458.9	56,042.9
2043	68,112.5	337.7	44,394.4	592.8	290.0	427.1
Units	Millions (2012 $)	Thousands	Millions (2012 $)	Thousands	Millions (2012 $)	Millions (2012 $)

Exhibit A-10

Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Manufacturing Energy Sales Models

Year	SWEPCO Arkansas Gross Regional Product - Manufacturing	SWEPCO Louisana Gross Regional Product - Manufacturing	SWEPCO Louisana Manufacturing Employment	FRB Industrial Producion Index - Manufacturing	SWEPCO Texas Manufacturing Employment
1995	5,112.2	3,775.3	28.0	70.0	48.8
1996	4,916.4	3,315.3	27.2	73.7	49.4
1997	4,942.0	3,645.9	25.5	79.9	50.2
1998	4,880.2	3,729.8	25.2	85.2	51.4
1999	5,478.0	4,077.2	25.1	89.6	51.2
2000	5,518.5	3,170.8	25.0	93.5	51.1
2001	5,497.2	2,805.5	23.3	90.2	49.7
2002	5,944.0	3,301.2	21.2	90.8	48.2
2003	6,428.2	4,988.6	21.0	92.2	47.7
2004	6,950.3	5,913.0	21.3	95.2	49.0
2005	7,033.0	7,267.7	21.6	99.3	49.2
2006	7,113.5	6,140.4	21.3	102.1	50.0
2007	5,991.9	5,029.5	21.1	105.4	50.4
2008	5,328.0	4,507.1	18.6	100.5	48.9
2009	4,833.1	4,107.1	16.6	86.8	41.7
2010	5,305.9	4,970.3	16.6	92.5	39.2
2011	5,076.6	4,329.8	16.6	95.5	38.9
2012	4,599.7	4,111.9	16.3	98.2	37.6
2013	4,953.1	3,674.6	15.9	99.3	37.7
2014	5,125.8	3,996.2	16.2	100.5	39.4
2015	4,991.5	3,826.9	15.9	100.1	39.5
2016	4,982.5	3,637.1	15.3	99.3	38.2
2017	5,058.9	3,861.3	15.2	100.0	38.1
2018	5,276.2	3,950.6	15.6	101.5	39.8
2019	5,545.4	3,891.0	16.0	99.5	40.6
2020	5,560.7	3,586.4	14.9	93.2	39.6
2021	5,767.4	3,652.9	14.4	99.2	40.9
2022	5,933.3	3,812.0	14.8	103.6	41.7
2023	6,082.4	3,912.3	14.9	105.7	41.5
2024	6,238.0	3,990.9	14.9	107.7	41.1
2025	6,375.0	4,021.8	14.9	109.3	40.6
2026	6,487.2	4,008.8	14.7	110.5	40.1
2027	6,588.3	3,988.5	14.5	111.9	39.7
2028	6,696.3	3,987.9	14.3	113.5	39.3
2029	6,810.1	4,005.7	14.2	115.2	38.9
2030	6,925.2	4,037.0	14.0	117.1	38.6
2031	7,052.9	4,078.8	13.9	119.1	38.2
2032	7,188.2	4,125.8	13.7	121.3	37.9
2033	7,328.9	4,179.9	13.6	123.5	37.6
2034	7,470.9	4,239.4	13.5	125.8	37.2
2035	7,615.9	4,303.7	13.3	128.1	36.9
2036	7,761.5	4,370.6	13.2	130.3	36.6
2037	7,904.6	4,433.8	13.1	132.5	36.3
2038	8,046.7	4,499.0	12.9	134.7	35.9
2039	8,191.5	4,566.2	12.8	136.9	35.6
2040	8,334.8	4,634.6	12.7	139.2	35.4
2041	8,478.0	4,703.9	12.6	141.3	35.1
2042	8,620.2	4,773.8	12.5	143.4	34.9
Units	**Millions (2012 $)**	**Millions (2012 $)**	**Thousands**	**Index (2015=100)**	**Thousands**

Exhibit A-11

Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Other Retail and Wholesale Energy Sales Models

Year	SWEPCO Arkansas Population	SWEPCO Arkansas Employment	SWEPCO Arkansas Gross Regional Product	SWEPCO Louisana Employment	SWEPCO Arkansas Regulated Employment	SWEPCO Texas Population
1995	572.4	287.5	18,775.1	273.3	16.0	784.8
1996	573.6	294.1	19,505.6	278.5	16.1	796.2
1997	574.1	305.5	19,942.2	283.1	15.8	804.8
1998	573.0	309.6	20,345.6	288.1	15.7	813.4
1999	575.5	312.8	22,010.6	296.6	16.4	819.5
2000	577.2	318.1	22,560.8	303.8	16.3	825.4
2001	576.6	320.9	23,291.5	309.4	18.8	830.1
2002	576.7	321.0	24,842.6	313.1	22.1	837.4
2003	575.9	323.6	26,627.5	315.3	22.1	845.2
2004	579.9	333.3	28,392.2	321.6	21.7	853.1
2005	583.4	340.1	29,992.9	332.3	22.2	861.1
2006	589.7	347.4	30,710.8	340.7	22.6	873.9
2007	589.7	358.0	29,855.3	342.5	22.5	882.2
2008	590.3	366.2	29,174.2	340.7	21.1	890.2
2009	596.1	352.5	27,906.2	326.9	18.6	900.5
2010	603.4	354.1	29,076.7	327.3	19.3	907.8
2011	606.9	356.4	29,333.3	329.3	19.4	912.4
2012	611.8	360.8	29,767.5	334.5	19.5	915.6
2013	608.3	367.3	30,851.4	337.1	19.2	916.9
2014	605.8	371.4	31,616.2	347.6	19.8	921.0
2015	603.5	372.0	32,486.6	360.3	20.9	924.9
2016	600.9	366.1	33,131.6	371.8	21.4	929.4
2017	596.6	367.4	34,031.8	378.7	21.2	933.7
2018	591.0	373.3	35,023.2	384.8	21.9	939.6
2019	586.6	377.2	35,898.0	390.4	22.8	944.9
2020	587.2	362.7	35,921.9	382.6	22.3	958.3
2021	584.9	372.5	38,442.1	396.1	22.5	956.2
2022	584.2	386.8	40,145.6	411.3	23.4	961.6
2023	583.7	393.9	41,501.5	416.9	23.7	967.7
2024	583.2	398.2	42,886.5	420.5	24.0	972.8
2025	582.4	400.6	44,303.6	422.8	24.2	977.4
2026	581.4	402.8	45,647.4	424.8	24.4	981.7
2027	580.2	405.1	46,824.7	426.5	24.5	986.2
2028	578.8	407.6	47,975.7	428.1	24.6	990.8
2029	577.4	410.3	49,165.6	429.7	24.7	995.8
2030	576.0	413.0	50,353.7	431.1	24.9	1,001.0
2031	574.6	415.5	51,579.2	432.3	25.0	1,006.2
2032	573.1	417.9	52,868.8	433.3	25.1	1,011.3
2033	571.7	420.6	54,203.6	434.5	25.2	1,016.4
2034	570.3	423.1	55,564.7	435.6	25.3	1,021.4
2035	568.9	425.6	56,954.7	436.6	25.4	1,026.3
2036	567.4	427.8	58,382.3	437.5	25.4	1,030.8
2037	566.0	429.9	59,827.2	438.3	25.5	1,035.2
2038	564.6	432.0	61,288.3	439.2	25.5	1,039.5
2039	563.1	434.2	62,793.8	440.1	25.6	1,043.6
2040	561.5	436.6	64,305.2	441.1	25.6	1,047.6
2041	559.9	439.0	65,861.3	442.2	25.6	1,051.5
2042	558.2	441.6	67,439.4	443.3	25.7	1,055.3
Units	Thousands	Thousands	Millions (2012 $)	Thousands	Thousands	Thousands

Exhibit A-12

Southwestern Electric Power Company and State Jurisdictions
DSM/Energy Efficiency Included in Load Forecast
Energy (GWh) and Coincident Peak Demand (MW)

	SWEPCO DSM/EE			SWEPCO - Arkansas DSM/EE			SWEPCO - Louisana DSM/EE			SWEPCO - Texas DSM/EE		
Year	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand
2022	18.7	4.2	3.2	9.6	2.0	1.5	9.2	1.9	1.5	0.0	0.2	0.1
2023	31.7	7.1	5.2	15.2	3.3	2.5	16.5	3.7	2.7	0.0	0.1	0.0
2024	33.8	8.9	5.6	18.9	4.2	3.2	14.9	4.1	2.3	0.0	0.6	0.1
2025	28.6	9.8	5.0	14.6	4.2	2.7	14.0	4.6	2.0	0.0	1.0	0.2
2026	30.6	12.0	5.1	15.9	5.5	2.8	14.6	5.1	1.9	0.0	1.4	0.3
2027	33.1	14.1	5.3	17.8	6.8	3.0	15.3	5.5	1.8	0.0	1.8	0.4
2028	28.4	13.2	4.2	15.1	6.3	2.5	13.3	5.1	1.3	0.0	1.8	0.4
2029	23.0	10.9	3.0	12.5	5.4	1.9	10.5	4.2	0.9	0.0	1.4	0.2
2030	18.6	8.9	2.2	9.9	4.4	1.4	8.7	3.5	0.7	0.0	1.0	0.0
2031	14.4	6.8	1.5	7.5	3.4	0.9	6.9	2.8	0.6	0.0	0.7	0.0
2032	10.4	4.9	0.9	5.1	2.5	0.5	5.2	2.1	0.4	0.0	0.3	0.0
2033	5.6	2.7	0.2	2.3	1.3	0.0	3.2	1.4	0.2	0.0	0.0	0.0
2034	1.2	0.5	0.0	0.0	0.0	0.0	1.2	0.5	0.0	0.0	0.0	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2037	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2038	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2039	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2040	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2041	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2042	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

*Demand coincident with Company's seasonal peak demand.

Exhibit A-13

Southwestern Electric Power Company
Actual and Forecast Losses (GWh)

Year	Losses
2012	924.0
2013	1,049.7
2014	1,009.5
2015	1,004.0
2016	911.6
2017	905.7
2018	1,072.4
2019	1,038.6
2020	1,105.2
2021	1,073.7
2022	1,187.6
2023	1,016.6
2024	1,008.0
2025	1,045.1
2026	1,030.6
2027	1,037.8
2028	1,042.9
2029	1,039.4
2030	1,040.6
2031	1,042.1
2032	1,046.7
2033	1,051.1
2034	1,051.7
2035	1,053.7
2036	1,056.8
2037	1,061.4
2038	1,066.9
2039	1,070.7
2040	1,072.0
2041	1,075.5
2042	1,078.0

Note: *2022 data are six months actual
six months forecast

Exhibit A-14

Southwestern Electric Power Company
Short-Term Load Forecast
Blended Forecast vs. Long-Term Model Results

Class	Arkansas	Louisiana	Texas
Residential	Long-Term	Long-Term	Long-Term
Commercial	Long-Term	Long-Term	Long-Term
Industrial	Long-Term	Long-Term	Long-Term
Other Retail	Long-Term	Long-Term	Long-Term

Exhibit A-15

Blending Illustration

Month	Short-term Forecast	Weight	Long-term Forecast	Weight	Blended Forecast
1	1,000	100%	1,150	0%	1,000
2	1,010	100%	1,160	0%	1,010
3	1,020	100%	1,170	0%	1,020
4	1,030	100%	1,180	0%	1,030
5	1,040	83%	1,190	17%	1,065
6	1,050	67%	1,200	33%	1,100
7	1,060	50%	1,210	50%	1,135
8	1,070	33%	1,220	67%	1,170
9	1,080	17%	1,230	83%	1,205
10	1,090	0%	1,240	100%	1,240
11	1,100	0%	1,250	100%	1,250
12	1,110	0%	1,260	100%	1,260

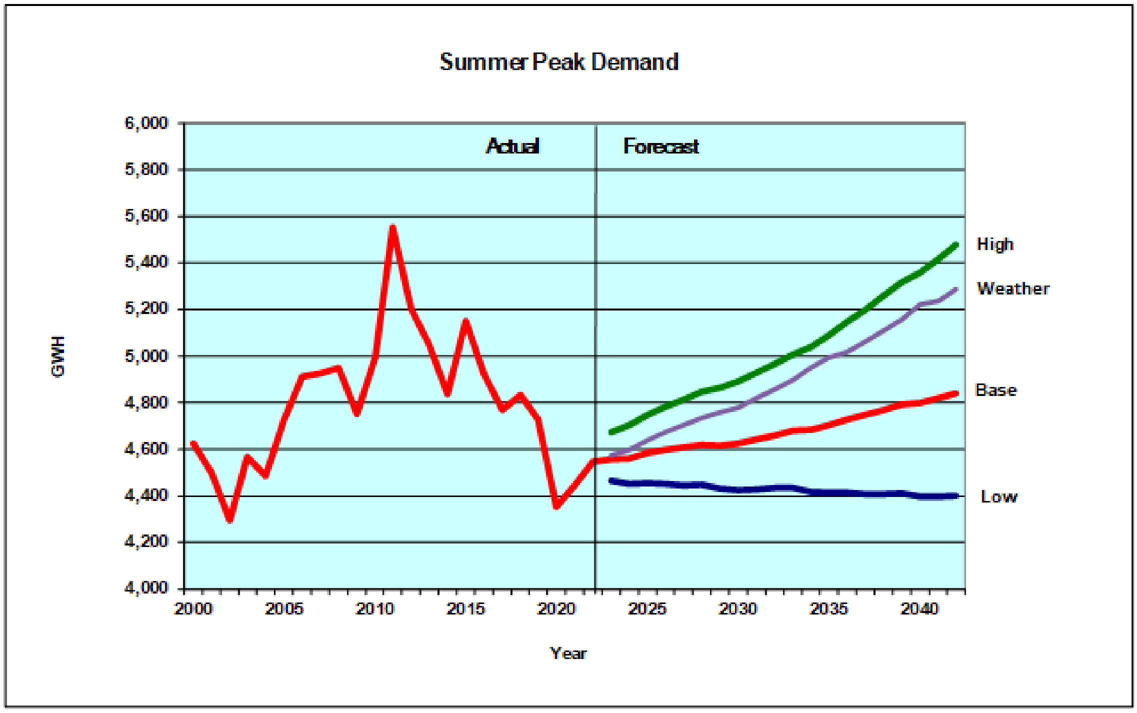
Exhibit A-16

Southwestern Electric Power Company
Seasonal Peak Demand (MW), Energy Sales (GWh) and High/Low Scenarios

	Winter Peak Demand			Summer Peak Demand			Energy Sales		
Year	Low Scenario	Base Forecast	High Scenario	Low Scenario	Base Forecast	High Scenario	Low Scenario	Base Forecast	High Scenario
2023	4,137	4,223	4,332	4,464	4,557	4,675	21,974	22,432	23,010
2024	4,129	4,230	4,362	4,452	4,561	4,704	21,964	22,504	23,206
2025	4,129	4,248	4,401	4,456	4,585	4,750	21,987	22,622	23,437
2026	4,123	4,260	4,432	4,450	4,598	4,784	21,967	22,697	23,613
2027	4,117	4,268	4,458	4,446	4,608	4,814	21,946	22,747	23,762
2028	4,125	4,285	4,495	4,447	4,619	4,846	21,940	22,788	23,908
2029	4,112	4,284	4,513	4,432	4,617	4,864	21,903	22,818	24,039
2030	4,101	4,288	4,535	4,425	4,626	4,893	21,854	22,846	24,163
2031	4,096	4,297	4,562	4,427	4,644	4,930	21,835	22,904	24,318
2032	4,097	4,308	4,591	4,433	4,661	4,966	21,850	22,975	24,480
2033	4,096	4,321	4,625	4,435	4,679	5,009	21,846	23,045	24,671
2034	4,084	4,331	4,659	4,418	4,685	5,040	21,799	23,117	24,867
2035	4,072	4,341	4,695	4,414	4,706	5,090	21,755	23,193	25,086
2036	4,070	4,362	4,746	4,413	4,729	5,146	21,715	23,270	25,321
2037	4,050	4,363	4,778	4,407	4,748	5,198	21,686	23,362	25,580
2038	4,043	4,375	4,825	4,408	4,770	5,260	21,670	23,452	25,862
2039	4,041	4,391	4,873	4,410	4,792	5,319	21,665	23,541	26,126
2040	4,035	4,403	4,916	4,397	4,799	5,357	21,646	23,621	26,371
2041	4,026	4,412	4,960	4,399	4,820	5,418	21,629	23,699	26,644
2042	4,018	4,423	5,003	4,399	4,842	5,476	21,607	23,781	26,900

Exhibit A-17

Southwestern Electric Power Company
Range of Forecasts and Weather Scenario



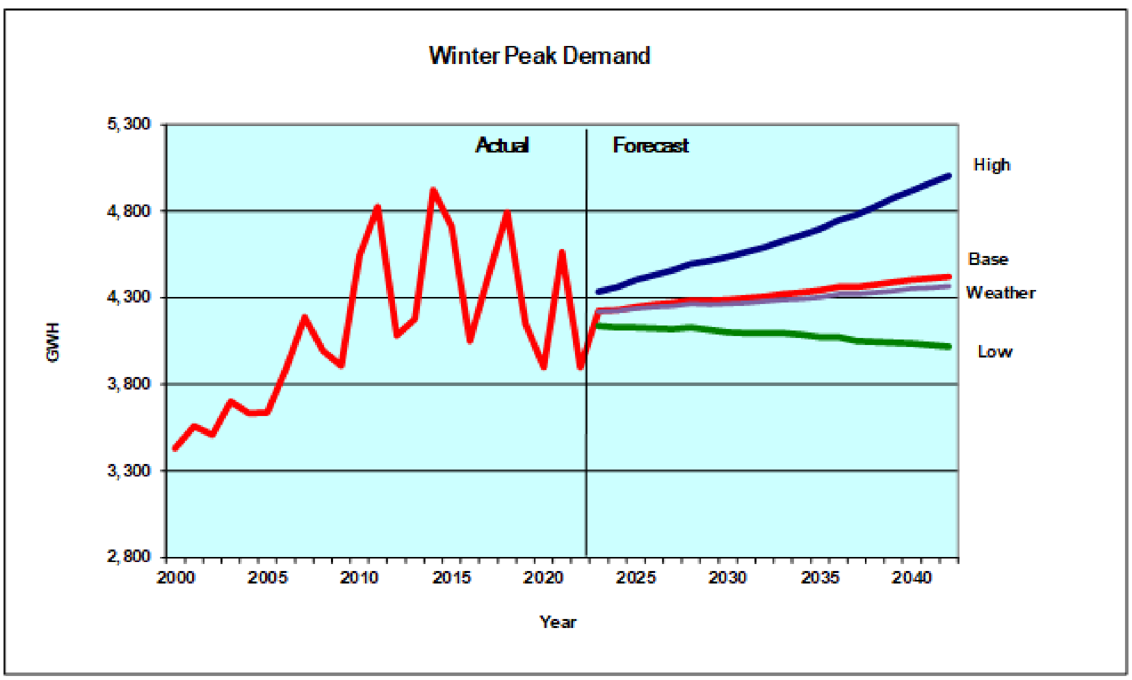
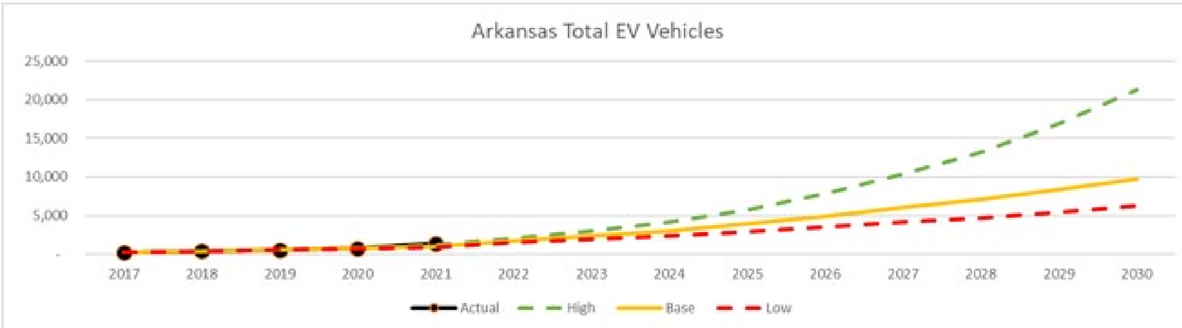
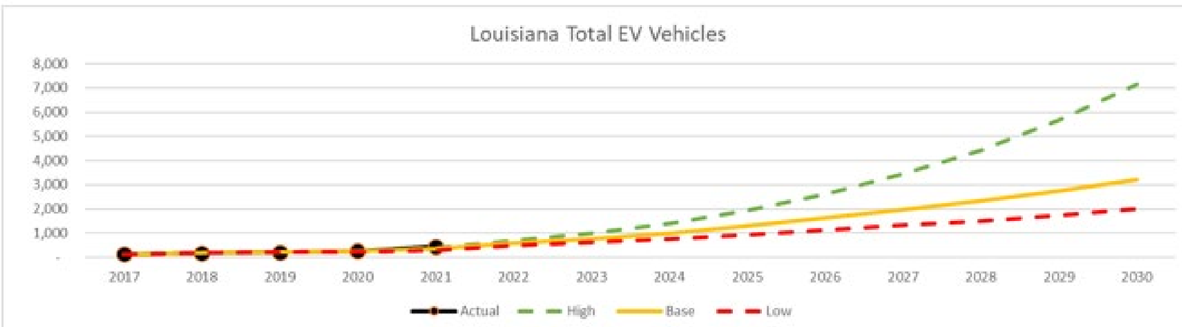


Exhibit A-18

SWEPCO Electric Vehicle Adoption Scenarios by State Jurisdiction





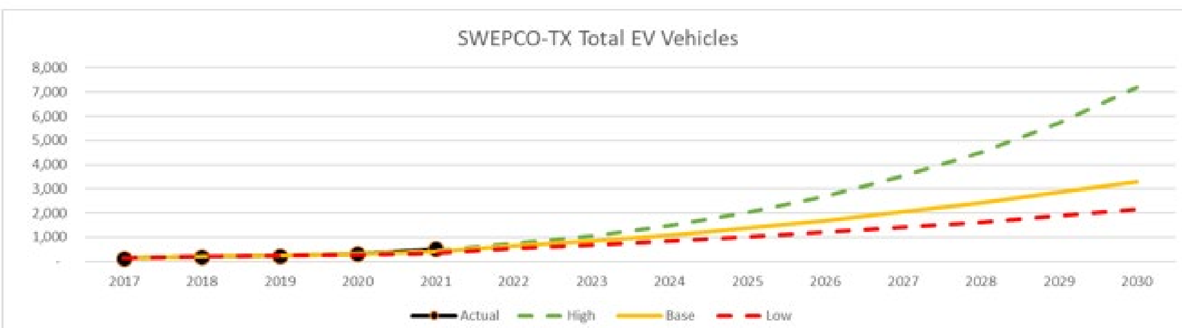


Exhibit A-19

SWEPCO Distributed Generation

	Distributed Energy Resources			In Service Capacity (kW)		
Year	Arkansas	Louisiana	Texas	Arkansas	Louisiana	Texas
2010	8	195	15	38	770	167
2011	15	305	27	70	1,345	344
2012	18	472	39	81	2,789	489
2013	20	763	55	104	4,172	1,385
2014	28	1,120	56	536	7,150	1,387
2015	33	1,518	60	649	9,215	1,396
2016	44	1,603	62	6,303	9,696	1,429
2017	84	1,668	64	8,457	10,110	1,445
2018	138	1,710	85	8,902	10,401	1,606
2019	237	1,735	131	9,773	10,624	1,965
2020	397	1,752	181	13,700	10,790	2,433
2021	635	1,815	280	15,180	11,366	3,239
2022	711	2,032	313	16,992	12,723	3,626
2023	788	2,253	347	18,839	14,106	4,020
2024	855	2,446	377	20,454	15,315	4,364
2025	910	2,601	401	21,758	16,291	4,643
2026	969	2,770	427	23,169	17,348	4,944
2027	1,024	2,928	452	24,490	18,337	5,226
2028	1,073	3,068	473	25,661	19,213	5,475
2029	1,129	3,229	498	27,008	20,222	5,763
2030	1,176	3,361	519	28,113	21,049	5,999
2031	1,233	3,526	544	29,491	22,081	6,293
2032	1,284	3,671	566	30,700	22,986	6,550
2033	1,347	3,850	594	32,204	24,113	6,871
2034	1,410	4,030	622	33,708	25,239	7,192
2035	1,460	4,175	644	34,915	26,143	7,450
2036	1,529	4,371	674	36,553	27,369	7,800
2037	1,599	4,573	706	38,248	28,638	8,161
2038	1,668	4,771	736	39,900	29,875	8,514
2039	1,755	5,017	774	41,957	31,415	8,953
2040	1,840	5,262	812	44,010	32,953	9,391
2041	1,922	5,494	848	45,953	34,407	9,805
2042	2,013	5,757	888	48,146	36,050	10,273

Exhibit B: Detailed Generation Technology Modeling Parameters

AEP System
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)

Type	First Available Year	Capacity (MW) Summer	Overnight Cost (b)(c) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Fuel Cost (a),(c) (nom$/MMBtu)	Variable O&M (c) (nom$/MWh)	Fixed O&M (c) (nom$/kW-yr)	Emission Rates SO2 (Lb/mmBtu)	Emission Rates NOx (Lb/mmBtu)	Emission Rates CO2 (Lb/mmBtu)	Levelized Capacity Factor (%)	LCOE (e) ($/MWh)
Base Load												
SMALL MODULAR REACTOR	2035	600	7,900	10,443	0.99	4.16	131.90	0.00	0.00	0.00	80%	121.00
ULTRA-SUPERCRITICAL COAL WITH 90% CO2 CAPTURE	2033	650	8,500	11,341	2.70	14.68	76.95	0.05460	0.00450	21.43	92%	88.00
COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT W/90% CO2 CAPTURE	2031	377	3,600	6,696	4.23	7.52	35.56	0.00000	0.01460	11.70	92%	63.00
COMBUSTION TURBINE H CLASS, COMBINED CYCLE MULTI SHAFT	2031	1,100	1,400	6,370	4.23	2.41	15.72	0.00752	0.00056	122.00	66%	70.00
COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT	2031	418	1,600	6,431	4.23	3.29	18.17	0.00752	0.00056	122.00	60%	78.00
Peaking												
COMBUSTION TURBINE F CLASS, 240-MW SIMPLE CYCLE	2031	240	1,000	9,905	4.23	5.80	9.02	0.00752	0.00056	122.00	7%	236.00
COMBUSTION TURBINES AERODERIVATIVE	2031	105	1,600	9,124	4.23	6.06	21.00	0.00752	0.00056	122.00	11%	240.00
INTERNAL COMBUSTION ENGINES	2031	21	2,600	8,295	4.23	7.34	45.31	0.00752	0.00056	122.00	15%	318.00
HYDROGEN GAS COMBUSTION TURBINE	2034	240	2,300	9,655	48.15(i)	6.13	9.54	0.00	0.00	0.00	N/A (h)	N/A
HYDROGEN ELECTROLYZER + HYDROGEN GAS CT	2034	240	4,800	30% (f)	N/A (g)	6.78	70.48	0.00	0.00	0.00	N/A (h)	N/A
20-HOUR DURATION PUMPED THERMAL ENERGY STORAGE	2033	25	4,300	65% (f)	N/A	N/A	60.42	0.00	0.00	0.00	10%	N/A
20-HOUR DURATION VANADIUM FLOW BATTERY STORAGE	2033	25	3,900	70% (f)	N/A	N/A	11.93	0.00	0.00	0.00	9%	N/A
20-HOUR DURATION COMPRESSED AIR ENERGY STORAGE	2033	25	4,700	52% (f)	N/A	N/A	22.19	0.00	0.00	0.00	5%	N/A
4-HOUR DURATION LITHIUM-ION BATTERY	2026	50	1,300	85% (f)	N/A	N/A	29.20	0.00	0.00	0.00	N/A	N/A
Intermittent												
UTILITY-SCALE ONSHORE WIND TIER 1	2026	100	2,000	N/A	N/A	N/A (j)	29.96	0.00	0.00	0.00	43%	62.00
UTILITY-SCALE ONSHORE WIND TIER 2	2026	100	2,200	N/A	N/A	N/A (j)	29.96	0.00	0.00	0.00	43%	68.00
UTILITY-SCALE SOLAR PHOTOVOLTAIC TIER 1	2026	50	1,900	N/A	N/A	N/A (j)	22.06	0.00	0.00	0.00	25%	83.00
UTILITY-SCALE SOLAR PHOTOVOLTAIC TIER 2	2026	50	2,100	N/A	N/A	N/A (j)	22.06	0.00	0.00	0.00	25%	93.00
UTILITY-SCALE SOLAR + STORAGE (3:1)	2026	150	2,700	N/A	N/A	N/A	36.21	0.00	0.00	0.00	10%	249.00

Notes:
(a) Intsalled cost, capability and heat rate have been rounded
(b) Total Plant overnight cost including interconnection cost estimate
(c) Costs provided in nominal terms in the first available year
(d) Average fuel price across study horizon
(e) First year levelized cost of energy based on capacity factors shown in table. Not shown for storage as LCOE is dependent on charging. Not shown for low dispatch.
(f) Denotes efficiency, (w/ power electronics)
(g) Fuel input is dependent on electricty price for electrolyzer
(h) Capacity factor not shown due to low dispatch
(i) Denotes levelized cost of hydrogen before PTC
(j) Denotes VOM before PTC

Exhibit C: Capability, Demand and Reserve (CDR) – "Going-In"

	Plant Capabilities	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
	ARSENAL HILL 5	108	108	108	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	J.L. STALL CC	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511
	FLINT CREEK 1	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	0	0	0	0
	TURK	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477
	KNOX LEE 5	335	335	335	335	335	335	335	335	335	335	335	335	335	335	335	335	335	0	0	0
	LIEBERMAN 3	109	109	109	109	0	0	0	0	0	0	0	0	0	0	0	0	0			
	LIEBERMAN 4	108	108	108	108	0	0	0	0	0	0	0	0	0	0	0	0	0			
	MATTISON 1	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
	MATTISON 2	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
	MATTISON 3	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
	MATTISON 4	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
	WELSH 1	525	525	525	525	525	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	WELSH 3	528	528	528	528	528	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	WILKES 1	162	162	162	162	162	162	162	0	0	0	0	0	0	0	0	0	0	0	0	0
	WILKES 2	352	352	352	352	352	352	352	352	352	352	352	352	352	0	0	0	0	0	0	0
	WILKES 3	350	350	350	350	350	350	350	350	350	350	350	350	350	350	0	0	0	0	0	0
	SUNDANCE	16.7	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	MAVERICK	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
	TRAVERSE	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
	Diversion			31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	0
	Wagon Wheel			0	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	0
	Mooringsport				120	120	114	107	94	85	76	68	64	60	58	57	55	55	54	52	0
1 (Summer)	**Total**	**4,220**	**4,220**	**4,251**	**4,355**	**4,138**	**3,079**	**3,072**	**2,897**	**2,888**	**2,879**	**2,871**	**2,867**	**2,863**	**2,509**	**2,158**	**2,156**	**1,898**	**1,562**	**1,560**	**1,385**
	Adjustments to Plant Capability	0	0	-11	-23	-34	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	0
2	**TOTAL**	**0**	**0**	**-11**	**-23**	**-34**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**-45**	**0**
3 (Summer)	**Net Plant Capability (1 + 2)**	**4,220**	**4,220**	**4,240**	**4,332**	**4,104**	**3,034**	**3,027**	**2,852**	**2,843**	**2,834**	**2,826**	**2,822**	**2,818**	**2,464**	**2,113**	**2,111**	**1,853**	**1,517**	**1,515**	**1,385**
	Sales Without Reserves																				
4	**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Purchases Without Reserves																				
	NTEC - HCPP	300	341	341	341	341	341	341	341	341	341	341	341	341	341	341	341	341	341	341	341
	NTEC GENERATION - PIRKEY/DOLET HILLS/TU	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
	NTEC - SPA NARROWS	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
	MAJESTIC WIND PROJECT	12	12	12	12	12	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	HIGH MAJESTIC WIND PROJECT	12	12	12	12	12	12	12	12	12	12	0	0	0	0	0	0	0	0	0	0
	FLAT RIDGE WIND PROJECT	17	17	17	17	17	17	17	17	17	17	0	0	0	0	0	0	0	0	0	0
	CANADIAN HILLS WIND PROJECT	31	31	31	31	31	31	31	31	31	31	0	0	0	0	0	0	0	0	0	0
	ROCKING R			44	44	44	41	39	34	31	28	25	23	22	21	21	20	20	20	19	0
	SHORT TERM CAPACITY PURCHASE	383	469	410	200																
5 (Summer)	**TOTAL**	**914**	**1,041**	**1,026**	**816**	**560**	**557**	**543**	**538**	**535**	**531**	**446**	**444**	**443**	**442**	**442**	**441**	**441**	**441**	**442**	**424**
6 (Summer)	**Total Capability (3 - 4 + 5)**	**5,134**	**5,261**	**5,266**	**5,148**	**4,664**	**3,591**	**3,570**	**3,391**	**3,377**	**3,365**	**3,272**	**3,266**	**3,261**	**2,907**	**2,555**	**2,552**	**2,294**	**1,958**	**1,957**	**1,809**

DEMAND			2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
	Original Forecast		3,608	3,613	3,633	3,645	3,654	3,662	3,654	3,659	3,671	3,684	3,695	3,697	3,714	3,733	3,749	3,767	3,786	3,792	3,809	3,827
A	Peak Demand Before Passive DSM Adjusted		4,564	4,570	4,594	4,610	4,622	4,632	4,628	4,635	4,650	4,666	4,681	4,685	4,706	4,729	4,748	4,770	4,792	4,799	4,820	4,842
B	Passive DSM																					
		TOTAL	7	4	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C	Peak Demand (A - B)		4,558	4,566	4,593	4,610	4,622	4,632	4,628	4,635	4,650	4,666	4,681	4,685	4,706	4,729	4,748	4,770	4,792	4,799	4,820	4,842
D	Active DSM																					
		TOTAL	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
E	Firm Demand (C - D)		4,524	4,533	4,560	4,576	4,589	4,598	4,594	4,601	4,617	4,633	4,648	4,652	4,672	4,695	4,714	4,737	4,759	4,765	4,786	4,808
F	Other Demand Adjustments																					
		TOTAL	29	30	29	27	27	27	27	28	28	27	26	26	26	27	26	26	26	28	29	29
7	Native Load Responsibility (E - F)		4,495	4,503	4,531	4,549	4,562	4,572	4,568	4,573	4,589	4,605	4,622	4,627	4,646	4,668	4,688	4,711	4,733	4,737	4,758	4,779
	Sales With Reserves																					
8		TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Purchases With Reserves																					
9		TOTAL	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
10	Load Responsibility (7 + 8 - 9)		4,427	4,434	4,462	4,480	4,493	4,503	4,499	4,505	4,521	4,537	4,554	4,558	4,577	4,600	4,620	4,642	4,664	4,669	4,689	4,711

RESERVES - Summer		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
11 (Summer)	Reserve Capacity (6 - 10)	707	827	803	667	170	-912	-929	-1,114	-1,143	-1,171	-1,282	-1,292	-1,316	-1,693	-2,065	-2,090	-2,370	-2,710	-2,732	-2,902
12 (Summer)	% Reserve Margin ((11/10) * *100*)	16	19	18	15	4	-20	-21	-25	-25	-26	-28	-28	-29	-37	-45	-45	-51	-58	-58	-62
13 (Summer)	% Capacity Margin (11/(6) * *100*)	14	16	15	13	4	-25	-26	-33	-34	-35	-39	-40	-40	-58	-81	-82	-103	-138	-140	-160
14 (Summer)	Reserves Above Minimum 22% Reserve Margin (MW)	(1)	(16)	(179)	(318)	(818)	(1,903)	(1,919)	(2,105)	(2,138)	(2,169)	(2,284)	(2,295)	(2,323)	(2,705)	(3,081)	(3,111)	(3,396)	(3,737)	(3,763)	(3,938)

Exhibit D: Long-Term Commodity Price Forecast

SUMMARY OF LONG-TERM COMMODITY PRICE FORECASTS
Annual Average (Nominal Dollars)

	Natural Gas (Henry Hub) $/mmbtu				CO2 $/Short ton			Coal (FOB) $/ton		
	Base	High	Low		Base	High	No Price	PRB 8800	PRB 8400	CAPP
2023	3.70	4.62	3.24	2023	0.00	0.00	0.00	17.0	15.0	75.9
2024	3.43	4.58	2.87	2024	0.00	0.00	0.00	13.0	11.4	68.4
2025	3.31	4.66	2.71	2025	0.00	0.00	0.00	13.1	11.6	61.8
2026	3.35	4.88	2.70	2026	0.00	0.00	0.00	13.3	11.8	64.0
2027	3.53	5.08	2.79	2027	0.00	0.00	0.00	13.7	12.0	64.3
2028	3.79	5.49	3.00	2028	0.00	0.00	0.00	13.8	12.3	64.3
2029	4.00	5.92	3.14	2029	0.00	0.00	0.00	13.7	12.2	65.1
2030	4.18	6.23	3.29	2030	13.61	46.31	0.00	13.7	12.1	58.2
2031	4.36	6.59	3.38	2031	14.08	48.63	0.00	13.4	11.9	59.4
2032	4.49	6.94	3.46	2032	14.58	51.06	0.00	14.1	12.2	57.7
2033	4.66	7.28	3.62	2033	15.09	53.61	0.00	14.7	12.7	59.2
2034	4.74	7.56	3.69	2034	15.62	56.29	0.00	15.4	13.2	53.0
2035	4.82	7.79	3.71	2035	16.16	59.11	0.00	16.0	13.8	55.0
2036	4.93	8.20	3.76	2036	16.73	62.06	0.00	16.6	14.3	54.5
2037	5.05	8.43	3.83	2037	17.31	65.17	0.00	17.3	14.9	59.7
2038	5.17	8.69	3.87	2038	17.92	68.43	0.00	17.9	15.4	83.9
2039	5.28	9.04	3.96	2039	18.55	71.85	0.00	18.6	16.0	85.6
2040	5.43	9.40	4.00	2040	19.20	75.44	0.00	19.2	16.5	87.3
2041	5.54	9.52	4.02	2041	19.87	79.21	0.00	19.8	18.4	89.1
2042	5.62	9.60	4.00	2042	20.56	83.17	0.00	20.5	19.0	126.9

	Power On-Peak (SPP) $/MWh						Power Off-Peak (SPP) $/MWh				
	REF	NCR	FOR	CETA	ECR		REF	NCR	FOR	CETA	ECR
2023	47.89	44.84	47.89	48.14	53.30	2023	31.87	28.94	31.89	32.16	37.26
2024	42.67	38.98	42.66	43.09	49.22	2024	28.20	24.81	28.21	28.62	34.32
2025	40.48	36.49	40.50	40.95	47.99	2025	26.49	22.93	26.50	27.00	33.41
2026	38.24	34.31	38.25	38.77	46.17	2026	25.45	21.76	25.46	25.98	32.73
2027	36.72	32.65	36.74	37.10	44.28	2027	23.59	19.72	23.57	24.08	30.28
2028	37.91	33.01	37.45	38.07	46.13	2028	24.94	20.36	24.60	25.48	32.34
2029	38.01	32.70	37.59	38.05	69.70	2029	25.77	20.79	25.40	26.33	54.19
2030	47.20	33.02	46.24	46.41	71.55	2030	34.31	21.08	33.18	34.68	56.38
2031	47.59	32.94	46.95	45.45	73.56	2031	35.78	21.59	34.49	34.85	58.98
2032	47.18	33.34	47.09	43.72	74.12	2032	36.09	22.38	35.06	33.71	60.23
2033	48.05	34.31	48.47	44.34	77.03	2033	37.34	23.59	36.38	34.16	62.98
2034	48.54	34.79	48.90	44.19	78.19	2034	38.11	24.29	37.18	34.43	64.82
2035	48.81	33.98	49.11	44.72	79.58	2035	38.89	24.16	38.03	35.52	67.14
2036	49.36	34.30	49.66	45.70	81.91	2036	39.38	24.30	38.69	36.34	69.52
2037	49.56	34.40	49.92	46.42	83.07	2037	40.39	25.00	39.67	37.70	71.74
2038	49.71	33.92	50.19	46.97	85.08	2038	40.92	24.98	40.25	38.42	74.07
2039	50.42	34.37	50.76	47.58	87.05	2039	42.05	25.52	41.32	39.46	77.26
2040	51.69	34.46	51.68	48.06	89.22	2040	43.81	25.87	42.68	40.90	80.53
2041	51.65	34.99	52.65	48.72	90.03	2041	44.52	26.46	43.93	41.77	82.93
2042	52.63	35.32	53.80	49.88	91.95	2042	45.41	26.56	45.13	43.14	84.69

Exhibit E: Cost of Capital

Cap Structure	SWE
Cost of Debt (%)	4.47%
Return on Equity (%)	9.52%
Equity % Rate Base	45.10%
State Income Tax Rate (if applicable)	4.8%
Property Tax Rate	1.4%
SWEPCO Discount Rate for Economic Analys	6.52%
AFUDC %	5.97%

Exhibit F: Modeled Portfolio Results

Annual Portfolio Additions in nameplate MW (EE in cumulative MW per year) :

Reference

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Planned Solar	0	73	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Solar T1	0	0	150	150	150	150	150	150	150	0	150	150	0	0	0	0	0	0	0
New Solar T2	0	0	0	450	0	200	400	0	0	0	0	0	0	0	0	0	0	0	0
Planned Wind	0	200	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Wind T1	0	0	0	0	0	0	400	400	400	0	400	400	0	0	0	0	0	0	0
New Wind T2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CT	0	0	0	0	0	0	0	0	0	240	0	0	480	480	480	240	480	0	0
New Gas Aero	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CC (2X1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	550	0	0	0	0
New Storage	0	0	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Optional MP	0	0	0	150	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Welsh 1&3 Gas Conversion	0	0	0	0	1053	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Annual EE	20	38	54	67	79	72	64	57	50	43	36	31	26	22	19	15	11	8	6

NCR

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Planned Solar	0	73	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Solar T1	0	0	150	150	150	150	150	150	100	0	0	0	0	0	0	0	0	0	0
New Solar T2	0	0	0	350	0	250	300	0	0	0	0	0	0	0	0	0	0	0	0
Planned Wind	0	200	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Wind T1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Wind T2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CT	0	0	0	0	0	0	0	0	0	240	0	0	480	480	720	240	240	0	0
New Gas Aero	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	105
New Gas CC (2X1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	550	0	0	0	0
New Storage	0	0	200	0	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Optional MP	0	0	0	200	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Welsh 1&3 Gas Conversion	0	0	0	0	1053	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Annual EE	20	38	54	67	79	70	61	53	45	38	29	22	16	11	7	5	3	2	1

FOR - Summer

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Planned Solar	0	73	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Solar T1	0	0	150	150	150	150	150	150	100	0	0	0	0	0	0	0	0	0	0
New Solar T2	0	0	0	350	0	350	350	50	0	0	0	0	0	0	0	0	0	0	0
Planned Wind	0	200	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Wind T1	0	0	0	0	0	0	400	400	400	200	400	400	0	0	0	0	0	0	0
New Wind T2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CT	0	0	0	0	0	0	0	0	0	240	0	0	480	480	720	240	480	0	0
New Gas Aero	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CC (2X1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	550	0	0	0	0
New Storage	0	0	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Optional MP	0	0	0	200	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Welsh 1&3 Gas Conversion	0	0	0	0	1,053	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Annual EE	20	38	54	67	79	72	64	57	50	43	36	29	24	19	16	12	9	6	4

FOR - Winter

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Planned Solar	0	73	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Solar T1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Solar T2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned Wind	0	200	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Wind T1	0	0	300	400	400	100	400	0	0	0	0	200	0	0	0	0	0	0	0
New Wind T2	0	0	0	0	1,000	0	800	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	480	720	720	480	480	0	0
New Gas Aero	0	0	0	0	0	0	0	0	0	0	0	0	0	0	105	0	0	0	0
New Hybrid (Solar + Storage)	0	0	400	400	400	400	400	0	0	0	0	0	0	0	0	0	0	0	0
New Storage	0	0	200	200	200	200	200	200	200	0	150	0	0	0	0	0	0	0	0
Optional MP	0	0	0	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Welsh 1&3 Gas Conversion	0	0	0	0	1,053	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Annual EE	20	38	54	67	79	69	58	49	39	31	25	20	15	12	10	7	5	4	3

CETA

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Planned Solar	0	73	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Solar T1	0	0	150	150	150	150	150	150	150	0	0	0	0	0	0	0	0	0	0
New Solar T2	0	0	200	100	0	300	450	0	0	0	0	0	0	0	0	0	0	0	0
Planned Wind	0	200	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Wind T1	0	0	100	0	0	400	400	400	400	400	400	400	0	0	0	0	0	0	0
New Wind T2	0	0	0	0	0	0	0	0	300	0	0	0	0	0	0	0	0	0	0
New Gas CT	0	0	0	0	0	0	0	240	0	240	0	0	480	480	720	480	480	0	0
New Gas Aero	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Gas CC (2X1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	550	0	0	0	0
New Storage	0	0	200	200	50	150	150	0	0	0	0	150	100	0	0	0	0	50	100
Optional MP	0	0	0	200	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Welsh 1&3 Gas Conversion	0	0	0	0	1,053	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Annual EE	20	38	54	67	79	70	61	53	45	38	31	25	20	16	13	10	7	5	4

ECR

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Planned Solar	0	73	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Solar T1	0	0	0	100	150	150	150	0	50	0	0	0	0	0	50	50	0	0	0
New Solar T2	0	0	0	0	0	200	100	0	0	0	0	0	0	0	0	0	0	0	0
Planned Wind	0	200	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Wind T1	0	0	0	0	0	400	400	400	400	400	100	200	0	0	0	100	0	200	100
New Wind T2	0	0	0	0	0	0	0	300	0	0	0	0	0	0	0	0	0	0	0
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	240	480	720	240	240	0	0
New Gas Aero	0	0	0	0	0	0	0	0	0	0	0	0	0	0	105	0	0	0	0
New Gas ICE	0	0	0	0	0	0	0	0	0	0	0	0	21	0	42	0	0	0	0
New Storage	0	0	200	200	0	0	100	0	0	50	0	150	200	200	200	100	200	0	0
Optional MP	0	0	0	200	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Welsh 1&3 Gas Conversion	0	0	0	0	1,053	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cumulative Annual EE	20	38	54	67	79	70	61	53	45	38	31	25	20	16	13	10	7	5	4

Portfolio NPV Revenue Requirements:

SOUTHWESTERN ELECTRIC POWER COMPANY
2023 INTEGRATED RESOURCE PLAN
Reference Portfolio Under Reference Scenario

Utility Costs (Nominal$000)

	(1) Existing Depreciation	(2) New Depreciation	(3) Capital Charge	(4) Fixed O&M	(5) Fuel Costs	(6) Emission Costs	(7) Other VOM Costs	(8) Market Purchases Costs	(9) *Less:* Market Sales Revenue	(10) Taxes	(11)=(1)thru(8)-(9)+(10) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2023	222,624	0	279,060	76,758	579,832	1,170	67,860	83,544	328,697	92,841	1,074,993
2024	223,884	0	267,092	76,163	490,076	1,037	59,913	128,271	240,902	88,480	1,094,013
2025	241,130	0	283,278	87,757	447,551	1,018	57,979	143,064	216,301	93,504	1,138,979
2026	302,010	27,110	404,629	138,631	383,269	945	-58,083	139,194	232,969	139,152	1,243,888
2027	303,791	78,481	461,476	151,498	291,998	761	-130,360	168,795	168,161	166,567	1,324,848
2028	305,913	90,114	453,192	173,848	240,955	317	-144,655	186,679	112,012	166,271	1,360,622
2029	307,460	118,486	468,908	168,018	230,373	289	-175,417	175,769	105,879	176,572	1,364,578
2030	309,304	196,585	557,031	186,198	207,749	58,729	-255,799	160,201	166,796	219,649	1,472,851
2031	310,889	240,703	585,962	203,829	183,845	52,690	-334,935	147,829	177,780	238,309	1,451,340
2032	311,926	285,891	613,572	221,404	180,370	52,045	-384,049	132,636	228,204	256,932	1,442,522
2033	279,236	299,583	589,738	226,041	169,944	48,229	-382,512	122,317	168,137	253,490	1,437,928
2034	207,390	347,029	628,925	248,045	162,374	46,073	-433,415	107,971	211,602	276,748	1,379,538
2035	195,181	395,759	667,011	268,165	153,126	45,077	-538,400	96,447	252,210	299,955	1,330,111
2036	196,443	425,733	666,405	272,761	171,654	51,433	-379,743	84,864	261,199	306,334	1,534,684
2037	197,624	456,643	667,045	277,374	169,021	49,381	-316,264	101,457	261,317	313,376	1,654,340
2038	199,402	525,441	735,372	294,450	258,754	70,066	-316,418	64,198	370,131	349,529	1,810,663
2039	200,656	541,988	713,454	278,901	252,073	64,245	-312,416	69,930	350,158	347,862	1,806,535
2040	201,369	576,265	713,048	283,853	291,283	75,140	-173,647	60,093	395,472	355,377	1,987,309
2041	202,284	576,265	667,157	291,354	283,396	73,285	-80,650	60,923	364,971	344,294	2,053,335
2042	203,804	576,265	622,718	295,586	293,877	77,279	13,975	61,868	373,545	333,729	2,105,557
2043	203,804	576,265	578,619	301,203	299,462	78,747	14,241	63,044	380,643	322,414	2,057,156
2044	203,804	576,265	534,793	306,927	305,152	80,244	14,511	64,241	387,877	311,696	2,009,757
2045	203,804	576,265	491,119	312,759	310,951	81,769	14,787	65,462	395,248	301,009	1,962,679
2046	203,804	561,677	448,291	318,703	316,860	83,323	15,068	66,706	402,758	290,709	1,902,382
2047	203,804	561,677	405,707	324,759	322,882	84,906	15,354	67,974	410,412	280,251	1,856,902
2048	200,317	561,677	363,605	330,930	329,018	86,520	15,646	69,265	418,211	269,934	1,808,699
2049	178,185	561,677	323,097	337,219	335,270	88,164	15,943	70,582	426,159	260,212	1,744,190
2050	158,075	561,677	284,350	343,627	341,641	89,839	16,246	71,923	434,257	251,021	1,684,142
2051	70,542	549,155	252,842	350,157	348,133	91,546	16,555	73,290	442,509	244,275	1,553,987
2052	64,320	497,783	225,077	356,811	354,749	93,286	16,870	74,682	450,918	238,917	1,471,578
Net Present Value 2023-2052	3,160,397	3,499,924	6,357,727	2,694,756	3,958,862	491,468	(1,912,844)	1,501,751	3,405,173	2,870,493	19,217,363

SOUTHWESTERN ELECTRIC POWER COMPANY
2023 INTEGRATED RESOURCE PLAN
CETA Portfolio Under Reference Scenario

Utility Costs (Nominal$000)

	(1) Existing Depreciation	(2) New Depreciation	(3) Capital Charge	(4) Fixed O&M	(5) Fuel Costs	(6) Emission Costs	(7) Other VOM Costs	(8) Market Purchases Costs	(9) *Less:* Market Sales Revenue	(10) Taxes	(11)=(1)thru(8)-(9)+(10) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2023	222,624	0	279,060	76,758	579,832	1,170	67,860	83,544	328,697	92,841	1,074,993
2024	223,884	0	267,092	76,163	490,076	1,037	59,913	128,271	240,902	88,480	1,094,013
2025	241,130	0	283,278	87,757	447,551	1,018	57,979	143,064	216,301	93,504	1,138,979
2026	302,010	54,567	445,878	146,183	383,269	945	-81,232	131,698	254,137	157,293	1,286,475
2027	303,791	89,653	470,173	157,086	291,998	761	-125,964	172,123	172,512	171,212	1,358,321
2028	305,913	104,863	465,803	180,768	240,955	317	-140,297	189,714	117,306	172,716	1,403,446
2029	307,460	186,531	556,914	193,710	230,373	289	-212,980	155,987	150,069	216,487	1,484,703
2030	309,304	279,335	656,412	216,899	207,749	58,729	-297,038	142,209	236,256	266,272	1,603,616
2031	310,889	336,425	694,425	236,980	193,751	54,839	-380,323	131,925	265,823	290,386	1,603,473
2032	311,926	409,932	756,208	264,514	188,531	53,800	-457,173	115,422	361,367	325,964	1,607,757
2033	279,236	458,429	773,922	282,588	177,655	49,887	-492,565	82,936	346,189	343,266	1,609,165
2034	207,390	494,090	782,578	301,850	168,873	47,465	-530,469	80,636	386,780	356,047	1,521,679
2035	195,181	542,164	806,292	323,336	158,160	46,146	-635,654	82,807	431,361	375,187	1,462,258
2036	196,443	579,957	805,763	331,249	177,586	52,707	-439,305	65,347	441,653	383,721	1,711,814
2037	197,624	610,867	797,690	336,398	174,125	50,491	-411,347	76,529	437,143	388,936	1,784,170
2038	199,402	695,636	878,295	356,527	268,103	72,112	-416,901	48,922	563,019	432,034	1,971,113
2039	200,656	728,731	867,762	344,140	271,804	68,649	-337,117	51,487	556,320	437,282	2,077,073
2040	201,369	763,008	856,587	349,748	312,211	79,886	-193,463	42,391	608,919	442,539	2,245,356
2041	202,284	767,462	805,475	359,346	304,074	78,011	-100,468	41,896	581,095	431,579	2,308,565
2042	203,804	776,645	761,017	367,111	317,167	82,705	51,578	42,945	600,590	423,523	2,425,907
2043	203,804	776,645	717,700	374,088	323,194	84,277	52,558	43,761	612,003	412,372	2,376,397
2044	203,804	776,645	675,149	381,197	329,336	85,878	53,557	44,593	623,633	401,921	2,328,447
2045	203,804	776,645	633,210	388,440	335,594	87,510	54,575	45,440	635,484	391,598	2,281,333
2046	203,804	762,057	592,755	395,822	341,972	89,173	55,612	46,304	647,560	381,796	2,221,734
2047	203,804	747,608	553,709	403,344	348,470	90,868	56,669	47,183	659,866	372,288	2,164,078
2048	200,317	744,030	515,585	411,009	355,092	92,594	57,745	48,080	672,406	362,857	2,114,904
2049	178,185	733,425	479,858	418,819	361,840	94,354	58,843	48,994	685,183	354,290	2,043,425
2050	158,075	722,866	446,695	426,778	368,716	96,147	59,961	49,925	698,204	346,422	1,977,381
2051	70,542	669,916	423,097	434,888	375,723	97,974	61,100	50,873	711,472	341,918	1,814,560
2052	64,320	649,280	402,119	443,153	382,863	99,836	62,262	51,840	724,992	337,541	1,768,221
Net Present Value 2023-2052	3,160,397	4,757,786	7,530,372	3,177,403	4,064,041	515,374	(2,205,641)	1,331,624	4,857,408	3,517,268	20,991,217

SOUTHWESTERN ELECTRIC POWER COMPANY
2023 INTEGRATED RESOURCE PLAN
ECR Portfolio Under Reference Scenario

Utility Costs (Nominal$000)

	(1) Existing Depreciation	(2) New Depreciation	(3) Capital Charge	(4) Fixed O&M	(5) Fuel Costs	(6) Emission Costs	(7) Other VOM Costs	(8) Market Purchases Costs	(9) *Less:* Market Sales Revenue	(10) Taxes	(11)=(1)thru(8)-(9)+(10) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2023	222,624	0	279,060	76,758	579,832	1,170	67,860	83,544	328,697	92,841	1,074,993
2024	223,884	0	267,092	76,163	490,076	1,037	59,913	128,271	240,902	88,480	1,094,013
2025	241,130	0	283,278	87,757	447,551	1,018	57,979	143,064	216,301	93,504	1,138,979
2026	302,010	14,588	385,818	135,258	383,269	945	-46,269	142,056	223,145	130,878	1,225,408
2027	303,791	36,941	396,222	142,924	291,998	761	-74,603	188,953	138,541	137,483	1,285,929
2028	305,913	48,573	393,211	165,345	240,955	317	-89,369	212,020	89,087	138,293	1,326,172
2029	307,460	111,168	464,588	172,192	230,373	289	-154,439	170,839	100,939	172,096	1,373,626
2030	309,304	171,428	523,188	187,039	207,749	58,729	-209,989	163,213	143,425	202,309	1,469,547
2031	310,889	232,270	579,185	211,006	183,845	52,690	-302,722	145,695	182,977	232,426	1,462,306
2032	311,926	269,988	593,935	226,449	180,370	52,045	-343,975	139,395	236,533	245,770	1,439,369
2033	279,236	308,447	610,103	243,188	160,725	46,243	-382,120	117,216	218,928	260,001	1,424,110
2034	207,390	317,362	588,334	252,111	155,611	44,624	-391,482	126,467	226,635	257,157	1,330,940
2035	195,181	347,130	597,464	266,365	147,894	43,964	-461,104	131,291	244,634	266,911	1,290,463
2036	196,443	381,269	605,668	275,056	161,303	49,214	-319,263	117,238	250,419	276,277	1,492,786
2037	197,624	428,185	629,220	285,152	160,118	47,448	-306,880	137,525	261,114	292,506	1,609,782
2038	199,402	515,858	703,772	306,155	161,299	48,469	-313,381	144,199	276,422	331,199	1,820,551
2039	200,656	555,593	713,133	297,951	152,802	41,941	-228,439	161,968	293,109	343,499	1,945,996
2040	201,369	590,050	708,148	305,923	185,509	51,177	-123,923	153,933	335,456	350,104	2,086,833
2041	202,284	611,821	692,127	320,419	176,933	48,863	21,995	155,479	349,567	352,810	2,233,163
2042	203,804	623,082	660,050	328,184	184,936	51,825	111,664	154,721	373,415	348,731	2,293,584
2043	203,804	623,082	630,844	334,420	188,450	52,810	113,786	157,662	380,511	340,539	2,264,888
2044	203,804	623,082	603,388	340,775	192,031	53,814	115,949	160,658	387,742	333,254	2,239,014
2045	203,804	623,082	577,288	347,251	195,681	54,837	118,152	163,711	395,110	326,254	2,214,949
2046	203,804	608,494	553,211	353,850	199,399	55,879	120,397	166,822	402,619	319,887	2,179,125
2047	203,804	594,045	530,638	360,574	203,188	56,940	122,685	169,992	410,270	313,835	2,145,432
2048	200,317	594,045	508,807	367,426	207,050	58,023	125,017	173,222	418,066	307,769	2,123,608
2049	178,185	594,045	488,975	374,409	210,984	59,125	127,392	176,514	426,011	302,384	2,086,003
2050	158,075	587,005	471,559	381,524	214,994	60,249	129,813	179,868	434,106	297,769	2,046,749
2051	70,542	587,005	461,053	388,774	219,079	61,394	132,280	183,286	442,356	295,248	1,956,305
2052	64,320	579,102	452,857	396,162	223,242	62,560	134,794	186,769	450,762	293,369	1,942,414
Net Present Value 2023-2052	3,160,397	3,454,367	6,400,362	2,812,265	3,531,547	393,069	(1,339,542)	1,938,655	3,297,058	2,825,807	19,879,871

SOUTHWESTERN ELECTRIC POWER COMPANY
2023 INTEGRATED RESOURCE PLAN
FOR Portfolio Under Reference Scenario

Utility Costs (Nominal$000)

	(1) Existing Depreciation	(2) New Depreciation	(3) Capital Charge	(4) Fixed O&M	(5) Fuel Costs	(6) Emission Costs	(7) Other VOM Costs	(8) Market Purchases Costs	(9) *Less:* Market Sales Revenue	(10) Taxes	(11)=(1)thru(8)-(9)+(10) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2023	222,624	0	279,060	76,758	579,832	1,170	67,860	83,544	328,697	92,841	1,074,993
2024	223,884	0	267,092	76,163	490,076	1,037	59,913	128,271	240,902	88,480	1,094,013
2025	241,130	0	283,278	87,757	447,551	1,018	57,979	143,064	216,301	93,504	1,138,979
2026	302,010	27,110	404,629	138,631	383,269	945	-58,083	139,194	232,969	139,152	1,243,888
2027	303,791	69,700	448,284	149,282	291,998	761	-121,772	173,444	162,215	160,765	1,314,038
2028	305,913	81,332	441,150	171,668	240,955	317	-136,140	192,275	106,848	160,710	1,351,333
2029	307,460	122,409	476,820	169,088	230,373	289	-179,747	174,632	108,870	179,587	1,372,042
2030	309,304	196,361	557,918	186,198	207,749	58,729	-255,866	160,186	166,862	219,758	1,473,476
2031	310,889	244,528	592,876	204,889	183,845	52,690	-339,540	147,011	182,025	241,081	1,456,244
2032	311,926	285,981	613,942	221,404	180,370	52,045	-384,093	132,628	228,245	257,041	1,442,999
2033	279,236	317,076	616,247	232,555	169,944	48,229	-401,193	110,619	189,011	265,096	1,448,800
2034	207,390	352,736	635,528	251,336	162,374	46,073	-438,661	102,834	224,529	280,106	1,375,187
2035	195,181	389,350	655,313	268,155	153,126	45,077	-530,553	95,327	255,122	295,286	1,311,140
2036	196,443	419,324	655,824	272,744	171,654	51,433	-372,058	82,469	263,614	301,899	1,516,119
2037	197,624	450,234	657,522	277,350	169,021	49,381	-318,853	100,190	266,085	309,164	1,625,549
2038	199,402	535,004	747,278	296,937	263,435	71,090	-318,451	62,356	382,212	354,181	1,829,020
2039	200,656	551,551	724,710	281,428	258,629	65,708	-298,922	68,242	365,764	352,377	1,838,616
2040	201,369	585,828	723,407	286,422	298,250	76,720	-165,798	58,437	412,947	359,705	2,011,392
2041	202,284	585,828	676,660	293,964	290,290	74,860	-67,439	58,958	382,902	348,442	2,080,945
2042	203,804	585,828	631,402	298,238	301,628	79,085	21,670	59,980	393,216	337,706	2,126,125
2043	203,804	585,828	586,503	303,905	307,360	80,587	22,081	61,120	400,688	326,223	2,076,725
2044	203,804	585,828	541,876	309,681	313,201	82,119	22,501	62,281	408,303	315,336	2,028,325
2045	203,804	585,828	497,402	315,565	319,153	83,679	22,929	63,465	416,062	304,482	1,980,245
2046	203,804	571,240	453,773	321,562	325,218	85,270	23,364	64,671	423,968	294,014	1,918,947
2047	203,804	571,240	410,388	327,673	331,398	86,890	23,808	65,900	432,025	283,388	1,872,464
2048	200,317	571,240	367,485	333,900	337,695	88,541	24,261	67,152	440,235	272,903	1,823,258
2049	178,185	571,240	326,177	340,245	344,113	90,224	24,722	68,428	448,601	263,013	1,757,745
2050	158,075	571,240	286,629	346,711	350,652	91,938	25,192	69,729	457,126	253,654	1,696,692
2051	70,542	558,718	254,319	353,299	357,315	93,685	25,670	71,054	465,812	246,740	1,565,531
2052	64,320	516,128	225,466	360,013	364,105	95,466	26,158	72,404	474,664	241,027	1,490,423
Net Present Value 2023-2052	3,160,397	3,531,704	6,379,027	2,707,762	3,986,621	497,866	(1,882,638)	1,490,426	3,492,529	2,881,281	19,259,918

SOUTHWESTERN ELECTRIC POWER COMPANY
2023 INTEGRATED RESOURCE PLAN
FOR-Wint Portfolio Under Reference Scenario

Utility Costs (Nominal$000)

	(1) Existing Depreciation	(2) New Depreciation	(3) Capital Charge	(4) Fixed O&M	(5) Fuel Costs	(6) Emission Costs	(7) Other VOM Costs	(8) Market Purchases Costs	(9) *Less:* Market Sales Revenue	(10) Taxes	(11)=(1)thru(8)-(9)+(10) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2023	222,624	0	279,060	76,758	579,832	1,170	67,860	83,544	328,697	92,841	1,074,993
2024	223,884	0	267,092	76,163	490,076	1,037	59,913	128,271	240,902	88,480	1,094,013
2025	241,130	0	283,278	87,757	447,551	1,018	57,979	143,064	216,301	93,504	1,138,979
2026	302,010	89,540	498,419	159,185	383,269	945	-68,455	127,450	259,606	180,400	1,413,158
2027	303,791	184,062	607,423	190,913	291,998	761	-126,033	152,293	201,058	232,629	1,636,780
2028	305,913	372,496	848,705	272,339	240,955	317	-246,549	123,962	279,179	344,753	1,983,712
2029	307,460	437,017	881,091	280,095	230,373	289	-253,910	128,399	286,876	370,025	2,093,962
2030	309,304	599,839	1,061,459	328,688	207,749	58,729	-353,076	114,264	500,884	460,719	2,286,792
2031	310,889	613,847	1,002,807	337,185	183,845	52,690	-405,102	127,635	471,793	449,592	2,201,594
2032	311,926	628,156	953,547	345,435	180,370	52,045	-404,216	138,716	481,683	440,389	2,164,684
2033	279,236	628,156	894,544	348,963	160,725	46,243	-405,063	122,297	406,492	425,824	2,094,434
2034	207,390	639,352	860,750	359,809	155,611	44,624	-405,497	137,010	407,796	420,440	2,011,693
2035	195,181	657,659	844,158	370,931	147,894	43,964	-481,687	141,753	425,856	421,663	1,915,661
2036	196,443	687,633	835,689	376,431	165,642	50,141	-286,202	122,872	431,279	426,393	2,143,764
2037	197,624	733,998	846,226	384,429	169,105	49,399	-212,872	132,422	438,599	439,740	2,301,472
2038	199,402	793,362	870,927	397,491	166,861	49,675	9,173	128,985	425,367	459,915	2,650,424
2039	200,656	826,456	857,351	385,389	167,745	45,266	12,163	141,033	423,354	464,525	2,677,232
2040	201,369	860,733	842,308	391,285	207,771	56,213	243,221	124,573	461,927	468,970	2,934,516
2041	202,284	860,733	781,854	399,728	199,071	53,912	241,173	123,796	431,300	454,832	2,886,082
2042	203,804	860,733	722,901	404,858	210,119	57,684	243,435	123,018	436,195	441,224	2,831,581
2043	203,804	860,733	664,289	412,551	214,112	58,781	248,061	125,356	444,484	426,864	2,770,068
2044	203,804	860,733	605,905	420,391	218,181	59,898	252,775	127,738	452,931	413,092	2,709,586
2045	203,804	860,733	547,662	428,380	222,327	61,036	257,578	130,166	461,538	399,349	2,649,497
2046	203,804	846,145	490,264	436,520	226,552	62,196	262,473	132,639	470,309	385,994	2,576,278
2047	203,804	831,696	433,710	444,816	230,857	63,378	267,461	135,160	479,246	372,813	2,504,447
2048	200,317	817,384	378,227	453,268	235,244	64,582	272,543	137,728	488,353	359,895	2,430,835
2049	178,185	803,245	325,057	461,882	239,715	65,809	277,723	140,345	497,634	347,721	2,342,048
2050	158,075	789,165	274,361	470,659	244,270	67,060	283,000	143,012	507,090	336,226	2,258,739
2051	70,542	700,206	234,936	479,603	248,912	68,334	288,378	145,730	516,727	328,921	2,048,836
2052	64,320	605,824	201,862	488,717	253,642	69,633	293,858	148,499	526,546	323,068	1,922,877
Net Present Value 2023-2052	3,160,397	6,247,777	8,538,625	3,765,589	3,621,131	413,663	(1,004,137)	1,673,903	4,853,837	4,235,589	25,798,701

SOUTHWESTERN ELECTRIC POWER COMPANY
2023 INTEGRATED RESOURCE PLAN
NCR Portfolio Under Reference Scenario

Utility Costs (Nominal$000)

	(1) Existing Depreciation	(2) New Depreciation	(3) Capital Charge	(4) Fixed O&M	(5) Fuel Costs	(6) Emission Costs	(7) Other VOM Costs	(8) Market Purchases Costs	(9) *Less:* Market Sales Revenue	(10) Taxes	(11)=(1)thru(8)-(9)+(10) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2023	222,624	0	279,060	76,758	579,832	1,170	67,860	83,544	328,697	92,841	1,074,993
2024	223,884	0	267,092	76,163	490,076	1,037	59,913	128,271	240,902	88,480	1,094,013
2025	241,130	0	283,278	87,757	447,551	1,018	57,979	143,064	216,301	93,504	1,138,979
2026	302,010	27,110	404,629	138,631	383,269	945	-58,083	139,194	232,969	139,152	1,243,888
2027	303,791	69,700	448,284	149,282	291,998	761	-121,772	173,444	162,215	160,765	1,314,038
2028	305,913	84,910	445,414	173,085	240,955	317	-136,140	189,946	108,278	162,584	1,358,706
2029	307,460	117,517	467,949	168,336	230,373	289	-171,277	176,702	104,290	175,778	1,368,837
2030	309,304	153,590	492,930	171,785	207,749	58,729	-210,359	197,946	130,103	191,087	1,442,659
2031	310,889	164,522	477,431	176,511	183,845	52,690	-246,192	220,433	112,118	188,958	1,416,969
2032	311,926	171,993	456,660	179,824	180,370	52,045	-254,294	226,528	113,395	184,398	1,396,054
2033	279,236	185,684	445,156	183,996	169,944	48,229	-253,419	246,570	80,082	183,542	1,408,857
2034	207,390	185,684	423,272	189,066	162,374	46,073	-253,624	265,341	73,901	177,593	1,329,268
2035	195,181	185,684	402,765	191,881	153,126	45,077	-278,117	279,367	53,692	171,668	1,292,941
2036	196,443	215,658	419,927	195,612	171,654	51,433	-118,554	274,719	65,217	181,774	1,523,449
2037	197,624	246,568	435,862	199,343	169,021	49,381	-66,658	297,296	63,528	192,025	1,656,934
2038	199,402	331,338	538,576	218,052	263,435	71,090	-52,853	196,011	111,923	239,760	1,892,888
2039	200,656	347,885	527,225	201,641	258,629	65,708	-14,477	223,042	109,895	240,309	1,940,723
2040	201,369	365,023	514,543	203,097	291,298	75,144	37,155	210,334	129,985	240,561	2,008,539
2041	202,284	365,023	479,493	209,658	283,382	73,281	53,234	225,778	113,423	231,751	2,010,461
2042	203,804	378,277	462,673	215,744	298,618	78,387	66,903	232,903	129,494	230,607	2,038,421
2043	203,804	378,277	446,551	219,844	304,293	79,877	68,174	237,329	131,955	225,160	2,031,352
2044	203,804	378,277	431,044	224,021	310,076	81,395	69,469	241,839	134,463	220,381	2,025,843
2045	203,804	378,277	416,058	228,278	315,968	82,941	70,790	246,434	137,018	215,712	2,021,245
2046	203,804	363,689	402,308	232,616	321,972	84,518	72,135	251,117	139,622	211,512	2,004,049
2047	203,804	363,689	389,184	237,037	328,091	86,124	73,506	255,889	142,275	207,233	2,002,281
2048	200,317	360,111	377,096	241,541	334,326	87,760	74,902	260,752	144,979	203,263	1,995,089
2049	178,185	360,111	366,984	246,131	340,679	89,428	76,326	265,707	147,734	199,917	1,975,734
2050	158,075	360,111	359,019	250,809	347,153	91,127	77,776	270,756	150,541	197,182	1,961,468
2051	70,542	347,589	358,689	255,575	353,750	92,859	79,254	275,901	153,402	196,976	1,877,734
2052	64,320	304,999	362,217	260,432	360,472	94,624	80,760	281,144	156,317	198,056	1,850,707
Net Present Value 2023-2052	3,160,397	2,238,453	5,350,551	2,196,615	3,974,738	495,130	(844,683)	2,620,902	1,972,324	2,218,835	19,438,614

Exhibit G: Stakeholder Comments

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
1.	Staff	SWEPCO's going-in position (page 12 of SWEPCO Assumptions), which begins with the year 2022, seems to include only about 150 MW of wind, while the North Central Wind project, which is nearing completion, is reported by AEP to total 1,484 MW. Further, SWEPCO notes on page 13 of SWEPCO Assumptions that its share of this project is 809 MW. The 809 MW might have been presented in de-rated (aka "firm"} terms by SWEPCO in its going in position so that the 809 MW nameplate capacity would be scaled back to a much lower number. Staff asks that this be clarified in SWEPCO Draft IRP, and that the role of existing power purchase agreements (for renewable or other generation) be made transparent and clearly accounted for (volume, time period of contract) in the going in position, as they do not seem to be included in the projection on page 12.	The 809 MW represents SWEPCO's share of the North Central Wind (NCW) wind farms. The information in the Going In position chart represents the accredited capacity of the 809 MW. Additionally, the Company will update the Going-In chart to differentiate the PPA resources more clearly from owned resources.
2.	Staff	Also on page 12 of SWEPCO Assumptions, the going in position includes an addition of what appears to be about 300 MW of coal capacity in 2038, though this may not have appeared in the version of the chart that SWEPCO presented on March 29, 2022; Staff asks that this be clearly identified in the Draft IRP, and if it is not an error, SWEPCO should explain why a capacity addition over 15 years into the future is included in its going in position.	The amount of Coal Resources was mis-represented in the presentation and was updated for the July Stakeholder meeting.
3.	Staff	Staff requests that SWEPCO provide, in the Draft IRP, an analysis of the historical and going forward costs for each of the existing supply side resources included in the going in position. This analysis should include transparent details of operating and maintenance costs, additional capital	The Company will prepare an indicative analysis.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
		costs including the cost of new equipment needed to comply with Federal and state-level emissions requirements such as the requirements discussed by SWEPCO in its 2019 IRP Final Report, in Section 3.3, especially for meeting potential future requirements under EPA 's Coal Combustion Residuals ("CCR") Rule and Effluent limitations Guidelines (" ELG"). 1 SWEPCO should then convert the going-forward costs (including a transparent assumption for each resource's capacity factor) to a levelized cost of energy ("LCOE") for each resource; and then SWEPCO should compare each resource's LCOE to SWEPCO's forecast of energy prices in each of its Scenarios. The Draft IRP should then discuss SWEPCO's decisions whether to deactivate or retire each of its existing resources in the context of the going-forward LCOE and energy prices as well as reliability and resource adequacy in each of SWEPCO's future Scenarios.	
4.	Staff	Staff requests that SWEPCO include total historical peak load and total energy for SWEPCO and SWEPCO LA for the past IO years, and the growth rate of load for the past I0 years, in its Draft IRP. This should be broken out by end-use sector (i.e., residential, commercial, industrial).	The Company has included SWEPCO historical peak demand and energy requirements in Exhibit A-3. Exhibits A-1 and A-2, page 2 provide energy sales for the Company and Louisiana.
5.	Staff	In the future Scenarios the actual rate of growth assumed in the Base, High and Low growth should be defined in transparent and quantitative terms. The role of customer counts, usage per customer, the customer segment, and role of incremental energy efficiency in driving peak load and energy consumption should be described, and annual tables of numbers for these drivers should be provided.	The Company’s Base, High and Low load forecast scenarios are provided on Exhibit A-16. The Company expects that any alternative scenario that might be affected by customer usage variation would fall within the High and Low ranges and does not quantify the customer usage variations in the load forecasts.
6.	Staff	Staff asks that any and all assumptions (in addition to overnight capex, variable operating and maintenance ("VOM"), fixed operating and maintenance ("FOM"), and heat rate)	The Company will include a summary table in the IRP identifying the Supply-Side modeling parameters and assumptions.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
		used by SWEPCO to characterize supply side resources for the purposes of modeling the resources, including capacity factors if these are used as inputs into any of the model, be provided transparently in the Draft IRP. SWEPCO did not provide a clear indication as to whether the cost of transmission interconnection was included in any of the supply resource costs for purposes of capacity expansion modeling, and Staff asks that these costs (if any are included in SWEPCO's modeling assumption) be made transparent in the Draft IRP.	Additionally, the Company intends to include a proxy for transmission interconnection costs and will provide this information in the Draft IRP.
7.	Staff	During the March 29, 2022 stakeholder meeting, SWEPCO's referred to its 2021 IRP for Arkansas, noting nameplate capacity for wind in SPP increases from about 20 gigawatts ("GW") in 2021 to about 35 GW (i.e., an additional 15 GW) in 2041 in SWEPCO's reference case, and about 40 GW (i.e., an additional 20 GW) in its Clean Energy Technology Acceleration ("CETA") scenario. SWEPCO's scenarios show about 15 GW of additional solar by 2041 in the reference case, and about 35 GW of additional solar in the CETA case. However, as of March I, 2022, there are already 29 GW of wind and 42 GW of solar capacity in the SPP interconnection queue. This increment is more than what is contemplated over 20 years in SWEPCO's scenarios. Staff recommends SWEPCO consider a scenario in which, at least, the capacity currently in the SPP queue is eventually developed, and it is assumed that the strong ongoing interest in solar and wind development does not come to an abrupt halt in 2023. This may have a large impact on projected SPP energy prices.	The Company included limits around the renewable resources available to the model informed by an assumption of an approximately 20% development of the SPP queue.
8.	Staff	SWEPCO does not consider any transmission options in its IRP process, which is not consistent with the IRP Rules.	SWEPCO is a member of SPP, and SPP has functional control of PSO's transmission facilities. SPP works with its members to determine the transmission infrastructure

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
		Section 5 of the IRP Rules require that "[t]he IRP shall include the most recent long-term transmission plan and planning study prepared by the entity charged with performing transmission planning pursuant to the effective FERC jurisdictional open access transmission tariff. Unless this information is included in the transmission planning study provided, the utility shall identify and describe significant transmission constraints and limitations within its system and identify and describe any Reliability Must Run ("RMR") units that it operates. *Furthermore, the utility shall discuss any actions that could be taken to eliminate the constraints, limitations, and RMR units*" (emphasis added).	needed in the near-term and long-term planning horizon to maintain electric reliability, meet public policy mandates and provide economic benefits. SWEPCO relies on the SPP Transmission Expansion Plan (STEP) which is a compilation of SPP-directed projects based on studies performed by SPP to determine upgrades needed to maintain reliability, provide transmission service, provide for generation interconnections, and provide economic benefit to its members into the future. Rather than looking at the needs of just one load serving entity (LSE), SPP assesses needs from a larger, regional perspective and determines necessary new transmission infrastructure that would provide the most net benefits to the region. SPP's Integrated Transmission Planning process assesses near and long term economic and reliability transmission needs. Their plan would attempt to mitigate these issues.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
9.	Staff	The previous SWEPCO Final 2019 IRP in Docket No. 1-34715 provided a narrative of transmission issues and noted that SWEPCO's (or, rather, AEP-SPP's) existing transmission system is designed to be used in the manner now required by SPP. SWEPCO noted that this "can stress the system ... when generation is dispatched in a manner substantially different from the original design of utilizing local generation to serve local load." 5 However, SWPECO provided no analysis of transmission and no discussion of actions to be taken to eliminate constraints or reduce stress on the system.	Please see response to item 8 above. Transmission system planning is coordinated through the ITP process of SPP.
10.	Staff	For the Draft IRP in the current docket, Staff wants SWEPCO to examine and transparently present the cost of transmission alternatives. This is needed to achieve a holistic view of future transmission and generation needs. SPP's process of approval for transmission lines includes an economic foundation as well as a reliability foundation; its economic foundation is based on congestion scores associated with a constraint. SPP South, the location of SWEPCO's service territory is a generally constrained area within SPP, with generally higher energy prices than SPP North. Most transmission projects in SPP are paid for by the highway/byway cost allocation methodology (based on the voltage level of the specific facility). This means that the cost of a high-voltage project that reduces congestion would not necessarily be allocated I 00% to the utilities in the zone where the project is located, and this cost allocation should be considered in SWEPCO's analyses where appropriate.	For this IRP, transmission considerations were evaluated through the analysis in all Portfolios. Specifically, the Company modeled portfolios to manage the net import and export of energy from the SWEPCO resources. Additionally, while the IRP serves to identify non-locational specific new resources to meet the Company’s capacity and demand obligations, an estimate of costs for transmission upgrades and congestion costs in the SPP South zone were included in the modeling. While market capacity and energy resources are available for economic consideration, the Transmission network upgrades required to interconnect and ensure firm delivery of energy from new resources is comprehensively analyzed for each RFP resource in response to SWEPCOs RFP request.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
			The regional transmission upgrade costs are coordinated through a detailed process by SPP (SPP ITP) where multiple complex factors such as expansion needs and cost allocation on a regional basis are evaluated.
11.	Staff	In addition, the SPP Market Monitoring Unit found that wind was the price-setting resource in over 20% of hours in 2020, with gas accounting for about 50% of hours, 6 and given that SPP has approved policies for expansion of SPP into the Western Energy Imbalance Service ("WEIS") market, SPP will likely have more access to renewable generation, namely wind, with this enlarged footprint. What would be the impact on energy prices in an expanded SPP in SWECPO's various scenarios if key SPP transmission projects went forward in the context of an expanded SPP? Staff would like to see this addressed in SWEPCO's Draft IRP.	The Company is unable to effectively analyze this request.
12.	Staff	SWEPCO noted at the March 29,2022 stakeholder meeting that natural gas prices used in its modelling outlook are prices recorded at the TX/OK hub, not delivered prices at its generation plants. Therefore, these are strictly commodity prices, and do not include delivery charges (whether fixed or variable) to the power plant. Such charges are tracked separately as FOM costs to the plant However, at the stakeholder meeting it was not clear how this is modelled. Staff asks that SWEPCO provide transparency on this in its Draft IRP.	The TX/OK hub price is used in the scenario modeling as an input to determine regional pricing dynamics reflected in the LMP prices. In the portfolio modeling, where the Company assesses the need to meet the local capacity requirements, each of the existing resources are modeled with gas prices that include the commodity price and delivery charges as an input.
13.	Staff	SWEPCO explained at the March 29,2022 stakeholder meeting that its base outlook for natural gas prices is the Energy Information Administration's Annual Energy Outlook 2020 Reference case projection (page 22 of SWEPCO Assumptions). SWEPCO explained that its high and low	SWEPCO evaluated a wide range of gas prices under the cost risk assessment described in Sections 7.5 and 8.4.1 of the Draft IRP.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
		natural gas prices outlooks were driven only by supply-side assumptions: In the Enhanced Carbon Regulation ("ECR") Scenario, regulatory pressure limits drilling and gas prices are higher, and in the No Carbon Regulation ("NCR") Scenario, regulators support exploration and production of new resources and gas prices are lower. Staff notes that North American natural gas prices have been much more volatile over the past 15-20 years than is captured by SWEPCO's scenarios, and that demand also plays a role in the formation of natural gas prices. The North American natural gas market is more exposed to international demand because of ever-increasing LNG export capacity, and the long-term trends in demand should be a consideration in SWEPCO's natural gas price outlook. Staff asks SWEPCO to include the role of demand for gas in its gas price forecasts and examine the potential for a wider range of outcomes for natural gas prices· in its scenarios.	
14.	Staff	As noted above, SWEPCO does not consider any transmission options in its IRP process. Staff has noted in a previous IRP filing that there are *"essentially two ways transmission may enter the !RP Process: 1) as an alternative to a generation project; or 2) through identified amounts of excess capacity available through the (RTO) network, which could be considered alternative resources. Both of these possibilities should be fully analyzed in the /RP Process and included in the Draft /RP Report*... "1 SWEPCO should examine and transparently present the cost of transmission alternatives, as noted above.	Please see responses to Staff comments 8 & 10.
15.	Sierra Club	Sierra Club urges SWEPCO to provide more detail about its plans for the Company's remaining solid-fuel units, including the Welsh and Flint Creek power plants. Ideally, SWEPCO would conduct a fleet optimization or retirement	Many specific details are required to conduct a unit specific disposition study that is beyond the scope of the IRP.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
		study, in which the Company allows its model to select the optimal retirement date for its existing, increasingly uncompetitive solid fuel units, including both Flint Creek and Welsh.	
16.	Sierra Club	Low gas prices observed in the wake of the fracking boom are not likely to continue into the future. This year, gas prices have reached highs not seen since 2008. Just this week, Henry Hub futures went above $6/MMBtu–approximately 50 percent higher than the highest levels in SWEPCO's current "high-case" gas price forecast.7 As Henry Hub prices are at their highest point since 2008, it appears likely that real-time gas prices for SWEPCO's region are also higher than any of their modeled IRP gas price scenarios. SWEPCO should be more transparent about how its gas price forecast was developed, including providing the baseline Henry Hub assumptions and the regional modifiers that were applied to it.	The Company is using the AEO2022 Henry Hub gas prices in this IRP.
17.	Sierra Club	The current reality of high gas prices should be incorporated into SWEPCO's IRP. Given the volatility of gas prices, it is critical that SWEPCO understand the risks to ratepayers from continued reliance on gas resources. These risks take the form of high fuel costs for existing gas resources, and stranded asset risk for existing, and especially new gas resources, that will be uneconomic sooner than projected if gas prices continue to rise. By using such low gas prices, SWEPCO has not assessed how ratepayers will be impacted if gas prices are significantly higher than projected moving forward.	Please see response to Staff 13.
18.	Sierra Club	SWEPCO's current portfolios hard-wire gas additions into the model (meaning the model does not choose to build gas, it is told to build it) and also use gas plants as "place-	In this IRP, the Company did not "hard-wire" any resources.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
		holders" in the 2030s. Taking this approach to capacity expansion modeling, while neglecting to analyze the threat that high gas prices pose to gas-reliant portfolios, is a disservice to ratepayers, who will bear the cost of insufficient planning. SWEPCO should model the performance of each portfolio against a gas price forecast 25 percent higher than the current "high-case" forecast to fully assess the impact on ratepayers of SWEPCO's proposed portfolios if high gas prices persist. Because SWEPCO already locked in many of its gas additions, this sensitivity will provide clarity on (1) which scenarios are least impacted by high gas prices, and therefore protect customers most from potential future volatility; and (2) the magnitude of the potential risk.	
19.	Sierra Club	SWEPCO should issue an all-source RFP or RFI as part of its planning process, as soon as possible, to acquire current market data and to help inform decision-making on low-cost, low-risk resources with high benefit to customers.	Renewable technology resource costs were informed by the Company's 2022 RFP.
20.	Sierra Club	SWEPCO likely overstates the cost of renewable energy and storage options. Given SWEPCO's pursuit of power purchase agreements (PPAs) in the past and likely future market procurement (which we address further in these comments), the IRP should have included these options. One of the primary goals of the IRP modeling is to optimize resources on a cost-basis; but to do so requires modeling the best information and ownership options available. To preclude the IRP modeling from accessing lower-cost resources means that, by definition, it will choose more expensive ones because the model cannot select resources that it does not know exist. PPAs could offer reduced prices and different financing structures that offer lower customer costs than self-build resources. For instance, PPA's allow	The Company included two tiers of Solar and Wind resources, informed by its 2022 RFP, to test a range of assumed responses that would come from a specific RFP process. Furthermore, the Inflation Reduction Act (IRA) signed into law in August 2022, released the requirement for regulated utilities to "normalize" the associated tax credits. The IRP will include the new IRA tax benefits related to the clean energy resources modeled in this IRP.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
		the developer (and by extension the buyer) to benefit from the full Investment Tax Credit (ITC) for solar or solar-battery hybrids immediately, whereas regulated utilities must "normalize" the credit over the life of the project, as SWEPCO is assuming in this IRP. The Company must consider these potentially lower-cost ownership options in its model to ensure that it is truly developing a low-cost plan and that the plan comports more closely with reality.	
21.	Sierra Club	To protect the communities SWEPCO serves, and also account for the environmental impacts of its fleet, it is increasingly important for SWEPCO to include quantified health impacts in its assessments of its portfolio options in this IRP process. SWEPCO should quantify and analyze the comparative public health impacts from air pollution, namely SO2, NOx, PM, and mercury emissions, of each of the portfolios it considers in its IRP and evaluate the public health cost that various air pollutants have on public health, especially in environmental justice communities.	The Company will include a CO_2 emissions reductions metric as part of the Scorecard assessment of the different Portfolios modeled. Any further analysis to quantify public health impacts on non-location specific resource additions would be highly speculative.
22.	Sierra Club	SWEPCO should consider the environmental justice implications associated with its ultimate selection of its preferred portfolio because the communities that are harmed most by persisting reliance on fossil fuel burning power plants are the communities who should benefit the greatest from reduced emissions, coal retirements, and investments in renewable energy. EJSCREEN14 is EPA's environmental justice screening and mapping tool that combines environmental and demographic indicators based on nationally consistent data and allows utilities to do just that. When run for a particular power plant, EJScreen demonstrates the relative environmental justice concerns for designated areas by "EJ Indexes," making significant data explicit, especially when reviewing communities that surround facilities and	The IRP serves to inform the Company of types and amounts of different resources to meet its obligation without specific locational assessments. The Company does not consider the EJ screen to be an appropriate tool for use in non-locational specific plans.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
		their racial composition, per capita income, and other demographic indicators in relation to various pollutants. SWEPCO should take care to consider the distinct communities whose health is impacted by SWEPCO's continued reliance on fossil fuel generation.	
23.	Sierra Club	We recommend that SWEPCO hold two interim stakeholder meetings between now and the draft IRP filing with the understanding that the input from stakeholders will be considered throughout the modeling process leading up to the Draft IRP filing.	The Company held an additional Stakeholder meeting in July 2022 to engage stakeholders throughout the process. Another Stakeholder meeting will be offered in accordance with the LPSC IRP Process Schedule of Events.
24.	AEMA	In the IRP Scenario #2, the Clean Energy Technology Advancement, tax extensions for renewable energy and a new credit for storage were the only credits included. Based on the tax credits currently under consideration, it would be useful in at least one scenario additional tax incentives for microgrids, interconnection, and bonus credits for deployment in low-income communities—all of which will materially lower the cost of DERs while increasing access to clean energy for many more residents and business in Louisiana.	The Company will evaluate a Clean Energy Technology Advancement (CETA) Portfolio where higher levels of tax incentives under the Inflation Reduction Act (IRA) are assumed and where Technology costs decline more rapidly. This will be modeled under a high load condition.
25.	AEMA	AEMA inquired during the stakeholder presentation if Order 2222 ("Order") had been considered in the IRP development process.6 SWEPCO is part of Southwest Power Pool ("SPP") which is under the jurisdiction of the Federal Energy Regulatory Commission ("FERC") and as such is required to comply with Order 2222 which mandates that DERs be able to fully participate in all wholesale markets. We recommend that implementation of this Order be made clear in the scenarios for the IRP.	As it pertains to the Company's Demand and Energy needs, while the net impact of DERs to the load forecast is not explicitly quantified, to the extent that it affects historical trends, it is implicitly captured in the load forecast.
26.	AEMA	SWEPCO reports that at the end of 2020, only 0.4% of all customers had Distributed Generation ("DG") installed (fewer than 2,300 customers) and that by 2030, SWEPCO	Please see the Company's response to question 25.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
		projects only 0.9% of customers will have installed DG at their premise.7 If Order 2222 is implemented as FERC intended in SPP and other organized markets, AEMA would predict the deployment of DERs, including DG, could be much greater than anticipated. In addition, given the rapid move toward electrification, AEMA would recommends that SWEPCO consider that customer DER deployment could increase faster than anticipated and that these trends be considered in the planning process.	
27.	AEMA	When discussing DER, SWEPCO explicitly only considers rooftop solar, not a more holistic list of community solar, distributed storage, microgrids, energy efficiency, and demand response. While electric vehicles are included in the analysis, other forms of electrification, such as electric heat pump and transitioning from natural gas to electric appliances, are not considered. It would be prudent for SWEPCO to include a wider variety of technologies in the planning process and modeling runs to ensure that a range of outcomes are considered more fully in developing a long range portfolio.	Please see the Company’s response to question 25
28.	AEMA	Only utility-scale solar plus 4 -hour battery storage are considered in the capacity credit planning, yet with Order 2222 implementation, resources of all types on the customer side will be eligible to participate in wholesale markets and, as such, could be considered for capacity credits within SWEPCO’s system.	Please see the Company’s response to question 25.
29.	AEMA	AEMA’s recommendations for more complete inclusion of DERs in the IRP modeling points to the need to determine the full value of these resources and account for that value in the planning process.	Please see the Company’s response to question 25.

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	Stake-holder	Comment	SWEPCO Response
30.	AEMA	AEMA recommends DERs being taken into consideration for resilience purposes which, while not explicit in the IRP, will be crucial to include in long term planning given the increased frequency and severity of storms.	Please see the Company's response to question 25.
31.	SREA	Complete the 3,000 MW wind RFP	The Company has conducted and will continue to conduct RFPs for new resources.
32.	SREA	Announce plans to issue a 1,000 MW solar RFP in early 2023	The Company has conducted and will continue to conduct RFPs for new resources.
33.	SREA	Use the most up-to-date NREL ATB cost assumptions for renewable generation resources	Resource costs were informed from multiple resources including EIA, Charles River Associates and RFP data. NREL was used to identify the associated technology learning curves used for future resource cost assumptions.
34.	SREA	Provide an analysis showing the effect of modeling renewable generation resources as PPA's in the IRP model	The Company included two tiers of Solar and Wind resources to test a range of assumed responses that would come from a specific RFP process.
35.	SREA	Incorporate multiple battery storage configurations (1-hr, 2-hr, and 4-hr), and develop different dispatch strategies that may better highlight battery storage value	The Company considered multiple battery considerations in the portfolio selection process. The development of different dispatch strategies is outside of the IRP scope.
36.	SREA	Conduct a reliability study that evaluates the loss of load expectations (LOLE) and ELCC's for resources on SWEPCO's system and captures the interaction between all resources across the Company's entire portfolio	LOLE study is an RTO function to which, the Company is actively engaged with SPP. For this IRP, the Company modeled a dynamic ELCC for solar resources for each Portfolio.
37.	SREA	Conduct an ELCC analysis on its existing fossil generation fleet, as well as new fossil units	For traditional resources such as a thermal generator, ELCC is approximately equal to its unforced capacity (UCAP) value (which is determined based on the resource's forced outage rate).

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	Stake-holder	Comment	SWEPCO Response
			The Company continues to be engaged with SPP with respect to their Resource Adequacy assessments and the associated accredited capacities for each of its thermal resources.
38.	SREA	Provide an updated Action Plan with details on the costs of winterizing its fossil fleet, in alignment with SPP and LPSC recommendations	NERC updated their rules shortly after Winter Storm Uri to which, SWEPCO is in full compliance with at this time. SPP and LPS recommendations are in alignment with NERC standards. All SWEPCO plants also updated their winterization plans following winter storm Uri that were modified to include additional areas required by updated NERC rules.
39.	SREA	Allow renewable energy resources and energy storage options to be selected by the model within a reasonable amount of time (1-2 years)	The First-Year availability for resources identified for the modeling considered the timing needed to conduct an RFP process, evaluate responses, proposed any new resources to the commission for approval and for the final construction of new resources. The Company does not consider a 1-2 year time frame to be reasonable.
40.	SREA	Do not include annual limits on solar or wind resource additions	Modeling results did not reach annual limits for solar and wind resources suggesting the limits included were not a limiting factor. A sensitivity to remove any annual limits is not expected to provide any further insights.
41.	SREA	Include a much higher cost natural gas cost assumption to better capture a broader band of risk	The stochastics analysis considered a wide range of gas prices that reflect a broader band of risk as discussed in section 7.5.1 of the draft IRP.
42.	SREA	Continue monitoring federal policy changes (e.g., PTC/ITC extensions)	The Company acknowledges this feedback.
43.	SREA	Improve modeling of paired resources, solar-battery hybrids in particular by recognizing the economics of scale that exist when co-locating resources	For this IRP, the Company included a paired Solar + Storage resource for selection.

2023 SWEPCO IRP Stakeholder Comment Summary			
	Stake-holder	Comment	SWEPCO Response
44.	SREA	Provide additional details regarding “green hydrogen” production or use cases	The Company will include additional discussion around “Green Hydrogen” production in the IRP.

Confidential Exhibits

Volume 2

Exhibit H: Confidential – Existing Unit Fuel Forecast

Exhibit I: Confidential – Existing Unit Performance

Exhibit J: Confidential – Supplemental Analysis, Existing Units

Volume 3

Exhibit K: Confidential – SWEPCO Load Forecast Model Information