SOUTHWESTERN ELECTRIC POWER COMPANY℠

An AEP Company

2021 Integrated Resource Plan Report

to the

Arkansas Public Service Commission

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Executive Summary

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.

SWEPCO defined four objectives for the preferred plan in the 2021 IRP that align to customer and corporate priorities, these are: customer affordability, rate stability, maintaining reliability, and sustainability. SWEPCO evaluated candidate resource plans against these four objectives using the IRP Scorecard and considered trade-offs to select the preferred plan. This report sets out how the Company is planning to meet the four objectives over the 20-year planning period for the benefit of its customers.

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 owned resources and contracts. This going-in position reveals a need for new capacity in 2023, reflecting the retirement of SWEPCO's Pirkey 1 coal unit and the Lieberman gas steam units 3&4[1]. The gap widens in 2028 and 2030 with planned retirements at SWEPCO's Welsh 1 & 3 coal units and Wilkes 1 gas unit. 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 the 2021 IRP includes Distributed Generation and Energy Efficiency ("EE") options that can be selected alongside, or as an alternative to, new utility-scale resources when meeting customer needs. The candidate resources reflect the priorities and objectives defined by SWEPCO and are aligned to customer needs.

In addition, the Company has taken into consideration the recommendations of the Arkansas Energy Resources Planning Task Force when constructing the Preferred Portfolio. In particular, the Preferred Portfolio includes further expansion of demand-side resources. Furthermore, the Company explicitly considers a scenario where a winter reserve requirement is enforced, in addition to the summer reserve requirement, to ensure year-round reliability of electricity supply to customers.

SWEPCO determined that the No Early CT portfolio provides the best combination of supply- and demand-side resources to meet SWEPCO's future customer needs. The plan maintains affordable and stable rates for SWEPCO customers, is expected to maintain reliability across all seasons, and creates opportunities for local development all while reducing greenhouse gas emissions in line with AEP corporate targets. Figure 78 summarizes the additions to the SWEPCO portfolio over the 2022-2041 time period under the Preferred Plan.

1 On December2, 2021, AEP/SWEPCO decided to delay the planned retirement of Lieberman Units 3 and 4 in December 2022 and December 2024 respectively, to no later than December 31, 2026. Given the timing of this decision, this was unable to be represented in this IRP. However, SWEPCO intends to update the information in its upcoming Louisiana IRP as the extension provides for a smooth transition to preferred plan resources in 2026.

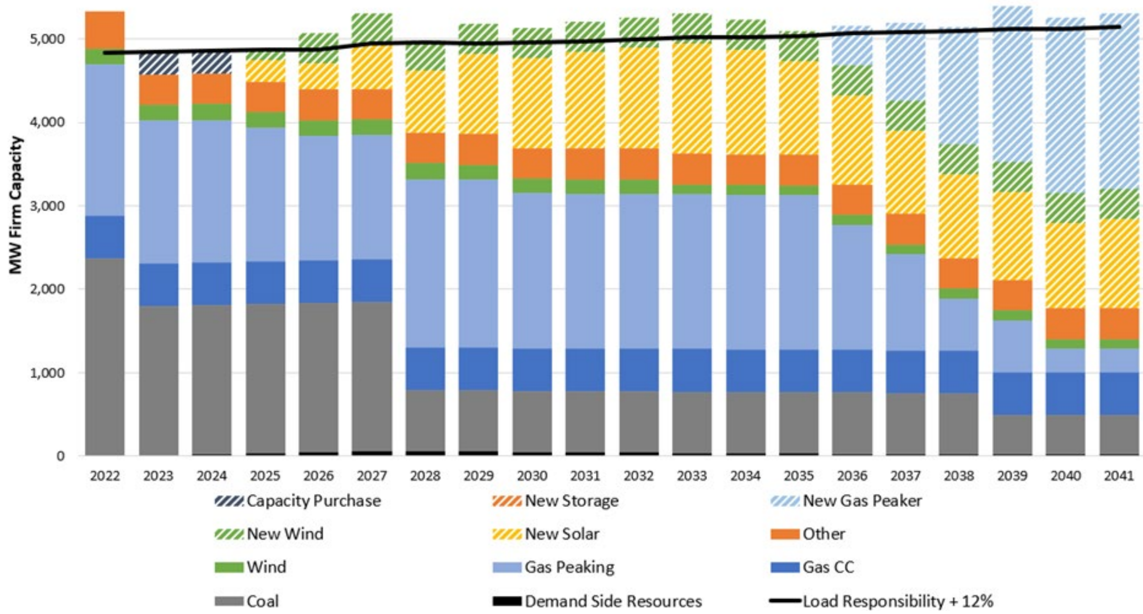


Figure 1: SWEPCO Preferred Plan Summer Capacity Position

Under the Preferred Plan, the Welsh 1 coal unit is converted to run on natural gas in 2028 and operates for an additional 10 years through the end of 2037. On the demand side, SWEPCO proposes approximately 50 MW of demand-side resources between 2022 and 2028, which serve to offset approximately 59 MW of supply-side resources by 2028.

In addition to demand-side programs, SWEPCO proposes to add 4,000 MW of new solar and 2,450 MW of new wind by 2041. All of the wind is added in the near-term to take advantage of the production tax credit. A smaller amount of new solar (550 MW) is added over the next five years, with the majority of new additions made during the 2027-2033 time period after solar costs are forecasted to decline and the capacity need increases. The Preferred Plan also proposes to add 2,160 MW of new gas CT units between 2036 and 2040 as the Welsh 1 gas conversion unit retires along with Flint Creek coal plant and Wilkes 1 & 2 gas units. The Preferred Plan also assumes that between 270-280 MW of short-term capacity purchases are made during 2023 and 2024 as new resources are phased into the portfolio.[2]

Responsive to Changing Customers' Needs

Through increased electrification, deployment of electric vehicles ("EVs") and higher penetration of distributed energy resources ("DERs"), the way SWEPCO's customers are interacting with the electricity system is changing and SWEPCO's preferred plan must be 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

2 With the late decision to delay the Lieberman 3 & 4 retirements to Dec 2026, the amount of short-term capacity purchases will be re-evaluated.

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 through 2041. Retail sales are also expected to grow at 0.2% 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 0.2% per year through 2041.

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, including emission-constrained scenarios.

SWEPCO also evaluated the adequacy of its transmission system to accommodate changing customers' needs and this IRP introduces a discussion of SWEPCO's distribution system and the role that distribution-level solutions can plan to meet customers' needs in the future.

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 a broad range of demand-side resource options to meet future capacity needs. Options include energy efficiency measures and utility-scale distributed energy resources that can be selected alongside new utility-scale generation. These options empower customers with choices over how and when they interact with the energy system.

Under the Preferred Plan, SWEPCO proposes to implement approximately 50 MW of additional demand-side resources between 2022 and 2028, which serve to offset approximately 59 MW of supply-side resources by 2028. After 2028, the impact of demand-side programs is reduced as the measures age and more efficient technologies are adopted market-wide.

Planning for Uncertain Futures

SWEPCO knows the importance of reliability to its customers and set an objective for the preferred plan to shield customers, to the extent practicable, from high costs during unexpected or adverse market conditions. This IRP includes two methods for evaluating cost risks, the results of which inform the development of the Preferred Portfolio:

- 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 generator output to observe how the candidate portfolio performed.

The Preferred Plan contains a diverse mixture of demand-side and supply-side resources. The Preferred Plan performs well across all customer objectives and serves to shield ratepayers from large swings in cost due to market uncertainty base on both the scenario and stochastic measures of risk.

Powering a Greener Future for All

Under the Preferred Plan, SWEPCO proposes to add 4,000 MW of new solar and 2,450 MW of new wind by 2041. All of the wind is added in the near-term to take advantage of the production tax credit. In total, the SWEPCO portfolio is expected to reduce emissions by 80% by 2030 relative to the 2000 baseline, consistent with AEP corporate goals. In addition, the Preferred Plan is expected to reduce NOx emissions by 85% and SO2 emissions by 96% over the next decade.

Consulting Stakeholders

The Arkansas stakeholder process is designed to allow key IRP stakeholders an opportunity to gain an understanding and comment on SWEPCO's IRP process and the key assumptions to the 2021 IRP. The Stakeholder Committee is to be broadly representative of retail and wholesale customers, independent power suppliers, marketers, and other interested entities in the SWEPCO service area.

SWEPCO held a virtual stakeholder meeting on September 15, 2021 during which a "Draft IRP" was reviewed with the stakeholders. The stakeholders then prepared a "Stakeholder Report" addressing key issues, concerns, and feedback. SWEPCO took any issues or comments from the Stakeholder Report under advisement as part of the final SWEPCO IRP for Arkansas. The stakeholder report is included in Appendix B of this report.

Five-Year Action Plan (2022 to 2026)

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

- Continue the planning and regulatory actions to implement cost effective energy efficiency and demand response programs that reduce energy use and peak demand for SWEPCO customers
- Continue to investigate opportunities to incorporate advanced technologies related to DER technology to provide both capacity relief and improved reliability
- Develop more refined estimates about which technologies and what quantity of resources can be integrated into the SWEPCO territory
- Seek to refine cost estimates and develop plans for the potential Welsh 1 gas conversion
- Continue to evaluate and/or conduct Request for Proposals (RFP) to explore opportunities to add cost-effective renewable generation in the near future to take advantage of the Federal Tax Credit
- Evaluate the Request for Proposals (RFP) to explore opportunities to add cost-effective capacity in the near future to meet capacity need in 2023-2024 as needed
- Be ready to adjust this Action Plan and future IRPs to reflect changing circumstances

The Preferred Plan is informed by an optimized analysis to meet the Southwest Power Pool (SPP) minimum reserve margins given assumptions about resource availability and constraints on portfolio energy sales. However, this plan is based on an uncertain future regarding events that can impact the Company's capacity position, including uncertainty around load growth, new environmental and tax policy, reserve margins, contribution of intermittent resources, and existing unit performance. Consequently, the Company will continue to evaluate its capacity position relative to these risks and may consider adding additional resources in the future to ensure a capacity position in compliance with SPP's capacity reserve requirement.

1. Introduction

This Report presents the 2021 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 located in Washington DC, Boston, 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 not just used to develop the scorecard. They also informed 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 considering a suite of demand-side measures including energy efficiency, demand response and time-of-use rates;
- **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 beginning to incorporate transmission and distribution considerations in generation resource planning; and,
- **Local impact & sustainability** through inclusion of renewable and advanced generation technologies as resource options to enable greener future for all as well as responding to customers' other needs including demand for clean energy, electrification, and customer-sited generation.

The details of the 2021 IRP portfolio analysis framework and the scorecard elements are discussed below in Section 8.

1.2. IRP Process

This Report covers the processes and assumptions required to develop an IRP for the Company. The IRP process for SWEPCO includes the following components/steps:

- Describe future customer needs and evaluate how those needs were likely to change over the 20-year period forecast in the 2021 IRP (see Chapter 2);

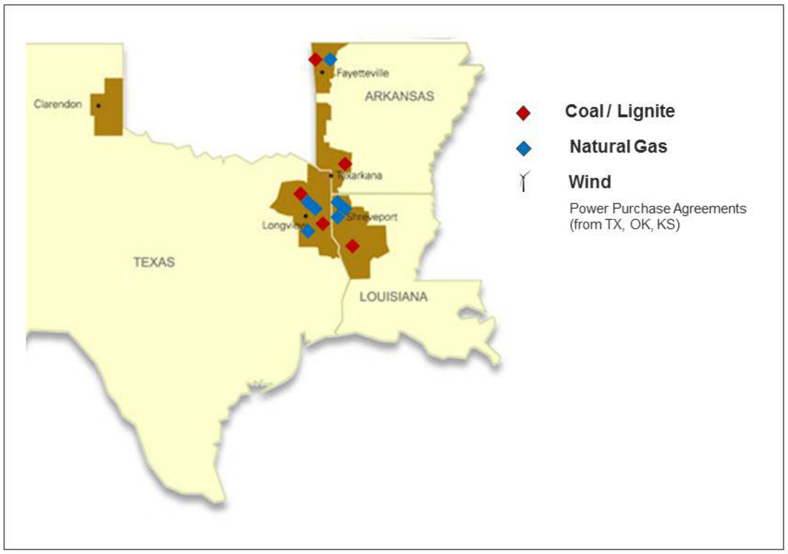
- Assess the adequacy of current resources, both demand- and supply-side, in meeting future customers' needs taking into account near term changes in the portfolio and the potential impact of future legislations on the resource performance (see Chapter 3);
- Evaluate transmission and distribution system integration issues in meeting future customer needs and the impact on potential future resource options (see Chapter 4);
- Identify a list of candidate resources that could be selected by the portfolio model to meet future customer needs. Candidate resources include both supply-side (see Chapter 5) and demand-side options (see Chapter 6) including for instance energy efficiency measures, renewables technologies and advanced generation technologies;
- 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 incorporate feedback (See Chapter **Error! Reference source not found.**); and
- Reflect stakeholder feedback in formulating the preferred resource plan and the associated five-year action plan (See Chapter 9).

1.3. Introduction to SWEPCO

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 543,000 retail customers in those states; including approximately 123,000, 233,000 and 187,000 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 (2020-21) actual SWEPCO summer and winter peak demands were 4,351MW and 4,563MW, occurring on August 10th and February 16th of (2021), respectively.

SWEPCO is an affiliate company of American Electric Power Company, Inc. ("AEP").

Figure 2 SWEPCO's Service Territory



1.3.1. Annual Planning Process

This IRP is based upon the best available information at the time of preparation. However, changes that may impact this plan can, and do, occur without notice. Therefore, this plan is not a commitment to a specific course of action, since the future is highly uncertain, particularly in light of economic conditions, access to capital, the movement towards increasing use of renewable generation and end-use efficiency, as well as legislation to control greenhouse gases.

The implementation action items as described herein are subject to change as new information becomes available or as circumstances warrant.

SWEPCO and AEP are engaged in planning activities throughout the year which impact the IRP. Major activities include updating the load forecast, fundamental commodity pricing forecast, and soliciting market data on the cost of new resources. The load forecasting process is ongoing; however, on an annual basis the load forecasting group produces a peak demand and energy usage forecast for each operating company. This process typically begins as actual values are received and reviewed and adjusted.

The fundamental commodity forecasting process is ongoing as well and is continually monitored relative to ongoing activities that could potentially impact the existing commodity forecast values. Typically, the fundamental commodity forecast is updated when material changes are observed or expected. The most recent commodity forecast relied upon in this IRP was released in July of 2021.

New generation resource cost and characteristics are generally based on the assumptions used by the US Energy Information Administration in the 2021 Annual Energy Outlook report. SWEPCO generally relies on technology cost improvements rates from the NREL Annual Technology Baseline report.

Other input data utilized with the IRP process is generally updated on an annual basis unless material differences are identified between the existing input values and expected future values.

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 2021.[3] 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 (2022-2041)[4], SWEPCO's service territory is expected to see population and non-farm employment experience similar growth of 0.5% and 0.7% 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 0.2% per year with stronger growth expected from the residential class (0.3% per year) while the commercial class experiences a modest decrease (0.1% per year) and the industrial class experiences modest increases (0.3% 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 0.2% per year. Finally, SWEPCO's peak demand is also expected to increase at an average rate of 0.2% per year through 2041.

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 January 2021. Moody's Analytics projects moderate growth in the U.S. economy during the 2022-2041 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 2.1% per year. Industrial output, as measured by the Federal Reserve Board's index of industrial production, is expected to grow at 1.5% per year during the same period. Moody's projected regional employment growth of 0.7% per year during the forecast period and real regional income per-capita annual growth of 1.7% 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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3 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

4 20 year forecast periods begin with the first full forecast year, 2022

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.

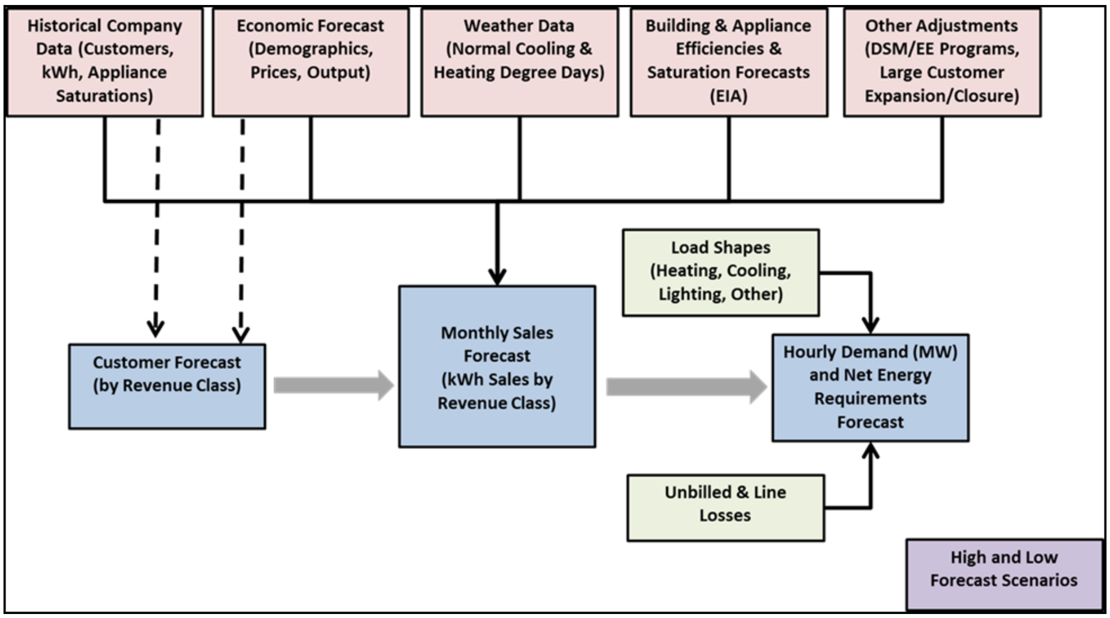
For the first full year of the forecast, the forecast values are generally governed by the short-term models. The short-term models are regression models with time series errors which analyze the latest sales and weather data to better capture the monthly variation in energy sales for short-term applications 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 2.

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 2011 through January 2021.

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 20 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, East Texas Electric Cooperative, 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 “2021 Annual Energy Outlook.” The natural gas price model is based upon 1980-2020 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 2021. 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 2020 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 2021. 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 2021.

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 2021 and 2022 are 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 of 2023, 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

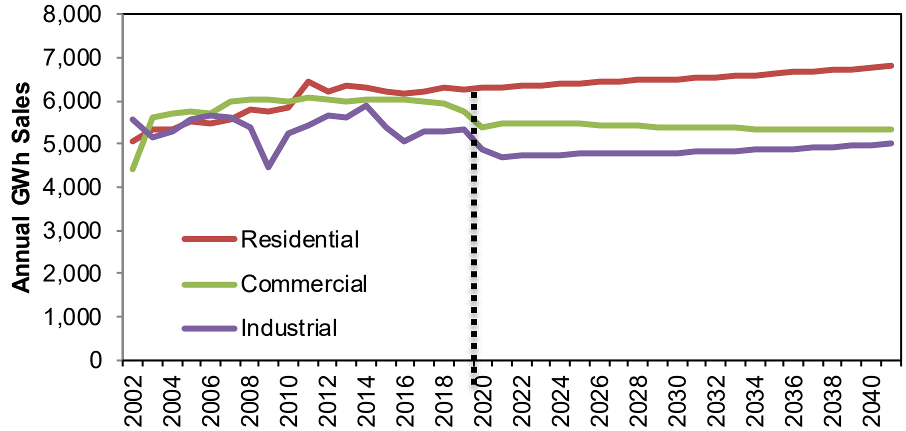
All tables referenced in this section can be found in the Appendix of this Report in Exhibit A.

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 2011-2020. 2021 data are six months actual and six months forecast and on a forecast basis for the years 2022-2041. 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 2041.

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

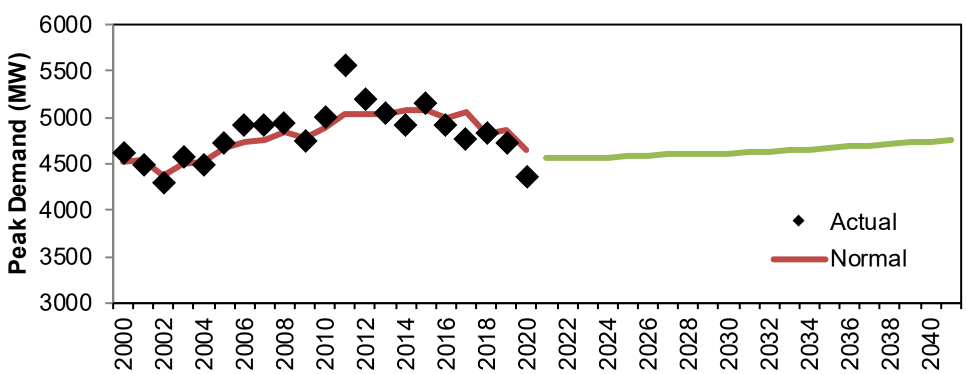


2.5.2. Peak Demand and Load Factor

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 2011-2020. 2021 data are six months actual and six months forecast and on a forecast basis for the year 2022-2041. 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 2041

Figure 5 SWEPCO's Peak Demand Between 2000 and 2041



2.5.3. Weather Normalization

Table A-4 provides historical monthly sales data for SWEPCO by customer class (residential, commercial, industrial, other retail and wholesale) for the period January 2011 through June 2021. Table A-5 provides forecast SWEPCO monthly sales data by customer class for July 2021 through December 2041.

2.5.4. Prior Load Forecast Evaluation

Table A-6 presents a comparison of SWEPCO's energy sales and peak demand forecasts in the 2018 IRP with the actual and weather normal data for 2018, 2019 and 2020. After the forecast utilized in 2018 IRP was developed, three wholesale customers did not renew their contracts resulting in significant over forecasting of wholesale energy sales. The other 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 0.8%. 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 2018 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

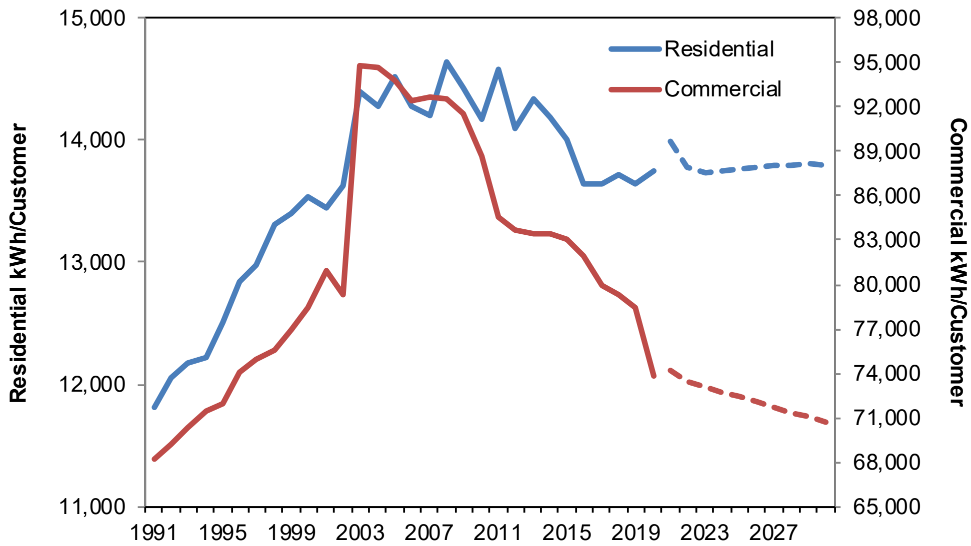
Table A-8 provides significant economic and demographic variables incorporated in the various residential long-term energy sales models for the Company. Table A-9 provides significant economic variables utilized in the various SWEPCO jurisdictional commercial energy sales models. Table A-10 presents 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 1.3% per year. The COVID-19 Pandemic had a significant impact on residential and 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 (2021-2030), with residential usage declining at a rate of 0.2% per year while commercial usage falls by 0.5%.

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 15.2 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

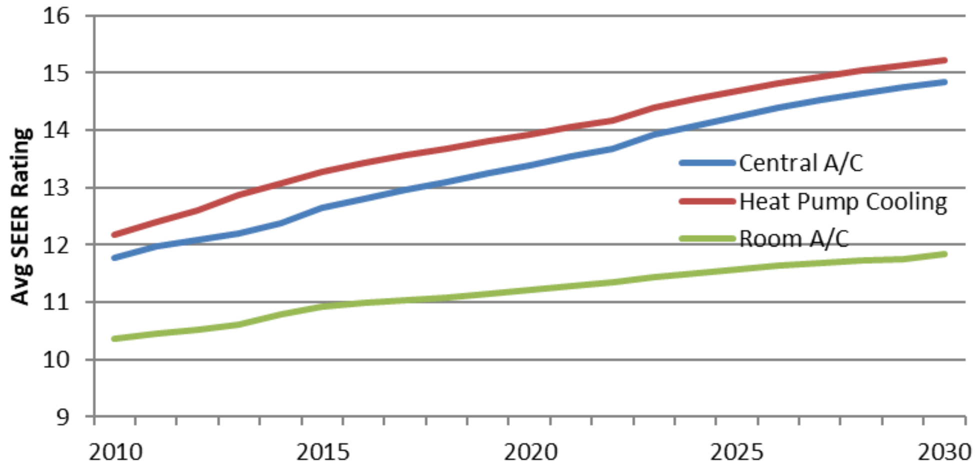


Figure 8 Projected Changes in Lighting & Clothes Washer Efficiencies, 2010-2030

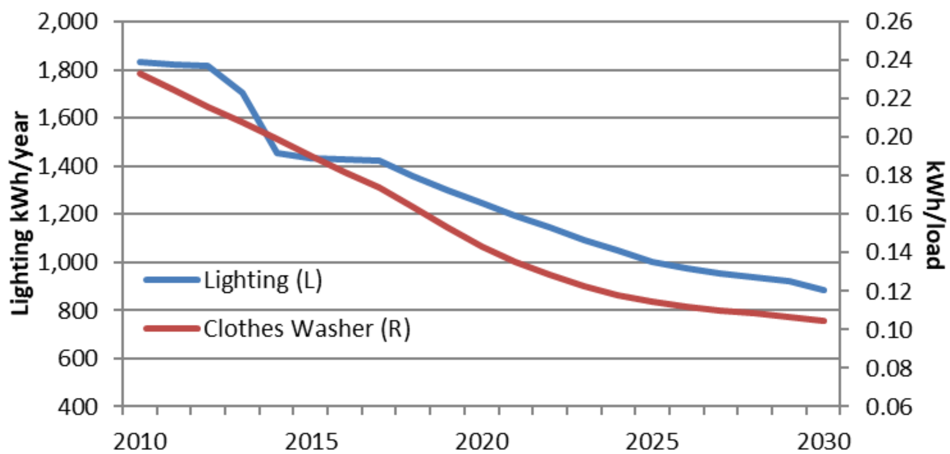
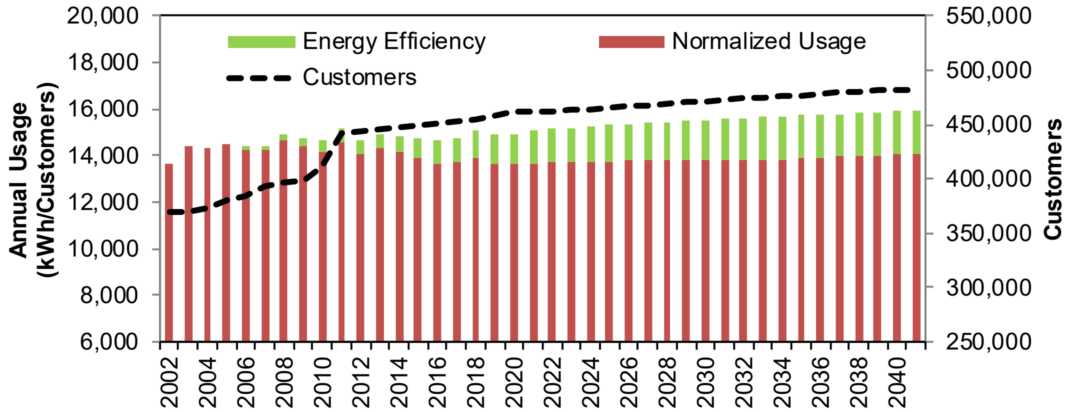


Figure 9 shows the impact of appliance, equipment, and lighting efficiencies on the Company's weather normal residential usage per customer. This graph provides weather normalized residential energy per customer and an estimate of the effects of efficiencies on usage. In addition, historical and forecast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

Figure 9 Residential Usage and Customer Growth, 2002 - 2041



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 Arkansas 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

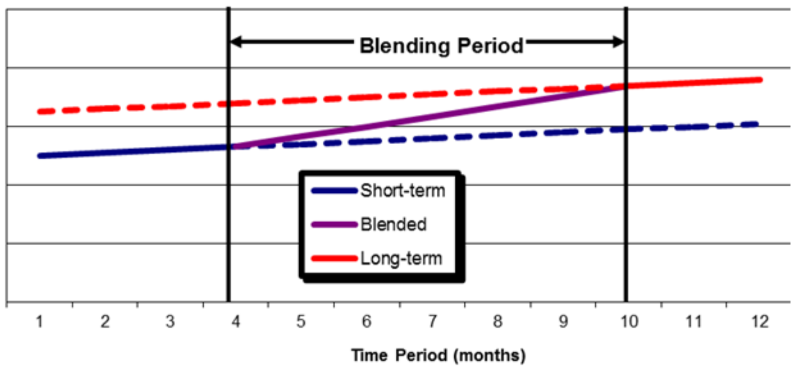
The Company has 27 customers with interruptible provisions in their contracts. The aggregate on-peak capacity available for interruptions is 34.5MW. The load forecast does not reflect any load reductions for these customers. Rather, the interruptible load is seen as a resource when the Company's load 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 2021 and 2022 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 2023 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.

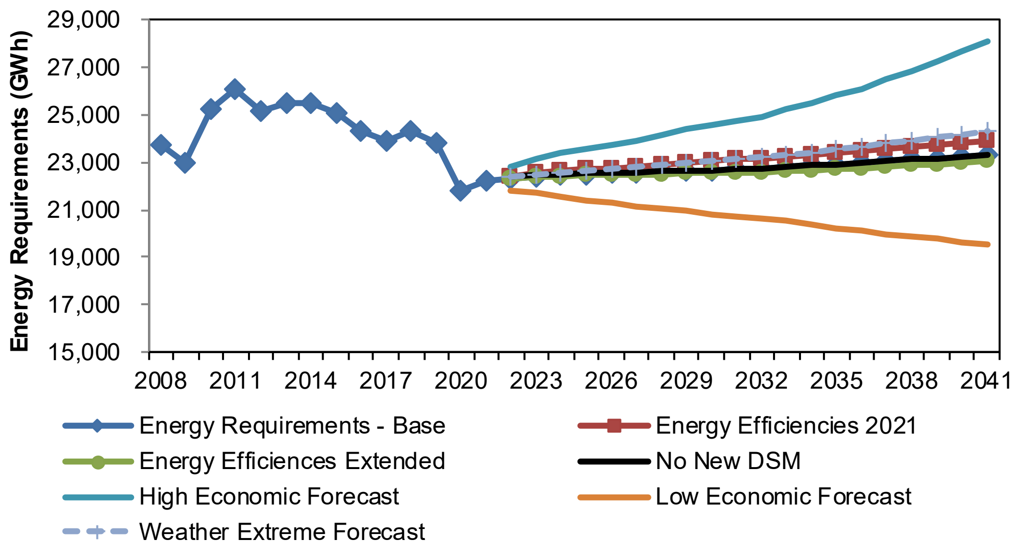
Forecast sensitivity scenarios have been established which are tied to respective high and low economic growth cases. The high and low economic growth scenarios are consistent with scenarios laid out in the EIA's 2021 Annual Outlook. While other factors may affect load growth, this analysis only considered 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, 2041, represent deviations of about 16.4% below and 20.3% 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.

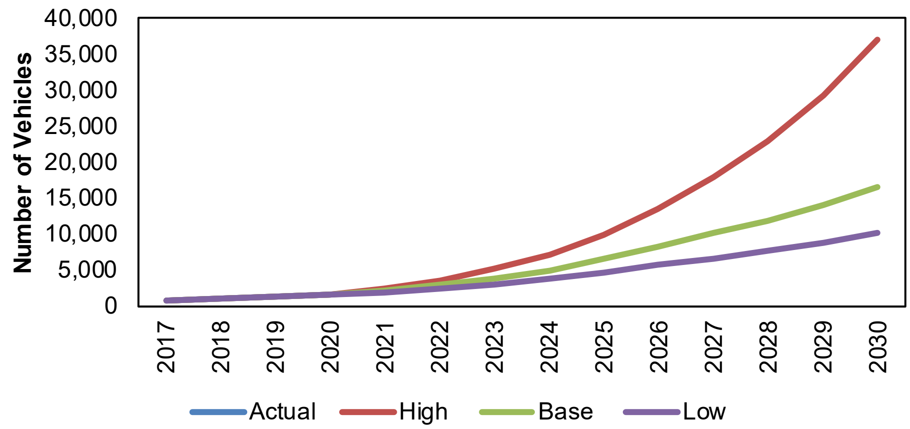
The energy efficiencies extended scenario has energy efficiencies developing at a faster pace than is represented in the base forecast. This scenario is based on analysis developed by the Energy Information Administration. This forecast is lower than the base forecast due to enhanced energy efficiency 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 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; however, the Company anticipates that number will grow in the coming years. 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.

Figure 12 SWEPCO Service Area Electric Vehicle Forecast Scenarios



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 0.32. For comparison, the estimated long-term elasticity for gasoline is 0.6 while the elasticity for restaurant meals is 2.3[5]. (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.)

5 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 1 identifies the current SWEPCO generating resources.

Table 1 SWEPCO's Owned Generation Asset as of May 7, 2021

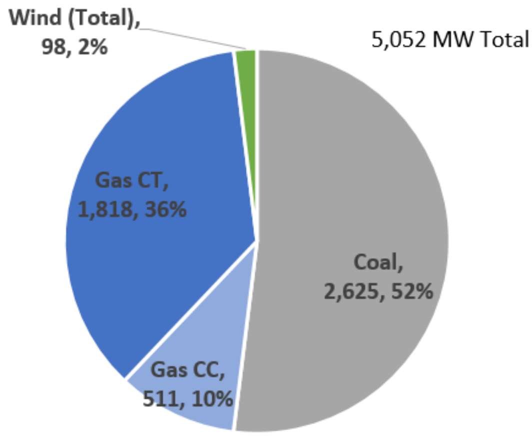
Unit Name	Primary Fuel Type	C.O.D.[1]	Rating (MW)[2]
Arsenal Hill 5	Gas Steam	1960	108
Dolet Hills 1[3]	Lignite	1986	257
Flint Creek 1	Coal	1978	258
Harry D. Mattison 1	Gas (CT)	2007	70
Harry D. Mattison 2	Gas (CT)	2007	71
Harry D. Mattison 3	Gas (CT)	2007	71
Harry D. Mattison 4	Gas (CT)	2007	71
J Lamar Stall	Gas (CC)	2010	511
John W. Turk, Jr. 1	Coal	2012	477
Knox Lee 5	Gas Steam	1974	338
Lieberman 3	Gas Steam	1957	109
Lieberman 4	Gas Steam	1959	108
Pirkey 1	Lignite	1985	580
Welsh 1	Coal	1977	525
Welsh 3	Coal	1982	528
Wilkes 1	Gas Steam	1964	164
Wilkes 2	Gas Steam	1964	360
Wilkes 3	Gas Steam	1964	353
Sundance	Wind	2021	109 (A)
Maverick	Wind	2021	156 (A)
Traverse	Wind	2022	544 (A)

(1) Commercial operation date
(2) Peak net dependable capability (Summer) as of filing.
(3) Dolet Hills retires 12/31/2021
(A) Installed capacity; Represents SWEPCO's 54,5% ownership stake

Based on the assessment of the AEP-SPP 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 13 shows SWEPCO's owned and contracted generation summer capacity contribution for peak.

Figure 13 SWEPCO 2021 Generation Asset Summer Capacity (MW) Contribution by Type



3.3. Current Demand-Side Programs

SWEPCO's distribution demand response programs are designed to minimize the long-term cost of utility service; avoid or delay the need for new generation, transmission, and distribution investment; and encourage and enable utility customers to make the most efficient use of utility capacity and energy and reduce wasteful use of energy. SWEPCO's demand response programs seek to accomplish these goals by overcoming barriers that prevent residential and business customers from adopting energy efficient technologies. SWEPCO also intends for its programs to leverage load management capability to reduce peak demand on the system, which should, all things being equal, decrease the amount of investment required to meet its peak demand. The Company also seeks to conduct research and development for potential programs to be included in future portfolios.

Peak demand, measured in MW, can be thought of as the amount of power used at the time of maximum customer usage. SWEPCO's maximum (system peak) demand is likely to occur on the hottest summer weekday of the year, in the late afternoon. This happens as a result of the near-simultaneous use of air conditioning by the majority of customers, as well as the normal use of other appliances, commercial equipment, and (industrial) machinery. At other times during the day, and throughout the year, the use of power is less.

As peak demand grows with the economy and population, new capacity must ultimately be built. To defer construction of new power plants, the amount of power consumed at the peak can be reduced. This can be addressed several ways via both "active" and "passive" measures:

- Interruptible loads (Active DR). This refers to a contractual agreement between the utility and a large consumer of power, typically an industrial customer. In return for reduced rates, an industrial customer allows the utility to "interrupt" or reduce power consumption during peak periods, freeing up that capacity for use by other consumers.
- Direct load control (Active DR). This is very much like an (industrial) interruptible load, but accomplished with many more, smaller, individual loads. Commercial and residential customers, in exchange for monthly credits or payments, allow the energy manager to deactivate or cycle discrete appliances, typically air conditioners, hot water heaters, lighting banks, or pool pumps during periods of peak demand. These power interruptions can be accomplished through radio signals that activate switches or through a digital "smart" meter that allows activation of thermostats and other control devices.

- Time-differentiated rates (Active DR). This offers customers different rates for power at different times during the year and even the day. During periods of peak demand, power would be relatively more expensive, encouraging conservation. Rates can be split into as few as two rates (peak and off-peak) to as often as 15-minute increments in what is known as "real-time pricing." Accomplishing real-time pricing requires digital (smart) metering.
- EE measures (Passive DR). If the appliances that are in use during peak periods use less energy to accomplish the same task, peak energy requirements will likewise be less.
- Voltage Regulation (Passive DR). Certain technologies can be deployed that allow for improved monitoring of voltage throughout the distribution system. The ability to deliver electricity at design voltages improves the efficiency of many end use devices, resulting in less energy consumption. This resource was not modeled at this time and will be considered in the future.

What may not be apparent is that, with the exception of EE, the remaining Distributed Energy Resources ("DERs") programs do not significantly reduce the amount of energy consumed by customers. Less energy may be consumed at the time of peak load, but that energy will be consumed at some point during the day. For example, if rates encourage customers to avoid running their clothes dryer at 4:00 P.M., then they will run it at some other point in the day. This is often referred to as load shifting.

3.3.1. Customer Energy Efficiency Programs

EE measures reduce bills and save money for customers billed on a per kilowatt-hour usage basis. The trade-off is the up-front investment in a building/appliance/equipment modification, upgrade, or new technology. If consumers conclude that the new technology is a viable substitute and will pay them back in the form of reduced bills over an acceptable period, they will adopt it.

EE measures most commonly include efficient lighting, weatherization, efficient pumps and motors, efficient Heating (via heat pump technology), Ventilation and Air Conditioning (HVAC) infrastructure (including smart EV charging), and efficient appliances. Often, multiple measures are bundled into a single program that might be offered to either residential or commercial/industrial customers.

EE measures will reduce the amount of energy consumed but may have limited effectiveness at the time of peak demand. EE is viewed as a readily deployable, relatively low cost, and clean energy resource that provides many benefits. However, market barriers to EE may exist for the potential participant. To overcome participant barriers, a portfolio of EE programs may often include several of the following elements:

- Consumer education
- Technical training
- Energy audits
- Rebates and discounts for efficient appliances, equipment, and buildings
- Industrial process improvements

The level of incentives (rebates or discounts) offered to participants is a major determinant in the pace of EE measure adoption.

Additionally, the speed with which programs can be rolled out also varies with the jurisdictional differences in stakeholder and regulatory review processes. The lead time can easily exceed a year for getting programs implemented or modified.

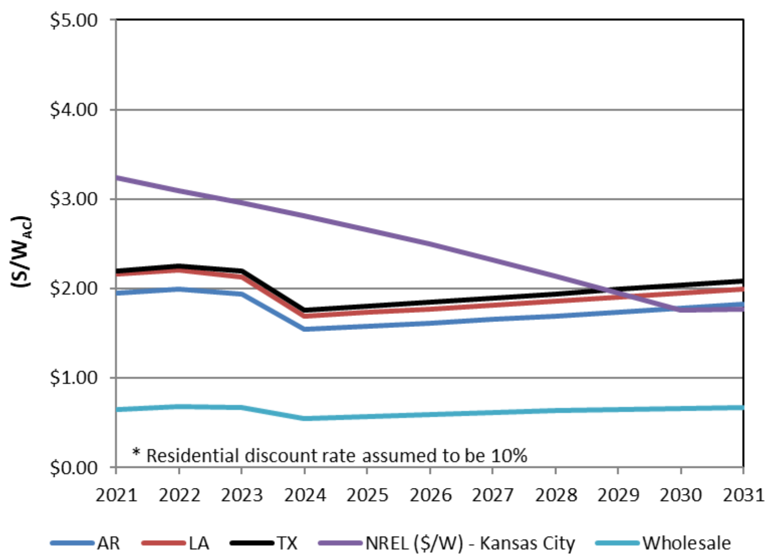
SWEPCO currently has EE programs in place in its Arkansas, Louisiana, and Texas service territories. SWEPCO forecasts EE measures will reduce peak demand in 2021 by 16.7 MW and reduce 2021 energy consumption by approximately 55 GWh.

3.3.2. Distributed Energy Resources

Distributed Energy Resources ("DERs") 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. SWEPCO's Arkansas retail jurisdiction has "net metering" tariffs in place which currently allow excess generation to be credited to customers at the retail rate. In SWEPCO's Texas and Louisiana jurisdictions, Distributed Generation ("DG") tariffs are in place where SWEPCO credits the customer for excess kWh sent back to the grid at the Avoided Cost Rate, with grandfathering in Louisiana for a number of customers at the full retail rate.

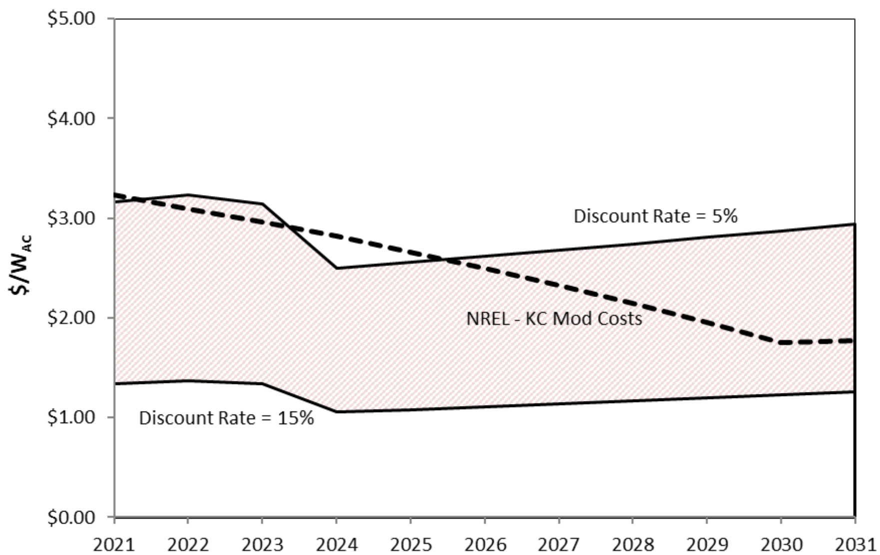
The economics of DG, particularly small-scale solar, continue to improve but the economics of such an investment are not favorable for the customer for a number of years. Figure 14 below illustrates, by SWEPCO state jurisdictional residential sector, the equivalent value a customer would need to achieve, on a dollar per watt-AC ($/WAC) basis, in order to breakeven on their investment, assuming a 25-year life of the installed solar panels based on the customer's avoided retail rate. Also included is the NREL cost of solar residential installations in SPP. Figure 14 below shows that the current cost of residential solar exceeds the cost which would allow a customer to breakeven on an investment over a 25-year period.

Figure 14 - Distributed Solar Customer Breakeven Costs for Residential Customers ($/$W_{AC}$)



A challenge of determining the value of a residential solar system is assigning an appropriate cost of capital or discount rate. Discount rates for residential investments vary dramatically and are based on each individual's financial situation. Figure 15, below, shows how the value of an Arkansas residential customer's DERs system can vary based on discount rate.

Figure 15 Distributed Solar Customer Breakeven Costs for Residential Customers ($/W$_{AC}$)



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. 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.

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 operating companies' existing generating units include: (a) periodic revisions to National Ambient Air Quality Standards ("NAAQS") and the development of state implementation plans 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 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. 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 must require 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.

3.4.3. **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.

ADEQ is currently in the process of developing a Regional Haze Program SIP that demonstrates reasonable progress toward achieving natural visibility conditions in Arkansas Class I areas for the period between 2018 and 2028 (Planning Period II). SWEPCO has responded to Information Collection Requests for the John W. Turk Jr. Power Plant and the Flint Creek Power Plant. Based on the information provided by SWEPCO, ADEQ will evaluate the need for additional emission reductions and determine the cost effectiveness of any further controls on the units.

3.4.4. **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.

3.4.5. **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.

3.4.6. Mercury and Other Hazardous Air Pollutants Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of Hazardous Air Pollutants ("HAPs") from coal and oil-fired power plants. The rule established unit-specific emission rates for units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of non-mercury metals) and hydrogen chloride (as a surrogate for acid gases). In addition, the rule proposed work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. Compliance was required within three years. The Company obtained administrative extensions for up to one year at several units to facilitate the installation of controls or to avoid a serious reliability problem.

In 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the 2012 final rule. Industry trade groups and several states filed petitions for further review in the U.S. Supreme Court.

In 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The court remanded the MATS rule to the Federal EPA to consider costs in determining whether to regulate emissions of HAPs from power plants. In 2016, the Federal EPA issued a supplemental finding concluding that, after considering the costs of compliance, it was appropriate and necessary to regulate HAP emissions from coal and oil-fired units. Petitions for review of the Federal EPA's determination were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2018, the Federal EPA released a revised finding that the costs of reducing HAP emissions to the level in the current rule exceed the benefits of those HAP emission reductions. The Federal EPA also determined that there are no significant changes in control technologies and the remaining risks associated with HAP emissions do not justify any more stringent standards. Therefore, the Federal EPA proposed to retain the current MATS standards without change. A final rule adopting the findings in the proposal was issued in April 2020. The rule has been challenged in the U.S. Court of Appeals for the District of Columbia Circuit.

3.4.7. Cross-State Air Pollution Rule (CSAPR)

In 2011, the Federal EPA issued CSAPR as a replacement for the Clean Air Interstate Rule, a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind non-attainment with the 1997 ozone and PM NAAQS. 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 sub-regional basis.

Petitions to review the CSAPR were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2015, the court found that the Federal EPA over-controlled the SO2 and/or NOx budgets of 14 states. The court remanded the rule to the Federal EPA for revision consistent with the court's opinion while CSAPR remained in place.

In 2016, the Federal EPA issued a final rule, the CSAPR Update, to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The CSAPR Update significantly reduced ozone season budgets in many states, and discounted the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. The rule was challenged in the courts and in 2019, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) remanded the CSAPR Update to the Federal EPA because it determined the Federal EPA had not properly considered the attainment dates for downwind areas in establishing its partial remedy, and should have considered whether there were available measures to control emissions from sources other than generating units. In March 2021, EPA finalized a Revised CSAPR Update Rule to address the Court's concerns. The revised rule reduced the Ozone Season NOx budgets of 12 states beginning in 2021.

3.4.8. Climate Change, CO_2 Regulation and Energy Policy

In 2015, the Federal EPA published the final CO2 emissions standards for new, modified, and reconstructed fossil fuel-fired steam generating units and combustion turbines, and final guidelines for the development of state plans to regulate CO2 emissions from existing sources, known as the Clean Power Plan ("CPP").

The final rules were challenged in the courts. In 2016, the U.S. Supreme Court issued a stay on the final CPP, including all of the deadlines for submission of initial or final state plans, pending a final decision by the U.S. Court of Appeals for the District of Columbia Circuit and any petitions for review to the U.S. Supreme Court. In 2017, the President issued an Executive Order directing the Federal EPA to reconsider the CPP and the associated standards for new sources. The Federal EPA filed a motion to hold the challenges to the CPP in abeyance, and issued a final rule repealing the CPP in 2019. The cases were then dismissed.

In 2019, the Federal EPA finalized the Affordable Clean Energy ("ACE") rule replacing the CPP with new emission guidelines for regulating CO2 from existing sources. The ACE rule required states to evaluate the applicability and effect of implementing specific heat rate improvement measures at coal-fired generating units, and to develop a standard of performance for each affected unit within their jurisdiction. State plans were due in July 2022; however, in January 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE rule and remanded it to the Federal EPA. It is too soon to predict how the Federal EPA will respond to the court's remand. Meanwhile, several groups have petitioned the U.S. Supreme Court to review the D.C. Circuit's vacatur of the ACE Rule.

In 2018, the Federal EPA also proposed to revise 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.

3.4.9. **Coal Combustion Residuals (CCR) Rule**

In 2015, the Federal EPA published a final rule to regulate the disposal and beneficial re-use of Coal Combustion Residuals (CCR), including fly ash and bottom ash generated at coal-fired EGUs and also FGD gypsum generated at some coal-fired plants. The rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria, and additional groundwater monitoring requirements to be implemented on a schedule spanning an approximate four-year implementation period. Certain records must be posted to a publicly available internet site. In 2018, some AEP operating company facilities were required to begin monitoring programs to determine if unacceptable groundwater impacts will trigger future corrective measures. Based on additional groundwater data, further studies to design and assess appropriate corrective measures have been undertaken at two facilities.

In a challenge to the final 2015 rule, the parties initially agreed to settle some of the issues. In 2018, the U.S. Court of Appeals for the District of Columbia Circuit addressed or dismissed the remaining issues in its decision vacating and remanding certain provisions of the 2015 rule. The provisions addressed by the court's decision, including changes to the provisions for unlined impoundments and legacy sites, will be the subject of further rulemaking consistent with the court's decision.

Prior to the court's decision, the Federal EPA issued the July 2018 rule that modifies certain compliance deadlines and other requirements in the 2015 rule. In December 2018, challengers filed a motion for partial stay or vacatur of the July 2018 rule. On the same day, the Federal EPA filed a motion for partial remand of the July 2018 rule. The court granted the Federal EPA's motion. During 2019 and 2020, Federal EPA proposed multiple rulemakings to address the court's decisions and stakeholder concerns. In August 2019, the Federal EPA published a proposal to revise the beneficial use criteria and definition of CCR piles. In December 2019, the Federal EPA published proposed revisions to implement the court's decision regarding timing for closure of unlined surface impoundments and impoundments not meeting the required distance from an aquifer. The comment period closed in January 2020. The Federal EPA also published a proposed federal CCR permit program in February 2020, implementing the Water Infrastructure Improvements for the Nation Act, which will apply in states that do not have a federally approved state CCR program. In March 2020, the Federal EPA published a proposed rule that would allow a facility to make an alternative demonstration to continue operating unlined surface impoundments. In August 2020, the Federal EPA finalized its proposed revisions to 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 Federal EPA. AEP's applications are still pending before Federal EPA.

Because AEP operating companies 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.

Other utilities and industrial sources have been engaged in litigation with environmental advocacy groups who claim that releases of contaminants from wells, CCR units, pipelines and other facilities to ground waters that have a hydrologic connection to a surface water body represent an "unpermitted discharge" under the Clean Water Act (CWA). Two cases were accepted by the U.S. Supreme Court for further review of the scope of CWA jurisdiction. In April 2020, the Supreme Court issued an opinion remanding one of these cases to the Ninth Circuit Court of Appeals based on its determination that discharges from an injection well that make their way to the Pacific Ocean through groundwater may require a permit, if the distance traveled, the length of time to reach the ocean, and other factors make it "functionally equivalent" to a direct discharge from a point source. The second case was also remanded to the lower court.

Prior to the Supreme Court's decision, the Federal EPA opened a rulemaking docket to solicit information to determine whether it should provide additional clarification of the scope of CWA permitting requirements for discharges to ground water, and issued an interpretative statement considering comments received in the rulemaking docket and determined that "releases to groundwater are excluded from the scope of the National Pollutant Discharge Elimination System (NPDES) program, even where pollutants are conveyed to jurisdictional surface waters via groundwater." In December 2020, the Federal EPA issued draft guidance for public comment on applying the outcome of the Supreme Court's decision and consideration of functionally equivalent factors. The impact of these developments on CCR units will be determined by further EPA guidance, additional permitting decisions, and future action from the courts.

3.4.10. Clean Water Act Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants pursuant to section 316(b) of the Clean Water Act that is intended to reduce mortality of aquatic organisms impinged or entrained in the cooling water. The rule was upheld on review by the U.S. Court of Appeals for the Second Circuit. Compliance timeframes are established by the permit agency through each facility's NPDES permit as those permits are renewed and have been incorporated into permits at several AEP facilities. AEP facilities that have had their wastewater discharge permits renewed have been asked to monitor intake flows or to enhance monitoring practices to assure the current technology is being properly managed to ensure compliance with this rule.

3.4.11. Effluent Limitation Guidelines and Standards (ELG)

In 2015, the Federal EPA issued a final rule revising effluent limitation guidelines ("ELG") for generating facilities. The rule established limits on FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater to be imposed as soon as possible after November 2018 and no later than December 2023. These requirements would be implemented through each facility's wastewater discharge permit. The rule was challenged in the U.S. Court of Appeals for the Fifth Circuit. In 2017, the Federal EPA announced its intent to reconsider and potentially revise the standards for FGD wastewater and bottom ash transport water. The Federal EPA postponed the compliance deadlines for those wastewater categories to be no earlier than 2020, to allow for reconsideration. In April 2019, the Fifth Circuit vacated the standards for landfill leachate and legacy wastewater, and remanded them to the Federal EPA for reconsideration. Those standards have not been reissued. In November 2019, the Federal EPA proposed revisions to the standards for FGD wastewater and bottom ash transport water discharges from existing generation facilities. A final rule was published in the Federal Register on October 13, 2020, establishing additional options for reusing and discharging small volumes of bottom ash transport water, provides an exception for retiring units, and extends the compliance deadline to a date as soon as possible beginning one year after the rule is published but no later than December 2025. The Company has assessed technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting for FGD wastewater and bottom ash transport water. Permit modifications for affected facilities were filed in January 2021 that reflect the outcome of that assessment.

3.4.12. Waters of the United States ("WOTUS") Rule

In 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of "waters of the United States" in light of several U.S. Supreme Court cases. Various parties challenged the 2015 rule in different U.S. District Courts, which resulted in a patchwork of applicability of the 2015 rule and its predecessor. In December 2018, the Federal EPA and the U.S. Army Corps of Engineers proposed a replacement rule. In September 2019, the Federal EPA repealed the 2015 rule. The final replacement rule was published in the Federal Register in April 2020 and became effective in June 2020. The final rule limits the scope of CWA jurisdiction to four categories of waters, and clarifies exclusions for ground water, ephemeral streams, artificial ponds, and waste treatment systems. Challenges to the final rule and requests for a preliminary injunction have been brought by states and other groups in multiple U.S. District Courts. In June 2021, federal EPA announced its intent to reconsider and revise the rule. Meanwhile, in August 2021, a District Court in Arizona vacated the rule and remanded it to federal EPA. Federal EPA and the Army Corps of Engineers have indicated that in light of the District Court's order, the agencies will halt implementation of the 2020 rule and will interpret "Waters of the United States" consistent with the pre-2015 regulatory regime until further notice. The Company is monitoring these various proceedings.

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.

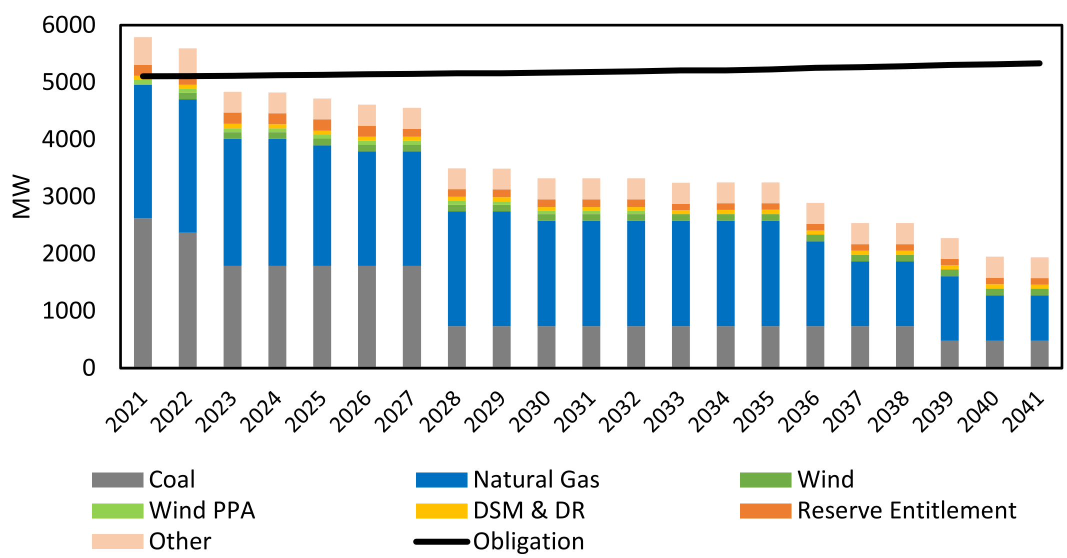
In September 2020, the Corps issued for public comment the proposed renewal of all General Nationwide Permits. As part of that proposal the Corps narrowed the focus of NWP 12 to only oil and natural gas pipeline activities. The Corps proposed two new Nationwide Permits governing electric utility line 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

Figure 16 illustrates the starting capacity needs of SWEPCO through 2041. SWEPCO's capacity need is the difference between the load obligation and the minimum reserve margin (denoted by the black line), and the capacity of the existing generation resources by year (denoted by the bars).

The capacity gap begins to emerge beginning in 2023, due to planned retirement of existing units. Specifically, SWEPCO plans to retire five units in the next five years: Dolet Hills (lignite) unit 1 12/31/2021; Pirkey (lignite) unit 1 in 2023; Lieberman (gas steam) unit 3 in 2023 and unit 4 in 2025[6]; and the Arsenal Hill (gas steam) unit 5 in 2026. Additionally, 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. The other agreements all 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.

Figure 16 SWEPCO "Going-In" SPP Capacity Position and Obligation



SWEPCO assumes a minimum reserve margin of 12.0%[7] in its resource planning. The minimum reserve margin is the result of SPP's own system reliability assessment. Figure 17 illustrates SWEPCO's net capacity position with respect to the Company's load obligation, and with respect to SPP's 12% reserve margin requirement.

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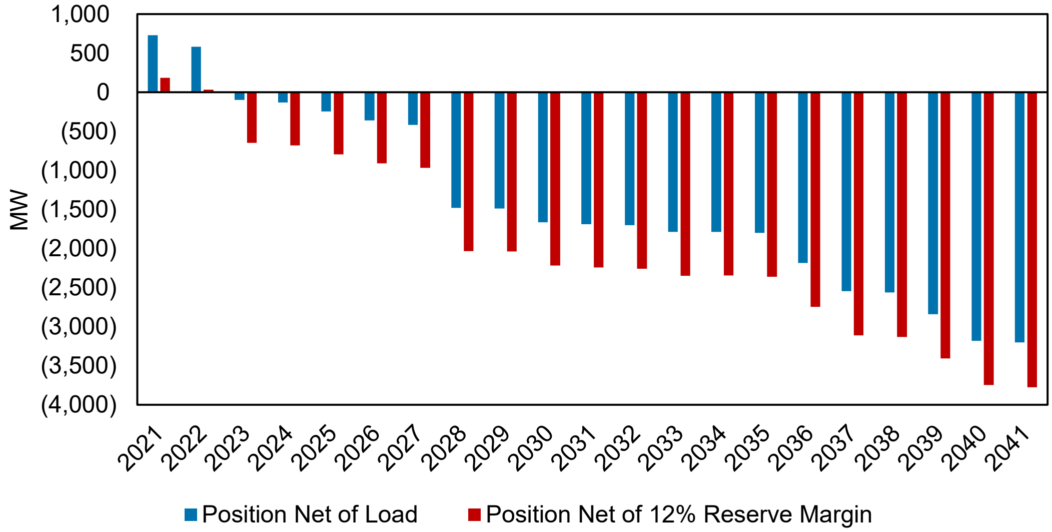
6 On December2, 2021, AEP/SWEPCO decided to delay the planned retirement of Lieberman Units 3 and 4 in December 2022 and December 2024 respectively, to no later than December 31, 2026. Given the timing of this decision, this was unable to be represented in this IRP. However, SWEPCO intends to update the information in its upcoming Louisiana IRP as the extension provides for a smooth transition to preferred plan resources in 2026.

7 Per Section 4 of the "SPP Planning Criteria" (Latest Revision: April 2, 2021).

Figure 17 SWEPCO Capacity Position net of SPP Reserve Obligation



SWEPCO also considered winter seasonal requirements as part of the 2021 IRP. One market scenario, the Focus on Resiliency case (discussed in Section 7), enforces a 12% planning requirement in winter and changes to the resource adequacy contribution of different technologies. 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.

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 ten other companies at approximately 90 interconnection points, of which approximately 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. This 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 constrained when generation is dispatched in a manner substantially different from the original design of utilizing local generation to serve local load.

SPP has made efforts to solve seams issues, and SPP and MISO have engaged in a coordinated study process in an effort 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 2021 STEP summarizes 2020 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. Integrated Transmission Planning (ITP),
4. Balanced Portfolio,
5. High Priority Studies,

6. Sponsored Upgrades,
7. Interregional Coordination, and
8. Integrated Transmission Planning 20-Year Assessment

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; and
- Zonal-Sponsored – Projects sponsored by facility owner with no Project Sponsor Agreement.

The 2021 STEP[8] identified 386 transmission network upgrades with a total cost of approximately $3.19 billion. At the heart of SPP's STEP process is its ITP process, which represented approximately 68% of the total cost in the 2021 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 ITP10 assessment 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. Also, in the ITP Near-Term assessment, the reliability of the SPP transmission system was studied, resulting in Notification to Construct ("NTC") letters issued by SPP for upgrades that require a financial commitment within the next four years.

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 sponsored upgrades by SPP transmission owners. An analysis of the cost of the upgrades

[8] The 2021 STEP is available at: https://www.spp.org/documents/56611/2021%20step%20report.pdf

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 and regions include: Chisholm – Woodward/Border tie 345 kV line. This project allows more east Texas/ west Oklahoma bulk transfer capabilities.

- Chisholm – Woodward/Border tie 345 kV line. This project allows more east Texas/ west Oklahoma bulk transfer capabilities.
- Sooner to Wekiwa 345 kV line build. This project was a competitive project awarded to Transource and relieves congestion in the west Tulsa area for the outage of Cleveland to Tulsa North 345 kV line.

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 AEP Transmission System serves approximately 1,300 MW of load in the Northwest Arkansas area, about 53% of which is Arkansas Electric Cooperative Commission ("AECC") load. This load is supplied primarily by the SWEPCO and AECC jointly-owned Flint Creek generating plant, the SWEPCO Mattison generating plant, the Grand River Dam Authority ("GRDA")-Flint Creek 345 kV line, and the Clarksville-Chamber Springs 345 kV line. Wal-Mart's international headquarters and its supplying businesses' offices and Tyson's headquarters are all located in this area. The Siloam Springs (GRDA)-Siloam Springs (SWEPCO) 161 kV line has been upgraded to a larger conductor with improved thermal capacity.
- **McAlester, Oklahoma area:** The McAlester City to Atoka 69 kV line has been rebuilt with new structures and upgraded to a larger conductor with improved thermal capacity.
- **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. Additionally, the SPP recently announced that millions of customers in five states will benefit from a 345 kV transmission line project in eastern Oklahoma that is being constructed by Transource Energy, a partnership between AEP and Evergy.

SPP awarded the FERC 1000 competitive transmission project, Sooner-Wekiwa, which 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.

4.5. SWEPCO Distribution System Overview

SWEPCO serves approximately 543,000 customers across 20,701 square miles of Arkansas, Louisiana, and Texas. This includes approximately 462,000 residential, 73,400 commercial, 7,200 industrial, and 500 other customers. SWEPCO's Distribution Operations organization includes five districts: Longview, Fayetteville, Texarkana, Shreveport, and Valley. SWEPCO's distribution system includes approximately 21,700 overhead circuit miles and approximately 3,500 underground circuit miles. SWEPCO's distribution system includes approximately 19,973 primary miles and 5,290 secondary miles. Distribution Investments

SWEPCO's Distribution Operations organization includes four functional support departments: Risk and Project Management (which includes distribution automation design and installation), Distribution Systems, Continuous Improvement, and Distribution Dispatch. 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 an approximately $245M in capital investment in SWEPCO's distribution grid over the next five years. Table 2 below provides an overview of this plan.

Table 2. SWEPCO Grid Transformation and Infrastructure Program

Project Type	**Estimated Spend (Millions $)**
Capacity	70.24
Grid Modernization	58.82
Service Reliability	14.98
System Improvement	100.71
Total	244.75

4.6. Impacts of New Energy Future

The current power system is designed for a one-way power flow with electricity flowing from transmission-connected generators through the transmission system down to the distribution system to customers. This is changing. The new energy future will require changes in how transmission, distribution and generation planning are conducted for SWEPCO to continue delivering on our objectives of customer affordability, rate stability, system reliability, and positive local impacts and sustainability. This section discusses the impact of emerging trends of the new energy future that will impact future planning process and how SWEPCO is evolving its planning capability to address future challenges. The emerging trends include:

- Increasing new transmission-connected additions;
- Electrification; and
- Increased DERs.

4.6.1. New Transmission-Connected Generation Capacity

Integration of additional transmission-connected generation capacity within the AEP-SPP zone will likely require significant transmission upgrades. At most locations, any additional generation resources will aggravate existing transmission constraints. Specifically:

- **Western Oklahoma/Texas Panhandle:** This area is one of the highest wind density areas within the SPP footprint and the country. The potential wind farm capacity for this area has exceeded 10,000 MW and has potential for substantial additional growth. Many wind farms are in operation, and several more are in the development stages. Wind generation additions in the SPP footprint in this region will likely require significant transmission enhancements, including extra high voltage ("EHV") line and station construction, to address thermal, voltage, and stability constraints.

- **SPP Eastern Interface:** There are only five east-west EHV lines into the SPP region, which stretches from the Gulf of Mexico (east of Houston) north to Des Moines, Iowa. This limitation constrains the quantity of imports and exports along the eastern interface of SPP with neighboring regions. It also constrains the quantity of transfers from the capacity rich western SPP region to the market hubs east and north of the SPP region. Significant generation additions near or along the SPP eastern interface would likely require significant transmission enhancements, including EHV line and station construction, to address thermal and stability constraints should such generation additions adversely impact existing transactions along the interface.

Integration of generation resources at any location within the AEP-SPP zone will require significant analysis by SPP to identify potential thermal, short circuit, and stability constraints resulting from the addition of generation. Depending on the specific location, EHV line and station construction, in addition to connection facilities, could be necessary. Other station enhancements, including transformer additions and breaker replacements, may be necessary. Some of the required transmission upgrades could be reduced or increased in scope if existing generating capacity is retired concurrent with the addition of new capacity.

4.6.2. Distributed Energy Resources

Increasing levels of DERs present challenges for SWEPCO from a distribution planning perspective. Higher penetration of DERs can potentially mask the true load on distribution circuits and stations if the instantaneous output of connected DERs is not known, which can lead to under-planning for the load that must be served should DERs become unavailable or reverse power flow during periods when demand is low but generation from DERs is high. Increased levels of DERs could lead to a requirement that DER installations include smart inverters so that voltage and other circuit parameters can be controlled within required levels. Additional performance monitoring capabilities for DER systems will facilitate accurate tracking and integration of DER generators into the existing resource mix. Currently, DER applicants in SWEPCO's jurisdictions are required to fund any improvements needed to mitigate impacts to the operation and power quality of affected distribution stations and circuits. As DER penetration grows there is potential that the "next" applicant would be required to fund improvements that are a result of the aggregate impacts of previous DER customers because the incremental impact of the "next" customer now drives a need for improvements.

4.7. Journey to Fully Integrated Planning Process

Technology continues to change rapidly providing a greater number and more dynamic set of supply-side and demand-side resource options. It appears that this trend will continue. Resource options are becoming more distributed in nature and customers have increasingly more economic options available to provide some of their own energy needs. These trends impact consumption patterns, load assumptions, and increase the overall complexity of maintaining the stability and reliability of the distribution system. The result is that changes are needed across the planning and operations functions to continue to provide safe and reliable service to our customers.

4.7.1. Planning

System planning across generation, transmission, and distribution (GT&D) is becoming more dynamic and integrated. This creates increasing challenges to predicting the future.

SWEPCO believes that continuing to deliver safe, reliable, and affordable energy in the future power system will require a more integrated approach between transmission, distribution, and resource planning. Effective January 1, 2021, AEP reorganized its central planning functions with the formation of the Grid Solutions business unit. AEP combined integrated generation, transmission, and distribution planning to create this single unit. These changes will help foster the collaboration of information exchanges and input assumptions across the various planning functions. To assist with the successful transition to a comprehensive, holistic approach to integrated GT&D planning, AEP has engaged an external consultant to leverage their expertise in this area and assist in (a) the evaluation of AEP's current planning processes and (b) the development of a roadmap that leads to a fully integrated planning process. AEP also established a sponsorship team at the leadership level whose focus is on evolving tools, processes, and standards to thrive in a world with dynamic system planning requirements. The longer-term goal is to provide clean, affordable, and reliable energy with customer centric options.

4.7.2. **Operations**

AEP and SWEPCO are actively taking steps to ensure the right operational systems are in place to manage the increasing complexity of the grid,

AEP's current operational systems (OMS & DMS) are approaching end of life and are unable to support the added complexity caused by DER two-way power flow and other advancements in grid technology (such as automated circuit reconfiguration, etc.). The Company is pursuing a new suite of operational systems that will offer the flexibility needed to adapt and adjust to continued changes in this space.

AEP has issued a RFP to select an Advanced Distribution Management System ("ADMS") product with embedded operational-side Distributed Energy Resource Management System ("DERMS") capabilities by the end of 2021, with implementation taking place over the next several years.

The core ADMS will offer a seamless network model that will provide the framework and functionality needed to effectively manage the distribution system and provide greater situational awareness to our operators. The DERMS capabilities will fully integrate DER resources into the core ADMS, enabling management of the grid as a "system" across T&D.

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 five categories: base / intermediate alternatives, peaking alternatives, renewable alternatives, advanced generation alternatives and long-duration storage alternatives. As part of the consideration for advanced generation alternatives, this IRP also considers the potential opportunity to transition natural gas fueled technologies to utilize hydrogen when the hydrogen supply chain is sufficiently developed.

Unless stated otherwise, SWEPCO relied on EIA's 2021 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 2020 National Renewable Energy Laboratory's ("NREL") annual technology baseline ("NREL ATB 2020") report.[9] 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.

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

9 NREL Electricity Annual Technology Baseline (ATB) 2020: https://atb-archive.nrel.gov/electricity/2020/data.php

generate steam to drive a steam turbine to generate additional electricity, increasing generation efficiency.

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.

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[10] in the gas steam, and can potentially be retrofitted to burn 100% hydrogen when the hydrogen supply chain is sufficiently developed. Section 5.5.3 provides further details on the modelling assumptions associated with retrofitting NGCC units to burn hydrogen exclusively.

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 430 MW capacity and the H-class turbine multi-shaft configuration with 1,100 MW capacity.

Overnight capital cost assumptions for NGCC options are shown Figure 18. The variable operations and maintenance cost ("VOM"), the fixed operations and maintenance cost ("FOM") and heat rate assumptions are shown in Table 3.

Figure 18 Capital Cost Assumptions for NGCC

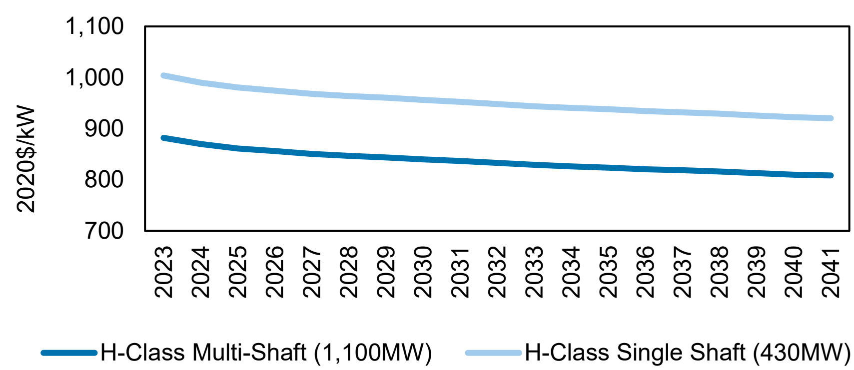


Table 3 Operating and Heat Rate Assumptions for NGCC

		H-Class Multi-Shaft (1,100 MW)	H-Class Single Shaft (430 MW)
VOM	$2020 / MWh	1.88	2.56
FOM	$2020 / kW-yr	12.26	14.17
Heat Rate	Btu / kWh	6,370	6,431

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

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.

More recently, greater amounts of intermittent renewable generation in the market combined with more extreme weather patterns have necessitated more flexible resources. For example, an unanticipated drop in wind generation during the day will require quick response from other generators to keep supply and demand in balance. A string of extreme cold weather days will require top-up generating capacity beyond the few hours each year traditionally supplied by peak generators. Certain peaking technologies can also provide ancillary services such as frequency response, black start, and inertia that help keep the system reliable. 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.

As discussed in Section 5.2.1, recent turbines can burn up to 30% hydrogen by volume 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 modelling 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.

The NGCT overnight capital cost assumptions are shown in Figure 19. FOM, VOM, and heat rate assumptions are shown in Table 4.

Figure 19 Capital Cost Assumptions for NGCT

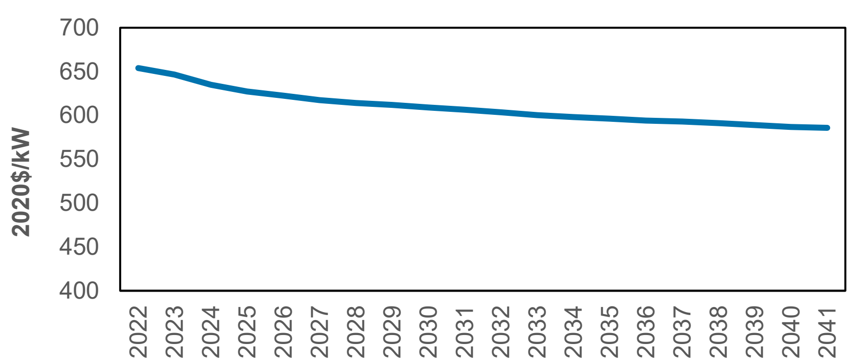


Table 4 Operating and Heat Rate Assumptions for NGCT

		F-Class CT (240 MW)
VOM	$2020 / MWh	0.61
FOM	$2020 / kW-yr	7.04

Heat Rate	Btu / kWh	9,905

5.3.2. Aeroderivatives (AD)

Aeroderivatives units are aircraft jet engines used for power generation. Their operating characteristics make them well suited with high renewable penetration as they can quickly response to significant shift 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 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 100 MW units as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints.

The AD overnight capital cost assumptions are shown in Figure 20. FOM, VOM, and heat rate assumptions are shown in Table 5.

Figure 20 Capital Cost Assumptions for AD

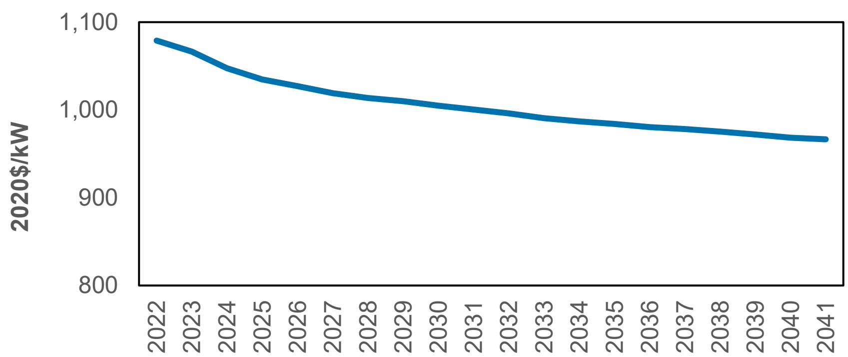


Table 5 Operating and Heat Rate Assumptions for AD

		AD (100 MW)
VOM	$2020 / MWh	4.72
FOM	$2020 / kW-yr	16.38
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 by 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 20 MW units as a standard dispatch resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints.

The RE overnight capital cost assumptions are shown in Figure 21. FOM, VOM, and heat rate assumptions are shown in Table 6.

Figure 21 Capital Cost Assumptions for RE

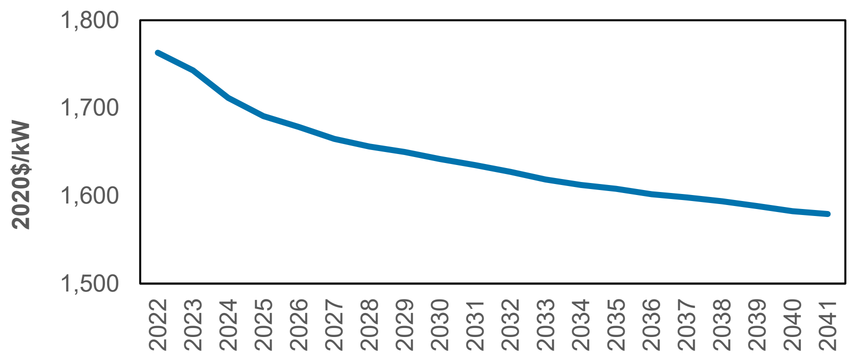


Table 6 Operating and Heat Rate Assumptions for RE

		RE (20 MW)
VOM	$2020 / MWh	5.72
FOM	$2020 / kW-yr	35.34
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 modeled in AURORA 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 0.3% per day, maximum of one cycle per day, a minimum charge level of 10%, and a maximum charge level of 90%. 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 46-69% by 2041, depending on the amount of renewable generation in the scenario (see section 7.3).

The overnight capital cost assumptions for Li-ion batteries in 2021 are shown in Figure 22. Figure 23 shows the assumed FOM for a Li-ion battery built in that specific year.

Figure 22 Capital Cost Assumptions for Li-Ion

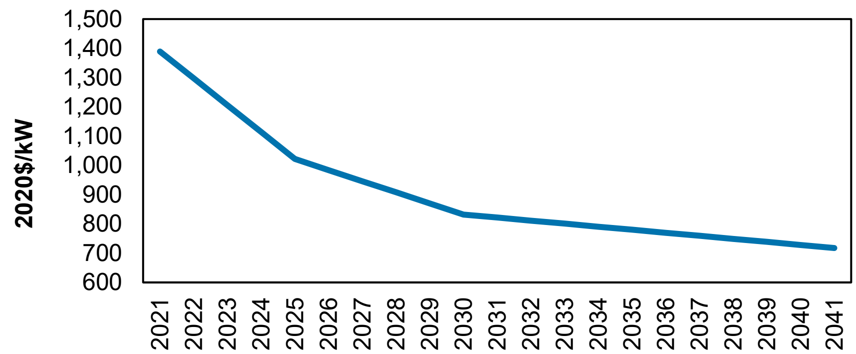
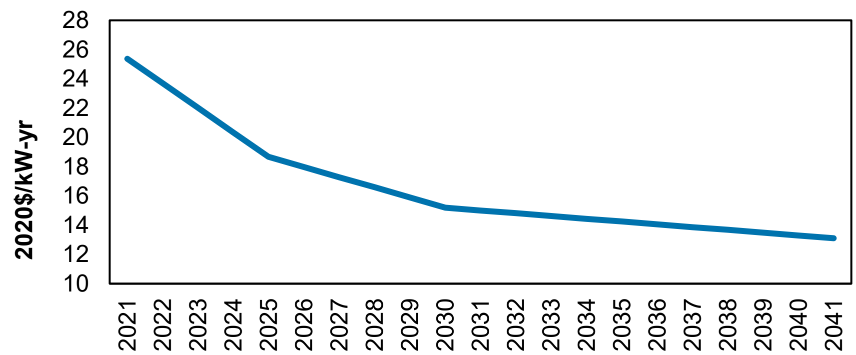


Figure 23 FOM Assumptions for Li-Ion



5.4. Renewable Alternatives

The cost of renewable generation alternatives is expected to continue to decline, providing an opportunity to increase affordable clean energy to address future electricity needs, consistent with SWEPCO's aim of enabling a greener future for all. These 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. The impact of increased renewable generation on the electricity system is further discussed in Section 7.5.2.

In this IRP, two renewable alternatives considered are onshore wind and utility-scale photovoltaic. These two technologies are made available as resource options in AURORA. In addition, AURORA can also choose to pair either onshore wind or utility-scale 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 from the end of 2024. It is modeled as a generation resource dispatching according to a generic production profile representative of the region with an average capacity factor of 44%. As an intermittent resource, wind may not be generating at full capacity during the time of system peak.

Capacity credit for wind is assumed to be 14.7% across all months. Both the hourly production profile, average capacity factor, and capacity values are estimated based on historical production data of existing AEP wind resources in SPP.

The overnight capital cost for onshore wind in 2023 is based on EIA AEO 2021. The cost reduction curve from NREL ATB 2020 is applied to the capital cost in 2023 to project the capital costs for 2024 and beyond, as shown in Figure 24 below.

Figure 24 Capital Cost Assumptions for Onshore Wind

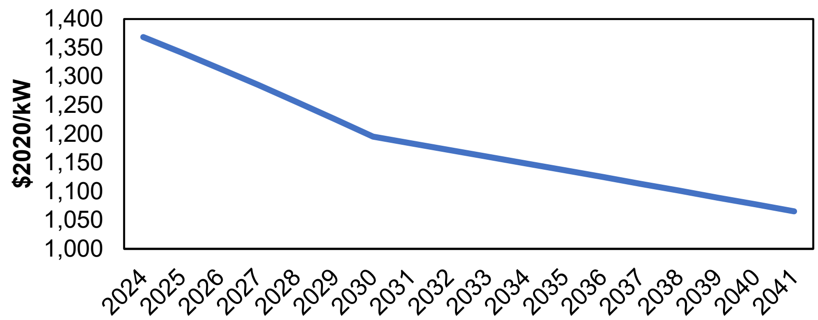
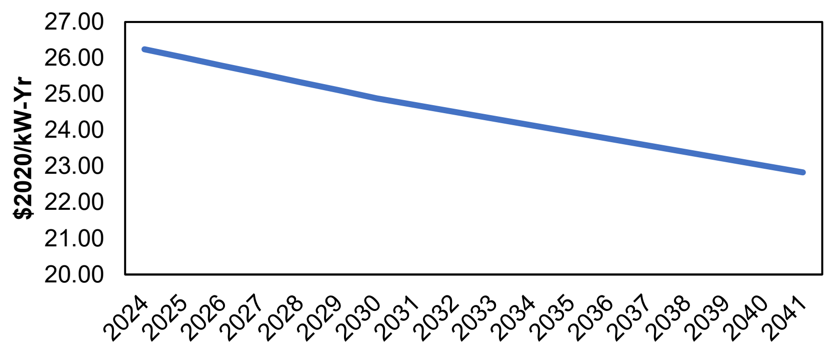


Figure 25 illustrates the FOM cost assumptions for onshore wind, excluding property tax and insurance, for a wind farm built in that specific year. Property tax and insurance premium are modelled as a positive adder to the FOM costs.

Figure 25 FOM Assumptions for Onshore Wind



Sites with high quality wind resources are often in rural areas far from demand centers. The reliance on transmission networks to deliver wind energy leads to transmission losses as well as network congestion. To account for the full cost of wind resources, a congestion charge is added as a variable cost adder for new wind projects at a rate of $2 / MWh for the first 2 GW, and $5 / MWh thereafter.

Projects whose construction begins by the end of 2021 are eligible for a Production Tax Credit ("PTC"), added to the project value at a rate of 60% of the PTC, or $15 / MWh[11], which is implemented in AURORA as a negative variable cost adder. PTC levels vary by scenario, described further in Section 7.3. Additional new wind is limited to annual amounts of 1,600 MW per year with a total limit of 4,400 MW over the modeling period.

11 In 2021 dollars

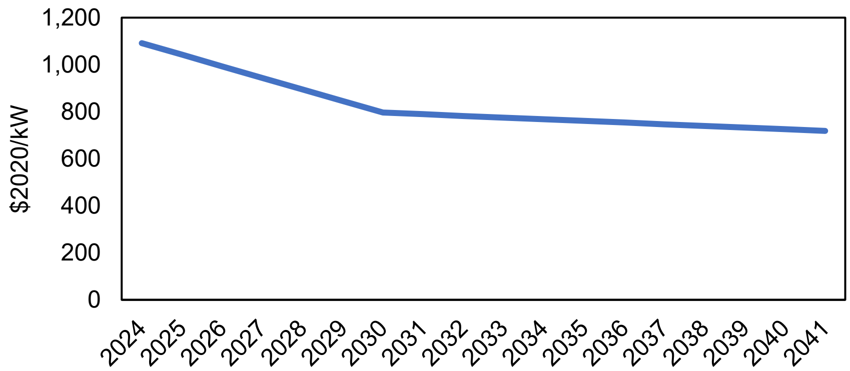
5.4.2. Solar

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 2024. 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 26.6%. Solar capacity credit for summer is estimated at a percentage of ICAP. Currently that percentage is 60% but it declines to 27-34% by 2041, depending on the scenario (see Section 7.5.2). The hourly production profile, average capacity factor and capacity values are estimated based on historical production data of existing AEP solar resources within SPP.

The overnight capital cost assumptions for solar PV are shown in Figure 26.

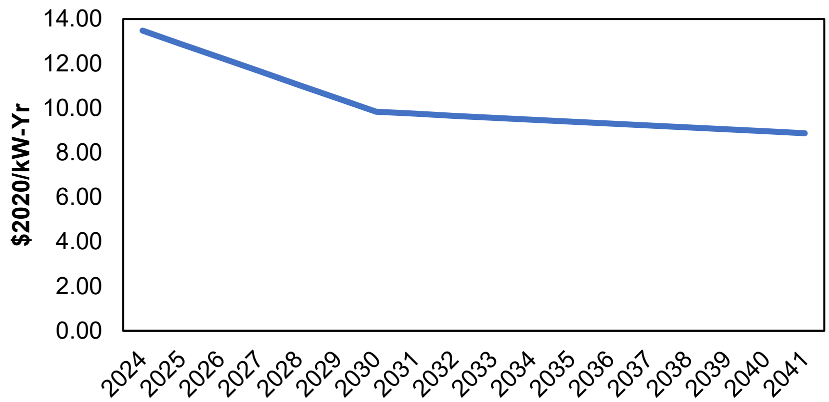
Figure 26 Capital Cost Assumptions for Utility-Scale Solar PV



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 2023, 26% for projects entering service before the end of 2025, and 10% thereafter. In order to comply with requirements for regulated utilities to normalize tax credit benefits over the life of owned projects, an adjustment cost of $5.61/MWh was applied for the lifetime of owned solar projects which received 26% ITC benefit. An adjustment of $6.08/MWh was applied to solar+storage projects with a 3-1 solar-storage ratio. ITC levels vary by scenario, described further in see Section 7.4.

Figure 27 shows the FOM cost assumptions for onshore wind, excluding land lease, property tax and insurance, for a wind farm built in that specific year. Land lease, property tax and insurance premium are modelled as a positive adder to the FOM costs on a levelized basis.

Figure 27 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 portfolio 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. 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.

SMR 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.

SMR 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") is taken from the EIA AEO 2021, adjusted to include AEP overheads. 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[12]. 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. Figure 28 below shows the assumed overnight capital cost of SMR cost over time.

Figure 28 Capital Cost Assumptions for SMR

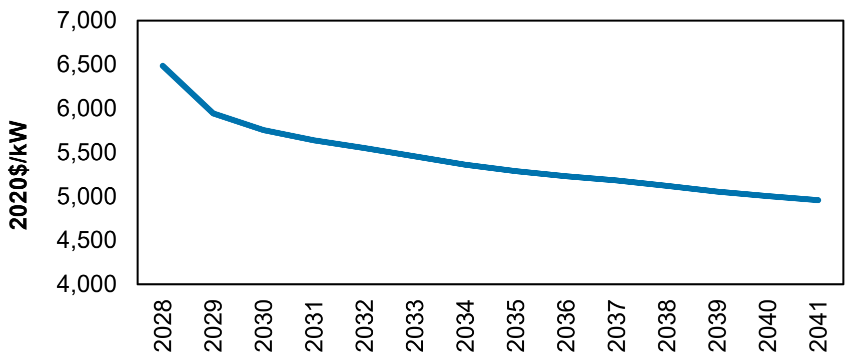


Table 7 Operating and Heat Rate Assumptions for SMR

		SMR
VOM	$2020 / MWh	3.02
FOM	$2020 / kW-yr	95.48
Heat Rate	Btu / kWh	10,455

Like traditional nuclear, SMR cannot adjust its output to match fluctuating electricity demand easily. Therefore, SMR is modeled in AURORA as a must-run resource. It is assumed that SMR will not be available for commercial deployment until 2032.

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 from 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. The passage of Section 45Q legislation provides a tax credit of $50 / t of CO_2 sequestered. This incentive is implemented in AURORA as a negative variable cost adder, improving dispatch economics.

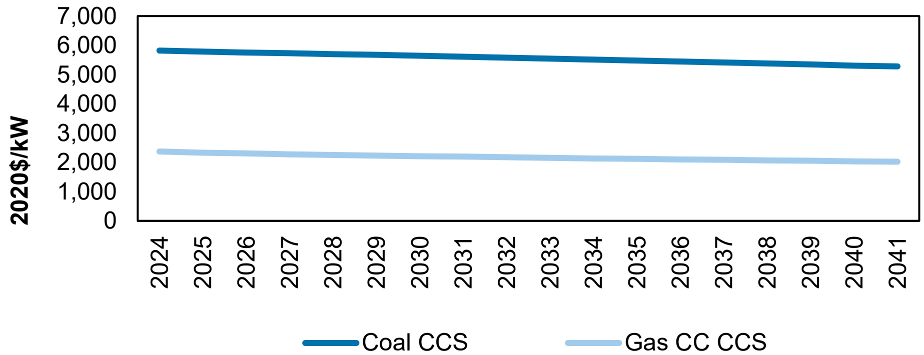
12 Department of Energy (2013), Small Modular Nuclear Reactors: Parametric Modeling of Integrated Reactor Vessel Manufacturing Within a Factory Environment Volume 2, p. 59

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 430 MW H-class combined-cycle natural gas turbine with 90% carbon capture.

The assumptions on overnight capital costs for new build CCS are shown in Figure 29. FOM, VOM, and heat rate assumptions are shown in Table 8 below.

Figure 29 Capital Cost Assumptions for New Build CCS



Note – Coal CCS represents a 665 MW ultra-supercritical unit with 90% capture rate; Gas CC CCS represents a 430 MW single shaft CCGT with 90% capture rate

Table 8 Operating and Heat Rate Assumptions for New Build CCS

		Coal	Gas
VOM	$2020 / MWh	11.03	5.87
FOM	$2020 / kW-yr	59.85	27.74
Heat Rate	Btu / kWh	12,507	7,124

Retrofit options

It is also possible for AURORA to choose to retrofit SWEPCO's 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 9 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	$2020 / kW post-retrofit capacity	870
Incremental FOM	$2020 / kW post-retrofit capacity	19.6
Incremental VOM	$ / kWh	1.2

The cost and performance parameters for retrofit coal units are taken from the Environmental Protection Agency's ("EPA") modelling assumptions in its power sector modeling platform[13]. The applied parameters vary based on the capacity and heat rate of the coal unit as shown in Table 10 below. The table shows significant heat rate and capacity penalties on coal units with 400 MW capacity; coal units with lower than 400 MW capacity are assumed to be ineligible for retrofit due to unfavorable economics.

Table 10 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 11 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 sites for SWEPCO power plants. 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 11 Carbon transport and storage schedule ($2020 / t$CO_2$)

	Texas	Oklahoma	Kansas	Missouri	Arkansas	Colorado	New Mexico
Storage Cost	9.86	4.93	4.93	9.86	9.86	9.86	14.79
Transport Cost	21.54	13.57	19.16	16.32	10.31	29.11	36.18
Total Cost	**31.40**	**18.50**	**24.09**	**26.18**	**20.17**	**38.97**	**50.97**

5.5.3. Hydrogen (H_2)

Two key components that make up a "green" hydrogen system[14] are the polymer electrolyte membrane ("PEM") electrolyzer and the hydrogen gas combusting turbine ("H_2 CT").

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

13 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

14 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 CO2 byproduct.

- **Energy density**: H_2 is one third 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
- **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[15], IEA[16], EPRI[17], DOE[18] and the International Council on Clean Transportation[19]. 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 30, FOM for electrolyzer in Figure 31, efficiency for electrolyzer in Figure 32. Other parameters shown in Table 12 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 twice the EIA AEO 2021 estimate for NGCT, reflecting additional costs for maintaining a system with high levels of water and steam injection for emission control.

15 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

16 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

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

18 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

19 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 30 Capital Cost Assumptions for PEM Electrolyzer and H_2 CT Components

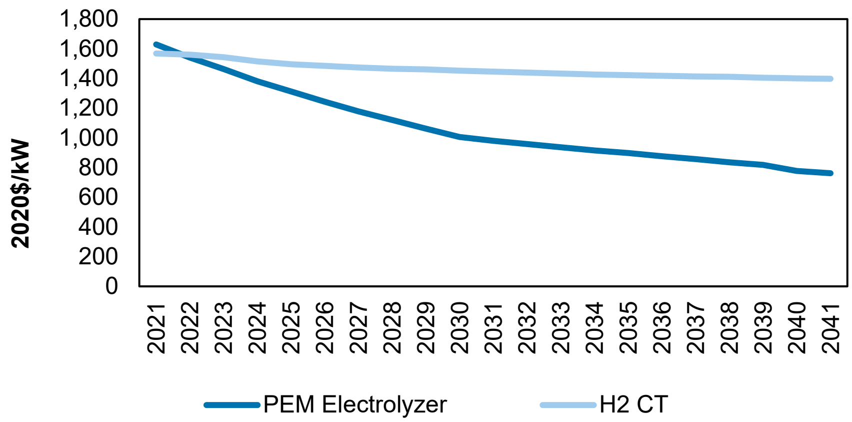


Figure 31 FOM Assumptions for PEM Electrolyzer

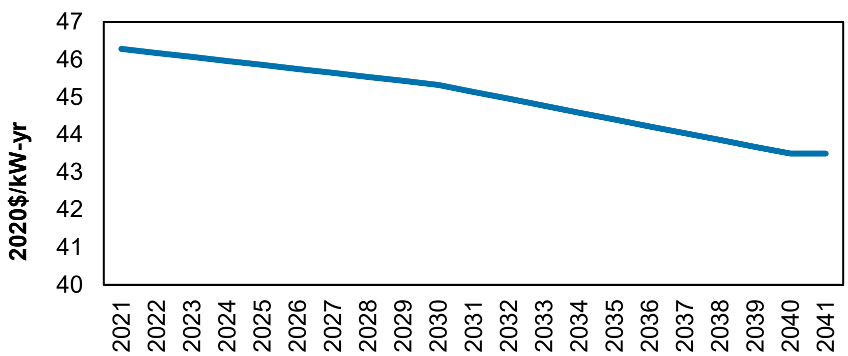


Figure 32 Efficiency Assumptions for PEM Electrolyzer

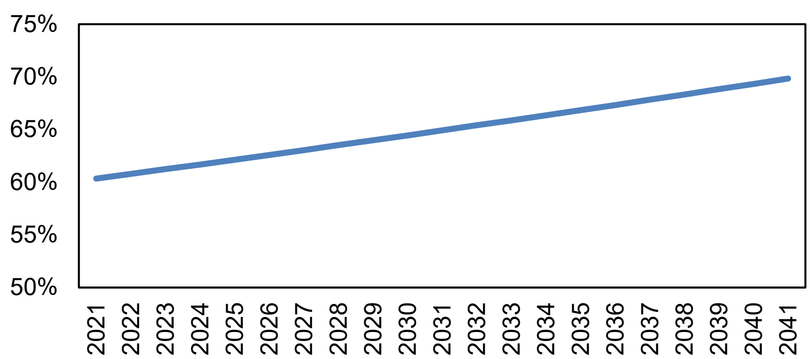


Table 12 Operating and Heat Rate Assumptions for PEM Electrolyzer and H_2 CT

		PEM Electrolyzer	**H_2 CT**
VOM	$2020 / MWh	0.50	0.61
FOM	$2020 / kW-yr	Figure 31	7.04
Heat Rate	Btu / kWh	Figure 32	9,655

Hydrogen is made available in AURORA starting in 2030. The year is based on statements by various major power equipment providers committing to provide 100% H_2 CTs by 2030. Hydrogen resources are offered in AURORA in three possible configurations:

- **Integrated H_2 chain** - SWEPCO owns both the electrolyzer and the H_2 CT, thus the modeled cost is a combined cost of both elements. The resource is modeled as a storage option. AURORA optimizes the production of H_2 and the firing of H_2 against projected SPP hourly electricity prices, considering efficiency losses at both the PEM electrolyzer and H_2 CT. The resource is assumed to have no self-discharge and no cycling limits;
- **Third-party H_2 supply** – SWEPCO only owns the H_2 CT, thus the modeled costs comprise the capital cost, FOM and VOM of H_2 CT only with fuel prices being 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. Relative to the first configuration, this configuration will have lower capital costs and FOM but higher variable fuel cost. 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;
- **Third-party H_2 + retrofit CT** – This is similar to the second configuration except that instead of building a new H_2 CT unit AURORA can choose to retrofit an existing NGCT unit to burn 100% H_2 fuel. Retrofitting an existing NGCT unit will incur additional capital costs due to the difference in operating characteristics between natural gas and H_2 as discussed earlier. The retrofit will incur a one-time cost of 15% of the capital cost of the new CT cost, based on a bottom-up analysis of the costs of the H2 accessory system and the selective catalytic reduction system as well as a study on the H_2 retrofit cost in the UK. Post-retrofit, the FOM, VOM and heat rate are assumed to be the same as for a new build H_2 CT.

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.

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.

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 33 and Figure 34 below.

Figure 33 Capital Cost Assumptions for 20-hour duration PTES

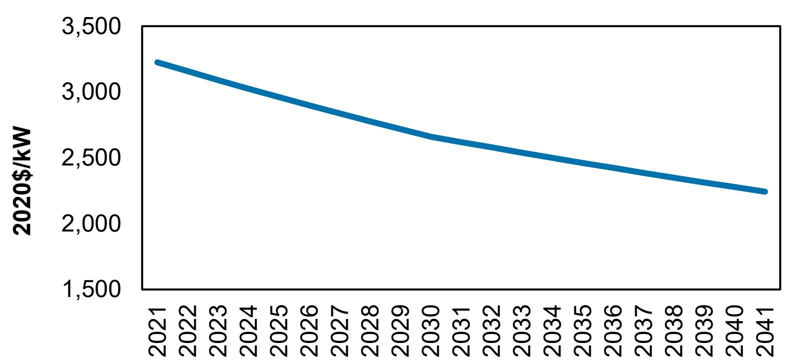
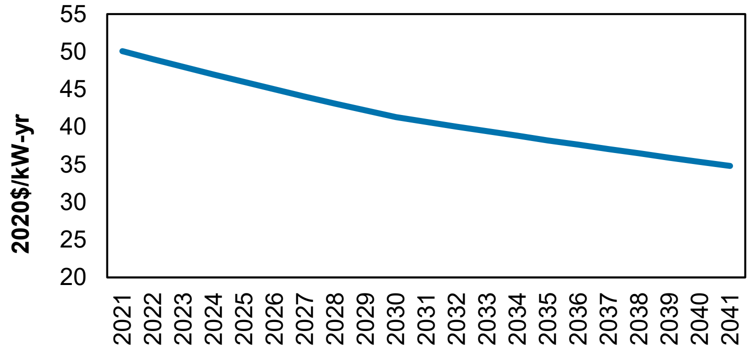


Figure 34 FOM Assumptions for 20-hour duration PTES



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.

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 35 and Figure 36 below.

Figure 35 Capital Cost Assumptions for 20-hour duration VFB

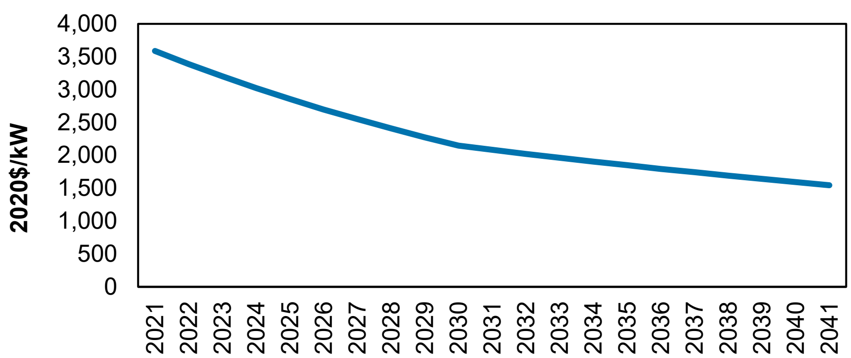
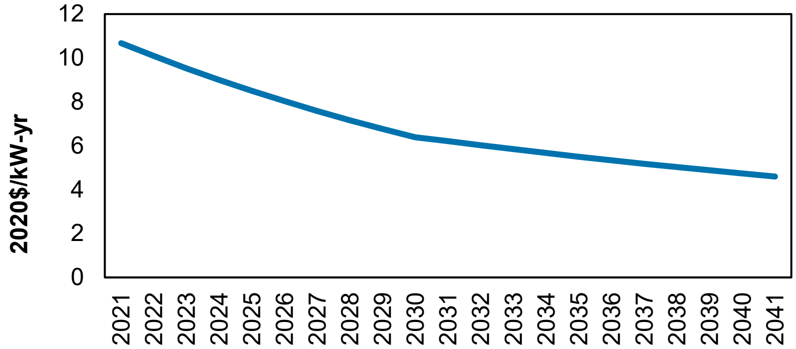


Figure 36 FOM Assumptions for 20-hour duration VFB



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.

The forecasted CAES overnight capital cost and FOM is based on an average of a wide range of sources including reports from DOE, PNNL, BEIS and academic studies. Reflecting the relative maturity of the technology, the FOM and capital cost are assumed to be constant in real terms at 2020$17.19 / kW-yea and 2020$1,771 / kW, respectively.

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 2023, are in addition to the existing demand-side programs that run until 2022 and are discussed in Section 3.3.1.

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 13 provides a list of current and anticipated EE measures for both the residential and commercial sectors.

Table 13 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. Modelling 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 1% 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 14 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 14 Energy Efficiency Bundles Statistics

	LCOE ($ / MWh)			2023 Gross Total Energy Savings Potential (MWh)	Energy Saving as % of Total 2023 Load
	Min	Mean	Max		
Residential					
Low	3	15	30	236,127	2.0%
Medium	34	49	64	233,140	2.0%
High	72	94	129	463,766	3.9%
Commercial					
Low	3	6	13	185,165	2.9%
Medium	15	27	50	192,440	3.0%
High	971	1306	1678	299,322	4.7%

Table 15 provides incremental gross average yearly energy savings potential for each bundle overtime.

Table 15 Incremental Gross Average Yearly Energy Savings

	Time Period (MWh / Year)		
	2023-2027	2028-2032	2033-2037
Residential			
Low	37,668	4,748	5,993
Medium	52,114	12,472	6,826
High	52,938	11,359	6,333
Commercial			
Low	33,880	2,622	0
Medium	11,115	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 16 shows the composition of individual EE measures comprising the low-cost bundle for residential sector for 2023-27 and 2028-32. The individual EE measures are from four electricity end-uses: residential heating, residential cooling, lighting and other.[20] 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.

Table 16 Composition of Individual EE measures in Low Residential Bundle by Year

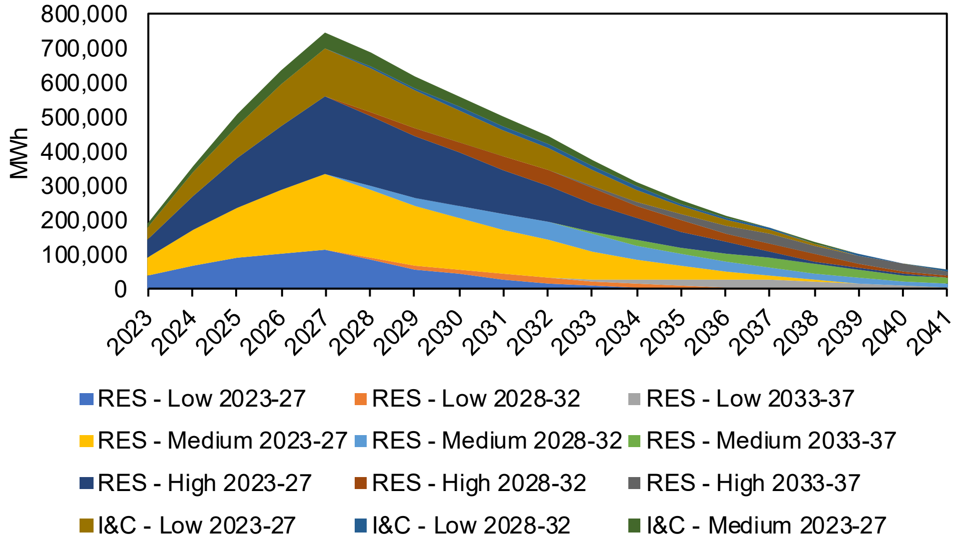
		Gross Incremental Energy Savings Potential (MWh)	
Individual EE measure	**Electricity End Use**	**2027**	**2032**
Low Flow Showerheads	Other	17,527	1,264
Screw-In - Halogen to LED	Lighting	11,682	0
Faucet Aerators	Other	4,179	301
Duct Insulation	Heating + Cooling	12,325	2,477
Pipe Insulation	Other	9,977	720
Energy Star Television	Other	44,922	7,584
Behavioral Program	All	68,685	1,006
Duct Repair	Heating + Cooling	19,046	10,390
Total		**188,342**	**23,472**

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 37 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 2027, net annual energy savings potential available to AURORA accounts for 3.3% of total energy demand in the year.

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

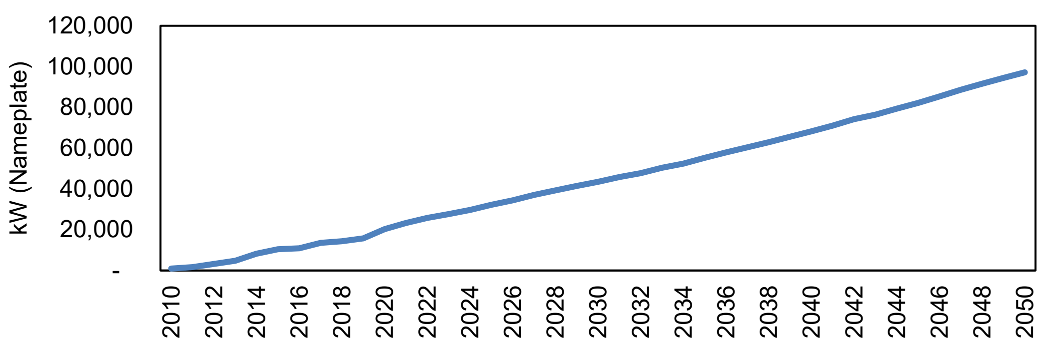
Figure 37 Net Annual Energy Savings Potential Across EE Bundles



6.3. Customer-owned Distributed Generation

DG resources are evaluated assuming a residential and commercial rooftop solar resource, as this is the primary distributed resource. To determine the level of customer penetration, the DG forecast was based on EIA AEP2021 Residential and Commercial Solar Photovoltaic ("PV") forecast. This forecast considered the level of solar photovoltaic ("PV") installations over the period of 2020-2050. Figure 38 below depicts the historical and forecast of nameplate DG resources in SWEPCO over the planning period. To determine the level of DG penetration, SWEPCO applied the incremental growth rates from EIA's forecast to existing levels of DG in the service territory.

Figure 38 Installed Nameplate Capacity of Rooftop Solar in SWEPCO's Territory



7. Planning Scenarios and Uncertainties

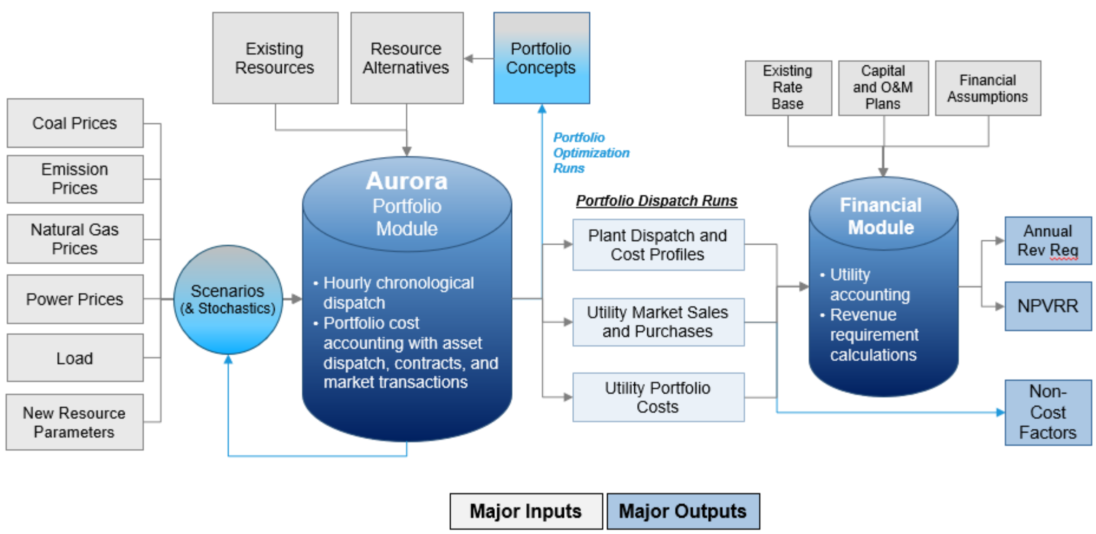
7.1. Introduction

Rate stability and maintaining reliability are two of SWEPCO's objectives for the 2021 IRP. In the context of rising future uncertainties, this section explains how the 2021 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 2021 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 market scenarios 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 2021 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 2021 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 39.

Figure 39: 2021 IRP Modeling Framework



The second method subjected the candidate portfolios to a large number of randomly drawn market simulations in the 2021 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

AEP's EIA-based Fundamentals Forecast is a long-term, weather-normalized commodity market forecast principally based upon the assumptions contained in the EIA's Annual Energy Outlook (EIA AEO). The Fundamentals Forecast is not specific to this IRP analysis; rather, it is made available to AEPSC and all AEP operating companies for various planning and analysis uses. Outputs of the Fundamentals Forecast include: 1) hourly, monthly and annual regional power prices (in both nominal and real dollars); 2) prices for various qualities of coals; 3) monthly and annual locational natural gas prices, including the benchmark Henry Hub; 4) nuclear fuel prices; 5) sulfur dioxide, nitrogen oxides, and CO_2 burden values; 6) locational implied heat rates; 7) electric generation capacity values; 8) renewable energy subsidies; and 9) inflation factors.

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.

Figure 39 below describes AEP's EIA-based Fundamentals Forecast components, which were sourced directly from the previously-described EIA AEO, third-party energy consultancies, and internally-generated information.

Figure 40: EIA-based Fundamentals Forecast Components

Forecast Components	EIA	Other	Source
Economy; Inflation/GDP deflators	✓		EIA Reference case
Generating Reserve Margins		✓	RTO Requirements
Electric Load		✓	AEP Load Forecasting
Electric Load shapes		✓	AEP Fundamentals
Solar/Wind production shapes by area		✓	NREL
Coal; Delivered price to EIA regions	✓	✓	EIA Reference case FOB prices + AEP Fundamentals
Natural gas price; Henry Hub	✓		EIA Reference case
Natural gas price; Locational values	✓	✓	EIA Reference case - Henry Hub + AEP Fundamentals
Natural gas supply; Lower 48 production	✓		EIA Reference case
Natural gas demand (incl. losses)	✓		EIA Reference case
Natural gas; net pipeline/LNG exports	✓		EIA Reference case
Oil price, WTI	✓		EIA Reference case
Fuel Oil price; locational values	✓	✓	EIA Reference case - WTI + AEP Fundamentals
Uranium prices		✓	AEP Fundamentals
Other Fuel(Biofuel, etc…)	✓		EIA Reference case
New gen unit options and capital costs	✓		EIA Reference case
Existing gen units	✓		EIA Reference case
Announced new gen units	✓		EIA Reference case
Aged-out retirements of existing gen units	✓		EIA Reference case
Gen unit maintenance schedule		✓	AEP Fundamentals
Gen unit outages		✓	AEP Fundamentals
Unit-level emission rates; CO_2, SO_2, NO_x		✓	US EPA CEMS data
Application of a CO_2 burden		✓	AEP Environmental
REC		✓	AEP Regulatory Forecast
PTC	✓		EIA Reference case
ITC	✓		EIA Reference case
State-mandated Renewable Portfolio Standards		✓	AEP Environmental
Reporting parameters; Peak/Off-Peak/NERC Holidays		✓	PJM/SPP/other RTO and/or internal guidelines
Transmission/links between Zones		✓	AEP Fundamentals

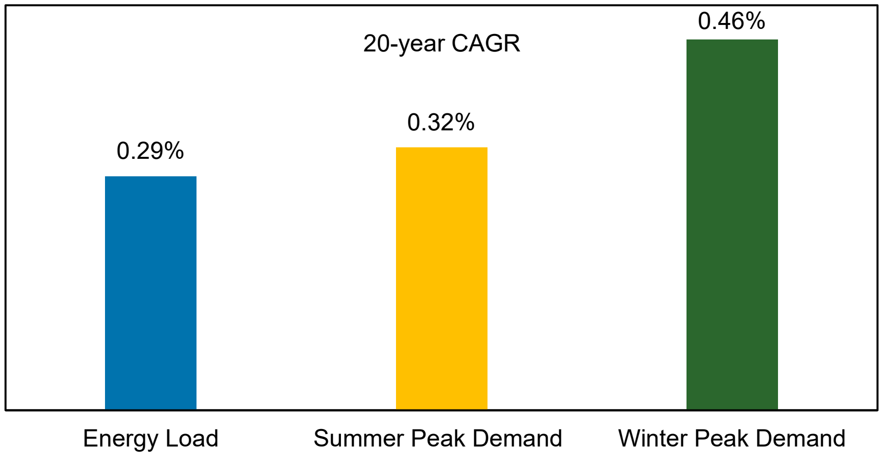
7.3. Reference Scenario Market Drivers and Assumptions

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.

7.3.1. Reference Scenario Load

Under the Reference scenario, demand for energy in SPP is expected to grow by 0.29% per year over the 20-year forecast period (2022-2041). Peak summer demand is expected to grow at a rate of 0.31% per year, while peak winter demand grows more quickly at 0.46% per year. These figures are illustrated in Figure 41. The details of the analysis and the assumptions underlying the load forecast are discussed in Section 2 above.

Figure 41: Reference case SPP energy and seasonal peak demand growth rates (2022-2041)



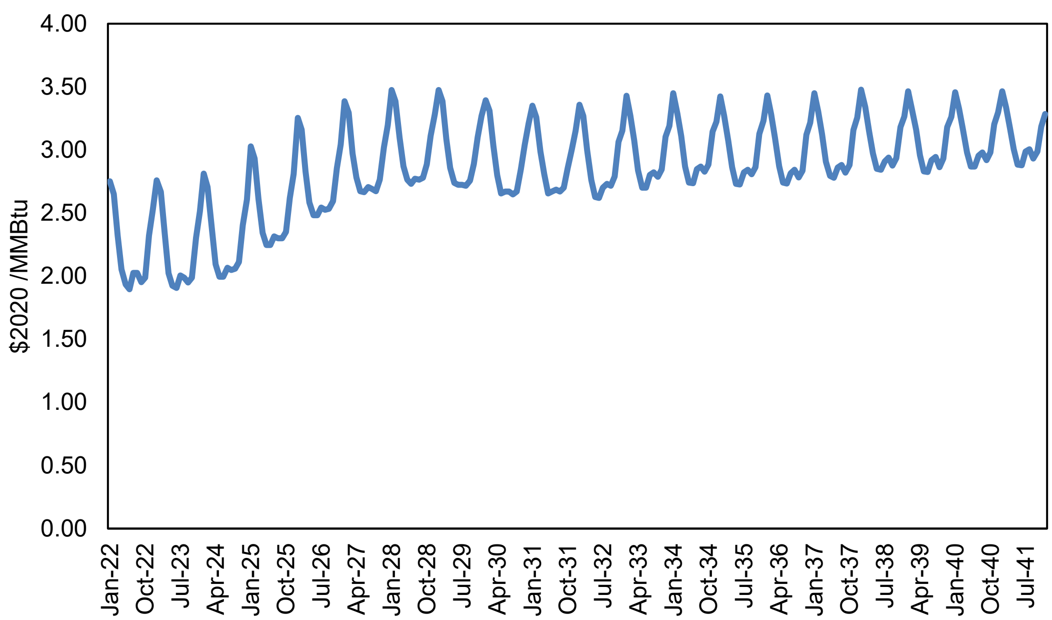
7.3.2. Reference Scenario Fuel & CO_2 Prices

The commodity price inputs to the Reference scenario reflect the "base" view from AEP's Fundamentals Forecast for natural gas, coal, and CO_2 emissions pricing. For the 2021 IRP Reference scenario, these "base" commodity price outlooks were used to represent the expected conditions for the broader SPP market.

Natural Gas Prices

Figure 42 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 rise from current levels through 2028 in real terms, after which annual growth in prices is largely flat for the remainder of the forecast period.

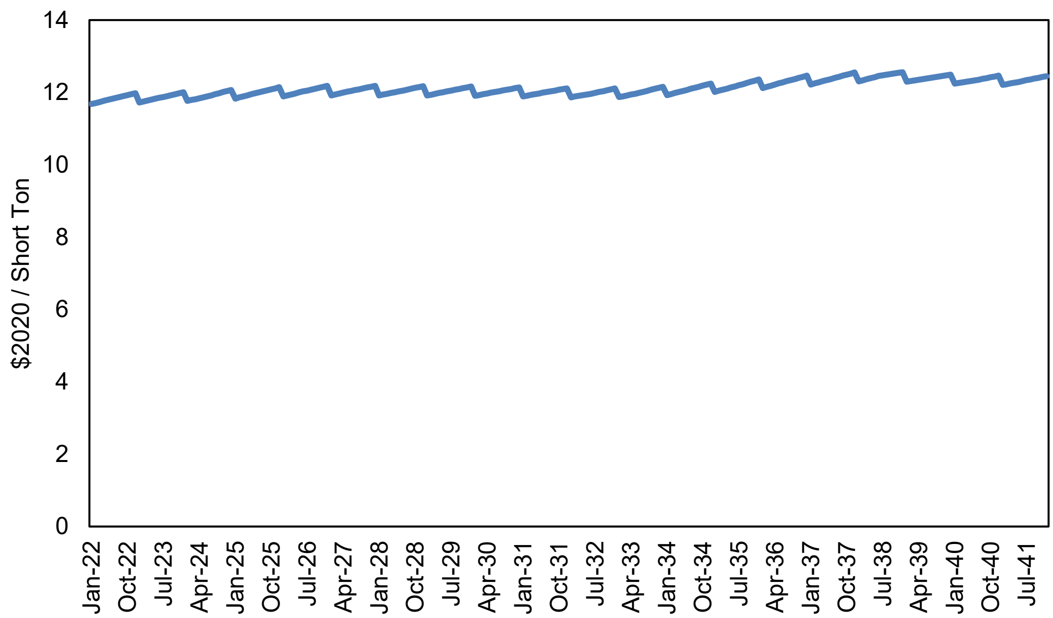
Figure 42: Panhandle Eastern TX-OK Natural Gas Prices (real $ / MMBtu)



Coal Prices

SWEPCO also relied on the AEP Fundamentals Forecast for coal price inputs to the 2021 IRP. Figure 43 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. Unlike natural gas that exhibits a rise in prices over the forecast period, the forecast PRB price remains largely consistent through the mid-2030s in the Reference Scenario, but begins to rise slightly towards the end of the forecast period in real dollar terms.

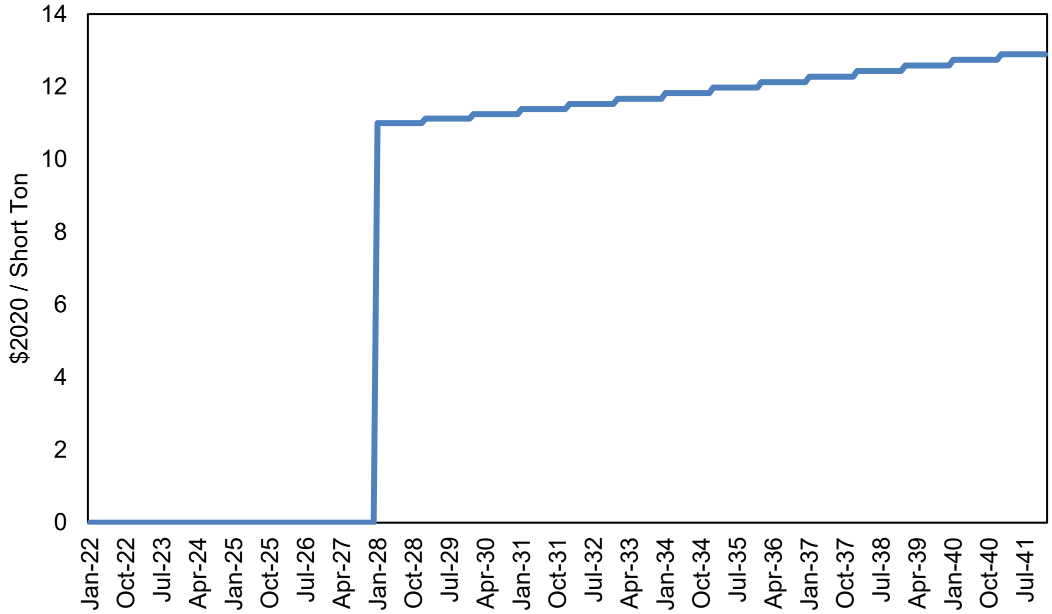
Figure 43: PRB 8,800 Coal Prices (real $ / ton, FOB origin)



CO_2 Prices

SWEPCO assumes that policymakers enact a moderate CO_2 price starting in 2028 as part of the 2021 IRP Reference scenario. This price is assumed to start around $12 / Ton (in real $2020) and rises modestly throughout the forecast period, as illustrated in Figure 44. 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 44: Moderate CO2 Price Forecast ($2020 / Short Ton)



7.3.3. Reference Scenario Reserve Requirements

SWEPCO assumes that the Company will need to procure sufficient resources to meet expected load plus a planning reserve margin of 12%.

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.[21,22] Section 7.4.3 discusses the assumed reduction in ELCC over time.

7.3.4. Reference Scenario Technology Assumptions

In general, SWEPCO relied on EIA's 2021 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 2020 National Renewable Energy Laboratory's ("NREL") annual technology baseline ("ATB") report.[23] SWEPCO assumes federal tax credits for new renewable generation in the Reference scenario reflect current law and the schedules enacted in the December 2020 COVID Relief Bill.

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[21] 2019 SPP Solar & Wind ELCC Accreditation. SPP. August 2019. <https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf>

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

[23] NREL Electricity Annual Technology Baseline (ATB) 2020. <https://atb-archive.nrel.gov/electricity/2020/data.php>

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

Cost and performance assumptions for demand-side technologies, including EE and other NWAs were develop by AEP staff. The details of the approach and underlying assumptions underlying the new supply-side technologies are discussed in Section 5.

7.4. 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 2021 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 allow for a no or least regrets evaluation of options. Figure 45 summarizes the key drivers of each scenario in a matrix.

Clean Energy Technology Advancement (“CETA”)

The CETA scenario is one of two in the 2021 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 incentives for deployment of clean supply- and demand-side technologies. For example, under the CETA scenario SWEPCO assumes that federal tax credits for renewable resources are extended and 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 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 CO2 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. 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 45: 2021 IRP Scenario Assumption Matrix

Scenario Concept	Load	Natural Gas	Carbon	Reserve Margin	New Resource Cost	Renewable Peak 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)	Base	Base	Moderate	Summer & Winter Requirements	Base	Low
No Carbon Regulation (NCR)	Base	Low	No Price	Base	Base	Base

7.4.1. Scenario Load

Two of the 2021 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.

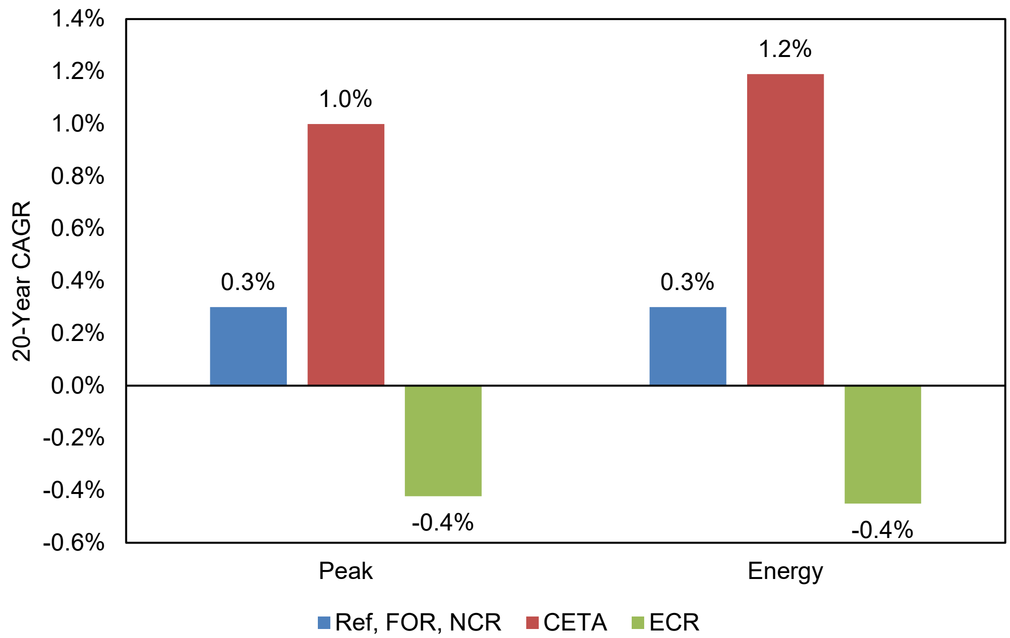
Under the CETA scenario, load grows more quickly than under the Reference scenario driven by increased economic growth, deployment of electric vehicles, and greater building electrification. Overall annual load growth for the SPP market in the CETA scenario is 1.19% per year, or approximately 0.9% higher than the Reference scenario. The accelerated adoption of EVs[24] 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 -0.41% per year, or approximately 0.7% lower than the 20-year forecast of load growth from the Reference scenario.

Changes to annual energy for load across the SPP market are illustrated in Figure 46, below.

[24] Incremental to the Reference scenario, the CETA scenario assumes an additional ~7-8 million EVs in the SPP region over 2022-2041 period. The incremental EV penetration assumption under the CETA scenario is scaled to SPP loads based on projections from the MISO MTEP 2020 study. < https://cdn.misoenergy.org//MTEP20%20Full%20Report485662.pdf>

Figure 46: SPP Load Growth 20-Year CAGR and Comparison with the Reference Scenario



7.4.2. 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 factors that may result in market conditions that produce higher or lower prices for natural gas and CO_2 permits.

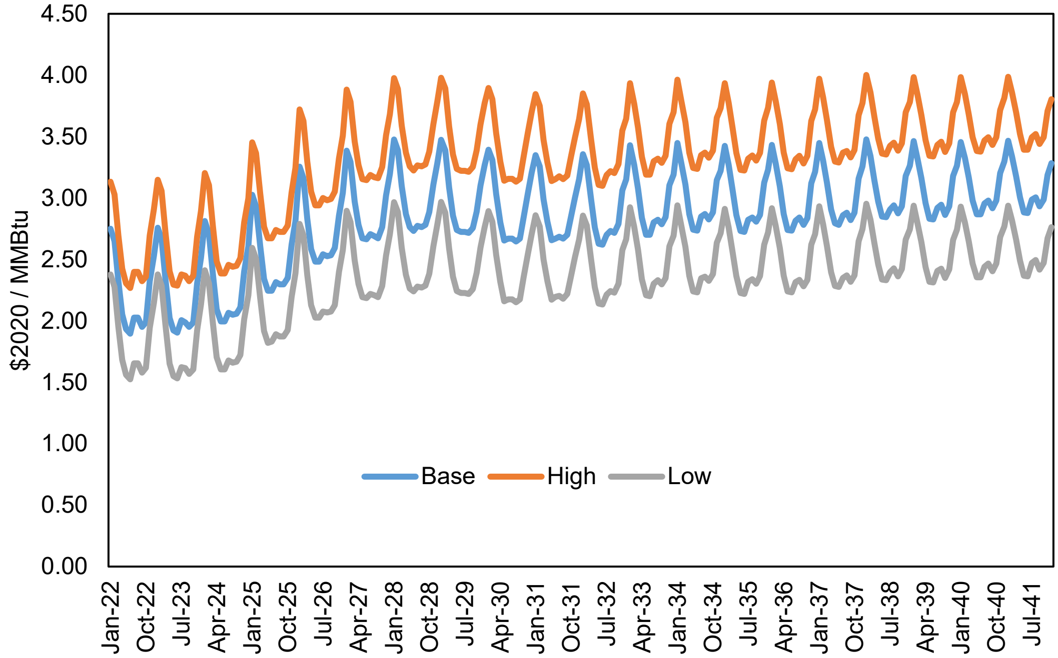
Natural Gas Prices

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 CO2 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 $0.50 / MMBtu higher than in the Reference scenario over the course of the forecast period. Under the NCR case, policymakers place less pressure on economy-wide GHG emissions than under the Reference scenario and natural gas prices are approximately $0.50 / MMBtu lower.

Figure 47 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 are taken from AEP's Fundamentals Forecast.

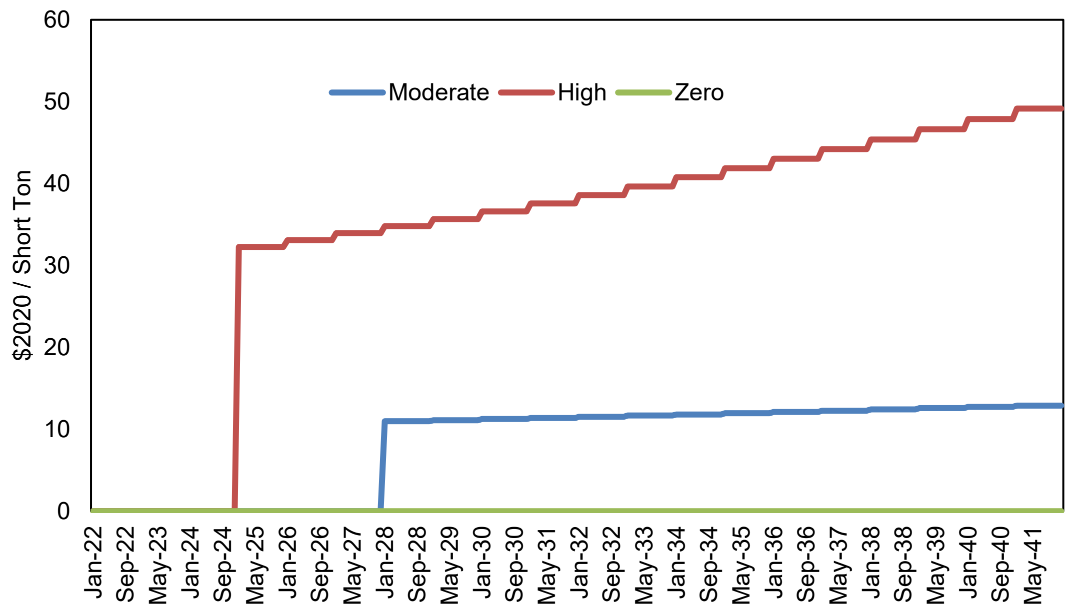
Figure 47: High and Low Panhandle Eastern TX-OK Natural Gas Price Forecasts (real $ / MMBtu)



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 2028. 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 2025 with prices starting at approximately $32 / Ton in (in real $2020) and rising to around $49 / Ton by 2041. Under the NCR scenario, policymakers do not enact a price on CO2, and prices are assumed to be zero throughout the forecast period. Figure 48 below illustrates how the high and zero CO_2 prices in the ECR and NCR scenarios (respectively) compare to the moderate CO_2 price view used in the remaining three scenarios.

Figure 48: High and Zero CO2 Price Forecasts ($2020 / Short Ton)



7.4.3. Scenario Reserve Requirements

Summer Capacity Requirements

Currently, SPP requires LSE's to maintain sufficient firm capacity to meet a 12% planning reserve margin above summer peak demand to maintain system reliability. This summer planning requirement is observed in all five 2021 IRP scenarios.

Increments of certain new resources, including some renewables and 4-hour 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 ELCC the next increment provides. Figure 49 summarizes the reference and low ELCC views for select technologies used in the 2021 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 7.5.2.

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 SPP.[25,26]

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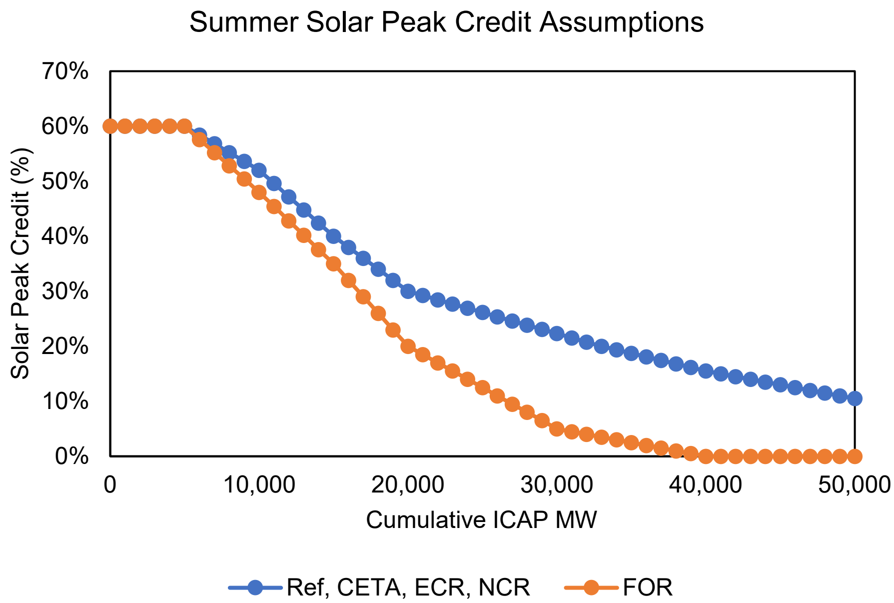
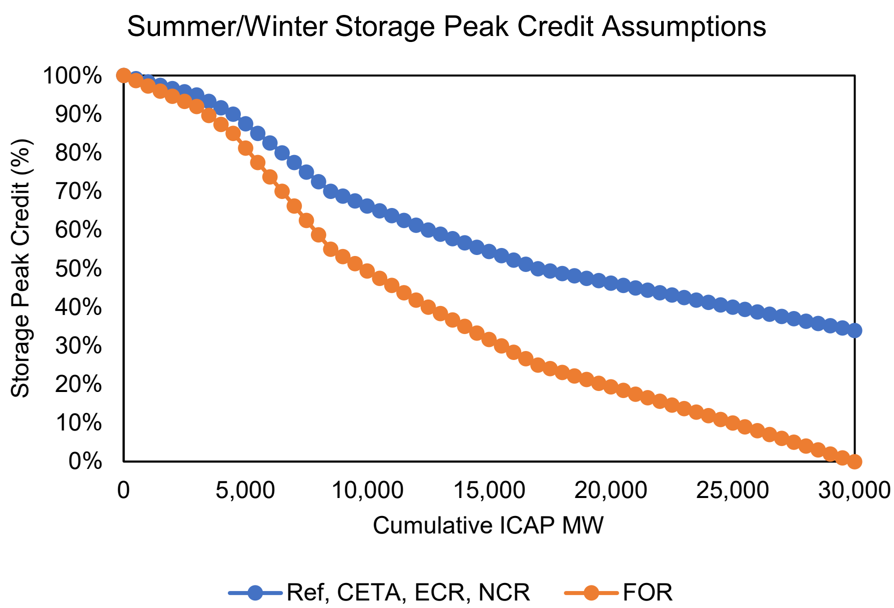
[25] 2019 SPP Solar & Wind ELCC Accreditation. SPP. August 2019. <https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf>

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

Figure 49: ELCC Assumptions for Select Resources by Cumulative ICAP MW [27,28]





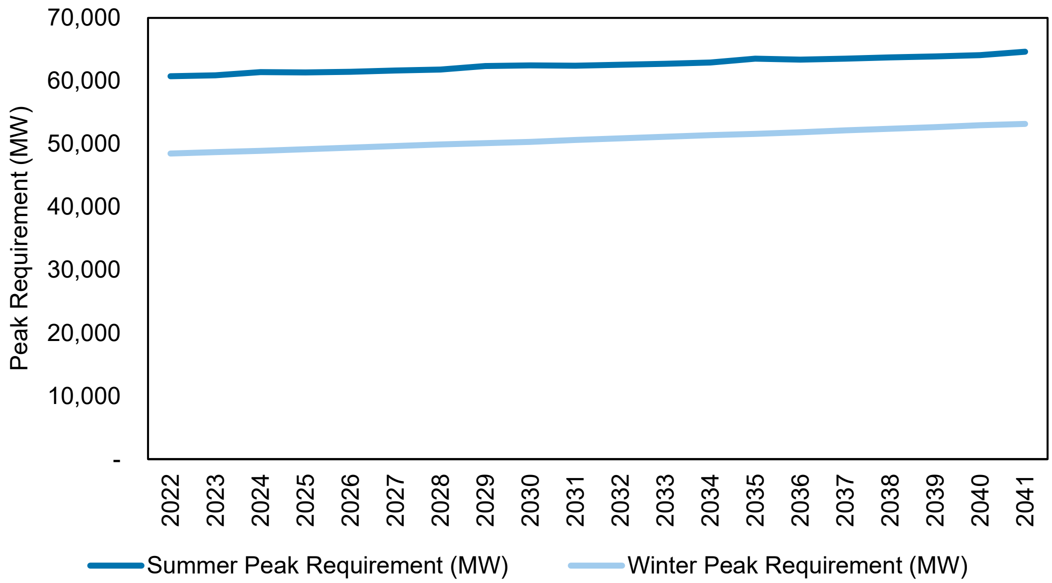
27 2019 SPP Solar & Wind ELCC Accreditation. SPP. August 2019. <https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf>

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

Winter Capacity Requirements

Outside of the summer capacity requirements that are enforced for all five scenarios, in the FOR scenario, SWEPCO enforces a 12% 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 50 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 more quickly than summer peak demand.

Figure 50: Comparison of FOR Scenario SPP Winter and Summer Peak Requirements (2022-2041)



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 decline over time from 10% in 2022 to 2% in 2041. Storage peak credits are not assumed to differ from summer.

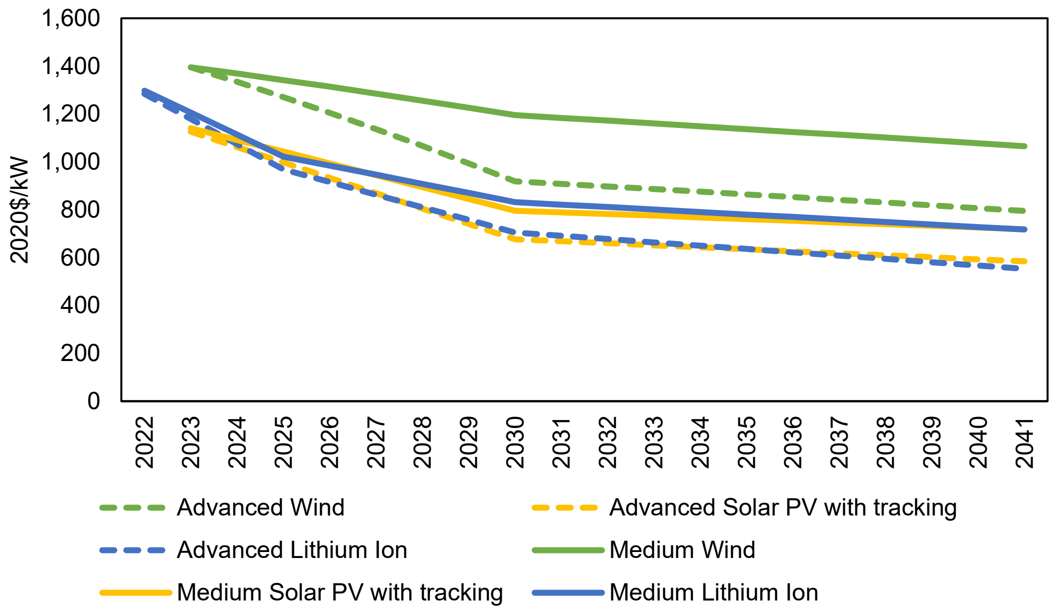
7.4.4. Scenario Technology Assumptions

SWEPCO's 2021 IRP scenario flexed a number of technology-related assumptions including the expected capital cost, congestion costs, and federal tax benefits available to renewable units as part of the 2021 IRP scenarios.

Unit Capital Costs

As described in Section 5, SWEPCO generally relies on technology cost assumptions from EIA's 2021 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 2021 ATB. This outlook of new unit costs is used for three of the 2021 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 throughout the forecast period. Figure 51 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 51: Comparison of Capital Costs Under Advanced and Medium Outlooks for Select Technologies (2022-2041 | $2020 / kw)

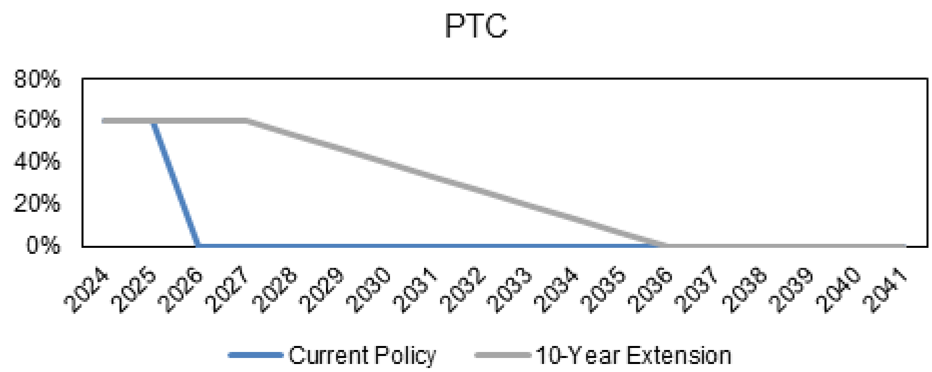


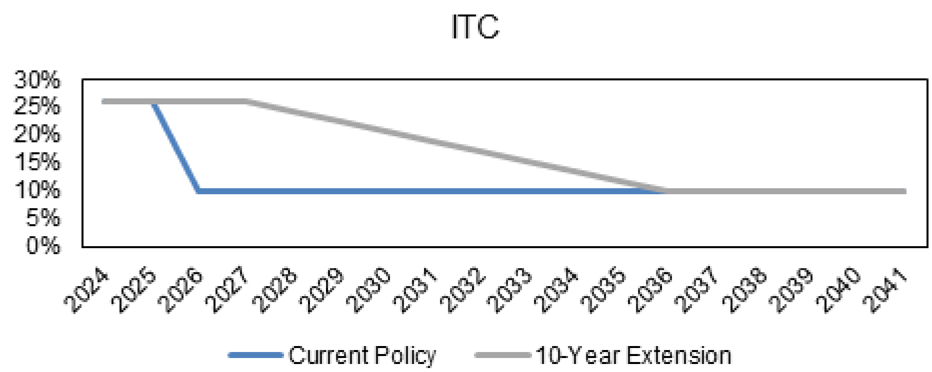
Federal Tax Credits for Renewable Energy

SWEPCO considers how the benefits provided by federal tax credits for renewable energy may evolve under each scenario. As seen above in Figure 44, SWEPCO modeled two different outlooks for federal tax policy as part of the 2021 IRP.

The current policy view reflects the level of benefit provided by the production tax credit ("PTC") and investment tax credit ("ITC") under current law, including the extensions approved in the December 2020 COVID relief bill. This view is adopted for the Reference scenario, as well as for the FOR, ECR, and NCR scenarios. Under the CETA scenario, it is assumed that these federal tax credits are extended for 10 years and decline gradually. This assumption is consistent with the theme of providing support for clean technologies as a method for achieving emissions reductions. Figure 52 below illustrates how these benefits are assumed to decline over time under the current policy and 10-year extension views used in the 2021 IRP. The PTC value in Figure 52 represents the multiplier applied to the statutorily defined value of the credit (e.g., in 2022 it is assumed that new wind units will receive 60% 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 2022 it is assumed that new solar will receive a 26% rebate on capital costs).

Figure 52: Federal Tax Credit Assumptions Used in the 2021 IRP (2022-2041)





Congestion Charges

SWEPCO's scenarios also include varying views on the future of the transmission system in SPP. Under the CETA scenario, congestion charges for wind resources are expected to be higher than in the other cases because higher load growth coupled with lower net costs. SWEPCO has modeled a $5 per MWh congestion adder for new wind resources in the CETA scenario and a $2 per MWh adder in the other four scenarios.

7.5. 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 in each one of the five scenarios.

7.5.1. 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 53 and Figure 54 below illustrate the 2041 SPP capacity and generation mix (respectively) across all five market scenarios compared with the SPP resource mix in 2021.

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 2028, only 4 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 16 GW of new wind, 24 GW of new solar, 20 GW of new storage units, 6 GW of new gas peakers, and 3 GW of new combined cycles are added by 2041. The gas units are installed primarily to meet firm requirements. Under the Reference scenario, solar and wind generators provide more than 75% of the total SPP generation by 2041. The result is that total CO_2 emissions in the SPP market drop by 70% in the Reference Scenario from 2021 to 2041.

Figure 53: Comparison of 2021 and 2041 Nameplate Capacity by Technology in SPP

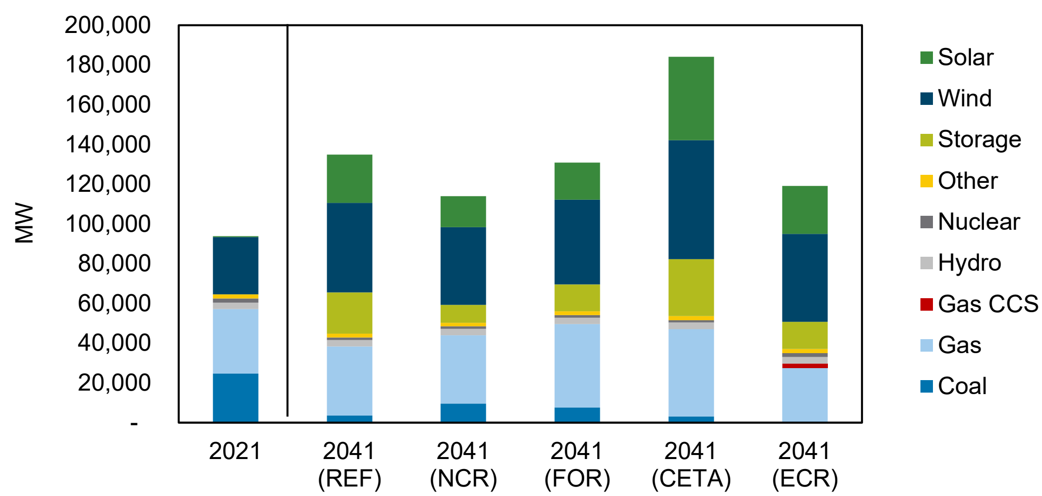
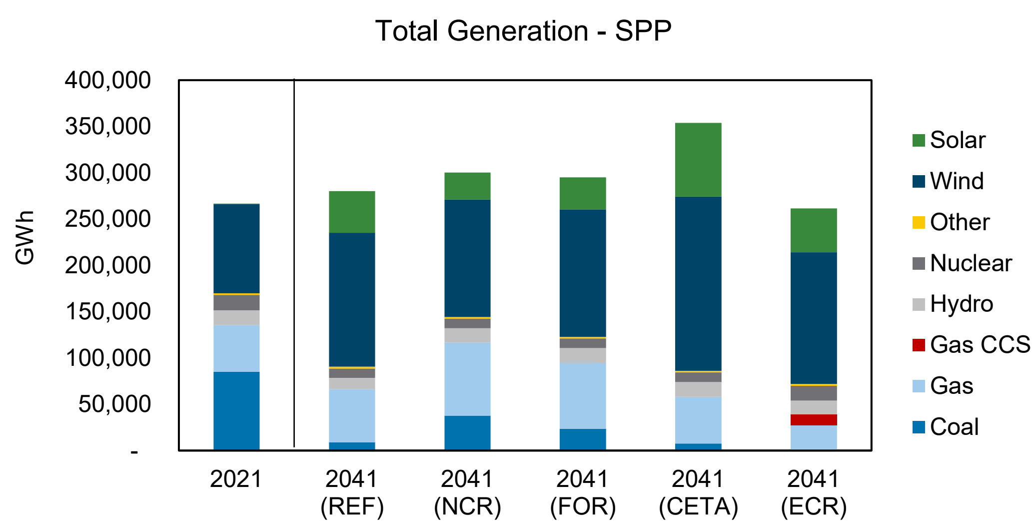


Figure 54: Comparison of 2021 and 2041 Generation by Technology in SPP



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 10 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, 15 GW of new solar, and 9 GW of new 4-hour battery storage added by 2041. 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 renewable units comprise only about 50% of total SPP generation by 2041 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 40% from 2021 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 2041, there is approximately 4 GW more coal capacity remaining in the market and 7 GW of additional gas-fired generation relative to the Reference scenario by.

Deployment of renewable technologies is lower than in the Reference scenario due to the lower reserve margin value of these units. Approximately 18 GW of new solar, 14 GW of new wind, and 13 GW of new 4-hour battery storage are added by 2041. Renewable sources comprise just under 60% of SPP market generation in this year. SPP CO_2 emissions drop by approximately 50% from 2021 to 2041, compared to around 70% 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 a combination of faster learning rates and an extension of federal renewable tax credits. 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 2041, nearly 42 GW of new solar, 31 GW of new wind, and 29 GW of new 4-hour battery storage are added in SPP under the CETA scenario. Coal retirements are similar and there is slightly more gas generation in SPP under the CETA case than under the Reference scenario despite greater penetration of renewables due to the higher load forecast assumed in this scenario. Despite a higher installed capacity, gas units generate less in the CETA case than the Reference scenario due to greater competition from new renewable sources. Solar and wind units comprise more than 75% of total SPP generation by 2041, and CO_2 emissions fall by around 74% SPP-wide relative to 2021 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 2041. 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. Due to the more favorable outlook for nuclear, the 770 MW Cooper plant is relicensed in 2034 under the ECR scenario. 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 similar amounts of wind and solar deployment as the Reference scenario (around 24 GW and 15 GW respectively) and lower levels of 4-hour battery storage (around 13 GW). However, due to lower load growth, these resources make up a large proportion of the overall system, with wind and solar accounting for 75% of total SPP generation by 2041. SPP-wide CO_2 emissions are the lowest in this scenario and decline by 90% relative to 2021 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.

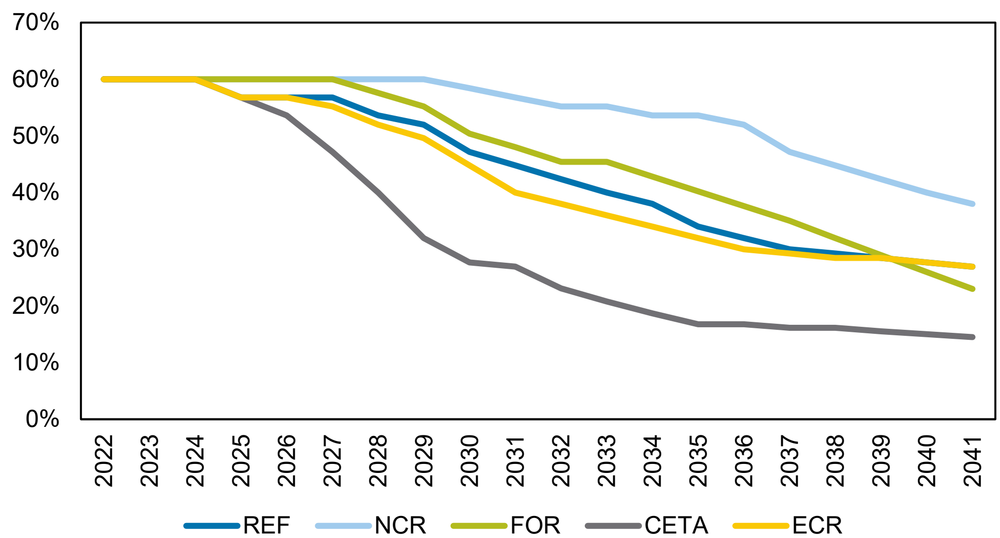
7.5.2. Effective Load Carrying Capability (ELCC) Results

As described in Section 7.3.3 and Section 7.5.1, 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 49. While solar and storage credits vary by case, wind ELCC is assumed to stay constant at 14.7% informed by a SPP Study.[29]

Under the Reference, FOR, and ECR scenarios, solar ELCC values decline from the current 60% value to levels near 25% by 2041, 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 39% peak value by 2041. 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 and tax credits are extended, 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 35% to 70% by 2041. The resulting solar and storage summer ELCC values are summarized in Figure 55.

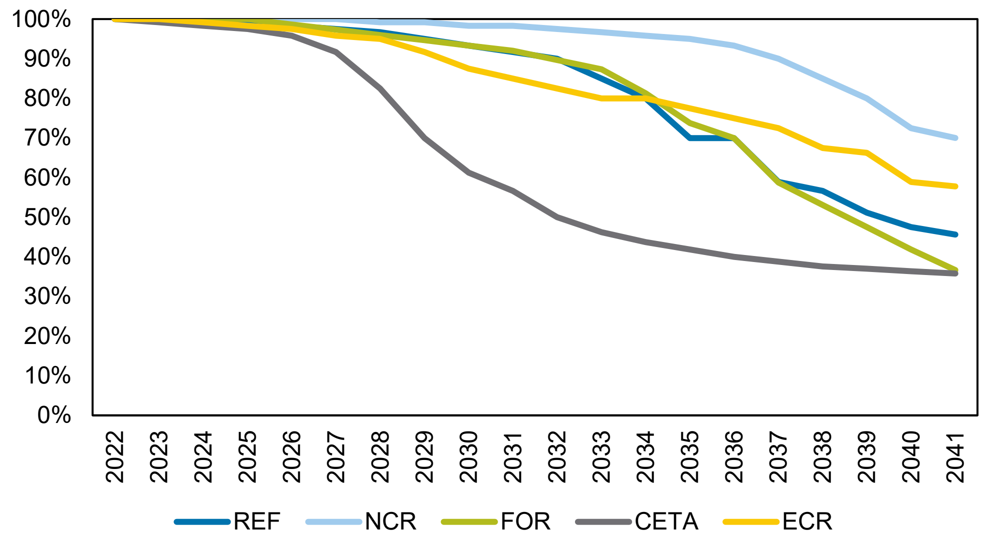
Under the FOR scenarios, solar winter ELCC values are assumed to decline from 10% in 2022 to 2% by 2041. Winter season reserve margin requirements were not enforced in the remaining market scenarios.

Figure 55: Comparison of Solar Summer Peak Credits by Scenario



[29] 2019 SPP Solar & Wind ELCC Accreditation. SPP. August 2019. <https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf>

Figure 56: Comparison of Storage Summer Peak Credits by Scenario



7.5.3. Market Price Results

The key market outputs from the scenario modeling process are the power prices illustrated below in Figure 57 and Figure 58. Shown are all five market scenarios modeled in the 2021 IRP. These figures illustrate the wide but plausible range of energy prices that emerge from the scenario modeling step that were used to develop and select the preferred plan.

Figure 57: Annual On-Peak SPP South Hub Electricity Price ($2020 / MWh)

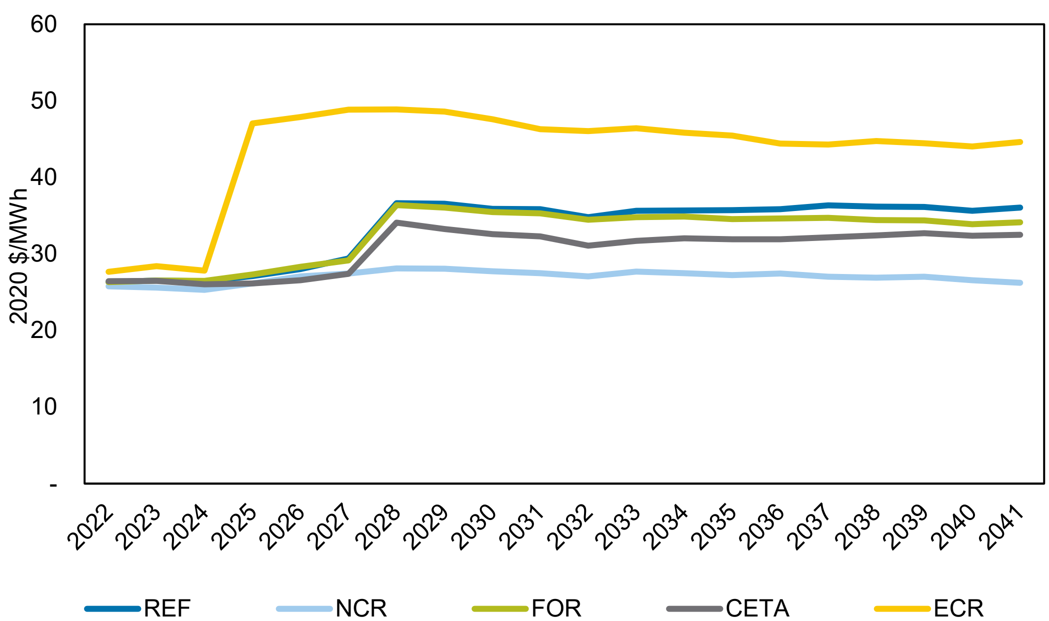
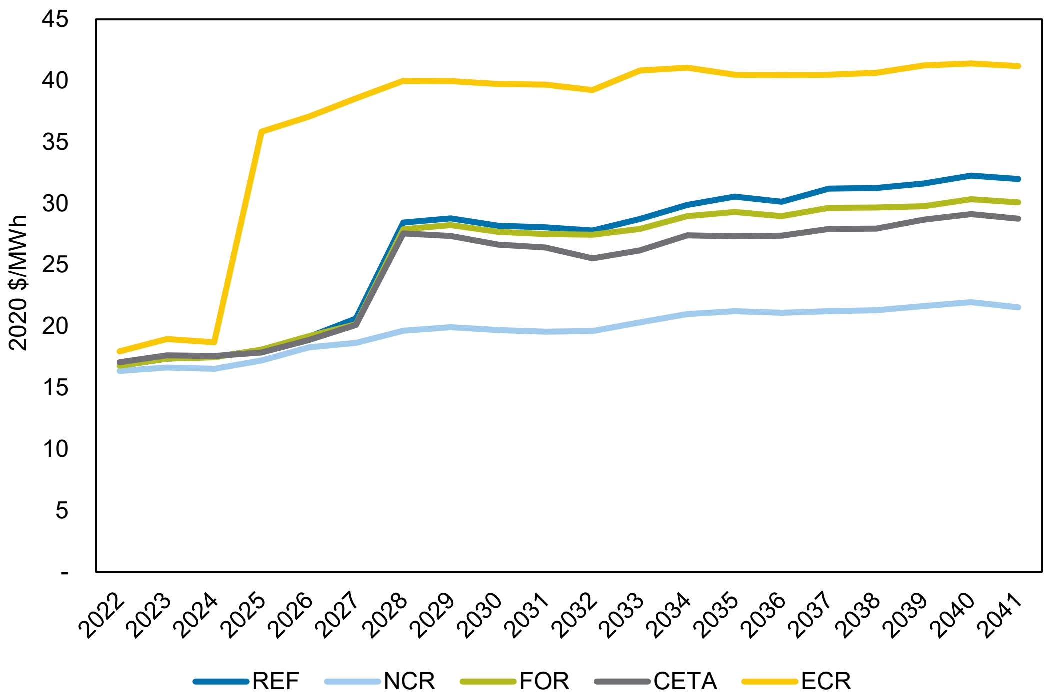


Figure 58: Annual Off-Peak SPP South Hub Electricity Price ($2020 / MWh)



Under the Reference scenario, on-peak energy prices in SPP South Hub rise gradually from around $26 / MWh ($2020 real) in 2022 to $29 / MWh by 2027 in large part due to the increase in natural prices over the period. There is approximately a $9 / MWh spread between on- and off-peak pricing over this same period, in real dollar terms. Starting in 2028 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 little growth in on-peak pricing from 2029 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, rise more quickly 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 / MWh by 2041.

Under the FOR and CETA scenarios, SPP market prices are largely similar, though forecasted to be somewhat lower, 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 FOR scenario, long term prices for both on- and off-peak energy are around $2 / MWh lower than under the Reference scenario due to the higher market-wide reserve margins. Under the CETA scenario, prices are between $2-4 / 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 2022-2024 period, both on- and off-peak prices are approximately $2-3 / MWh higher than in the Reference scenario due the higher natural gas price assumed in this scenario. In 2025, the high CO_2 price is introduced and SPP market prices rise by around $20 / MWh in both on- and off-peak periods. From 2025 onward, on-peak prices tend to fall modestly (in real terms) due to the lower load growth assumption in this scenario and the high penetration of renewable generation. Conversely, off-peak prices grow slightly from 2025-2041 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 $3.50 /MWh by 2041 in the ECR scenario when viewed on an annual average basis.

The NCR scenario sets the lower bound of SPP market prices. From 2022-2027, overall market prices are around $2-4 / MWh lower than in the Reference scenario due to the low natural gas prices forecast that is assumed in this scenario. After 2028, 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 that are assumed as part of the scenario. On-peak prices are largely steady from 2028 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 2030's, 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 to between $4-5 / MWh in this scenario on an annual basis.

7.6. 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 for the preferred portfolio. The scorecard metric "Cost Risk" is defined as the NPVRR increase between the 95th percentile and 50th 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 95th and 50th percentile NPVRR among the set of portfolio cost realizations are identified to calculate the "Cost Risk" scorecard metric.

7.6.1. 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[30] model that takes as input expected paths for gas and power, based on SWEPCO's Reference scenario outlined in Section 7.3. 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 2021-2042, data from 2031 and 2041 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

30 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 modelling of high volatility, mean-reverting, spike-prone commodities: The Australian wholesale electricity market." Energy Economics, 2008.

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, 2016 to December 31, 2020 were used to summarize the relevant market price behavior and include only the most recent market dynamics.

Figure 59 and Figure 60 illustrate one sample iteration of gas and power daily prices in 2031 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 59 Sample Iteration of Daily Natural Gas Price Simulation for 2031

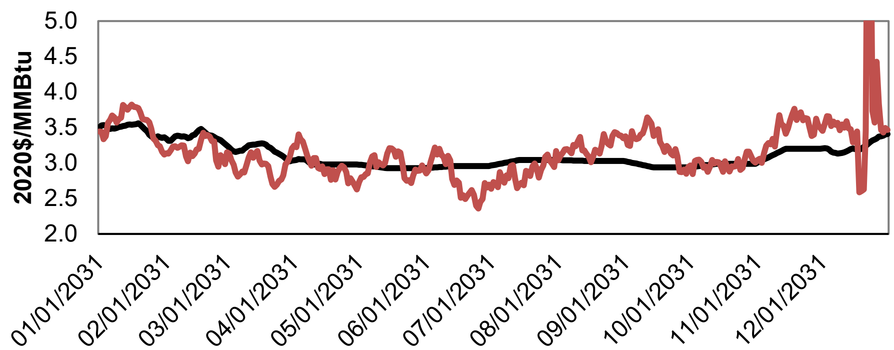
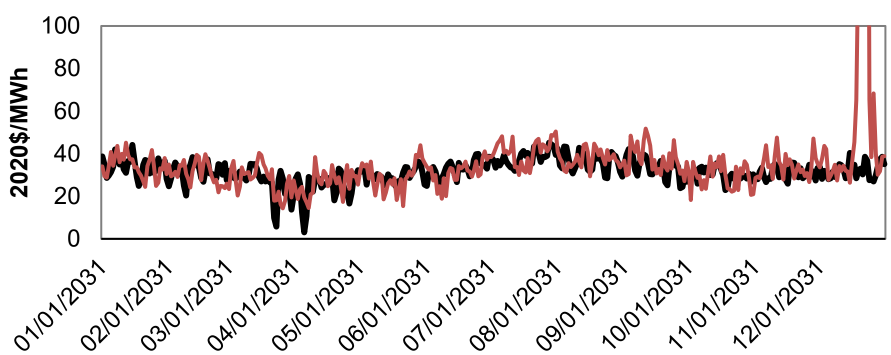


Figure 60 Sample Iteration of Daily Power Price Simulation for 2031



7.6.2. Renewable Output Stochastics

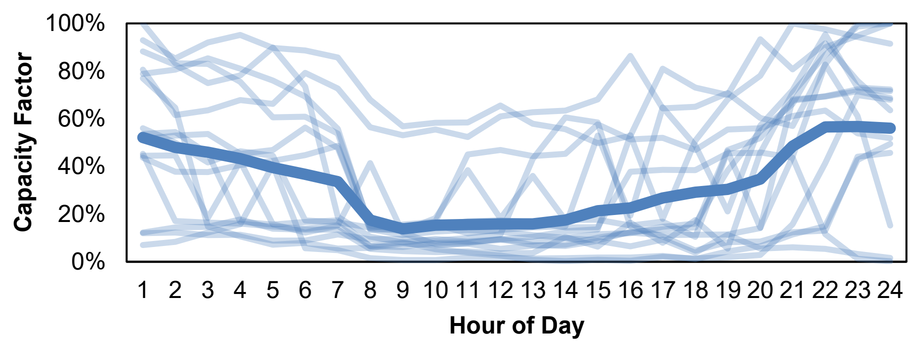
Renewable output uncertainty is integrated in SWEPCO's stochastic analysis process to address the risks associated with energy market exposure. To widen the range of modeled renewable availability, historical weather data from NREL was used to proxy wind and solar availability using NREL's System Advisor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

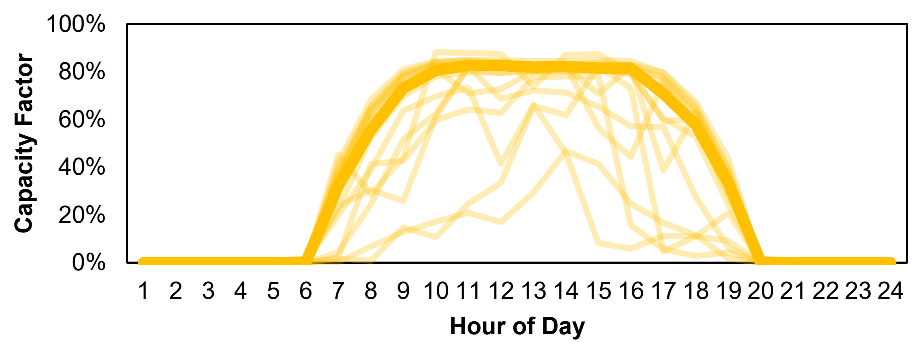
Historical hourly weather conditions for the years 2008 to 2012 (5 weather years) for counties across Oklahoma[31] were used as inputs into the SAM tool. Proxies for a farm of wind turbines and single-axis tilt solar panels were used in SAM to simulate hourly wind and solar power output, respectively. Adjustments to SAM power estimates were used to align with SWEPCO's capacity factor assumptions for new wind and solar resources.

Figure 61 illustrates 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 61 Simulated Hourly Wind and Solar Capacity Factor for July



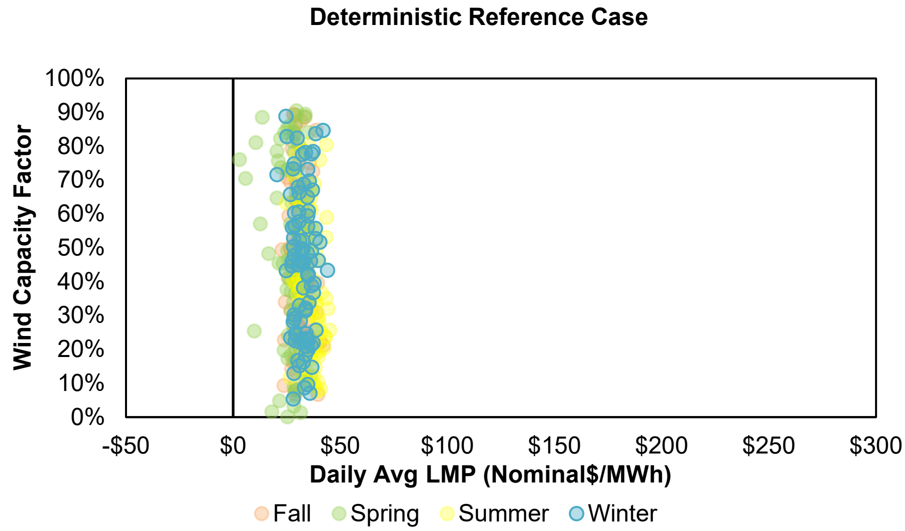


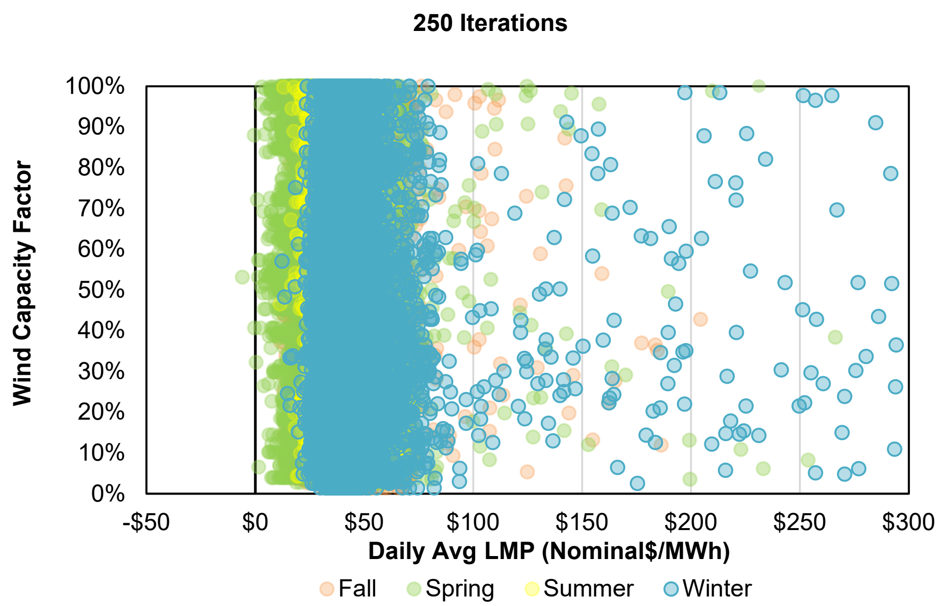
By incorporating stochastic renewable profiles and gas and power outputs, the combinations of renewable output and price paths cover a greater range than the Reference scenario. This is illustrated in Figure 62 that compares combinations of daily average wind capacity factors and the daily average power 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

31 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.

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 62 Daily Average Wind Capacity Factor and Power Price, under Deterministic Reference Scenario vs. 250 Stochastic Iterations





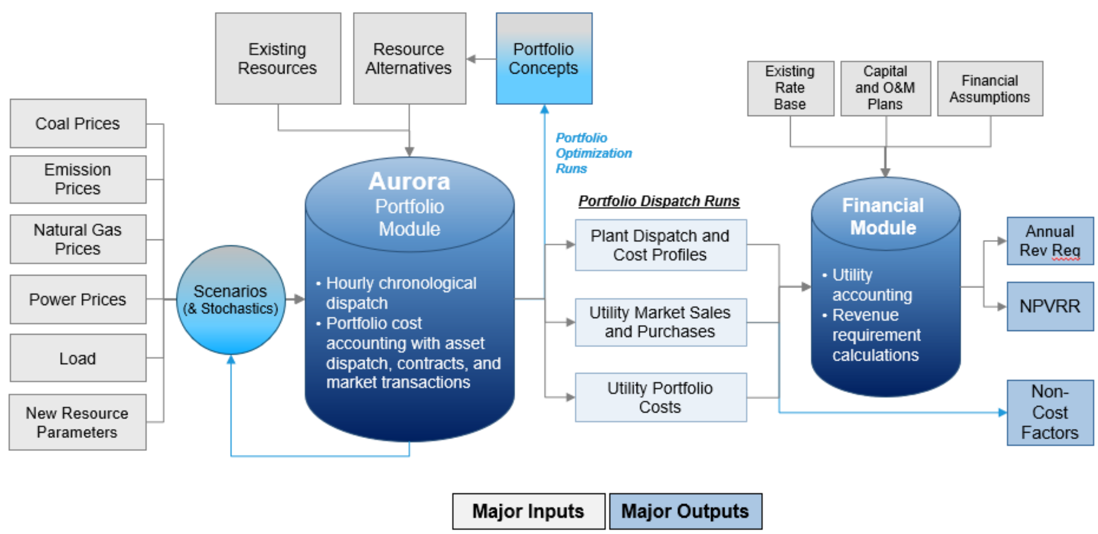
8. Portfolio Analysis

8.1. Introduction

The 2021 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 2021 IRP. The 2021 IRP scorecard and metrics are detailed below in this chapter.

In terms of impact on the IRP analysis, the priorities and objectives informed the 2021 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, capacity, and other services changed across the SPP market under different combinations of these fundamental conditions. These scenarios were used to inform the development of six portfolio options using a combination of the capacity expansion model in AURORA and expert judgements 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 63: 2021 IRP Modeling Framework



Further, concerns and risks raised by SWEPCO leadership informed the cost metrics and broader risk analysis performed in the IRP. For example, leadership noted the market events of February 2021 in ERCOT and SPP, and set an objective for the preferred plan to provide reliable service for SWEPCO customers during extended periods of extreme weather or broader system outages, and also the goal to protect 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, and our 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.

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 64:

- **Objectives** are overarching goals that align to SWEPCO or stakeholder priorities. The four objectives of the 2021 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 64: Elements of the 2021 SWEPCO IRP Scorecard

Objective	Performance Indicator	Description
Customer Affordability	NPVRR	Total long-term annual costs paid by ratepayers
	% of Income	Percentage of wallet for residential customers
	Near-Term Rates	Near-term rate 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 purchases 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 metric is described in the following sections. The scorecard is found below as Figure 65.

8.2.1. Objective 1: Customer Affordability

Customer affordability is a primary goal for SWEPCO. Affordable power and lowest reasonable rates were identified as key considerations for stakeholders who may be sensitive to increases in energy costs and may therefore object to certain resource plans if those plans are expected to result in higher rates. Further, 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."[32] For the SWEPCO 2021 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.

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 2022-2027.

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.

Current SWEPCO plans include retiring Dolet Hills in 2021, Pirkey in 2023, and the Welsh plant in 2028, creating a need for new capacity in the near-term. Longer-term, SWEPCO is facing additional age-based retirements of thermal units in the late 2030s that create a capacity need. This performance indicator allows SWEPCO to evaluate the risk of higher cost 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 (2022-2051) 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 Texas power crisis where a historic cold weather event led to rolling blackouts, forced generator outages, and high wholesale gas and electricity prices. While the 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.

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

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 were 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 2020's and later in the 2030's. Using a long-term metric allows for all of the resource decisions made in the IRP to be fully reflected and maintains consistency 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 (2022-2051) 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 2031 and 2041

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 2031 and 2041. 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.

2031 and 2041 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 2020's and 2030's 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 2041

SWEPCO has repeatedly expressed an interest in this IRP to track resource requirements seasonally to illuminate how different candidate portfolios may expose SWEPCO customers to winter and summer market events that result in high (or low) wholesale energy prices.

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 currently purchased between 30-50% 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 2041, 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.

2041 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 2022-2041

SWEPCO seeks to track energy and capacity exposure separately in the 2021 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 2021 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 2022-2041 time period will be included in the scorecard. The period 2022-2041 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 2022-2041 across all five market scenarios. This results in 50 winter values and 50 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 a 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 2031 and 2041. Dispatchable resources include new gas peaking units (multiple configurations), new gas combined cycle units (with or without CCUS), 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 2031 and 2041. 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 2041

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 2041 and under the Reference scenario. The metric is measured in 2041 to capture the full range of replacement decisions and because it is expected that many advanced technologies may not become economic until the 2030's 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 AEP corporate 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 2021 IRP. Further, AEP has defined corporate-level sustainability goals of reducing carbon emissions by 80% by 2030 relative to 2000 and achieving net zero carbon emissions by 2050 across all operating companies.

SWEPCO indicated interest in measuring the performance of alternative resources against those goals when selecting the preferred plan. 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 SWEPCO's serve customers.

Two performance indicators were selected to measure progress towards local impacts & 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 CO2 emissions, and the level of reductions achieved relative to the baselines use for the AEP corporate targets.

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 2022-2031 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 2022-2031; and, (2) the cumulative capital invested in the SWEPCO service territory from 2022-2031, calculated as the sum of capital spent over the period in current year (e.g., 2021) US dollars.

The 2022-2031 period was selected to align the scorecard to the portfolio modeling results that are presented in the 2021 IRP and to focus the evaluation on local impacts over the first 10 years of the overall resource plan.

CO2 Emissions: Percent reduction from 2000 in the Reference Scenario in 2031 & 2041

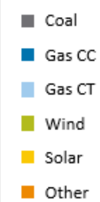
SWEPCO's parent company, AEP, has defined corporate sustainability goals across all of their electric operating companies. Specifically, AEP has defined corporate-level sustainability goals of reducing carbon emissions by 80% by 2030 and achieving net zero carbon emissions by 2050 relative to a 2000 baseline.

This performance indicator allows SWEPCO to evaluate progress towards those goals as one element of the preferred plan 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 2000. Carbon emissions are defined as the direct emissions from SWEPCO's owned and contracted generating resources and the baseline year was selected to align with the AEP corporate targets. This metric is calculated by dividing the total SWEPCO portfolio emission in the test year (2031 or 2041) by total SWEPCO portfolio emission from the year 2000 and evaluating the percentage reduced. Despite AEP having announced targets in 2030 and 2050, the scorecard uses the test years 2031 and 2041. This decision was made to maintain consistency with the 10- and 20-year outlooks reflected in the IRP report and appendix. Further, it is SWEPCO's view that portfolio emissions in 2031 are a reasonable proxy for progress towards AEP's 2030 aspirations, and the 2041 date measures the level of continue progress towards AEP's 2050 announced targets.

Figure 65: 2021 IRP Scorecard

	Customer Affordability		Rate Stability			Maintaining Reliability			Local Impacts & 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 50^{th} 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*	***Local Impacts:*** *New Nameplate MW & Total CAPEX Installed Inside SWEPCO Territory*	***CO2 Emissions:*** *Percent Reduction from 2000 Baseline - Reference Case*
Year Ref.	2022-2027	2022-2051	2022-2051	2031 | 2041	2031	2022-2041	2031 | 2041	2041	2022-2031	2031 | 2041
Units	%	$MM Levelized Rate	$MM Levelized Rate	$MM	Summer | Winter	Summer | Winter	MW	%	MW | $MM	% Reduction
Reference Portfolio										
CC Portfolio										
Welsh 1 Gas Conv.										
NCR Portfolio										
CETA Portfolio										
ECR Portfolio										
No Early CT Portfolio										



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 assumptions including tax credits where relevant as discussed for each market scenario in Section 7. The candidate resources made available to the model include 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 of which are discussed in Section 7.

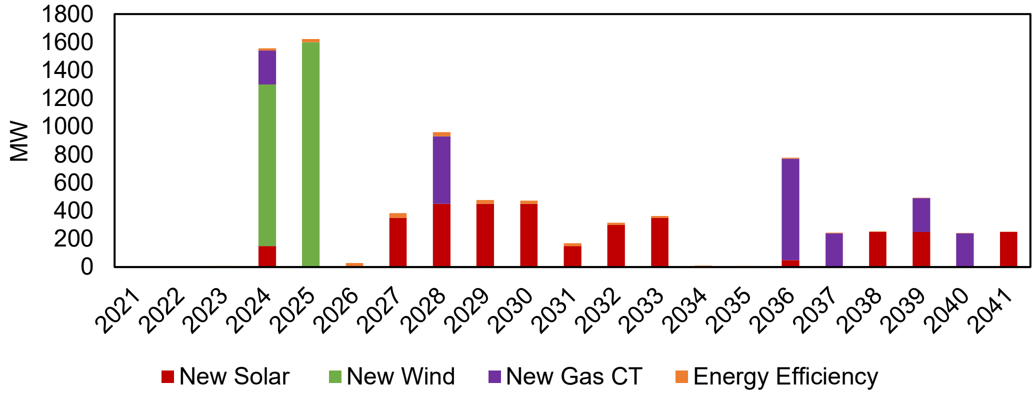
SWEPCO used four of the resulting least-cost plans as candidate portfolios in the 2021 IRP. One duplicative plan was removed, and three new plans were created. The "CC Portfolio" tests the impact of additional gas exposure on SWEPCO customer costs because no plans that included a CC build resulted from the AURORA optimizations. The "Welsh 1 Gas Conversion" portfolio was also created to test the impact of the potential opportunity to convert the Welsh 1 coal power station to burn natural gas and extend the plant's lifetime by ten years. The portfolio is based on optimizing the resource selection using the Reference market scenario but with the coal-to-gas conversion of Welsh 1 pre-selected in 2028. Finally, the "No Early CT" portfolio also pre-selects the Welsh 1 conversion in 2028 and in addition does not allow a combustion turbine to be added in 2024 due to various concerns, including its timing since this resource type might not be able to progress through the SPP queue in time to be in service by January 1, 2024.

Each of the seven candidate portfolios was then stress-tested under all five market scenarios as well as stochastic distributions of gas, power prices and renewable outputs (as discussed in Section 7) using a suite of resource planning tools, namely AURORA and a utility financial model known as PERFORM. 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 net present value estimates of revenue requirements over the planning horizon. The outputs from AURORA and PERFORM are then used to populate the 2021 IRP Scorecard to inform the selection of the preferred portfolio.

8.3.1. Resource Additions by Portfolio

Resource additions in each of the seven portfolios considered are shown in Figure 66 to 72 below.

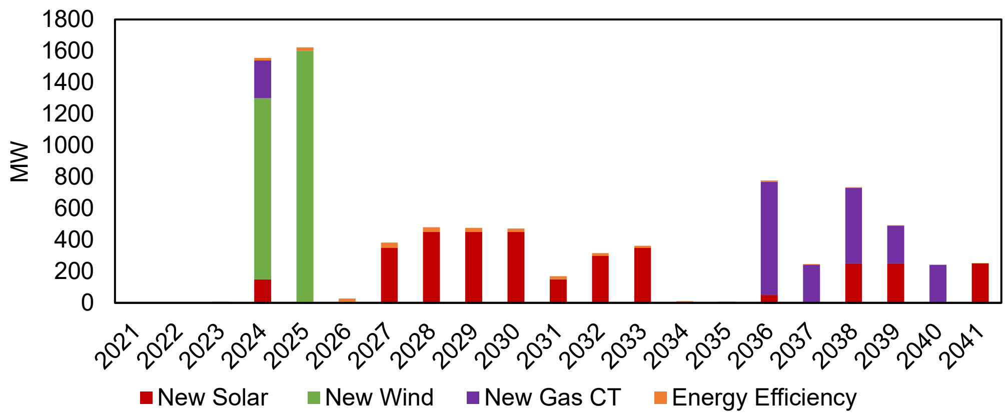
Figure 66: Resource Additions in the Reference Portfolio



For the Reference portfolio, approximately 3.5 GW of new solar, 2.8 GW of new wind, and 2.2 GW of new NGCTs are added by 2041. Of the new solar and new wind added, 0.2 GW and 2.8 GW of new solar and wind, respectively, are added by the end of 2025 to take advantage of the ITC and PTC for customers. New NGCT units are installed from 2036 onward, primarily to replace retiring existing NGCT units to meet firm requirements.

In addition, demand-side resources including incremental DG and EE programs are pursued. The summer peak contribution of incremental customer DG rises from 2 MW in 2022 to 13 MW in 2041. The contribution of incremental EE programs ranges from 8.0 MW – 44.3 MW depending on the year, with the peak of 44.3 MW registered in 2027. In total, the summer peak contribution from incremental demand-side resources is 2.0 MW in 2022, rising to 59.1 MW in 2028 before declining to 17.0 MW by 2041.

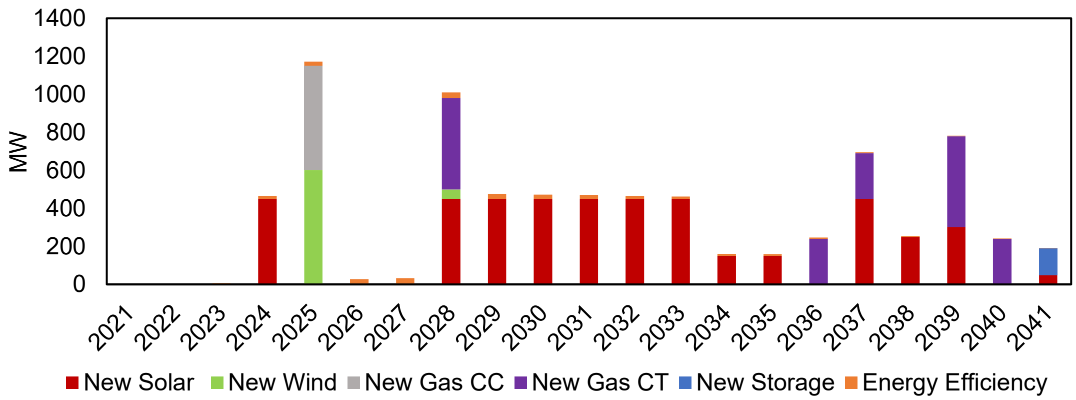
Figure 67: Resource Additions in the Welsh 1 Gas Conversion Portfolio



The Welsh 1 Gas Conversion portfolio tests the impact of exercising the option to convert the power station from burning coal to burning gas and extend the lifetime by ten years in the process. Converting Welsh 1 results in a delay in the addition of a 480-MW in NGCT capacity from 2028 to 2038 relative to the Reference portfolio. The build out plan is the same as the Reference Plan otherwise on both supply and demand sides.

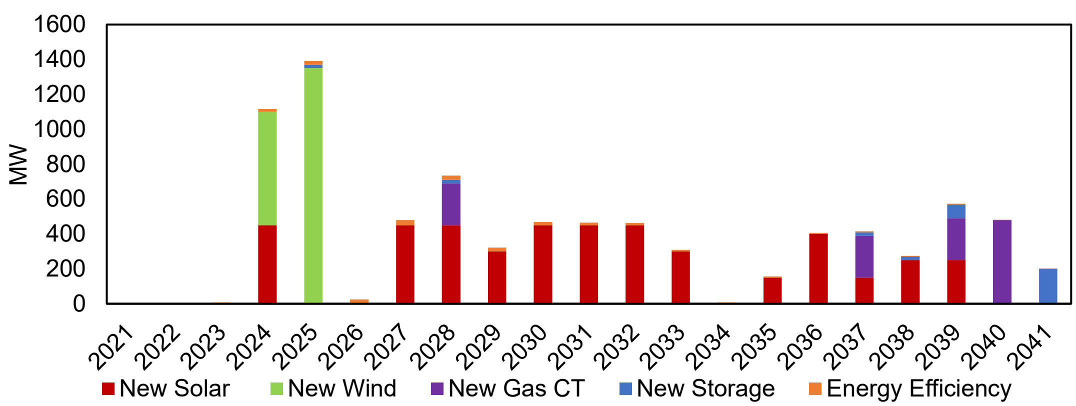
When optimized in the FOR scenario, AURORA returns the same supply-side and demand-side resource additions as the Reference portfolio. This is because SWEPCO's summer capacity peak requirement is materially higher than its winter capacity peak requirement, and the remaining market drivers (e.g., load, fuel price, etc.) are the same across these two cases. The least-cost capacity buildout needed to satisfy the Reference summer requirement provides sufficient capacity in winter to meet the 12% reserve margin requirement under the FOR scenario, even accounting for the reduction in the peak contribution for solar resources in winter. In other words, the winter reserve requirement was not binding when optimizing the SWEPCO portfolios under the FOR scenario, and as a result, the resulting optimal capacity additions were identical to the Reference Portfolio. Therefore, SWEPCO developed an additional CC portfolio, optimized under the Reference Scenario, to avoid duplicate resource plans in the 2021 IRP and test the impacts of additional gas exposure on expected customer costs. This portfolio ("CC portfolio") is created by optimizing resource selection under the Reference Scenario but with the 550-MW NGCC pre-selected for 2025.

Figure 68: Resource Additions in the CC Portfolio



This early addition of a baseload gas unit results in lower capacity and energy requirements relative to the Reference portfolio, as such, the CC portfolio contains lower additions of new solar, wind and NGCTs relative to the Reference portfolio. Approximately 4.5 GW of new solar, 0.7 GW of new wind, 0.7 GW of new NGCTs, and 0.1 GW of storage units are added by 2041 in addition to the NGCC unit. The addition of the NGCC unit does not change the economics of demand-side resources and therefore the selection of demand-side resources in the CC portfolio are the same as in the Reference portfolio.

Figure 69: Resource Additions in the NCR Portfolio

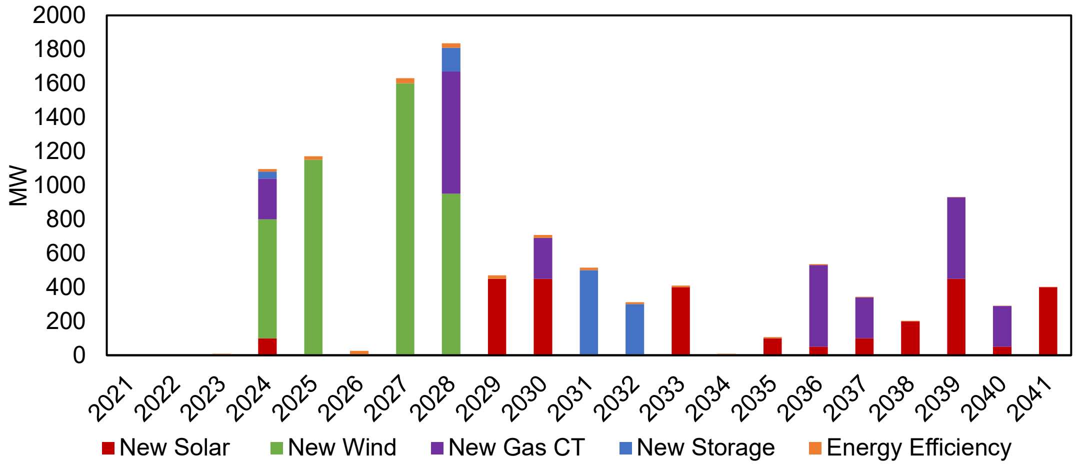


The NCR Scenario has lower natural gas prices and zero carbon prices that generally improve the economics of gas-fired generation relative to other scenarios. However, lower additions of renewables in the SPP region means that solar PV installed in this portfolio has a higher ELCC, giving this technology's 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. By 2041, the NCR portfolio adds 4.5 GW of new solar, 2.8 GW of new wind, 1.2 GW of new NGCTs and 0.4 GW of new storage units.

Lower gas and zero carbon prices result in limited deployment of demand-side resources in the NCR portfolio. In total, the contribution from incremental demand side resources is 2.0 MW in 2022, rising to 52 MW in 2028 before declining to 23 MW by 2041.

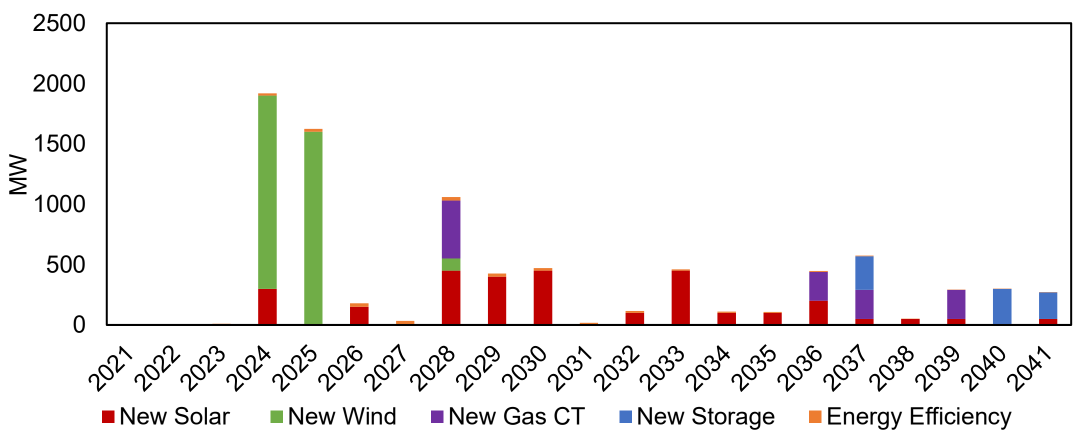
Figure 70: Resource Additions in the CETA Portfolio



The CETA Scenario combines higher load and more affordable renewable technologies that result in faster decline in renewable technology costs and assumes an extension of federal renewable tax credits. As a result of higher load, the CETA portfolio has larger capacity additions. 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 2041, approximately 2.8 GW of solar, 4.4 GW of wind, 2.6 GW of CTs, and 1.0 GW of storage units are added.

On the demand side, the medium industrial and commercial EE bundle is no longer competitive against other resources, and as such it is not selected in the CETA portfolio. In total, the contribution from incremental demand side resources is 2.0 MW in 2022, rising to 49 MW in 2028 before declining to 10 MW by 2041.

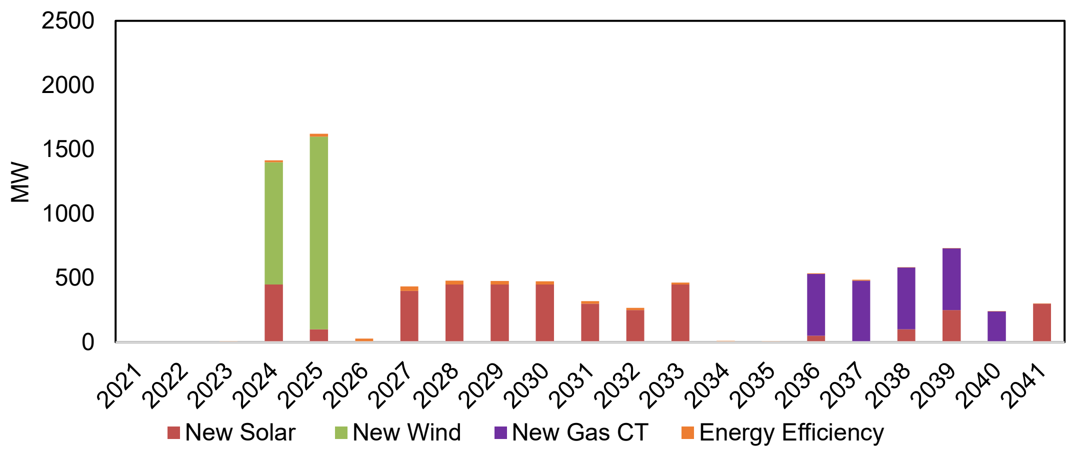
Figure 71: Resource Additions in the ECR Portfolio



The ECR Scenario combines lower load growth with high-cost gas and carbon. Due to the lower load forecast, the ECR portfolio adds fewer resource 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 2041, approximately 2.9 GW of solar, 3.3 GW of wind, 1.2 GW of CTs, and 0.8 GW of storage units are added. The amount of new NGCTs added is about a half the level in the Reference portfolio.

On the demand side, the high gas price improves the economics of energy efficiency bundles and as a result the medium industrial and commercial EE bundle is selected two years earlier than in the Reference portfolio. In total, the contribution from incremental demand side resources is 2.0 MW in 2022, rising to 55.5 MW in 2027 before declining to 17.0 MW in 2041.

Figure 72: Resource Additions in the No Early CT Portfolio



The No Early CT portfolio is a sensitivity of the Welsh 1 Gas Conversion portfolio that pre-selects the Welsh 1 gas conversion in 2028 and tests the additions that would be needed if the model does not allow a combustion turbine to be added in 2024 due to concerns that this resource type might not be able to progress through the SPP queue in time to be in service by January 1, 2024. Without the ability to add gas CTs to meet the capacity requirement in 2024, this portfolio adds 550 MW of solar and 2,450 MW of wind in 2024-2025 time period. In addition, this portfolio adds 2,750 MW of solar from 2027-2033 as the capacity need grows. Similar to other portfolios, there is a large quantity of gas CTs added 2036-2040 to replace the significant retiring capacity during that time. Overall, the No Early CT portfolio adds more solar, less wind, and the same quantity of gas and demand side resources as the Welsh 1 Gas Conversion portfolio.

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 17 shows the portfolio performance under 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 17 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	2.6%	15,435	56.1
CC	2.8%	16,309	59.3
Welsh 1 Gas Conv.	2.6%	15,287	55.6
NCR	2.4%	15,500	56.4
CETA	4.2%	16,475	59.9
ECR	2.6%	15,270	55.5
No Early CT	2.5%	15,331	55.8

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 NCR portfolio has the smallest amount of capacity additions in this period and this portfolio exhibits the slowest rate of growth at 2.4% per year. Conversely the CETA portfolio has the highest rate of growth at 4.2% per years, owing to the greater amount of new resource added to the portfolio over this period. The remaining portfolios fall in between these two extremes, with the CC portfolio showing higher costs, with rates growing at 2.8% over the 2022-2027 period relative to the Reference, ECR, Welsh 1 Gas Conversion, and No Early CT portfolios that grow at a rate of 2.5-2.6%.

Long-term

In terms of revenue requirements over the next 30 years, the Reference, Welsh 1 Gas Conversion, No Early CT, NCR and ECR portfolios perform similarly on both the NPVRR and the levelized rate basis. However, the ECR portfolio is capacity short and relies on market purchases, which could leave ratepayers exposed to future market prices. The Welsh 1 Gas Conversion portfolio has $150 million in NPVRR ($0.5/MWh levelized rates) savings against the Reference portfolio. This is because converting Welsh 1 is a cheaper capacity option relative to building a new greenfield site. The No Early CT portfolio is similar in cost to the Welsh 1 Gas Conversion portfolio, despite the added constraint of not allowing a new gas CT in 2024. The No Early CT portfolio is only $44 million more expensive than the Welsh 1 Gas Conversion portfolio, which is approximately $0.20 per MWh in levelized rates.

The CC portfolio and the CETA portfolio have the highest long-term revenue requirements. For the CC portfolio, this is driven by the rising fuel and carbon costs associated with operating the NGCC unit added in 2025. The CETA portfolio has the highest amount of cumulative capacity additions as the portfolio is optimized for meeting the higher load growth and assuming an extension to the federal renewable tax credits in the CETA scenario. The portfolio therefore has the highest revenue requirements. In other words, the CETA portfolio could leave customers at risks of higher rates if either the demand growth or the tax credit extension does not 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 2031 and 2041; and
- Market exposure as measured by net sales in the summer and winter seasons as a percentage of load in 2041.

Scenario Resilience

Table 18 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 18: The 30-Year NPVRRs of the Portfolio Across Market Scenarios ($Million)

Portfolio	Market Scenarios					
	Reference	FOR	NCR	CETA	ECR	High/Low Difference
Reference	15,435	15,437	14,919	15,570	14,984	652
CC	16,309	16,273	15,118	16,565	17,078	1,960
Welsh 1 Gas Conv.	15,287	15,287	14,772	15,421	14,836	649
NCR	15,500	15,462	14,807	15,644	15,312	837
CETA	16,475	16,590	16,451	15,128	14,720	1,870
ECR	15,270	15,297	14,926	15,324	14,281	1,044
No Early CT	15,331	15,315	14,781	15,516	14,962	735

In general, the CETA scenario produces the highest expected 20-year portfolio NPVRRs under the candidate portfolios due to the higher load growth assumed in that scenario. The exception to this is the CETA portfolio that was optimized under these market conditions. Similarly, the IRP portfolios tend to report the lowest costs under the ECR scenario, because customer loads are assumed to be lower in this forecast than under the other SPP outlooks.

The Reference portfolio and Welsh 1 Gas Conversion portfolio are most resilient to the five market scenarios with an NPVRR range of approximately $650 million. The No Early CT portfolio ranks third with a slightly higher range of $735 million. The NCR portfolio produces the next highest range of NPVRRs at $837 million.

The ECR, CC and CETA portfolios are least resilient by this measure with an NPVRR range of greater than $1 billion when solved under different fundamental conditions. The CC portfolio is more dependent on natural gas resources compared to other portfolios, and the range exhibited by the CC portfolio is primarily driven by the variation in natural gas prices. Indeed, the CC portfolio has the highest NPVRR in the ECR scenario where gas and carbon prices are high, and the lowest NPVRR in the NCR scenario where gas and carbon prices are low. As such, the CC portfolio exposes ratepayers to gas and carbon price risks. On the other hand, the CETA portfolio is optimal for a high-load environment where the federal renewable tax credits are extended. In other scenarios where those two factors do not materialize, the portfolio performs materially worse relative to the other candidate portfolios.

Cost Risk

Figure 73 and Figure 74 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 2031 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. Table 19 shows a summary of the cost risk across each candidate portfolio.

Figure 73: Distribution of Revenue Requirements Based on Stochastic Analysis (2031)

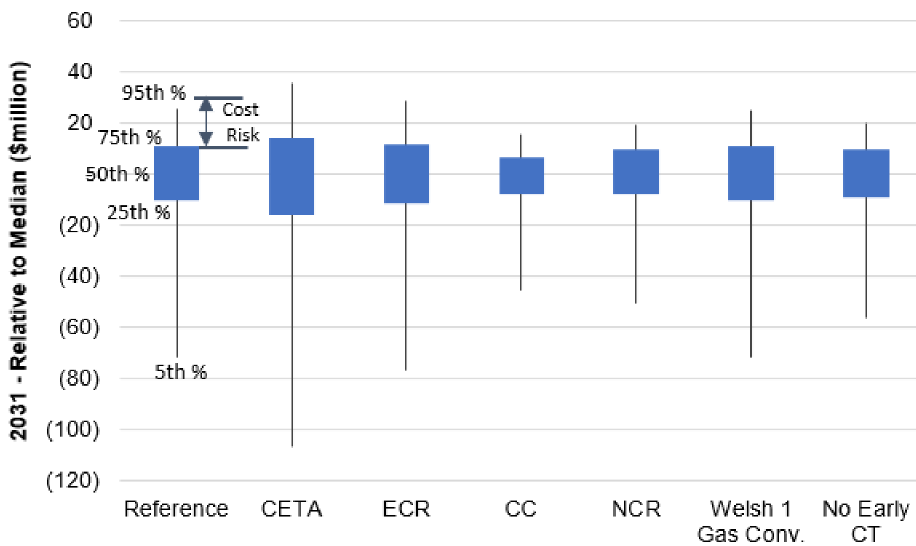


Figure 74: Distribution of Revenue Requirements Based on Stochastic Analysis (2041)

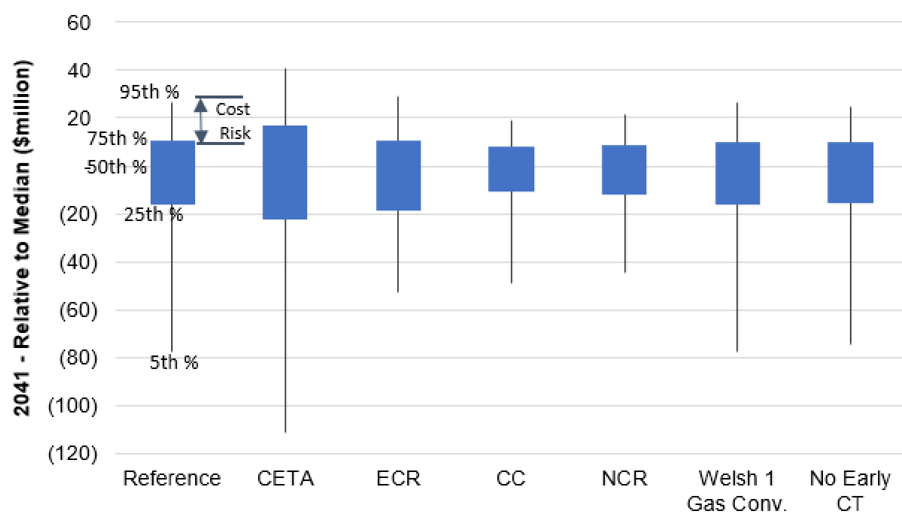


Table 19: Cost Risk - 50th to 95th Percentile Distribution Range ($million)

Portfolio	2031	2041
Reference	25.4	26.8
CC	15.7	19.3
Welsh 1 Gas Conv.	24.9	26.7
NCR	19.5	21.4
CETA	35.9	40.7
ECR	28.9	28.7
No Early CT	20.3	24.6

The CETA portfolio in both 2031 and 2041 has the highest cost risk and thus is more exposed to short-term volatility in power prices, gas prices, and renewable output. The ECR portfolio has the second highest cost risk, followed by the Reference and the Welsh 1 Gas Conversion portfolios. The CC and NCR and No Early CT portfolios have the lowest cost risk, with a much narrower distribution of outcomes.

Market Exposure

Table 20 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 20: Average Net Energy Sales as % of Portfolio Load Across All Scenarios

Portfolio	Summer			Winter		
	2022	2031	2041	*2022*	2031	2041
Reference	-5%	11%	17%	3%	21%	20%
CC	-5%	1%	15%	3%	0%	5%
Welsh 1 Gas Conv.	-5%	9%	17%	3%	21%	20%
NCR	-5%	4%	15%	3%	11%	14%
CETA	-5%	24%	33%	3%	43%	43%
ECR	-5%	14%	13%	3%	29%	23%
No Early CT	-5%	10%	17%	3%	21%	20%

Generation from SWEPCO's current portfolio is relatively balanced with demand and not expected to result in large net sales or purchases to meet customer requirements in 2022.

By 2031, all portfolios evaluated in the 2021 IRP show a tendency for greater net sales in summer relative to 2022. In winter, all portfolios except the CC portfolio also tend to increase their share of net sales by 2031 as a percent of customer load, compared with 2022 levels. The CETA portfolio relies most heavily on market sales to balance customer requirements while the CC portfolio has the least reliance on market in 2031.

The summer net sales position of all portfolios tends to increase between 2031 and 2041 primarily due to later additions of new solar resources. Net sales in winter tend to grow less between 2031 and 2041 relative to the summer season. This is explained, in part, by the fact that many candidate portfolios include significant amounts of new solar by year 2041, and solar resources tend to produce less energy during winter months.

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 2041;
- Operational flexibility measured as the total firm capacity (UCAP) provided by fast-ramping technologies in years 2031 and 2041;
- Resource diversity measured as the percentage of total generation provided by the different generating technologies selected in each candidate resource plan in model year 2041 under the Reference scenario; and

Planning Reserves

Table 21 shows the summer and winter planning reserves, averaged over the period between 2022 and 2041 and across all market scenarios.

Table 21 Planning Reserves Between 2022 and 2041 by Portfolio

Portfolio	Summer	Winter
Reference	16%	30%
CC	17%	27%
Welsh 1 Gas Conv.	16%	31%
NCR	8%	13%
CETA	26%	50%
ECR	10%	23%
No Early CT	15%	25%

SWEPCO assumed that each candidate portfolio would need to meet a SPP planning reserve margin of 12% above summer peak load 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 be 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 NCR and ECR portfolios fall short of the 12% 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 NCR portfolio, the result is driven by the reduction in solar ELCC that results from greater SPP-wide deployment of this technology under other market scenarios. The CETA portfolio has an average summer reserve margin of 26% by this measure, more than twice the 12% SPP planning reserve margin requirements. This is driven greater capacity additions in this portfolio in anticipation of high load growth, and the great ELCC value awarded to solar resources in any of the non-CETA scenarios.

Operational Flexibility

Table 22 shows the capacity of dispatchable units in 2031 and 2041 in each of the portfolio considered.

Table 22 The Amount of Dispatchable Capacity in 2031 and 2041 by Portfolio

Portfolio	2031 Dispatchable Capacity (MW)	2041 Dispatchable Capacity (MW)
Reference	3,295	3,431
CC	3,605	3,641
Welsh 1 Gas Conv.	3,340	3,431
NCR	2,855	2,831
CETA	4,455	4,891
ECR	3,055	3,271
No Early CT	3,100	3,431

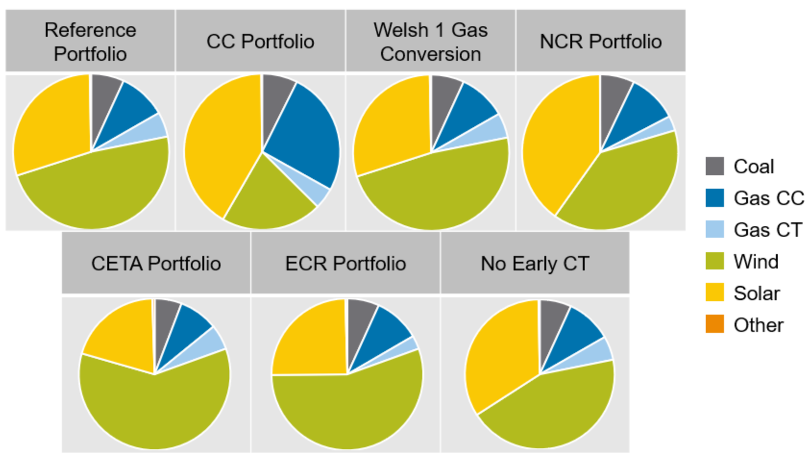
The NCR, ECR, and No Early CT portfolios tend to score lowest on this metric, particularly over the first 10 years, owing to the greater reliance on solar in the NCR and No Early CT case and the overall lower amount of new resources constructed in the ECR portfolio in anticipation of lower customer loads. The CETA and CC portfolios both show greater amounts of operational flexibility. Under the CC portfolio, this increase is due to the assumption that a 550 MW NGCC unit will be added to the portfolio in 2025, even if it is not least-cost. Under the CETA portfolio, the overall higher amount of new resource additions needed to meet higher load growth results in the greatest operational flexibility.

The Reference and Welsh 1 Gas Conversion portfolios have similar amounts of dispatchable capacity in both 2031 and 2041. The Welsh 1 Gas Conversion portfolio scores slightly higher than the Reference portfolio because it benefits from the higher capacity credit associated with the converted Welsh 1 unit.

Resource Diversity

Figure 75 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 2041 under Reference Scenario market conditions.

Figure 75: 2041 Generation Mix by Technology and Portfolio (MWh)



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

The CC portfolio is most diverse, owing to the assumption that this resource will be added despite the fact that it is not least-cost. The NCR and No Early CT portfolios are the next most diverse, with similar proportions of energy provided by new solar and wind units. Reference and Welsh 1 Gas Conversion portfolios score similarly on this metric, but are slightly more wind-heavy than the NCR or No Early CT portfolios. Finally, the ECR and CETA portfolios are the least diverse, with wind dominating total portfolio generation in 2041.

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 2022 and 2031; and
- The percentage reduction in CO_2 emissions in 2031 and 2041 from owned resources relative to the baseline year 2000 in the Reference Scenario.

Local Impacts

Table 23 compares the total new installed nameplate capacity and total expected CAPEX invested inside SWEPCO service territory between 2022 and 2031 for each candidate portfolio. This includes assumptions that most assets would be located inside SWEPCO's territory. 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 23: Local Impacts Metrics by Portfolio

Portfolio	New Nameplate Capacity Between 2022 and 2031 (MW)	Total CAPEX Invested Inside SWEPCO Territory ($ Millions)
Reference	2,720	2,201
CC	3,030	2,559
Welsh 1 Gas Conv.	2,240	1,906
NCR	2,280	2,037
CETA	2,880	2,171
ECR	2,230	1,878
No Early CT	2,000	1,875

The CC portfolio scores best by the MW metric and by the dollar metric. The CETA portfolio is next best by the MW metric and third by the dollar metric, owing to the greater deployment of new resources under this case to meet faster growth in customer load. The Reference portfolio is third-best in capacity metric with more than 2,700 MW installed in the territory and a total expected investment of approximately $2.2 billion over the 10 years which ranks second across the portfolio options. The Welsh 1 Gas Conversion, No Early CT, ECR, and NCR portfolios score similarly by this measure and result in approximately $1.9-$2.0 billion in new investment in the SWEPCO territory over the next 10 years.

CO_2 Emissions

Table 24 shows the levels of carbon emissions in 2030 and 2041 in the Reference scenario by portfolio and expresses the reduction in carbon emissions relative to the level of emissions to 2000 in percentage terms. Total CO_2 emissions from both SWEPCO owned plants and contracted output was 24.7mt in year 2000. Emissions have since declined and are now forecast to be around 16.5mt in 2022.

Table 24 CO_2 Emission Reductions by Portfolio

Portfolio	Level of Emissions in 2000 ($mtCO_2$)	Level of Emissions in 2031 ($mtCO_2$)	% reduction in 2031 relative to 2000	Level of Emissions in 2041 ($mtCO_2$)	% reduction in 2041 relative to 2000
Reference	24.7	5.0	79%	4.0	84%
CC	24.7	6.6	73%	5.4	78%
Welsh 1 Gas Conv.	24.7	4.9	80%	4.0	84%
NCR	24.7	4.9	80%	3.6	85%
CETA	24.7	5.2	78%	4.2	83%
ECR	24.7	4.9	79%	3.6	85%
No Early CT	24.7	4.8	80%	4.0	84%

By 2031, all portfolios except the CC portfolio have similar levels of CO_2 emissions between 4.8 and 5.2mt and put SWEPCO on a pathway to achieve or nearly achieve the 2030 CO2 emissions reduction targets announced by AEP. The CC portfolio scores worst by this metric in 2031 due to the addition of the 550 MW NGCC unit that increases the forecast of generation from fossil fuels.

By 2041, all portfolios but the CC portfolio have similar levels of CO_2 emissions between 3.6 and 4.2mt. Again, the CC portfolio has the greatest emissions due to continued operations of the 550 MW NGCC resource not added in any of the other portfolios.

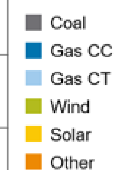
8.4.5. Evaluating the 2021 IRP Scorecard

The fully populated scorecard is shown in Figure 76. The key results from the scorecard are summarized below:

- The Reference and the Welsh 1 Gas Conversion portfolios perform similarly well across all criteria. However, the Welsh 1 Gas Conversion portfolio has a slightly lower revenue requirements due to the savings associated with avoiding a new and costlier greenfield investment.
- The Welsh 1 Gas Conversion and the No Early CT portfolios are similar in cost, with the No Early CT resulting in lower near-term rate increases but a slightly higher 30-year NPVRR by about $44 million or $0.20 per MWh in levelized rates. The No Early CT portfolio shows a slightly higher scenario range but lower cost risk. All other metrics show very similar outcomes.
- The CETA portfolio is a clear outlier when measured against the customer affordability objective. While lowest cost under CETA Scenario conditions, the CETA portfolio exposes customers to higher costs if load growth does not accelerate and federal tax credits are not extended. However, the greater amount of new resource additions in this portfolio results in the highest levels of planning reserves and operational flexibility.
- The CC portfolio similarly performs well on reliability metrics due to the addition of the 550 MW NGCC unit providing additional dispatchable capacity and firm capacity. However, its high reliance on gas-fired generation leaves ratepayers exposed to gas and carbon price risks.
- 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 12% reserve margin requirement for the SPP region. The ECR portfolio is also capacity short and so it is exposed to market prices in the surrounding markets.

Figure 76: Populated 2021 IRP Scorecard

	Customer Affordability		**Rate Stability**			**Maintaining Reliability**			**Local Impacts & 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*	***Local Impacts:*** *New Nameplate MW & Total CAPEX Installed Inside SWEPCO Territory*	***CO2 Emissions:*** *Percent Reduction from 2000 Baseline - Reference Case*
Year Ref.	2022-2027	2022-2051	2022-2051	2031 | 2041	2031	2022-2041	2031 | 2041	2041	2022-2031	2031 | 2041
Units	%	$MM Levelized Rate	$MM Levelized Rate	$MM	Summer | Winter	Summer | Winter	MW	%	MW | $MM	% Reduction
Reference Portfolio	2.57	15,435 $56.1	652 $3.7	25.4 | 26.8	11% | 21%	16% | 30%	3,295 | 3,431		2,720 | $2,201	79% | 84%
CC Portfolio	2.84	16,309 $59.3	1,960 $11.1	15.7 | 19.3	1% | 0%	17% | 27%	3,605 | 3,641		3,030 | $2,559	73% | 78%
Welsh 1 Gas Conv.	2.57	15,287 $55.6	649 $3.7	24.9 | 26.7	9% | 21%	16% | 31%	3,340 | 3,431		2,240 | $1,906	80% | 84%
NCR Portfolio	2.35	15,500 $56.4	837 $5.4	19.5 | 21.4	4% | 15%	8% | 13%	2,855 | 2,831		2,280 | $2,037	80% | 85%
CETA Portfolio	4.22	16,475 $59.9	1,870 $7.6	35.9 | 40.7	24% | 43%	26% | 50%	4,455 | 4,891		2,880 | $2,171	78% | 83%
ECR Portfolio	2.55	15,270 $55.5	1,044 $2.2	28.9 | 28.7	14% | 29%	10% | 23%	3,055 | 3,271		2,230 | $1,878	79% | 85%
No Early CT Portfolio	2.51	15,331 $55.8	735 $4.1	20.3 | 24.6	10% | 21%	15% | 25%	3,100 | 3,431		2,000 | $1,875	80% | 84%



Note - 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 Portfolio

The IRP Scorecard does not select a Preferred Plan on its own, rather it provides a way of systematically comparing how each of the candidate plans perform across the four IRP objectives. Each candidate resource plan considered in the 2021 IRP represents a trade-off between the objectives defined by SWEPCO. The CETA portfolio, for example, provides the greatest level of seasonal reliability, but has the highest expected costs to customers. Conversely, the ECR portfolio performs well in Customer Affordability but has low rankings in Rate Stability and Maintaining Reliability. The purpose of the Scorecard is therefore to provide SWEPCO management with a tool that illustrates these trade-offs and enables the selection of the best path forward for SWEPCO's customers and stakeholders.

After consideration of the portfolio needs and risks, SWEPCO selected the No Early CT portfolio as the Preferred Plan for the 2021 IRP. SWEPCO selected the No Early CT portfolio because it scores competitively across all scorecard elements and provides a clear path forward to meeting SWEPCO load requirements in the next five years. The rest of this section will review the detailed outputs of the Preferred Plan and discuss its performance relative to the other candidate portfolios considered as part of the 2021 IRP.

8.5.1. Details of the Preferred Portfolio

SWEPCO determined that the No Early CT portfolio provides the best combination of supply- and demand-side resources to meet SWEPCO's future customer needs. The plan maintains affordable and stable rates for SWEPCO customers, is expected to maintain reliability across seasons, and creates opportunities for local development all while reducing greenhouse gas emissions in line with AEP corporate targets. Details of the annual capacity additions in the Preferred Plan are displayed in Figure 77.

Figure 77: Annual Capacity Additions in the 2021 IRP Preferred Plan

Utility-Scale New Build Additions by Year (Nameplate MW)						
Year	New Solar	New Wind	New Gas CT	Welsh 1 Gas Conv.	New Storage	Capacity Purchases
2022						
2023						271
2024	450*	950*				279
2025	100*	1,500*				
2026						
2027	400					
2028	450			525		
2029	450					
2030	450					
2031	300					
2032	250					
2033	450					
2034						
2035						
2036	50		480			
2037			480			
2038	100		480			
2039	250		480			
2040			240			
2041	300					
Total	4,000	2,450	2,160	525	0	

Demand Side Additions by Year (Peak Credit MW)			
Year	Energy Efficiency	Distributed Generation	Total + 12%
2022		1.8	2.02
2023	7.9	3.0	12.19
2024	17.9	3.6	24.14
2025	27.7	5.1	36.74
2026	36.1	6.2	47.41
2027	44.3	8.0	58.47
2028	44.2	8.6	59.08
2029	39.7	9.4	55.00
2030	35.1	9.4	49.89
2031	30.2	10.3	45.34
2032	28.5	10.6	43.78
2033	23.7	10.8	38.67
2034	18.6	11.0	33.19
2035	14.8	10.9	28.71
2036	12.6	11.2	26.66
2037	11.0	11.1	24.74
2038	7.9	11.7	22.00
2039	5.4	12.0	19.46
2040	3.3	12.5	17.63
2041	2.3	12.9	17.01

**Resources are added 12/31 of given year due to tax incentive deadlines*

Under the Preferred Plan, the Welsh 1 coal unit is converted to run on natural gas in 2028 and is assumed to operate for an additional 10 years through the end of 2037. On the demand side, SWEPCO proposes approximately 50 MW of demand-side resources between 2022 and 2028, which serve to offset approximately 59 MW of resources by 2028. After 2028, the impact of demand-side programs is reduced as the measures age and more efficient technologies are adopted market-wide. In addition to demand-side programs, SWEPCO proposes to add 4,000 MW of new solar and 2,450 MW of new wind. All of the wind is added in the near-term to take advantage of the production tax credit. A small amount of new solar (550 MW) is added over the next five years, with the majority added during the 2027-2033 time period as solar costs are forecasted to decline and the capacity need increases. The Preferred Plan also proposes to add 2,160 MW of new gas CT in 2036-2040 as the Welsh 1 gas conversion unit retires along with Flint Creek coal plant and Wilkes 1 & 2 gas units. The Preferred Plan also assumes 270-280 MW of capacity purchases during 2023-2024 as new resources are phased into the portfolio.

The Preferred Plan is informed by an optimized analysis to meet SPP minimum reserve margins given assumptions about resource availability and constraints on portfolio energy sales. However, this plan is based on an uncertain future regarding events that can impact the Company's capacity position, including uncertainty around intermittent resources contribution to reserve margins, load growth, new environmental and tax policy, and existing unit performance. Consequently, the Company will continue to evaluate its capacity position relative to these risks and may consider adding additional resources in the future to the plan to ensure a capacity position in compliance with SPP's summer capacity reserve requirement.

8.5.1. The Preferred Plan Best Achieves SWEPCO's IRP Objectives

Customer Affordability

When measured against the customer affordability objective, the Preferred Plan is among the most affordable resource plans evaluated in the 2021 IRP. In the short-term, the overall rate impact of the Preferred Plan is the second lowest-cost plan that was evaluated in the 2021 IRP. In the long-term, the Preferred Plan is among the lowest cost plans evaluated in the 2021 IRP. The Preferred Plan is within $61 million in NPVRR or about $0.20 in levelized rates of the lowest cost plan, representing about a 0.4% increase. Two of the seven portfolios evaluated are more than $978 million higher under the 30-year NPVRR, so the Preferred Plan serves to protect customers from extremely high costs seen in some of the other portfolios.

Rate Stability

When measured against the rate stability objective, the Scenario Range metric shows that expected costs under the Preferred Plan varied much less across the fundamental market scenarios compared to the CC, CETA, and ECR portfolios, but slightly more than the Reference and Welsh 1 Gas Conversion portfolios.

The cost risk measure shows that the Preferred Plan is able to withstand price and renewable output volatility better than average. The Preferred Plan has slightly more cost risk than the CC and NCR portfolios, but lower cost risk than the Welsh 1 Gas Conversion, Reference, ECR and CETA portfolios. The Preferred plan was among the lowest-risk portfolios in both 2031 and 2041.

The seasonal market exposure of the Preferred Plan is limited in summer with only a 10% net sales position needed to balance customer loads. Owing to lower load in winter, there is greater reliance on sales in this season under all plans, but the Preferred Plan performs the same or better than four of the other six portfolios during the winter season.

Maintaining Reliability

In the Planning Reserves metric, The Preferred Plan performs adequately to maintain a greater than 12% reserve margin in both the summer and winter seasons. While the SPP currently only enforces summer planning requirements, it is possible a seasonal requirement could be implemented in the future. The Preferred Plan has less planning reserves than the Reference, CC, Welsh 1 Gas Conversion, and CETA portfolios but is very close to all except CETA, which is optimized under higher native load conditions.

The Preferred Plan has average operational flexibility rankings when compared with other candidate portfolios, though outcomes are largely similar to the Reference and Welsh 1 Gas Conversion portfolios.

The resource diversity indicator shows the Preferred Plan ranks above average in terms of generation diversity, only behind the CC portfolio. Most all portfolios have a high reliance on wind, although the Preferred Plan has roughly similar quantities of wind and solar generation, helping it score well based on this metric.

Local Impacts & Sustainability

The Preferred Plan scores the lowest on the Local Impact indicator when compared to the other portfolio alternatives. While the dollar investment in the SWEPCO territory is very close to the ECR and Welsh 1 Gas Conversion portfolios, this is one area of tradeoff for the Preferred Plan. Since new resources have yet to be selected or sited, an action item in the five-year plan is to refine estimates for resources that can be integrated into the SWEPCO territory.

In the Sustainability metric, the Preferred Plan puts SWEPCO on a pathway to meet a portion of the 80% CO_2 emissions reduction target announced by AEP relative to the 2000 baseline. By 2041, all plans except the CC portfolio are on track to achieve reductions around 84% relative to the 2000 baseline. In the Preferred Plan, SWEPCO would seek opportunities for further reduction or offset during the 2040s to meet the 2050 net-zero target.

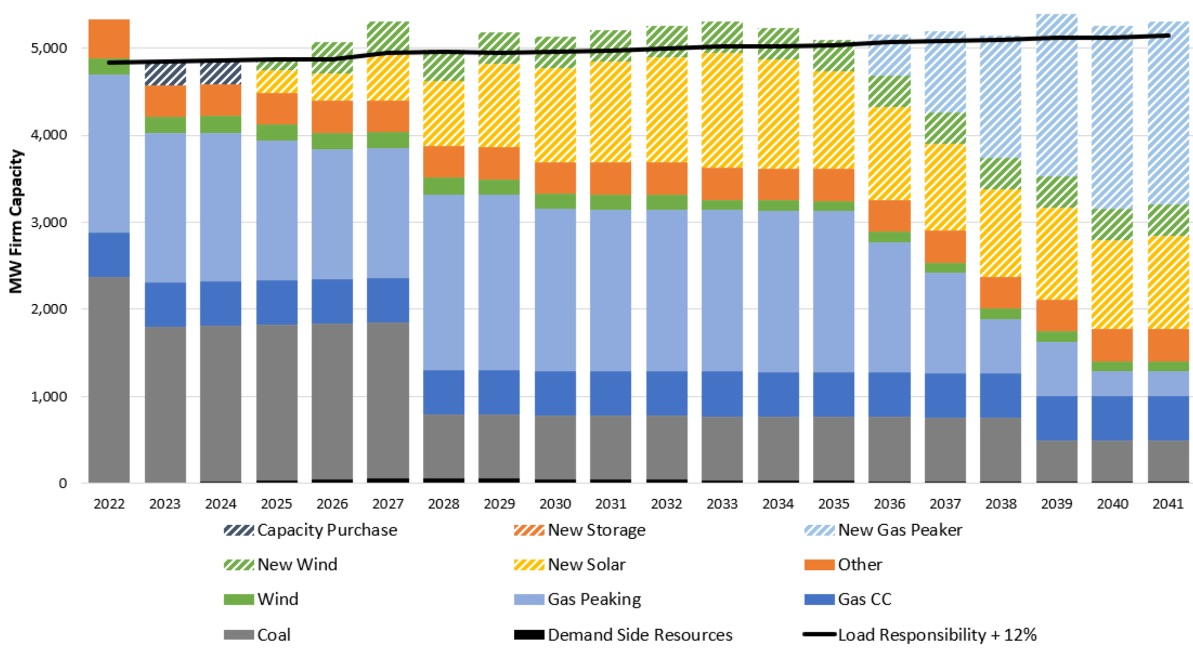
9. Conclusion

SWEPCO selected the No Early CT portfolio as the Preferred Plan for the 2021 IRP because it best meets the objectives of providing affordable, reliable electricity for customers while also maintaining rate stability and achieving AEP sustainability targets.

9.1. Plan Summary

Figure 78 summarizes the additions to the SWEPCO portfolio over the 2022-2041 time period under the Preferred Plan. It shows how a combination of new supply- and demand-side resources meets expected customer needs and maintains or exceeds the 12% planning reserve margin required by SPP. The Preferred Plan retains the 525 MW Welsh 1 unit for an additional 10 years past the original retirement date by converting it to burn natural gas, adds 4,000 MW of new Solar PV, 2,450 MW of new wind, and adds both energy efficiency and distributed generation resources over the next 20 years.

Figure 78: 2021 IRP Preferred Plan Summer Capacity Position (MW Firm Capacity)



9.2. Five-Year Action Plan

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

- Continue the planning and regulatory actions to implement cost effective energy efficiency and demand response programs that reduce energy use and peak demand for SWEPCO customers.
- Continue to investigate opportunities to incorporate advanced technologies related to DER technology to provide both capacity relief and improved reliability
- Develop more refined estimates about which technologies and what quantity of resources can be integrated into the SWEPCO territory
- Seek to refine cost estimates and develop plans for a potential Welsh 1 gas conversion

- Continue to evaluate and/or conduct Request for Proposals (RFP) to explore opportunities to add cost-effective renewable generation in the near future to take advantage of the Federal Tax Credit.
- Evaluate the Request for Proposals (RFP) to explore opportunities to add cost-effective capacity in the near future to meet capacity need in 2023-2024 as needed.
- Be ready to adjust this Action Plan and future IRPs to reflect changing circumstances.

The Preferred Plan is informed by an optimized analysis to meet SPP minimum reserve margins given assumptions about resource availability and constraints on portfolio energy sales. However, this plan is based on an uncertain future regarding events that can impact the Company's capacity position, including uncertainty around intermittent resources contribution to reserve margins, load growth, new environmental and tax policy, and existing unit performance. Consequently, the Company will continue to evaluate its capacity position relative to these risks and may consider adding additional resources in the future to ensure a capacity position in compliance with SPP's capacity reserve requirement.[33]

33 On December2, 2021, AEP/SWEPCO decided to delay the planned retirement of Lieberman Units 3 and 4 in December 2022 and December 2024 respectively, to no later than December 31, 2026. Given the timing of this decision, this was unable to be represented in this IRP. However, SWEPCO intends to update the information in its upcoming Louisiana IRP as the extension provides for a smooth transition to preferred plan resources in 2026.

Appendix A: Supplemental Data

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										
2011	6,908	---	6,280	---	5,408	---	7,480	---	26,077	---
2012	6,301	-8.8	6,103	-2.8	5,661	4.7	7,123	-4.8	25,188	-3.4
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
Forecast										
2021*	6,347	6.0	5,494	3.7	4,690	-4.1	5,725	1.9	22,255	2.1
2022	6,357	0.2	5,468	-0.5	4,729	0.8	5,784	1.0	22,339	0.4
2023	6,360	0.0	5,472	0.1	4,755	0.5	5,834	0.9	22,422	0.4
2024	6,384	0.4	5,464	-0.1	4,759	0.1	5,858	0.4	22,465	0.2
2025	6,409	0.4	5,461	-0.1	4,767	0.2	5,871	0.2	22,509	0.2
2026	6,430	0.3	5,441	-0.4	4,772	0.1	5,904	0.6	22,547	0.2
2027	6,454	0.4	5,426	-0.3	4,787	0.3	5,922	0.3	22,588	0.2
2028	6,469	0.2	5,406	-0.4	4,790	0.1	5,954	0.6	22,620	0.1
2029	6,495	0.4	5,399	-0.1	4,798	0.2	5,964	0.2	22,655	0.2
2030	6,507	0.2	5,386	-0.2	4,806	0.2	5,982	0.3	22,681	0.1
2031	6,525	0.3	5,375	-0.2	4,816	0.2	6,001	0.3	22,718	0.2
2032	6,545	0.3	5,364	-0.2	4,824	0.2	6,027	0.4	22,761	0.2
2033	6,573	0.4	5,361	-0.1	4,840	0.3	6,038	0.2	22,812	0.2
2034	6,594	0.3	5,349	-0.2	4,854	0.3	6,067	0.5	22,863	0.2
2035	6,623	0.4	5,346	-0.1	4,871	0.4	6,079	0.2	22,919	0.2
2036	6,651	0.4	5,343	-0.1	4,888	0.3	6,096	0.3	22,978	0.3
2037	6,681	0.5	5,341	0.0	4,907	0.4	6,115	0.3	23,044	0.3
2038	6,709	0.4	5,339	-0.1	4,928	0.4	6,138	0.4	23,113	0.3
2039	6,737	0.4	5,336	0.0	4,951	0.5	6,165	0.4	23,189	0.3
2040	6,762	0.4	5,333	-0.1	4,974	0.5	6,186	0.3	23,255	0.3
2041	6,793	0.5	5,334	0.0	4,999	0.5	6,199	0.2	23,325	0.3

Note: *2021 data are six months acutal and six months forecast.
**Other energy requirements include other retail sales, wholesale sales and losses.

	Residential		Commercial		Industrial		Other** Energy Requirements		Internal Energy Requirements	
Compound Annual Growth Rate 2011-2020										
	-1.6		-1.9		-1.1		-3.1		-2.0	
Compound Annual Growth Rate 2022-40										
	0.3		-0.1		0.3		0.4		0.2	

Exhibit A -2
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										
2011	1,198	---	1,390	---	1,575	---	12	---	4,175	---
2012	1,132	-5.5	1,356	-2.4	1,562	-0.8	12	-0.2	4,062	-2.7
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
Forecast										
2021*	1,179	5.9	1,249	3.9	986	-11.7	11	-2.5	3,425	-0.5
2022	1,174	-0.5	1,223	-2.0	902	-8.5	11	1.4	3,310	-3.4
2023	1,178	0.3	1,229	0.5	906	0.5	11	0.0	3,324	0.4
2024	1,187	0.8	1,230	0.0	913	0.8	11	0.0	3,341	0.5
2025	1,198	0.9	1,231	0.1	919	0.6	11	0.1	3,359	0.5
2026	1,212	1.2	1,230	-0.1	922	0.3	11	-0.1	3,375	0.5
2027	1,224	1.0	1,230	0.0	925	0.4	11	0.0	3,390	0.4
2028	1,230	0.5	1,228	-0.1	927	0.1	11	-0.1	3,396	0.2
2029	1,238	0.7	1,229	0.1	929	0.2	11	0.1	3,407	0.3
2030	1,245	0.5	1,230	0.0	930	0.2	11	0.0	3,416	0.2
2031	1,252	0.6	1,230	0.0	932	0.2	11	0.0	3,425	0.3
2032	1,260	0.6	1,230	0.0	934	0.2	11	-0.1	3,435	0.3
2033	1,268	0.7	1,232	0.1	937	0.3	11	0.1	3,448	0.4
2034	1,275	0.5	1,232	0.0	940	0.2	11	-0.1	3,457	0.3
2035	1,284	0.7	1,233	0.1	943	0.3	11	0.0	3,471	0.4
2036	1,292	0.7	1,235	0.1	946	0.3	11	0.0	3,483	0.4
2037	1,301	0.7	1,237	0.1	949	0.4	11	0.0	3,497	0.4
2038	1,309	0.6	1,238	0.1	952	0.3	11	0.0	3,510	0.4
2039	1,317	0.6	1,240	0.1	956	0.3	11	0.0	3,524	0.4
2040	1,324	0.5	1,241	0.1	959	0.3	11	0.0	3,535	0.3
2041	1,333	0.7	1,244	0.2	963	0.4	11	0.1	3,551	0.4
Note: *2021 data are six months acutal and six months forecast.										
Compound Annual Growth Rate 2011-2020										
	-0.8		-1.6		-3.8		-0.6		-2.1	
Compound Annual Growth Rate 2022-2041										
	0.7		0.1		0.3		0.0		0.4	

Exhibit A - 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										
2011	3,291	---	2,525	---	1,103	---	40	---	6,959	---
2012	2,990	-9.1	2,453	-2.9	1,080	-2.1	40	0.5	6,563	-5.7
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
Forecast										
2021*	2,929	4.6	2,181	3.0	1,097	-1.7	41	-0.6	6,248	2.8
2022	2,934	0.2	2,149	-1.5	1,151	4.9	41	0.0	6,274	0.4
2023	2,934	0.0	2,145	-0.2	1,158	0.7	41	0.0	6,279	0.1
2024	2,942	0.3	2,140	-0.2	1,162	0.3	41	0.0	6,285	0.1
2025	2,949	0.2	2,137	-0.2	1,163	0.1	41	0.0	6,289	0.1
2026	2,951	0.1	2,127	-0.5	1,161	-0.2	41	-0.1	6,279	-0.2
2027	2,957	0.2	2,120	-0.3	1,161	0.0	41	0.0	6,278	0.0
2028	2,960	0.1	2,111	-0.4	1,159	-0.1	41	-0.1	6,271	-0.1
2029	2,969	0.3	2,107	-0.2	1,159	0.0	41	0.0	6,276	0.1
2030	2,969	0.0	2,101	-0.3	1,160	0.1	41	0.0	6,270	-0.1
2031	2,972	0.1	2,096	-0.2	1,161	0.1	41	0.0	6,270	0.0
2032	2,978	0.2	2,091	-0.2	1,162	0.1	41	-0.1	6,271	0.0
2033	2,987	0.3	2,089	-0.1	1,165	0.2	41	0.0	6,281	0.2
2034	2,994	0.2	2,083	-0.3	1,167	0.2	41	-0.1	6,284	0.0
2035	3,004	0.4	2,081	-0.1	1,170	0.3	41	0.0	6,296	0.2
2036	3,016	0.4	2,078	-0.1	1,173	0.3	41	0.0	6,308	0.2
2037	3,028	0.4	2,077	-0.1	1,177	0.3	41	0.0	6,322	0.2
2038	3,039	0.4	2,074	-0.1	1,180	0.3	41	0.0	6,334	0.2
2039	3,050	0.4	2,072	-0.1	1,184	0.3	41	0.0	6,346	0.2
2040	3,060	0.3	2,069	-0.1	1,187	0.3	41	0.0	6,357	0.2
2041	3,072	0.4	2,069	0.0	1,192	0.4	41	0.0	6,373	0.2
Note: *2021 data are six months acutal and six months forecast.										
Compound Annual Growth Rate 2011-2020										
	-1.8		-1.9		0.1		0.3		-1.5	
Compound Annual Growth Rate 2022-2041										
	0.2		-0.2		0.2		0.0		0.1	

Exhibit A - 2
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										
2011	2,419	---	2,365	---	2,730	---	31	---	7,544	---
2012	2,179	-9.9	2,294	-3.0	3,018	10.6	30	-3.5	7,521	-0.3
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
Forecast										
2021*	2,238	8.0	2,064	4.4	2,607	-1.9	27	0.8	6,937	3.0
2022	2,250	0.5	2,097	1.6	2,677	2.7	27	0.0	7,051	1.6
2023	2,248	-0.1	2,098	0.1	2,691	0.5	27	0.3	7,064	0.2
2024	2,254	0.3	2,094	-0.2	2,684	-0.3	27	0.2	7,060	-0.1
2025	2,263	0.4	2,093	-0.1	2,685	0.0	27	0.2	7,068	0.1
2026	2,267	0.2	2,084	-0.4	2,689	0.2	27	0.0	7,068	0.0
2027	2,274	0.3	2,076	-0.4	2,701	0.4	27	0.1	7,078	0.2
2028	2,279	0.2	2,066	-0.5	2,704	0.1	27	0.0	7,077	0.0
2029	2,288	0.4	2,062	-0.2	2,710	0.2	27	0.2	7,087	0.1
2030	2,294	0.3	2,056	-0.3	2,716	0.2	27	0.1	7,093	0.1
2031	2,301	0.3	2,050	-0.3	2,723	0.3	27	0.1	7,101	0.1
2032	2,308	0.3	2,043	-0.3	2,728	0.2	27	0.0	7,107	0.1
2033	2,318	0.4	2,040	-0.1	2,738	0.4	28	0.1	7,124	0.2
2034	2,325	0.3	2,034	-0.3	2,747	0.3	28	0.0	7,134	0.1
2035	2,335	0.4	2,032	-0.1	2,758	0.4	28	0.1	7,152	0.3
2036	2,344	0.4	2,030	-0.1	2,769	0.4	28	0.1	7,170	0.2
2037	2,353	0.4	2,028	-0.1	2,781	0.4	28	0.1	7,190	0.3
2038	2,361	0.4	2,026	-0.1	2,795	0.5	28	0.0	7,210	0.3
2039	2,370	0.3	2,025	-0.1	2,811	0.6	28	0.0	7,233	0.3
2040	2,378	0.3	2,022	-0.1	2,828	0.6	28	0.1	7,255	0.3
2041	2,388	0.4	2,022	0.0	2,844	0.6	28	0.1	7,282	0.4

Note: *2021 data are six months acutal and six months forecast.

Compound Annual Growth Rate	Residential	Commercial	Industrial	Other Retail	Retail Sales
Compound Annual Growth Rate 2011-2020	-1.7	-2.0	-0.3	-1.4	-1.3
Compound Annual Growth Rate 2022-2041	0.3	-0.2	0.3	0.1	0.2

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					
2011	5,554	4,823	5,554	26,077	53.6
2012	5,205	4,080	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	59.1
2015	5,149	4,708	5,149	25,115	55.7
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	57.2
2019	4,727	4,148	4,727	23,790	57.4
2020	4,351	3,900	4,351	21,792	57.2
Forecast					
2021*	4,556	4,563	4,563	22,255	55.7
2022	4,555	4,238	4,555	22,339	55.8
2023	4,563	4,253	4,563	22,422	56.1
2024	4,575	4,267	4,575	22,465	56.1
2025	4,583	4,278	4,583	22,509	56.1
2026	4,589	4,287	4,589	22,547	55.9
2027	4,597	4,296	4,597	22,588	56.1
2028	4,606	4,312	4,606	22,620	56.1
2029	4,605	4,314	4,605	22,655	56.2
2030	4,614	4,322	4,614	22,681	56.0
2031	4,625	4,332	4,625	22,718	56.1
2032	4,638	4,341	4,638	22,761	56.0
2033	4,649	4,352	4,649	22,812	56.0
2034	4,653	4,361	4,653	22,863	55.9
2035	4,668	4,371	4,668	22,919	56.1
2036	4,690	4,392	4,690	22,978	55.9
2037	4,700	4,393	4,700	23,044	56.0
2038	4,717	4,404	4,717	23,113	55.8
2039	4,735	4,418	4,735	23,189	55.9
2040	4,744	4,429	4,744	23,255	56.0
2041	4,761	4,441	4,761	23,325	55.9

Note: *2021 data are six months acutal and six months forecast.

Compound Annual Growth Rate 2011-2020					
	-2.7	-2.3	-2.7	-2.0	0.7
Compound Annual Growth Rate 2022-2040					
	0.2	0.2	0.2	0.2	0.0

Exhibit A - 4
Southwestern Electric Power Company
Actual Internal Energy Requirements (GWh)
By Customer Class

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2011	1	656.7	458.9	404.6	727.1	2,247.3
2011	2	575.3	440.2	380.1	546.4	1,942.0
2011	3	372.0	466.5	466.8	501.7	1,806.9
2011	4	405.2	483.7	460.8	468.2	1,818.0
2011	5	479.0	533.4	473.7	550.1	2,036.2
2011	6	761.2	646.6	490.4	705.2	2,603.3
2011	7	904.1	649.1	468.0	828.5	2,849.8
2011	8	931.2	691.4	500.6	830.9	2,954.0
2011	9	536.2	490.9	403.9	697.8	2,128.8
2011	10	384.9	500.1	472.8	491.4	1,849.2
2011	11	356.0	464.7	464.4	478.3	1,763.4
2011	12	545.8	454.8	422.4	655.0	2,078.0
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
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
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	369.5	1,506.9
2021	5	412.6	460.2	436.0	349.8	1,658.6
2021	6	555.7	524.6	437.5	529.9	2,047.7

*Other energy requirements include other retail sales, wholesale sales and losses.

Exhibit A - 5

Southwestern Electric Power Company

Forecast Internal Energy Requirements (GWh)

By Customer Class

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2021	7	734.7	553.0	405.5	590.5	2,283.8
2021	8	747.7	581.8	428.4	532.2	2,290.1
2021	9	548.0	477.1	382.9	514.5	1,922.5
2021	10	395.4	425.0	398.5	432.8	1,651.7
2021	11	398.0	440.7	426.9	355.3	1,620.9
2021	12	548.7	411.7	382.9	511.9	1,855.3
2022	1	636.3	412.7	354.5	564.8	1,968.3
2022	2	515.2	394.7	361.8	452.2	1,723.9
2022	3	410.5	385.9	376.8	448.6	1,621.8
2022	4	359.3	387.9	384.3	405.6	1,537.2
2022	5	478.7	494.4	437.1	388.1	1,798.4
2022	6	600.4	503.1	402.3	526.4	2,032.2
2022	7	738.0	559.0	407.9	578.5	2,283.3
2022	8	734.9	574.7	423.9	563.6	2,297.1
2022	9	546.5	479.1	382.2	518.6	1,926.4
2022	10	396.1	428.0	397.7	437.2	1,659.0
2022	11	391.5	435.3	420.5	383.6	1,630.8
2022	12	549.7	413.7	380.5	516.6	1,860.5
2023	1	635.5	414.1	358.4	572.0	1,980.0
2023	2	533.3	411.0	374.2	412.2	1,730.8
2023	3	407.7	386.0	380.3	453.0	1,627.0
2023	4	354.4	384.2	384.8	418.3	1,541.7
2023	5	473.8	488.7	435.6	409.9	1,807.9
2023	6	609.2	511.2	408.5	509.9	2,038.8
2023	7	724.4	546.4	402.6	618.1	2,291.5
2023	8	732.7	573.3	424.6	574.9	2,305.4
2023	9	545.5	478.1	383.1	522.6	1,929.3
2023	10	405.0	435.8	403.4	424.6	1,668.8
2023	11	385.9	428.3	417.2	407.0	1,638.4
2023	12	552.5	415.0	382.6	511.9	1,862.0
2024	1	648.8	421.1	364.1	542.4	1,976.3
2024	2	537.1	411.1	375.4	486.0	1,809.5
2024	3	403.6	380.3	377.7	454.9	1,616.4
2024	4	356.3	383.9	385.0	421.1	1,546.3
2024	5	474.6	487.2	434.8	409.3	1,805.8
2024	6	601.4	501.2	403.3	522.9	2,028.8
2024	7	732.5	551.9	406.3	604.6	2,295.3
2024	8	738.8	576.1	426.9	555.7	2,297.4
2024	9	544.4	475.1	382.4	524.2	1,926.1
2024	10	399.1	428.2	399.8	441.9	1,669.0
2024	11	397.2	438.0	423.5	373.3	1,632.0
2024	12	550.3	410.1	380.1	521.6	1,862.1
2025	1	648.2	418.5	363.2	560.2	1,990.1
2025	2	533.3	405.8	372.8	428.2	1,740.1
2025	3	408.5	381.3	378.7	457.3	1,625.8
2025	4	360.2	385.3	386.5	423.5	1,555.5
2025	5	479.0	490.2	437.6	405.1	1,811.9
2025	6	606.2	503.8	405.6	526.3	2,041.9
2025	7	734.2	550.6	406.6	615.1	2,306.6
2025	8	738.5	573.3	426.5	566.0	2,304.3
2025	9	550.1	477.6	384.6	526.9	1,939.2
2025	10	401.6	429.1	401.3	445.7	1,677.6
2025	11	393.4	432.4	420.9	392.7	1,639.4
2025	12	556.3	413.2	382.8	524.5	1,876.7
2026	1	648.1	415.0	361.9	566.2	1,991.3
2026	2	539.8	408.4	375.2	420.3	1,743.7
2026	3	410.4	381.3	379.7	459.3	1,630.7
2026	4	361.4	384.4	387.0	425.4	1,558.2
2026	5	477.3	485.3	435.6	413.4	1,811.5
2026	6	608.8	502.6	406.4	530.3	2,048.1
2026	7	734.2	546.5	406.1	622.0	2,308.9
2026	8	740.5	571.0	427.3	568.5	2,307.3
2026	9	552.2	475.5	385.4	528.8	1,941.9
2026	10	402.1	426.3	401.4	447.3	1,677.1
2026	11	396.5	432.6	422.7	396.4	1,648.2
2026	12	558.3	411.7	383.8	526.4	1,880.3
2027	1	652.3	415.4	364.1	560.7	1,992.4
2027	2	541.2	406.9	376.3	422.7	1,747.2
2027	3	414.8	383.0	382.6	461.9	1,642.4
2027	4	362.1	383.0	388.0	427.2	1,560.4
2027	5	476.3	481.1	434.9	422.8	1,815.0
2027	6	608.9	499.2	406.8	536.2	2,051.1
2027	7	737.9	545.9	408.1	616.6	2,308.5
2027	8	743.1	569.2	428.6	573.8	2,314.6
2027	9	554.1	473.5	386.5	530.6	1,944.7
2027	10	402.4	423.7	401.7	448.9	1,676.8
2027	11	399.7	433.3	424.5	391.7	1,649.2
2027	12	561.4	411.3	385.0	528.4	1,886.2

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2028	1	652.2	412.2	363.6	562.7	1,990.6
2028	2	539.5	402.9	375.2	507.5	1,825.1
2028	3	413.9	379.0	381.3	463.0	1,637.2
2028	4	360.0	377.1	385.1	427.9	1,550.2
2028	5	487.8	491.4	442.8	396.6	1,818.6
2028	6	611.6	498.7	407.8	529.6	2,047.8
2028	7	739.6	544.0	408.5	609.7	2,301.7
2028	8	744.2	566.8	428.7	575.2	2,314.9
2028	9	551.8	468.3	385.0	531.5	1,936.6
2028	10	407.8	426.0	403.8	438.9	1,676.4
2028	11	401.4	432.6	424.9	388.3	1,647.2
2028	12	559.6	407.0	383.2	523.4	1,873.3
2029	1	657.9	414.4	365.9	568.3	2,006.6
2029	2	544.7	404.8	377.1	427.5	1,754.1
2029	3	415.7	378.9	382.1	464.9	1,641.6
2029	4	364.4	380.1	388.0	430.5	1,563.0
2029	5	483.2	483.7	438.7	421.3	1,827.0
2029	6	613.4	497.8	408.3	532.9	2,052.4
2029	7	740.9	542.3	408.6	623.3	2,315.1
2029	8	746.3	565.8	429.3	583.1	2,324.6
2029	9	554.4	467.9	385.9	533.5	1,941.6
2029	10	408.7	424.7	404.1	450.0	1,687.5
2029	11	402.6	431.7	425.3	397.3	1,656.9
2029	12	562.3	406.9	384.2	531.4	1,884.8
2030	1	658.4	412.5	366.0	572.3	2,009.2
2030	2	545.5	403.4	377.6	430.1	1,756.6
2030	3	415.1	376.3	381.7	466.3	1,639.3
2030	4	366.3	380.1	389.1	432.4	1,567.9
2030	5	484.7	483.5	439.8	420.8	1,828.7
2030	6	614.4	496.5	408.8	531.7	2,051.4
2030	7	742.4	541.2	409.4	628.9	2,321.9
2030	8	748.0	564.9	430.2	580.7	2,323.8
2030	9	557.0	468.0	387.2	535.4	1,947.5
2030	10	408.3	422.6	404.3	454.4	1,689.7
2030	11	403.1	430.6	426.0	395.9	1,655.7
2030	12	564.3	406.6	385.6	533.2	1,889.7
2031	1	658.8	410.2	366.1	577.3	2,012.5
2031	2	546.7	402.3	378.3	432.3	1,759.6
2031	3	415.8	374.9	382.1	467.8	1,640.7
2031	4	367.4	379.1	389.8	434.0	1,570.4
2031	5	487.0	483.9	441.5	416.1	1,828.6
2031	6	616.1	495.6	409.8	537.2	2,058.7
2031	7	744.5	540.3	410.3	631.6	2,326.6
2031	8	750.1	564.0	431.2	578.8	2,324.0
2031	9	560.3	468.4	388.8	537.3	1,954.9
2031	10	409.2	421.6	405.2	455.9	1,692.0
2031	11	402.9	428.5	426.1	397.6	1,655.2
2031	12	566.6	406.5	386.9	535.0	1,894.9
2032	1	660.5	408.8	366.6	567.6	2,003.5
2032	2	546.3	399.6	378.0	511.7	1,835.7
2032	3	419.0	375.3	383.6	469.6	1,647.5
2032	4	366.9	376.1	389.0	435.1	1,567.1
2032	5	491.4	486.3	444.2	401.9	1,823.8
2032	6	618.0	494.8	410.4	537.3	2,060.6
2032	7	747.2	539.9	411.2	621.4	2,319.7
2032	8	752.4	563.3	431.9	577.4	2,325.0
2032	9	559.7	465.3	388.4	538.4	1,951.7
2032	10	412.0	421.8	406.4	441.2	1,681.3
2032	11	406.0	429.7	428.0	389.4	1,653.1
2032	12	565.9	403.5	386.3	536.0	1,891.7
2033	1	664.6	409.8	368.7	574.5	2,017.6
2033	2	550.3	400.7	380.0	436.1	1,767.0
2033	3	422.5	376.9	386.0	471.6	1,656.9
2033	4	368.5	376.1	390.5	436.7	1,571.8
2033	5	489.2	481.5	442.5	423.9	1,837.0
2033	6	620.2	494.3	411.6	545.4	2,071.6
2033	7	749.9	539.4	412.5	627.1	2,329.0
2033	8	754.9	562.6	433.1	591.3	2,341.9
2033	9	564.2	466.5	390.6	540.4	1,961.8
2033	10	411.6	419.2	406.6	453.7	1,691.2
2033	11	407.7	429.1	429.3	398.7	1,664.7
2033	12	569.9	404.6	388.8	538.1	1,901.4
2034	1	664.5	407.0	368.7	585.5	2,025.7
2034	2	552.1	400.0	381.2	437.7	1,771.0
2034	3	423.5	375.6	386.9	473.2	1,659.1
2034	4	369.5	374.8	391.3	438.2	1,573.9
2034	5	492.4	482.4	444.8	424.6	1,844.1
2034	6	622.6	493.9	413.1	546.5	2,076.1
2034	7	752.6	538.8	413.8	629.7	2,335.0
2034	8	757.6	562.0	434.5	593.9	2,348.1
2034	9	565.1	464.5	391.2	541.9	1,962.7
2034	10	414.9	419.8	408.6	454.8	1,698.2
2034	11	409.4	428.6	430.7	401.2	1,669.9
2034	12	569.6	401.8	388.8	539.3	1,899.5

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2035	1	668.9	408.3	371.2	581.8	2,030.3
2035	2	553.9	399.4	382.5	439.3	1,775.1
2035	3	423.2	373.2	387.0	474.5	1,657.9
2035	4	372.2	375.1	393.0	440.1	1,580.5
2035	5	495.5	483.4	447.0	423.2	1,849.1
2035	6	625.2	493.6	414.5	544.3	2,077.6
2035	7	755.4	538.3	415.1	636.1	2,344.9
2035	8	760.7	561.8	436.0	595.4	2,354.0
2035	9	566.4	462.9	392.0	543.4	1,964.7
2035	10	418.0	420.3	410.5	457.0	1,705.8
2035	11	411.2	428.3	432.1	402.6	1,674.3
2035	12	571.8	401.4	390.2	541.1	1,904.5
2036	1	671.1	407.5	372.4	578.6	2,029.6
2036	2	554.1	397.5	383.0	498.6	1,833.2
2036	3	420.7	368.3	385.4	475.2	1,649.6
2036	4	374.6	374.6	394.1	441.9	1,585.1
2036	5	503.3	489.6	452.6	401.6	1,847.1
2036	6	627.9	493.4	415.9	542.9	2,080.0
2036	7	758.6	538.3	416.5	637.4	2,350.8
2036	8	764.4	562.2	437.7	583.2	2,347.5
2036	9	570.3	463.6	393.9	545.4	1,973.1
2036	10	418.8	418.9	411.3	456.5	1,705.5
2036	11	413.3	428.3	433.7	391.8	1,667.1
2036	12	574.0	400.8	391.6	542.8	1,909.2
2037	1	672.9	406.5	373.5	584.6	2,037.5
2037	2	557.6	398.3	385.1	443.8	1,784.7
2037	3	425.8	371.4	389.1	477.7	1,664.0
2037	4	377.1	375.7	396.5	443.8	1,593.2
2037	5	500.2	483.6	450.2	419.6	1,853.6
2037	6	630.5	493.1	417.3	553.5	2,094.4
2037	7	762.1	538.4	418.1	643.7	2,362.3
2037	8	767.9	562.3	439.3	590.3	2,359.8
2037	9	574.9	464.8	396.2	547.6	1,983.5
2037	10	419.4	417.2	412.1	462.4	1,711.1
2037	11	415.1	427.9	435.1	403.0	1,681.1
2037	12	577.9	402.0	394.2	544.9	1,919.0
2038	1	673.5	404.6	374.2	587.3	2,039.6
2038	2	559.3	397.9	386.6	445.5	1,789.3
2038	3	430.6	374.1	392.5	480.0	1,677.2
2038	4	378.3	375.1	398.0	445.5	1,596.9
2038	5	500.3	481.3	450.5	427.6	1,859.7
2038	6	633.2	493.1	419.1	555.6	2,101.1
2038	7	765.4	538.6	420.0	642.1	2,366.1
2038	8	771.0	562.3	441.2	596.9	2,371.4
2038	9	577.6	464.6	398.0	549.4	1,989.7
2038	10	421.8	417.1	414.2	459.6	1,712.7
2038	11	417.1	427.7	437.1	401.5	1,683.4
2038	12	580.7	402.1	396.4	546.9	1,926.1
2039	1	674.9	403.3	375.5	595.3	2,049.0
2039	2	561.4	397.6	388.5	447.1	1,794.6
2039	3	432.0	373.4	394.1	481.8	1,681.3
2039	4	378.6	373.1	398.7	447.0	1,597.4
2039	5	504.7	483.8	454.1	426.3	1,868.9
2039	6	636.1	493.4	421.3	557.7	2,108.4
2039	7	768.9	539.0	422.1	641.1	2,371.1
2039	8	774.2	562.5	443.2	604.0	2,384.0
2039	9	580.3	464.6	399.9	551.4	1,996.2
2039	10	424.3	417.2	416.3	460.9	1,718.7
2039	11	419.1	427.7	439.2	403.8	1,689.7
2039	12	582.0	400.8	397.8	548.5	1,929.1
2040	1	678.0	403.6	378.0	589.4	2,048.9
2040	2	560.8	395.2	389.3	531.2	1,876.4
2040	3	429.3	368.4	393.2	482.6	1,673.5
2040	4	379.6	371.0	399.3	448.5	1,598.5
2040	5	514.3	492.1	461.7	404.1	1,872.3
2040	6	638.9	493.6	423.4	548.8	2,104.7
2040	7	771.8	539.1	424.1	640.3	2,375.2
2040	8	777.4	562.9	445.4	598.0	2,383.8
2040	9	577.3	459.6	399.3	552.2	1,988.5
2040	10	431.6	421.7	420.7	449.6	1,723.6
2040	11	421.1	427.6	441.3	398.6	1,688.5
2040	12	581.7	398.2	398.3	542.3	1,920.5
2041	1	681.9	404.7	380.9	596.7	2,064.2
2041	2	565.0	396.7	392.3	451.3	1,805.3
2041	3	431.8	369.1	395.7	484.7	1,681.3
2041	4	383.9	374.1	403.4	451.0	1,612.4
2041	5	511.0	486.1	459.8	427.1	1,884.0
2041	6	641.6	493.8	425.4	553.7	2,114.6
2041	7	774.7	539.2	425.9	654.3	2,394.1
2041	8	780.9	563.5	447.5	603.2	2,395.1
2041	9	583.9	463.0	403.0	555.0	2,004.8
2041	10	429.7	417.9	420.8	466.9	1,735.3
2041	11	423.0	427.4	443.2	403.2	1,696.9
2041	12	585.2	398.9	400.9	552.1	1,937.1

Exhibit A - 6
Southwestern Electric Power Company
Actual and Weather Normal Energy Sales (GWh)
And Peak Demand (MW) vs. 2015 IRP Forecast

	2019 Forecast		Actual		Difference		%Difference	
	2019	2020	2019	2020	2019	2020	2019	2020
Residential	6,126	6,243	6,303	5,988	-177	255	-2.8%	4.3%
Commercial	5,751	5,855	5,776	5,296	-25	559	-0.4%	10.6%
Industrial	5,356	5,473	5,338	4,891	18	582	0.3%	11.9%
Other Retail	79	80	80	79	-1	1	-0.9%	0.8%
Wholesale	5,171	4,610	2,396	1,909	2,775	2,701	115.8%	141.5%
Total Sales	22,483	22,261	19,892	18,163	2,591	4,098	13.0%	22.6%

	2019 Forecast		Normal		Difference		%Difference	
	2019	2020	2019	2020	2019	2020	2019	2020
Residential	6,126	6,243	6,263	6,310	-137	-67	-2.2%	-1.1%
Commercial	5,751	5,855	5,756	5,394	-5	461	-0.1%	8.5%
Industrial	5,356	5,473	5,338	4,891	18	582	0.3%	11.9%
Other Retail	79	80	80	79	-1	1	-0.9%	0.8%
Wholesale	5,171	4,610	2,391	1,948	2,780	2,662	116.3%	136.7%
Total Sales	22,483	22,261	19,828	18,622	2,656	3,639	13.4%	19.5%

	2019 Forecast		Actual		Difference		%Difference	
	2019	2020	2019	2020	2019	2020	2019	2020
Winter Peak	4,148	4,170	4,148	3,900	0	271	0.0%	6.9%
Summer Peak	4,784	4,673	4,727	4,351	57	322	1.2%	7.4%

	2019 Forecast		Normal		Difference		%Difference	
	2019	2020	2019	2020	2019	2020	2019	2020
Winter Peak	4,148	4,170	4,322	4,272	-174	-101	-4.0%	-2.4%
Summer Peak	4,784	4,673	4,869	4,640	-85	34	-1.7%	0.7%

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		
		Summer*	Winter*		Summer*	Winter*		Summer*	Winter*		Summer*	Winter*
Year	Energy	Demand	Demand	Energy	Demand	Demand	Energy	Demand	Demand	Energy	Demand	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 Households	SWEPCO Arkansas Employment	SWEPCO Louisiana Population	SWEPCO Louisiana Real Personal Income	SWEPCO Louisiana Households	SWEPCO Texas Employment	SWEPCO Texas Real Personal Income
1995	566.0	15,328.5	218.4	273.3	572.4	15,253.8	211.6	784.8	20,336.3
1996	582.1	16,056.6	224.4	278.5	573.6	15,462.5	212.9	796.2	21,251.7
1997	593.8	16,796.7	228.9	283.1	574.1	15,787.9	214.2	804.8	22,470.1
1998	602.5	17,917.9	232.9	288.1	573.0	16,248.6	215.6	813.4	23,509.8
1999	613.6	18,700.6	237.7	296.6	575.5	16,592.4	218.6	819.5	23,927.4
2000	627.3	19,499.7	242.3	303.8	577.2	17,066.6	219.7	825.4	24,986.4
2001	636.3	20,012.8	245.8	309.5	576.6	18,165.8	220.0	830.1	25,856.8
2002	647.0	20,378.7	250.9	313.1	576.7	18,378.8	220.4	837.4	26,034.6
2003	659.7	21,237.6	256.6	315.3	575.9	18,541.2	220.8	845.2	26,495.9
2004	672.9	22,970.9	261.7	321.6	579.9	18,831.2	221.5	853.1	26,948.2
2005	690.0	24,109.7	268.4	332.0	583.4	19,803.9	225.2	861.1	28,162.8
2006	708.5	25,529.8	274.5	340.4	589.7	20,493.0	229.4	873.9	29,602.9
2007	722.3	26,810.8	279.5	342.5	589.7	20,505.1	231.9	882.2	30,454.6
2008	733.4	27,727.2	283.8	340.7	590.3	22,681.4	232.6	890.2	33,596.4
2009	743.7	26,268.2	286.5	326.9	596.1	21,889.6	234.6	900.5	31,948.7
2010	755.6	27,093.5	289.5	327.3	603.4	23,067.4	236.5	907.8	33,572.5
2011	767.2	29,581.9	294.4	329.3	606.9	23,316.9	238.7	912.4	35,626.9
2012	776.3	32,872.7	298.4	334.5	611.8	23,440.1	241.1	915.6	35,813.1
2013	784.3	32,321.1	302.7	337.1	608.3	23,391.5	241.1	916.9	35,691.9
2014	792.2	35,609.5	307.2	347.6	605.8	24,287.1	241.2	921.0	36,863.4
2015	803.3	37,624.7	312.5	360.3	603.5	23,960.0	241.0	924.9	35,918.9
2016	814.3	39,100.3	317.8	371.9	600.9	23,068.3	240.9	929.4	34,909.7
2017	826.4	40,038.3	322.2	378.7	596.6	22,995.8	239.6	933.7	36,369.5
2018	834.9	42,078.9	325.9	384.8	591.0	23,742.3	238.8	939.6	37,482.6
2019	844.2	42,504.4	329.6	390.4	586.6	23,794.1	237.7	945.0	37,907.0
2020	855.2	45,267.6	335.8	382.5	585.8	25,148.5	240.1	950.3	40,562.1
2021	865.5	47,273.7	339.8	392.7	585.7	26,092.3	240.7	954.7	42,905.8
2022	875.5	47,332.3	344.6	402.5	585.2	24,820.5	241.6	959.6	41,278.7
2023	885.4	49,349.7	349.5	410.5	584.8	25,245.3	242.6	964.7	42,367.7
2024	895.6	50,861.8	354.4	414.7	584.5	25,525.6	243.6	969.9	43,257.6
2025	905.6	52,368.7	359.4	417.6	583.9	25,701.5	244.5	975.0	44,040.6
2026	915.7	54,029.5	364.4	420.3	583.1	25,946.3	245.3	979.9	45,016.7
2027	925.7	55,830.9	369.1	422.9	582.2	26,273.6	245.8	984.7	46,146.9
2028	935.6	57,734.3	373.7	425.3	581.0	26,641.2	246.3	989.7	47,307.1
2029	945.4	59,726.6	378.3	428.1	579.8	26,998.5	246.7	994.9	48,459.4
2030	955.1	61,678.9	382.8	431.0	578.5	27,324.4	247.1	1,000.2	49,555.0
2031	964.8	63,579.2	387.3	433.7	577.3	27,627.7	247.5	1,005.5	50,632.6
2032	974.4	65,526.7	391.6	436.3	576.0	27,931.3	247.9	1,010.7	51,687.4
2033	984.1	67,474.7	395.9	439.0	574.8	28,209.1	248.3	1,015.8	52,706.8
2034	993.7	69,442.3	400.1	441.8	573.6	28,470.2	248.5	1,020.7	53,718.6
2035	1,003.3	71,428.8	404.3	444.7	572.4	28,713.4	248.8	1,025.5	54,701.7
2036	1,012.9	73,417.5	408.6	447.7	571.2	28,928.1	249.1	1,030.0	55,623.9
2037	1,022.4	75,408.0	412.7	450.6	570.0	29,131.1	249.3	1,034.3	56,531.1
2038	1,031.9	77,409.2	416.7	453.6	568.8	29,319.6	249.4	1,038.5	57,417.6
2039	1,041.3	79,419.4	420.7	456.7	567.6	29,500.2	249.4	1,042.6	58,324.0
2040	1,050.5	81,475.0	424.6	459.9	566.3	29,693.7	249.5	1,046.6	59,269.5
2041	1,059.5	83,574.2	428.3	463.1	565.0	29,893.1	249.4	1,050.5	60,235.8
2042	1,068.4	85,754.8	432.0	466.4	563.6	30,106.3	249.3	1,054.3	61,245.6
2043	1,077.1	87,989.6	435.6	469.6	562.2	30,326.4	249.2	1,058.0	62,283.5
2044	1,085.8	90,272.7	439.1	472.9	560.8	30,556.0	249.1	1,061.7	63,361.2
2045	1,094.3	92,583.8	442.8	476.1	559.4	30,783.5	249.1	1,065.3	64,460.2
2046	1,102.7	94,995.0	446.5	479.3	557.9	31,029.4	249.2	1,068.9	65,615.9
2047	1,110.6	97,544.9	450.1	482.4	556.5	31,300.8	249.2	1,072.2	66,827.1
2048	1,118.6	100,148.2	453.7	485.5	555.0	31,578.7	249.2	1,075.6	68,075.2
2049	1,126.7	102,769.8	457.3	488.5	553.6	31,855.4	249.3	1,078.8	69,357.7
2050	1,135.0	105,412.2	461.1	491.5	552.3	32,133.5	249.3	1,082.0	70,690.6
2051	1,143.4	108,135.3	464.9	494.5	551.0	32,415.2	249.4	1,085.2	72,051.7
2052	1,152.0	110,941.5	468.7	497.5	549.6	32,700.6	249.5	1,088.4	73,441.3
2053	1,160.7	113,833.6	472.7	500.5	548.3	32,989.8	249.5	1,091.7	74,860.3
2054	1,169.6	116,814.1	476.7	503.6	547.0	33,282.7	249.6	1,095.0	76,309.2
2055	1,178.6	119,885.8	480.7	506.7	545.7	33,579.5	249.7	1,098.3	77,788.7
2056	1,187.8	123,051.7	484.8	509.8	544.4	33,880.2	249.7	1,101.6	79,299.4
2057	1,197.1	126,314.5	489.0	513.0	543.1	34,185.0	249.8	1,104.9	80,842.1
Units	Thousands	Millions (2012 $)	Thousands	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 Texas Commercial Employment
YEAR	gdp_swa	n_swl	yr_swl	lcom_swt
1995	18,719.0	572.4	15,253.8	160.0
1996	19,449.7	573.6	15,462.5	164.6
1997	19,974.3	574.1	15,787.9	172.3
1998	20,390.9	573.0	16,248.6	176.0
1999	22,053.7	575.5	16,592.4	178.4
2000	22,628.0	577.2	17,066.6	181.4
2001	23,343.6	576.6	18,165.8	184.5
2002	24,830.8	576.7	18,378.8	186.9
2003	26,545.6	575.9	18,541.2	189.7
2004	28,219.4	579.9	18,831.2	196.9
2005	29,594.8	583.4	19,803.9	200.6
2006	30,256.9	589.7	20,493.0	204.8
2007	29,464.9	589.7	20,505.1	211.1
2008	28,995.2	590.3	22,681.4	215.2
2009	27,765.6	596.1	21,889.6	212.1
2010	28,936.4	603.4	23,067.4	213.5
2011	29,151.8	606.9	23,316.9	216.9
2012	29,556.6	611.8	23,440.1	222.3
2013	30,666.3	608.3	23,391.5	227.2
2014	31,478.5	605.8	24,287.1	228.3
2015	32,443.8	603.5	23,960.0	231.6
2016	33,118.9	600.9	23,068.3	231.5
2017	34,107.3	596.6	22,995.8	232.9
2018	35,063.9	591.0	23,742.3	235.3
2019	35,752.8	586.6	23,794.1	238.7
2020	35,443.6	585.8	25,148.5	230.2
2021	37,523.7	585.7	26,092.3	238.3
2022	39,567.3	585.2	24,820.5	245.4
2023	41,088.2	584.8	25,245.3	252.5
2024	42,161.0	584.5	25,525.6	256.1
2025	43,312.0	583.9	25,701.5	258.5
2026	44,443.7	583.1	25,946.3	260.9
2027	45,659.9	582.2	26,273.6	263.2
2028	46,844.0	581.0	26,641.2	265.3
2029	48,057.8	579.8	26,998.5	267.5
2030	49,253.1	578.5	27,324.4	269.6
2031	50,455.4	577.3	27,627.7	271.3
2032	51,671.9	576.0	27,931.3	272.6
2033	52,931.6	574.8	28,209.1	273.9
2034	54,235.6	573.6	28,470.2	275.3
2035	55,579.7	572.4	28,713.4	276.9
2036	56,960.7	571.2	28,928.1	278.3
2037	58,360.4	570.0	29,131.1	279.7
2038	59,789.8	568.8	29,319.6	281.1
2039	61,282.3	567.6	29,500.2	282.7
2040	62,811.2	566.3	29,693.7	284.3
2041	64,377.1	565.0	29,893.1	286.0
2042	65,966.1	563.6	30,106.3	287.8
2043	67,566.4	562.2	30,326.4	289.6
2044	69,203.1	560.8	30,556.0	291.5
2045	70,827.4	559.4	30,783.5	293.5
2046	72,448.3	557.9	31,029.4	295.6
2047	74,095.6	556.5	31,300.8	297.6
2048	75,737.3	555.0	31,578.7	299.6
2049	77,415.0	553.6	31,855.4	301.6
2050	79,120.9	552.3	32,133.5	303.5
2051	80,868.8	551.0	32,415.2	305.4
2052	82,659.8	549.6	32,700.6	307.4
2053	84,495.1	548.3	32,989.8	309.4
2054	86,375.7	547.0	33,282.7	311.4
2055	88,302.9	545.7	33,579.5	313.4
2056	90,277.8	544.4	33,880.2	315.5
2057	92,301.6	543.1	34,185.0	317.6
Units	Millions (2012 $)	Thousands	Millions (2012 $)	Thousands

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 Texas Gross Regional Product - Manufacturing	SWEPCO Texas Manufacturing Employment
1995	5,097.4	3,748.9	48.7	71.2
1996	4,902.4	3,292.3	49.3	74.9
1997	4,957.9	3,633.7	50.2	81.2
1998	4,899.1	3,707.6	51.3	86.6
1999	5,497.4	4,048.9	51.1	91.1
2000	5,543.2	3,161.9	51.1	95.1
2001	5,503.0	2,779.0	49.7	91.8
2002	5,945.6	3,266.0	48.2	92.4
2003	6,425.8	4,893.5	47.7	93.9
2004	6,946.6	5,806.7	49.0	97.0
2005	7,029.7	7,146.5	49.2	101.2
2006	7,102.4	6,057.6	50.0	104.0
2007	5,974.6	4,975.5	50.4	107.3
2008	5,312.2	4,448.4	48.9	102.4
2009	4,830.1	4,068.6	41.7	88.4
2010	5,291.3	4,914.6	39.2	94.1
2011	5,058.8	4,316.5	38.9	97.2
2012	4,580.3	4,089.9	37.6	100.0
2013	4,938.3	3,663.5	37.7	101.1
2014	5,106.3	3,960.4	39.4	102.3
2015	4,971.6	3,807.3	39.6	101.9
2016	4,932.3	3,597.6	38.1	101.1
2017	5,046.4	3,662.3	37.7	103.2
2018	5,262.5	3,905.2	38.9	106.0
2019	5,397.8	4,251.3	39.2	106.0
2020	5,254.7	4,214.2	37.0	98.9
2021	5,529.5	4,506.4	37.5	105.4
2022	5,779.1	4,732.1	37.9	109.2
2023	5,898.8	4,844.1	38.0	110.8
2024	5,966.1	4,874.5	37.6	111.8
2025	6,051.2	4,867.1	37.1	113.0
2026	6,130.5	4,827.8	36.7	114.2
2027	6,240.0	4,813.7	36.3	116.0
2028	6,355.0	4,821.3	35.8	118.0
2029	6,471.2	4,847.2	35.5	119.9
2030	6,586.1	4,887.8	35.1	122.0
2031	6,704.5	4,935.0	34.7	124.1
2032	6,817.3	4,982.3	34.2	126.1
2033	6,934.0	5,035.3	33.8	128.2
2034	7,054.2	5,096.1	33.4	130.4
2035	7,177.1	5,164.5	33.0	132.5
2036	7,299.6	5,236.5	32.6	134.6
2037	7,419.1	5,303.1	32.3	136.5
2038	7,537.8	5,373.4	31.9	138.6
2039	7,660.0	5,445.8	31.6	140.7
2040	7,782.9	5,520.6	31.3	142.8
2041	7,902.3	5,594.4	31.0	144.8
2042	8,021.0	5,667.8	30.8	146.7
2043	8,141.0	5,745.4	30.5	148.7
2044	8,272.9	5,836.1	30.3	150.8
2045	8,411.1	5,934.3	30.0	152.9
2046	8,544.3	6,031.2	29.8	155.0
2047	8,662.0	6,116.4	29.6	157.1
2048	8,763.7	6,190.0	29.4	159.3
2049	8,860.7	6,258.8	29.1	161.4
2050	8,959.4	6,330.0	28.9	163.6
2051	9,059.8	6,402.1	28.7	165.8
2052	9,161.8	6,475.1	28.4	168.0
2053	9,265.5	6,549.1	28.2	170.3
2054	9,370.9	6,624.0	28.0	172.5
Units	Millions (2012 $)	Millions (2012 $)	Thousands	Index (2012=100)

Exhbit A - 11
Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Other Retail and Wholesale Energy Sales Models

Year	SWEPCO Arkansas Gross Regional Product	SWEPCO Arkansas Employment	SWEPCO Arkansas Regulated Industries Employment	SWEPCO Louisiana Population	SWEPCO Texas Employment
1995	18,719.0	273.3	16.0	572.4	287.5
1996	19,449.7	278.5	16.1	573.6	294.1
1997	19,974.3	283.1	15.8	574.1	305.4
1998	20,390.9	288.1	15.7	573.0	309.6
1999	22,053.7	296.6	16.4	575.5	312.8
2000	22,628.0	303.8	16.3	577.2	318.2
2001	23,343.6	309.5	18.8	576.6	321.0
2002	24,830.8	313.1	22.1	576.7	321.1
2003	26,545.6	315.3	22.1	575.9	323.7
2004	28,219.4	321.6	21.7	579.9	333.3
2005	29,594.8	332.0	22.2	583.4	340.3
2006	30,256.9	340.4	22.6	589.7	347.5
2007	29,464.9	342.5	22.5	589.7	358.0
2008	28,995.2	340.7	21.1	590.3	366.4
2009	27,765.6	326.9	18.6	596.1	352.5
2010	28,936.4	327.3	19.3	603.4	354.1
2011	29,151.8	329.3	19.4	606.9	356.5
2012	29,556.6	334.5	19.5	611.8	360.9
2013	30,666.3	337.1	19.2	608.3	367.3
2014	31,478.5	347.6	19.8	605.8	371.4
2015	32,443.8	360.3	20.9	603.5	372.1
2016	33,118.9	371.9	21.4	600.9	366.2
2017	34,107.3	378.7	21.2	596.6	366.9
2018	35,063.9	384.8	21.9	591.0	372.3
2019	35,752.8	390.4	22.9	586.6	377.7
2020	35,443.6	382.5	23.4	585.8	362.8
2021	37,523.7	392.7	24.4	585.7	372.3
2022	39,567.3	402.5	25.0	585.2	383.2
2023	41,088.2	410.5	25.4	584.8	392.8
2024	42,161.0	414.7	25.7	584.5	397.5
2025	43,312.0	417.6	25.9	583.9	400.2
2026	44,443.7	420.3	26.1	583.1	402.8
2027	45,659.9	422.9	26.3	582.2	405.3
2028	46,844.0	425.3	26.5	581.0	407.6
2029	48,057.8	428.1	26.7	579.8	410.2
2030	49,253.1	431.0	26.9	578.5	412.6
2031	50,455.4	433.7	27.1	577.3	414.7
2032	51,671.9	436.3	27.2	576.0	416.2
2033	52,931.6	439.0	27.4	574.8	417.6
2034	54,235.6	441.8	27.6	573.6	419.3
2035	55,579.7	444.7	27.8	572.4	421.2
2036	56,960.7	447.7	27.9	571.2	422.9
2037	58,360.4	450.6	28.1	570.0	424.5
2038	59,789.8	453.6	28.2	568.8	426.3
2039	61,282.3	456.7	28.4	567.6	428.3
2040	62,811.2	459.9	28.5	566.3	430.4
2041	64,377.1	463.1	28.6	565.0	432.6
2042	65,966.1	466.4	28.7	563.6	435.0
2043	67,566.4	469.6	28.8	562.2	437.3
2044	69,203.1	472.9	28.8	560.8	439.9
2045	70,827.4	476.1	28.8	559.4	442.5
2046	72,448.3	479.3	28.9	557.9	445.2
2047	74,095.6	482.4	28.9	556.5	447.9
2048	75,737.3	485.5	28.9	555.0	450.6
2049	77,415.0	488.5	29.0	553.6	453.3
2050	79,120.9	491.5	29.0	552.3	455.9
2051	80,868.8	494.5	29.0	551.0	458.5
2052	82,659.8	497.5	29.0	549.6	461.1
2053	84,495.1	500.5	29.0	548.3	463.7
2054	86,375.7	503.6	29.0	547.0	466.4
Units	**Millions (2012 $)**	**Thousands**	**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
2021	16.2	2.9	3.4	10.8	1.7	2.5	5.4	1.1	0.9	0.0	0.0	0.0
2022	25.4	4.8	5.5	19.1	3.4	4.5	6.3	1.4	1.0	0.1	0.0	0.0
2023	19.7	3.4	4.0	15.6	2.4	3.6	3.6	1.0	0.3	0.5	0.0	0.1
2024	17.3	2.1	1.7	13.8	1.4	1.5	2.6	0.7	0.2	0.9	0.0	0.1
2025	14.9	1.5	1.6	11.9	0.9	1.3	2.2	0.5	0.2	0.8	0.0	0.1
2026	5.6	0.5	0.6	4.2	0.2	0.5	1.3	0.3	0.1	0.2	0.0	0.0
2027	0.4	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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

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

Exhibit A - 13		
Southwestern Electric Power Company		
Actual and Forecast Losses (GWh)		
Year		**Losses**
2011		902.2
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		1,031.1
2022		1,017.3
2023		1,018.5
2024		1,014.4
2025		1,005.7
2026		1,017.3
2027		1,013.6
2028		1,027.5
2029		1,017.2
2030		1,015.9
2031		1,016.9
2032		1,026.5
2033		1,020.3
2034		1,032.0
2035		1,026.3
2036		1,025.8
2037		1,027.2
2038		1,032.6
2039		1,041.0
2040		1,043.2
2041		1,037.7
Note: *2019 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

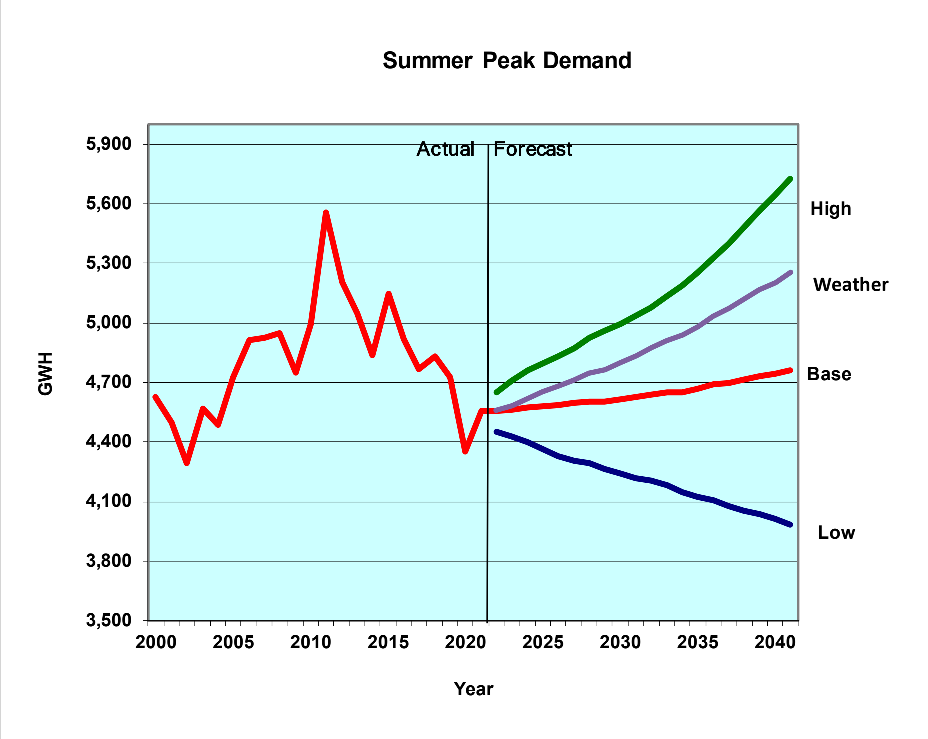
Exhbit A - 15
Blending Illustration

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
2022	4,144	4,238	4,328	4,455	4,555	4,653	21,845	22,339	22,818
2023	4,125	4,253	4,390	4,426	4,563	4,710	21,749	22,422	23,146
2024	4,102	4,267	4,440	4,397	4,575	4,760	21,594	22,465	23,376
2025	4,072	4,278	4,479	4,362	4,583	4,798	21,423	22,509	23,562
2026	4,044	4,287	4,514	4,329	4,589	4,831	21,270	22,547	23,739
2027	4,024	4,296	4,554	4,305	4,597	4,872	21,155	22,588	23,941
2028	4,017	4,312	4,609	4,292	4,606	4,923	21,074	22,620	24,176
2029	3,994	4,314	4,646	4,263	4,605	4,959	20,973	22,655	24,399
2030	3,972	4,322	4,683	4,239	4,614	4,998	20,841	22,681	24,573
2031	3,950	4,332	4,714	4,217	4,625	5,034	20,714	22,718	24,725
2032	3,934	4,341	4,750	4,203	4,638	5,076	20,629	22,761	24,909
2033	3,917	4,352	4,810	4,184	4,649	5,137	20,531	22,812	25,211
2034	3,888	4,361	4,861	4,148	4,653	5,186	20,384	22,863	25,486
2035	3,862	4,371	4,919	4,124	4,668	5,253	20,250	22,919	25,792
2036	3,846	4,392	4,991	4,107	4,690	5,329	20,120	22,978	26,112
2037	3,811	4,393	5,044	4,078	4,700	5,396	19,994	23,044	26,460
2038	3,785	4,404	5,115	4,053	4,717	5,478	19,863	23,113	26,845
2039	3,764	4,418	5,196	4,035	4,735	5,568	19,758	23,189	27,269
2040	3,745	4,429	5,270	4,011	4,744	5,645	19,662	23,255	27,671
2041	3,716	4,441	5,343	3,983	4,761	5,727	19,517	23,325	28,060

Exhbit A - 17
Southwestern Electric Power Company
Range of Forecasts and Weather Scenario



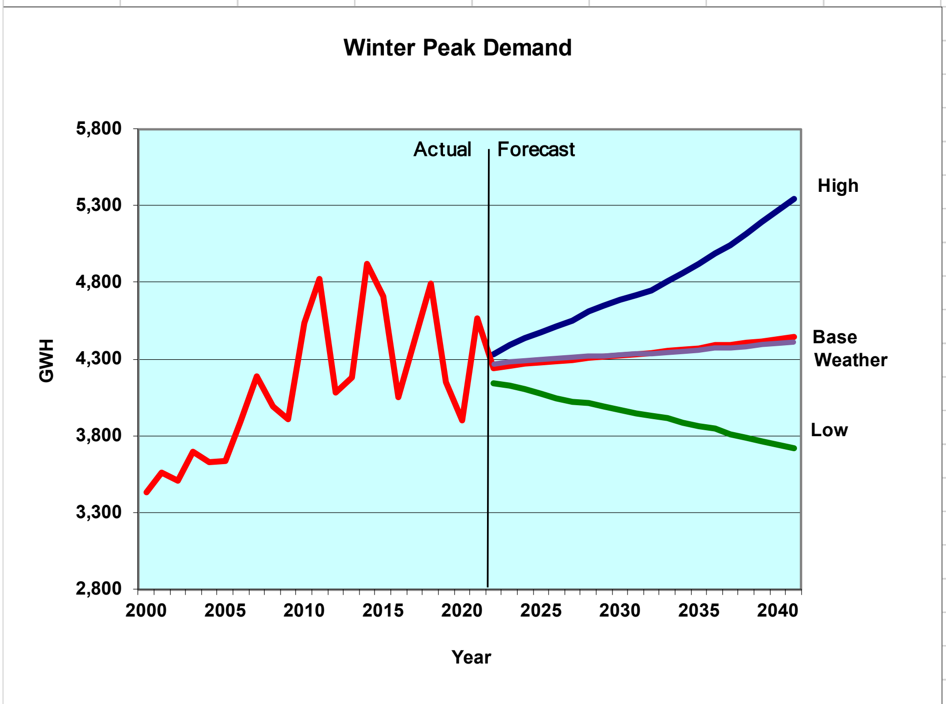


Exhibit B: Detailed Generation Technology Modeling Parameters

	Technology	Capital Cost $2020/kW	VOM $2020/MWh	FOM $2020/kW-yr	Heat Rate Btu/kWh	First Available Year
Coal and Gas	ULTRA-SUPERCRITICAL COAL WITH 90% CO2 CAPTURE, 650 MW	5,821	11.03	59.85	12,507	2024
	COMB TURBINE H CLASS, COMB-CYCLE SINGLE SHAFT W/90% CO2 CAPTURE, 430 MW	2,428	5.87	27.74	7,124	2023
	COMB TURBINE H CLASS, 1100-MW COMBINED CYCLE	882	1.88	12.26	6,370	2023
	COMB TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT, 430 MW	1,004	2.56	14.17	6,431	2023
	COMB TURBINE F CLASS, 240-MW SIMPLE CYCLE	654	0.61	7.04	9,905	2022
	COMB TURBINES AERODERIVATIVE, 100-MW SIMPLE CYCLE	1,079	4.72	16.38	9,124	2022
	INTERNAL COMBUSTION ENGINES, 20 MW	1,763	5.72	35.34	8,295	2022
	NG CC CCS Retrofit	869	1.23	19.64	17.2% Penalty	2020

	Technology	Capital Cost $2020/kW	VOM $2020/MWh	FOM $2020/kW-yr	Capacity Factor %	First Available Year
Renewable	Wind	1,395	0.00	26.47	44.0%	2023
	Solar PV with tracking	1,190	0.00	14.70	26.6%	2022

	Technology	Capital Cost $2020/kW	VOM $2020/MWh	FOM $2020/kW-yr	Heat Rate Btu/kWh	First Available Year
Hydrogen and Nuclear	PEM Electrolyzer + 10 Hr Storage PSO	1,715	0.50	46.39	60% Efficiency	2020
	H2 CT	1,576	0.61	7.04	9,655	2020
	SMR	6,485	3.02	95.48	10,455	2028

	Technology	Capital Cost $2020/kW	VOM $2020/MWh	FOM $2020/kW-yr	Efficiency %	Self-discharge rate % per day	Depth-of-Discharge Limit %	Duration Years	Asset Life Years	First Available Year
Storage	Compressed Air	1,771	0.00	17.19	52%	0.1%	100%	20	25	2020
	Flow Battery	3,798	0.00	11.30	70%	1.0%	100%	20	15	2020
	Pumped Thermal	3,295	0.00	51.16	65%	1.0%	100%	20	20	2020
	Lithium Ion	1,389	0.00	25.37	85%	0.3%	80%	4	10	2021

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

CAPABILITY

	Plant Capabilities	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	ARSENAL HILL 5	108	108	108	108	108	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
	DOLET HILLS 1	257	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	FLINT CREEK 1	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258
	TURK	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477
	KNOX LEE 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	KNOX LEE 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	KNOX LEE 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	KNOX LEE 5	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338
	LIEBERMAN 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LIEBERMAN 3	109	109	0	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
	LONE STAR 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	PIRKEY 1	580	580	0	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
	MATTISON 2	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
	MATTISON 4	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
	WELSH 1	525	525	525	525	525	525	525	0	0	0	0	0	0	0	0	0
	WELSH 3	528	528	528	528	528	528	528	0	0	0	0	0	0	0	0	0
	WILKES 1	164	164	164	164	164	164	164	164	164	0	0	0	0	0	0	0
	WILKES 2	355	355	355	355	355	355	355	355	355	355	355	355	355	355	355	0
	WILKES 3	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353
1	**TOTAL**	**4,954**	**4,697**	**4,008**	**4,008**	**3,900**	**3,792**	**3,792**	**2,739**	**2,739**	**2,575**	**2,575**	**2,575**	**2,575**	**2,575**	**2,575**	**2,220**
	Adjustments to Plant Capability																
	North Central	22	129	138	130	130	130	130	130	130	130	121	121	121	121	121	121
2	**TOTAL**	**22**	**129**	**138**	**130**	**130**	**130**	**130**	**130**	**130**	**130**	**121**	**121**	**121**	**121**	**121**	**121**
3	**Net Plant Capability (1 + 2)**	**4,975**	**4,825**	**4,145**	**4,137**	**4,029**	**3,921**	**3,921**	**2,868**	**2,868**	**2,704**	**2,696**	**2,696**	**2,696**	**2,696**	**2,696**	**2,341**
	Sales Without Reserves																
	Backup contracts (Eastman & Domtar)	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
4	**TOTAL**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**
	Purchases Without Reserves																
	NTEC - HCPP	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	NTEC GENERATION - PIRKEY/DOLET HILLS/TURK	171	133	54	54	54	54	54	54	54	54	54	54	54	54	54	54
	NTEC - SPA NARROWS	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
	MAJESTIC WIND PROJECT	21	21	14	13	13	13	13	13								
	HIGH MAJESTIC WIND PROJECT	18	18	14	13	13	13	13	13	13	13	12	12				
	FLAT RIDGE WIND PROJECT	11	11	18	17	17	17	17	17	17	17	16	16				
	CANADIAN HILLS WIND PROJECT	26	26	34	32	32	32	32	32	32	32	30	30				
5	**TOTAL**	**574**	**537**	**461**	**456**	**456**	**456**	**456**	**456**	**444**	**444**	**440**	**440**	**381**	**381**	**381**	**381**
6	**Total Capability (3 - 4 + 5)**	**5,535**	**5,348**	**4,592**	**4,579**	**4,471**	**4,363**	**4,363**	**3,310**	**3,297**	**3,133**	**3,121**	**3,121**	**3,063**	**3,063**	**3,063**	**2,708**

	DEMAND	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A	Peak Demand Before Passive DSM	4,559	4,560	4,566	4,577	4,585	4,589	4,597	4,606	4,605	4,614	4,625	4,638	4,649	4,653	4,668	4,690
	Peak Demand Before Passive DSM Adjusted	4,559	4,560	4,566	4,577	4,585	4,589	4,597	4,606	4,605	4,614	4,625	4,638	4,649	4,653	4,668	4,690
B	Passive DSM																
	Approved Passive DSM	3	5	3													
	TOTAL	3	5	3	0	0	0	0	0	0	0	0	0	0	0	0	0
C	Peak Demand (A - B)	4,556	4,555	4,564	4,577	4,585	4,589	4,597	4,606	4,605	4,614	4,625	4,638	4,649	4,653	4,668	4,690
D	Active DSM																
	DLC/ELM	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	Interruptible	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
	TOTAL	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
E	Firm Demand (C - D)	4,520	4,519	4,528	4,541	4,549	4,553	4,561	4,570	4,569	4,578	4,589	4,602	4,613	4,617	4,632	4,654
F	Other Demand Adjustments																
	DIVERSITY	27	25	32	27	26	25	25	25	32	26	26	26	25	32	33	27
	TOTAL	27	25	32	27	26	25	25	25	32	26	26	26	25	32	33	27
7	Native Load Responsibility (E - F)	4,493	4,494	4,496	4,514	4,523	4,528	4,535	4,545	4,537	4,551	4,563	4,576	4,587	4,585	4,599	4,627
	Sales With Reserves																
8	TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Purchases With Reserves																
	NTEC SPA HYDRO PEAKING	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
	LOUISIANA GENERATION (FORMERLY CAJUN)	50	50	50	50	50	50										
	SPA HYDRO-B'VILLE/R'BURN/MINDEN/TEXLA	20	20	20	20	20	20	20	20	18	18	18	18				
9	TOTAL	172	172	172	172	172	172	122	122	120	120	120	120	102	102	102	102
10	Load Responsibility (7 + 8 - 9)	4,321	4,322	4,324	4,342	4,350	4,356	4,413	4,423	4,417	4,431	4,443	4,456	4,485	4,483	4,497	4,525

	RESERVES	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
11	Reserve Capacity, MW (6 - 10)	1,214	1,026	268	237	121	7	-50	-1,113	-1,119	-1,298	-1,322	-1,334	-1,423	-1,420	-1,434	-1,817
12	% Reserve Margin ((11/10) * *100*)	28.1	23.7	6.2	5.5	2.8	0.2	-1.1	-25.2	-25.3	-29.3	-29.7	-29.9	-31.7	-31.7	-31.9	-40.2
13	% Capacity Margin (11/(6) * *100*)	21.9	19.2	5.8	5.2	2.7	0.2	-1.1	-33.6	-34.0	-41.4	-42.3	-42.8	-46.4	-46.4	-46.8	-67.1
14	Reserve Above 12% Reserve Margin, MW	696.0	508.0	(251.0)	(284.0)	(401.0)	(515.0)	(579.0)	(1643.0)	(1650.0)	(1830.0)	(1855.0)	(1869.0)	(1961.0)	(1958.0)	(1973.0)	(2360.0)

Appendix B: Stakeholder Committee Report

Southwestern Electric Power Company
2021 Integrated Resource Plan
Stakeholder Committee Report

As outlined by the Arkansas Public Service Commission's Resource Planning Guidelines for Electric Utilities,[34] SWEPCO organized and facilitated meetings of a Stakeholder Committee for resource planning purposes. The Stakeholder Committee has met and discussed SWEPCO's 2021 Integrated Resource Plan and we would like to provide the following observations and recommendations.

I. Review of Renewable Energy Assumptions

Stakeholders requested that SWEPCO use the latest National Renewable Energy Lab (NREL) Annual Technology Baseline (ATB) data for renewable energy resources. SWEPCO provided a reasonable response to stakeholders (SWEPCO Attachments 5 and 6) that at the time the IRP analyses began, the NREL ATB 2020 data and the Energy Information Administration's (EIA) 2021 Annual Energy Outlook (AEO) 2021 data were available, but not the NREL ATB 2021 data. The NREL ATB 2021 data were published mid-July 2021.

In previous IRP's, SWEPCO relied fully on the NREL ATB data. The NREL ATB data provide more granularity and forward projections than EIA data. Further, EIA data has historically not adequately captured the rapid pace of pricing and performance improvements in the renewable energy industries. The 2021 NREL ATB includes the ability for users to include (and exclude) the effects of the federal Production Tax Credit (PTC) for wind energy resources, and the Investment Tax Credit (ITC) for solar resources.

SWEPCO used the EIA AEO for generation technology prices and performance. The EIA data do not provide forward forecast improvements for price and performance; to resolve this deficiency, SWEPCO used learning curves and forecast rates from the NREL ATB 2020. SWEPCO provided a qualitative assessment of the NREL ATB 2021 data, compared to the data used in this IRP (SWEPCO Attachments 5 and 6). Stakeholders appreciate SWEPCO's responses and assessments, and while we find them generally satisfactory, we wish we had the opportunity to provide feedback prior to the data inputs being

[34] http://www.apscservices.info/Rules/resource_plan_guid_for_elec_06-028-R_1-7-07.pdf

selected. The Stakeholders recommend that in the next IRP, SWEPCO begin the stakeholder process prior to selecting data inputs for model runs.

a. Renewable Pricing

Stakeholders requested that SWEPCO provide the Levelized Cost of Energy (LCOE) value associated with the various generation technologies. SWEPCO noted that LCOE's are not inputs to the IRP models; however, LCOE's provide valuable insight regarding the model's methodologies. LCOE's help stakeholders quickly compare publicly available power purchase agreement (PPA) data against model assumptions. Often, IRP models include many more input assumptions than shared with stakeholders, making it virtually impossible for stakeholders to replicate the final and full costs associated with generation resources, such as inflation rates, interest rates, rate of return on equity, weighted average cost of capital, tax rates, and other financial metrics. Sometimes, these additional costs can be unintentionally double-counted if, for instance, the model requires Overnight CAPEX costs, but users input full CAPEX costs into the model.

While both solar PV and battery overnight capital costs are similar between SWEPCO's assumptions and the NREL ATB 2021 data, there appears to be a wider discrepancy with wind energy resources. SWEPCO's near-term wind energy overnight capital costs appear to be almost 18% higher than the NREL ATB data.

2024 Overnight Capital Costs ($/kW)

	SWEPCO	NREL ATB Moderate
Solar PV	$1,092	$1,112
Wind	$1,369	$1,164
Battery (Li-Ion)	$1,114	$1,037

SWEPCO Figure 21 (Battery), Figure 23 (Wind), Figure 25 (Solar), NREL ATB 2021 Moderate Assumptions

SWEPCO incorporated the federal ITC/PTC for solar and wind resources, respectively. SWEPCO explained that the PTC for wind "is implemented in AURORA as a negative variable cost adder", of $15/MWh, depending on the scenario evaluated. This is an innovative and novel approach that could potentially be modified to allow SWEPCO to evaluate power purchase agreement (PPA) arrangements. Because the AURORA planning software so heavily weighs capital costs against capacity additions, wind or solar resource costs may appear front-loaded in the model results. However, PPA's shift capital costs away from utility ratepayers. PPA's may more closely resemble a zero-capital cost resource, with a variable cost component in the model (on a dollar per megawatt hour basis, $/MWh), much like how fossil units have variable fuel costs. In this configuration, the variable cost component of a renewable PPA would appear to be very much like an LCOE calculation. Stakeholders request that SWEPCO provide an analysis showing the effect of renewable PPA's in the IRP model.

Throughout the IRP results, battery storage resources are not readily selected. The Stakeholders believe this to be due, in part, to the higher capital costs assumed for the 4-hour energy storage resources used in the model, as opposed to a 1-hour or 2-hour battery resource. The Stakeholders request that SWEPCO incorporate multiple battery configurations, as well as develop different dispatch strategies that may highlight battery storage value better than only energy-arbitrage.

b. Renewable Performance Levels

SWEPCO used a capacity factor of 26.6% for solar resources, and 44% for wind energy resources. These are reasonable levels, and align fairly well with the NREL ATB 2021.

In the IRP, SWEPCO provides a good summary of its Scenario Reserve Requirements in Section 7.4.3. SWEPCO cited recent studies conducted at SPP regarding Effective Load Carrying Capacity (ELCC) methodologies regarding renewables (IRP Footnotes 20, 21). SWEPCO assumed wind energy capacity credit to be "14.7% across all months" and solar energy capacity credit to be "60% but it declines to 27-34% by 2041". SWEPCO varied capacity credit for solar resources, based on the solar growth rate in its various scenarios; meaning, in a scenario where less solar resources are adopted across SPP, a higher capacity credit is assigned (e.g., No Carbon Regulation Scenario). Under SWEPCO's Focus on Resiliency (FOR) Scenario, "SPP is assumed to enforce both winter and summer reserve requirements on participating utilities." In the FOR Scenario, SWEPCO reduced solar capacity accreditation in wintertime "from 10% in 2022 to 2% in 2041." However, SWEPCO did not improve the wintertime wind energy capacity accreditation. In a wintertime reliability construct, wind energy resources are likely to have a significantly higher capacity accreditation value, because wind resources perform very well during wintertime peak periods. Energy storage capacity credit assumptions show a decline in storage value, as more energy storage is added to the SPP grid, but no material difference from summertime to wintertime capacity accreditation. Stakeholders commend SWEPCO for evaluating multiple seasons and using a variable ELCC methodology. Stakeholders recommend that SWEPCO continue to refine the capacity accreditation values for its generation resources based on ELCC calculations across multiple seasons.

Stakeholders also request that SWEPCO conduct an ELCC analysis on its existing fossil generation fleet, as well as new fossil units. In February 2021, Winter Storm Uri wreaked havoc across the SPP footprint, when fossil units failed to turn on during the peak of the storm. Further, Stakeholders request SWEPCO provide an updated Action Plan with details on the costs of winterizing its fossil fleet, in alignment with SPP recommendations.[35]

c. Additions and Caps on Renewable Resources

SWEPCO has already released a 3,000 MW wind RFP, and Stakeholders applaud SWEPCO's efforts. This IRP underscores the value of adding more wind resources sooner, rather than later. SWEPCO prevented the model from selecting solar and wind energy resources prior to 2024. Stakeholders recognize that procuring new resources takes time; however, a three or four-year delay in modeling solar and wind resources is excessive. The next IRP will be filed in 2024, meaning SWEPCO may miss opportunities over the next three years, particularly as it relates to solar procurement. Stakeholders request that in future IRP's, SWEPCO allow renewable energy resources and energy storage options to be selected by the model within a year (e.g., the 2024 IRP would allow resources to come online at the end of 2025).

SWEPCO capped solar and wind annual additions. For solar, SWEPCO capped annual additions at 450 MW's per year. In multiple scenarios, the model selected the maximum amount of solar in multiple years, indicating that the solar cap was impeding the model's optimization. While its reasonable for SWEPCO to represent feasible limits on annual installs by resource type, it is also critical for the Company to understand how much the model would opt to build based purely on economics in the absence of a cap. Stakeholders requested SWEPCO run a sensitivity that removed the solar cap. SWEPCO quickly provided an updated sensitivity where it removed the solar cap in the reference scenario. In the sensitivity, the model selected more solar, sooner,

[35] https://spp.org/documents/65037/comprehensive%20review%20of%20spp's%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf

than the reference case, indicating that the solar cap was artificially constraining procurement. SWEPCO also included caps for wind resource additions, albeit, significantly higher caps than solar resources. Stakeholders recommend that SWEPCO adopt the Solar #2 Reference Portfolio as the Preferred Portfolio, and update its Action Plan to issue a 1,000 MW solar RFP in 2022.

SWEPCO Attachment 10

SOUTHWESTERN ELECTRIC POWER COMPANY
An AEP Company

Solar #2: No Annual Cap

Reference Portfolio: 450 MW annual solar limit

Utility-Scale New Build Additions by Year (Nameplate MW)					
Year	New Solar	New Wind	New Gas CT	New Storage	Capacity Purchases
2022					
2023					271
2024	150*	1150*	240		46
2025		1600*			
2026					
2027	350				
2028	450		480		
2029	450				
2030	450				
2031	150				
2032	300				
2033	350				
2034					
2035					
2036	50		720		
2037			240		
2038	250				
2039	250		240		
2040			240		
2041	250				
Total	3,450	2,750	2,160	0	

Reference Portfolio: no annual solar limit

Utility-Scale New Build Additions by Year (Nameplate MW)					
Year	New Solar	New Wind	New Gas CT	New Storage	Capacity Purchases
2022					
2023					271
2024	250*	1,100*	240		46
2025		1,600*			
2026					
2027					
2028	1,600				
2029	200				
2030	50		240		
2031					
2032	300				
2033	350				
2034					
2035			240		
2036	50		720		
2037			240		
2038	250				
2039	250		240		
2040			240		
2041	300				
Total	3,600	2,700	2,160	0	

- Portfolios are very similar in total build quantities
- Optimizing with no annual limit produces 1,600 MW portfolio addition in single year 2028

SWEPCO has done a good job at issuing competitive RFPs for renewable resources. Competitive RFPs expand SWEPCO's ability to transact on multiple renewable energy projects simultaneously. Stakeholders request that in the next IRP that SWEPCO not include unreasonable annual limits on solar or wind resource additions.

II. Review of Natural Gas Assumptions

SWEPCO's high gas price forecast is far below current gas prices and therefore likely fails to adequately capture gas risk. Stakeholders requested on September 17, 2021, that SWEPCO conduct "Run a sensitivity analysis on gas prices +25% higher than the highest natural gas price against the Reference Scenario/Portfolio". On October 15, 2021, SWEPCO provided the gas sensitivity as Attachment 9 in its responses to the Stakeholders, and noted, "A higher gas price and power price environment produces lower 30-year NPVRRs for all portfolios except the CC Portfolio." Stakeholders appreciate SWEPCO's additional analysis provided. We recommend for the next IRP that SWEPCO include a much higher cost natural gas cost assumption to better capture a broader band of risk.

III. SWEPCO Should Re-Evaluate the Flint Creek Spending Decisions

SWEPCO indicated at the stakeholder workshop that it intends to complete retrofits to comply with the Effluent Limitation Guidelines (ELG) and Coal Combustion Residuals (CCR) legislation at the Flint Creek coal plant that will allow the plant to operate through 2038. It does not appear that any IRP scenario assessed the impact of an alternative retirement date for Flint Creek. Instead, the Company locked in the 2038 retirement date, and did not let the model test whether any alternative retirement or operational options (including transitioning to seasonal operations) would deliver ratepayers higher value.

We understand that the Company conducted analysis of completing the CCR and ELG upgrades at Flint Creek and continuing to operate the plant in prior dockets. But this does not negate the need to conduct ongoing assessments.

The CCR and ELG analysis that the Company relied on is now over a year old. In this time, numerous input assumptions, from peak forecasts to fuel price forecasts, have changed. Further, the assumptions used by SWEPCO to model the CCR/ELG upgrades are not readily available to stakeholder of this IRP docket, as the assumptions used in the IRP are.

Utility law holds that the prudence of a project should be continually evaluated, and this is especially important when ratepayers will be asked to bear the costs associated with stranded assets, as the Arizona Corporation Commission recently explained:

> We believe that a utility has a duty to monitor the economics of its investments in a project from the inception . . . until the project is completed and that each investment made along the way is subject to a prudency determination. We also believe that a utility has a duty to alter its choices and its course for a project if doing so makes sense economically and is in the public interest, even if altering the course may not be as advantageous to the utility's shareholders . . . .[36]

[36] Arizona Corporation Commission, Arizona Public Service Company, Docket No. E-01345A-19-0236, Oct. 26, 2021, available online at: https://docket.images.azcc.gov/E000016333.pdf

This admonition applies to the Flint Creek spending SWEPCO is contemplating. Up until the Company begins operation of the investments, the Company can and should evaluate if conditions have changed enough to warrant canceling the upgrades. Canceling a project, even after some of the project funds have been spent, can still result in savings for ratepayers.

These CCR and ELG projects have not yet been approved by the Commission, and recent utility Commission rulings in other states cast doubt on the economics of investing in environmental upgrades to prolong the life of aging coal plants. In July, the Public Service Commission of Kentucky denied Kentucky Power's request for the ELG upgrades at AEP plant Mitchell, stating that the Company "failed to carry its burden of proof that there is a need to construct projects to comply with ELG rules, that the proposed ELG compliance project will not create a wasteful duplication of facilities, and that the proposed ELG compliance project is reasonable and cost effective."[37] Similarly, in August, the State Corporation Commission in Virginia denied Application Power's requests for approval of ELG upgrades at AEP plants Amos and Mountaineer on the basis that the Company failed to demonstrate that such investments are reasonable and prudent.[38] At the end of October, the Arizona Corporation Commission, as noted above, denied recovery to Arizona Public Service of $215.5 million out of the full $450 million in environmental upgrades that the Company made to the Four Corners coal plant.[39]

Given the declining economics of coal plants today, including specifically at Flint Creek, it is unlikely that Flint Creek will actually operate through its planned retirement date in 2038. If the ELG and CCR projects are completed and approved by the Commission, they are very likely to become stranded assets. Given that these project costs will be added to the Flint Creeks' undepreciated plant balance, this could create rate shock for SWEPCO's ratepayers when the plant inevitably does retire.

Given all of these factors, we therefore request that SWEPCO test at least one scenario, with the most up-to-date resource cost, fuel cost and market power price assumptions, that retires Flint Creek in 2028 (or 2027) and avoids the capital outlay associated with retrofitting the site. In this scenario, SWEPCO

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[37] Kentucky Public Service Commission Order, Case No. 2021-00004.

[38] Virginia State Corporation Commission Order Granting Rate Adjustment Clause, Case NO. PUR-2020-00258.

[39] Van Voorhis, Scott. *APS vows legal action after Arizona regulators deny cost recovery of $215.5 M coal plant upgrades*. Utility Dive. October 2021.

should assume that transmission funding from the recently enacted bipartisan infrastructure bill (that has now been signed into law) will cover half of the cost of the transmission upgrades that SWEPCO assumes are required in the northwest Arkansas load pocket if Flint Creek retires.

IV. SWEPCO's Scorecard is Not Reasonably Constructed

The Stakeholder Group recommends that SWEPCO include public health and environmental justice impacts as a metric in its portfolio scorecard. In addition, the Stakeholder Group recommends that the "Local Impacts" metric be adjusted to consider respending benefits and the unique job impacts of different resource types.

In developing its IRP and selecting a preferred portfolio, Sierra Club encourages SWEPCO to include quantified consideration of the health impacts of each portfolio. To achieve this, SWEPCO should document the impacts that air pollutants—sulfur dioxide, nitrogen oxides, and particulate matter—have on public health, which include increased instances of asthma attacks, respiratory infections, hospital admissions, missed school and work days, and a variety of other health problems. Air pollution contributes significantly to increased morbidity and mortality, and existing, publicly available modeling tools—such EPA's BenMAP[40] or the Clean Air Task Force's "Toll From Coal"[41]—can be used to translate air pollution into social cost estimates.

SWEPCO should also incorporate consideration of the environmental justice impacts of its portfolios when selecting its preferred plan. Communities that are harmed most by utilities' persistent reliance on fossil-burning power plants, based on their geographic proximity to fossil plants, are often disproportionately composed of minority and low-income populations. These communities would benefit the most from reduced emissions, coal retirements, and investments in renewable energy and should be involved in the development of plans to retire and replace these existing polluting resources. Integrating community involvement into the resource planning process can deliver better and lower-cost solutions than soiled centralized resource planning processes can deliver alone.

SWEPCO should begin by assessing the environmental justice implications of its resource selections, including its existing resources, in this planning process

40 https://www.epa.gov/benmap

41 https://www.tollfromcoal.org/

— by using and EPA's EJ Screen tool.[42] The Company should then develop a plan for engaging the local community in resource planning decisions that directly impact the identified environmental justice communities. Entergy Arkansas stated that it plans to outline measures the Company has taken and plans to take to address environmental justice concerns and public health impacts in their operations and in their IRP process, and we similarly urge SWEPCO to address these issues directly and with the attention they merit.[43]

In addition to adding scorecard metrics on public health impacts and environmental implications, the stakeholders note certain limitations to the categories that are already included on the scorecard. The "Local Impacts" metric appears to unfairly benefit high-cost portfolios and omits certain components that should be considered. SWEPCO has chosen to measure "Local Impacts" using Total New Nameplate MWs and Total Capital Expenditures within SWEPCO's service territory. However, not all megawatts and capital expenditures are created equal when it comes to local economic impact and job creation.

Using Total capital expenditures as a measure of local impact ensures that expensive portfolios will rank highly on the scorecard. But this obscures the full picture of direct, indirect, and induced effects of various portfolios. A lower cost portfolio would result in lower electricity costs for SWEPCO customers. This money would be respent locally in other industries, spurring local job creation in other parts of the local economy. These outcomes are referred to as "induced" effects within the field of economic impact analysis.[44] A full economic impact analysis would count the direct effects of capital expenditures but also consider the indirect supply chain effects and the induced respending effects.

The choice of Total MWs as a metric similarly obscures the nuances of resource job creation. Not all resource types create the same type or quality of jobs. Renewable projects can often be smaller and more modular than traditional fossil resources, a feature that distributes economic and employment benefits across a wider area. Meanwhile, energy efficiency and demand-side management is the fastest growing energy employment sector. According to

42 https://www.epa.gov/ejscreen

43 EAL Response to Stakeholder Group (Sept. 30, 2020).

44 Joe Demski, "Understanding IMPLAN: Direct, Indirect, and Induced Effects," *IMPLAN,* 18 June 2020. Available at: https://blog.implan.com/understanding-implan-effects

the U.S. Energy and Employment Report 2020 ("USEER"), the EE/DSM industry has created over 400,000 jobs in three years nationwide, a growth rate of 5.8%.[45]

In conjunction with the 2020 USEER report, the National Association of State Energy Officials ("NASEO") also released a report on the wages and benefits associated with energy industry employment.[46] NASEO found that opportunities created by investment in EE/DSM are not just high in number, they also often have higher wages, are more likely to be permanent, and are less geographically constrained. In fact, NASEO found that 99.8% of all counties in the U.S. had EE jobs and that the average median hourly income of these jobs was 28% higher than the national median income.[47] Jobs in EE are so widespread because "energy efficiency technologies and services are applicable to commercial, industrial, and residential sectors across the economy. Unlike many other energy jobs, installation, maintenance, and repair jobs in the energy efficiency sector are more universally distributed."[48]

Utility investment in renewable energy and energy efficiency provides a more effective and certain way to spur job creation across SWEPCO's territory relative to investment in large fossil plants that face an uncertain future due to carbon policy and low-cost renewables. SWEPCO's "Local Impacts" section in the scorecard should reflect this by focusing on a full economic and job impact analysis, rather than an approach that simply benefits high-cost portfolios.

V. SWEPCO Did Not Seriously Consider Solar-Battery Hybrids in Its Portfolios

As discussed in the Renewable section above, the Stakeholders appreciate SWEPCO's efforts to respond to stakeholder modeling requests and provide

[45] National Association of State Energy Officials and the Energy Futures Initiative, "U.S. Energy and Employment Report 2020," available at: https://www.usenergyjobs.org/.

[46] National Association of State Energy Officials and the Energy Futures Initiative, "Wages, Benefits, and Change: A Supplement Report to the Annual U.S. Energy and Employment Report," p. 5, available at: https://www.usenergyjobs.org/.

[47] National Association of State Energy Officials and the Energy Futures Initiative, "Wages, Benefits, and Change: A Supplement Report to the Annual U.S. Energy and Employment Report," p. 5, available at: https://www.usenergyjobs.org/.

[48] Ibid.

the cost and operational assumptions for renewable resources that the Company relied on in its IRP modeling. One area of concern that remains is the Company's assumptions around hybrid paired resources.

SWEPCO indicated that it assumed that the cost of paired resources was equal to the sum of the cost of each stand-alone resource. But often paired resources share hardware, such as inverters, and therefore there are economies of scale relative to building each resource individually. NREL ATB projects that paired solar and storage resources experience around 25 percent cost savings relative to standalone solar PV and battery storage systems. By failing to capture this cost efficiency, SWEPCO is substantially over-stating the cost of paired resources. It is therefore not surprising that no paired resources were selected as part of any of SWEPCO's IRP portfolios.

The Company is also modeling the ELCC for paired resources as simply the sum of the ELCC for each individual resource. SWEPCO defended this decision by citing the two most recent SPP ELCC studies, stating that "SWEPCO does not believe a hybrid solar+storage or wind+storage facility would provide a meaningful increase in the ELCC value when compared to modeling as standalong resources." This approach oversimplifies the dynamic between two or more resources, and likely underestimates the combined contribution of the resources to SWEPCO's reliability. This can be addressed with an evaluation of system reliability more broadly.

We recommend that SWEPCO 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. As the penetration of solar and wind on the system increases, the timing of system peaks will change. For example, as the penetration of solar on the system increases, the peak may shift later in the evening. But wind generation tends to pick up later in the evening, and this later peak may now align better with wind generation. This dynamic, and many others, are critical to capture in resource planning modeling as the penetration of renewables (paired and stand-alone) increases.

VI. <u>SWEPCO includes minimal Energy Efficiency Investment in its IRP</u>

SWEPCO included very minimal energy efficiency investment as part of all scenarios in its IRP. Even more concerning is that it projects a significant decline in EE investment beyond 2028 for reasons that are not explained in the IRP.

Stakeholders requested SWEPCO provide data on the Company's projected net annual incremental savings from EE as a percentage of sales for each scenario. The Company indicated that it did not calculate this metric as part of its IRP, but did provide annual energy saved under each portfolio. The stakeholders appreciate the Company providing this data, but we are concerned that this data provides little information on the investments that the Company plans to make in each year, and over the resource planning period. EE measures have a measure life, after which they are no longer credited as providing savings. Because of this, the annual savings data does not provide a clear picture of the Company's plan to invest in EE.

This is especially concerning because SWEPCO has historically invested minimally in EE. In 2020, the Company's EE investments accounted for only 0.41 percent of total sales.[49] This is less than a half the national average reported by ACEEE in its most recent report (which was based on 2018 data), and nearly a tenth the level seen among leading utilities.[50] EE has been proven time and again to be the lowest cost energy resource, and will become even more critical as the Company retires its existing fossil resources and invests in renewables and battery storage. Additionally, investment in EE lowers energy bills by reducing the quantity of electricity that people need to purchase. This has an outsized benefit for low-income customers by reducing their energy burden (that is the percentage of their income that goes towards their electricity bill).

Based on these concerns, we encourage the Company as part of the next IRP to (1) have a full energy efficiency potential study conducted by an outside firm with expertise to fully understand its EE potential; (2) increase investment to at least approach the national average over the next five years; (3) report annual incremental EE investments.

VII. <u>Review of IRP Process</u>

Stakeholders appreciate SWEPCO's IRP process. SWEPCO provided stakeholders with a robust IRP analysis prior to the Stakeholder meeting. SWEPCO responded to the Stakeholder Committee's requests quickly and in easy formats as requested. SWEPCO did not deny any Stakeholder request based on

[49] Calculated based on EIA 861 data on Energy Efficiency Investment and Sales for 2020.

[50] Grace Relf, Emma Cooper, Rachel Gold, Akanksha Goyal, and Corri Waters. *2020 Utility Energy Efficiency Scorecard.* ACEEE. February 2020.

any assertion of confidentiality or proprietary information. While SWEPCO and Stakeholders had disagreements, SWEPCO earnestly engaged Stakeholders' requests.

The Stakeholder Committee has made several requests and recommendations for the next IRP process. The most important request is that SWEPCO engage with the Stakeholder Committee earlier in the process, prior to selecting data inputs and running models. This IRP process has been the quickest IRP process in recent history. SWEPCO's analyses could be improved and Stakeholders feel that SWEPCO will earnestly want to engage in dialog on the topics.

IRP Stakeholder Process Timeline

6/18/21 - SWEPCO contacts previous stakeholders asking for meeting preference on 9/15, whether virtual or in-person in Texarkana

7/28/21 - SWEPCO informs stakeholders the meeting will be virtual

9/2/21 - SWEPCO sends Webex and meeting agenda

9/13/21 - SWEPCO emails Draft IRP report, invited stakeholder list, meeting agenda, and APSC Resource Planning Guidelines

9/15/21 - SWEPCO hosts IRP Stakeholder meeting, sends slide deck materials and contact information

9/17/21 - Stakeholders submit list of questions and requests to SWEPCO

9/24/21 - SWEPCO responds to Stakeholder requests, providing materials in Excel spreadsheet format via large file format. SWEPCO lets Stakeholders know that additional material will be made available by 10/16/21.

10/15/21 - SWEPCO provides additional data, along with sensitivity analyses requested by stakeholders

10/18/21 - Stakeholders hold a conference call to discuss materials shared, and timeline to draft the Stakeholder Report

11/5/21 - Stakeholders complete draft Stakeholder Report

11/12/21 - Stakeholders finalize Stakeholder Report

VIII. Stakeholder Recommendations

The Stakeholder Committee proposes the following recommendations for consideration in this and future IRP's:

1. Complete the 3,000 MW wind RFP
2. Adopt the Solar #2 Reference Portfolio as the Preferred Portfolio
3. Update the Action Plan to issue a 1,000 MW solar RFP in 2022
4. Use the most up-to-date NREL ATB cost assumptions for renewable generation resources
5. Begin the stakeholder process prior to selecting data inputs for model runs
6. Provide an analysis showing the effect of modeling renewable generation resources as PPA's in the IRP model
7. Incorporate multiple battery storage configurations (1-hr, 2-hr, and 4-hr), and develop different dispatch strategies that may better highlight battery storage value
8. 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
9. Conduct an ELCC analysis on its existing fossil generation fleet, as well as new fossil units
10. Provide an updated Action Plan with details on the costs of winterizing its fossil fleet, in alignment with SPP recommendations
11. Allow renewable energy resources and energy storage options to be selected by the model within a reasonable amount of time (1-2 years)
12. Do not include annual limits on solar or wind resource additions
13. Include a much higher cost natural gas cost assumption to better capture a broader band of risk
14. Continue monitoring federal policy changes (e.g., PTC/ITC extensions)
15. Include a sensitivity in this Arkansas IRP that tests the prudence of going forward with the ELG/CCR retrofits at Flint Creek based on current inputs
16. Revise the IRP scorecard to include public health and environmental justice impacts
17. Adjust the IRP scorecard measure of local jobs impact to more accurately capture the number of jobs created by different portfolios
18. Improve modeling of paired resources, solar-battery hybrids in particular by recognizing the economics of scale that exist when co-locating resources.
19. Conduct a full energy efficiency potential study by an outside firm with expertise to fully understand EE potential
20. Increase energy efficiency investment to at least approach the national average over the next five years and report annual incremental EE investments

Southwestern Electric Power Company
Docket No. 07-011-U Integrated Resource Plan
Stakeholder Committee Requests September 17, 2021
Updated Responses October 15, 2021

General Requests

1. Provide all Figures/Charts in the 9/15 slides and draft IRP as Excel spreadsheets.	The details of the charts and figures included in the 2021 Draft IRP and Technical Meeting presentation are included in the following Attachments Attachment 1 - SWEPCO IRP Draft Figures.xlsx Attachment 2 - SWEPCO Technical Conference Figures.xlsx
2. What version of AURORA are you using?	CRA used AURORA version 13.5.1048 to perform the 2021 IRP analysis.
3. Does the AURORA model naturally retire units, or are unit retirement dates manually added to the model?	Both. When performing the scenario modeling of long-term SPP market outcomes, we include a number of announced retirements with manually defined retirement dates. The scenario model also has the ability to economically retire units and add new resources as part of the long-term capacity expansion solution. When modeling the SWEPCO portfolios, CRA relied on the retirement schedules provided by AEP and manually defined the retirement dates of any units expect to retire over the 2022-2041 period.
4. Are any existing SWEPCO units "hard wired" or "self scheduled" or otherwise not economically merit-order committed or dispatched in the models? If so, please describe those units and how they are /committed/dispatched.	All units are dispatched economically except Wilkes 1, which has a must-run requirement of 30 MW.
5. Provide the estimated retirement dates for all existing units.	See Table 1 at the end of this Document.
6. Provide the generic retirement dates for new units for all generation types.	In the 2021 IRP, all new units added to the portfolio have an assumed operating lifetime of 30 years. For 4-hr battery storage, the operating lifetime is assumed to be 15 years with one replacement of the lithium-ion modules included, making the total operating lifetime 30 years. For all new units added 2024-2041, the retirement date would thus occur outside the fundamental modeling period of 2022-2041.

7. Provide the hourly SPP market LMP for each Market Scenario forecast in Excel spreadsheets.	The hourly LMPs for each market scenario are included in the following Attachment: Attachment 3 - SWEPCO LMPs.xlsx
8. Provide LCOE's for all new generation technologies on an annual basis.	SWEPCO did not calculate the levelized cost of energy for the generating technologies as part of the 2021 IRP and LCOE's are not an input into the analysis performed for the 2021 IRP. As described in Chapter 5 of the 2021 Draft IRP, CRA provided the AURORA model with a set of new unit characteristics describing installed and operating costs, federal tax credit eligibility, and operational performance characteristics. AURORA then selected the least-cost combination of resources to meet SWEPCO's expected future energy and capacity needs. Stakeholders can use the information provided in the 2021 Draft IRP and this data request to calculate LCOE's, if desired.
9. Provide the projected capacity factors for existing units in each scenario.	SWEPCO is reviewing the request and will provide a response by October 16. Update: Please see the requested data in the following Attachment: Attachment 8 - SWEPCO_C.F_Generation_Data Annual.xlsx

Coal

1. Provide the previous five years worth of generation (MWh's), heatrate (BTU/kWh), operational costs ($/MWh), and hourly dispatch of each existing coal unit in Excel spreadsheet format.	Historical data is provided on pages 402 and 403 of FERC Form 1. Links to the FERC Form 1 documents filed with the APSC are provided below: 2020 http://www.apscservices.info/RcvdDocs/16_1_04292021_2_1.pdf 2019 http://www.apscservices.info/RcvdDocs/16_1_05042020_2_1.pdf 2018 http://www.apscservices.info/RcvdDocs/16_1_04292019_1_2.pdf 2017 http://www.apscservices.info/RcvdDocs/16_1_04262018_1_2.pdf 2016 http://www.apscservices.info/RcvdDocs/16_1_05022017_2_1.pdf
2. Provide the Reference Portfolio forecasted generation (MWh's),	SWEPCO is reviewing the request and will provide a response by October 16.

heatrate (BTU/kWh), operational costs, and hourly dispatch of each existing coal unit in Excel spreadsheet format.	SWEPCO does not produce hourly dispatch reports for every individual generation unit as part of the standard model outputs due the high volume of data generated. Update: The forecasted operational parameters are sensitive and confidential. The Stakeholders are recommended to utilize the information referenced in item #1 of this section as a proxy for any analysis they might want to perform.
3. Study a Flint Creek retirement in 2027 as a reference case portfolio.	This analysis was already completed in the SWEPCO CCR/ELG analysis

Natural Gas

1. Provide the previous five years worth of generation (MWh's), heatrate (BTU/kWh), operational costs ($/MWh), and hourly dispatch of each existing natural gas unit in Excel spreadsheet format.	Historical data is provided on pages 402 and 403 of FERC Form 1. Links to the FERC Form 1 documents filed with the APSC are provided in response to Coal item 1.
2. Provide the Reference Portfolio forecasted generation (MWh's), heatrate (BTU/kWh), operational costs, and hourly dispatch of each existing natural gas unit in Excel spreadsheet format.	SWEPCO is reviewing the request and will provide a response by October 16. SWEPCO does not produce hourly dispatch reports for every individual generation unit as part of the standard model outputs due the high volume of data generated. Update: The forecasted operational parameters are sensitive and confidential. The Stakeholders are recommended to utilize the information referenced in Coal item #1 as a proxy for any analysis they might want to perform.
3. When were the gas assumptions developed? Gas prices have increased significantly in the past few months. Does SWEPCO consider its earlier assumptions reasonable?	The EIA AEO 2020 gas price assumptions used in the analysis were developed for use in the Y2020H2 Fundamentals Forecast. Long-term gas prices did not change significantly enough between the AEO 2020 and AEO 2021 to warrant updating the Fundamentals Forecast and risk delaying the 2021 SWEPCO IRP. While AEO 2021 projected prices in 2022-23 were higher, they averaged just over $3/MMBtu and would not have changed the results of the IRP analysis presented to SWEPCO stakeholders. Similarly, the elevated prices seen in the current spot and futures gas markets are not expected to remain beyond late-2022 to mid-2023, as reflected in recent NYMEX Henry Hub Futures price settlements. As of 9/20/2021, longer-dated futures contract prices (beyond 2023) are comparable to closing prices at the beginning of January 2021. Given the long-term outlook has not changed significantly between the release of the Fundamentals Forecast and now, the gas price assumptions remain reasonable.

4. What is the capacity value of existing and new gas units?	See Table 1 at the end of this Document for existing units. New gas units modeled are described in section 5 of the report and include a 240 MW F-Class Combustion Turbine, a 2x1 1,100 MW Combined Cycle unit and a 1x1 430 MW Combined Cycle unit.
5. Are existing gas units capacity values set to decline over time, to reflect maintenance issues?	No, units are assumed to be maintained such that capacity values do not decline over time.
6. Run a sensitivity analysis on gas prices +25% higher than the highest natural gas price against the Reference Scenario/Portfolio.	SWEPCO understands that Stakeholders are requesting a sensitivity run off the Reference Scenario using gas prices that are 25% higher than the "High" natural gas forecast used in the existing Enhanced Carbon Regulation scenario and a "Base" view of all other inputs, as illustrated in Figure 44 of the draft IRP. SWEPCO will provide the results of this sensitivity to Stakeholders by October 16. Results will include the new LMPs for the SPP market and the impact of the higher fuel cost to each portfolio (30-year NPVRR of sensitivity minus the 30-year NPVRR of the Reference Case as shown in the second column of scorecard). Update: The requested sensitivity was run and the summarized results are shown in the following Attachment: Attachment 9 - SWEPCO_GasSensitivity.pdf
7. Is SWEPCO going to propose adding a new combustion turbine either as a self-build or contractual option anytime within the next five years?	The preferred plan has not yet been selected.
8. Section 8.4.4 details various carbon dioxide emissions projections by portfolio. Will SWEPCO add estimates of total lifecycle emissions for each portfolio, including methane and other emissions from fuel extraction and transport.	No. The Company is unaware of any projections given the unknowns in sources of supply, changing environmental regulations and modes of transport and production.

Wind

1. Do capacity factors improve over time for new vintage wind projects?	Yes. The capacity factor of new wind units increases over time. For example, the capacity factor of a new wind unit added in 2024 is assumed to be 44.3%. The capacity factor assumption rises steadily over the forecast period and reaches a value of 47.1% for new wind units added in 2041.

2. In the FOR case, won't wind have a higher capacity credit during the wintertime?	No. The assumed ELCC value for new wind units is 14.7% in both the summer and the winter. This assumption does not vary by scenario.
3. Provide annual curtailment values (in MWhs) for each portfolio.	Please see the requested data in the following file: Attachment 4 - SWEPCO_Wind_Solar_Curtailment.xlsx
4. Use the NREL ATB 2021 capacity factors and LCOE's for Moderate Class 1 and Class 5 wind resources with the "Market Factors Financials" financial assumptions.	SWEPCO used the NREL ATB 2020 to inform the wind assumptions to the 2021 IRP. The NREL ATB 2020 was used because it was the vintage of this study available at the time the IRP analysis was being developed. We do not expect that adopting the NREL ATB 2021 assumptions would provide materially different outcome to the 2021 IRP than the costs that were already modeled. For a more detailed discussion, please see the following Attachment: Attachment 5 - NREL_Wind.docx

Solar

1. Figure 25, $/kWAC or $/kWDC? Real or nominal? Source EIA/NREL?	Figure 25 of the 2021 Draft IRP shows solar costs in real 2020 $ / kWAC. The 2024 value was the assumed cost from EIA's 2021 Annual Energy Outlook for the SPP market region. These costs decline over time based on the moderate learning rate from the NREL ATB 2020.
2. Re-run the Reference Scenario and Portfolio without the 450 MW solar/year cap (or set the cap to 2,000 MW per year).	SWEPCO understands that Stakeholders are requesting the development of a new candidate portfolio optimized under the Reference Scenario with a 2000MW / year annual limit on new solar additions. SWEPCO will provide the additional portfolio requested by Stakeholders by October 16. Update: The requested portfolio was rerun and the summarized results of the resource selections are shown in the following Attachment: Attachment 10 - SWEPCO_SolarSensitivity.pdf
3. Provide annual curtailment values (in MWhs) for each portfolio.	Please see the requested data in the following Attachment: Attachment 4 - SWEPCO_Wind_Solar_Curtailment.xlsx
4. Use the NREL ATB 2021 capacity factors and LCOE's for Moderate Class 1 and Class 5 utility-scale solar PV resources with the "Market Factors Financials" financial assumptions.	SWEPCO used the NREL ATB 2020 to inform the solar assumptions to the 2021 IRP. The NREL ATB 2020 was used because it was the vintage of this study available at the time the IRP analysis was being developed. We do not expect that adopting the NREL ATB 2021 assumptions would provide materially different outcome to the 2021 IRP than the costs that were already modeled. For a more detailed discussion, please see the following Attachment:

	Attachment 6 - NREL_Solar.docx

Hybrid

1. For the "solar+storage projects with a 3-1 solar-storage ratio", please provide an example of this set up.	SWEPCO includes hybrid solar+storage resources with a 3-1 solar-storage ratio in its IRP. The cost of this resource is the sum of the components, which are described in the IRP Report. Paired units exhibit different charge and discharge behavior than standalone units. Paired storage units may also benefit from tax credit benefits relative to standalone storage units. Additional detail described in Hybrid #3.
2. The SPP ELCC analyses (as well as MISO ELCC analyses) show that adding wind+solar together, the net capacity values increase for both resources. Could SWEPCO create a hybrid wind+solar resource for model selection?	After reviewing both the 2019 and 2020 SPP ELCC studies, SWEPCO does not believe a hybrid wind+solar facility would provide a meaningful increase in the ELCC value when compared to modeling as stand-alone resources. As such, there is no need to model these resources as a hybrid since the performance of the individual components would be the same.
3. Adding storage to either wind or solar increases the relative capacity values of those resources, and charging/dispatch profiles for those resources is differentthan stand-alone battery storage. SWEPCO should create hybrid solar+storage and wind+storage resource options	SWEPCO includes hybrid solar+storage resources with a 3-1 solar to storage ratio in its IRP since both projects would be eligible for the ITC. SWEPCO does not model hybrid wind+storage resources because there would be no added tax benefits than would be available by modeling each resource individually. For paired solar+storage resources, the charge/discharge cycles are different than stand-alone resources because Aurora employs a paired resource functionality that optimizes the operation of both resources to maximize portfolio value. After reviewing both the 2019 and 2020 SPP ELCC studies, SWEPCO does not believe a hybrid solar+storage or wind+storage facility would provide a meaningful increase in the ELCC value when compared to modeling as stand-alone resources. Therefore, the ELCC is simply the sum of the components of the solar and storage resources.

DER's

1. Describe each technology of DER's evaluated.	DER's are discussed generally in section 3.3.2. For the IRP, rooftop solar as discussed in section 6.3, was the associated DER (Distributed Generation) resource.

2. Did SWEPCO evaluate aggregated DER's?	See response to DER's item 1. All individual rooftop solar units referenced in item 1 above are assumed as an aggregated resource for the purposes of IRP modeling.
3. What effect will FERC Order 2222 have on DER growth in SWEPCO territory?	For this IRP, the Company did not assess the impact of Order 2222 on DER growth in SWEPCO territory.

Hydrogen

1. Did AURORA economically select any H2 resources in any portfolio or scenario?	No.
2. Explain the "15% penalty" for the H2 retrofit cost assumptions with citations.	SWEPCO is not aware that a "15% penalty" associated with hydrogen retrofits is described in the 2021 Draft IRP. In the 2021 IRP, when an existing NGCT is retrofit to burn 100% hydrogen fuel, the capital cost of this retrofit is assumed to be 15% of the cost of a new NGCT. The source for this estimate is the 2019 Element Energy Report "Opportunities for hydrogen and CCS in the UK power mix".
3. Provide H2 annual price forecasts on a $/MMBTu basis.	Yes, SWEPCO will provide the annual cost of hydrogen used under the "third party" configuration described in Chapter 5 of the 2021 Draft IRP by October 16. Update: Please see the requested data in the following Attachment: Attachment 11 - SWEPCO_HydrogenPrices.xlsx

Nuclear

4. Did AURORA economically select any nuclear resources in any portfolio or scenario?	No. However, in the ECR Scenario which represents the SPP Region, it is assumed the Cooper Nuclear Station which is in SPP but not a SWEPCO resource, is currently scheduled to retire in 2034, receives a further license extension and continues to operate for an additional 20 years within the SPP Region.

Carbon Emission Plans

1. The proposed Clean Electricity Performance Program (CEPP) in the federal Build Back Better Act includes a $40/MWh penalty for overly relying on carbon-intensive resources, and a $150/MWh clean energy benefit for exceeding certain benchmarks. How does	As discussed in more detail to response #2 below, The current CETA analysis is a fair proxy that represents a similar level of carbon burden/renewable energy incentives that are currently being contemplated in draft legislation. SWEPCO cannot run a new scenario and optimize a new portfolio using the currently proposed draft language by October 16. Many of the details of the proposed CEPP program are not yet defined and are subject to future decisions by the secretary of energy. This includes, among other things, the share of any unallocated qualified clean

SWEPCO/AEP propose modeling this type of program in its IRP's?	electricity that would be added to the 2019/2020 historical values to set individual utility baselines. SWEPCO can, however, evaluate the compliance position the 2021 IRP candidate portfolios assuming a "simple" 2019/2020 baseline and accounting for the amount of new qualifying generation added to each portfolio between 2023-2030. This analysis would compare the resulting benefit or costs to SWEPCO's customers associated with achieving or failing to achieve the annual incremental clean energy targets defined in the currently proposed draft CEPP language. Additionally, SWEPCO's Louisiana IRP process will kick off in 2022. If the draft CEPP or other proposed legislation is ultimately adopted, SWEPCO will include any new laws or regulations from the legislation as part of its Louisiana IRP modeling. Update: An analysis was performed on the modeled portfolios and the summarized results are shown in the following Attachment: Attachment 12 - SWEPCO_CEPP Analysis.pdf
2. SWEPCO should develop a sensitivity assessment regarding the CEPP implementation.	The 2021 IRP already includes a CETA scenario that thematically incorporates many of the same elements of the integrated draft infrastructure bill (which is not solely driven by the CEPP). The current CETA analysis is a fair proxy that represents a similar level of carbon burden/renewable energy incentives that are currently being contemplated in draft legislation. The CETA scenario drives rapid decarbonization in the broader SPP market, with the total proportion of clean energy increasing significantly from 2023-2030, reaching 85% of total load over the longer term. Further, SWEPCO will evaluate the compliance position of the candidate portfolios against the proposed draft CEPP language and share the resulting benefit or costs to SWEPCO's customers with Stakeholders prior to October 16.
3. If the CEPP is adopted, then SWEPCO should submit additional analysis after this IRP evaluating that program.	The Company will have the opportunity to address the proposed CEPP or other legislation in future IRP's including the upcoming SWEPCO LA IRP if it is adopted.
4. Add a scoring metric in the scorecard evaluating SWEPCO's adherence to the CEPP where the company achieves the 4% annual clean energy increase.	SWEPCO already includes a metric on the 2021 IRP Scorecard that evaluates the emissions performance of the candidate portfolios. It is not necessary, cost effective, or appropriate to add performance against <u>draft</u> legislative language to the Scorecard.

Energy Efficiency

1. Provide the EE/DSM achieved for each year of each scenario (via the model selection of EE bundles), expressed as Net Annual Incremental Savings Percentage.	SWEPCO did not calculate Net Annual Incremental Savings Percentage as part of the 2021 IRP. SWEPCO will provide Stakeholders the annual values describing the peak contribution and total energy saved under each candidate portfolio by October 16. Update: Please see the requested data in the following Attachment: Attachment 13 – SWEPCO EE Data.xlsx
2. Provide the average measure life for each EE/DSM bundle.	SWEPCO will provide the requested information by October 16. Update: Please see the requested data in the following Attachment: Attachment 13 – SWEPCO EE Data.xlsx
3. Provide the gradual savings decay rate assumed for each EE/DSM bundle.	SWEPCO will provide the requested information by October 16. Update: Please see the requested data in the following Attachment: Attachment 13 – SWEPCO EE Data.xlsx

Electric Vehicles

1. How many EV's are currently in SWEPCO's service territory? How does SWEPCO know?	Slide 19 of the SH Presentation shows that there are just over 1,500 electric vehicles registered in SWEPCO's service territory. (AR: 902 LA:291 TX:327). We know the number of EVs based on the vehicle registration dataset. We get the total number of vehicles registered by zip code for the states served by SWEPCO and match those with the zip codes from the Company's customer billing system.
2. Provide the analysis regarding EV growth in the region.	The growth rates on slide 19 of the SH Presentation is the analysis.
3. How many time-of-use (TOU) customers does SWEPCO currently have?	There are two customers in SWEPCO Arkansas territory on the Lighting and Power Time of Use Tariff.
4. Has SWEPCO considered developing a V1G/V2G pilot program regarding electric vehicles? Provide any reports.	No. Without AMI metering, SWEPCO is limited in the options it may offer. SWEPCO does offer a $250 rebate for a customer's installation of a Level 2 charger. Additionally, SWEPCO recently a filed time of use tariff and an electric vehicle charging tariff for residential customers as well as a time of use tariff for lighting and power customers as part of its 2021 rate case in APSC Docket No. 21-070-U.

Transmission

1. Provide reports/studies/analysis/justification regarding the "congestion charge" of $2/MWh and $5/MWh assumptions.	Please refer to the following attachment: Attachment 7 - SPP_Queue_Congestion_20210301.pdf file.
2. How often does SWEPCO conduct assessments of its transmission system for age and condition?	Criteria and guidelines necessary to identify and quantify needs associated with transmission facilities comprising AEP's system can be reviewed in the AEP Transmission Planning Criteria and Guidelines for End-Of-Life and Other Asset Management Needs document found at: https://aep.com/assets/docs/requiredpostings/AEPTransmissionOwnerIdentifiedNeedsGuidelines_4.pdf
3. Does SWEPCO have a five year capital expenditure plan for maintaining existing transmission facilities? Provide the plan.	The information in this request was not included in the analysis with this IRP and would not impact the final results.
4. Does the Welsh repowering portfolio include transmission retrofits or upgrades to maintain the local point of interconnect for Welsh?	SWEPCO is reviewing the request and will provide a response by October 16. Update: No, the repowering portfolio does not assume or include any transmission retrofits or upgrades.

IRP Stakeholder Process

1. Is there a centralized website where all these materials will be saved?	A website is being developed and will be in production the week of September 27. Update: The website is now functional and may be accessed via the following link: https://www.swepco.com/community/projects/arkansasirp/
2. Request an extension of the IRP filing for stakeholder feedback.	SWEPCO is agreeable to extending the timeframe for the submittal of the stakeholder report to SWEPCO from November 1 to November 15. Also, SWEPCO intends to provide its responses to the stakeholders' requests no later than October 16, which the stakeholders indicated at the stakeholder meeting on September 15, should provide them enough time to study the information and develop a report by November 15. SWEPCO must submit its IRP in December 2021 and does not believe an extension beyond that is necessary nor productive to the IRP process as a whole.
3. Need to score the scorecard with the CEPP	Please refer to item the Carbon Emissions requests, item #4 response.

Please let the Stakeholder Committee know by September 24th, 2021 if SWEPCO can provide the requested information and conduct the requested analysis sensitivities by mid-October. If SWEPCO is unable to provide the stakeholders with the requested information and analysis, the Stakeholder Committee requests that SWEPCO request an extension for the IRP to better enable public input in this process.

Table 1

Plant	Unit	MW Capability	In-Service Year	Expected Useful Life	Primary Fuel	State	Retirement Date [1]
Arsenal Hill	5	110	1960	66	Natural Gas	LA	1/1/2026
Dolet Hills	1	262 [b]	1986	36	Lignite	LA	1/1/2022
Flint Creek	1	264[a]	1978	61	Coal	AR	1/1/2039
Knox Lee	5	348	1974	66	Natural Gas	TX	1/1/2040
Lieberman	3	109	1957	66	Natural Gas	LA	1/1/2023
Lieberman	4	108	1959	66	Natural Gas	LA	1/1/2025
Mattison	1	76	2007	46	Natural Gas (CT)	AR	1/1/2053
Mattison	2	76	2007	46	Natural Gas (CT)	AR	1/1/2053
Mattison	3	76	2007	46	Natural Gas (CT)	AR	1/1/2053
Mattison	4	76	2007	46	Natural Gas (CT)	AR	1/1/2053
Pirkey	1	580 [c]	1985	38	Lignite	TX	6/1/2023
Stall	6A,6B,6S	511	2010	41	Natural Gas (CC)	LA	1/1/2051
Turk	1	650	2012	56	Coal	AR	1/1/2068
Welsh	1	528	1977	51	Coal	TX	3/1/2028
Welsh	3	528	1982	46	Coal	TX	3/1/2028
Wilkes	1	177	1964	66	Natural Gas	TX	1/1/2030
Wilkes	2	362	1970	66	Natural Gas	TX	1/1/2036
Wilkes	3	362	1971	66	Natural Gas	TX	1/1/2037
Sundance		109 [d]	2021	30	Wind	OK	2051
Maverick		156 [d]	2021	30	Wind	OK	2051
Traverse		544 [d]	2022	30	Wind	OK	2052

[a] SWEPCO's Share is 264 MW. Whole unit is 528MW

[b] SWEPCO's Share is 262 MW. Whole unit is 650MW.

[c] SWEPCO's Share is 580 MW. Whole unit is 675MW.

[d] Installed capacity; Represents SWEPCO's 54.5% ownership stake

(1) Retirement date based on Commission approved depreciation rates

List of Attachments

Attachment 1 - SWEPCO IRP Draft Figures_aep.xlsx

Attachment 2 - SWEPCO Technical Conference Figures.xlsx (Need attachment)

Attachment 3 - SWEPCO LMPs.xlsx

Attachment 4 - SWEPCO_Wind_Solar_Curtailment.xlsx

Attachment 5 - NREL_Wind.docx

Attachment 6 - NREL_Solar.docx

Attachment 7 - SPP_Queue_Congestion_20210301.pdf

Attachment 8 - SWEPCO_C.F_Generation_Data Annual.xlsx

Attachment 9 - SWEPCO_GasSensitivity.pdf

Attachment 10 - SWEPCO_SolarSensitivity.pdf

Attachment 11 - SWEPCO_HydrogenPrices.xlsx

Attachment 12 - SWEPCO_CEPP Analysis.pdf

Attachment 13 – SWEPCO EE Data.xlsx