SOUTHWESTERN ELECTRIC POWER COMPANY

An AEP Company

BOUNDLESS ENERGY

INTEGRATED RESOURCE PLANNING REPORT

TO THE

ARKANSAS PUBLIC SERVICE COMMISSION

December 14, 2018

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Executive Summary

This Integrated Resource Plan (IRP, Plan, 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.

An IRP explains how a utility company plans to meet the projected capacity (*i.e.*, peak demand) and energy requirements of its customers. SWEPCO is required to provide an IRP that encompasses a 20-year forecast planning period (in this filing, 2019-2038). This IRP has been developed using the Company's current long-term assumptions for:

- Customer load requirements – peak demand and energy;
- commodity prices – coal, natural gas, on-peak and off-peak power prices, capacity and emission prices;
- supply-side alternative costs – including fossil fuel, renewable generation, and storage resources; and
- demand-side program costs and impacts.

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

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

Environmental Compliance Issues

This 2018 IRP considers the impacts of final and proposed U.S. Environmental Protection Agency (EPA) regulations to SWEPCO generating facilities. Environmental compliance requirements have a major influence on the consideration of new supply-side resources for inclusion in the IRP because of the potential significant effects on both capital and operational costs. In addition, the IRP development process assumes potential future regulation of greenhouse gas (GHG)/carbon dioxide (CO_2). For that purpose, a reasonable proxy was utilized in the IRP that assumed that the resulting economic impact would be equivalent to a CO_2 "tax" applicable to each ton of carbon emitted from fossil-fired generation which would take effect beginning in 2028. Under the Company's Base commodity pricing scenario, the cost of such CO_2 emissions is equal to $15/metric ton commencing in 2028 and escalating at 5% per annum thereafter on a nominal dollar basis.

Arkansas IRP Stakeholder Process

The Arkansas stakeholder process is designed to allow key IRP stakeholders an opportunity to gain an understanding of SWEPCO's IRP process and key assumptions, and then prepare a "Stakeholder Report". SWEPCO can then address any issues or comments from the Stakeholder Report within the final SWEPCO IRP for Arkansas. 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. The stakeholder meeting was held August 14, 2018 in Fayetteville, Arkansas during which a "Draft" IRP was reviewed with the stakeholders. The stakeholders then prepared a report addressing key issues or concerns that they would like addressed in the IRP. The stakeholder report with SWEPCO's responses are included in the Appendix C of this report.

Louisiana IRP Stakeholder Process

In Louisiana, various stakeholders, including Louisiana Commission staff, were presented IRP assumptions in July 2018 and provided useful feedback which has been considered and incorporated in the analysis assumptions, where warranted.

Summary of SWEPCO Resource Plan

SWEPCO's retail sales are projected to grow at 0.4% per year with stronger growth expected from the residential class (+0.5% per year) while the commercial and industrial classes experience modest increases (0.3% and 0.2% per year, respectively) over the forecast horizon. The projected change in SWEPCO's internal energy over the next 20 years is for requirements to increase by 0.3% per year. Figure ES - 1 below shows SWEPCO's "going-in" (i.e. before resource additions) capacity position over the planning period.[1] In 2026, SWEPCO anticipates experiencing a slight capacity shortfall which then grows to a 1,886MW shortfall by 2038.

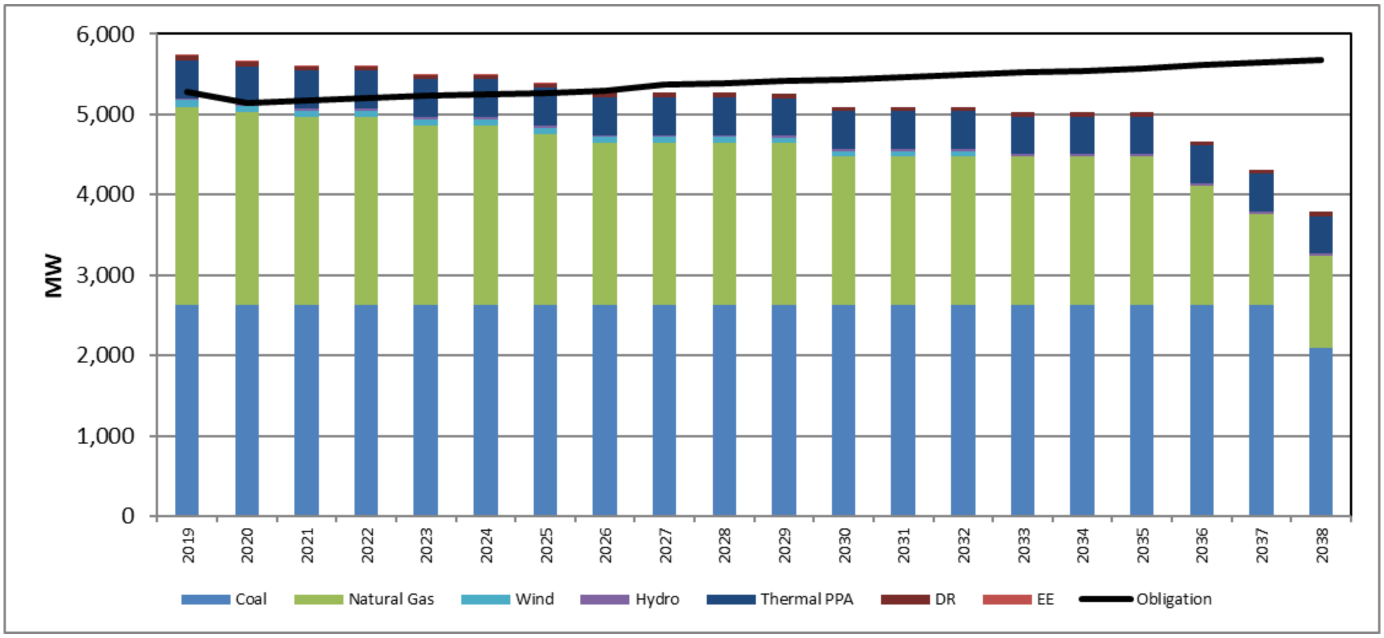

Figure ES - 1. SWEPCO "Going-In" SPP Capacity Position

To determine the appropriate level and mix of incremental supply and demand-side resources required to offset such going-in capacity deficiencies, SWEPCO utilized the *Plexos*® Linear Program (LP) optimization model to develop a "least-cost" resource plan. Although the IRP planning period is limited to 20 years (through 2038), the *Plexos*® modeling was performed

[1] This is based on a capacity reserve and demand forecast that includes the Turk Power Plant which is not used or recoverable in Arkansas.

through the year 2048 so as to properly consider various cost-based "end-effects" for the resource alternatives being considered.

SWEPCO used the modeling results to develop a Preferred Plan or "Plan". To arrive at the Preferred Plan, using Plexos®, SWEPCO developed optimal portfolios based on four long-term commodity price forecasts and two load sensitivities. The Preferred Plan balances cost and other factors such as risk and environmental regulatory considerations, to cost effectively meet SWEPCO's demand and energy obligations. Given that the optimal portfolios under the four commodity pricing scenarios offer comparable resource additions, SWEPCO has elected to use the optimal plan developed under the Base commodity pricing scenario as its Preferred Plan.

Table ES - 1 provides a summary of the Preferred Plan, which was selected based on the results from optimization modeling under various load and commodity pricing scenarios:

Table ES - 1. Preferred Plan Cumulative Capacity Additions throughout Planning Period (2019-2038)

Preferred Plan		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Base	Base/Intermediate																			373	1,119
Commodity,	Solar (Firm)							15	30	45	95	144	204	253	303	360	395	429	429	429	429
Base Load	Solar (Nameplate)							150	300	450	600	750	1,000	1,150	1,300	1,300	1,300	1,300	1,300	1,300	1,300
	Wind (Firm)				30	60	70	220	370	420	420	450	450	450	600	600	600	600	600	600	600
	Wind (Nameplate)				600	1,200	1,400	1,400	1,400	1,400	1,400	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	Energy Efficiency		8	15	21	20	25	23	20	17	13	12	11	10	7	5	3	3	2	2	1
	VVO		24	24	24	24	24	37	37	37	37	37	37	37	37	48	48	48	48	48	48
	Distr. Gen. (Firm)	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
Capacity Reserves (MW) Above SPP Requirement without New Additions		449	519	419	386	258	237	109	(22)	(101)	(121)	(159)	(348)	(376)	(404)	(497)	(521)	(552)	(946)	(1,330)	(1,886)
Capacity Reserves (MW) Above SPP Requirement with New Additions		452	553	462	465	366	360	409	439	423	448	490	359	379	548	522	531	534	140	129	318

In summary, the Preferred Plan:

- Adds utility-scale solar resources in 2025 through 2032, for a total of 1,300MW (nameplate) of utility-scale solar by the end of the planning period.
- Adds 600MW (nameplate) of wind resources in 2022 and 2023 and 200MW (nameplate) in 2024, with additional wind resources added through 2029, for a total of 2,000MW (nameplate) by the end of the planning period.
- Implements customer and grid energy efficiency programs, including VVO, reducing energy requirements by 202GWh and capacity requirements by 49MW by 2038.
- Fills long-term needs through the addition of a total of 1,119MW of natural gas combined-cycle generation in 2037 and 2038 to replace planned unit retirements.
- Recognizes additional distributed solar capacity will be added by SWEPCO's customers, beginning with 10MW (nameplate) in 2019 and ramping up to 24MW (nameplate) by 2038.

SWEPCO capacity changes over the 20-year planning period associated with the Preferred Plan are shown in Figure ES - 2 and Figure ES - 3.

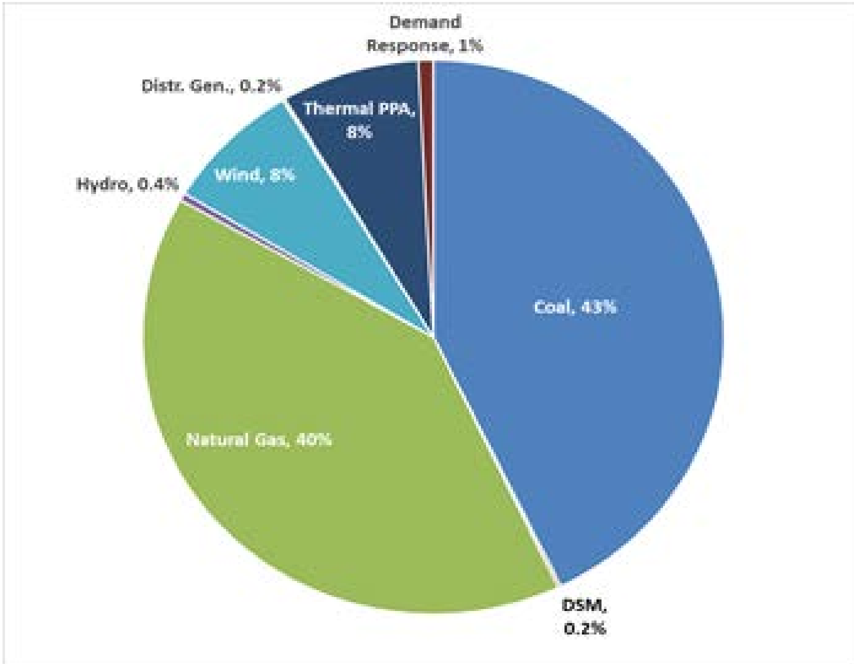

Figure ES - 2. 2019 SWEPCO Nameplate Capacity Mix

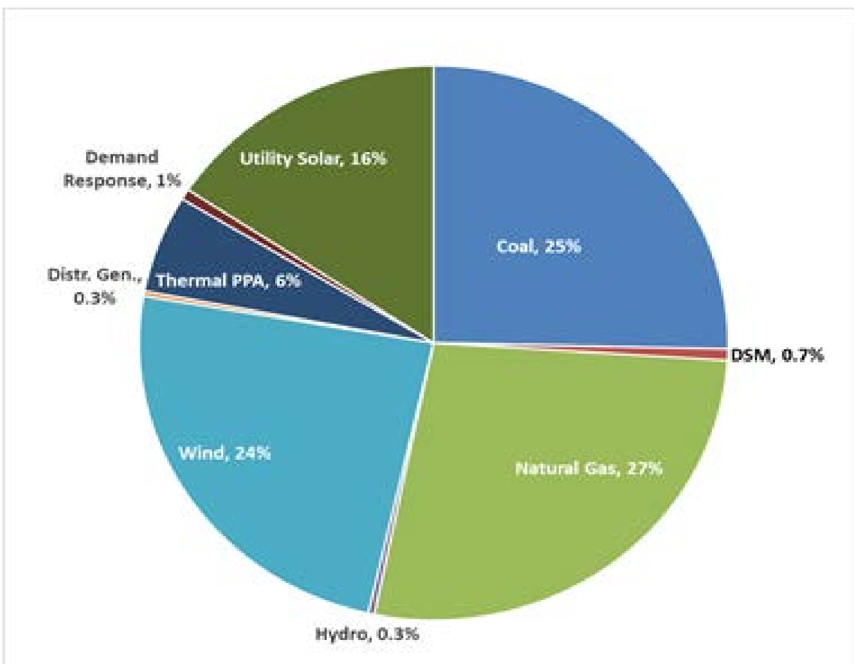

Figure ES - 3. 2038 SWEPCO Nameplate Capacity Mix

The relative impacts to SWEPCO's annual energy position are shown in Figure ES - 4 and Figure ES - 5.

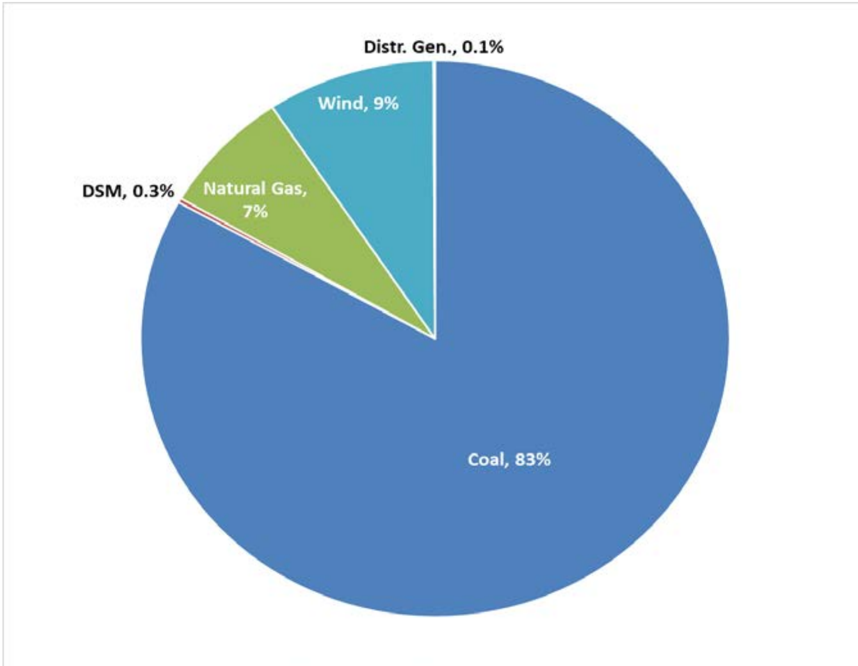

Figure ES - 4. 2019 SWEPCO Energy Mix

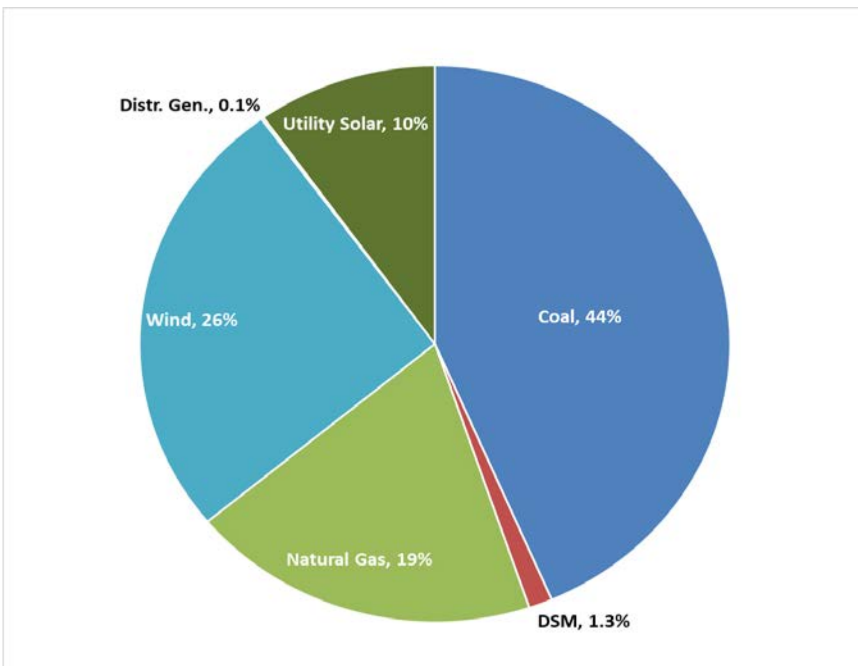

Figure ES - 5. 2039 SWEPCO Energy Mix

Figure ES - 2 through Figure ES - 5 indicate that this Preferred Plan would reduce SWEPCO's reliance on solid fuel-based generation, and increase reliance on demand-side, natural gas, and renewable resources. Specifically, over the 20-year planning horizon the Company's nameplate capacity mix attributable to solid fuel-fired assets declines from 43% to 25%, and natural gas assets would decrease from 40% to 27%. Solar assets make up 16% of the capacity mix and wind assets increase to 24%. Demand-side management (DSM) resources are added to the mix at 0.7% of total nameplate capacity resources.

SWEPCO's energy output attributable to solid fuel generation decreases from 83% to 44% over the planning period, while energy from natural gas resources increases from 7% to 19%. The Preferred Plan introduces solar resources, which contributes to 10% of total energy. Additionally, energy from wind resources increases from 9% to 26%, while DSM resources increase from 0.3% to 1.3% of SWEPCO's total energy mix.

Figure ES - 6 and Figure ES - 7 show annual changes in capacity and energy mix, respectively, that result from the Preferred Plan, relative to capacity and energy requirements. The capacity contribution from renewable resources is fairly modest due to the treatment of capacity credit for intermittent resources within SPP; however, those resources (particularly wind) provide a significant volume of energy. Wind resources were selected in all of the scenarios because they were a low cost energy resource. When comparing the capacity values in Figure ES - 6 with those in Figure ES - 2 and Figure ES - 3, it is important to note that Figure ES - 6 provides an analysis of SPP-recognized capacity, while Figure ES - 2 and Figure ES - 3 depict nameplate capacity.

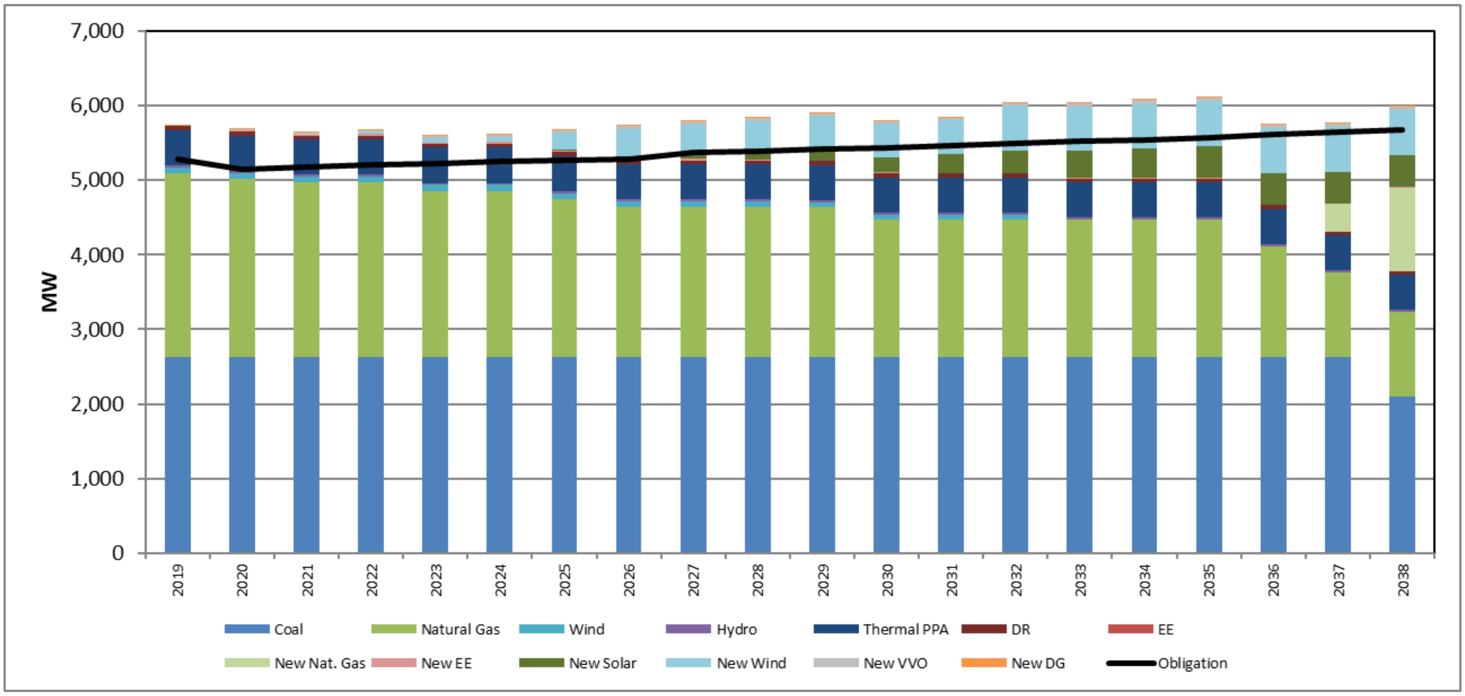

Figure ES - 6. SWEPCO Annual SPP Capacity Position (MW) per the Preferred Plan

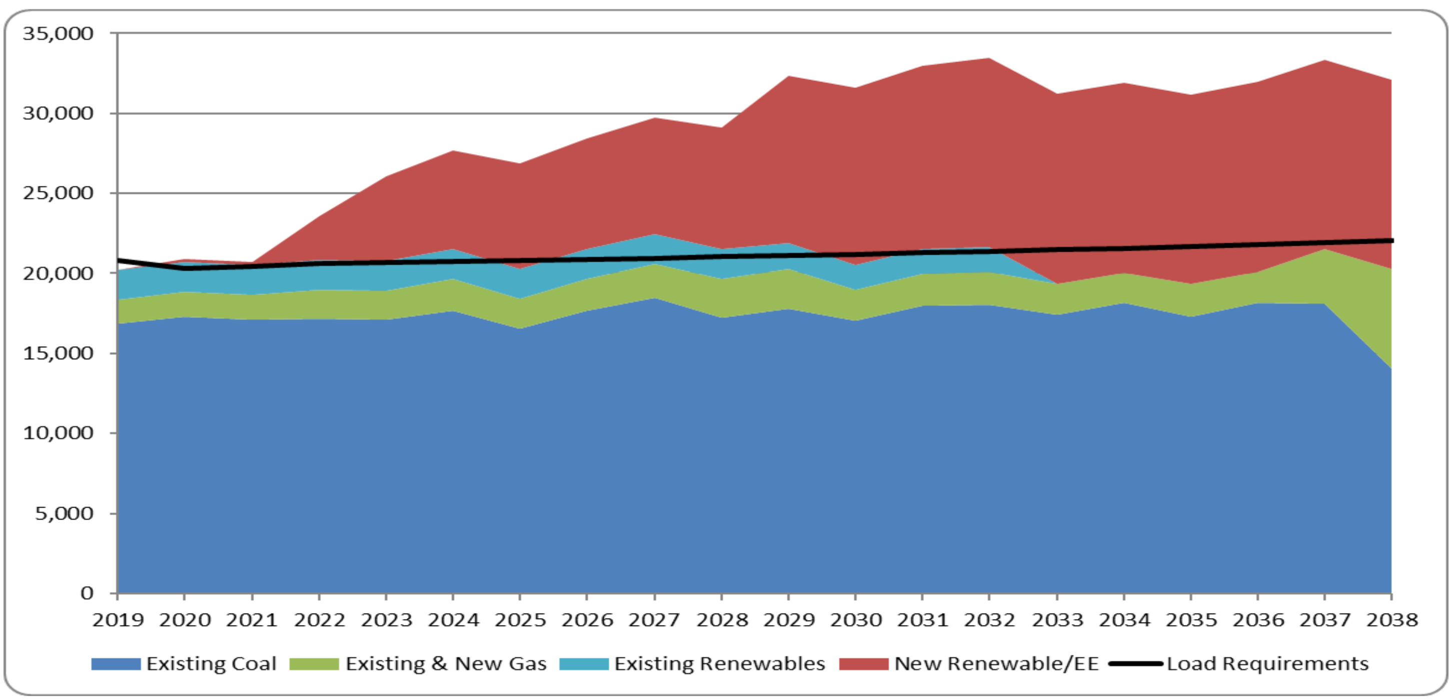

Figure ES - 7. SWEPCO Annual Energy Position (GWh) per the Preferred Plan

SWEPCO Five-Year Action Plan

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

1. Continue the planning and regulatory actions necessary to implement economic DSM programs in Arkansas, Louisiana and Texas.
2. Continue with the recently released Request for Proposal (RFP) to explore opportunities to add cost-effective wind generation in the near future to take advantage of the Federal Production Tax Credit.
3. Consider conducting an RFP to explore adding cost effective utility-scale solar resources.
4. Be ready to adjust this Action Plan and future IRPs to reflect changing circumstances.

Conclusion

SWEPCO's Preferred Plan provides the Company with an increasingly diversified portfolio of supply- and demand-side resources which provides flexibility to adapt to future changes to the power market, technology, and environmental regulations. The addition of renewables and demand-side management mitigates fuel price and environmental compliance risk. At the end of the planning period efficient natural gas-fired generation will replace the capacity from solid fuel units that are planned for retirement.

Inasmuch as there are many assumptions, each with its own degree of uncertainty, which had to be made in the course of resource portfolio evaluations, material changes in these assumptions could result in modifications. The action plan presented in this IRP is sufficiently flexible to accommodate possible changes in key parameters, including load growth, environmental compliance assumptions, fuel costs, and construction cost estimates, which may impact this IRP. By minimizing SWEPCO's costs in the optimization process, the Company's model produced optimized portfolios with the lowest reasonable impact on customers' rates.

1.0 Introduction

1.1 Overview

This Report presents the 2018 Integrated Resource Plan (IRP, Plan, or Report) for Southwestern Electric Power Company (SWEPCO or Company) including descriptions of assumptions, study parameters, and methodologies. The results integrate supply- and demand-side resources.

*The goal of the IRP process is to identify the **amount**, **timing** and **type** of resources required to ensure a reliable supply of capacity and energy to customers at the least reasonable cost.*

In addition to developing a long-term strategy for achieving reliability/reserve margin requirements as set forth by SPP, resource planning is critical to SWEPCO due to its impact on such things as determining capital expenditure requirements, regulatory planning, environmental compliance, and other planning processes.

1.2 Integrated Resource Plan (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:

- Description of the Company, the resource planning process in general, and the implications of current issues as they relate to resource planning;
- provide projected growth in demand and energy which serves as the underpinning of the Plan;
- identify and evaluate demand-side options such as Energy Efficiency (EE) measures, Demand Response (DR) and Distributed Generation (DG);
- identify current supply-side resources, including projected changes to those resources (*e.g.,* de-rates or retirements), and transmission system integration issues; and
- identify and evaluate supply-side resource options;
- perform resource modeling;
- and utilize results to develop recommended portfolio.

1.3 Introduction to SWEPCO

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

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

The operating companies in AEP's Southwest Power Pool (SPP) zone collectively serve a population of about 4.25 million, which includes over 1 million retail customers in a 36,000 square mile area in parts of Arkansas, Louisiana, Oklahoma, and Texas.

SWEPCO's customers consist of both retail and sales-for-resale (wholesale) customers located in the states of Arkansas, Louisiana and Texas (see Figure 1). Currently, SWEPCO serves approximately 535,000 retail customers in those states; including over 231,000 and 119,000 in the states of Louisiana and Arkansas, 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 (2017-18) actual SWEPCO summer and winter peak demands were 4,768MW and 4,792MW, occurring on July 20th and January 17th (2018), respectively.

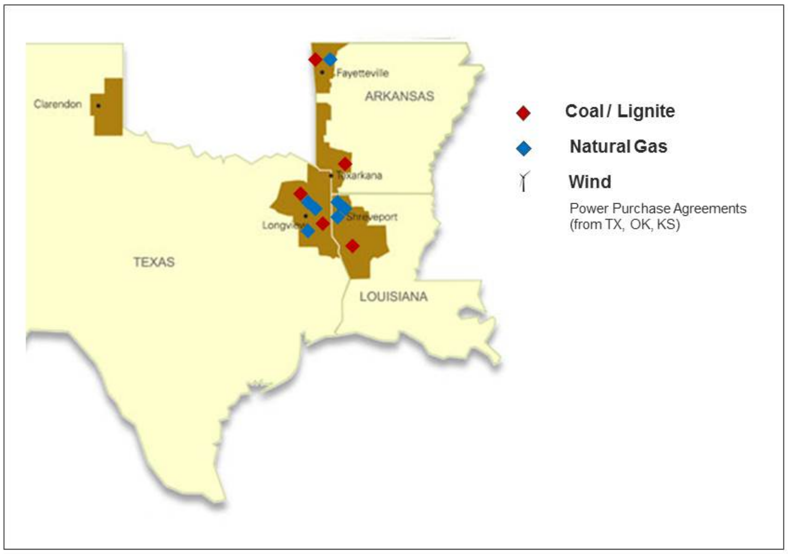

Figure 1. SWEPCO Service Territory

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, now more than ever before, 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.

1.3.1 Annual Planning Process

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 new generation cost and performance characteristics. 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 annual forecast is generally available in June of each year.

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 was released in August of 2018.

New generation resource cost and characteristics are generally updated on an annual basis with a typical first quarter release date. This data is often updated as needed if additional material data is made known between the typical release dates.

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.

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2.0 Load Forecast and Forecasting Methodology

2.1 Summary of SWEPCO Load Forecast

The SWEPCO load forecast was developed by AEP's Economic Forecasting organization and completed in June 2018.[2] The final load forecast is the culmination of a series of underlying forecasts that build on each other. In other words, the economic forecast provided by Moody's Analytics is used to develop the customer forecast which is then used to develop the sales forecast which is ultimately used to develop the peak load and internal energy requirements forecast.

Over the next 20 year period (2019-2038)[3], SWEPCO's service territory is expected to see population and non-farm employment experience similar growth of 0.8% and 0.6% per year, respectively. Not surprisingly, SWEPCO is projected to see customer count growth at a rate of 0.4% per year. Over the same forecast period, SWEPCO's retail sales are projected to grow at 0.4% per year with stronger growth expected from the residential class (+0.5% per year) while the commercial and industrial classes experience modest increases (0.3% and 0.2% per year, respectively) over the forecast horizon. The projected change in SWEPCO's internal energy over the next 20 years is for requirements to increase by 0.3% per year. Finally, SWEPCO's peak demand is also expected to increase at an average rate of 0.3% per year through 2038.

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

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

[3] 20 year forecast periods begin with the first full forecast year, 2019

load forecasts utilized Moody's Analytics economic forecast issued in December 2017. Moody's Analytics projects moderate growth in the U.S. economy during the 2019-2038 forecast period, characterized by a 2.0% annual rise in real Gross Domestic Product (GDP), and moderate inflation as well, with the implicit GDP price deflator expected to rise by 2.0% per year. Industrial output, as measured by the Federal Reserve Board's (FRBs) index of industrial production, is expected to grow at 1.3% per year during the same period. Moody's projected employment growth of 0.6% per year during the forecast period and real regional income per-capita annual growth of 2.3% for the SWEPCO service area.

2.2.2 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.

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 deletions 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

Inherent in the historical data used to specify the load forecast models are the impacts of past customer energy conservation and load management behaviors. Energy usage is being impacted by a combination of federal and/or state efficiency mandates in addition to company sponsored Energy Efficiency (EE) and DSM programs. The statistical adjusted end-use models incorporate changing saturations and efficiencies of the various end-use appliances which results in a certain amount of EE to be "embedded" into the load forecast.

In addition to the "embedded" EE, the Company also accounts for Commission-approved DSM program impacts in the load forecasting process. For the IRP, the load forecast is used as described with a major assumption change to the state approved EE programs. At a given year, the state approved incremental EE assumption is assumed to stop, with some residual EE going forward due to lingering degradation impacts of prior years. Then, new annual EE assumptions are layered in to replace the state approved EE levels.

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 extends 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 below.

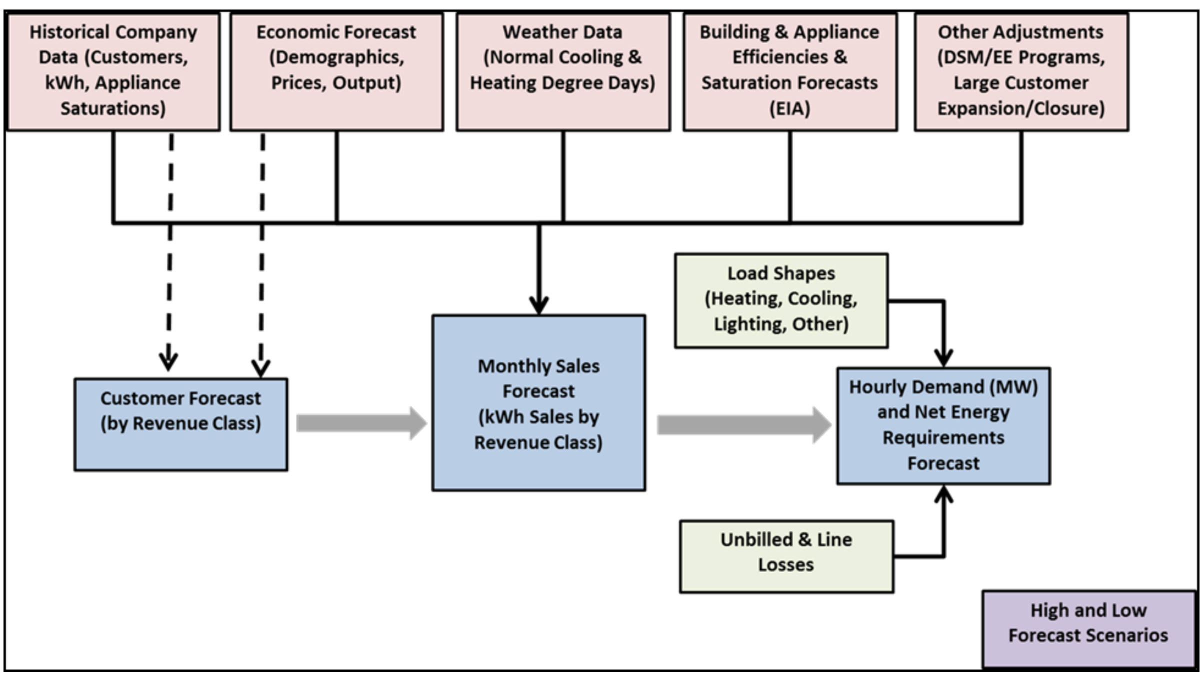

Figure 2. SWEPCO Internal Energy Requirements and Peak Demand Forecasting Method

2.4 Detailed Explanation of Load Forecast

2.4.1 General

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 impact 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.

2.4.2 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 economic and demographic variables include population and households used in various combinations for each jurisdiction. 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.

2.4.3 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 2007 through December 2017.

2.4.3.1 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.

2.4.3.2 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.

2.4.3.3 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 municipals. Current SWEPCO wholesale requirements customers include the cities of Bentonville, Hope and Prescott in Arkansas, City of Minden in Louisiana, Northeast Texas Electric Cooperative, and Rayburn County Electric Coop. Figures from 2017 and prior years also include East Texas Electric Cooperative and Tex-La Electric Reliability Cooperative. Wholesale loads are generally longer term, full requirements, and cost-of-service based contracts.

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.

2.4.4 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 annual 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 1995-2017 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.

2.4.4.1 Supporting Models

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.

2.4.4.1.1 Consumed Natural Gas Pricing Model

The forecast price of natural gas used in the Company's energy models comes from a model of state natural gas prices for four 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 sectorial prices, with the forecast being obtained from EIA's "2018 Annual Energy Outlook." The natural gas price model is based upon 1980-2017 historical data.

2.4.4.2 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 December 2017. 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.

2.4.4.3 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 2017 Annual Energy Outlook. Billing days and electricity prices are developed internally. The commercial output measure is real commercial gross regional product 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 December 2017. 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.

2.4.4.4 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 December 2017.

2.4.4.5 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. The long-term forecast reflects the effects of two wholesale contracts that expired December 31st, 2017 and one contract being terminated by 2020.

2.4.5 Final Monthly Internal Energy Forecast

2.4.5.1 Blending Short and Long-Term Sales

Forecast values for 2018 and 2019 are taken from the short-term process. Forecast values for 2020 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 2020 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.

2.4.5.2 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.

2.4.5.3 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.

2.4.6 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 of the report can be found in the appendix of this report in Exhibit A.

2.5.1 Load Forecast

Table 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 2008-2017. 2018 data are three months actual and nine months forecast and on a forecast basis for the years 2019-2038. 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 3 below provides a graphical depiction of weather normal and forecast Company residential, commercial and industrial sales for 2002 through 2038.

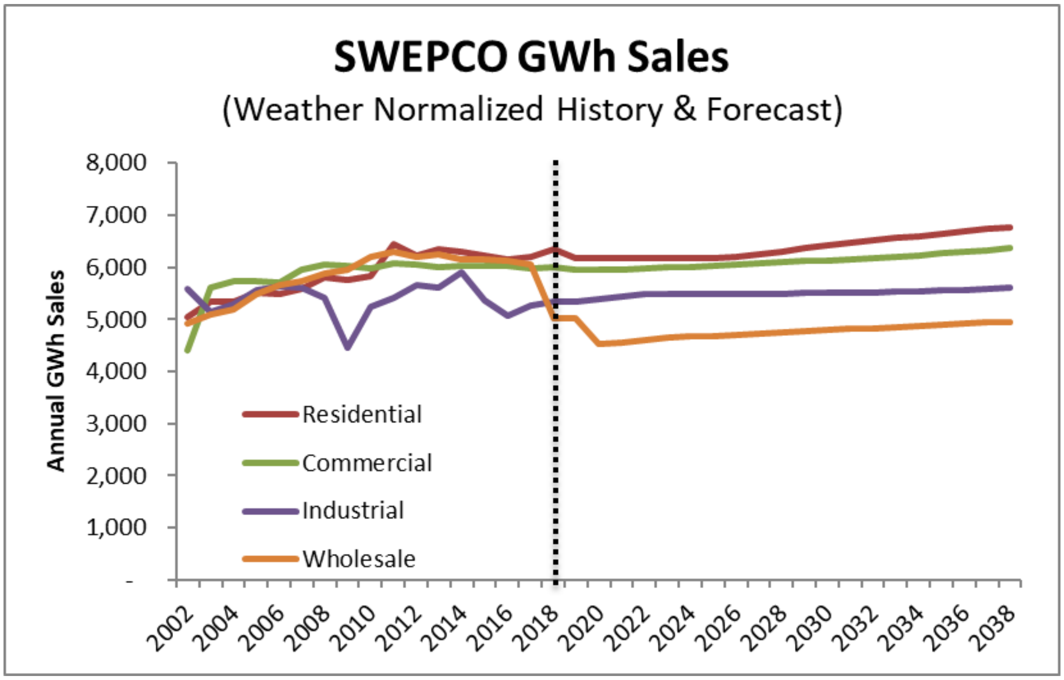

Figure 3. SWEPCO GWh Sales

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 2008-2017. 2018 data are three months actual and nine months forecast and on a forecast basis for the year 2019-2038. The table also shows annual growth rates for both the historical and forecast periods.

Figure 4 presents actual, weather normal and forecast PSO peak demand for the period 2000 through 2038.

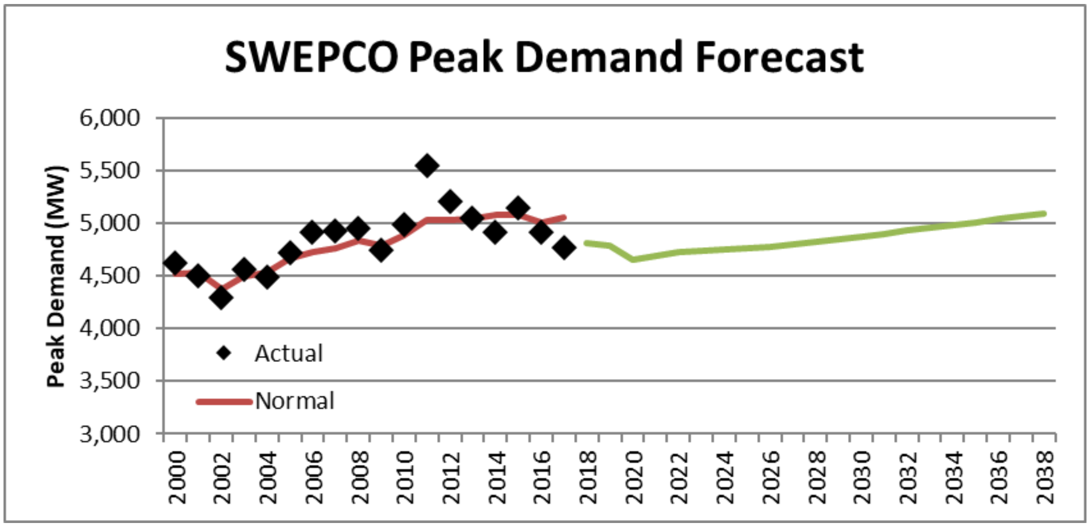

Figure 4. SWEPCO Peak Demand Forecast

2.5.3 Monthly Data

Table A-4 provides historical monthly sales data for SWEPCO by customer class (residential, commercial, industrial, other retail and wholesale) for the period January 2007 through March 2018. Table A-5 provides forecast SWEPCO monthly sales data by customer class for April 2018 through December 2038.

2.5.4 Prior Load Forecast Evaluation

Table A-6 presents a comparison of SWEPCO's energy sales and peak demand forecasts in the 2015 IRP with the actual and weather normal data for 2015, 2016 and 2017. The primary reason for the forecast differences is that the SWEPCO service area economy did not expand as quickly as was expected when the load forecast used in the previous (2015) IRP was developed. In fact, the SWEPCO service area experienced year-over-year contractions in real output from the 4th quarter in 2015 through the 3rd quarter in 2016. On a regional level, real GDP was expected to grow at 3.3%, 3.5% and 2.6% in 2015, 2016 and 2017, respectively. Meanwhile, real GDP grew by .7% in 2015, declined by 0.6% in 2016, and grew by 2.3% in 2017. As the sluggish economy was seen as the primary reason for the forecast differences, there were no significant changes to the forecast model structures. But, 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 2015 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 5 presents SWEPCO's historical and forecasted residential and commercial usage per customer between 1991 and 2025. 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 1.0% per year. For the last decade shown (2011-2020) Residential usage is projected to decline at a rate of 0.8% per year while the Commercial usage is falls by an average of 0.6% per year. This decline is expected to moderate for the last 5 years shown (2021-2025), with residential usage declining at a rate of 0.3% per year while commercial usage falls by 0.1%.

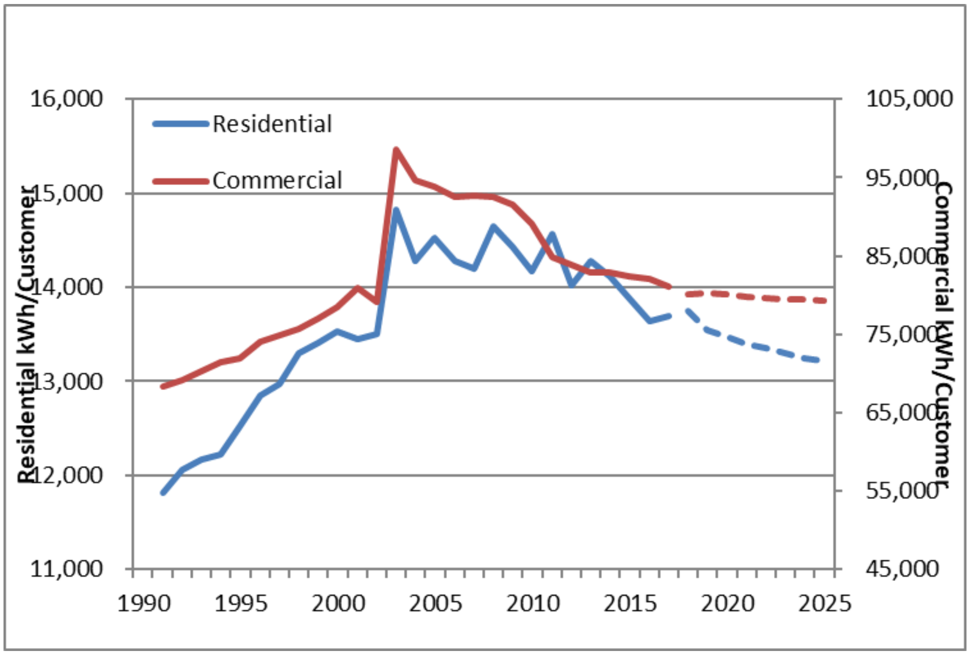

Figure 5. SWEPCO Normalized Use per Customer (kWh)

The statistically adjusted end-use 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 energy efficiency. For example, Figure 6 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 11.94 in 2010 to over 14.3 by 2035. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units as well.

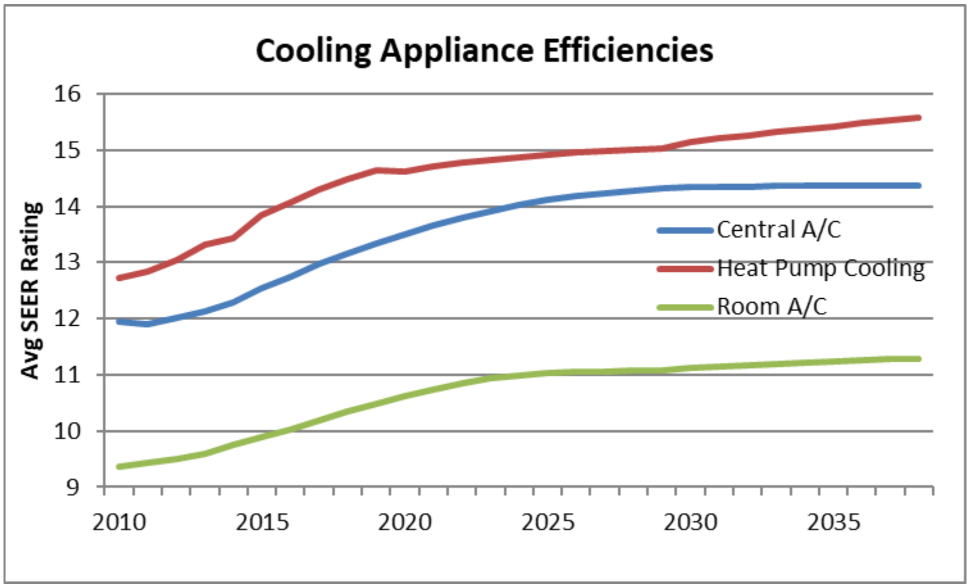

Figure 6. Projected Changes in Cooling Efficiencies, 2010-2038

Figure 7 below 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.

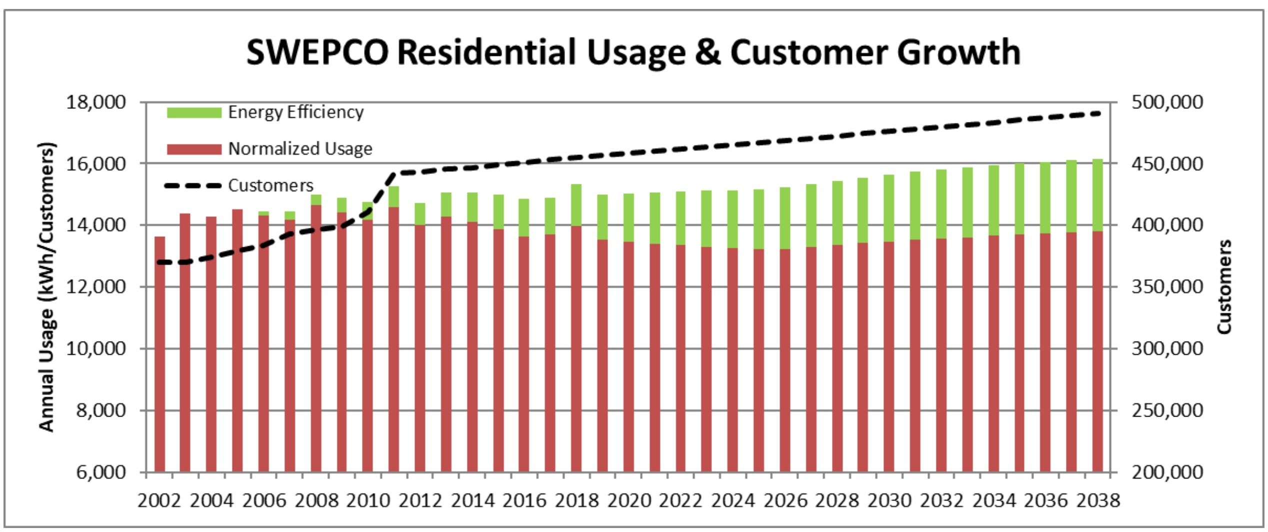

Figure 7. Residential Usage and Customer Growth, 2002-2038

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

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

2.6.3 Losses and Unaccounted for Energy

Actual and forecast losses and unaccounted for energy are provided in Table A-13. See Section 2.4.5.3 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 26 customers with interruptible provisions in their contracts. The aggregate on-peak capacity available for interruptions is 36.8MW. 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. 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 the year 2018 were typically taken from the short-term process. Forecast values for 2020 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 2020 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

8 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.

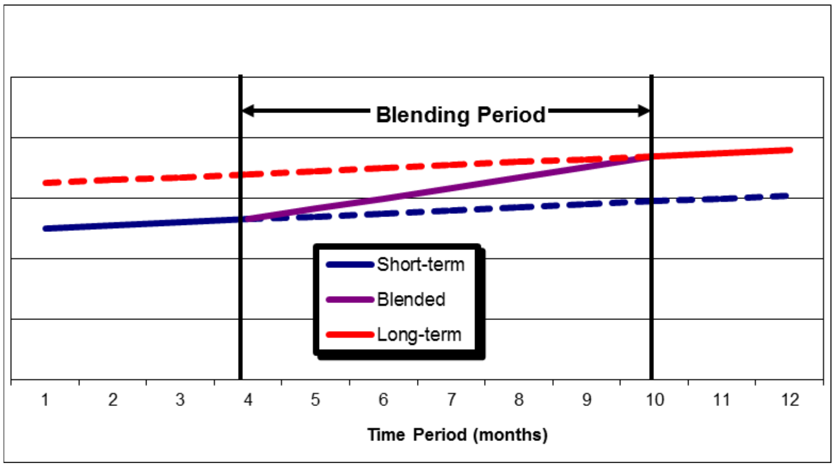

Figure 8. 2018 Load Forecast Blending Illustration

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 add factors may be used to reflect those large changes that are different from those 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. Within the context of these two items, the Company has two wholesale customers with "full requirements" load contracts that expired at the end of 2017 and one such customer whose contract will expire by

2020. The load for these wholesale customers has been removed from the load forecast at the appropriate dates. 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 exact quantification of outcomes, but the reality is if the all possible outcomes were known with a degree of certainty, then it 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 2018 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.

2.7.1 Low Load Sensitivity Case

The Low Load forecast reflects the impact of low economic growth for the region and consistent with the low economic growth presented by EIA.

The Low Load forecast projects firm peak load growth to average -0.27% per year on a compound basis. Total energy growth is also projected to average about -0.33% per year. The load factor is unchanged from the Base Case at about 56% to 57%. The low forecast for energy is 12.1% below the base forecast in 2038.

2.7.2 High Load Sensitivity Case

The High Load forecast represents a scenario of more sustained growth for the residential, commercial and industrial customer classes. As with the Low Load Case Load Forecast the high economic growth scenario is consistent with EIA high growth in its economic scenario.

The High Load forecast projects firm peak load growth to average 0.83% per year. Energy growth is also projected to average 0.77% per year with a load factor of 56% to 57%. The high forecast for energy is 11% above the base forecast in 2038.

Figure 9 below provides a graphical depiction of the scenarios developed in conjunction with the load provided in this report.

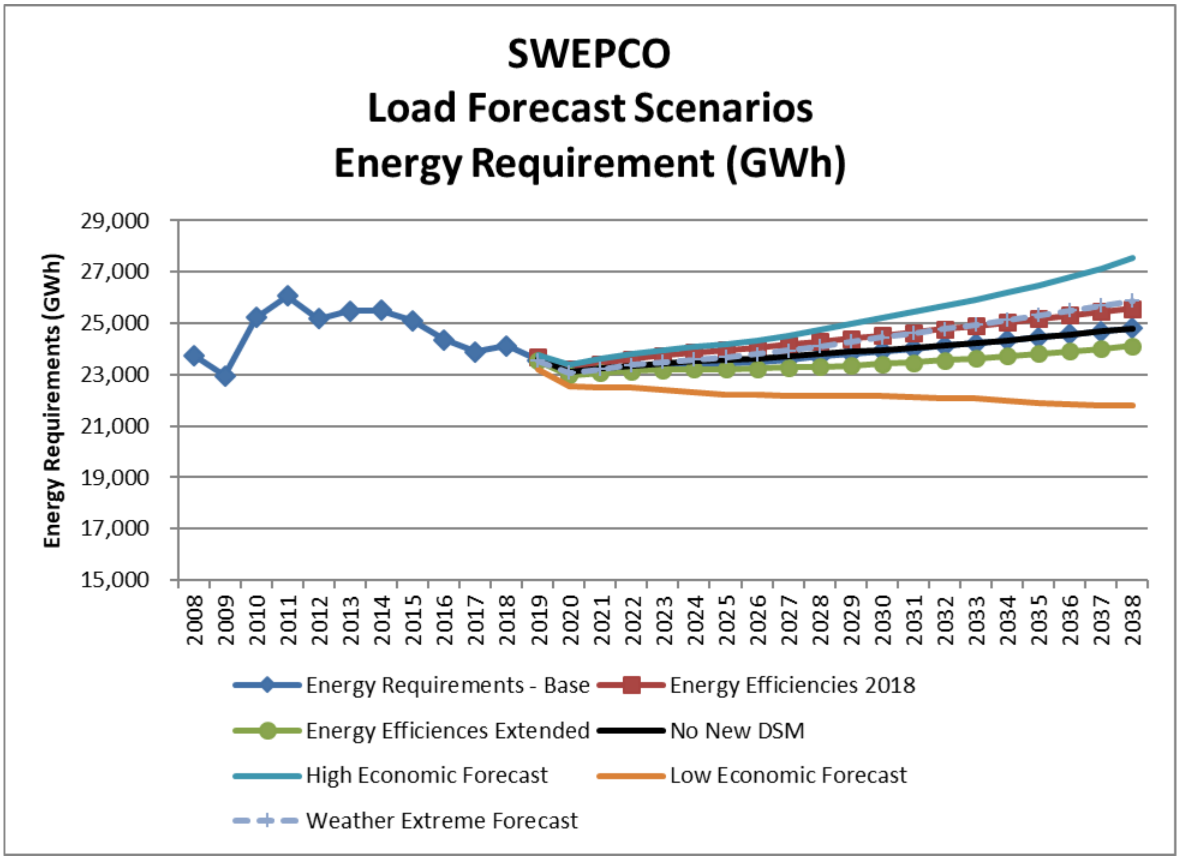

Figure 9. Load Forecast Scenarios

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 2018 scenario keeps energy efficiencies at 2018 levels for the residential and commercial equipment. Both of these 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 accelerated temperatures for both the winter and summer seasons. This analysis based on a study developed by Purdue University. This scenario results increased load in the summer and diminished load in the winter, with the net result being a higher energy requirements forecast.

3.0 Resource Evaluation

3.1 Current Resources

An initial step in the IRP process is the demonstration of the capacity resource requirements. This aspect of the traditional "needs" assessment must consider projections of:

- existing capacity resources—current levels and anticipated changes;
- anticipated changes in capability due to efficiency and/or environmental considerations;
- changes resulting from decisions surrounding unit disposition evaluations;
- regional and sub-regional capacity and transmission constraints/limitations;
- load and peak demand;
- current DR/EE; and
- SPP capacity reserve margin and reliability criteria.

3.2 Existing SWEPCO Generating Resources

The underlying minimum reserve margin criterion to be utilized in SWEPCO's resource needs assessment is based on the current SPP minimum capacity margin of 10.7 percent.[4] As a function of peak demand this converts to an equivalent "reserve margin" of 12.0 percent.[5] The reserve margin is the result of SPP's own system reliability assessment. Table 1 displays key parameters for SWEPCO's current supply-side resources.

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[4] Per Section 4.1.9 of the "Southwest Power Pool Planning Criteria" (Latest Revision: July 25, 2017).

[5] 0.107 / (1 – 0.107) = 0.12.

Table 1. Current Supply-Side Resources, as of July 1, 2018[6,7]

Unit Name	Primary Fuel Type	C.O.D. [1]	Rating (MW) [2]	
Arsenal Hill 5	Gas Steam	1960	110	
Knox Lee 2	Gas Steam	1950	30	
Knox Lee 3	Gas Steam	1952	26	
Knox Lee 4	Gas Steam	1956	71	
Knox Lee 5	Gas Steam	1974	342	
Lieberman 2	Gas Steam	1949	25	
Lieberman 3	Gas Steam	1957	109	
Lieberman 4	Gas Steam	1959	108	
Lonestar 1	Gas Steam	1954	50	
Wilkes 1	Gas Steam	1964	164	
Wilkes 2	Gas Steam	1970	360	
Wilkes 3	Gas Steam	1971	353	
Mattison 1	Gas (CT)	2007	71	
Mattison 2	Gas (CT)	2007	71	
Mattison 3	Gas (CT)	2007	71	
Mattison 4	Gas (CT)	2007	71	
J.L. Stall 6	Gas (CC)	2010	511	
Dolet Hills 1	Lignite	1986	257	
Flint Creek 1	Coal	1978	258	
Pirkey 1	Lignite	1985	580	
Turk 1	Coal	2012	477	
Welsh 1	Coal	1977	525	
Welsh 3	Coal	1982	528	
Majestic	Wind	2009	80	(A)
High Majestic II	Wind	2012	80	(A)
Flat Ridge 2	Wind	2013	109	(A)
Canadian Hills	Wind	2012	201	(A)
			5,638	

(1) Commercial operation date.
(2) Peak net dependable capability (Summer) as of filing.
(A) Represents capacity from Power Purchase Agreements (PPAs)

For purposes of establishing a modeling "baseline," it is necessary to establish assumptions pertaining to all of the capacity and energy resources available to SWEPCO[8]. Figure 10 below depicts SWEPCO's current generation resources along with their current age. Unit ratings displayed in this figure are nameplate ratings.

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[6] Represents SWEPCO-owned installed capacity.

[7] Table 1 includes the Turk Power Plant which is not used or recoverable in Arkansas.

[8] See Appendix G for the complete view of the Capacity, Demand, and Reserves summary (CDR).

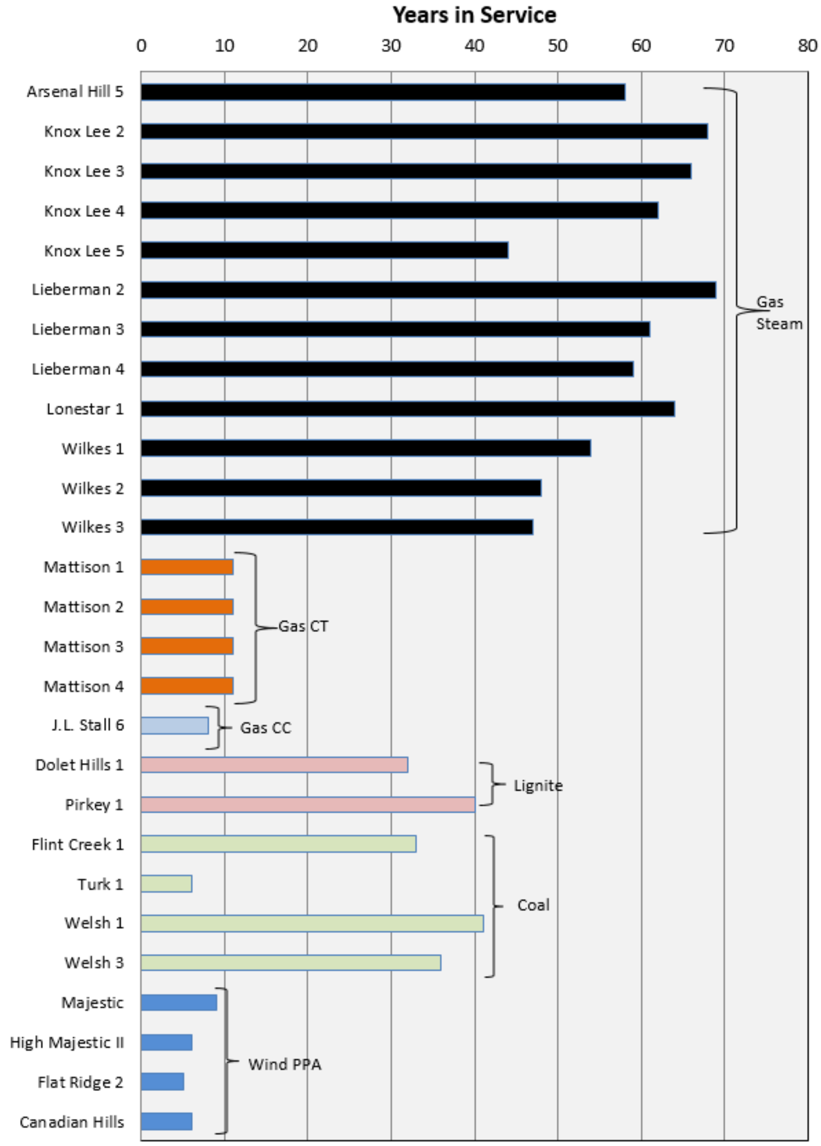

Figure 10. Current Resource Fleet (Owned and Contracted) with Years in Service, as of July 1, 2018

It is worth noting that it was recently announced that the Dolet Hills Power Plant, which is co-owned by SWEPCO and Cleco Power, LLC (CLECO), will transition from year-round to seasonal operations (generally June through September). Given that Dolet Hills will continue to operate during summer peak months, this recent change does not affect the Report's results from a capacity planning perspective; however, from an energy perspective this transition is not reflected in this report. The transition will reduce the energy contribution from this plant relative to what is reflected in this IRP.

Furthermore, in Arkansas, the cost of the Turk Power Plant is not recoverable by SWEPCO nor can the Turk Power Plant's capacity be used for planning purposes to meet load obligations. Under this view, SWEPCO would anticipate experiencing a slight capacity shortfall beginning in 2019 which grows to a 2,363MW shortfall by 2038.

3.3 Environmental Issues and Implications

It should be noted that the following discussion of environmental regulations is based on the assumptions made by the Company and incorporated into its analysis within this IRP. Activity including but not limited to Presidential Executive Orders, litigation, petitions for review, and Federal Environmental Protection Agency (EPA) proposals may delay the implementation of these rules, or eventually affect the requirements set forth by these regulations. While such activities have the potential to materially change the regulatory requirements the Company will face in the future, all potential outcomes cannot be reasonably foreseen or estimated and the assumptions made within the IRP represent the Company's best estimation of outcomes as of the filing date. The Company is committed to closely following developments related to environmental regulations, and will update its analysis of compliance options and timelines when sufficient information becomes available to make such judgments.

3.3.1 Clean Air Act (CAA) Requirements

The 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 SWEPCO's existing generating units include: (a) periodic revisions to the National Ambient Air Quality Standards (NAAQS) and the development of State Implementation Plans (SIPs) to achieve any more stringent standards; (b) implementation of the regional haze program by the states and the Federal EPA; (c) regulation of hazardous air pollutant emissions under the Mercury and Air Toxics Standards (MATS) Rule; (d) implementation and review of the Cross-State Air Pollution Rule (CSAPR), a Federal Implementation Plan (FIP) designed to eliminate significant contributions from sources in upwind states to nonattainment 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.

In March 2017, President Trump issued a series of executive orders designed to allow the Federal EPA to review and take appropriate action to revise or rescind regulatory requirements that place undue burdens on affected entities, including specific orders directing the Federal EPA to review rules that unnecessarily burden the production and use of energy. The Federal EPA published notice and an opportunity to comment on how to identify such requirements and what steps can be taken to reduce or eliminate such burdens. Future changes that result from this effort may affect SWEPCO's compliance plans.

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

3.3.2 National Ambient Air Quality Standards (NAAQS)

The CAA requires the Federal EPA to establish and periodically review NAAQS designed to protect public health and welfare. The Federal EPA issued new, more stringent NAAQS for PM in 2012, SO_2 in 2010 and ozone in 2015; the existing standards for NO_2 were retained after review by the Federal EPA in 2018. Implementation of these standards is underway. States are still in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the 2010 SO_2 NAAQS and may develop additional requirements for our facilities as a result of those evaluations. In April 2017, Federal EPA requested a stay of proceedings in the U.S. Circuit Court for the District of Columbia Circuit where challenges to the 2015 ozone standard are pending, to allow reconsideration of that standard by the new administration. The Federal EPA initially announced a one-year delay in the designation of ozone non-attainment areas, but withdrew that decision. In December 2017, the Federal EPA issued a notice of data availability and requested public comment on recommended designations for compliance with the 2015 ozone standard. Final designations for 51 nonattainment areas were published on June 4, 2018. In April and July 2018, the Federal EPA finalized nonattainment designations for the remaining areas. The Federal EPA has also issued information to assist the states in developing plans that address their obligations under the interstate transport provisions of the CAA. On November 7, 2018, EPA issued a final rule to provide state and local air management agencies with rules and guidance on planning to meet the 2015 ozone standard and setting SIP submittal deadlines for various elements of the 2015 standard. The earliest SIP revision is due within two years of the effective date of the non-attainment designation, during year 2020. SWEPCO cannot currently predict the nature, stringency or timing of additional requirements for SWEPCO's facilities based on the outcome of these activities.

3.3.3 Regional Haze Rule (RHR)

The RHR requires affected states to develop regional haze SIPs that contain enforceable measures and strategies for reducing emissions of pollutants that can impair visibility in certain federally protected areas. Each 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 NO_X, SO_2 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 (MW) 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. 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 SO_2 and NO_x 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.

3.3.4 Arkansas Regional Haze

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

On November 16, 2011, the Federal EPA issued its proposed decision on Arkansas's 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 RHR NO_X 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 SO_2 Regional Haze requirements through the installation of a dry scrubber (NID™ technology).

In 2015, the Federal EPA proposed a FIP that accepted the SO_2 controls presented in Flint Creek's BART analysis. However, the proposed Federal EPA FIP included the installation of Low NO_x Burner with Over-Fire-Air (LNB/OFA) and an emission limitation of 0.23 lb. NO_x/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 NO_X obligations at Flint Creek.

In a final rule that became effective on October 27, 2016, the Federal EPA established a final SO_2 emission limitation of 0.06 lb./mmBtu, and a final NO_X 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 SO_2 reductions and the planned installation of LNB/OFA for NO_X 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 NO_x 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 NO_x requirements. The Federal EPA also withdrew the NO_x FIP requirements that would have required the installation of LNB/OFA and a NO_x limit of 0.23 lb/mmBtu by April 27, 2018. Installation of the LNB/OFA continued in order to enhance compliance with EPA's Mercury and Air Toxics Standards (MATS). On August 9, 2018, ADEQ finalized and submitted to EPA for approval a second SIP revision to address SO_2 and PM requirements for BART sources. In this SIP revision, ADEQ determined that equipment already installed at Flint Creek Plant satisfies the requirements for the SO_2 Regional Haze requirements.

3.3.5 Louisiana Regional Haze

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

The Federal EPA issued a final rule approving the Louisiana SIP on December 21, 2017. No requirements were included that specifically impact SWEPCO facilities. Petitions for review of the final approved Louisiana SIP were filed in the U.S. Court of Appeals for the Fifth Circuit and remain pending.

3.3.6 Texas Regional Haze

Texas submitted its initial regional haze SIP to the Federal EPA in February 2009, and the 5-year update February 2014. Both submittals state that BART-eligible facilities in Texas do not impact Class I areas such that emissions controls are required. The Federal EPA reviewed the Texas SIP and issued a proposed FIP in November 2014. The Federal EPA took no action on the portions of the Texas SIP that relate to BART-eligible facilities, however, the Federal EPA determined that the Reasonable Progress Goals and Long Term Strategy did not adequately address visibility improvements needed in certain Class I areas. The Federal EPA conducted impact analyses to identify cost-effective controls to achieve those improvements. The proposed FIP required SO_2 reductions for 15 units in Texas resulting in scrubber retrofits for 7 units and scrubber upgrades for 7 other units. One unit is believed to be able to meet its new limit without adding additional controls. No SWEPCO unit was included in the group for which the Federal EPA proposed additional controls. On January 5, 2016, the Federal EPA issued a Final Rule partially approving and partially disapproving portions of the Texas SIP and finalizing the FIP. The Federal EPA took no action on the BART-eligible facilities since litigation with respect to the CSAPR budgets in Texas was still ongoing. No changes were included in the Final Rule that would impact any of the SWEPCO units. The FIP was challenged in the Fifth Circuit Court of Appeals, which issued a stay of the FIP. The parties engaged in unsuccessful settlement negotiations, and the Federal EPA later withdrew the FIP, and proposed to remove Texas from the CSAPR Rule.

On December 9, 2016, the Federal EPA proposed a clean air plan for the State of Texas to meet the regional haze BART and Interstate Visibility Transport requirements of the CAA. The proposed rule was published in the Federal Register on January 4, 2017. The proposal included SO_2 and NO_X 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 SO_2 for Welsh Unit 1 based on the retrofit of wet FGD technology. SWEPCO submitted comments on the proposal as did other companies and the State of Texas. On September 29, 2017 the 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 PM. The Federal EPA followed this rulemaking with the finalization of a BART alternative to source specific controls to address Texas Regional Haze requirements for SO_2 and NO_x in the federal register on October 17, 2017. Specifically, the Federal EPA issued a FIP that established a federal intrastate trading program to address SO_2 emissions and determined that Texas' participation in the CSAPR NO_x ozone season trading program satisfied Texas' Regional Haze NO_x requirements. The Federal EPA also determined that the BART alternatives satisfied many of Texas' interstate transport requirements. A petition for review of this final FIP was filed in the Fifth Circuit in December 2017. That challenge is currently stayed pending reconsideration of the FIP by the Federal EPA. On August 17, 2018, EPA issued a proposal to affirm the October 2017 Regional Haze Plan. SWEPCO commented its support for the proposal to affirm the intrastate trading program.

3.3.7 Mercury and Air Toxics Standard (MATS) Rule

The final MATS Rule became effective on April 16, 2012, and required compliance by April 16, 2015. This rule regulates emissions of Hazardous Air Pollutants (HAPS) from coal and oil-fired electric generating units. HAPS regulated by this rule are: 1) mercury; 2) certain non-mercury metals such as arsenic, lead, cadmium and selenium; 3) certain acid gases, including Hydrochloric Acid (HCl); and 4) certain organic hazardous air pollutants. The MATS Rule establishes stringent emission rate limits for mercury, filterable Particulate Matter (PM) as a surrogate for all regulated non-mercury metals, and HCl as a surrogate for all acid gases. Alternative emission limits were also established for the individual non-mercury metals, and for sulfur dioxide (SO_2) (as an alternate to HCl) for generating units that have operating Flue Gas Desulfurization (FGD) systems. The rule regulates organic HAPS through work practice standards.

The following is a list of retrofit technologies that have been added to the SWEPCO fleet, including technologies to meet the requirements of the MATS Rule.

- Flint Creek installed a dry FGD (NID™ technology), an ACI system, a baghouse to meet MATS and regional haze requirements, and LNB/OFA burners.
- Dolet Hills Unit 1 installed an activated coal injection (ACI) system, dry sorbent injection (DSI) technology, and a baghouse to mitigate mercury and PM emissions.
- Pirkey Unit 1 installed an ACI system.
- Welsh (Units 1 &3) installed an ACI system with a baghouse.
- Welsh Unit 2, per an unrelated settlement agreement, received an extension of the MATS requirements until the unit was retired on April 16, 2016.

All other SWEPCO generating units have been meeting the MATS requirements without additional control technologies.

In June 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit remanded the MATS rule for further proceedings consistent with the U.S. Supreme Court's decision that the Federal EPA was unreasonable in refusing to consider costs in its determination whether to regulate emissions of HAPS from power plants. The Federal EPA issued notice of a supplemental finding concluding that it is appropriate and necessary to regulate HAP emissions from coal-fired and oil-fired units. Management submitted comments on the proposal. In April 2016, the Federal EPA affirmed its determination that regulation of HAPs from electric generating units is necessary and appropriate. Petitions for review of the Federal EPA's April 2016 determination have been filed in the U.S. Court of Appeals for the District of Columbia Circuit. Oral argument was scheduled for May 2017, but in April 2017 the Federal EPA requested that oral argument be postponed to facilitate its review of the rule. The rule remains in effect.

3.3.8 Cross-State Air Pollution Rule (CSAPR)

In 2011, the Federal EPA issued CSAPR as a replacement for the Clean Air Interstate Rule (CAIR), a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind nonattainment with the 1997 ozone and particulate matter national ambient air quality standards. Certain revisions to the rule were finalized in 2012. CSAPR relies on newly-created SO_2 and NO_x 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.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. In 2012, the court issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing CAIR until a replacement rule is finalized. Federal EPA and other parties filed a petition for review in the U.S. Supreme Court, which was granted in June 2013. In April 2014, the U.S. Supreme Court issued a decision reversing in part the decision of the U.S. Court of Appeals for the District of Columbia Circuit and remanding the case for further proceedings consistent with the opinion.

The Federal EPA filed a motion to lift the stay and allow Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. The court granted the Federal EPA's motion. The parties filed briefs and presented oral arguments. In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit found that the Federal EPA over-controlled the SO_2 and/or NO_x budgets of 14 states. The U.S. Court of Appeals for the District of Columbia Circuit remanded the rule to the Federal EPA to timely revise the rule consistent with the court's opinion while CSAPR remained in place.

In October 2016, a final CSAPR Update rule was issued to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The final rule significantly reduced ozone season budgets in many states, including Arkansas and Texas, and discounted the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. The rule has been challenged in the courts and petitions for administrative reconsideration have been filed. Oral arguments occurred in October of 2018. SWEPCO has been complying with the more stringent ozone season budgets while these petitions were pending. In a related case, other parties challenged in the U.S. Court of Appeals for the District of Columbia Circuit a final rule withdrawing Texas from the CSAPR annual program and reaffirming that compliance with CSAPR remained better than compliance with BART. The U.S. Court of Appeals for the District of Columbia Circuit granted a motion in March 2018 to hold the case in abeyance until completion of the Federal EPA's review of pending petitions for reconsideration of the Texas RHR.

SWEPCO will rely on the installed NO_x and SO_2 reduction systems, the use of allocated NO_x and SO_2 emission allowances in conjunction with adjusted banked allowances, and the purchase of additional allowances as needed through the open market to comply with CSAPR Phase II and the CSAPR Update.

3.3.9 Carbon Dioxide (CO_2) Regulations, Including the Clean Power Plan (CPP)

On October 23, 2015, the Federal EPA published two final rules to regulate CO_2 emissions from fossil fuel-based electric generating units. The Federal EPA finalized New Source Performance Standards (NSPS) under Section 111(b) of the CAA that apply to new fossil units, as well as separate standards for modified or reconstructed existing fossil steam units. Separately, the Federal EPA finalized a rule referred to as the CPP, which establishes CO_2 emission guidelines for existing fossil generation sources under Section 111(d) of the CAA. The Federal EPA also issued for public comment a proposed federal plan to implement the CPP if states fail to submit or do not develop an approvable state plan for compliance.

The Federal EPA finalized CO_2 NSPS for *new* sources at 1,400 pounds CO_2 per megawatt-hour gross (lb/MWh-g) for new coal units based on the agency's assumption that carbon capture and storage technology can be implemented. Reconstructed coal units have a limit of 1,800 or 2,000 lb/MWh-g based on the size of the unit. The NSPS for modified coal units is site-specific based on historical operations. For new and reconstructed Natural Gas Combined Cycle (NGCC) units, the NSPS was finalized at 1,000 lb/MWh-g based on the use of efficient combustion turbine designs. No limit was proposed for modified NGCC or simple cycle units.

The CPP for *existing* sources establishes separate, uniform national CO_2 emission performance rates for fossil steam units (coal-, oil-, and gas-steam based units) and for stationary combustion turbines (which the Federal EPA defines as NGCC units). The rates were established based on the Federal EPA's application of three building blocks as the Best System of Emission Reduction (BSER) for existing fossil generating units. Block 1 assumes efficiency improvements at existing coal units. Building Block 2 assumes the increased use of NGCC units that would displace coal based generation. Building Block 3 entails the expansion of renewable energy sources that would displace generation from both coal and NGCC units. Excluded from the BSER process was consideration of nuclear energy, simple cycle gas turbines, and energy efficiency measures (originally proposed by the Federal EPA as Building Block 4), all of which had been included in the 2014 proposed rule.

The final rules are being challenged in the courts. In February 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. The stay will remain in effect until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review. Proceedings in the Court of Appeals on both the CPP and the NSPS for new units have been held in abeyance.

On October 16, 2017, the Federal EPA issued a proposed rule to repeal the CPP. Comments on this proposal were due by April 26, 2018. SWEPCO submitted comments in support of repealing the CPP. On August 31, 2018, the Federal EPA released a proposed rule called the

Affordable Clean Energy Rule (ACE) to establish guidelines to reduce emissions of greenhouse gases from existing electric generating units based on heat rate improvement measures applied to those units which would replace the CPP. In December 2018, Federal EPA released a proposal to revise the new source performance standards for new, reconstructed and modified fossil-fueled generating units that would revise the standards for coal units to a level that can be achieved through the most efficient generating cycles without the use of carbon capture and storage. SWEPCO submitted comments on the proposed ACE rule and will is currently reviewing the proposed new source standards.

3.3.10 Coal Combustion Residuals (CCR) Rule

In April 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 electric generating units and FGD gypsum generated at some coal-fired plants. The final rule has been challenged in the courts.

The final rule became effective in October 2015. The Federal EPA regulates CCR as a non-hazardous solid waste by its issuance of new minimum federal solid waste management standards. 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 new and additional 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. Challenges to the rule by industry associations of which SWEPCO is a member are proceeding.

In December 2016, the U.S. Congress passed legislation authorizing states to submit programs to regulate CCR facilities, and the Federal EPA to approve such programs if they are no less stringent than the minimum federal standards. The Federal EPA may also enforce compliance with the minimum standards until a state program is approved or if states fail to adopt their own programs. In September 2017, the Federal EPA granted industry petitions to reconsider the CCR rule and asked that litigation regarding the rule be held in abeyance. The U.S. Court of Appeals for the District of Columbia Circuit heard oral argument in November 2017.

On August 2018, the U.S. Court of Appeals for the District of Columbia issued its decision that addressed all remaining issues in the litigation. In particular, the Court denied the EPA's request to hold the litigation in abeyance while it developed rules to implement and enforce the CCR legislation. The Court also decided that all unlined surface impoundments must close and vacated and remanded the provisions of the CCR rule that permit unlined ponds to receive ash. The Court also remanded to Federal EPA the provisions with respect to inactive surface impoundments and landfills. SWEPCO continues to evaluate the impact of this rule on its CCR units and anticipates additional rulemaking from Federal EPA to implement the Court's decision. SWEPCO is unable to predict the outcome of these rulemakings but they could result in significant additional cost.

In March 2018, the Federal EPA issued a proposed rule to modify certain provisions of the solid waste management standards and provide additional flexibility to facilities regulated under approved state programs. Federal EPA published a final rule in July 2018 that modifies certain compliance deadlines and other requirements in the rule, including postponing the closure obligation for unlined surface impoundments that exceed a groundwater protection standard or fail to meet the minimum separation distance from the upper-most aquifer until October 2020, establishing numeric groundwater protection standards for four compounds that do not have primary drinking water standards, authorizing state and federal regulators to suspend groundwater monitoring requirements under limited circumstances and issue technical certifications. Additional changes to the minimum performance standards that were contained in the March proposed rule will be addressed in future rulemakings. SWEPCO supports the adoption of more flexible compliance alternatives subject to the Federal EPA or state oversight.

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 represents an "unpermitted discharge" under the Clean Water Act. The Federal EPA has opened a rulemaking docket to solicit information to determine whether it should provide additional clarification of the scope of Clean Water Act permitting requirements for discharges to ground water. Comments were due in May 2018. SWEPCO is unable to predict the outcome of these cases or the Federal EPA's rulemaking, but they could impose significant additional costs on SWEPCO's facilities.

While the necessary site-specific analyses to determine the requirements under the final CCR Rule are ongoing, initial estimates of anticipated plant modifications and capital expenditures are factored into this IRP. It should be noted that SWEPCO's solid-fuel plants are already equipped with dry fly ash handling systems and dry ash landfills to meet current permit requirements, and are well-positioned to meet future compliance with the CCR rulemaking.

3.3.11 Clean Water Act "316(b)" Rule

A final rule under Section 316(b) of the Clean Water Act was issued by the Federal EPA on August 15, 2014, with an effective date of October 14, 2014, and affects all existing power plants (generally those whose construction began prior to January 17, 2002) withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with a standard that addresses impingement of aquatic organisms on cooling water intake screens and requires site-specific studies to determine appropriate compliance measures to address entrainment of organisms in cooling water systems for those facilities withdrawing more than 125 million gallons per day. The overall goal of the rule is to decrease impacts on fish and other aquatic organisms from operation of cooling water intake systems. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats.

Facilities subject to both the impingement standard and site-specific entrainment studies are required to conduct and submit the results of those studies to the permit agency. Compliance timeframes will then be established by the permit agency through each facility's NPDES permit for installation of any required technology changes, as those permits are renewed. Petitions for review of the final rule were filed by industry and environmental groups and in July 2018 the U.S. Court of Appeals for the Second Circuit denied the petitions for review and upheld the final rule.

SWEPCO's generating plants may be required to make investments to upgrade cooling water intake screen systems as a result of this rule, and any requirement for this relatively modest cost will be determined through each plant's NPDES permitting cycle. At this time, the 316(b)

Rule is not expected to require major capital investment, such as the addition of cooling towers, at any SWEPCO plants.

3.3.12 Effluent Limitation Guidelines and Standards (ELG)

In November 2015, the Federal EPA issued a final rule revising effluent limitation guidelines for electricity generating facilities. The final rule established limits on flue gas desulfurization (FGD) wastewater, fly ash and bottom ash transport water (BATW) and flue gas mercury control wastewater as soon as possible after November 2018 and no later than December 2023. These new requirements will be implemented through each facility's wastewater discharge permit. The rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit. In March 2017, industry associations, of which SWEPCO is a member, filed a petition for reconsideration of the rule with the Federal EPA. In April 2017, the Federal EPA granted reconsideration of the rule and issued a stay of the rule's future compliance deadlines, which has now expired. In April 2017, the U.S. Court of Appeals for the Fifth Circuit granted a stay of the litigation for 120 days. In June 2017, the Federal EPA also issued a proposal to temporarily postpone certain compliance deadlines in the rule. A final rule revising the compliance deadlines for FGD wastewater and bottom ash transport water to be no earlier than 2020 was issued in September 2017. SWEPCO's parent company, AEP, submitted comments supporting the proposed postponement while Federal EPA reconsidered certain aspects of the rule. SWEPCO continues to assess technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting.

SWEPCO's solid-fueled generating plants are well positioned to comply with the ELG Rule because they utilize dry fly ash handling systems. The Dolet Hills, Flint Creek, and Pirkey Plants may require the addition of wastewater treatment facilities in future years and initial estimates of anticipated plant modifications and capital expenditures to comply with the ELG Rule are factored into this IRP.

3.4 SWEPCO Current Demand-Side Programs

3.4.1 Background

DSM refers to, for the purposes of this IRP, utility programs, including tariffs, which encourage reduced energy consumption, either at times of peak consumption or throughout the day/year. Programs or tariffs that reduce consumption primarily at periods of peak consumption are DR programs, while around-the-clock measures are typically categorized as EE programs. The distinction between DR and EE is important, as the solutions for accomplishing each objective are typically different, but not necessarily mutually exclusive.

Included in the load forecast discussed in Section 2.0 of this Report are the demand and energy impacts associated with SWEPCO's DSM programs that have been approved in Arkansas, Louisiana, and Texas prior to preparation of this IRP. As will be discussed later, within the IRP process, the potential for additional or "incremental" demand-side resources, including EE activity—over and above the levels embedded in the load forecast—as well as other grid related projects such as Volt VAR Optimization (VVO), are modeled on the same economic basis as supply-side resources. However, because customer-based EE programs are limited by factors such as customer acceptance and saturation, an estimate as to their costs, timing and maximum impacts must be formulated. For the year 2018, the Company anticipates 51MW of peak DSM reduction (total company basis); consisting of 5MW and 46MW of "passive" EE and "active" DR activity, respectively.[9]

3.4.2 Impacts of Existing and Future Codes and Standards

The EISA requires, among other things, a phase-in of heightened lighting efficiency standards, appliance standards, and building codes. The increased standards will have a pronounced effect on energy consumption as explained in Section 2.6. Many of the standards already in place impact lighting. For instance, since 2013 and 2014 common residential

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[9] "Passive" demand reductions are achieved via "around-the-clock" *EE* program activity as well as voluntary price response programs; "Active" DR is centered on summer peak reduction initiatives, including interruptible contracts, tariffs, and direct load control programs.

incandescent lighting options have been phased out as have common commercial lighting fixtures. Given that "lighting" measures have comprised a large portion of utility-sponsored EE programs prior to the phase-out, this pre-established transition is already incorporated into the SAE long-term load forecast modeling previously described in Section 2.4.4 and may greatly affect the market potential of utility EE programs in the near and intermediate term. Table 2 and Table 3 depict the current schedule for the implementation of new EISA codes and standards.

Table 2. Forecasted View of Relevant Residential Energy Efficiency Code Improvements

<table>
<tr><th>Technology</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>2021</th><th>2022</th><th>2023</th><th>2024</th><th>2025</th></tr>
<tr><td>Central AC</td><td colspan="11">SEER 13; SEER 14 in South</td></tr>
<tr><td>Room AC</td><td colspan="11">EER 11.0</td></tr>
<tr><td>Heat Pump</td><td colspan="11">SEER 14.0/HSPF 8.0</td></tr>
<tr><td>Water Heater (<=55 gallons)</td><td colspan="11">EF 0.95</td></tr>
<tr><td>Water Heater (>55 gallons)</td><td colspan="11">Heat Pump Water Heater</td></tr>
<tr><td>Screw-in/Pin Lamps</td><td colspan="5">Advanced Incandescent (20 lumens/watt)</td><td colspan="6">Advanced Incandescent (45 lumens/watt)</td></tr>
<tr><td>Linear Fluorescent</td><td colspan="3">T8 (89 lumens/watt)</td><td colspan="8">T8 (92.5 lumens/watt)</td></tr>
<tr><td>Refrigerator</td><td colspan="11">25% more efficient</td></tr>
<tr><td>Freezer</td><td colspan="11">25% more efficient</td></tr>
<tr><td>Clothes Washer</td><td colspan="3">1.29 IMEF top loader</td><td colspan="8">1.57 IMEF top loader</td></tr>
<tr><td>Clothes Dryer</td><td colspan="11">3.73 Combined EF</td></tr>
<tr><td>Furnace Fans</td><td colspan="4">Conventional</td><td colspan="7">40% more efficient</td></tr>
</table>

Table 3. Forecasted View of Relevant Non-Residential Energy Efficiency Code Improvements

<table>
<tr><th>Technology</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>2021</th><th>2022</th><th>2023</th><th>2024</th><th>2025</th></tr>
<tr><td>Chillers</td><td colspan="11">2007 ASHRAE 90.1</td></tr>
<tr><td>Roof Top Units</td><td colspan="11">EER 11.0/11.2</td></tr>
<tr><td>PTAC</td><td colspan="2">EER 11.7</td><td colspan="9">EER 11.9</td></tr>
<tr><td>Heat Pump</td><td colspan="11">EER 11.0/COP 3.3</td></tr>
<tr><td>PTHP</td><td colspan="11">EER 11.9/COP 3.3</td></tr>
<tr><td>Ventilation</td><td colspan="11">Constant Air Volume/Variable Air Volume</td></tr>
<tr><td>Screw-in/Pin Lamps</td><td colspan="5">Advanced Incandescent (20</td><td colspan="6">Advanced Incandescent (45 lumens/watt)</td></tr>
<tr><td>Linear Fluorescent</td><td colspan="3">T8 (89 lumens/watt)</td><td colspan="8">T8 (92.5 lumens/watt)</td></tr>
<tr><td>High Intensity Discharge</td><td colspan="2">EPACT 2005</td><td colspan="9">Metal Halide Ballast Improvement</td></tr>
<tr><td>Water Heater</td><td colspan="11">EF 0.97</td></tr>
<tr><td>Walk-in Refrigerator/Freezer</td><td colspan="2">EISA 2007</td><td colspan="9">10-38% more efficient</td></tr>
<tr><td>Reach-in Refrigerator/Freezer</td><td colspan="2">EPACT 2005</td><td colspan="9">40% more efficient</td></tr>
<tr><td>Glass Door Display</td><td colspan="2">EPACT 2005</td><td colspan="9">12-28% more efficient</td></tr>
<tr><td>Open Display Case</td><td colspan="2">EPACT 2005</td><td colspan="9">10-20% more efficient</td></tr>
<tr><td>Ice maker</td><td colspan="3">EPACT 2005</td><td colspan="8">15% more efficient</td></tr>
<tr><td>Pre-rinse Spray Valve</td><td colspan="4">1.6 GPM</td><td colspan="7">1.0 GPM</td></tr>
<tr><td>Motors</td><td colspan="1">EISA 2007</td><td colspan="10">Expanded EISA 2007</td></tr>
</table>

The impact of energy efficiency, including codes and standards, is expected to reduce residential load, commercial load, and industrial lighting load in total by over 5%, as shown in Figure 11.

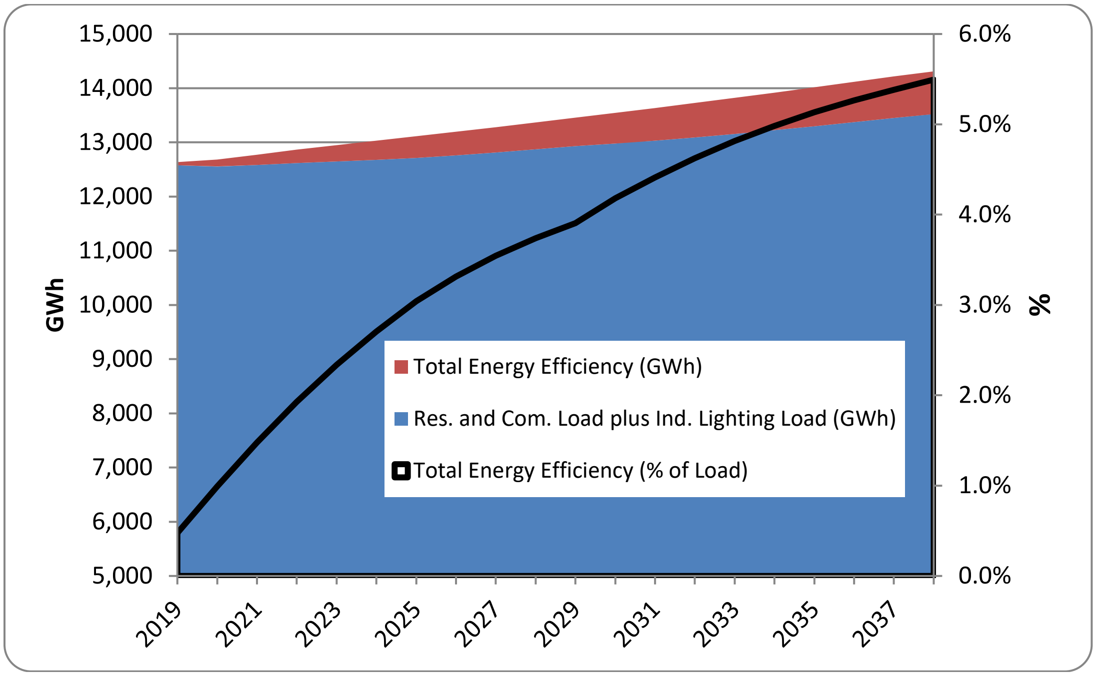

Figure 11. Total Energy Efficiency (GWh) Compared with Total Residential and Commercial Load (GWh)

3.4.3 Demand Response (DR)

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).* 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.

What may not be apparent is that, with the exception of EE and voltage regulation measures, the remaining DR 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.

3.4.3.1 Existing Levels of Active Demand Response (DR)

SWEPCO currently has active DR programs totaling 46MW of peak DR capability. The majority of this DR is achieved through interruptible load agreements. A smaller portion is achieved through direct load control.

3.4.4 Energy Efficiency (EE)

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, Ventilation and Air Conditioning (HVAC) infrastructure, 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. This IRP begins adding new demand-side resources in 2020 that are incremental to programs that are currently approved or pending approval.

3.4.4.1 Existing Levels of Energy Efficiency (EE)

SWEPCO currently has EE programs in place in its Arkansas, Louisiana, and Texas service territories. SWEPCO forecasts EE measures will reduce peak demand in 2018 by 3.9MW and reduce 2018 energy consumption by approximately 26GWh.

3.4.5 Distributed Generation (DG)

DG typically refers to small-scale customer-sited generation behind the customer meter. Common examples are Combined Heat and Power (CHP), residential and small commercial solar applications, and even wind. Currently, these sources represent a small component of demand-side resources, even with available federal tax credits and tariffs favorable to such applications. SWEPCO's retail jurisdictions have "net metering" tariffs in place which currently allow excess generation to be credited to customers at the retail rate.

The economics of DG, particularly solar, continue to improve. Figure 12 below charts the fairly rapid decline of expected installed solar costs, based on a combination of AEP market intelligence and the Bloomberg New Energy Finance's (BNEF) U.S. Renewable Energy Market Outlook forecast. The following installed cost forecast as well as the breakeven values calculated and shown in Figure 12 and Figure 13 do not include an estimate of the impact of the solar tariffs that went into effect earlier this year.

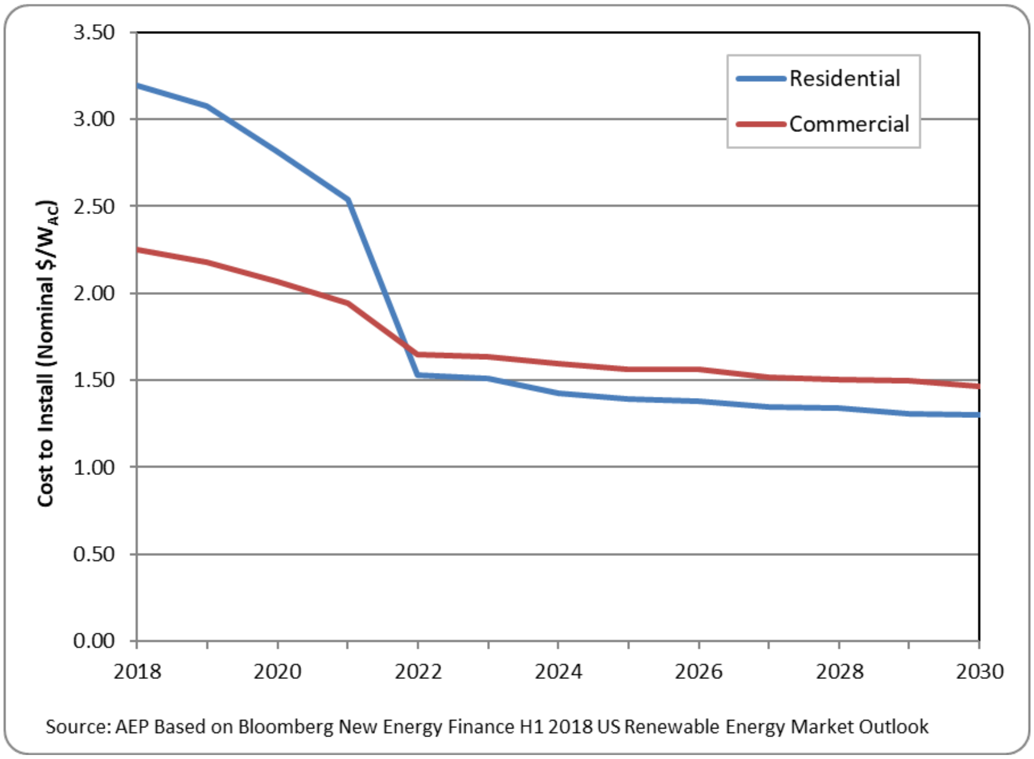

Figure 12. Residential and Commercial Forecasted Solar Installed Costs (Nominal $/W$_{AC}$) for SWEPCO States

Prior to 2022, during the ITC phase out for residential systems, costs for residential customers are expected to decline rapidly. This decline, which is forecasted to bring residential costs down to commercial cost levels, is attributed to a shift from value-based pricing to cost-plus-margin pricing. Installers are expected to spend less on customer acquisition and less on customer specific solutions as they aim for the lowest cost installations possible.

While the cost to install residential solar continues to decline, the economics of such an investment are not favorable for the customer for a number of years. Figure 13 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 average cost of solar residential installations in SPP. Figure 13 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.

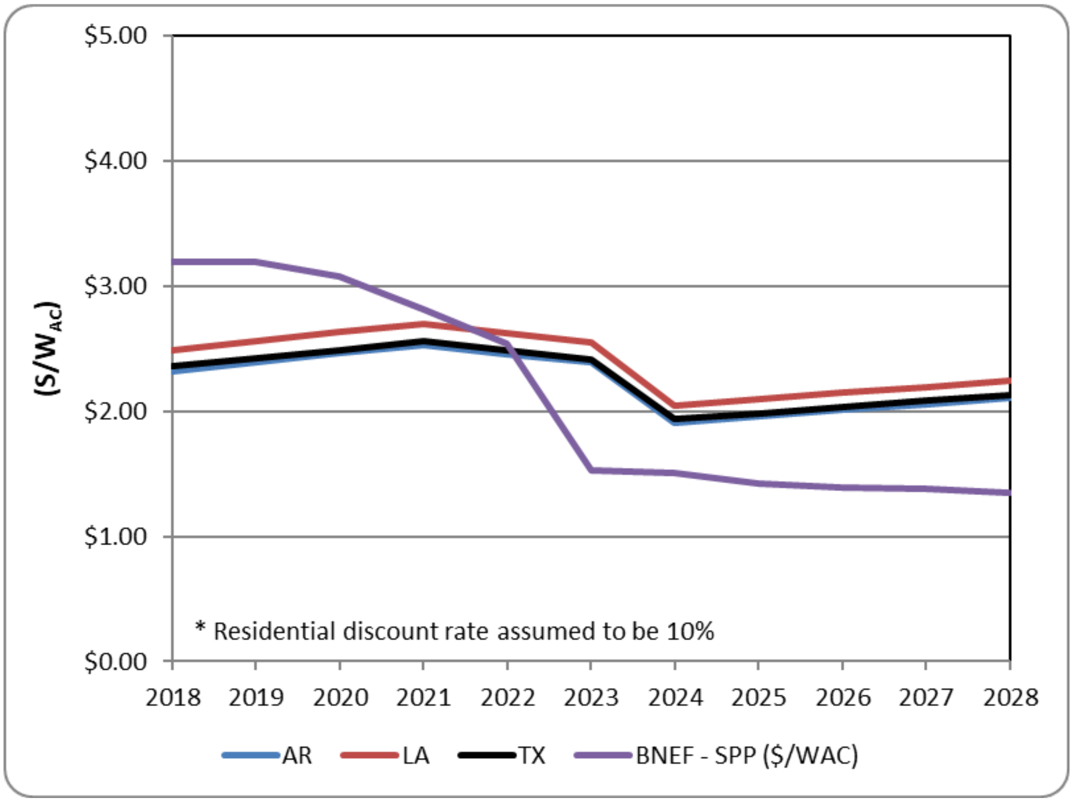

Figure 13. Distributed Solar Customer Breakeven Costs for Residential Customers ($\$/W_{AC}$)

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 14, below, shows how the value of an Arkansas residential customer's DG system can vary based on discount rate.

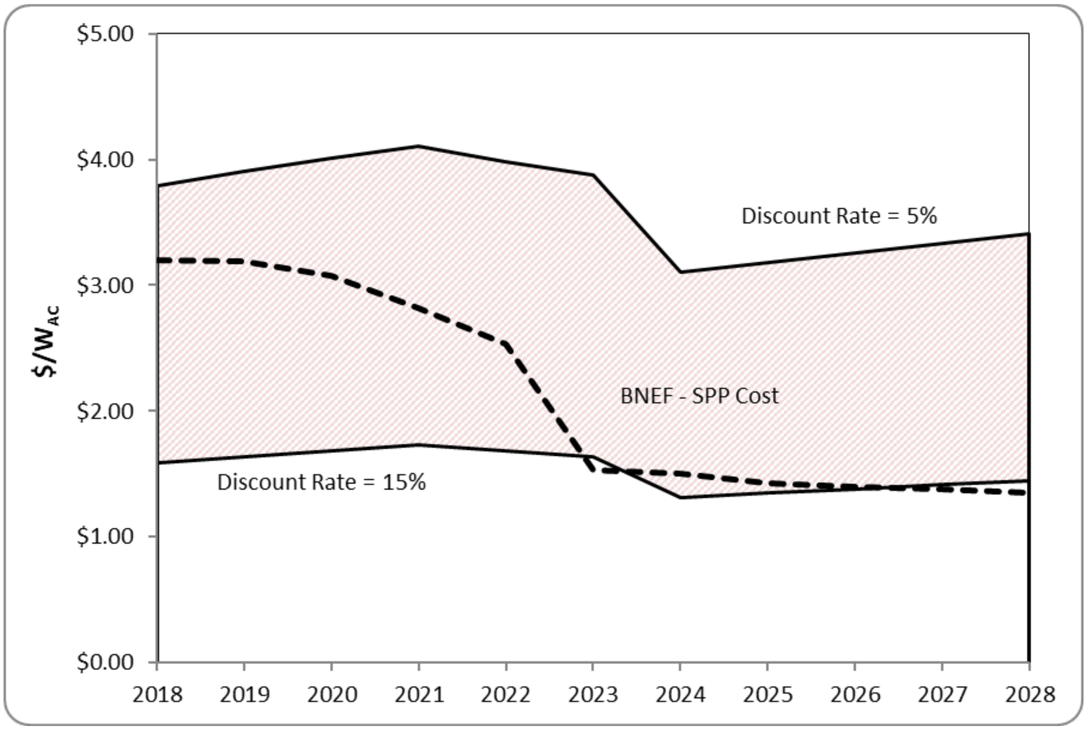

Figure 14. Range of Arkansas Residential Distributed Solar Breakeven Values Based on Discount Rate

3.4.5.1 Existing Levels of Distributed Generation (DG)

At the end of 2017 SWEPCO has a total of 9.3MW of customer-installed DG consisting of 0.7MW in Arkansas, 8.0MW in Louisiana, and 0.6MW in Texas.

3.4.5.2 Impacts of Increased Levels of Distributed Generation (DG)

Increasing levels of DG present challenges for the Company from a distribution planning perspective. Higher penetration of DG can potentially mask the true load on distribution circuits and stations if the instantaneous output of connected DG is not known, which can lead to under-planning for the load that must be served should DG become unavailable. Increased levels of DG could lead to a requirement that DG installations include smart inverters so that voltage and other circuit parameters can be controlled within required levels. Additional performance monitoring capabilities for DG systems will facilitate accurate tracking and integration of DG generators into the existing resource mix.

Currently, DG 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 DG 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 DG customers because the incremental impact of the "next" customer now drives a need for improvements. This could lead to inequities among DG customers if necessary improvements are not planned appropriately.

3.4.6 Volt VAR Optimization (VVO)

An emerging technology known as VVO represents a form of voltage control that allows the grid to operate more efficiently. Depicted at a high-level in Figure 15, with VVO sensors and intelligent controllers monitor load flow characteristics and direct controls on capacitor and voltage regulating equipment to optimize power factor and voltage levels. Power factor is the ratio of real power to apparent power, and is a characteristic of electric power flow which is controlled to optimize power flow on an electric network. Power factor optimization also improves energy efficiency by reducing losses on the system. VVO enables Conservation Voltage Reduction (CVR) on a utility's system. CVR is a process by which the utility systematically reduces voltages in its distribution network, resulting in a proportional reduction of load on the network. Voltage optimization can allow a reduction of system voltage that still maintains minimum levels needed by customers, thereby allowing customers to use less energy without any changes in behavior or appliance efficiencies. Early results from limited rollouts in AEP affiliate operating companies indicate a range of 0.7% to 1.2% of energy demand reduction for each 1% voltage reduction is possible. Furthermore, in late 2016 an AEP affiliate operating company placed in service a VVO pilot on 3 circuits in West Virginia where approximately 3% energy and demand savings have been observed to-date.

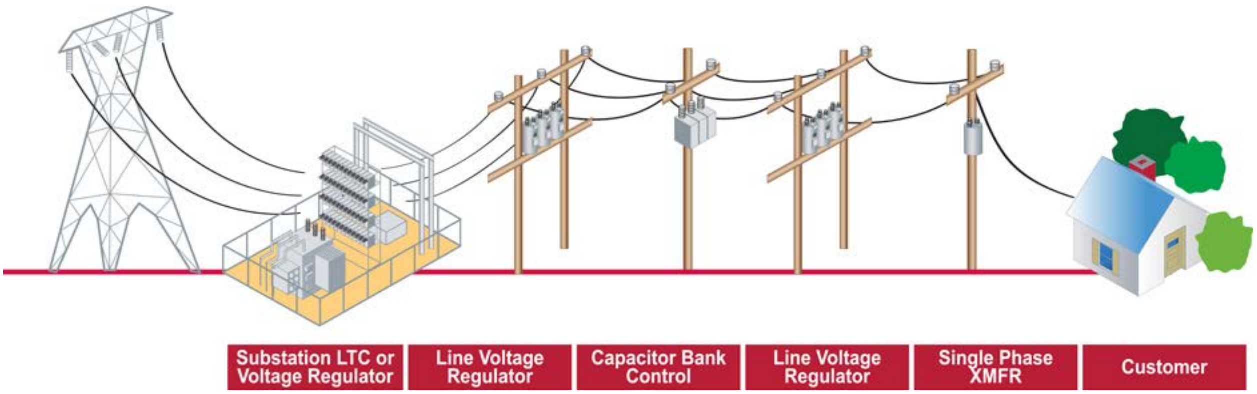

Figure 15. Volt VAR Optimization Schematic

While there is no "embedded" incremental VVO load reduction impacts implicit in the base load forecast case, VVO has been modeled as a unique EE resource.

3.5 AEP-SPP Transmission

3.5.1 Transmission System Overview

The portion of the AEP Transmission System operating in SPP (AEP-SPP zone) consists of approximately 1300 miles of 345 kV, approximately 3600 miles of 138 kV, approximately 2500 miles of 69 kV, and approximately 400 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.

3.5.2 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, in order to meet SPP RTO requirements, which can stress the system. In addition, factors such as outages, extreme weather, and power transfers also stress the system. This has resulted in a transmission system in the AEP-SPP zone that is 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. One project along the SPP-Midcontinent Independent System Operator (MISO) seam that came from the SPP Transmission Expansion Plan (STEP) process is a Layfield 500-230 kV station in northwestern Louisiana. This project, a joint effort by SWEPCO and Cleco, which relieves loading on a SWEPCO to Cleco tie line to prevent overloading, could also improve transfer capability between SPP and MISO.

Also, 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/

3.5.2.1 The SPP Transmission Planning Process

Currently, SPP produces an annual STEP. 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 2018 STEP summarizes 2017 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) High Priority Studies,

5) Sponsored Upgrades,

6) Regional Cost Allocation Review,

7) Interregional Coordination, and

8) Project Tracking

These topics are critical to meeting mandates of either the SPP strategic plan or the nine planning principles in FERC Order 890. As a 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 through the high priority studies 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 2018 STEP identified 445 transmission network upgrades with a total cost of approximately $4.96 billion. At the heart of SPP's STEP process is its ITP process, which represented approximately 81% of the total cost in the 2018 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. The 2018 STEP is available at:

https://www.spp.org/documents/56611/2018_spp_transmission_expansion_plan_report.pdf

3.5.2.2 SWEPCO-PSO Interchange Capability

In past years, operational experience and internal assessments of company transmission capabilities had indicated that, when considering a single contingency outage event, the firm capability transfer limit from Public Service Oklahoma (PSO) to SWEPCO and from SWEPCO to PSO was about 200 MW. However, in 2016, the Valliant-Northwest Texarkana 345 kV line from southeastern Oklahoma to northeastern Texas was placed in service, substantially improving the ability to transfer power across the SWEPCO-PSO interface. Note that the transfer capability between the two companies is available to all transmission users under the provisions established by FERC Order 888 and subsequent orders. Thus, depending upon future transfers in and through the SPP region, the availability of future transfer capability between SWEPCO and PSO is unknown.

As previously indicated, each company's generation capacity additions are planned so that each meets its own reserve requirement over the long-term. Any capacity transfers (i.e., "reserve sharing") should be considered for short time frames only. Specifically, the practice has been that, as the last step of the planning process, the respective SWEPCO and PSO expansion plans are adjusted to take advantage of any surplus of one company that might match a potential deficit of the other, and thereby delay some of the identified new capacity. Because of the sizes, demand growth rates, and peak coincidence of the two companies, it rarely appears that either company would ever have more than 200MW of surplus capacity in any year that could be transferred to the other company.

3.5.2.3 AEP-SPP Import Capability

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.

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 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.

3.5.2.4 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:

- A Chisholm-Gracemont 345 kV line across western Oklahoma from a new Chisholm 345-230 kV station west of Elk City to Gracemont station near Anadarko (completed)
- A new Layfield 500-230 kV station in northwestern Louisiana (completed)
- A Valliant-Northwest Texarkana 345 kV line from southeastern Oklahoma to northeastern Texas (completed)
- Woodward District Extra High Voltage (EHV) - Tatonga-Matthewson-Cimarron 345 kV, second circuit

3.5.3 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 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 Chamber Springs-Farmington Rural Electric Cooperative 161 kV line has been upgraded to a larger conductor with improved thermal capacity. The Siloam Springs (GRDA)-Siloam Springs (SWEPCO) 161 kV line is also being upgraded to a larger conductor with improved thermal capacity.

- **McAlester, Oklahoma area –** The Lone Oak-Broken Bow (Southwestern Power Administration) 138 kV line rebuilt with new structures and upgraded to a larger conductor with improved thermal capacity.
- **Cornville/Rush Springs, Oklahoma area –** In addition to the previously completed 138 kV rebuild and conversion of the Cornville-Lindsay Water Flood radial line, approximately 33 miles, a 138 kV connection, approximately 10 miles, has been built from this line to an existing radial that serves Rush Springs Natural Gas from the existing Cornville-Duncan 138 kV line. This has created a 138 kV loop, improving reliability of the transmission system in this area.

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.

3.5.4 Impacts of New Generation

Integration of additional 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 RTO footprint. The 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 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 amount of imports and exports along the eastern interface of SPP with neighboring regions. It also constrains the

amount of transfers from the capacity-rich western SPP region to the market hubs east and north of the SPP RTO 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 also be necessary. Some of the required transmission upgrades could be <u>reduced or increased</u> in scope if existing generating capacity is retired concurrent with the addition of new capacity. For example, if SWEPCO's Flint Creek Generating Plant were to have been retired, rather than retrofitted with environmental controls (for which SWEPCO received approval from the APSC in Docket No. 12-008-U), SWEPCO's transmission system would have required *significant* upgrades to support the delivery of power from remote generating plants, provide transfer capability, and supply reactive power for voltage support into that northwest Arkansas load pocket.

3.5.5 Summary of Transmission Overview

In the SPP region, the process of truly integrating Generation and Transmission planning is still developing. AEP continues to stand ready to engage in that process. AEP also continues supporting the SPP STEP and ITP transmission expansion processes, which include some projects which may improve import capability. Such capability improvements are more likely to be within SPP, but less so between SPP and neighboring regions to the east, partly due to lack of seams agreements which slows the development of new interconnections as discussed above. SWEPCO and PSO have been open to imports from other control areas as evidenced by the issuing of recent Request for Proposals (RFPs) for non-site specific generation types. Such RFP solicitations allow bidding entities to offer generation coupled with transmission solutions, which would be subject to SPP approvals.

4.0 Modeling Parameters

4.1 Modeling and Planning Process – An Overview

The objective of a resource planning effort is to recommend a system resource expansion plan that balances "least-cost" objectives with planning flexibility, asset mix considerations, adaptability to risk, and conformance with applicable NERC and RTO criteria. In addition, the planning effort must ultimately be in concert with anticipated long-term requirements established by the EPA-driven environmental compliance planning process. Resources selected through the modeling process are not locational specific.

The information presented with this IRP includes descriptions of assumptions, study parameters, methodologies, and results including the integration of supply-side resources and DSM programs.

In general, assumptions and plans are continually reviewed and modified as new information becomes available to ensure that market structures and governances, technical parameters, regulatory constructs, capacity supply, energy adequacy and operational reliability, and environmental mandate requirements are routinely reassessed to ensure optimal capacity resource planning.

Further impacting this process are a growing number of federal and state initiatives that address many issues relating to industry restructuring, customer choice, and reliability planning. Currently, fulfilling a regulatory obligation to serve native load customers represents one of the cornerstones of the SWEPCO IRP process. Therefore, as a result, the "objective function" of the modeling applications utilized in this process is the establishment of the least-cost plan, with *cost* being more accurately described as *revenue requirement* under a traditional ratemaking construct.

That does not mean, however, that the best or optimal plan is the one with the absolute least cost over the planning horizon evaluated. Other factors–some more difficult to monetize than others–were considered in the determination of the plan. Sensitivity analyses were performed to understand the impact of addressing factors which may increase costs.

4.2 Methodology

The IRP process aims to address the long-term “gap” between resource needs and current resources. Given the various assets and resources that can satisfy this expected long-term gap, a tool is needed to sort through the myriad of potential combinations and return an optimum solution–or portfolio–subject to constraints. *Plexos®* is the primary modeling application, used by SWEPCO and AEP for identifying and ranking portfolios that address the gap between needs and current available resources.[10] Given the cost and performance parameters around sets of potentially-available supply- and demand-side proxy resources and a scenario of economic conditions that include long-term fuel prices, capacity costs, energy costs, emission-based pricing proxies including CO_2, as well as projections of energy usage and peak demand, *Plexos®* will return the optimal suite of proxy resources (portfolio) that meet the resource need. Portfolios created under similar pricing scenarios may be ranked on the basis of cost, or the Cumulative Present Worth (CPW), of the resulting stream of revenue requirements. The least cost option is considered the “optimum” portfolio for that unique input parameter scenario.

4.3 The Fundamentals Forecast

The Fundamentals Forecast is a long-term, weather-normalized commodity market forecast. It is not created to meet a specific regulatory need in a particular jurisdiction; rather, it is made available to all AEP operating companies after completion. It is often referenced for purposes such as fixed asset impairment accounting, capital improvement analyses, resource planning, and strategic planning. These projections cover the electricity market within the Eastern Interconnect (which includes the Southwest Power Pool), the Electric Reliability Council of Texas (ERCOT) and the Western Electricity Coordinating Council (WECC). The Fundamentals Forecasts include: 1) monthly and annual regional power prices (in both nominal and real dollars), 2) prices for various qualities of Central Appalachian (CAPP), Northern Appalachian (NAPP), Illinois Basin (ILB), Powder River Basin (PRB) and Colorado coals, 3) monthly and annual

[10] *Plexos®* is a production cost-based resource optimization model, which was developed and supported by Energy Exemplar, LLC. The *Plexos®* model is currently licensed for use in 37 countries throughout the world.

locational natural gas prices, including the benchmark Henry Hub, 4) uranium fuel prices, 5) SO_2, NO_x and CO_2 values, 6) locational implied heat rates, 7) electric generation capacity values, 8) renewable energy subsidies and, 9) inflation factors, among others.

The primary tool used for the development of the Fundamentals Forecast is the AURORA Energy Market model which 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. It 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, among others. Ultimately, AURORA creates a weather-normalized, long-term forecast of the market in which a utility would be operating. AEP also has ample energy market research information available for its reference which includes third-party consultants, industry groups, governmental agencies, trade press, investment community, AEP-internal expertise, various stakeholders, and others. Although no exact forecast inputs from these sources of energy market research information are utilized, an in-depth assessment of this research information can yield, among other things, an indication of the supply, demand and price relationship (price elasticity) over a period of time. This price elasticity, when applied to the AURORA-derived natural gas fuel consumption, yields a corresponding change in natural gas prices – which is recycled through the AURORA model iteratively until the change in natural gas burn is de minimis. Figure 16 illustrates that the magnitude of that effect must be recycled through AURORA to determine a new merit order of dispatch. It is this new merit order of dispatch that takes into account the effect of operating conditions across North America and, in turn, determines zonal energy market prices.

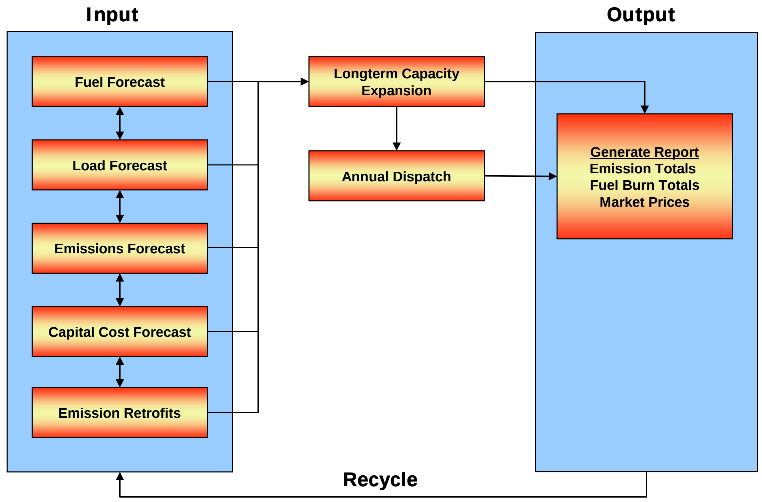

Figure 16. Long-term Power Price Forecast Process Flow

4.3.1 Commodity Pricing Scenarios

Four scenarios were developed that enabled *Plexos*® to construct resource plans for SWEPCO under various long-term pricing conditions. In this Report, the four distinct long-term commodity pricing scenarios that were developed for *Plexos*® are the Base Case, Lower Band, Upper Band, and Status Quo scenarios. The overall fundamentals forecasting effort was most recently completed in August of 2018. The Base, Low Band, and High Band scenarios each consider the potential impact of carbon regulations. The modeling associated with each of these scenarios assumed a CO_2 dispatch burden, or allowance value, equal to $15/ton commencing in 2028 and escalating at 5% per annum thereafter on a nominal dollar basis. The associated cases were designed and generated to define a plausible range of outcomes surrounding the Base Case. The Lower and Upper Band forecasts consider lower and higher North American demand for electric generation and fuels and, consequently, lower and higher fuels prices. Generally, fossil fuel prices vary one standard deviation above and below Base Case values. The Status Quo Scenario assumes there will be no regulations limiting CO_2 emissions throughout the entire forecast period.

4.3.2 Forecasted Fundamental Parameters

Figure 17 through Figure 23 below illustrate the forecasted fundamental parameters (fuel, energy, capacity and CO_2 emission prices) that were used in the long-term optimization modeling for this IRP.

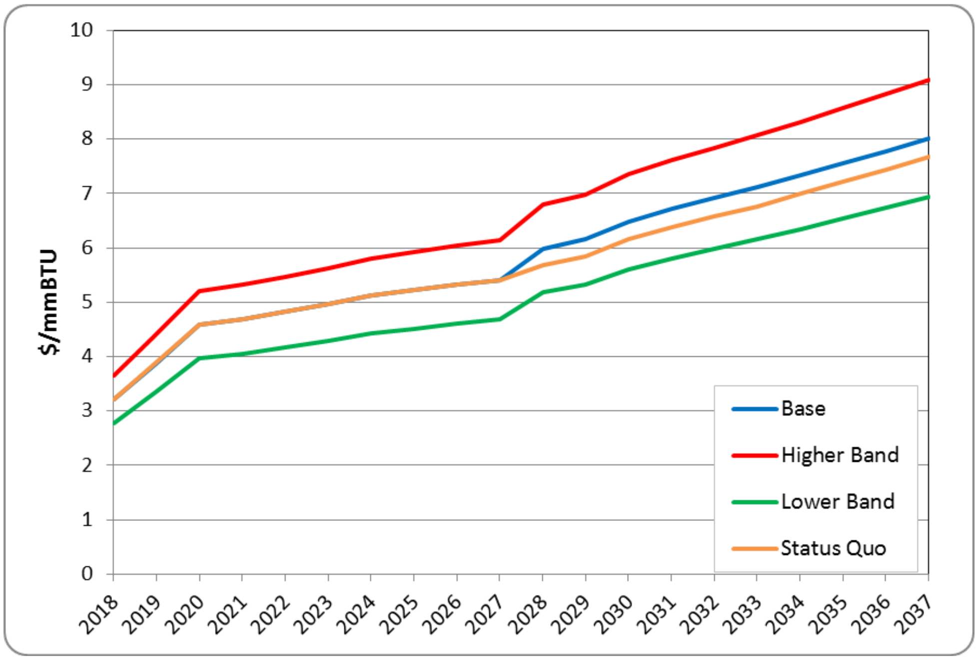

Figure 17. Henry Hub Natural Gas Prices (2018 Nominal $/mmBTU)

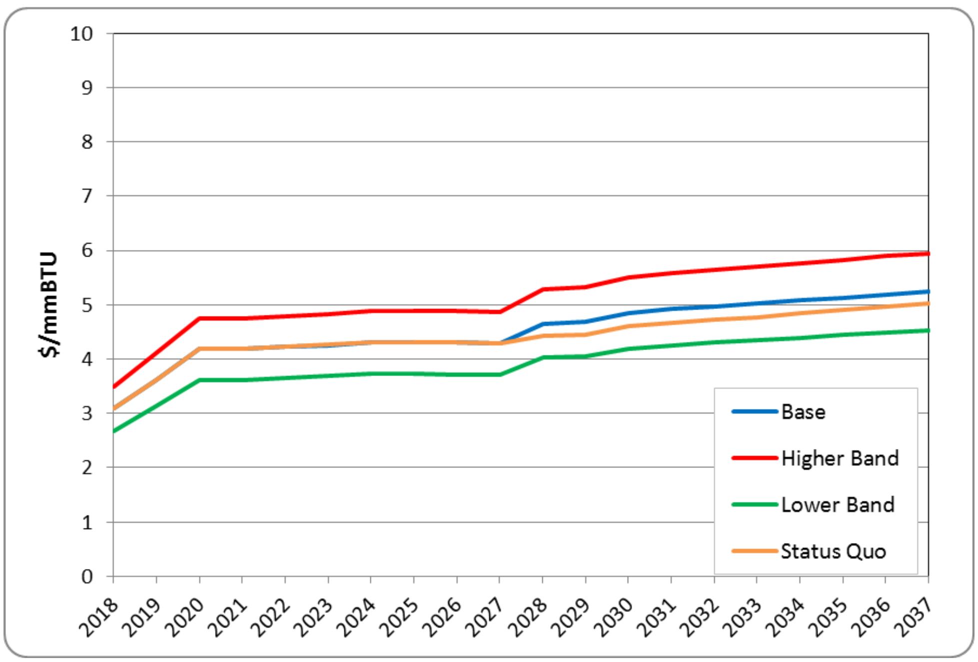

Figure 18. Henry Hub Natural Gas Prices (2018 Real $/mmBTU)

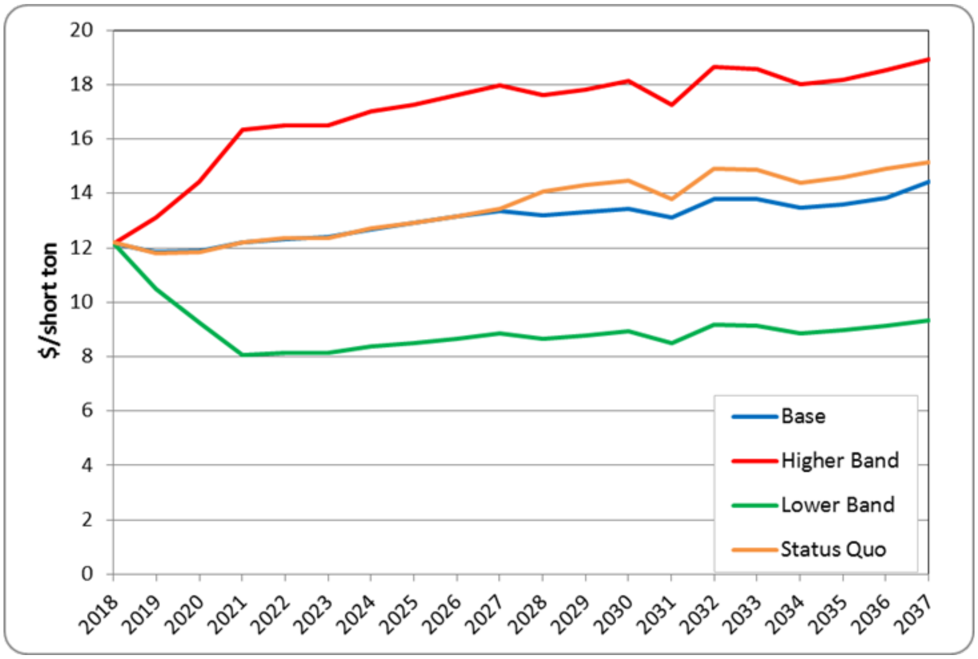

Figure 19. PRB 8800 Coal Prices (Nominal $/ton, FOB origin)

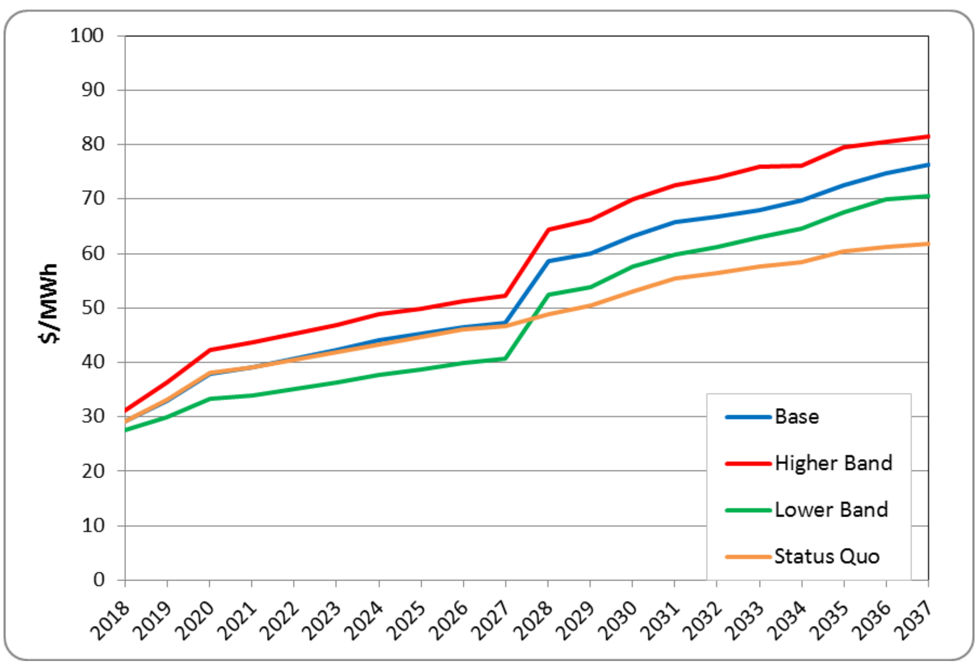

Figure 20. SPP Central On-Peak Energy Prices (Nominal $/MWh)

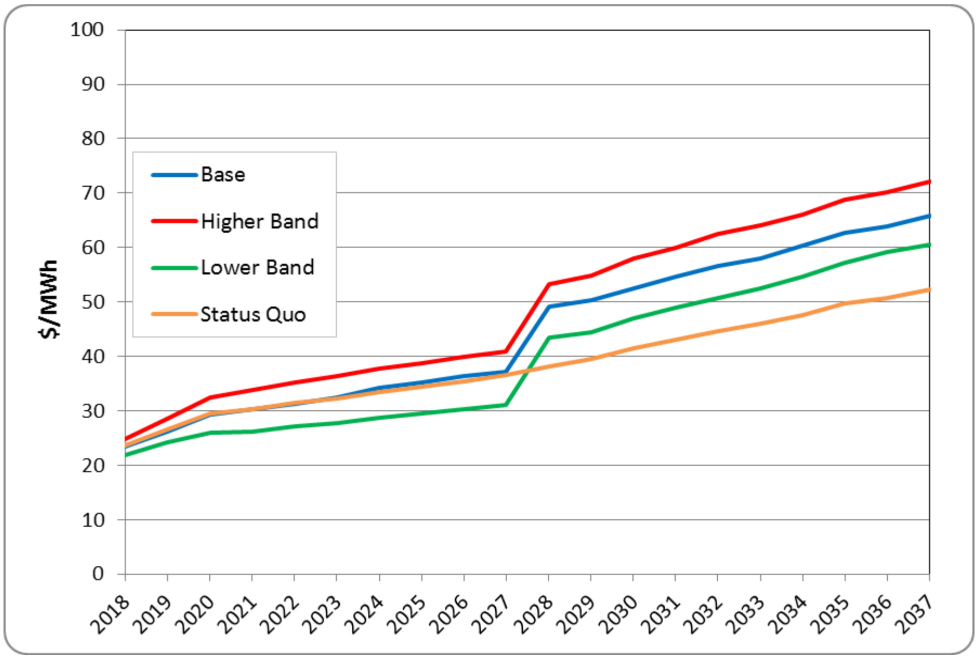

Figure 21. SPP Central Off-Peak Energy Prices (Nominal $/MWh)

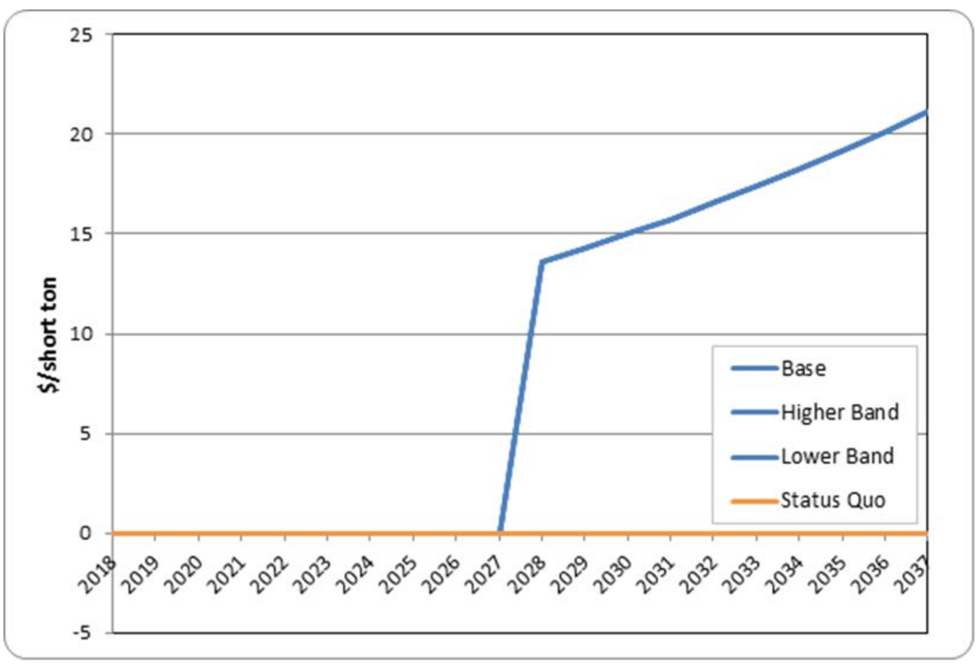

Figure 22. CO_2 Prices (Nominal $/short ton)

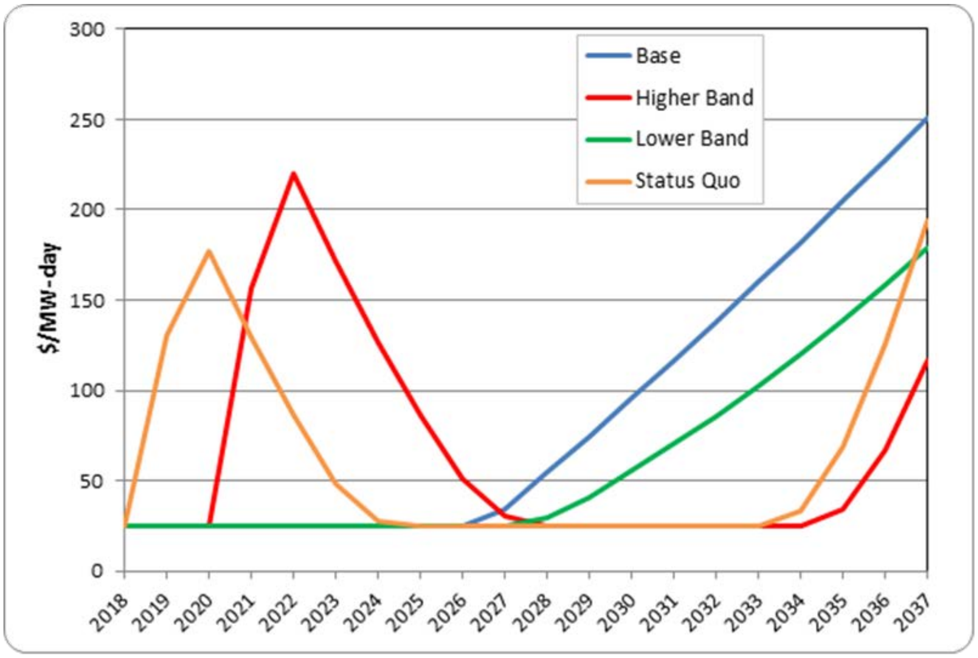

Figure 23. SPP Capacity Prices (Nominal $/MW-day)

4.4 Demand-Side Management (DSM) Program Screening & Evaluation Process

4.4.1 Overview

The process for evaluating DSM impacts for SWEPCO is divided into two spheres: “existing DSM programs” and “incremental DSM programs.” Existing DSM programs are those that are known or are reasonably well-defined, and follow a pre-existing process for screening and determining ultimate regulatory approval. The impacts of SWEPCO’s existing DSM programs are propagated throughout the long-term load forecast. Incremental DSM program impacts which are, naturally, less-defined, are developed with a dynamic modeling process using more generic cost and performance parameter data.

For SWEPCO, the potential incremental DSM programs were developed and ultimately modeled based on SWEPCO’s DSM team input and the Electric Power Research Institute’s (EPRI) “2014 U.S. Energy Efficiency Potential Through 2035” report. This report served as the basic underpinning for the establishment of potential EE “bundles”, developed for residential and commercial customers that were then introduced as a resource option in the *Plexos*® optimization model. In order to reflect potential energy savings available in the industrial sector, the end-usage associated with lighting was combined for both the commercial and industrial sectors. The indoor and outdoor lighting bundles shown below in Table 7 reflect the potential energy savings for both sectors.

4.4.2 Achievable Potential (AP)

The amount of available EE is typically described in three sets: technical potential, economic potential, and achievable potential. The previously-cited EPRI report breaks down the achievable potential into a High Achievable Potential (HAP) and an Achievable Potential (AP), with the HAP having a higher utility cost than the AP. Briefly, the technical potential encompasses all known efficiency improvements that are possible, regardless of cost, and thus, whether or not it is cost-effective (i.e., all EE measures would be adopted if technically feasible). The logical subset of this pool is the economic potential. Most commonly, the total resource cost test is used to define economic potential. This compares the avoided cost savings achieved over the life of a measure/program with the cost to implement it, regardless of who paid for it and regardless of the age and remaining economic life of any system/equipment that would be replaced (i.e., all EE measures would be adopted if economic). The third set of efficiency assets is that which is achievable. As highlighted above, the HAP is the economic potential discounted for market barriers such as customer preferences and supply chain maturity; the AP is additionally discounted for programmatic barriers such as program budgets and execution proficiency.

Of the total technical potential, typically only a fraction is ultimately achievable and only then over time due to the existence of market barriers. The question of how much effort and money is to be deployed towards removing or lowering the barriers is a decision made by state governing bodies (legislatures, regulators or both).

The AP range is typically a fraction of the economic potential range. This achievable amount must be further split between what can or should be accomplished with utility-sponsored programs and what should fall under codes and standards. Both amounts are represented in this IRP as reductions to what would otherwise be in the load forecast.

4.4.3 Evaluating Incremental Demand-Side Resources

The *Plexos*® model allows the user to input incremental CHP, EE, DG, DR and VVO as resources, thereby considering such alternatives in the model on equal-footing with more traditional "supply-side" generation resource options.

4.4.3.1 Incremental Energy Efficiency (EE) Modeled

To determine the economic demand-side EE activity to be modeled that would be over-and-above existing EE program offerings in the load forecast, a determination was made as to the potential level and cost of such incremental EE activity as well as the ability to expand current programs. It was assumed that the incremental programs modeled would be effective in 2020. Given that each of SWEPCO's jurisdictions have a subset of customers that are allowed to opt-out of participating in EE programs, these customers were removed from the available EE potential and thus not modeled. Figure 24 and Figure 25 show the "going-in" make-up of projected end-usage in 2020 for SWEPCO's residential and commercial sectors with lighting end-use also included for the industrial sector. Future incremental EE activity can further target these areas or address other end-uses.

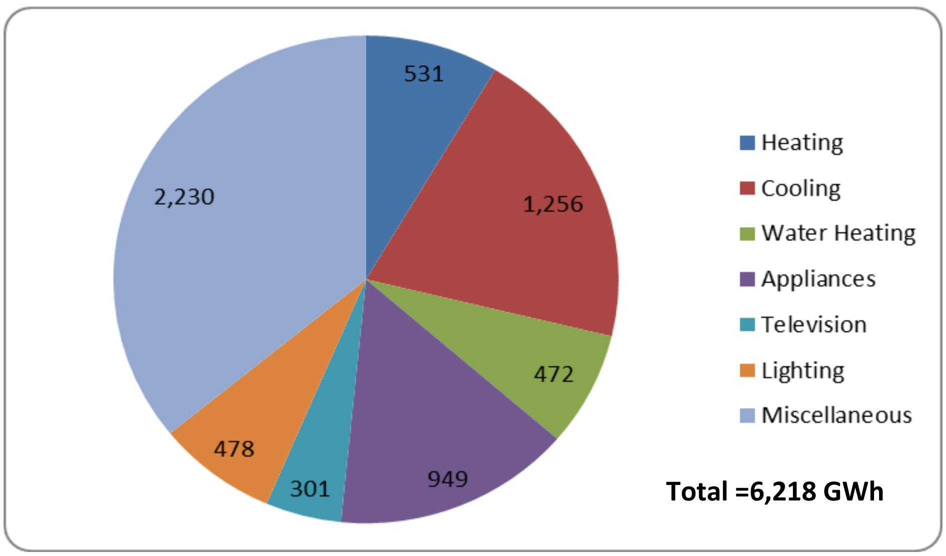

Figure 24. 2020 SWEPCO Residential End-Use (GWh)

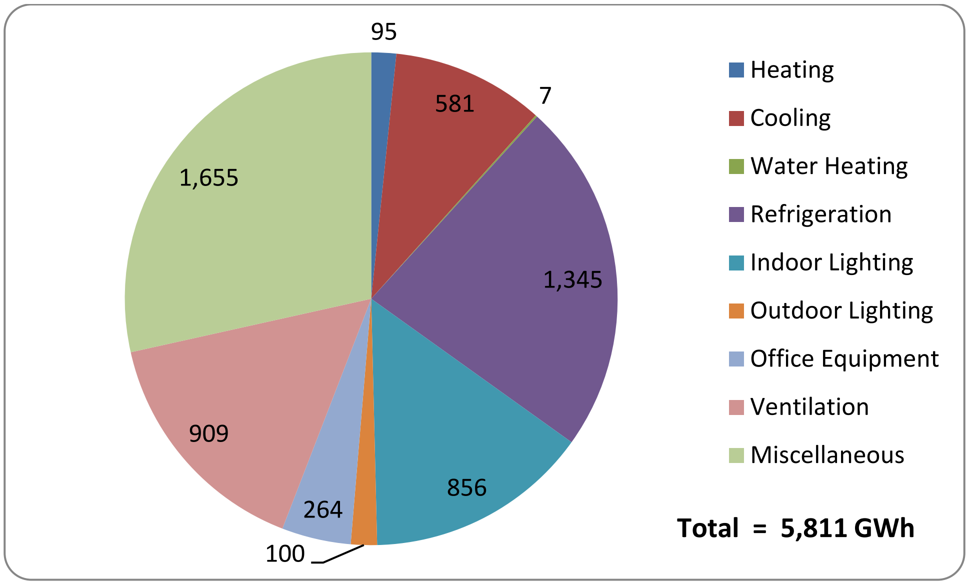

Figure 25. 2020 SWEPCO Commercial End-Use & Industrial Lighting End-Use (GWh)

To determine which end-uses are targeted, and in what amounts, SWEPCO looked at the previously-cited 2014 EPRI report and consulted its DSM team. The EPRI report and the SWEPCO DSM 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. SWEPCO utilized this data to develop "bundles" of future EE activity for the demographics and weather-related impacts of its service territory. Table 4 and Table 5**,** from the EPRI report, list the individual measure categories considered for both the residential and commercial sectors.

Table 4. Residential Sector Energy Efficiency (EE) Measure Categories

Central Air Conditioning	Programmable Thermostat	Storm Doors	Dishwashers
Air-Source Heat Pumps	Water Heating	External Shades	Clothes Washers
Ground-Source Heat Pumps	Faucet Aerators	Ceiling Insulation	Clothes Dryers
Room Air Conditioning	Pipe Insulation	Foundation Insulation	Refrigerators
Air Conditioning Maintenance	Low-Flow Showerheads	Duct Insulation	Freezers
Heat Pump Maintenance	Duct Repair	Wall Insulation	Cooking
Attic Fan	Dehumidifier	Windows	Televisions
Furnace Fans	Lighting – Linear Fluorescent	Reflective Roof	Personal Computers
Ceiling Fan	Lighting – Screw-in	Infiltration Control	Smart Plug Strips, Reduce Standby Wattage
Whole-House Fan	Enhanced Customer Bill Presentment		

Table 5. Commercial Sector Energy Efficiency (EE) Measure Categories

Heat Pumps	Water Heater	Energy-Efficient Motors	Lighting – Screw-in
Central Air Conditioning	Water Temperature Reset	Variable Speed Controls	Lighting – LED Street Lighting
Chiller	Computers	Programmable Thermostat	Anti-Sweat Heater Controls
Cool Roof	Servers	Duct Testing and Sealing	Floating Head Pressure Controls
Economizer	Displays	HVAC Retro-commissioning	Installation of Glass Doors
Energy Management System	Copiers Printers	Efficient Windows	High-Efficiency Vending Machine
Roof Insulation	Other Electronics	Lighting – Linear Fluorescent	Icemakers
Duct Insulation		Lighting – HID to LED	Reach-in Coolers and Freezers

What can be derived from the tables is that the 2014 EPRI report has taken a comprehensive approach to identifying available EE measures. From this information and recent SWEPCO DSM activity, SWEPCO has developed proxy EE bundles for residential, commercial and industrial customer classes to be modeled within *Plexos*®. These bundles are based on measure characteristics identified within the EPRI report, recent SWEPCO DSM planning, and SWEPCO customer usage.

Table 6 and Table 7 list the energy and cost profiles of EE resource "bundles" for the residential and commercial sectors, respectively. In order to reflect the potential EE savings available in the industrial sector, each of the lighting bundles shown in Table 7 includes potential savings for both commercial and industrial customers.

Table 6. Incremental Residential Energy Efficiency (EE) Bundle Summary

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2020-2024	Yearly Potential Savings (MWh) 2025-2029	Yearly Potential Savings (MWh) 2030-2040	Yearly Potential Savings (MWh) 2041-2045	Bundle Life
Thermal Shell - AP	$0.23	2,596	1,847	2,778	3,509	10
Thermal Shell - HAP	$0.35	11,215	3,410	3,816	1,958	10
Cooling - AP	$1.18	22,729	8,924	5,738	1,637	17
Cooling - HAP	$1.65	9,761	5,825	2,710	1,637	17
Water Heating - AP	$0.07	894	0	0	0	10
Water Heating - HAP	$0.10	3,862	0	0	0	10
Appliances - AP	$0.08	2,650	956	692	0	13
Appliances - HAP	$0.13	1,465	0	0	0	13
Lighting - AP	$0.03	8,705	0	0	0	30
Lighting - HAP	$0.05	7,597	0	0	0	30
Enhanced Customer Bill	$0.74	26,839	0	0	0	10

**HAP Potential is incremental to AP Potential*

Table 7. Incremental Commercial and Industrial (Lighting) Energy Efficiency (EE) Bundle Summary

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2020-2024	Yearly Potential Savings (MWh) 2025-2029	Yearly Potential Savings (MWh) 2030-2040	Yearly Potential Savings (MWh) 2041-2045	Bundle Life
Heat Pump - AP	$9.93	3,006	845	0	0	15
Heat Pump - HAP	$14.89	751	0	0	0	15
HVAC Equipment - AP	$0.19	1,444	0	0	0	16
HVAC Equipment - HAP	$0.28	2,284	0	0	0	17
Indoor Screw-In Lighting - AP	$0.01	3,741	0	0	0	6
Indoor Screw-In Lighting - HAP	$0.02	1,979	0	0	0	6
Indoor HID/Fluorescent Lighting - AP	$0.19	39,152	9,555	3,338	0	13
Indoor HID/Fluorescent Lighting - HAP	$0.29	9,788	3,717	1,543	0	13
Outdoor Lighting - AP	$0.13	5,972	1,570	0	0	15
Outdoor Lighting - HAP	$0.19	1,493	688	0	0	15

**HAP Potential is incremental to AP Potential*

As can be seen from the tables, each program has both AP and HAP characteristics. The development of these characteristics is based on the feedback from SWEPCO's DSM team and the 2014 EPRI EE Potential report that has been previously referenced. This report further identifies Market Acceptance Ratios (MAR) and Program Implementation Factors (PIF) to apply to primary measure savings, as well as Application Factors for secondary measures. Secondary measures are not consumers of energy, but do influence the system that is consuming energy. The Residential Thermal Shell, Residential Water Heating and Commercial Cooling bundles—in both AP and HAP—include secondary measures. The MAR and PIF are utilized to develop the incremental AP program characteristics and the MAR only is used to develop the incremental HAP program characteristics.

Figure 26 below shows the Levelized Cost of Electricity (LCOE) and potential energy savings in 2020 for each of the bundles offered into the model as a potential resource. To preserve a reasonable scale for illustrative purposes, the two bundles with the highest LCOE, Commercial Heat Pump AP and Commercial Heat Pump HAP, were omitted from Figure 26. The total potential energy savings for EE programs that begin in 2020 is 721GWh, 2% of SWEPCO's total load. Figure 26 is offered as a rough comparison of EE bundle cost versus levelized market prices. However, it is not intended to illustrate which EE resources the model will select. Ultimately, the model will determine if an EE bundle is beneficial to an optimization scenario[11].

[11] For illustrative purposes, the Company has included in Figure 26 a proxy for the SPP Around-the-Clock LCOE, it should be noted within this calculation that, for comparison purposes only, these annual values are degraded over 15 years, which is similar to EE bundles with a 15-year life.

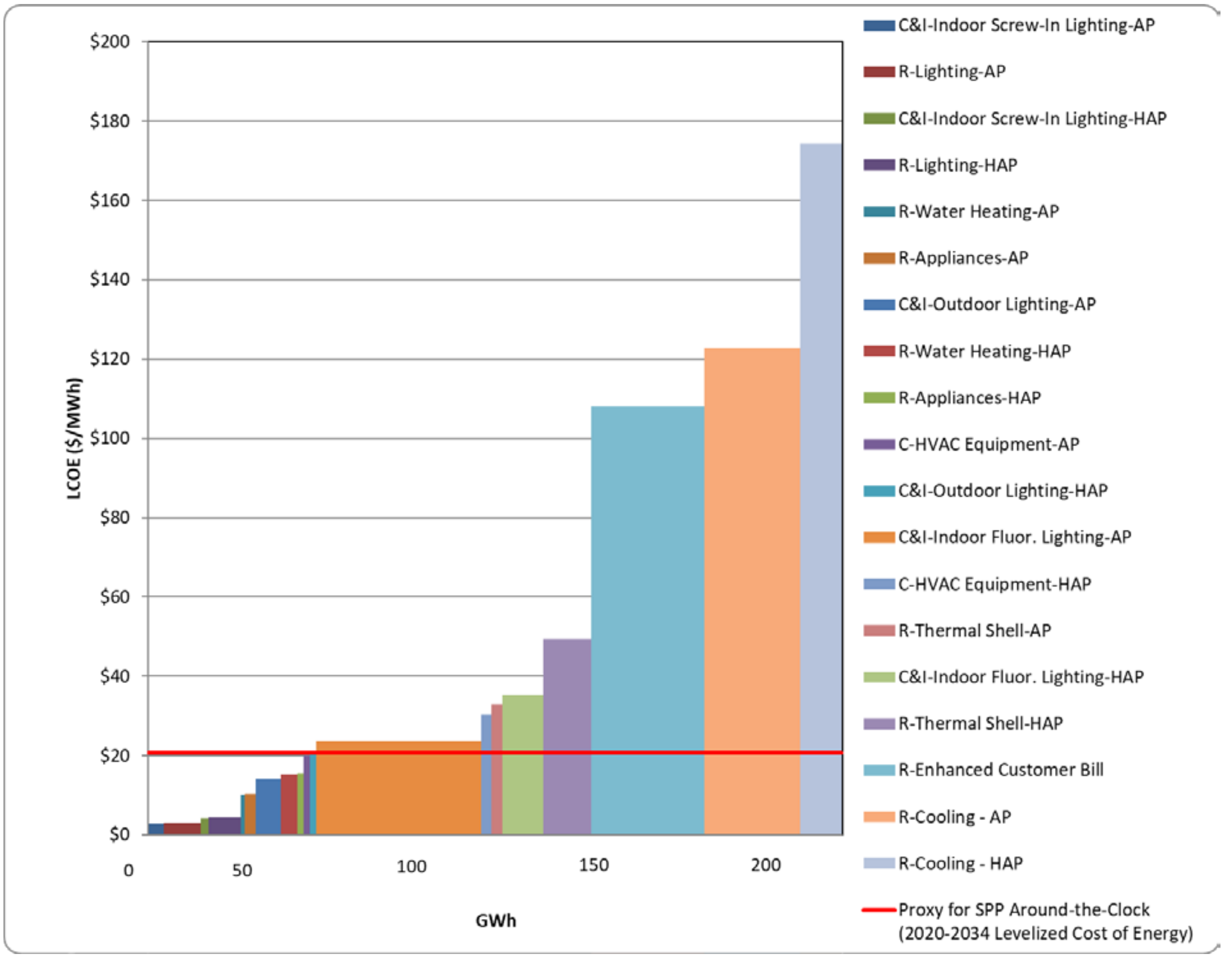

Figure 26. EE Bundle Levelized Cost vs. Potential Energy Savings for 2020

Each EE bundle is offered into the model as a stand-alone resource with its own unique cost and potential energy and demand savings. Should the model determine that a bundle is economical, that bundle will be included in the portfolio of optimized resources. SWEPCO will consider the details of which EE bundles were selected by the Plexos model, and included in the Low Band Portfolio, to develop appropriate EE offerings to propose for SWEPCO's customers. Efforts to determine program attributes such as participant costs, penetration rates, and bill savings, prior to that point in time would be highly speculative and potentially inaccurate.

4.4.3.2 Volt VAR Optimization (VVO) Modeled

Potential future VVO circuits considered for modeling varied in relative cost and energy-reduction effectiveness. The circuits were grouped into 15 "tranches" based on the relative potential peak demand and energy reduction of each tranche of circuits. The *Plexos*® model was able to pick the most cost-effective tranches first and add subsequent tranches as merited. Each VVO tranche is estimated to encompass approximately 41 circuits. Table 8 details all of the tranches offered into the model and the respective cost and performance of each. The costs shown are in 2017 dollars.

Table 8. Volt VAR Optimization (VVO) Tranche Profiles

Tranche	No. of Circuits	Capital Investment	Annual O&M	Demand Reduction (kW)	Energy Reduction (MWh)
1	40	$13,360,000	$400,800	20,679	96,007
2	41	$13,694,000	$410,820	11,323	52,570
3	41	$13,694,000	$410,820	9,585	44,503
4	40	$13,360,000	$400,800	8,443	39,200
5	40	$13,360,000	$400,800	7,778	36,111
6	40	$13,360,000	$400,800	7,334	34,048
7	40	$13,360,000	$400,800	6,766	31,414
8	40	$13,360,000	$400,800	6,164	28,616
9	41	$13,694,000	$410,820	5,567	25,847
10	41	$13,694,000	$410,820	5,012	23,270
11	40	$13,360,000	$400,800	3,992	18,533
12	41	$13,694,000	$410,820	3,420	15,878
13	41	$13,694,000	$410,820	2,816	13,072
14	41	$13,694,000	$410,820	2,247	10,432
15	41	$13,694,000	$410,820	1,586	7,365

4.4.3.3 Demand Response (DR) Modeled

The current level of DR is maintained throughout the plan. SWEPCO has and will continue to provide demand response tariffs to meet customer needs. Company personnel work with customers to identify load suitable for interruption and will continue to do so. SWEPCO has offered demand response rates to other customer classes (including residential) and will continue to evaluate the value of these types of programs that will meet both customer and Company needs.

4.4.3.4 Distributed Generation (DG) Modeled

Distributed solar resources were evaluated assuming a residential rooftop solar resource, as this is the primary distributed resource. Solar has favorable characteristics in that it produces the majority of its energy at near-peak usage times. Distributed solar resources (i.e., rooftop Solar) are included in the model at an assumed growth rate based on the current level of federal incentives, future estimated costs of rooftop solar and historical rooftop solar additions.

The current distributed resources net metering cap for SWEPCO Louisiana is 7.8MW and SWEPCO Louisiana met this cap in 2016. The assumed annual growth rate for rooftop solar is 5% per year after SWEPCO Louisiana reaches the cap. The assumed growth rate is an estimate and is based on both the declining cost for rooftop solar as well as the historical additions by SWEPCO state jurisdiction.

Figure 27 below demonstrates the historical installed rooftop solar capacity for SWEPCO by jurisdiction and projected rooftop solar capacity additions.

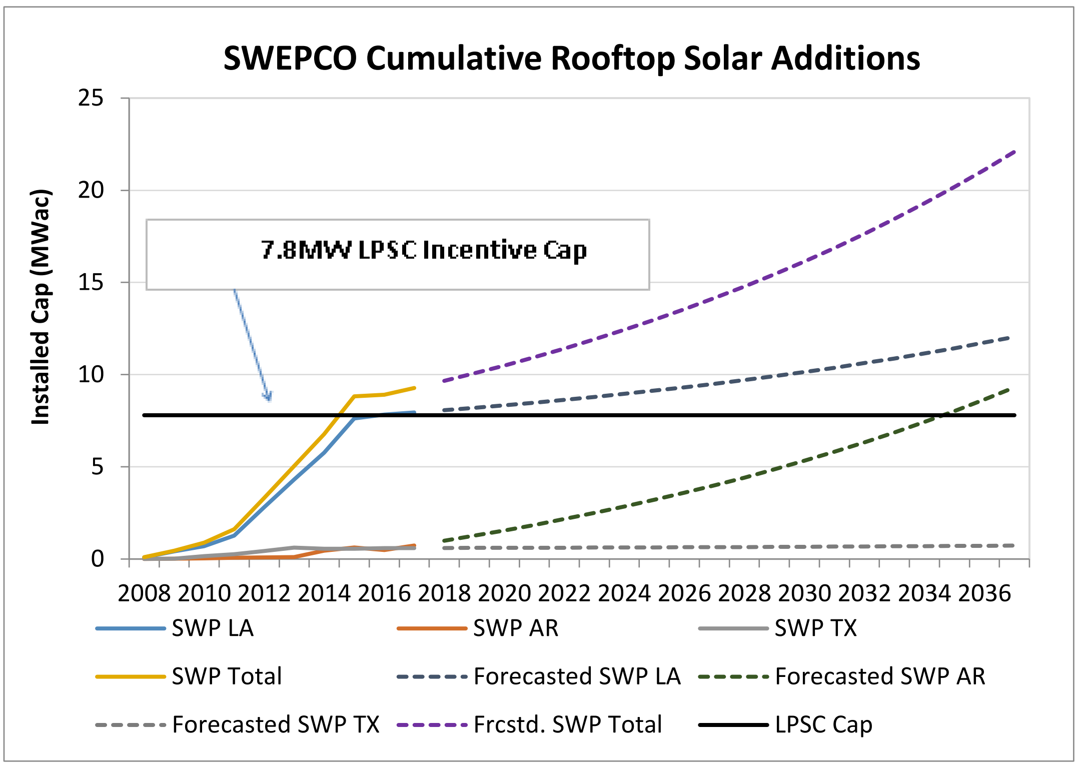

Figure 27. Distributed Generation (Rooftop Solar) Additions/Projections

4.4.3.5 Optimizing Incremental Demand-side Resources

The *Plexos®* software views demand-side resources as non-dispatchable "generators" that produce energy similar to non-dispatchable supply-side generators such as wind or solar. Thus, the value of each resource is impacted by the hours of the day and time of the year that it "generates" energy.

4.4.3.6 Combined Heat and Power (CHP)

CHP (also known as Cogeneration) is a process where electricity is generated and the waste heat by-product is used for heating or other processes, raising the net thermal efficiency of the facility. To take advantage of the increased efficiency associated with CHP, the host must have a ready need for the heat that is otherwise potentially wasted in the generation of electricity.

SWEPCO worked with AEP Generation Engineering to develop a generic CHP option. The CHP option developed is a 15MW facility utilizing a natural gas fired combustion turbine, Heat Recovery Steam Generator (HRSG) and SCR to control NO_x. A major assumption is that all of the steam is taken by the host and the efficiency of the modeled CHP resource is credited for the value of the steam provided to the host. The overnight installed cost is estimated to be $2,100/kW and the assumed modeled full load heat rate is approximately 4,800 Btu/kWh. Additionally, the assumed capacity factor was 90%.

4.5 Identify and Screen Supply-side Resource Options

4.5.1 Capacity Resource Options

New construction supply-side alternatives were modeled to represent peaking and base-load/intermediate capacity resource options. To reduce the number of modeling permutations in *Plexos®*, the available technology options were limited to certain representative unit types. However, it is important to note that alternative technologies with comparable cost and performance characteristics may ultimately be substituted should technological or market-based profile changes warrant.

When applicable, SWEPCO may take advantage of economic market capacity and energy opportunities. Prospectively, these opportunities could take the place of currently planned resources and will be evaluated on a case-by-case basis.

4.5.2 New Supply-Side Capacity Alternatives

Natural gas base/intermediate and peaking generating technologies were considered in this IRP as well as large-scale solar and wind. Further details on these technologies are available in Exhibit B of the Appendix. To reduce the computational problem size within *Plexos*®, the number of alternatives explicitly modeled was reduced through an economic screening process which analyzed various supply options and developed a quantitative comparison for each duty-cycle type of capacity (i.e., base-load, intermediate, and peaking) on a forty year levelized basis. The options were screened by comparing levelized annual busbar costs over a range of capacity factors.

In this evaluation, each type of technology is represented by a line showing the relationship between its total levelized annual cost per kW and an assumed annual capacity factor. The value at a capacity factor of zero represents the fixed costs, including carrying charges and fixed Operations and Maintenance (O&M) costs, which would be incurred even if the unit produced no energy. The slope of the line reflects variable costs, including fuel, emissions, and variable O&M, which increase in proportion to the energy produced.

The best of class technology, for each duty cycle, determined by this screening process was explicitly modeled in *Plexos*®. These generation technologies were intended to represent reasonable proxies for each capacity type (base-load, intermediate, peaking). Subsequent substitution of specific technologies could occur in any later plan, based on emerging economic or non-economic factors not yet identified.

AEP continually tracks and monitors changes in the estimated cost and performance parameters for a wide array of generation technologies. Access to industry collaborative organizations such as EPRI and the Edison Electric Institute, AEP's association with architect and engineering firms and original equipment manufacturers, as well as its own experience and market intelligence, provides AEP with current estimates for the planning process. Table 9 below offers a summary (see Appendix B for a more detailed description of the technologies and associated footnotes) of the most recent technology performance parameter data developed. Additional parameters such as the quantities and rates of solid waste production, hazardous material consumption, and water consumption are significant; however, the options which passed the screening phase and were included in *Plexos*® were natural gas facilities which generally have limited impacts on these areas of concern.

Table 9. New Generation Technology Options with Key Assumptions

Type	Capability (MW) (d) Std. ISO	Summer	Winter	Installed Cost (c,e) ($/kW)	Capacity Factor (%)	LCOE (f) ($/MWh)
Base Load						
Nuclear	1,610	1,560	1,690	7,900	80	176.3
Pulv. Coal with Carbon Capture (PRB)	540	520	570	9,200	75	230.6
Combined Cycle (1X1 "J" Class)	540	700	720	1,000	75	62.3
Combined Cycle (2X1 "J" Class)	1,080	1,410	1,450	800	75	57.5
Combined Cycle (2X1 "H" Class)	1,150	1,490	1,530	700	75	55.8
Peaking						
Combustion Turbine (2 - "E" Class) (g)	180	190	190	1,200	25	145.9
Combustion Turbine (2 - "F" Class, w/evap coolers) (g)	490	500	510	700	25	114.0
Aero-Derivative (2 - Small Machines) (g,h)	120	120	120	1,400	25	143.8
Recip Engine Farm	220	220	230	1,300	25	123.0
Battery	10	10	10	1,900	25	175.8

4.5.3 Base/Intermediate Alternatives

Coal and Nuclear base-load options were evaluated by SWEPCO but were not included in the *Plexos*® resource optimization modeling analyses. The forecasted difference between SWEPCO's load forecast and existing resources is such that a large, central generating station would not be required. In addition, for coal generation resources, environmental regulation (see Section 3.3) makes the construction of new coal plants economically impractical. New nuclear construction is also economically impractical since it would potentially require an investment of $7,900/kW or more.

Intermediate generating sources are typically expected to serve a load-following and cycling duty and effectively shield base-load units from that obligation. Historically, many generators relied on older, smaller, less-efficient/higher dispatch cost, subcritical coal-fired or gas-steam units to serve such load-following roles. Over the last several years, these units have improved ramp rates and regulation capability, and reduced downturn (minimum load capabilities). With the retirement of SWEPCO's subcritical units, other generation dispatch alternatives and new generation will need to be considered to cost effectively meet this duty cycle's operating characteristic.

4.5.3.1 Natural Gas Combined Cycle (NGCC)

An NGCC plant combines a steam cycle and a combustion gas turbine cycle to produce power. Waste heat (~1,100°F) from one or more combustion turbines passes through a HRSG producing steam. The steam drives a steam turbine generator which produces about one-third of the NGCC plant power, depending upon the gas-to-steam turbine design "platform," while the combustion turbines produce the other two-thirds.

The main features of the NGCC plant are high reliability, reasonable capital costs, operating efficiency (at 45-63% Lower Heating Value), low emission levels, small footprint and shorter construction periods than coal-based plants. In the past 8 to 10 years, NGCC plants were often selected to meet new intermediate and certain base-load needs. NGCC plants may be designed with the capability of being "islanded" which would allow them, in concert with an associated diesel generator, to perform system restoration (Black Start) services. Although cycling duty is typically not a concern, an issue faced by NGCC when load-following is the erosion of efficiency due to an inability to maintain optimum air-to-fuel pressure and turbine exhaust and steam temperatures. Methods to address these include:

- Installation of advanced automated controls.
- Supplemental firing while at full load with a reduction in firing when load decreases. When supplemental firing reaches zero, fuel to the gas turbine is cutback. This approach would reduce efficiency at full load, but would likewise greatly reduce efficiency degradation in lower-load ranges.
- Use of multiple gas turbines coupled with a waste heat boiler that will give the widest load range with minimum efficiency penalty.

4.5.4 Peaking Alternatives

Peaking generating sources provide needed capacity during extreme high-use peaking periods and/or periods in which significant shifts in the load (or supply) curve dictate the need for "quick-response" capability. The peaks occur for only a few hours each year and the installed reserve requirement is predicated on a one day in ten-year loss of load expectation, so the capacity dedicated to serving this reliability function can be expected to provide relatively little energy over an annual load cycle. As a result, fuel efficiency and other variable costs applicable to these resources are of lesser concern. Rather, this capacity should be obtained at the lowest practical installed/fixed cost, despite the fact that such capacity often has very high energy costs. Ultimately, such "peaking" resource requirements are manifested in the system load duration curve.

In addition, in certain situations, peaking capacity such as combustion turbines can provide backup and some have the ability to provide emergency, Black Start, capability to the grid.

4.5.4.1 Simple Cycle Combustion Turbines (NGCT)

In "industrial" or "frame-type" Combustion Turbine (CT) systems, air compressed by an axial compressor is mixed with fuel and burned in a combustion chamber. The resulting hot gas then expands and cools while passing through a turbine. The rotating rear turbine not only runs the axial compressor in the front section but also provides rotating shaft power to drive an electric generator. The exhaust from a combustion turbine can range in temperature between 800 and 1,150 degrees Fahrenheit and contains substantial thermal energy. A CT system is one in which the exhaust from the gas turbine is vented to the atmosphere and its energy lost, *i.e.*, not recovered as in a combined-cycle design. While not as efficient (at 30-35% Lower Heating Value), they are inexpensive to purchase, compact, and simple to operate.

4.5.4.2 Aeroderivatives (AD)

Aeroderivatives (AD) are aircraft jet engines used in ground installations for power generation. They are smaller in size, lighter weight, and can start and stop quicker than their larger industrial or "frame" counterparts. For example, the GE 7E frame machine requires 20 to 30 minutes to ramp up to full load while the smaller LM6000 aeroderivative only needs 10 minutes from start to full load. However, the cost per kW of an aeroderivative is considerably higher than a frame machine.

The AD performance operating characteristics of rapid startup and shutdown make the aeroderivatives well suited to peaking generation needs. ADs can operate at full load for a small percentage of the time allowing for multiple daily startups to meet peak demands, compared to frame machines which are more commonly expected to start up once per day and operate at continuous full load for 10 to 16 hours per day. The cycling capabilities provide ADs the ability to backup variable renewables such as solar and wind. This operating characteristic is expected to become more valuable over time as: A) the penetration of variable renewables increase; B) base-load generation processes become more complex limiting their ability to load-follow and; C) more intermediate coal-fueled generating units are retired from commercial service.

AD units weigh less than their industrial counterparts allowing for skid or modular installations. Efficiency is also a consideration in choosing an AD over an industrial turbine. AD units in the less than 100MW range are more efficient and have lower heat rates in simple cycle operation than industrial units of equivalent size. Exhaust gas temperatures are lower in AD units.

4.5.4.3 Reciprocating Engines (RE)

The use of Reciprocating Engines (RE) or internal combustion engines has increased over the last twenty years. According to EPRI, in 1993 about 5% of the total RE units sold were natural gas-fired spark ignition engines and post 2000 sales of natural gas-fired generators have remained above 10% of total units sold worldwide.

Improvements in emission control systems and thermal efficiency have led to the increased utilization of natural gas-fired RE generators incorporated into multi-unit power generation stations for main grid applications. RE generators' high efficiency, flat heat rate curves and rapid response make this technology very well suited for peaking and intermediate load service and as back up to intermittent generating resources. Additionally, the fuel supply pressure required is in the range of 40 to 70 psig; this lower gas pressure gives this technology more flexibility when identifying locations. A further advantage of RE generators is that power output is less affected by increasing elevation and ambient temperature as compared to gas turbine technology. Also, a RE plant generally would consist of multiple units, which will be more efficient at part load operation than a single gas turbine unit of equivalent size because of the ability to shut down units and to operate the remaining units at higher load. Common RE unit sizes have generally ranged from 8MW to 18MW per machine with heat rates in the range of 8,100 –to- 8,600 Btu/kWh (Higher Heating Value).

Regarding operating cost, RE generators have a somewhat greater variable O&M than a comparable gas turbine; however, over the long term, maintenance costs of RE are generally lower because the operating hours between major maintenance can be twice as long as gas turbines of similar size.

4.5.4.4 Battery Storage

The modeling of Battery Storage as a Peaking resource option is becoming a more common occurrence in IRPs. In recent years Lithium-ion battery technology has emerged as the fastest growing platform for stationary storage applications. The Battery Storage resource that was modeled in this IRP is a Lithium-ion storage technology and it has a nameplate rating of 10MW and 40MWh, with a round trip efficiency of 87%. To develop this resource, AEP's Generation Engineering Services considered a wide range of sources including: the DOE/EPRI 2015 Electricity Storage Handbook in Collaboration with the National Rural Electric Cooperative Association (NRECA), EPRI TAGWEB, BNEF and battery storage equipment suppliers. See Figure 28 below for an illustration of forecasted storage installed cost.

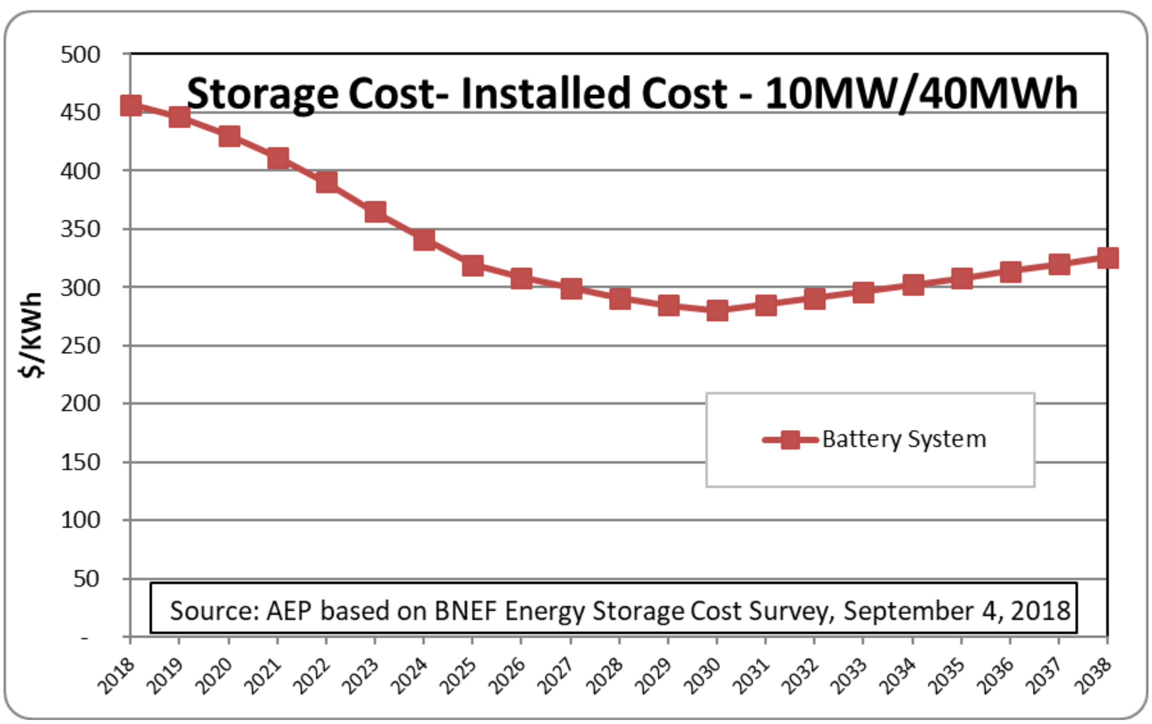

Figure 28. Forecasted Storage Installed Cost

4.5.5 Renewable Alternatives

Renewable generation alternatives use energy sources that are either naturally occurring (wind, solar, hydro or geothermal), or are sourced from a by-product or waste-product of another process (biomass or landfill gas). In the past, development of these resources has been driven primarily as the result of renewable portfolio requirements. That is not universally true now as advancements in both solar photovoltaics and wind turbine manufacturing have reduced both installed and ongoing costs.

At this time within the industry, renewable energy resources, because of their intermittent nature, provide more energy value than capacity value. For this IRP, the overall threshold for intermittent resource additions, 40% of SWEPCO's energy demand for wind and 15% for solar. This assumes that the RTO and other key stakeholders will advance the understanding, forecasting and management of intermittent resources, ultimately supporting a higher penetration level and capacity planning values.

4.5.5.1 Solar

4.5.5.1.1 Large-Scale Solar

Solar power comes in two forms to produce electricity: concentrating and photovoltaics. Concentrating solar — which heats a working fluid to temperatures sufficient to generate steam to power a turbine — produces electricity on a large scale and is similar to traditional centralized supply assets in that respect. Photovoltaics can be distributed throughout the grid and are a scalable resource that, for example, can be as small as a few kilowatts or as large as 500MW.

The cost of large-, or utility-scale, solar projects has declined in recent years and is expected to continue to decline (see Figure 29 below). This has been mostly a result of reduced panel prices that have resulted from manufacturing efficiencies spurred by accelerating penetration of solar energy in Europe, Japan, and California. With the trend firmly established, forecasts generally foresee declining nominal prices in the next decade as well, notwithstanding solar panel tariffs which from an IRP perspective are regarded as a short-term impact.

Large-scale solar plants require less lead time to build than fossil plants. There is no defined limit for how much utility solar can be built in a given time. However, in practice, solar facilities are not added in an unlimited fashion given siting and regulatory constraints.

Solar resources were made available in the *Plexos* model with some limits on the rate with which they could be chosen. In the IRP modeling, the assumption was made that large-scale solar resources were available in yearly quantities up to 300MWac[12] of nameplate capacity starting in June 2021. A limit on solar capacity additions is needed because as solar costs continue to decrease relative to the market price of energy, there will come a point where the optimization model will theoretically pick an unlimited amount of solar resources. Additionally, this 300MWac annual threshold recognizes that there is a practical limit as to the number of sites that can be identified, permitted, constructed, and interconnected by SWEPCO in a given year. For example, the land requirement to develop a 1MW solar plant is estimated to be 7 acres, implying that 700 acres of land would be required to develop 100MW of solar annually. Over the planning period the maximum threshold for solar resource additions was limited to approximately 15% of SWEPCO's load obligation or 1,300MW. Certainly, as SWEPCO gains experience with solar installations, this limit would likely be modified (for example, it may be lower earlier and greater later).

Solar resources were available in two tiers. Referred to as tier 2 in this IRP, the overall pricing trend over the planning period is based on the BNEF utility scale solar pricing forecast. An additional pricing tier was developed, tier 1, which is 10% lower than the base BNEF forecast. The tier 1 pricing is considered a "Best-In-Class" solar resource. The 10% discount from the tier 2 product is based on the concept that during an RFP process the "Best Bids" would be approximately 10% less than the average bids. Both tiers of solar resources were available in blocks of 150MW, which is comprised of three 50MW installations and totals 300MW annually. Additionally, both tiers of solar resources were modeled with capacity factors of approximately 28%.

[12] Manufacturers usually quote system performance in DC watts; however electric service from the utility is supplied in AC watts. An inverter converts the DC electrical current into AC electrical current. Depending on the inverter efficiency, the AC wattage may be anywhere from 80 to 95 percent of the DC wattage.

Figure 29 below illustrates the projected large-scale solar pricing included in the IRP model. Both tiers account for Federal ITCs. The large-scale solar pricing used in this IRP reflects a normalized treatment of the ITC, as well as a four-year safe harbor factor in ITC pricing. This safe harbor factor allows projects to lock in ITC benefits four years prior to commercial operation, as long as construction has been commenced. The ITC benefit is included through 2030. At this point in time the 10% ITC benefit would become indiscernible from potential variations in forecasted prices.

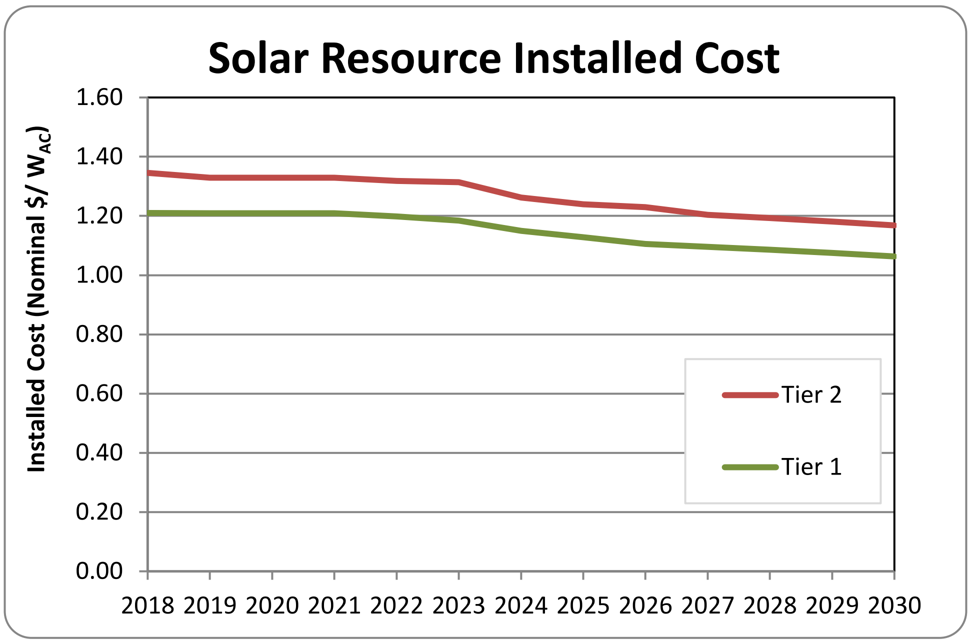

Figure 29. Large-Scale Solar Pricing Tiers

Solar resources are modeled with a 33% capacity credit, this is based on the expected long-term performance of the resource; however, SPP initially values solar at 10% of nameplate capacity rating for the first three years of operation and then allows the Company to adjust this value based on operating history. Solar capacity credit will be modeled with the SPP value for solar at 10% of nameplate capacity rating for the first three years of operation and then 33% based on the load shape and SPP Criteria for utility scale projects.

4.5.5.1.2 Trends in Solar Energy Pricing

As mentioned above, solar energy prices have declined significantly in recent years as shown below in Figure 30. From 2010 to 2018 installation costs have declined by more than 50% for residential, commercial, and large-scale solar. Further, large-scale solar has been, and is projected to be, substantially lower in cost compared to other sectors, with large-scale installations costing 51% and 31% less than residential and commercial installations, respectively, based on 2018 costs.

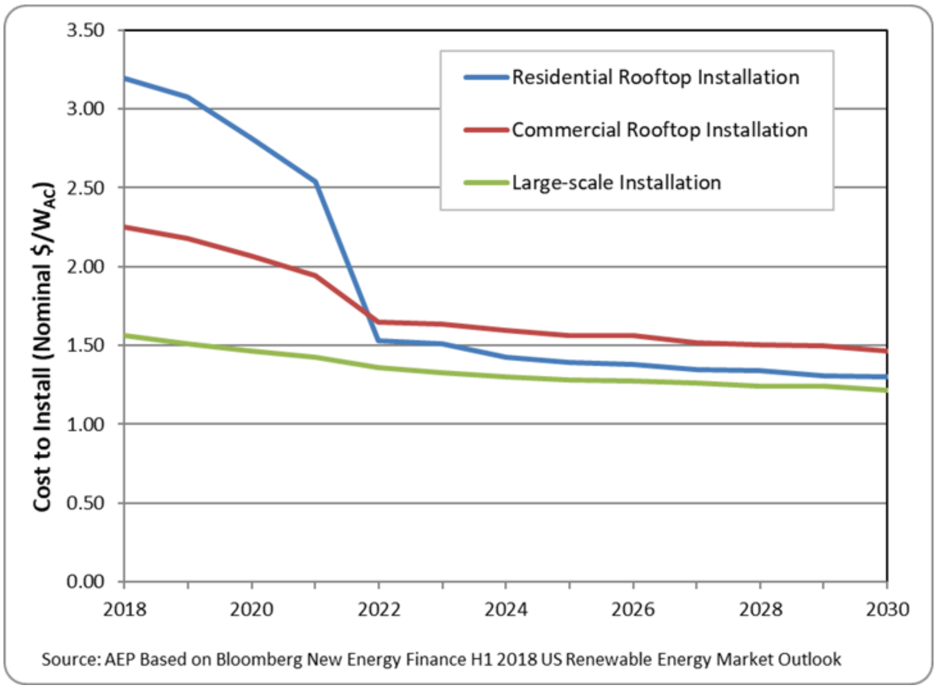

Figure 30. SPP Average Solar Photovoltaic (PV) Installation Cost (Nominal $/WAC) Trends, excluding Investment Tax Credit Benefits

4.5.5.2 Wind

Large-scale wind energy is generated by turbines ranging from 1.0 to 3.2MW. Typically, multiple wind turbines are grouped in rows or grids to develop a wind turbine power project which requires only a single connection to the transmission system. Location of wind turbines at the proper site is particularly critical as not only does the wind resource vary by geography, but also its proximity to a transmission system with available capacity, which will factor into the cost.

A variable source of power in most non-coastal locales, with capacity factors ranging from 30 percent (in the eastern portion of the U.S.) to over 50 percent (largely in more westerly portions of the U.S., including the Plains states), wind energy's life-cycle cost ($/MWh), excluding subsidies, is currently higher than the marginal (avoided) cost of energy, in spite of its negligible operating costs.

Another consideration with wind power is that its most critical factors (*i.e.*, wind speed and sustainability) are typically highest in more remote locations, which forces the electricity to be transmitted longer distances to load centers necessitating the build out of EHV transmission to optimally integrate large additions of wind into the grid.

For modeling purposes, wind resources are first made available to the model in 2022 (i.e., commercial operation date 12/31/21), due to the amount of time necessary to secure resources and obtain any necessary regulatory approvals. Figure 31 below shows the LCOE price of one wind resource tranche assumed for the IRP. The tranche was modeled as a 48% capacity factor load shape and will be available in 200 MW blocks. The wind pricing reflects the value of Federal Production Tax Credits (PTCs). After 2020 tax credits reduce to 80%, 60% and 40% of their 2020 value in 2021, 2022, and 2023, respectively. These PTC values are based on developers taking advantage of the safe-harbor guidelines which provide up to a four-year delay in the effects of declining tax credits as long as adequate construction has commenced. Wind prices were developed based on the Bloomberg New Energy Finance H1 2018 U.S. Renewable Energy Market Outlook and market knowledge.

The tranche was assigned a capacity value of 5% of nameplate rating in the first three years and given a 30% capacity value for the remainder of its 25-year life. The 30% capacity value assigned after the tranche's third year was based upon SPP criteria for calculating wind capacity value, which requires three years of historical performance data to make the calculation. The Company utilized historical data from three existing AEP wind resources within SPP to estimate the assumed 30% capacity value.

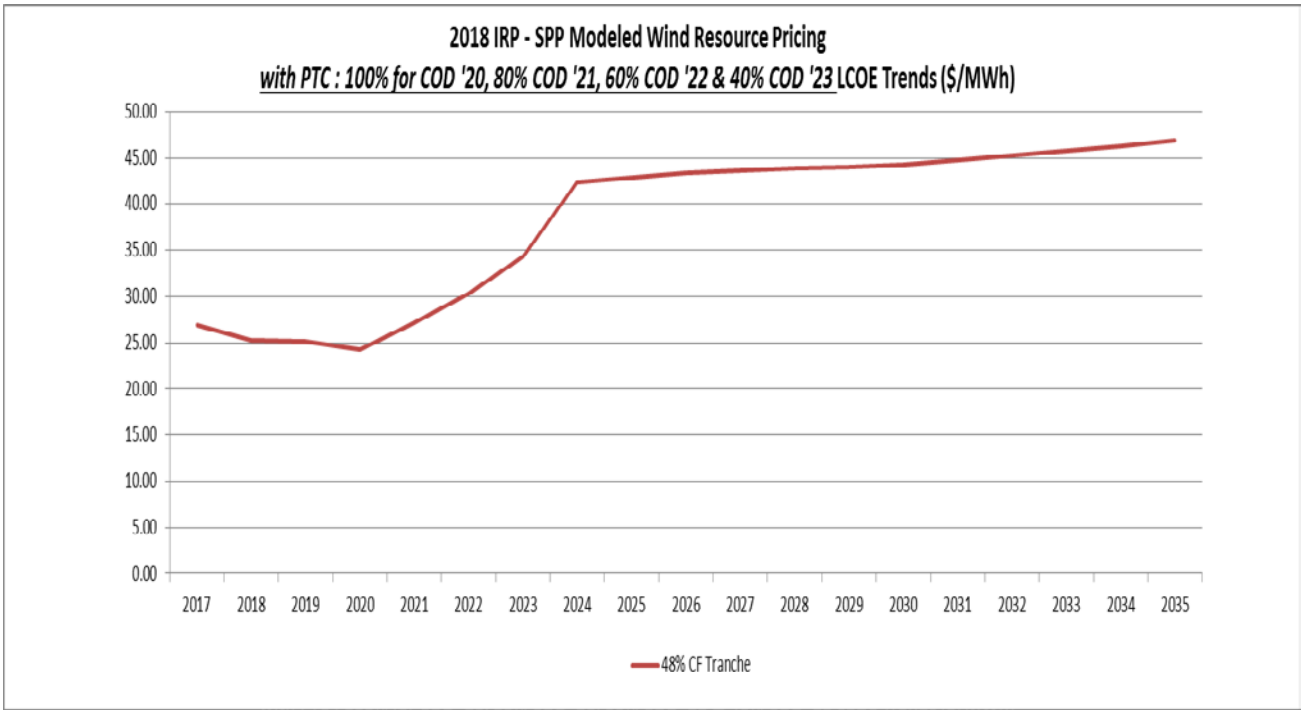

Figure 31.Levelized Cost of Electricity of Wind Resources (Nominal $/MWh)

The expected magnitude of wind resources available beginning in 2022 was limited to 600MW nameplate annually through the remainder of the planning period. In total, wind resources were limited to 2,000MW nameplate over the planning period. The annual limit on wind additions is based on SWEPCO's ability to plan, manage and develop either the construction or the procurement of these resources. As with solar resource additions, as SWEPCO gains experience with wind installations, this limit would likely be modified (for example, it may be lower earlier and greater later). This cap is based on the DOE's Wind Vision Report[13] which suggests from numerous transmission studies that transmission grids should be able to support 20% to 30% of intermittent resources in the 2020 to 2030 timeframe. The cap for SWEPCO allows the model to select up to 40% of generation energy resources as wind-powered by 2037.

[13] *Wind Vision: A New Era for Wind Power in the United States* (2015). Retrieved from http://www1.eere.energy.gov/library/default.aspx?Page=12, Figure 1-5.

Furthermore, based on recent experience and analysis the Company has included the cost of congestion and losses for incremental wind resource additions. Figure 32 below shows the annual value of congestion and losses included with the incremental wind resource.

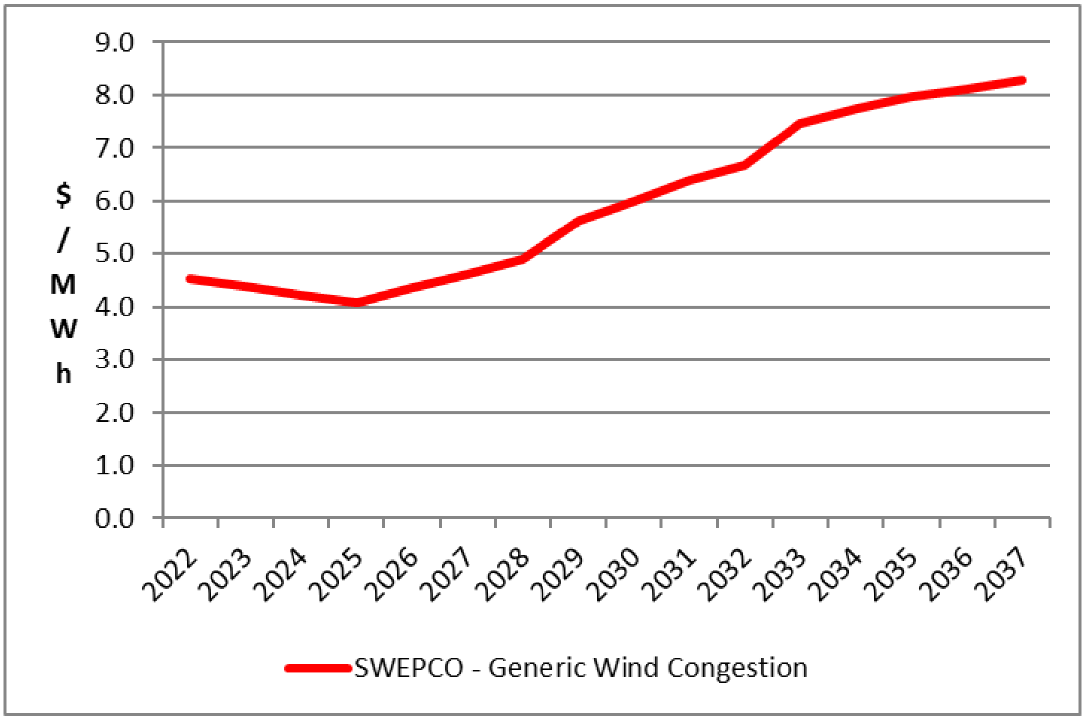

Figure 32. Modeled SPP Congestion & Losses for Wind Resources

4.5.5.3 Hydro

The available sources of, particularly, larger hydroelectric potential have largely been exploited and those that remain must compete with the other uses, including recreation and navigation. The potentially lengthy time associated with environmental studies, Federal Army Corp of Engineer permitting, high up-front construction costs, and environmental issues (fish and wildlife) make new hydro prohibitive at this time. As such, no incremental hydroelectric resources were considered in this IRP.

4.5.5.4 Biomass

Biomass is a term that typically includes organic waste products (sawdust or other wood waste), organic crops (corn, switchgrass, poplar trees, willow trees, etc.), or biogas produced from organic materials, as well as select other materials. Biomass costs will vary significantly depending upon the feedstock. Biomass is typically used in power generation to fuel a steam generator (boiler) that subsequently drives a steam turbine generator; similar to the same process of many traditional coal fired generation units. Some biomass generation facilities use biomass as the primary fuel, however, there are some existing coal-fired generating stations that will use biomass as a blend with the coal. Given these factors, plus the typical high cost and required feedstock supply and attendant long-term pricing issues, no incremental biomass resources were considered in this IRP.

4.6 Integration of Supply-Side and Demand-Side Options within *Plexos®* Modeling

Each supply-side and demand-side resource is offered into the *Plexos®* model on an equivalent basis. Each resource has specific values for capacity, energy production (or savings), and cost. The *Plexos®* model selects resources in order to reduce the overall portfolio cost, regardless of whether the resource is on the supply- or demand-side, and regardless of whether or not there is an absolute capacity need. In other words, the model selects resources that lower costs to customers.

4.6.1 Optimization of Expanded DSM Programs

As described in Section 4.4.3, EE and VVO options that would be incremental to the current programs were modeled as resources within *Plexos®*. In this regard, they are "demand-side power plants" that produce energy according to their end use load shape. They have an initial (program) cost with *no* subsequent annual operating costs. Likewise, they are "retired" at the end of their useful (EE measure) lives.

4.6.2 Optimization of Other Demand-Side Resources

Customer-sited DG, specifically rooftop solar, was not modeled. Instead, reductions in energy use and peak demand were built into the load forecast based on the adoption rates. CHP was modeled as a high thermal efficiency NGCC facility.

5.0 Resource Portfolio Modeling

5.1 The *Plexos*® Model - An Overview

Plexos® LP long-term optimization model, also known as “LT Plan®,” served as the basis from which the SWEPCO-specific capacity requirement evaluations were examined and recommendations were made. The LT Plan® model finds the optimal portfolio of future capacity and energy resources, including DSM additions, which minimizes the CPW of a planning entity’s generation-related variable and fixed costs over a long-term planning horizon. By minimizing CPW the model will provide optimized portfolios with the lowest and most stable customer rates, while adhering to the Company’s constraints. Low, stable rates benefit the entire region by attracting new commercial and industrial customers, and retaining/expanding existing load.

Plexos® accomplishes this by using an objective function which seeks to minimize the aggregate of the following capital and production-related (energy) costs of the portfolio of resources:

- Fixed costs of capacity additions, *i.e.*, carrying charges on incremental capacity additions (based on an SWEPCO-specific, weighted average cost of capital), and fixed O&M;
- fixed costs of any capacity purchases;
- program costs of (incremental) DSM alternatives;
- variable costs associated with SWEPCO generating units. This includes fuel, start-up, consumables, market replacement cost of emission allowances and/or carbon ‘tax,’ and variable O&M costs;
- distributed, or customer-domiciled, resources which were effectively valued at the equivalent of a full-retail “net metering” credit to those customers; and
- a ‘netting’ of the production revenue earned in the SPP power market from SWEPCO’s generation resource sales *and* the cost of energy – based on unique load shapes from SPP purchases necessary to meet SWEPCO’s load obligation.

Plexos® executes the objective function described above while abiding by the following possible constraints:

- Minimum and maximum reserve margins;
- resource additions (i.e., maximum units built);
- age and lifetime of power generation facilities;
- retrofit dependencies (SCR and FGD combinations);
- operation constraints such as ramp rates, minimum up/down times, capacity, heat rates, etc.;
- fuel burn minimum and maximums;
- emission limits on effluents such as SO_2 and NO_x; and
- energy contract parameters such as energy and capacity.

The model inputs that comprise the objective function and constraints are considered in the development of an integrated plan that best fits the utility system being analyzed. *Plexos*® does not develop a full regulatory Cost-of-Service (COS) profile. Rather, it typically considers only the relative load and generation COS that changes from plan-to-plan, and not fixed "embedded" costs associated with existing generating capacity and demand-side programs that would remain constant under any scenario. Likewise, transmission costs are included only to the extent that they are associated with new generating capacity, or are linked to specific supply alternatives. In other words, generic (nondescript or non-site-specific) capacity resource modeling would typically not incorporate significant capital expenditures for transmission interconnection costs.

5.1.1 Key Input Parameters

Two of the major underpinnings in this IRP are long-term forecasts of SWEPCO's energy requirements and peak demand, as well as the price of various generation-related commodities, including energy, capacity, coal, natural gas and, potentially, CO_2/carbon. Both forecasts were created internally within AEP. The load forecast was created by the AEP Economic Forecasting organization, while the long-term commodity pricing forecast was created by the AEP Fundamental Analysis group. These groups have many years of experience forecasting SWEPCO and AEP system-wide demand and energy requirements and fundamental pricing for both internal operational and regulatory purposes. Moreover, the Fundamental Analysis group constantly performs peer review by way of comparing and contrasting its commodity pricing projections versus "consensus" pricing on the part of outside forecasting entities such as IHS- Cambridge Energy Research Associates (CERA), Petroleum Industry Research Associates (PIRA) and the EIA.

Additional critical input parameters include the installed cost of replacement capacity alternative options, as well as the attendant operating costs associated with those options. This data came from the AEP Engineering Services organization.

5.2 *Plexos*® Optimization

5.2.1 Modeling Options and Constraints

The major system parameters that were modeled are elaborated on below. The *Plexos* LT Plan® models these parameters in tandem with the objective function in order to yield the least-cost resource plan.

There are many variants of available supply-side and demand-side resource options and types. As a practical limitation, not all known resource types are made available as modeling options. A screening of available supply-side technologies was performed with the optimum assets made subsequently available as options. Such screens for supply alternatives were performed for baseload, intermediate, and peaking duty cycles.

The selected technology alternatives from this screening process do not necessarily represent the optimum technology choice for that duty-cycle family. Rather, they reflect proxies for modeling purposes. Other factors which will determine the ultimate technology type (e.g., choices for peaking technologies) are taken into consideration. The full list of screened supply options is included in Exhibit B of the Appendix.

Based on the established comparative economic screenings, the following specific supply alternatives were modeled in *Plexos*® for each designated duty cycle:

- *Peaking* capacity was modeled, effective in 2021 due to the anticipated period required to approve, site, engineer and construct, from:

- A 50% share of two CT units consisting of "F" class turbines with evaporative coolers and dual fuel capability, rated at 500MW total at summer conditions.
- AD units consisting of 2 aeroderivative turbines at 120MW total at summer conditions.
- RICE units consisting of 12 reciprocating engines rated at 220MW total at summer conditions.
- Battery Storage units available in 10MW blocks per year.

- *Intermediate-Baseload* capacity was modeled, effective in 2022 due to anticipated period required to approve, site, engineer and construct, from:
    - A 25% share of a NGCC (2x1 "H" class turbines with duct firing and evaporative inlet air cooling) facility, rated at 1,490MW at summer conditions. The 25% interest assumes SWEPCO coordinates the addition of this resource with other parties.
- Wind resources were made available up to 600MW annually beginning in 2022 (commercial operation date 12/31/21). The resource had a LCOE of \$21.85/MWh in 2021 with an 80% PTC, without congestion and losses. The levelized congestion and losses for the 2021 wind resource is estimated to be approximately \$6/MWh. Wind resources were assumed to have a SPP capacity value equal to 5% of nameplate rating during the first three years and a 30% capacity rating thereafter.

- Large-scale solar resources were made available in two tiers, with up to 150MW of each tier available each year beginning in 2021, for a total of up to 300MW annually. Initial costs for Tier 1 were approximately \$1,180/kW in 2021 with the ITC. Tier 2 has an initial cost of approximately \$1,310/kW in 2021 with the ITC. Solar resources were assumed to have a SPP capacity value equal to 10% of nameplate rating in the first three years and a 33% capacity rating thereafter.

- Short-Term Market Purchase alternative resources were made available to the model for selection during the development of the various optimal plans. These short-term capacity purchases were assumed to have no energy associated with them, a contract term of one year, and 250MW was allowed to be added annually. The pricing of these purchases was based on the SPP Capacity Prices shown in Figure 23. The main purpose of these purchases was to assist in meeting the SPP reserve margin requirement during the initial 3 years after wind and/or large-scale solar resources were added that have limited capacity credits of 5% and 10%, respectively.

- DG, in the form of distributed solar resources, was embedded in amounts equal to a Compound Annual Growth Rate (CAGR) of 4.4% over the planning period.
- CHP resources were made available in 15MW (nameplate) blocks, with an overnight installed cost of $2,100/kW and assuming full host compensation for thermal energy for an effective full load heat rate of ~4,800 Btu/kWh.
- EE resources—incremental to those already incorporated into the Company's long-term load and peak demand forecast in up to 21 unique "bundles" of Residential, Commercial, and Industrial measures considering cost and performance parameters for both HAP and AP categories. Industrial measures were limited to lighting.
- VVO was available in 15 tranches of varying installed costs and number of circuits/sizes ranging from a low of 1.6MW up to 20.7MW of demand savings potential.

5.2.2 Traditional Optimized Portfolios

The key decision to be made by SWEPCO during the planning period is how to fill the resource need identified. Portfolios with various options addressing SWEPCO's capacity and energy resource needs over time were optimized under various conditions. Six traditional scenarios were initially analyzed for this IRP, resulting in six unique portfolios (see Table 10 below). The portfolios discussed below represent incremental resources which are in additional to those currently in-service. The portfolios discussed below represent incremental resources which are in additional to those currently in-service.

Table 10. Traditional Scenarios/Portfolios

Type	Name	Commodity Pricing Conditions	Load Conditions
Commodity Pricing Scenarios	Mid	Mid	Base
	Low Band	Low Band	Base
	High Band	High Band	Base
	Status Quo	No Carbon	Base
Load Scenarios	Low Load	Low Band	Low
	High Load	Low Band	High

5.2.2.1 Base, Low Band, High Band, and Status Quo Commodity Pricing Portfolios

Table 11 below shows the capacity additions associated with the Base, Low Band, and High Band, and Status Quo commodity pricing scenarios. Recall from Section 4.3 that the modeling associated with the Base, Low Band, and High Band scenarios assumed a CO_2 dispatch burden, or allowance value, equal to $15/ton commencing in 2028 and escalating at 5% per annum thereafter on a nominal dollar basis. The Status Quo scenario does not include a CO_2 dispatch burden.

In addition, recall from Sections 4.5.5.1 and 4.5.5.2 that wind and solar tranches were assigned different firm capacity values in Years 1-3 versus Years 4 and onward. As a result, wind and solar firm capacity may not be correlated to nameplate capacity in the same manner under one portfolio when comparing it to another portfolio. For example, all four portfolios show 1,300MW of solar nameplate capacity in 2034. However, each of the portfolios show unique amounts of solar firm capacity in 2034.

Table 11. Cumulative SPP Capacity Additions (MW) and Energy Positions (GWh) for Base, Low Band, High Band, and Status Quo Commodity Pricing Scenarios

Commodity Pricing Scenario		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Base	Base/Intermediate																			373	1,119
	Solar (Firm)							15	30	45	95	144	204	253	303	360	395	429	429	429	429
	Solar (Nameplate)							150	300	450	600	750	1,000	1,150	1,300	1,300	1,300	1,300	1,300	1,300	1,300
	Wind (Firm)				30	60	70	220	370	420	420	450	450	450	600	600	600	600	600	600	600
	Wind (Nameplate)				600	1,200	1,400	1,400	1,400	1,400	1,400	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	Energy Efficiency		8	15	21	20	25	23	20	17	13	12	11	10	7	5	3	3	2	2	1
	VVO		24	24	24	24	24	37	37	37	37	37	37	37	37	48	48	48	48	48	48
	Distr. Gen. (Firm)	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
Low Band	Base/Intermediate																			373	1,119
	Solar (Firm)								15	30	45	95	159	209	258	337	372	406	429	429	429
	Solar (Nameplate)								150	300	450	600	900	1,050	1,200	1,300	1,300	1,300	1,300	1,300	1,300
	Wind (Firm)				30	60	70	220	370	420	420	450	450	450	600	600	600	600	600	600	600
	Wind (Nameplate)				600	1,200	1,400	1,400	1,400	1,400	1,400	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	Energy Efficiency		8	14	19	18	20	19	17	15	11	11	10	8	6	5	3	2	2	1	1
	VVO		24	24	24	24	24	24	24	24	24	24	24	24	35	48	48	48	48	48	48
	Distr. Gen. (Firm)	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
High Band	Base/Intermediate																			373	1,119
	Solar (Firm)						15	30	45	95	154	204	253	326	360	395	429	429	429	429	429
	Solar (Nameplate)						150	300	450	600	850	1,000	1,150	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
	Wind (Firm)				30	60	70	220	370	420	420	450	450	450	600	600	600	600	600	600	600
	Wind (Nameplate)				600	1,200	1,400	1,400	1,400	1,400	1,400	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	Energy Efficiency		8	15	21	20	25	23	20	17	13	12	12	11	8	6	4	3	2	2	1
	VVO		24	24	37	37	37	37	37	37	37	37	46	56	64	75	75	75	75	75	75
	Distr. Gen. (Firm)	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
Status Quo	Base/Intermediate																			373	1,119
	Solar (Firm)								15	30	45	95	144	194	243	293	337	372	406	429	429
	Solar (Nameplate)								150	300	450	600	750	900	1,050	1,200	1,300	1,300	1,300	1,300	1,300
	Wind (Firm)				30	60	70	220	370	420	420	450	450	450	600	600	600	600	600	600	600
	Wind (Nameplate)				600	1,200	1,400	1,400	1,400	1,400	1,400	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	Energy Efficiency		8	15	21	19	25	23	20	17	12	11	10	8	6	5	2	2	2	1	1
	VVO		24	24	24	24	24	24	24	24	24	24	24	37	48	48	48	48	48	48	48
	Distr. Gen. (Firm)	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8

All four portfolios include similar resource additions, such as:

- Wind resources of 600MW (nameplate) beginning in 2022 and totaling 2,000MW (nameplate) by 2029;
- Solar resources of 150MW (nameplate) beginning as early as 2024 and totaling 1,300MW (nameplate) by the end of the planning period; and
- EE programs including CVR totaling 49MW or more by 2038.

All four portfolios result in SWEPCO having a positive annual net energy position in the last year of the planning period, 2038.

5.2.2.2 Load Sensitivity Scenario Portfolios

Table 12 below shows the capacity additions associated with the Low Load and High Load sensitivity scenarios, using Base commodity prices.

Table 12. Cumulative SPP Capacity Additions (MW) and Energy Positions (GWh) for Low Load and High Load Sensitivity Scenarios

Load Sensitivities		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Low Load	Base/Intermediate																				373
	Solar (Firm)							15	30	45	95	144	204	253	303	360	395	429	429	429	429
	Solar (Nameplate)							150	300	450	600	750	1,000	1,150	1,300	1,300	1,300	1,300	1,300	1,300	1,300
	Wind (Firm)				30	60	70	220	370	420	420	450	450	450	600	600	600	600	600	600	600
	Wind (Nameplate)				600	1,200	1,400	1,400	1,400	1,400	1,400	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	Energy Efficiency		8	15	21	20	25	23	20	17	13	12	11	10	7	5	3	3	2	2	1
	VVO		24	24	24	24	24	37	37	37	37	37	37	37	37	48	48	48	48	48	48
	Distr. Gen. (Firm)	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
High Load	Base/Intermediate																		373	1,119	1,492
	Solar (Firm)							15	30	45	95	144	204	253	303	360	395	429	429	429	429
	Solar (Nameplate)							150	300	450	600	750	1,000	1,150	1,300	1,300	1,300	1,300	1,300	1,300	1,300
	Wind (Firm)				30	60	70	220	370	420	420	450	450	450	600	600	600	600	600	600	600
	Wind (Nameplate)				600	1,200	1,400	1,400	1,400	1,400	1,400	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	Energy Efficiency		8	15	21	20	25	23	20	17	13	12	11	10	7	5	3	3	2	2	1
	VVO		24	24	24	24	24	37	37	37	37	37	37	37	37	48	48	48	48	48	48
	Distr. Gen. (Firm)	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8

As expected, the overall capacity additions in the High Load scenario are naturally greater than those in the Low Load scenario. The High Load scenario calls for a 1,492MW natural gas combined cycle (NGCC) resource for base/intermediate capacity by the end of the planning period whereas the Low Load calls for only a 373MW NGCC by the end of the planning period.

5.3 Preferred Plan

Each of the six scenarios provides insight into a potential alternative mix of resources for the future. Given that the resource additions under the four commodity pricing scenarios offer comparable resource additions, SWEPCO has elected to use the Base commodity pricing scenario as its Preferred Plan.

This plan was developed based on the following considerations:

- Minimizing revenue requirements (i.e. cost to customers) over the planning period, while meeting capacity obligations
- Optimizes the mix of generation to hedge short-term energy price volatility in the SPP Integrated Marketplace.
- Installing economical VVO and other incremental DSM.
- Adding renewable energy resources (wind and solar) in a cost effective manner.

The cumulative capacity additions associated with the Preferred Plan are shown below in Table 13.

Table 13. Cumulative SPP Capacity Additions (MW) and Average Annual Energy Position (GWh) for Preferred Plan

Preferred Plan		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Base Commodity, Base Load	Base/Intermediate																			373	1,119
	Solar (Firm)							15	30	45	95	144	204	253	303	360	395	429	429	429	429
	Solar (Nameplate)							150	300	450	600	750	1,000	1,150	1,300	1,300	1,300	1,300	1,300	1,300	1,300
	Wind (Firm)				30	60	70	220	370	420	420	450	450	450	600	600	600	600	600	600	600
	Wind (Nameplate)				600	1,200	1,400	1,400	1,400	1,400	1,400	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	Energy Efficiency		8	15	21	20	25	23	20	17	13	12	11	10	7	5	3	3	2	2	1
	VVO		24	24	24	24	24	37	37	37	37	37	37	37	37	48	48	48	48	48	48
	Distr. Gen. (Firm)	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
Capacity Reserves (MW) Above SPP Requirement without New Additions		449	519	419	386	258	237	109	(22)	(101)	(121)	(159)	(348)	(376)	(404)	(497)	(521)	(552)	(946)	(1,330)	(1,886)
Capacity Reserves (MW) Above SPP Requirement with New Additions		452	553	462	465	366	360	409	439	423	448	490	359	379	548	522	531	534	140	129	318

In conjunction with the Company's five-year action plan, the Preferred Plan offers SWEPCO significant flexibility should future conditions differ considerably from its assumptions. For example, as EE programs are implemented, SWEPCO will gain insight into customer acceptance and develop additional hard data as to the impact these programs have on load growth. This will assist SWEPCO in determining whether to expand program offerings, change incentive levels for programs, or target specific customer classes for the best results. If current long-term renewable costs assumptions change, SWEPCO could either accelerate or delay the installation of renewable generation facilities. Changes to SWEPCO's existing portfolio associated with this Preferred Plan are described in greater detail in Section 0 of this report.

5.3.1 Demand-Side Resources

In the Preferred Plan, incremental EE resources were selected beginning in 2020 and throughout the remainder of the planning period. Economic savings are attributable to both Commercial/Industrial and Residential programs, with the majority coming from Commercial/Industrial Lighting programs. By 2038, overall EE savings – consisting of Other Energy Efficiency, Existing DSM Programs, and Incremental DSM Programs – provide a decrease in residential and commercial energy usage of approximately 5.5% (see Figure 33 below).

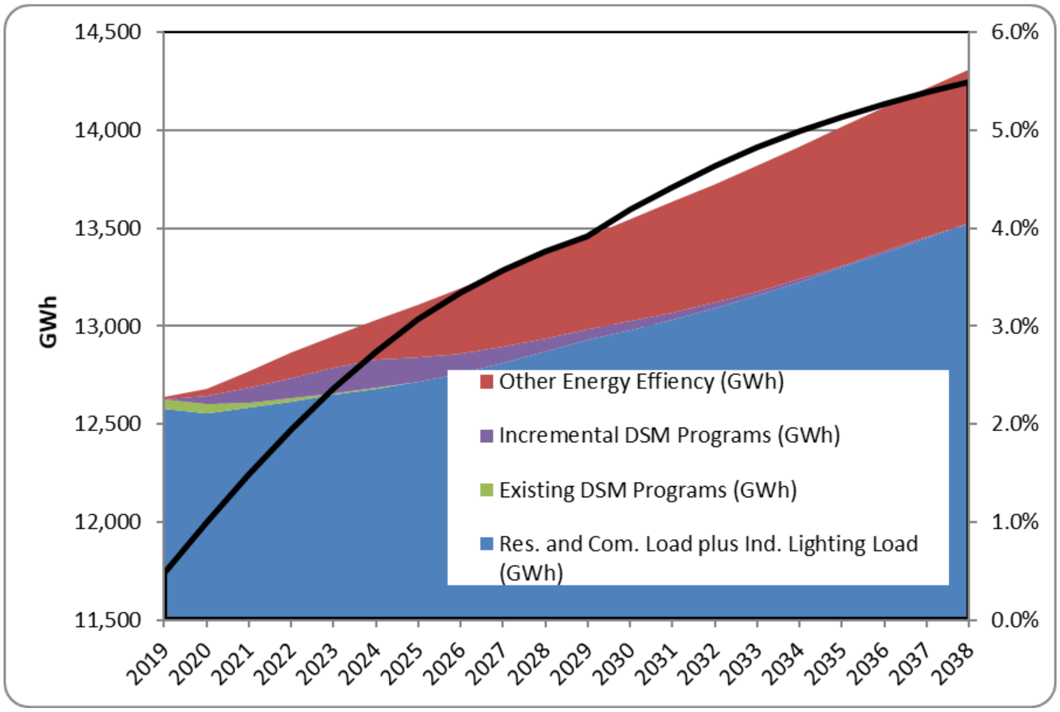

Figure 33. SWEPCO Energy Efficiency Savings According to Preferred Plan

As part of the Preferred Plan, three of the fifteen available VVO tranches are proposed additions, which results in a cumulative capacity reduction of 48MW by 2038. The three tranches of circuits are added from 2020 through 2033.

DG (i.e. rooftop solar) resources were not modeled during the planning period. DG resources were added incrementally at a 4.4% compounded annual growth rate (based on nameplate capacity), resulting in a total of 8MW of SPP capacity credit (23MW nameplate) by 2038.

5.4 Risk Analysis

In addition to comparing the Preferred Plan to the optimized portfolios under a variety of pricing assumptions, the Preferred Plan and an alternative portfolio were also evaluated using a stochastic, or "Monte Carlo" modeling technique where input variables are randomly selected from a universe of possible values, given certain standard deviation constraints and correlative relationships. This offers an additional approach by which to "test" the Preferred Plan over a distributed range of certain key variables. The output is, in turn, a distribution of possible outcomes, providing insight as to the risk or probability of a higher cost (revenue requirement) relative to the expected outcome.

This study included multiple risk iteration runs performed over the study period with three key price variables (risk factors) being subjected to this stochastic-based risk analysis. The results take the form of a distribution of possible revenue requirement outcomes for each plan. Table 14 below shows the input variables or risk factors within this IRP stochastic analysis and the historical correlative relationships to each other.

Table 14. Risk Analysis Factors and Their Relationships

	Gas	Market Prices	CO_2
Gas	1	0.73	0.97
Market Prices		1	0.76
CO_2			1
Standard Deviation	13%	14%	4%

Comparing the Preferred Plan to an alternative portfolio which is significantly different provides a data point that may be used to evaluate the risk associated with the Preferred Plan. The Preferred Plan has a similar resource profile to other optimized plans, so there would be little difference in the risk profiles between such portfolios and the Preferred Plan, and therefore those portfolios were not included in the stochastic analysis. Instead, a portfolio that does not contain any renewable resources was used for comparison. This allows SWEPCO to determine if the renewable resources in the Preferred Plan introduce more risk than relying on no renewable additions. The range of values associated with the variable inputs is shown in Figure 34.

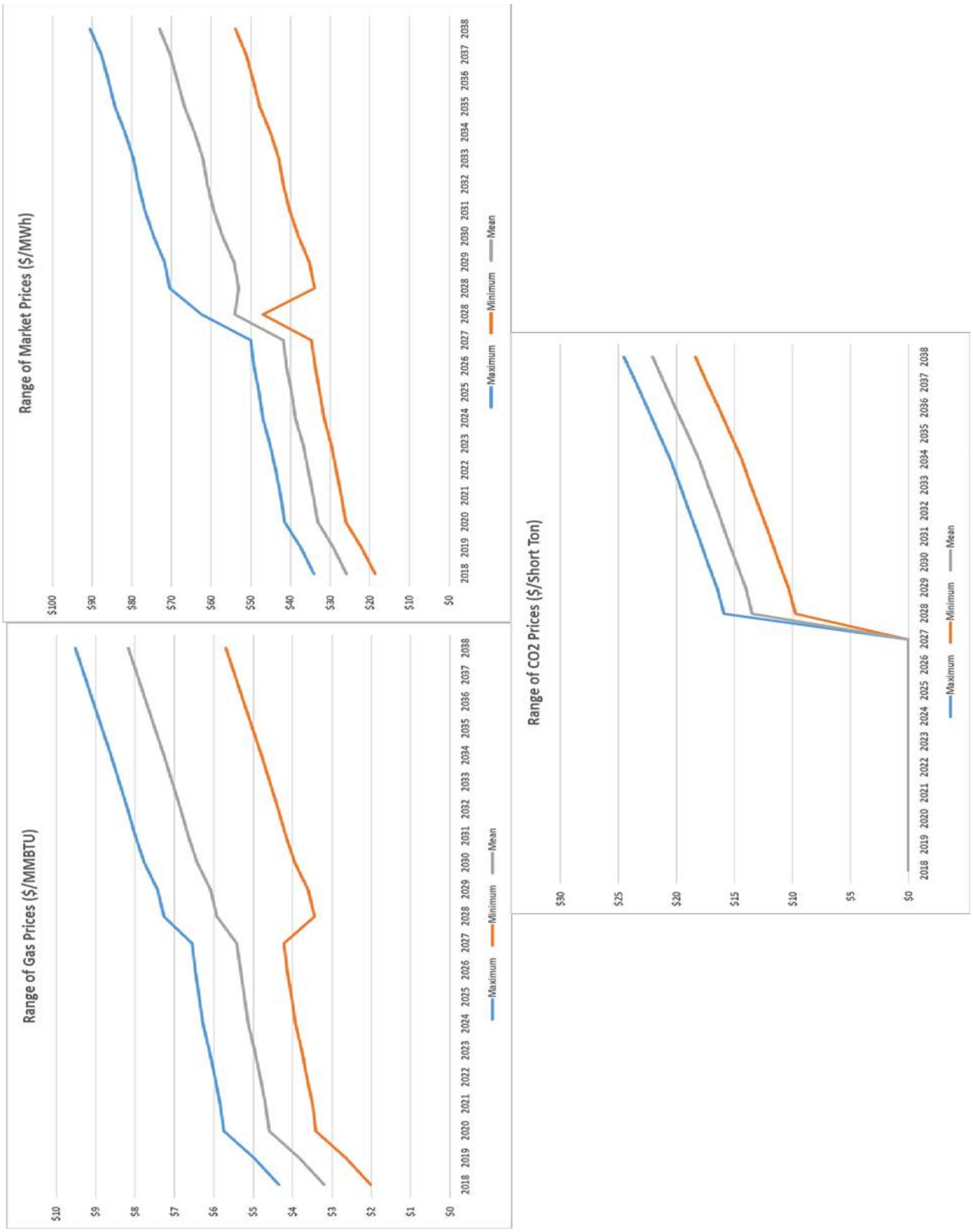

Figure 34. Range of Variable Inputs for Stochastic Analysis

5.4.1 Stochastic Modeling Process and Results

For each portfolio, the results of 100 random iterations are sorted from lowest cost to highest cost, with the differential between the median and higher percentile result from the multiple runs identified as Revenue Requirement at Risk (RRaR). For example, the 95th percentile is a level of required revenue sufficiently high that it will be exceeded, assuming the given plan is adopted, only five percent of the time. Thus, it is 95 percent likely that those higher-ends of revenue requirements would not be exceeded. The larger the RRaR, the greater the likelihood that customers could be subjected to higher costs relative to the portfolio's mean or expected cost. Conversely, there is equal likelihood that costs may be lower than the median value. These higher or lower costs are generally the result of the difference, or spread, between fuel prices and resultant SPP market energy prices. The greater that spread, the more "margin" is enjoyed by the Company and its customers. Figure 35 illustrates the RRaR (expressed in terms of incremental cost over the 50th percentile).

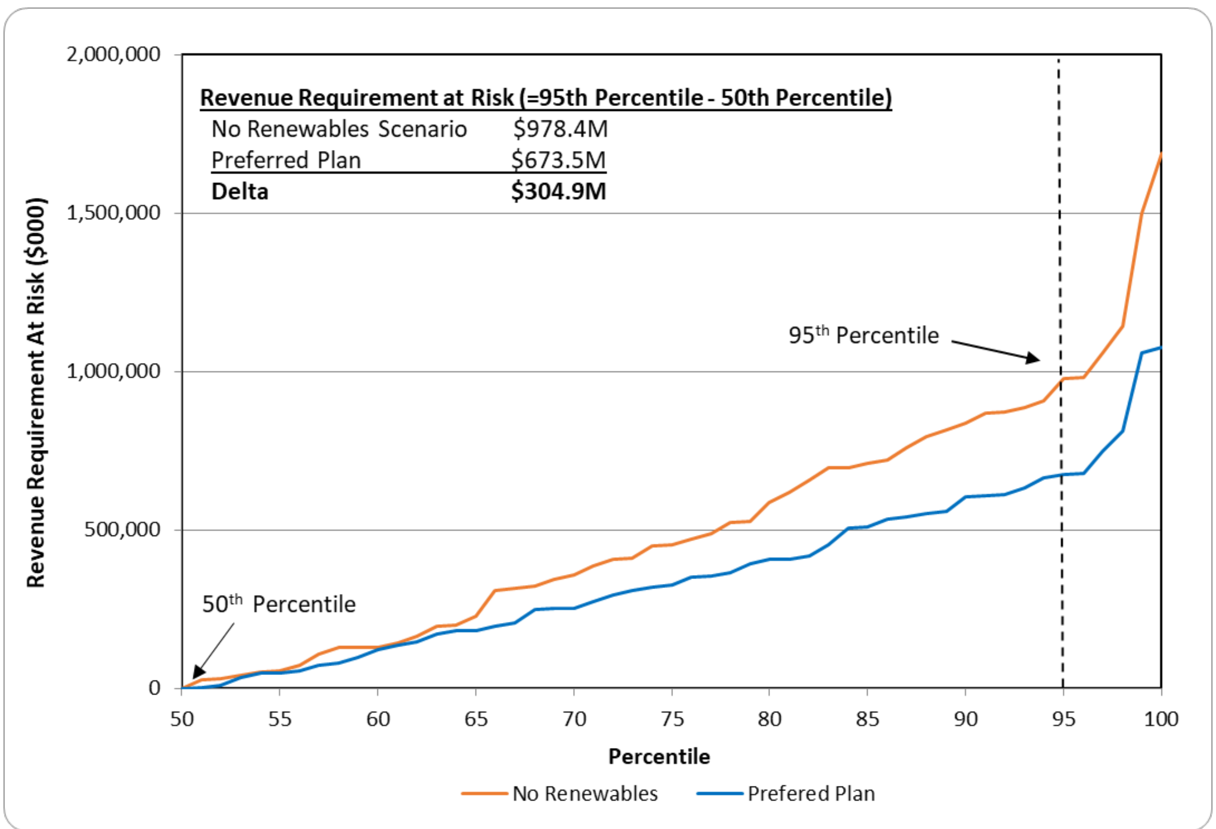

Figure 35. Revenue Requirement at Risk (RRaR) ($000) for Select Portfolios

The difference in RRaR between the two portfolios that were analyzed over the 100 simulations shows the Preferred Plan being less risky by about $305M, which indicates that the additional renewable generation in the Preferred Plan does not introduce significant additional risk.

Based on the risk modeling performed, it is reasonable to conclude that the inherent risk characteristics of the Preferred Plan, which includes a higher level of renewable resources, is significantly less than a portfolio with no renewable resources. This suggests that the Preferred Plan represents a reasonable combination of expected costs and risk.

6.0 Conclusions and Five-Year Action Plan

SWEPCO used the modeling results to develop a Preferred Plan or “Plan”. To arrive at the Preferred Plan, using Plexos®, SWEPCO developed optimal portfolios based on four long-term commodity price forecasts and two load sensitivities. The Preferred Plan balances cost and other factors such as risk and environmental regulatory considerations, to cost effectively meet SWEPCO’s demand and energy obligations. Given that the optimal portfolios under the four commodity pricing scenarios offer comparable resource additions, SWEPCO has elected to use the Base commodity pricing scenario as its Preferred Plan.

Table 15 provides a summary of the Preferred Plan, which was selected based on the results from optimization modeling under various load and commodity pricing scenarios:

Table 15. Preferred Plan Cumulative Capacity Additions throughout Planning Period (2019-2038)

Preferred Plan		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Base Commodity, Base Load	Base/Intermediate																			373	1,119
	Solar (Firm)							15	30	45	95	144	204	253	303	360	395	429	429	429	429
	Solar (Nameplate)							150	300	450	600	750	1,000	1,150	1,300	1,300	1,300	1,300	1,300	1,300	1,300
	Wind (Firm)				30	60	70	220	370	420	420	450	450	450	600	600	600	600	600	600	600
	Wind (Nameplate)				600	1,200	1,400	1,400	1,400	1,400	1,400	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	Energy Efficiency		8	15	21	20	25	23	20	17	13	12	11	10	7	5	3	3	2	2	1
	VVO		24	24	24	24	24	37	37	37	37	37	37	37	37	48	48	48	48	48	48
	Distr. Gen. (Firm)	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
Capacity Reserves (MW) Above SPP Requirement without New Additions		449	519	419	386	258	237	109	(22)	(101)	(121)	(159)	(348)	(376)	(404)	(497)	(521)	(552)	(946)	(1,330)	(1,886)
Capacity Reserves (MW) Above SPP Requirement with New Additions		452	553	462	465	366	360	409	439	423	448	490	359	379	548	522	531	534	140	129	318

In summary, the Preferred Plan:

- Adds utility-scale solar resources in 2025 through 2032, for a total of 1,300MW (nameplate) of utility-scale solar by the end of the planning period.
- Adds 600MW (nameplate) of wind resources in 2022 and 2023 and 200MW (nameplate) in 2024, with additional wind resources added through 2029, for a total of 2,000MW (nameplate) by the end of the planning period.
- Implements customer and grid energy efficiency programs, including VVO, reducing energy requirements by 202GWh and capacity requirements by 49MW by 2038.
- Fills long-term needs through the addition of a total of 1,119MW of natural gas combined-cycle generation in 2037 and 2038 to replace planned unit retirements.
- Recognizes additional distributed solar capacity will be added by SWEPCO's customers, beginning with 10MW (nameplate) in 2019 and ramping up to 24MW (nameplate) by 2038.

SWEPCO capacity changes over the 20-year planning period associated with the Preferred Plan are shown in Figure 36 and Figure 37.

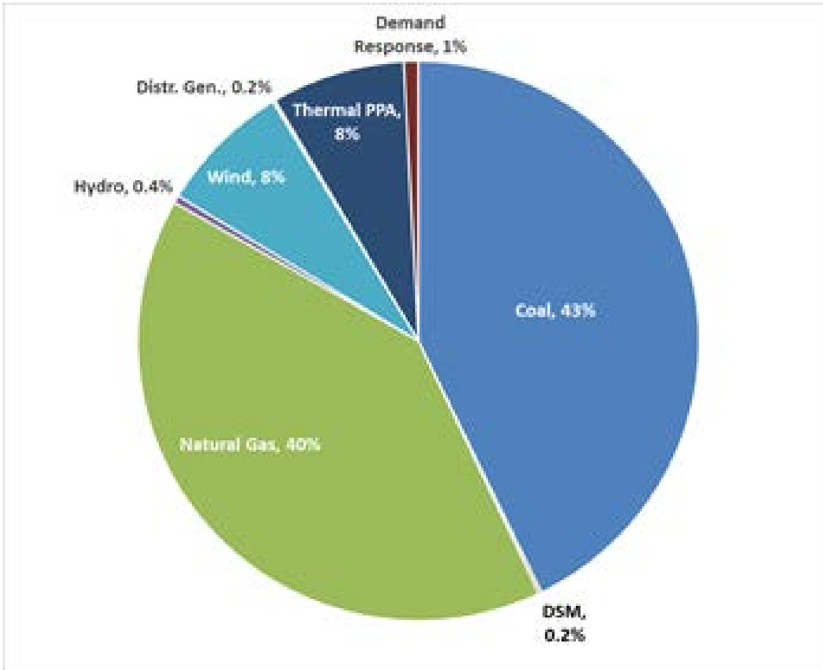

Figure 36. 2019 SWEPCO Nameplate Capacity Mix

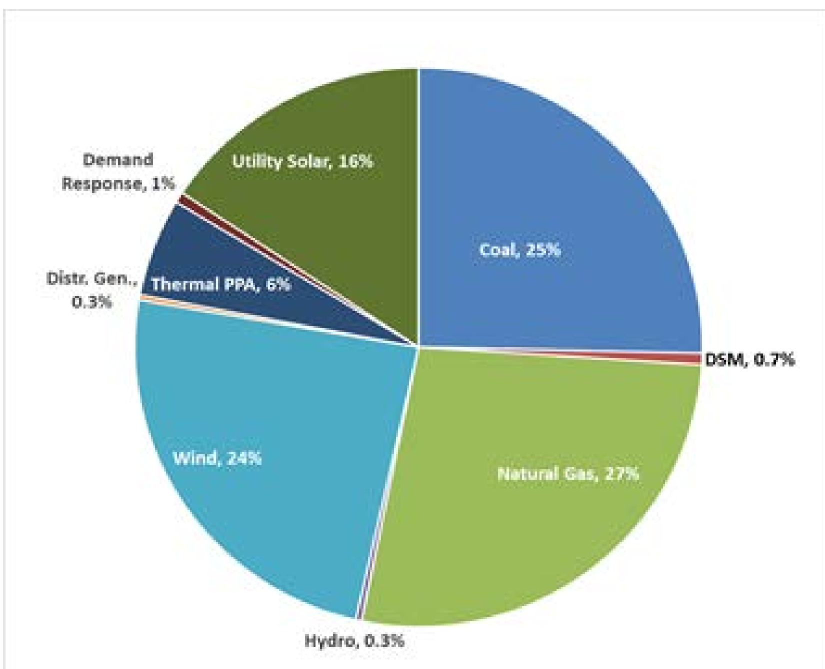

Figure 37. 2038 SWEPCO Nameplate Capacity Mix

The relative impacts to SWEPCO's annual energy position are shown in Figure 38 and Figure 39.

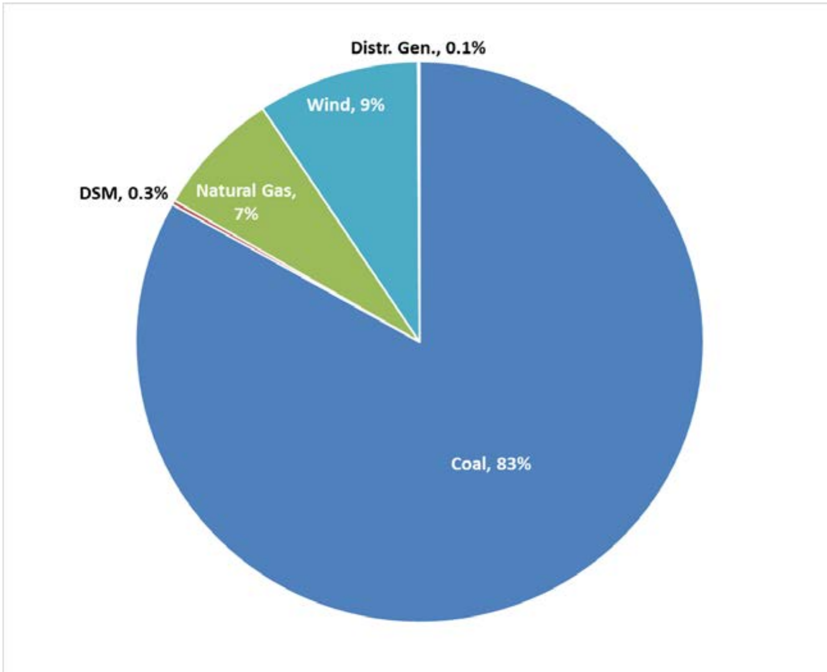

Figure 38. 2019 SWEPCO Energy Mix

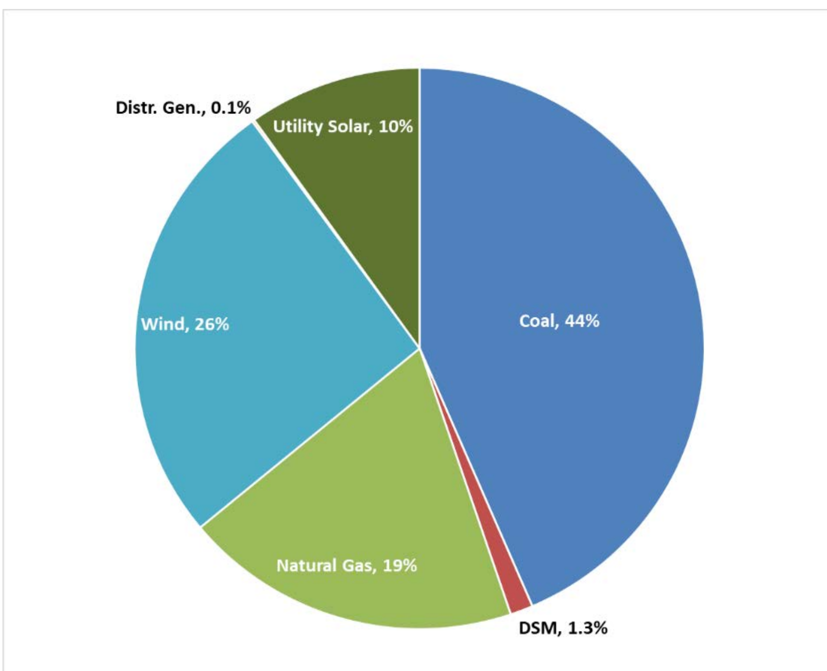

Figure 39. 2039 SWEPCO Energy Mix

Figure 36 through Figure 39 indicate that this Preferred Plan would reduce SWEPCO's reliance on solid fuel-based generation, and increase reliance on demand-side, natural gas, and renewable resources. Specifically, over the 20-year planning horizon the Company's nameplate capacity mix attributable to solid fuel-fired assets declines from 43% to 25%, and natural gas assets would decrease from 40% to 27%. Solar assets make up 16% of the capacity mix and wind assets increase to 24%. Demand-side management (DSM) resources are added to the mix at 0.7% of total nameplate capacity resources.

SWEPCO's energy output attributable to solid fuel generation decreases from 83% to 44% over the planning period, while energy from natural gas resources increases from 7% to 19%. The Preferred Plan introduces solar resources, which contributes to 10% of total energy. Additionally, energy from wind resources increases from 9% to 26%, while DSM resources increase from 0.3% to 1.3% of SWEPCO's total energy mix.

Figure 40 and Figure 41 show annual changes in capacity and energy mix, respectively, that result from the Preferred Plan, relative to capacity and energy requirements. The capacity contribution from renewable resources is fairly modest due to the treatment of capacity credit for intermittent resources within SPP; however, those resources (particularly wind) provide a significant volume of energy. Wind resources were selected in all of the scenarios because they were a low cost energy resource. When comparing the capacity values in Figure 40 with those in Figure 36 and Figure 37, it is important to note that Figure 40 provides an analysis of SPP-recognized capacity, while Figure 36 and Figure 37 depict nameplate capacity.

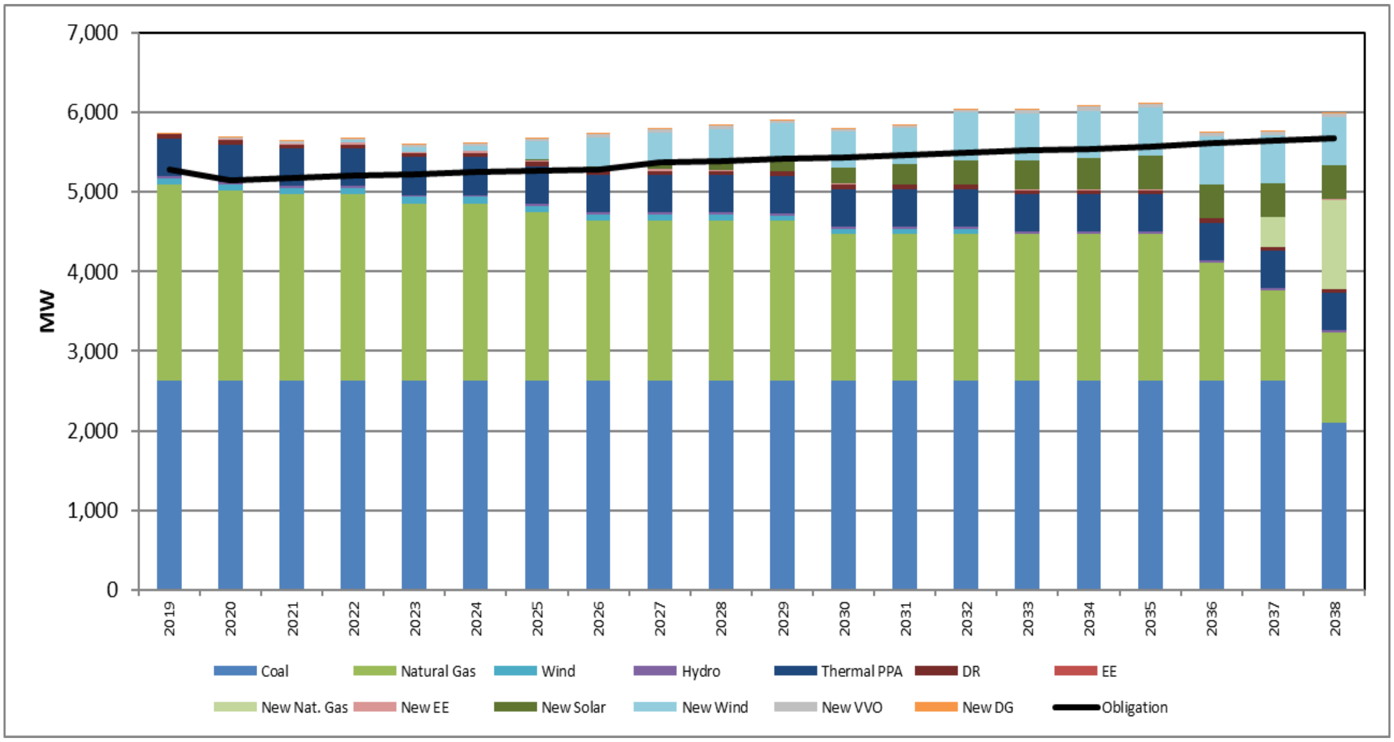

Figure 40. SWEPCO Annual SPP Capacity Position (MW) per the Preferred Plan

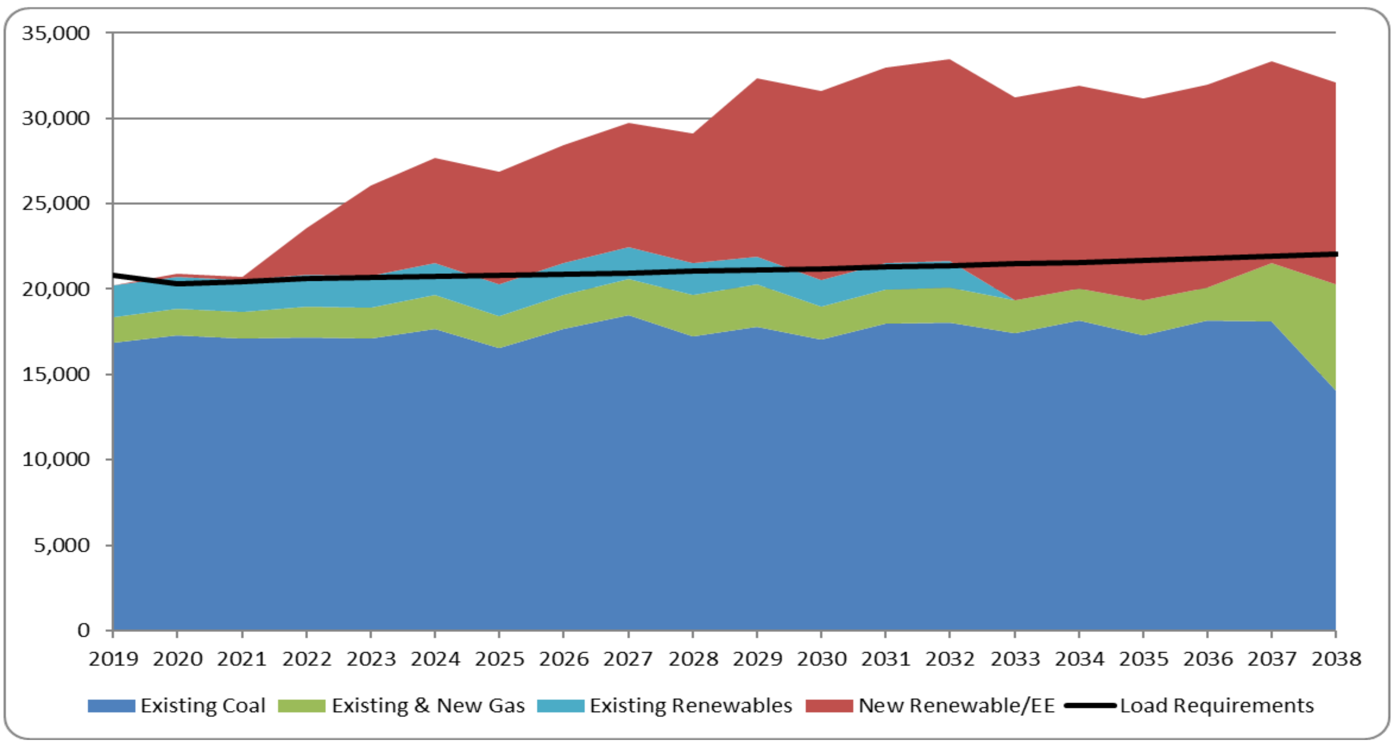

Figure 41. SWEPCO Annual Energy Position (GWh) per the Preferred Plan

SWEPCO Five-Year Action Plan

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

1. Continue the planning and regulatory actions necessary to implement economic DSM programs in Arkansas, Louisiana and Texas.
2. Continue with the recently released Request for Proposal (RFP) to explore opportunities to add cost-effective wind generation in the near future to take advantage of the Federal Production Tax Credit.
3. Consider conducting an RFP to explore adding cost effective utility-scale solar resources.
4. Be ready to adjust this Action Plan and future IRPs to reflect changing circumstances.

6.1 Plan Summary

SWEPCO's Preferred Plan provides the Company with an increasingly diversified portfolio of supply- and demand-side resources which provides flexibility to adapt to future changes to the power market, technology, and environmental regulations. The addition of renewables and demand-side management mitigates fuel price and environmental compliance risk. At the end of the planning period efficient natural gas-fired generation will replace the capacity from solid fuel units that are planned for retirement.

Inasmuch as there are many assumptions, each with its own degree of uncertainty, which had to be made in the course of resource portfolio evaluations, material changes in these assumptions could result in modifications. The action plan presented in this IRP is sufficiently flexible to accommodate possible changes in key parameters, including load growth, environmental compliance assumptions, fuel costs, and construction cost estimates, which may impact this IRP. By minimizing SWEPCO's costs in the optimization process, the Company's model produced optimized portfolios with the lowest reasonable impact on customers' rates.

Appendix

Exhibit A Load Forecast Tables

Southwestern Electric Power Company
Actual and Forecast Internal Energy Requirements (GWh)
By Customer Class
Table A-1

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other** Energy Requirements	Growth Rate	Internal Energy Requirements	Growth Rate
Actual										
2008	5,694	---	5,994	---	5,402	---	6,677	---	23,767	---
2009	5,587	-1.9	5,957	-0.6	4,460	-17.4	6,945	4.0	22,949	-3.4
2010	6,361	13.9	6,141	3.1	5,230	17.2	7,495	7.9	25,227	9.9
2011	6,908	8.6	6,280	2.3	5,408	3.4	7,480	-0.2	26,077	3.4
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	5,896	-2.8	5,268	3.8	6,817	-3.6	23,884	-2.0
Forecast										
2018*	6,292	6.6	5,951	0.9	5,268	0.0	6,105	-10.5	23,616	-1.1
2019	6,188	-1.7	5,964	0.2	5,290	0.4	6,071	-0.6	23,513	-0.4
2020	6,183	-0.1	5,965	0.0	5,334	0.8	5,519	-9.1	23,002	-2.2
2021	6,169	-0.2	5,963	0.0	5,374	0.7	5,598	1.4	23,104	0.4
2022	6,168	0.0	5,989	0.4	5,417	0.8	5,638	0.7	23,212	0.5
2023	6,168	0.0	6,006	0.3	5,433	0.3	5,672	0.6	23,279	0.3
2024	6,165	0.0	6,016	0.2	5,439	0.1	5,704	0.6	23,323	0.2
2025	6,173	0.1	6,029	0.2	5,437	0.0	5,720	0.3	23,359	0.2
2026	6,207	0.5	6,047	0.3	5,431	-0.1	5,742	0.4	23,428	0.3
2027	6,256	0.8	6,068	0.3	5,427	-0.1	5,769	0.5	23,521	0.4
2028	6,310	0.9	6,092	0.4	5,434	0.1	5,796	0.5	23,632	0.5
2029	6,367	0.9	6,115	0.4	5,443	0.2	5,824	0.5	23,749	0.5
2030	6,417	0.8	6,133	0.3	5,449	0.1	5,849	0.4	23,848	0.4
2031	6,467	0.8	6,155	0.3	5,456	0.1	5,872	0.4	23,950	0.4
2032	6,513	0.7	6,179	0.4	5,463	0.1	5,897	0.4	24,052	0.4
2033	6,558	0.7	6,206	0.4	5,472	0.2	5,922	0.4	24,158	0.4
2034	6,603	0.7	6,237	0.5	5,485	0.2	5,948	0.4	24,272	0.5
2035	6,644	0.6	6,270	0.5	5,498	0.3	5,974	0.4	24,386	0.5
2036	6,688	0.7	6,302	0.5	5,512	0.2	5,997	0.4	24,499	0.5
2037	6,730	0.6	6,335	0.5	5,526	0.3	6,025	0.5	24,616	0.5
2038	6,771	0.6	6,367	0.5	5,542	0.3	6,052	0.5	24,732	0.5

Note: *2018 data are three months acutal and nine 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 2008-2017	0.4	-0.2	-0.3	0.2	0.1
Compound Annual Growth Rate 2019-2038	0.5	0.3	0.2	0.0	0.3

Southwestern Electric Power Company-Arkansas
Actual and Forecast Retail Sales (GWh)
By Customer Class
Table A-2 (Page 1)

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other Retail	Growth Rate	Retail Sales	Growth Rate
Actual										
2008	1,113	---	1,367	---	1,646	---	12	---	4,138	---
2009	1,069	-4.0	1,313	-4.0	1,511	-8.2	12	-1.5	3,904	-5.7
2010	1,194	11.7	1,372	4.5	1,593	5.5	12	-1.5	4,170	6.8
2011	1,198	0.4	1,390	1.3	1,575	-1.1	12	2.3	4,175	0.1
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	1,315	-1.2	1,361	-4.5	12	0.6	3,775	-3.0
Forecast										
2018*	1,170	7.6	1,334	1.5	1,340	-1.6	11	-2.3	3,855	2.1
2019	1,153	-1.4	1,329	-0.4	1,362	1.6	12	0.7	3,856	0.0
2020	1,155	0.1	1,328	-0.1	1,373	0.8	12	0.4	3,868	0.3
2021	1,146	-0.8	1,332	0.3	1,383	0.7	12	-0.3	3,872	0.1
2022	1,134	-1.0	1,344	0.9	1,392	0.7	12	0.1	3,882	0.3
2023	1,124	-0.9	1,349	0.4	1,398	0.4	12	0.1	3,882	0.0
2024	1,114	-0.9	1,352	0.2	1,402	0.3	12	-0.1	3,880	-0.1
2025	1,110	-0.3	1,356	0.3	1,407	0.4	12	0.0	3,885	0.1
2026	1,122	1.0	1,361	0.4	1,412	0.3	12	0.0	3,906	0.5
2027	1,141	1.7	1,366	0.4	1,415	0.3	12	0.0	3,934	0.7
2028	1,160	1.7	1,372	0.4	1,419	0.3	12	0.0	3,963	0.7
2029	1,183	2.0	1,378	0.4	1,422	0.2	12	0.0	3,995	0.8
2030	1,208	2.1	1,383	0.4	1,426	0.2	12	0.0	4,028	0.8
2031	1,228	1.7	1,389	0.4	1,429	0.2	12	0.0	4,057	0.7
2032	1,245	1.4	1,395	0.4	1,432	0.2	12	0.0	4,083	0.6
2033	1,259	1.1	1,401	0.4	1,435	0.2	12	0.0	4,106	0.6
2034	1,272	1.0	1,407	0.5	1,438	0.2	12	0.0	4,128	0.5
2035	1,280	0.6	1,414	0.5	1,440	0.2	12	0.0	4,146	0.4
2036	1,288	0.6	1,421	0.5	1,444	0.2	12	0.0	4,164	0.4
2037	1,295	0.6	1,429	0.5	1,447	0.2	12	0.0	4,183	0.4
2038	1,303	0.6	1,436	0.5	1,451	0.2	12	0.0	4,201	0.4

Note: *2018 data are three months acutal and nine months forecast.

	Residential	Commercial	Industrial	Other Retail	Retail Sales
Compound Annual Growth Rate 2008-2017	-0.3	-0.4	-2.1	-0.2	-1.0
Compound Annual Growth Rate 2019-2038	0.6	0.4	0.3	0.0	0.5

Southwestern Electric Power Company-Louisiana
Actual and Forecast Retail Sales (GWh)
By Customer Class
Table A-2 (Page 2)

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other Retail	Growth Rate	Retail Sales	Growth Rate
Actual										
2008	2,405	---	2,344	---	853	---	39	---	5,641	---
2009	2,382	-0.9	2,417	3.1	791	-7.3	39	-0.5	5,630	-0.2
2010	2,804	17.7	2,439	0.9	967	22.2	39	-0.2	6,249	11.0
2011	3,291	17.3	2,525	3.5	1,103	14.1	40	1.8	6,959	11.4
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	2,380	-4.4	1,123	9.5	41	1.0	6,337	-2.1
Forecast										
2018*	2,918	4.5	2,395	0.6	1,127	0.3	40	-1.0	6,480	2.2
2019	2,858	-2.0	2,393	-0.1	1,127	0.0	40	0.1	6,419	-0.9
2020	2,851	-0.3	2,393	0.0	1,127	0.0	40	0.2	6,411	-0.1
2021	2,848	-0.1	2,388	-0.2	1,131	0.3	40	-0.2	6,407	-0.1
2022	2,852	0.1	2,393	0.2	1,137	0.5	40	0.0	6,422	0.2
2023	2,855	0.1	2,399	0.2	1,142	0.5	40	0.0	6,436	0.2
2024	2,857	0.1	2,403	0.2	1,145	0.3	40	0.0	6,446	0.1
2025	2,861	0.1	2,408	0.2	1,147	0.2	40	0.0	6,456	0.2
2026	2,871	0.3	2,414	0.3	1,150	0.2	40	0.0	6,475	0.3
2027	2,886	0.5	2,422	0.3	1,152	0.2	40	0.0	6,500	0.4
2028	2,903	0.6	2,431	0.4	1,155	0.3	40	0.0	6,530	0.5
2029	2,921	0.6	2,440	0.4	1,159	0.3	40	0.0	6,560	0.5
2030	2,934	0.5	2,447	0.3	1,162	0.3	40	0.0	6,584	0.4
2031	2,949	0.5	2,456	0.4	1,166	0.3	40	0.0	6,612	0.4
2032	2,965	0.5	2,467	0.4	1,170	0.4	40	0.0	6,642	0.5
2033	2,981	0.5	2,477	0.4	1,175	0.4	40	0.0	6,674	0.5
2034	2,999	0.6	2,490	0.5	1,180	0.4	40	0.0	6,710	0.5
2035	3,018	0.6	2,503	0.5	1,186	0.5	40	0.0	6,747	0.6
2036	3,037	0.6	2,517	0.6	1,191	0.4	40	0.0	6,786	0.6
2037	3,056	0.6	2,531	0.6	1,196	0.4	40	0.0	6,824	0.6
2038	3,074	0.6	2,544	0.5	1,201	0.4	40	0.0	6,860	0.5

Note: *2018 data are three months acutal and nine months forecast.

	Residential	Commercial	Industrial	Other Retail	Retail Sales
Compound Annual Growth Rate 2008-2017	1.7	0.2	3.1	0.4	1.3
Compound Annual Growth Rate 2019-2038	0.4	0.3	0.3	0.0	0.4

Southwestern Electric Power Company-Texas
Actual and Forecast Retail Sales (GWh)
By Customer Class
Table A-2 (Page 3)

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other Retail	Growth Rate	Retail Sales	Growth Rate
Actual										
2008	2,176	---	2,283	---	2,903	---	31	---	7,393	---
2009	2,136	-1.8	2,228	-2.4	2,158	-25.6	31	-1.3	6,553	-11.4
2010	2,363	10.6	2,330	4.6	2,670	23.7	30	-1.1	7,394	12.8
2011	2,419	2.3	2,365	1.5	2,730	2.3	31	0.7	7,544	2.0
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	2,200	-1.9	2,783	6.1	28	-0.7	7,035	0.5
Forecast										
2018*	2,205	9.0	2,222	1.0	2,801	0.7	27	-2.9	7,256	3.1
2019	2,176	-1.3	2,241	0.9	2,801	0.0	28	0.7	7,246	-0.1
2020	2,177	0.1	2,244	0.1	2,834	1.2	28	0.3	7,283	0.5
2021	2,176	0.0	2,243	-0.1	2,861	0.9	28	-0.1	7,307	0.3
2022	2,182	0.3	2,252	0.4	2,888	0.9	28	0.2	7,349	0.6
2023	2,188	0.3	2,259	0.3	2,894	0.2	28	0.2	7,368	0.3
2024	2,194	0.2	2,261	0.1	2,892	-0.1	28	0.0	7,374	0.1
2025	2,202	0.4	2,266	0.2	2,882	-0.3	28	0.1	7,378	0.0
2026	2,215	0.6	2,272	0.3	2,870	-0.4	28	0.1	7,385	0.1
2027	2,230	0.7	2,280	0.3	2,860	-0.4	28	0.1	7,398	0.2
2028	2,246	0.7	2,289	0.4	2,860	0.0	28	0.1	7,423	0.3
2029	2,263	0.7	2,297	0.3	2,862	0.1	28	0.1	7,450	0.4
2030	2,276	0.6	2,303	0.2	2,861	0.0	28	0.1	7,467	0.2
2031	2,289	0.6	2,310	0.3	2,861	0.0	28	0.1	7,488	0.3
2032	2,303	0.6	2,318	0.4	2,861	0.0	28	0.0	7,510	0.3
2033	2,317	0.6	2,328	0.4	2,863	0.1	28	0.0	7,536	0.3
2034	2,332	0.6	2,340	0.5	2,867	0.1	28	0.1	7,566	0.4
2035	2,347	0.7	2,352	0.5	2,872	0.2	28	0.1	7,599	0.4
2036	2,363	0.7	2,363	0.5	2,877	0.2	28	0.0	7,632	0.4
2037	2,379	0.7	2,375	0.5	2,883	0.2	28	0.1	7,665	0.4
2038	2,394	0.6	2,387	0.5	2,890	0.2	28	0.1	7,699	0.4

Note: *2018 data are three months acutal and nine months forecast.

	Residential	Commercial	Industrial	Other Retail	Retail Sales
Compound Annual Growth Rate 2008-2017	-0.8	-0.4	-0.5	-1.1	-0.5
Compound Annual Growth Rate 2019-2038	0.5	0.3	0.2	0.1	0.3

Southwestern Electric Power Company
Winter, Summer and Annual Peak Demand (MW)
Internal Energy Requirements (GWh) and Load Factor (%)
Table A-3

Year	Summer Peak Demand	Preceding Winter Peak Demand	Annual Peak Demand	Internal Energy Requirements	Load Factor
Actual					
2008	4,950	3,992	4,950	23,767	54.7
2009	4,750	3,909	4,750	22,949	55.2
2010	4,994	4,539	4,994	25,227	57.7
2011	5,554	4,823	5,554	26,077	53.6
2012	5,205	4,080	5,205	25,188	55.1
2013	5,048	4,178	5,048	25,484	57.6
2014	4,836	4,919	4,919	25,516	59.2
2015	5,149	4,708	5,149	25,115	55.7
2016	4,921	4,051	4,921	24,360	56.4
2017	4,769	4,419	4,769	23,884	57.2
Forecast					
2018*	4,803	4,792	4,803	23,616	56.1
2019	4,782	4,267	4,782	23,513	56.1
2020	4,648	4,109	4,648	23,002	56.3
2021	4,685	4,138	4,685	23,104	56.3
2022	4,715	4,157	4,715	23,212	56.2
2023	4,727	4,181	4,727	23,279	56.2
2024	4,744	4,189	4,744	23,323	56.0
2025	4,754	4,196	4,754	23,359	56.1
2026	4,770	4,208	4,770	23,428	56.1
2027	4,795	4,222	4,795	23,521	56.0
2028	4,818	4,248	4,818	23,632	55.8
2029	4,842	4,268	4,842	23,749	56.0
2030	4,867	4,283	4,867	23,848	55.9
2031	4,895	4,299	4,895	23,950	55.9
2032	4,922	4,320	4,922	24,052	55.6
2033	4,950	4,329	4,950	24,158	55.7
2034	4,971	4,358	4,971	24,272	55.7
2035	5,000	4,376	5,000	24,386	55.7
2036	5,030	4,396	5,030	24,499	55.4
2037	5,058	4,412	5,058	24,616	55.6
2038	5,086	4,430	5,086	24,732	55.5

Note: *2018 data are three months acutal and nine months forecast.

	Summer Peak Demand	Preceding Winter Peak Demand	Annual Peak Demand	Internal Energy Requirements	Load Factor
Compound Annual Growth Rate 2008-2017	-0.4	1.1	-0.4	0.1	0.5
Compound Annual Growth Rate 2019-2038	0.3	0.2	0.3	0.3	-0.1

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

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2007	1	519.6	458.9	472.3	546.5	1,997.3
2007	2	453.0	390.0	391.4	534.0	1,768.3
2007	3	353.8	434.6	471.4	421.7	1,681.6
2007	4	301.4	447.9	471.8	408.7	1,629.8
2007	5	421.0	518.9	524.2	399.2	1,863.3
2007	6	516.5	542.8	494.9	505.3	2,059.5
2007	7	595.9	560.0	484.7	602.1	2,242.6
2007	8	719.3	650.0	521.3	529.6	2,420.3
2007	9	565.1	538.1	432.5	566.0	2,101.7
2007	10	415.3	511.4	459.4	454.9	1,841.0
2007	11	312.3	453.7	448.2	479.9	1,694.1
2007	12	455.1	464.1	434.6	585.6	1,939.5
2008	1	563.7	458.7	408.8	544.9	1,976.1
2008	2	436.2	420.2	409.2	464.6	1,730.2
2008	3	390.7	455.1	409.4	443.4	1,698.7
2008	4	297.0	433.9	481.9	420.4	1,633.2
2008	5	386.4	524.3	490.0	474.7	1,875.4
2008	6	608.1	578.2	474.5	604.7	2,265.6
2008	7	704.2	625.0	482.6	654.0	2,465.8
2008	8	658.6	563.2	450.2	688.2	2,360.2
2008	9	446.7	508.8	456.7	724.4	2,136.6
2008	10	333.9	491.7	470.5	484.8	1,780.9
2008	11	317.7	442.1	450.5	496.4	1,706.7
2008	12	550.7	492.3	417.6	606.0	2,066.6
2009	1	517.8	419.7	321.1	551.5	1,810.1
2009	2	388.3	376.2	322.8	523.4	1,610.7
2009	3	377.0	467.0	376.2	460.0	1,680.2
2009	4	332.1	446.1	364.1	465.9	1,608.3
2009	5	389.5	517.2	403.3	638.6	1,948.6
2009	6	577.2	610.5	421.4	691.9	2,301.1
2009	7	748.2	589.8	346.5	734.4	2,419.0
2009	8	630.4	601.0	411.4	709.2	2,352.0
2009	9	464.9	523.1	371.5	626.4	1,985.8
2009	10	328.0	475.4	378.1	474.0	1,655.4
2009	11	295.1	433.7	369.4	480.6	1,578.8
2009	12	538.6	497.6	374.6	595.2	2,005.9
2010	1	650.6	453.3	346.8	643.6	2,094.4
2010	2	505.4	466.7	371.3	576.2	1,919.6
2010	3	443.0	418.5	403.9	463.8	1,729.1
2010	4	294.3	442.6	439.8	446.0	1,622.7
2010	5	405.6	534.2	470.6	467.8	1,878.3
2010	6	690.5	621.4	472.6	601.0	2,385.5
2010	7	752.2	622.4	407.1	608.5	2,390.2
2010	8	767.1	655.1	510.6	729.1	2,661.9
2010	9	586.8	552.7	429.5	594.7	2,163.7
2010	10	422.6	507.9	446.4	502.4	1,879.2

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

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2010	11	299.7	410.5	517.7	475.9	1,703.8
2010	12	543.4	455.9	413.3	553.5	1,966.0
2011	1	656.7	458.9	404.6	671.7	2,191.9
2011	2	575.3	440.2	380.1	504.5	1,900.1
2011	3	372.0	466.5	466.8	496.4	1,801.6
2011	4	405.2	483.7	460.8	448.7	1,798.5
2011	5	479.0	533.4	473.7	531.3	2,017.3
2011	6	761.2	646.6	490.4	605.1	2,503.3
2011	7	904.1	649.1	468.0	715.3	2,736.5
2011	8	931.2	691.4	500.6	722.4	2,845.5
2011	9	536.2	490.9	403.9	508.2	1,939.3
2011	10	384.9	500.1	472.8	468.2	1,825.9
2011	11	356.0	464.7	464.4	475.2	1,760.3
2011	12	545.8	454.8	422.4	530.3	1,953.2
2012	1	567.8	429.1	402.9	729.1	2,128.8
2012	2	417.4	422.7	420.6	508.7	1,769.4
2012	3	396.9	458.8	494.2	515.6	1,865.5
2012	4	368.8	484.4	474.1	460.9	1,788.3
2012	5	514.8	574.7	526.7	501.8	2,118.1
2012	6	686.5	584.1	512.5	650.7	2,433.8
2012	7	784.0	610.6	484.8	702.5	2,582.0
2012	8	790.3	632.2	486.7	680.7	2,590.0
2012	9	545.3	521.3	476.4	545.0	2,088.0
2012	10	378.2	484.9	473.6	463.0	1,799.6
2012	11	353.4	442.1	455.6	485.0	1,736.1
2012	12	497.7	458.3	452.5	701.8	2,110.3
2013	1	630.1	442.5	409.2	725.4	2,207.2
2013	2	390.8	393.1	398.2	629.8	1,811.8
2013	3	472.8	443.7	451.3	537.2	1,904.9
2013	4	390.3	453.6	465.4	461.1	1,770.4
2013	5	429.8	519.0	501.3	660.0	2,110.1
2013	6	626.6	582.6	498.6	634.5	2,342.3
2013	7	695.3	548.7	467.2	710.8	2,422.0
2013	8	750.2	635.5	513.5	782.7	2,681.9
2013	9	635.5	561.1	461.9	625.0	2,283.6
2013	10	414.8	482.6	456.0	498.5	1,851.9
2013	11	357.0	478.0	525.1	547.6	1,907.7
2013	12	638.2	470.3	464.5	682.6	2,255.6
2014	1	711.6	488.7	454.8	727.1	2,382.2
2014	2	550.0	434.6	437.0	546.4	1,968.0
2014	3	485.4	470.0	485.6	501.7	1,942.6
2014	4	312.2	407.0	563.0	468.2	1,750.5
2014	5	389.6	470.6	502.9	550.1	1,913.1
2014	6	576.0	567.8	498.7	705.2	2,347.7
2014	7	640.8	556.2	477.3	828.5	2,502.8
2014	8	750.8	690.1	590.8	830.9	2,862.6

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

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2014	9	557.6	498.4	442.6	697.8	2,196.4
2014	10	408.3	497.7	487.3	491.4	1,884.8
2014	11	387.2	470.8	505.7	478.3	1,842.1
2014	12	541.6	444.4	455.0	655.0	2,096.1
2015	1	674.7	491.3	433.6	597.0	2,196.6
2015	2	495.4	425.4	403.4	563.5	1,887.7
2015	3	536.1	448.9	408.5	473.0	1,866.5
2015	4	316.0	456.1	455.0	455.8	1,682.9
2015	5	428.9	528.0	491.2	568.5	2,016.6
2015	6	597.1	573.0	468.4	660.1	2,298.6
2015	7	778.8	621.6	483.4	769.7	2,653.4
2015	8	750.9	606.4	442.0	700.1	2,499.4
2015	9	557.1	554.0	493.8	649.2	2,254.1
2015	10	406.6	475.7	442.8	525.5	1,850.6
2015	11	344.8	469.6	448.9	545.2	1,808.5
2015	12	449.4	426.4	399.0	615.2	1,890.0
2016	1	605.3	492.7	444.0	646.6	2,188.6
2016	2	440.3	385.4	399.7	625.7	1,851.1
2016	3	349.1	423.1	404.3	526.9	1,703.5
2016	4	378.9	483.5	443.7	479.5	1,785.7
2016	5	409.2	501.1	433.3	561.6	1,905.1
2016	6	590.9	573.4	451.6	657.2	2,273.1
2016	7	796.5	611.8	402.9	757.5	2,568.6
2016	8	714.6	605.6	433.5	736.1	2,489.8
2016	9	593.9	575.8	417.5	655.7	2,242.8
2016	10	424.7	483.0	423.7	519.8	1,851.2
2016	11	342.9	466.8	400.0	565.2	1,774.9
2016	12	502.0	462.2	419.5	697.9	2,081.6
2017	1	557.7	454.8	392.1	723.5	2,128.1
2017	2	319.4	350.3	361.1	610.9	1,641.7
2017	3	432.6	500.5	468.6	622.3	2,024.1
2017	4	357.5	436.8	411.6	517.2	1,723.0
2017	5	434.1	507.1	459.3	602.7	2,003.2
2017	6	558.6	539.6	463.6	618.5	2,180.3
2017	7	721.8	593.9	457.1	722.4	2,495.1
2017	8	649.6	551.4	431.6	505.5	2,138.1
2017	9	515.5	531.7	450.7	705.1	2,203.0
2017	10	456.1	488.6	479.1	504.6	1,928.5
2017	11	388.8	471.6	445.2	564.2	1,869.7
2017	12	511.2	469.4	447.9	610.7	2,039.2
2018	1	737.4	462.2	381.9	696.3	2,277.8
2018	2	474.2	406.2	378.8	714.5	1,973.7
2018	3	346.7	419.8	438.2	533.5	1,738.3

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

Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class
Table A-5

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2018	4	338.2	438.5	442.1	440.1	1,659.0
2018	5	446.3	527.9	478.0	353.1	1,805.3
2018	6	587.0	551.9	462.9	509.2	2,111.1
2018	7	732.1	585.5	444.8	668.3	2,430.6
2018	8	713.4	590.1	465.4	630.6	2,399.5
2018	9	590.5	553.0	445.5	478.8	2,067.8
2018	10	389.7	462.9	434.9	465.3	1,752.8
2018	11	350.5	463.6	457.1	410.0	1,681.2
2018	12	586.4	489.1	438.2	501.1	2,014.7
2019	1	602.7	452.0	411.0	615.2	2,080.9
2019	2	448.3	413.8	389.4	510.3	1,761.8
2019	3	407.5	429.4	419.8	479.7	1,736.5
2019	4	339.8	442.9	432.7	447.6	1,663.0
2019	5	455.2	539.6	486.0	324.1	1,804.9
2019	6	591.3	554.3	465.0	497.3	2,107.9
2019	7	729.6	584.0	444.6	678.6	2,436.7
2019	8	716.4	592.4	466.9	620.3	2,396.1
2019	9	589.8	553.2	445.5	484.5	2,073.0
2019	10	387.8	464.5	438.3	465.1	1,755.6
2019	11	342.8	455.7	455.0	425.2	1,678.6
2019	12	576.6	482.1	435.8	523.3	2,017.8
2020	1	595.8	448.6	413.5	562.0	2,019.9
2020	2	464.7	427.1	400.4	482.0	1,774.2
2020	3	407.4	427.2	422.0	442.0	1,698.7
2020	4	340.6	438.7	433.5	416.4	1,629.2
2020	5	455.0	541.7	490.7	271.1	1,758.6
2020	6	587.0	548.6	465.1	466.6	2,067.3
2020	7	721.6	584.6	448.8	620.5	2,375.4
2020	8	698.6	583.9	466.6	584.1	2,333.2
2020	9	584.1	553.5	449.2	442.1	2,028.9
2020	10	385.0	461.7	440.0	426.2	1,713.0
2020	11	365.9	469.6	465.7	340.0	1,641.2
2020	12	576.9	480.3	438.8	466.3	1,962.3
2021	1	596.1	448.8	415.2	566.6	2,026.7
2021	2	447.3	412.8	394.9	472.3	1,727.4
2021	3	415.2	431.9	427.0	449.0	1,723.2
2021	4	342.3	439.7	437.1	420.1	1,639.2
2021	5	449.8	536.9	491.6	292.4	1,770.6
2021	6	589.3	552.3	471.1	469.5	2,082.2
2021	7	720.9	584.9	453.0	629.1	2,387.9
2021	8	701.4	587.7	472.6	593.6	2,355.2
2021	9	582.9	554.1	453.8	452.6	2,043.4
2021	10	385.5	464.2	445.5	425.7	1,720.8
2021	11	362.2	467.2	468.2	350.3	1,647.9
2021	12	576.4	482.5	444.1	476.4	1,979.4
2022	1	596.1	451.6	420.3	571.6	2,039.6

Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class
Table A-5

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2022	2	446.1	413.5	398.6	476.3	1,734.6
2022	3	413.9	432.5	430.3	452.4	1,729.1
2022	4	343.8	442.8	441.7	413.2	1,641.5
2022	5	454.9	545.6	499.1	283.3	1,782.9
2022	6	589.1	554.2	474.6	474.4	2,092.4
2022	7	720.0	586.1	455.8	633.8	2,395.8
2022	8	701.8	590.2	476.0	604.8	2,372.7
2022	9	582.6	556.3	456.7	457.5	2,053.1
2022	10	384.0	465.3	447.7	432.0	1,729.1
2022	11	361.2	468.4	470.2	357.7	1,657.6
2022	12	574.8	482.7	445.4	481.3	1,984.2
2023	1	597.3	454.1	422.7	575.7	2,049.8
2023	2	445.3	414.3	399.9	479.7	1,739.1
2023	3	412.3	432.6	431.1	455.0	1,731.0
2023	4	343.8	444.5	443.1	409.9	1,641.3
2023	5	454.9	547.1	500.5	290.0	1,792.5
2023	6	588.6	555.0	475.6	479.2	2,098.4
2023	7	720.9	588.4	457.5	638.0	2,404.8
2023	8	700.2	590.2	476.6	614.9	2,381.8
2023	9	582.8	557.9	458.2	455.9	2,054.8
2023	10	383.6	466.4	448.8	440.1	1,738.9
2023	11	362.4	471.4	472.5	357.5	1,663.8
2023	12	575.6	484.5	446.9	476.2	1,983.2
2024	1	594.8	453.1	422.4	576.5	2,046.9
2024	2	464.1	432.3	409.6	495.3	1,801.3
2024	3	405.1	428.3	429.4	454.5	1,717.4
2024	4	338.2	441.5	441.8	427.8	1,649.2
2024	5	448.9	541.0	497.3	304.5	1,791.7
2024	6	589.4	556.8	476.7	466.4	2,089.3
2024	7	723.8	591.8	459.2	639.6	2,414.4
2024	8	697.6	588.6	476.0	613.5	2,375.6
2024	9	582.3	558.4	458.3	454.5	2,053.5
2024	10	383.6	467.3	449.1	441.5	1,741.4
2024	11	361.9	471.6	472.2	352.7	1,658.4
2024	12	575.4	485.3	446.8	477.0	1,984.5
2025	1	598.0	455.9	423.3	580.1	2,057.3
2025	2	445.6	415.8	400.5	483.6	1,745.6
2025	3	408.0	429.5	429.0	456.8	1,723.4
2025	4	349.8	451.7	446.5	408.5	1,656.4
2025	5	456.1	549.7	501.3	287.1	1,794.2
2025	6	589.3	557.3	476.1	478.3	2,101.0
2025	7	726.2	595.1	460.0	643.1	2,424.4
2025	8	696.3	588.7	475.3	619.8	2,380.1
2025	9	580.3	557.9	457.3	470.9	2,066.5
2025	10	384.8	469.0	449.1	445.7	1,748.5
2025	11	362.5	472.6	471.8	356.5	1,663.5

Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class
Table A-5

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2025	12	576.1	486.1	446.2	489.6	1,997.9
2026	1	599.3	455.8	422.2	582.0	2,059.2
2026	2	448.2	416.8	400.0	485.6	1,750.5
2026	3	411.5	431.5	429.0	458.4	1,730.5
2026	4	353.5	454.5	446.8	406.0	1,660.7
2026	5	458.9	551.6	501.1	282.6	1,794.3
2026	6	591.9	558.4	475.5	485.7	2,111.5
2026	7	729.4	596.8	459.6	645.3	2,431.1
2026	8	699.8	590.7	475.1	622.0	2,387.6
2026	9	582.5	558.7	456.5	475.6	2,073.3
2026	10	387.2	470.2	448.4	443.4	1,749.3
2026	11	365.2	474.5	471.5	364.1	1,675.3
2026	12	579.4	487.9	445.7	491.7	2,004.7
2027	1	601.8	456.1	420.8	584.0	2,062.7
2027	2	451.4	418.0	399.3	487.6	1,756.4
2027	3	418.7	437.0	430.6	463.4	1,749.8
2027	4	353.6	453.4	444.8	413.6	1,665.5
2027	5	462.4	553.5	500.8	284.2	1,801.0
2027	6	596.9	560.5	475.2	488.2	2,120.8
2027	7	733.8	597.2	458.6	647.5	2,437.0
2027	8	708.2	594.4	475.8	624.9	2,403.3
2027	9	587.7	560.2	456.1	478.1	2,082.1
2027	10	390.9	471.9	448.3	440.2	1,751.3
2027	11	367.9	476.0	471.4	360.6	1,675.9
2027	12	583.1	489.6	445.7	496.8	2,015.2
2028	1	605.9	457.8	420.9	585.3	2,070.0
2028	2	474.9	437.6	408.7	503.6	1,824.8
2028	3	418.7	437.2	430.4	463.8	1,750.1
2028	4	344.2	443.7	439.0	434.8	1,661.7
2028	5	462.5	551.4	499.0	302.2	1,815.2
2028	6	602.4	563.0	475.9	485.1	2,126.4
2028	7	737.0	596.2	457.7	648.5	2,439.3
2028	8	715.2	597.0	476.7	626.5	2,415.4
2028	9	596.4	564.9	458.0	462.2	2,081.5
2028	10	394.2	473.2	448.8	442.8	1,759.0
2028	11	371.0	478.0	472.3	360.8	1,682.1
2028	12	587.4	492.0	446.6	480.8	2,006.8
2029	1	614.6	462.9	423.3	589.8	2,090.7
2029	2	458.8	421.8	400.3	492.4	1,773.3
2029	3	422.4	437.8	430.3	466.4	1,756.9
2029	4	359.4	456.5	445.6	415.8	1,677.4
2029	5	470.3	557.9	502.3	298.2	1,828.7
2029	6	608.2	565.4	476.8	486.8	2,137.2
2029	7	747.7	601.8	459.9	653.3	2,462.7
2029	8	723.7	600.3	478.1	630.8	2,432.9
2029	9	597.4	562.2	456.5	476.6	2,092.7

Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class
Table A-5

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2029	10	398.3	474.9	449.4	454.1	1,776.8
2029	11	374.2	479.7	473.0	369.1	1,696.0
2029	12	591.8	494.0	447.2	490.6	2,023.6
2030	1	618.8	464.4	424.0	592.3	2,099.5
2030	2	461.8	422.8	400.7	494.6	1,779.9
2030	3	423.2	436.7	429.6	467.7	1,757.2
2030	4	364.4	459.9	447.1	417.0	1,688.5
2030	5	474.1	559.9	503.1	298.2	1,835.3
2030	6	613.4	567.3	477.4	484.5	2,142.6
2030	7	756.1	605.5	461.3	656.3	2,479.3
2030	8	728.1	600.2	477.9	633.1	2,439.4
2030	9	602.5	563.4	456.7	484.3	2,106.8
2030	10	402.2	476.4	449.9	456.3	1,784.7
2030	11	377.2	481.2	473.5	367.6	1,699.7
2030	12	595.4	495.4	447.5	497.0	2,035.3
2031	1	622.2	465.8	424.4	594.6	2,106.9
2031	2	464.8	424.1	401.0	496.6	1,786.6
2031	3	425.4	437.6	429.7	469.3	1,762.0
2031	4	368.5	462.7	448.3	416.0	1,695.6
2031	5	478.0	562.1	504.0	294.5	1,838.5
2031	6	618.4	569.2	478.0	491.6	2,157.1
2031	7	763.0	608.0	462.1	659.0	2,492.2
2031	8	732.8	600.6	477.8	635.4	2,446.7
2031	9	609.4	566.5	457.9	488.3	2,122.0
2031	10	405.5	477.6	450.3	458.4	1,791.8
2031	11	380.4	483.4	474.5	365.3	1,703.6
2031	12	598.8	497.0	448.0	503.3	2,047.1
2032	1	621.3	464.3	423.1	594.8	2,103.5
2032	2	485.7	441.8	409.9	512.0	1,849.4
2032	3	431.1	443.5	432.8	473.0	1,780.4
2032	4	358.4	453.0	442.7	443.5	1,697.6
2032	5	477.3	559.4	502.0	298.8	1,837.6
2032	6	623.1	571.3	478.5	494.6	2,167.4
2032	7	765.2	606.8	461.0	659.4	2,492.3
2032	8	739.1	603.3	478.6	636.2	2,457.2
2032	9	618.6	572.0	460.0	475.8	2,126.3
2032	10	409.0	479.6	450.9	444.4	1,784.0
2032	11	382.7	485.0	475.0	362.2	1,704.9
2032	12	602.0	499.0	448.5	502.5	2,052.0
2033	1	627.1	468.5	424.9	598.7	2,119.1
2033	2	470.1	427.7	402.1	500.6	1,800.6
2033	3	435.7	446.2	433.5	475.6	1,791.0
2033	4	370.0	463.1	447.7	423.6	1,704.4
2033	5	484.8	567.0	505.7	297.2	1,854.6
2033	6	627.9	574.0	479.4	501.5	2,182.7
2033	7	771.1	609.6	461.8	663.1	2,505.6

Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class
Table A-5

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2033	8	748.9	609.4	481.2	640.9	2,480.3
2033	9	619.3	570.7	459.1	491.9	2,141.0
2033	10	412.2	481.6	451.7	451.4	1,796.9
2033	11	385.2	487.1	475.9	371.0	1,719.2
2033	12	605.3	501.4	449.4	506.3	2,062.5
2034	1	632.5	472.6	426.6	601.4	2,133.1
2034	2	472.7	429.9	402.9	502.8	1,808.4
2034	3	437.4	447.6	434.0	477.2	1,796.3
2034	4	371.8	464.7	448.2	423.1	1,707.7
2034	5	488.1	569.6	506.7	303.6	1,868.1
2034	6	632.6	577.0	480.5	503.0	2,193.2
2034	7	777.3	613.0	463.0	665.9	2,519.2
2034	8	755.1	612.8	482.6	643.7	2,494.1
2034	9	623.1	572.5	459.7	491.8	2,147.1
2034	10	415.1	483.6	452.6	459.1	1,810.4
2034	11	388.0	489.6	477.1	374.4	1,729.1
2034	12	608.9	504.1	450.6	501.5	2,065.2
2035	1	635.6	475.1	427.6	603.9	2,142.2
2035	2	475.0	432.1	403.8	505.1	1,816.0
2035	3	437.5	447.6	433.8	478.6	1,797.5
2035	4	376.8	469.6	450.6	422.4	1,719.4
2035	5	491.6	572.8	508.2	304.8	1,877.4
2035	6	637.2	580.2	481.8	500.2	2,199.4
2035	7	784.9	618.3	465.2	669.2	2,537.5
2035	8	760.4	615.9	483.9	646.5	2,506.6
2035	9	624.9	573.1	459.7	496.1	2,153.8
2035	10	417.8	485.8	453.6	466.5	1,823.8
2035	11	390.6	492.3	478.5	376.6	1,737.9
2035	12	612.2	506.8	451.7	503.9	2,074.6
2036	1	636.9	475.9	427.7	604.8	2,145.3
2036	2	497.7	452.1	414.0	521.3	1,885.0
2036	3	434.8	446.3	433.2	478.5	1,792.9
2036	4	368.7	462.0	446.2	451.9	1,728.8
2036	5	493.5	574.0	508.5	300.9	1,876.9
2036	6	641.5	583.1	482.9	498.1	2,205.6
2036	7	790.7	621.9	466.4	670.7	2,549.8
2036	8	759.6	613.7	482.5	646.8	2,502.7
2036	9	634.5	580.5	463.0	490.0	2,168.0
2036	10	421.2	488.5	454.8	461.8	1,826.2
2036	11	393.5	495.1	479.8	365.0	1,733.4
2036	12	615.2	509.1	452.6	507.6	2,084.5
2037	1	640.5	478.8	428.9	608.8	2,157.0
2037	2	480.4	436.7	405.8	509.7	1,832.6
2037	3	441.1	450.7	434.9	481.6	1,808.4
2037	4	385.4	478.1	454.5	423.0	1,741.1
2037	5	498.7	579.4	511.2	296.3	1,885.6

Southwestern Electric Power Company
Forecast Internal Energy Requirements (GWh)
By Customer Class
Table A-5

Year	Month	Residential	Commercial	Industrial	Other* Energy Requirements	Internal Energy Requirements
2037	6	645.6	585.9	484.0	511.1	2,226.6
2037	7	797.9	626.9	468.5	675.0	2,568.4
2037	8	767.1	618.8	484.8	651.1	2,521.8
2037	9	634.5	579.4	462.3	508.7	2,184.9
2037	10	424.3	491.0	456.0	464.0	1,835.4
2037	11	395.9	497.4	481.0	379.0	1,753.3
2037	12	618.6	511.9	453.9	516.5	2,100.9
2038	1	642.1	479.9	429.3	611.0	2,162.2
2038	2	482.8	438.7	406.8	511.9	1,840.2
2038	3	448.0	457.1	438.3	486.9	1,830.4
2038	4	385.8	478.5	454.7	428.7	1,747.6
2038	5	502.0	582.4	512.7	297.1	1,894.2
2038	6	649.8	588.8	485.4	513.9	2,237.8
2038	7	801.2	628.5	469.1	677.5	2,576.3
2038	8	774.3	624.0	487.2	654.2	2,539.8
2038	9	637.7	581.4	463.3	513.3	2,195.7

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

	2015 IRP Forecast			Actual			Difference			% Difference		
	2015	2016	2017	2015	2016	2017	2015	2016	2017	2015	2016	2017
Residential	6,483	6,421	6,452	6,336	6,148	5,903	147	273	549	2.3%	4.4%	9.3%
Commercial	6,151	6,141	6,173	6,076	6,064	5,896	74	77	277	1.2%	1.3%	4.7%
Industrial	5,676	5,979	5,983	5,370	5,074	5,268	306	905	715	5.7%	17.8%	13.6%
Other Retail	81	81	81	80	80	81	1	1	0	1.4%	0.7%	0.5%
Wholesale	6,371	6,542	6,670	6,248	6,082	5,831	123	460	839	2.0%	7.6%	14.4%
Total Sales	24,762	25,164	25,359	24,111	23,449	22,978	651	1,716	2,381	2.7%	7.3%	10.4%

	2015 IRP Forecast			Normal			Difference			% Difference		
	2015	2016	2017	2015	2016	2017	2015	2016	2017	2015	2016	2017
Residential	6,483	6,421	6,452	6,234	6,152	6,211	248	269	241	4.0%	4.4%	3.9%
Commercial	6,151	6,141	6,173	6,032	6,031	5,988	119	110	185	2.0%	1.8%	3.1%
Industrial	5,676	5,979	5,983	5,370	5,074	5,268	306	905	715	5.7%	17.8%	13.6%
Other Retail	81	81	81	80	80	81	1	1	0	1.4%	0.7%	0.5%
Wholesale	6,371	6,542	6,670	6,172	6,110	6,014	199	432	657	3.2%	7.1%	10.9%
Total Sales	24,762	25,164	25,359	23,888	23,447	23,561	874	1,717	1,798	3.7%	7.3%	7.6%

	2015 IRP Forecast			Actual			Difference			% Difference		
	2015	2016	2017	2015	2016	2017	2015	2016	2017	2015	2016	2017
Winter Peak	4,708	4,619	4,682	4,708	4,051	4,419	0	568	263	0.0%	14.0%	5.9%
Summer Peak	5,146	5,223	5,272	5,149	4,921	4,769	-3	302	504	-0.1%	6.1%	10.6%

	2015 IRP Forecast			Normal			Difference			% Difference		
	2015	2016	2017	2015	2016	2017	2015	2016	2017	2015	2016	2017
Winter Peak	4,708	4,619	4,682	4,438	4,451	4,100	270	168	582	6.1%	3.8%	14.2%
Summer Peak	5,146	5,223	5,272	5,052	5,003	5,079	94	220	193	1.9%	4.4%	3.8%

Southwestern Electric Power Company and State Jurisdictions
DSM/Energy Efficiency Included in 2015 IRP Load Forecast
Energy (GWh) and Coincident Peak Demand (MW)
Table A-7

	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
2015	24.5	4.9	3.9	19.6	3.7	3.2	3.3	0.7	0.5	1.5	0.5	0.2
2016	46.7	9.0	7.4	36.2	6.7	5.8	9.9	2.0	1.6	0.6	0.3	0.0
2017	63.5	12.3	9.9	47.9	9.1	7.4	15.3	3.1	2.5	0.3	0.1	0.0
2018	76.6	14.8	10.5	57.4	10.9	7.3	19.2	3.9	3.1	0.0	0.0	0.0
2019	88.4	16.9	12.1	66.1	12.4	8.4	22.2	4.6	3.7	0.0	0.0	0.0
2020	97.5	18.5	13.2	72.8	13.4	9.2	24.8	5.1	4.1	0.0	0.0	0.0
2021	103.9	19.6	14.2	77.2	14.1	9.7	26.8	5.5	4.4	0.0	0.0	0.0
2022	107.8	20.2	14.5	79.5	14.4	9.8	28.3	5.9	4.8	0.0	0.0	0.0
2023	109.8	20.5	14.9	80.5	14.4	10.0	29.3	6.1	4.9	0.0	0.0	0.0
2024	110.9	20.5	15.0	81.3	14.4	10.1	29.6	6.1	4.9	0.0	0.0	0.0
2025	111.0	20.6	15.0	81.5	14.5	10.1	29.5	6.1	4.9	0.0	0.0	0.0
2026	110.9	20.6	15.0	81.5	14.5	10.1	29.4	6.1	4.9	0.0	0.0	0.0
2027	110.9	20.6	15.0	81.5	14.5	10.1	29.4	6.1	4.9	0.0	0.0	0.0
2028	110.9	20.5	14.3	81.5	14.4	9.4	29.4	6.1	4.9	0.0	0.0	0.0
2029	110.9	20.6	15.0	81.5	14.5	10.1	29.4	6.1	4.9	0.0	0.0	0.0
2030	110.9	20.6	15.0	81.5	14.5	10.1	29.4	6.1	4.9	0.0	0.0	0.0
2031	110.9	20.6	15.0	81.5	14.5	10.1	29.4	6.1	4.9	0.0	0.0	0.0
2032	110.9	20.5	14.9	81.5	14.4	10.1	29.4	6.1	4.9	0.0	0.0	0.0
2033	110.9	20.6	14.3	81.5	14.5	9.4	29.4	6.1	4.9	0.0	0.0	0.0
2034	110.9	20.6	14.7	81.5	14.5	9.8	29.4	6.1	4.8	0.0	0.0	0.0
2035	110.9	20.6	14.7	81.5	14.5	9.8	29.4	6.1	4.8	0.0	0.0	0.0

*Demand coincident with Company's seasonal peak demand.

Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Residential Customer and Energy Usage Models
Table A-8

Year	SWEPCO Arkansas Population	SWEPCO Arkansas Real Personal Income	SWEPCO Arkansas Gross Regional Product	SWEPCO Arkansas Employment	SWEPCO Louisiana Population	SWEPCO Louisiana Real Personal Income	SWEPCO Louisiana Households	SWEPCO Louisana Employment	SWEPCO Texas Population	SWEPCO Texas Real Personal Income	SWEPCO Texas Employment
1995	566.0	14,628.0	18,210.0	273.4	572.4	14,410.3	211.6	209.4	784.8	19,341.0	287.5
1996	582.1	15,334.5	18,896.9	278.6	573.6	14,599.3	212.9	212.9	796.2	20,202.7	294.2
1997	593.8	16,020.9	19,546.6	283.2	574.1	14,918.8	214.2	214.4	804.8	21,348.5	305.6
1998	602.5	17,101.9	19,791.4	288.1	573.0	15,347.5	215.6	220.2	813.4	22,352.7	309.7
1999	613.6	17,853.4	21,322.9	296.6	575.5	15,648.9	218.6	222.9	819.5	22,784.3	312.9
2000	627.3	18,664.5	21,850.0	303.8	577.2	16,099.2	219.7	225.8	825.4	23,828.0	318.3
2001	636.3	19,120.8	22,582.5	309.6	576.6	17,195.7	220.0	223.8	830.1	24,632.4	321.1
2002	647.0	19,496.1	23,902.1	313.2	576.7	17,406.8	220.4	219.7	837.4	24,781.1	321.2
2003	659.7	20,303.4	25,620.3	315.4	575.9	17,573.6	220.8	219.8	845.2	25,239.5	323.8
2004	672.9	21,893.4	27,296.1	321.6	579.9	17,842.4	221.6	225.4	853.1	25,597.3	333.3
2005	690.0	22,927.8	28,577.0	332.1	583.4	18,747.6	225.2	232.0	861.1	26,823.4	340.1
2006	708.5	24,206.2	29,235.2	340.4	589.7	19,364.2	229.5	235.3	873.9	27,975.6	347.3
2007	722.3	25,496.9	28,475.7	342.6	589.7	19,373.1	232.0	237.0	882.2	28,970.7	357.9
2008	733.4	26,583.8	28,128.4	340.8	590.3	21,479.9	232.6	236.9	890.2	32,283.8	366.5
2009	743.7	25,176.8	27,127.4	327.0	596.1	20,549.3	234.6	232.1	900.5	30,255.5	352.6
2010	755.6	25,619.1	28,282.5	327.4	603.4	21,599.4	236.6	233.0	907.8	31,533.8	354.1
2011	766.5	28,086.3	28,457.9	329.4	607.0	21,795.4	238.6	235.0	912.6	33,451.8	356.4
2012	775.2	31,102.1	28,796.8	334.4	612.1	21,942.5	241.0	233.1	915.6	33,882.9	360.9
2013	783.5	30,494.7	29,961.4	337.0	608.3	21,728.0	240.7	228.7	917.6	33,677.5	367.2
2014	791.5	33,574.4	31,086.2	347.3	605.3	22,856.4	240.4	228.6	921.7	34,866.8	371.4
2015	802.7	35,235.4	31,872.3	360.1	603.0	23,492.0	240.3	227.9	926.9	35,051.2	372.6
2016	813.3	35,304.9	32,602.3	371.1	600.3	22,749.7	239.8	224.5	931.8	34,146.2	371.9
2017	824.9	36,801.8	33,748.1	379.8	600.7	23,144.5	241.3	222.4	938.5	34,381.1	375.1
2018	836.7	37,336.0	34,311.3	385.2	600.9	23,410.9	242.8	222.8	945.9	35,219.9	380.9
2019	848.6	37,832.1	34,893.2	389.2	601.1	23,674.4	244.1	223.4	953.1	35,816.9	384.6
2020	860.4	38,489.4	35,256.2	390.7	601.2	24,034.7	245.5	222.9	960.1	36,452.2	385.7
2021	872.3	39,572.3	36,182.8	394.2	601.3	24,605.2	246.9	223.4	967.2	37,354.0	389.1
2022	884.7	41,011.8	37,282.1	399.7	601.5	25,237.0	248.3	224.8	974.2	38,312.6	393.9
2023	897.3	42,377.6	38,421.1	405.1	601.8	25,876.7	249.8	226.0	981.3	39,179.5	397.8
2024	910.2	43,624.4	39,443.0	409.3	602.3	26,558.0	251.4	226.6	988.5	40,019.9	400.0
2025	923.2	45,171.4	40,499.1	413.0	602.6	27,241.1	253.0	227.0	995.4	40,909.5	401.8
2026	936.3	46,857.5	41,645.0	416.9	602.7	27,925.1	254.6	227.3	1,002.5	41,884.9	403.7
2027	949.4	48,706.1	42,799.2	420.7	602.8	28,619.0	256.1	227.6	1,009.5	42,930.5	405.6
2028	962.6	50,766.9	44,006.8	424.7	602.8	29,333.3	257.5	228.0	1,016.6	44,034.7	407.5
2029	975.7	52,937.1	45,226.5	428.7	602.9	30,043.7	258.8	228.4	1,023.7	45,121.0	409.5
2030	988.8	55,280.6	46,462.9	432.8	603.0	30,798.4	260.1	228.8	1,030.8	46,221.0	411.2
2031	1,001.9	57,829.7	47,729.0	437.0	603.1	31,594.8	261.3	229.3	1,038.1	47,364.6	412.7
2032	1,015.2	60,564.3	49,022.0	441.2	603.3	32,412.4	262.6	229.8	1,045.4	48,521.7	413.8
2033	1,028.3	63,432.9	50,340.1	445.6	603.4	33,227.5	263.8	230.3	1,052.6	49,686.9	414.9
2034	1,041.5	66,505.1	51,689.7	450.1	603.5	34,066.8	264.9	230.9	1,059.8	50,889.7	416.3
2035	1,054.6	69,762.8	53,059.3	454.7	603.6	34,928.6	266.1	231.6	1,066.8	52,124.6	417.9
2036	1,067.6	73,206.2	54,444.6	459.3	603.6	35,795.9	267.3	232.2	1,073.8	53,376.9	419.3
2037	1,080.7	76,830.6	55,850.3	464.1	603.6	36,672.7	268.5	232.8	1,080.6	54,675.6	420.9
2038	1,093.7	80,638.4	57,284.0	469.2	603.6	37,546.9	269.6	233.6	1,087.5	56,022.1	422.7
2039	1,106.8	84,627.2	58,736.0	474.4	603.6	38,415.7	270.6	234.4	1,094.3	57,426.5	424.9
2040	1,119.8	88,847.5	60,219.2	479.9	603.5	39,277.9	271.6	235.2	1,101.2	58,877.0	427.2
2041	1,132.7	93,261.5	61,716.3	485.5	603.3	40,110.2	272.5	236.1	1,108.1	60,297.2	429.4
2042	1,145.7	97,996.1	63,243.3	490.8	603.2	40,978.9	273.4	236.8	1,115.1	61,740.8	431.4
2043	1,158.6	103,084.4	64,813.4	496.0	603.0	41,877.4	274.3	237.6	1,122.1	63,228.3	433.3
2044	1,171.5	108,551.6	66,418.3	501.0	602.8	42,850.3	275.2	238.3	1,129.2	64,799.3	435.1
2045	1,184.3	114,495.3	68,064.9	506.1	602.5	43,945.7	276.2	239.1	1,136.3	66,532.3	437.2
2046	1,197.1	120,909.0	69,754.9	511.2	602.2	45,105.5	277.2	239.9	1,143.4	68,354.7	439.3
2047	1,209.8	127,807.7	71,476.0	516.1	601.9	46,329.1	278.1	240.7	1,150.6	70,221.7	441.2
2048	1,222.8	135,156.0	73,242.4	521.1	601.6	47,588.4	279.0	241.4	1,157.9	72,141.6	443.1
Units	Thousands	Millions (2009 $)	Millions (2009 $)	Thousands	Thousands	Millions (2009 $)	Thousands	Thousands	Thousands	Millions (2009 $)	Thousands

Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Commercial Energy Sales Models
Table A-9

Year	SWEPCO Arkansas Population	SWEPCO Arkansas Real Personal Income	SWEPCO Louisana Real Personal Income	SWEPCO Texas SWEPCO Louisana Emp[oyment	SWEPCO Texas Gross Regional Product	SWEPCO Texas Gross Regional Product - Commercial
1995	566.0	14,628.0	14,410.3	209.4	25,852.9	16,745.4
1996	582.1	15,334.5	14,599.3	212.9	26,989.4	17,515.1
1997	593.8	16,020.9	14,918.8	214.4	28,679.7	18,579.9
1998	602.5	17,101.9	15,347.5	220.2	29,461.1	18,925.5
1999	613.6	17,853.4	15,648.9	222.9	30,159.3	19,680.3
2000	627.3	18,664.5	16,099.2	225.8	30,864.4	20,137.6
2001	636.3	19,120.8	17,195.7	223.8	30,951.8	20,146.6
2002	647.0	19,496.1	17,406.8	219.7	31,657.8	20,496.0
2003	659.7	20,303.4	17,573.6	219.8	32,376.7	20,906.9
2004	672.9	21,893.4	17,842.4	225.4	35,189.2	21,838.2
2005	690.0	22,927.8	18,747.6	232.0	35,036.8	22,719.1
2006	708.5	24,206.2	19,364.2	235.3	37,068.6	23,679.9
2007	722.3	25,496.9	19,373.1	237.0	38,819.1	24,301.8
2008	733.4	26,583.8	21,479.9	236.9	39,133.4	24,919.8
2009	743.7	25,176.8	20,549.3	232.1	37,846.8	24,483.7
2010	755.6	25,619.1	21,599.4	233.0	39,263.1	25,266.1
2011	766.5	28,086.3	21,795.4	235.0	39,976.6	25,631.0
2012	775.2	31,102.1	21,942.5	233.1	42,081.0	27,468.6
2013	783.5	30,494.7	21,728.0	228.7	43,848.6	28,283.9
2014	791.5	33,574.4	22,856.4	228.6	44,740.6	28,741.9
2015	802.7	35,235.4	23,492.0	227.9	44,698.1	28,746.1
2016	813.3	35,304.9	22,749.7	224.5	43,472.6	28,659.8
2017	824.9	36,801.8	23,144.5	222.4	44,248.1	29,331.6
2018	836.7	37,336.0	23,410.9	222.8	45,488.7	30,138.7
2019	848.6	37,832.1	23,674.4	223.4	46,417.0	30,779.6
2020	860.4	38,489.4	24,034.7	222.9	46,856.6	31,055.9
2021	872.3	39,572.3	24,605.2	223.4	48,201.4	31,925.8
2022	884.7	41,011.8	25,237.0	224.8	49,617.4	33,011.2
2023	897.3	42,377.6	25,876.7	226.0	50,919.8	34,009.6
2024	910.2	43,624.4	26,558.0	226.6	51,963.6	34,846.3
2025	923.2	45,171.4	27,241.1	227.0	53,009.5	35,696.7
2026	936.3	46,857.5	27,925.1	227.3	54,150.0	36,613.5
2027	949.4	48,706.1	28,619.0	227.6	55,295.2	37,541.5
2028	962.6	50,766.9	29,333.3	228.0	56,525.3	38,500.2
2029	975.7	52,937.1	30,043.7	228.4	57,708.5	39,424.6
2030	988.8	55,280.6	30,798.4	228.8	58,863.7	40,345.8
2031	1,001.9	57,829.7	31,594.8	229.3	60,061.3	41,309.4
2032	1,015.2	60,564.3	32,412.4	229.8	61,290.4	42,330.9
2033	1,028.3	63,432.9	33,227.5	230.3	62,550.7	43,383.7
2034	1,041.5	66,505.1	34,066.8	230.9	63,849.6	44,464.8
2035	1,054.6	69,762.8	34,928.6	231.6	65,182.8	45,570.4
2036	1,067.6	73,206.2	35,795.9	232.2	66,514.9	46,674.5
2037	1,080.7	76,830.6	36,672.7	232.8	67,893.1	47,805.3
2038	1,093.7	80,638.4	37,546.9	233.6	69,343.7	48,983.5
2039	1,106.8	84,627.2	38,415.7	234.4	70,848.0	50,196.5
2040	1,119.8	88,847.5	39,277.9	235.2	72,410.9	51,447.1
2041	1,132.7	93,261.5	40,110.2	236.1	73,947.4	52,684.0
2042	1,145.7	97,996.1	40,978.9	236.8	75,496.1	53,940.5
2043	1,158.6	103,084.4	41,877.4	237.6	77,126.4	55,250.1
2044	1,171.5	108,551.6	42,850.3	238.3	78,837.4	56,611.4
2045	1,184.3	114,495.3	43,945.7	239.1	80,667.9	58,050.9
2046	1,197.1	120,909.0	45,105.5	239.9	82,582.3	59,547.4
2047	1,209.8	127,807.7	46,329.1	240.7	84,535.3	61,088.7
2048	1,222.8	135,156.0	47,588.4	241.4	86,535.4	62,675.8
Units	Thousands	Millions (2009 $)	Millions (2009 $)	Thousands	Millions (2009 $)	Millions (2009 $)

Southwestern Electric Power Company
Significant Economic and Demographic Variables
Utilized in Jurisdictional Manufacturing Energy Sales Models
Table A-10

Year	SWEPCO Arkansas Gross Regional Product - Manufacturing	SWEPCO Louisana Gross Regional Product - Manufacturing	SWEPCO Louisana Manufacturing Employment	SWEPCO Texas Manufacturing Employment	FRB Industrial Production Index Primary Metals
1995	5,098.2	2,868.3	28.2	5,687.3	100.4
1996	5,037.6	3,019.7	27.4	5,945.2	102.7
1997	5,179.9	2,941.8	25.8	6,166.7	107.0
1998	5,037.7	2,923.9	25.4	6,104.9	108.8
1999	5,543.7	3,096.2	25.3	5,870.1	108.7
2000	5,465.3	2,585.3	25.3	5,885.1	104.9
2001	5,355.7	2,237.7	23.5	5,677.4	95.4
2002	5,857.3	2,598.8	21.4	5,948.7	95.5
2003	6,393.7	3,526.2	21.2	6,230.9	93.7
2004	6,891.4	4,033.6	21.5	8,202.4	101.8
2005	6,959.2	4,841.1	21.8	7,042.9	99.0
2006	7,038.3	4,292.5	21.7	7,684.2	101.8
2007	5,926.0	3,757.9	21.4	8,151.8	103.9
2008	5,273.4	3,262.4	19.0	7,484.3	104.1
2009	4,873.5	3,131.7	16.9	6,574.6	77.5
2010	5,265.1	3,785.6	16.8	7,008.2	95.0
2011	4,994.5	3,633.0	16.9	7,159.0	102.0
2012	4,533.3	3,438.9	16.7	6,885.7	100.0
2013	4,814.7	3,081.6	16.2	7,172.7	103.3
2014	4,944.1	3,162.9	16.5	7,301.9	104.1
2015	4,788.4	3,175.0	16.3	7,461.9	96.7
2016	4,695.1	3,417.9	15.5	7,245.5	93.7
2017	4,743.6	3,696.8	15.3	7,408.1	95.8
2018	4,793.8	3,965.0	15.2	7,768.1	95.4
2019	4,879.5	4,003.0	15.1	7,934.7	95.1
2020	4,909.1	3,982.1	14.9	7,943.7	94.0
2021	5,050.9	4,069.8	14.8	8,213.3	97.0
2022	5,189.5	4,146.9	14.7	8,498.9	98.0
2023	5,312.0	4,210.3	14.6	8,717.4	98.7
2024	5,414.0	4,261.9	14.5	8,884.1	99.6
2025	5,524.8	4,311.5	14.4	9,060.5	99.7
2026	5,648.9	4,367.5	14.3	9,260.2	99.5
2027	5,771.9	4,423.9	14.1	9,461.8	99.6
2028	5,903.1	4,487.3	14.0	9,682.8	100.2
2029	6,030.6	4,546.6	14.0	9,895.4	100.4
2030	6,154.9	4,603.8	13.9	10,099.5	100.6
2031	6,283.0	4,666.1	13.8	10,316.7	100.8
2032	6,412.1	4,732.5	13.7	10,548.9	100.9
2033	6,542.8	4,801.6	13.6	10,792.2	101.0
2034	6,674.2	4,873.7	13.5	11,044.0	101.1
2035	6,805.4	4,948.6	13.5	11,304.7	101.2
2036	6,931.8	5,020.5	13.4	11,557.9	101.2
2037	7,056.2	5,091.0	13.3	11,813.3	101.2
2038	7,181.6	5,166.0	13.3	12,086.5	101.2
2039	7,305.5	5,243.1	13.3	12,372.7	101.2
2040	7,431.4	5,322.8	13.2	12,673.8	101.2
2041	7,551.8	5,398.9	13.2	12,964.8	101.1
2042	7,669.4	5,475.2	13.2	13,252.6	100.9
2043	7,791.4	5,557.9	13.2	13,560.0	100.6
2044	7,919.0	5,650.0	13.2	13,886.7	100.2
2045	8,057.8	5,752.8	13.2	14,236.7	99.8
2046	8,197.5	5,858.8	13.2	14,600.3	99.7
2047	8,327.9	5,960.6	13.2	14,954.8	99.5
2048	8,460.6	6,064.2	13.2	15,318.4	99.4
Units	Millions (2009 $)	Millions (2009 $)	Thousands	Thousands	Index (2007=100)

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

Year	SWEPCO Arkansas Population	SWEPCO Louisiana Population	SWEPCO Texas Employment	SWEPCO Texas Population	SWEPCO Texas Gross Regional Product - Commercial	SWEPCO Texas Gross Regional Product
1995	566.0	572.4	287.5	784.8	16,745.4	25,852.9
1996	582.1	573.6	294.2	796.2	17,515.1	26,989.4
1997	593.8	574.1	305.6	804.8	18,579.9	28,679.7
1998	602.5	573.0	309.7	813.4	18,925.5	29,461.1
1999	613.6	575.5	312.9	819.5	19,680.3	30,159.3
2000	627.3	577.2	318.3	825.4	20,137.6	30,864.4
2001	636.3	576.6	321.1	830.1	20,146.6	30,951.8
2002	647.0	576.7	321.2	837.4	20,496.0	31,657.8
2003	659.7	575.9	323.8	845.2	20,906.9	32,376.7
2004	672.9	579.9	333.3	853.1	21,838.2	35,189.2
2005	690.0	583.4	340.1	861.1	22,719.1	35,036.8
2006	708.5	589.7	347.3	873.9	23,679.9	37,068.6
2007	722.3	589.7	357.9	882.2	24,301.8	38,819.1
2008	733.4	590.3	366.5	890.2	24,919.8	39,133.4
2009	743.7	596.1	352.6	900.5	24,483.7	37,846.8
2010	755.6	603.4	354.1	907.8	25,266.1	39,263.1
2011	766.5	607.0	356.4	912.6	25,631.0	39,976.6
2012	775.2	612.1	360.9	915.6	27,468.6	42,081.0
2013	783.5	608.3	367.2	917.6	28,283.9	43,848.6
2014	791.5	605.3	371.4	921.7	28,741.9	44,740.6
2015	802.7	603.0	372.6	926.9	28,746.1	44,698.1
2016	813.3	600.3	371.9	931.8	28,659.8	43,472.6
2017	824.9	600.7	375.1	938.5	29,331.6	44,248.1
2018	836.7	600.9	380.9	945.9	30,138.7	45,488.7
2019	848.6	601.1	384.6	953.1	30,779.6	46,417.0
2020	860.4	601.2	385.7	960.1	31,055.9	46,856.6
2021	872.3	601.3	389.1	967.2	31,925.8	48,201.4
2022	884.7	601.5	393.9	974.2	33,011.2	49,617.4
2023	897.3	601.8	397.8	981.3	34,009.6	50,919.8
2024	910.2	602.3	400.0	988.5	34,846.3	51,963.6
2025	923.2	602.6	401.8	995.4	35,696.7	53,009.5
2026	936.3	602.7	403.7	1,002.5	36,613.5	54,150.0
2027	949.4	602.8	405.6	1,009.5	37,541.5	55,295.2
2028	962.6	602.8	407.5	1,016.6	38,500.2	56,525.3
2029	975.7	602.9	409.5	1,023.7	39,424.6	57,708.5
2030	988.8	603.0	411.2	1,030.8	40,345.8	58,863.7
2031	1,001.9	603.1	412.7	1,038.1	41,309.4	60,061.3
2032	1,015.2	603.3	413.8	1,045.4	42,330.9	61,290.4
2033	1,028.3	603.4	414.9	1,052.6	43,383.7	62,550.7
2034	1,041.5	603.5	416.3	1,059.8	44,464.8	63,849.6
2035	1,054.6	603.6	417.9	1,066.8	45,570.4	65,182.8
2036	1,067.6	603.6	419.3	1,073.8	46,674.5	66,514.9
2037	1,080.7	603.6	420.9	1,080.6	47,805.3	67,893.1
2038	1,093.7	603.6	422.7	1,087.5	48,983.5	69,343.7
2039	1,106.8	603.6	424.9	1,094.3	50,196.5	70,848.0
2040	1,119.8	603.5	427.2	1,101.2	51,447.1	72,410.9
2041	1,132.7	603.3	429.4	1,108.1	52,684.0	73,947.4
2042	1,145.7	603.2	431.4	1,115.1	53,940.5	75,496.1
2043	1,158.6	603.0	433.3	1,122.1	55,250.1	77,126.4
2044	1,171.5	602.8	435.1	1,129.2	56,611.4	78,837.4
2045	1,184.3	602.5	437.2	1,136.3	58,050.9	80,667.9
2046	1,197.1	602.2	439.3	1,143.4	59,547.4	82,582.3
2047	1,209.8	601.9	441.2	1,150.6	61,088.7	84,535.3
2048	1,222.8	601.6	443.1	1,157.9	62,675.8	86,535.4
Units	Thousands	Thousands	Thousands	Thousands	Millions (2009 $)	Millions (2009 $)

Southwestern Electric Power Company and State Jurisdictions
DSM/Energy Efficiency Included in Load Forecast
Energy (GWh) and Coincident Peak Demand (MW)
Table A-12

	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
2018	26.0	5.3	4.2	16.4	3.5	2.6	7.7	1.6	1.5	1.8	0.3	0.2
2019	51.6	9.2	8.0	30.3	6.3	4.7	14.5	2.5	2.5	6.9	0.3	0.8
2020	72.5	11.7	10.8	41.9	8.6	6.5	16.6	2.5	2.6	14.0	0.7	1.6
2021	81.6	10.8	11.5	48.8	8.0	7.2	14.7	1.9	2.2	18.1	0.9	2.1
2022	92.6	9.2	12.4	58.5	6.4	8.1	13.2	1.7	1.8	21.0	1.0	2.5
2023	113.4	10.9	15.1	77.1	7.5	10.7	13.3	2.1	1.7	22.9	1.2	2.7
2024	132.1	13.6	17.2	93.7	9.2	12.7	13.9	2.8	1.7	24.5	1.6	2.8
2025	147.9	20.8	18.8	105.0	13.3	14.1	17.4	4.7	1.9	25.5	2.8	2.8
2026	142.4	23.8	17.5	100.5	14.9	13.3	18.3	5.7	1.8	23.7	3.2	2.4
2027	123.3	20.0	14.8	87.6	12.8	11.3	15.6	4.9	1.5	20.1	2.3	2.0
2028	105.2	16.3	12.3	74.7	10.7	9.2	13.1	4.1	1.2	17.5	1.6	1.9
2029	82.7	12.7	9.4	57.4	8.4	6.8	10.4	3.3	0.9	14.9	1.0	1.7
2030	59.3	9.6	6.2	38.3	6.1	4.1	7.8	2.5	0.6	13.3	1.0	1.6
2031	41.4	6.9	3.9	23.5	4.0	2.1	5.5	1.8	0.3	12.4	1.0	1.5
2032	28.3	4.4	2.7	12.9	2.2	1.2	3.7	1.2	0.2	11.8	1.1	1.4
2033	18.5	2.6	1.9	5.4	0.9	0.5	2.4	0.7	0.1	10.7	1.0	1.3
2034	11.6	1.4	1.3	0.5	0.1	0.0	1.6	0.4	0.1	9.5	0.9	1.2
2035	9.8	1.2	1.3	0.1	0.0	0.1	1.1	0.3	0.1	8.6	0.9	1.2
2036	8.1	1.0	1.2	0.0	0.0	0.0	0.4	0.1	0.0	7.7	0.9	1.1
2037	7.4	0.8	1.0	0.0	0.0	0.0	0.2	0.0	0.0	7.2	0.8	1.0
2038	7.4	0.9	1.0	0.0	0.0	0.0	0.2	0.0	0.0	7.2	0.9	0.9

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

Southwestern Electric Power Company
Actual and Forecast Losses (GWh)
Table A-13

Year	Losses
2004	784.6
2005	972.6
2006	1,203.3
2007	808.5
2008	751.5
2009	965.9
2010	1,020.6
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*	1,049.0
2019	979.7
2020	917.0
2021	960.3
2022	955.4
2023	950.3
2024	958.2
2025	955.1
2026	957.5
2027	963.6
2028	968.1
2029	973.3
2030	976.8
2031	979.5
2032	986.2
2033	992.1
2034	996.7
2035	1,000.9
2036	1,003.2
2037	1,009.6
2038	1,015.7

Note: *2018 data are three months actual
nine months forecast

Southwestern Electric Power Company
Short-Term Load Forecast
Blended Forecast vs. Long-Term Model Results
Table A-14

Class	Arkansas	Louisiana	Texas
Residential	Long-Term	Short-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

Blending Illustration
Table A-15

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

Southwestern Electric Power Company
Table A-16
Forecasted DSM, Adjusted for IRP Modeling[1]

Total SWEPCO

Year	Energy (MWh)	Summer Peak (MW)	Winter Peak (MW)
2018	25,958	5.3	4.2
2019	51,620	9.2	8.0
2020	47,440	7.7	7.3
2021	26,866	4.0	4.0
2022	14,233	1.4	1.9
2023	7,534	0.4	0.9
2024	4,458	0.2	0.5
2025	1,997	0.1	0.2
2026	0.0	0.0	0.0
2027	0.0	0.0	0.0
2028	0.0	0.0	0.0
2029	0.0	0.0	0.0
2030	0.0	0.0	0.0
2031	0.0	0.0	0.0
2032	0.0	0.0	0.0
2033	0.0	0.0	0.0
2034	0.0	0.0	0.0
2035	0.0	0.0	0.0
2036	0.0	0.0	0.0
2037	0.0	0.0	0.0

(1) DSM values shown here reflect the most recent information for SWEPCO available at the time of the IRP. These values may differ from the DSM values shown in Table A-12, which are the SWEPCO DSM values at the time of the overall SWEPCO load forecast.

Southwestern Electric Power Company
Table A-17
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
2019	4,208	4,275	4,312	4,715	4,790	4,831	23,206	23,575	23,780
2020	4,024	4,117	4,174	4,551	4,656	4,721	22,542	23,064	23,383
2021	4,032	4,146	4,230	4,563	4,693	4,788	22,525	23,166	23,632
2022	4,023	4,165	4,262	4,562	4,722	4,832	22,482	23,274	23,817
2023	4,022	4,189	4,299	4,546	4,735	4,861	22,411	23,341	23,960
2024	4,008	4,197	4,319	4,538	4,751	4,890	22,333	23,385	24,068
2025	3,993	4,204	4,339	4,522	4,761	4,915	22,244	23,421	24,174
2026	3,984	4,216	4,367	4,516	4,778	4,949	22,200	23,490	24,331
2027	3,978	4,230	4,397	4,516	4,803	4,992	22,175	23,583	24,513
2028	3,984	4,255	4,446	4,519	4,826	5,043	22,185	23,694	24,757
2029	3,984	4,276	4,485	4,518	4,850	5,087	22,182	23,811	24,973
2030	3,977	4,291	4,527	4,518	4,875	5,143	22,160	23,910	25,225
2031	3,967	4,307	4,561	4,516	4,903	5,191	22,115	24,012	25,424
2032	3,965	4,327	4,605	4,517	4,930	5,246	22,094	24,114	25,661
2033	3,951	4,337	4,644	4,516	4,958	5,308	22,063	24,220	25,933
2034	3,946	4,366	4,696	4,500	4,979	5,355	21,995	24,334	26,174

Exhibit B Non-Renewable New Generation Technologies

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

Type	Capability (MW) (d) Std. ISO	Summer	Winter	Installed Cost (c,e) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Fuel Cost ($/MBtu)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Capacity Factor (%)	LCOE (f) ($/MWh)
Base Load										
Nuclear	1,610	1,560	1,690	7,900	10,500	0.91	6.24	145.43	80	176.3
Pulv. Coal with Carbon Capture (PRB)	540	520	570	9,200	12,500	2.28	5.60	91.79	75	230.6
Combined Cycle (1X1 "J" Class)	540	700	720	1,000	6,300	2.94	1.97	10.81	75	62.3
Combined Cycle (2X1 "J" Class)	1,080	1,410	1,450	800	6,300	2.94	1.73	9.16	75	57.5
Combined Cycle (2X1 "H" Class)	1,150	1,490	1,530	700	6,300	2.94	1.63	8.65	75	55.8
Peaking										
Combustion Turbine (2 - "E" Class) (g)	180	190	190	1,200	11,700	2.94	3.94	17.60	25	145.9
Combustion Turbine (2 - "F" Class, w/evap coolers) (g)	490	500	510	700	10,000	2.94	6.07	15.77	25	114.0
Aero-Derivative (2 - Small Machines) (g,h)	120	120	120	1,400	9,900	2.94	2.44	18.93	25	143.8
Recip Engine Farm	220	220	230	1,300	8,300	2.94	2.61	6.32	25	123.0
Battery	10	10	10	1,900	87% (i)	0.00	0.00	38.99	25	175.8

Notes: (a) Installed cost, capability and heat rate numbers have been rounded
(b) All costs in 2018 dollars, except as noted.
(c) $/kW costs are based on summer capability
(d) All Capabilities are at 1,000 feet above sea level
(e) Total Plant Investment Cost w/AFUDC (AEP-East rate of 5.5%,site rating $/kW)
(f) Levelized cost of energy based on capacity factors shown in table
(g) Includes Dual Fuel capability and SCR environmental installation
(h) Includes Black Start capability
(i) Denotes efficiency, (w/ power electronics)

Exhibit C Stakeholder Committee Report with Company Responses

AEP/Southwestern Electric Power Company
Integrated Resource Plan
Stakeholder Committee Report

With Company Responses – October 2018

Meeting Held August 14, 2018

Fayetteville, Arkansas

SWEPCO Stakeholder Report

November 9, 2018

Primary Author: Simon Mahan, Southern Renewable Energy Association

The Stakeholder Committee of the Southwestern Electric Power Company's 2018 Integrated Resource Planning process would like to commend the company on an excellently prepared IRP and a thoroughly collaborative process. The Arkansas Public Service Commission (PSC) IRP Guidelines underscore the importance of a robust stakeholder engagement process, and SWEPCO has exceeded those Guidelines. Even when SWEPCO and the Stakeholder Committee disagreed, SWEPCO still performed additional analysis at the request of the Stakeholder Committee and provided rationale.

The Stakeholder Committee would like to encourage SWEPCO to expeditiously implement the findings of this IRP. Due to the federal tax credits for renewable energy expiring soon, the Stakeholder Committee encourages SWEPCO to immediately issue Requests for Proposals for up to 2,000 megawatts of wind energy, and 1,500 megawatts of solar energy. The Stakeholder Committee also encourages SWEPCO to continually evaluate ways to incorporate energy storage, and towards that end, issue a 250 megawatt/1,000 MWh RFP.

The Stakeholder Committee thanks SWEPCO staff for their efforts and would like to encourage the Arkansas PSC, Arkansas PSC staff, and other Arkansas utilities to emulate SWEPCO's practices and attitude towards stakeholder engagement in future IRP planning.

Southwestern Electric Power Company 2018 Integrated Resource Plan

Stakeholder Committee Timeline

August 7, 2018 – SWEPCO emails stakeholders meeting agenda, draft IRP

August 14, 2018 – SWEPCO IRP Stakeholder Meeting, Fayetteville, Arkansas

August 15, 2018 – SWEPCO provides Stakeholder Committee with slides from Stakeholder Meeting

August 17, 2018 – SWEPCO IRP Stakeholder Committee submits questions to SWEPCO

August 29, 2018 – SWEPCO provides responses to the questions submitted by the Stakeholder Committee

September 4, 2018 – SWEPCO IRP Stakeholder Committee holds conference call to discuss responses

September 24, 2018 – SWEPCO provides the Stakeholder Committee with Preliminary IRP Modeling Results

October 5, 2018 – SWEPCO hosts a webinar for the Stakeholder Committee to discuss the Preliminary IRP Modeling Results

October 12, 2018 – SWEPCO IRP Stakeholder Committee holds conference call to discuss Preliminary IRP Modeling Results, and develop a list of requests and modifications

October 16, 2018 – SWEPCO IRP Stakeholder Committee submits additional sensitivity runs to SWEPCO

October 31, 2018 – SWEPCO provides response to the Stakeholder Committee additional sensitivity runs

November 9, 2018 – SWEPCO IRP Stakeholder Committee files Stakeholder Report

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Simon Mahan, Southern Renewable Energy Association, simon@southernwind.org

Company Response:
The Company would like to thank all of the Stakeholders for both participating in the Stakeholder meeting held in Fayetteville, Arkansas on August 14, 2018 and for developing very constructive comments and feedback on the Company's DRAFT IRP.

As referenced in the Stakeholder Report, stakeholders submitted two sets of questions to SWEPCO following the August 14th stakeholder meeting. Below are those questions with SWEPCO's responses.

Southwestern Electric Power Company
Responses to
1st Set of Stakeholder Questions for SWEPCO Arkansas IRP
Submitted August 17, 2018
Responded August 29, 2018

GENERAL

1. Provide specific individual information regarding SWEPCO's existing generating units, including:
   - Dollar per megawatt-hour ($/MWh) generation costs, for the past five years for each unit
   - Efficiency in BTU/kWh, for the past five years for each unit
   - Generation in MWh, and annual capacity factor, for the past five years for each unit

   RESPONSE: See Attached Excel workbook, tab labeled SWEPCO Plant Data for the requested information.

2. Provide the average age of the existing generation fleet by technology type.
   - This request does not pertain solely to SWEPCO's generation units, but encompasses the entire United States electric industry.
   - Technology types should include coal steam turbine, natural gas combustion turbine, natural gas steam turbine, natural gas combined cycle, natural gas reciprocating engine, nuclear reactor, hydro, and other technologies that may be relevant to the company's current fleet and possible generation resources.
   - Stakeholders believe this can be done relatively easily with the ABB/Ventyx data and software suite.
   - Also provide the average age of retired generation units by technology type that have retired in the past 10 years.

   RESPONSE: See Attached Excel workbook, tab labeled US Unit Age for the requested information.

3. Provide estimated rate impact by customer class, estimated overall SWEPCO system costs, and other financial metrics to compare and contrast implications of various scenarios and/or sensitivities.
   RESPONSE: The modeling in the IRP estimates the overall production costs of various scenarios and does not estimate rate impacts by class. This is generally not practical in an IRP as it cannot be known if future resources will be owned or acquired through purchase power agreements, which affect rates differently. We should encourage the stakeholders to focus on the overall production cost impacts. The modeling results will show incremental cost over the first, or base year, of the plan.

4. How will SWEPCO evaluate potential PURPA projects?
   RESPONSE: PURPA projects are evaluated on an as needed basis and upon request by third parties.

5. Would the model runs make recommendations with regards to retirements and deactivation schedules, or are those independent of the modeling?
   RESPONSE: Based on stakeholder input, portfolios modeled for the draft IRP update will include specific scenarios where units are retired during the planning period.

6. Are any units "must run"? If so, please list them and at what capacity factors or parameters they are considered "must run". Are any units "hard wired" to run in the model?
   RESPONSE: To the extent units are designated as "must run," they will be identified in the draft IRP update.

7. How will SWEPCO evaluate potential "corporate off-taker" or "Green Tariff" type renewable energy projects?
   RESPONSE: This type of information is not considered in the planning process. Renewable projects are selected due to economics or to fill a capacity need.

STORAGE

8. Explain SWEPCO's methodology regarding energy storage evaluations, including, but not limited to:
   - Energy arbitrage pricing, usage rates (e.g., subhourly, hourly, daily, weekly, etc.), and general performance time periods (e.g., charging from 10AM-1PM, discharging from 1PM-4PM).

   RESPONSE: The IRP model will dispatch the storage resource when its revenues are greater than its expenses from a variable perspective. The IRP model is an hourly simulation. The resource will charge when it is least costly and discharge when it can make the most revenue.

   - Possible ancillary services and pricing values.

   RESPONSE: The current IRP model used for this IRP will not quantify the value of ancillary services.

9. Provide a citation for capital cost estimate provided on slide 45.
   RESPONSE: The capital cost estimate citation is on slide 45.

10. Explain how the ITC is factored with energy storage.
    RESPONSE: The current IRP storage resource does not include the impact of ITC.

11. Explain how energy storage is modeled.
    RESPONSE: Storage is modeled as an independent resource that has capital and operating and maintenance expense and can earn revenue based on its variable cost relative to market pricing and it provides capacity value to meet the Company's capacity obligation.

12. What "value stack" components are considered, and at what values?
    RESPONSE: Energy. The energy values are the Fundamental Commodity prices shown in the Stakeholder presentation. All resources are evaluated against the four pricing Scenarios presented at the Stakeholder presentation and included in the DRAFT IRP.

COAL

13. What are the coal transportation costs?
    - What are the past five years of coal transportation costs, on a dollar per ton basis and a dollar per megawatt hour basis?
    - What is SWEPCO's forecast for coal transportation costs to be used for this IRP, on a dollar per ton basis and a dollar per megawatt hour basis?

Provide the all-in delivered cost of PRB coal on a dollar per ton basis and a dollar per megawatt hour basis, and forecasts.

RESPONSE: The coal transportation and commodity contract prices are confidential information. The attached Excel workbook, on the tab labeled "Coal Transp Data," shows publicly available coal transportation costs from the PRB basin to the states in and around SWEPCO's service territory. Cost of PRB coal will be based on the Fundamental Forecast, which has been provided in the Stakeholder Meeting slides. The actual historical information can be found in the FERC FORM 1.

WIND

14. Provide a synopsis of why the Wind Catcher project was rejected and steps SWEPCO plans to take in the future to improve the likelihood of approvals.
    RESPONSE: Wind Catcher provided a unique opportunity to get ahead of Public Service Company of Oklahoma (PSO) and SWEPCO's traditional integrated resource plans by aggregating smaller renewables projects into a viable option. The Wind Catcher project included a dedicated 765 kV tie line to deliver power directly to the Tulsa load center and would glean full benefits of the Renewable Energy Production Tax Credit (PTC). Despite the suite of guarantees offered by AEP, the risk profile was viewed by the Public Utility Commission of Texas as unacceptable. SWEPCO and other AEP operating companies will continue with their respective resource plans for smaller projects to fill their needs.

15. What are the capital cost assumptions for wind?
    RESPONSE: The Company's assumptions for wind are represented in a levelized cost approach and were provided both in the Stakeholder presentation and in the Draft IRP on page 90.

16. Why does the 600 MW annual limit exist?
    RESPONSE: The 600MW annual limit is a planning assumption that the Company believes is reasonable for this IRP. The limit is based on historical RFPs and regulatory approvals. The actual

quantity of wind resources added in a given year will be determined as the company evaluates future proposals and responses to RFPs.

17. Why does the 1,900MW limit exist?
RESPONSE: The cumulative 1,900MW limit is also a planning assumption that recognizes an overall penetration limit of intermittent resources within SPP. A further description of these planning assumptions is provided in the Draft IRP on page 90.

18. Will SWEPCO model multiple different tranches for wind energy?
RESPONSE: At this time, the Company is only modeling one tranche; however, initial runs are selecting all of the Wind resources subject to annual and cumulative constraints. Therefore, there would be limited value in adding another level of wind as it would not change the results.

NATURAL GAS

19. How do economies of scale affect new natural gas generation facilities?
RESPONSE: Larger gas facilities offer a lower installed cost per kW than smaller gas facilities because there are certain balance-of-plant costs that remain relatively independent of the facility size.

20. Why did SWEPCO choose such large natural gas facility capacities as opposed to smaller modular configurations?
RESPONSE: The Company chose the configuration shown because of the low installed cost and high efficiency levels. The Company is modeling a 25% share of the resource. This is discussed on page 96 of the DRAFT IRP.

EFFICIENCY

21. Does the energy efficiency savings include the 1% or 1.5% goal increase? Is SWEPCO modeling an increase in the EE goals?
RESPONSE: In order to preserve equal footing among all resource selections, SWEPCO allowed the model to optimize its resource selections based on the economics of EE costs and potential savings. EE costs and savings were derived from the Electric Power Research Institute's (EPRI) "2014 U.S. Energy Efficiency Potential Through 2035" report as well as through input from the SWEPCO DSM team. At the stakeholders' request, SWEPCO can run a scenario with a predetermined amount of EE to compare the costs of this scenario to the Preferred Plan.

DG SOLAR

22. Provide comment on the distributed/net meter solar information provided in the article, "Utilities' eyes on state's solar-power surge; dispute arises on generators' credit," Arkansas Democrat Gazette, July 22, 2018 (http://www.arkansasonline.com/news/2018/jul/22/utilities-eyes-on-state-s-solar-power-s/)
RESPONSE: For this IRP, distributed solar resources were evaluated based on historical rooftop solar additions, future estimated costs of rooftop solar, and the current level of federal incentives. As a result of this analysis, SWEPCO determined an assumed growth rate to embed distributed solar resources in the model. Distributed solar resources were embedded in amounts equal to a

Compound Annual Growth Rate of 4.4% over the planning period. SWEPCO will continue to monitor any changes to net-metering laws and its effect on rooftop solar costs. If projected costs were to change because of net-metering rule changes, SWEPCO may make the necessary adjustments at that time to its distributed generation resource assumptions.

UTILITY-SCALE SOLAR

23. Please provide methodology to calculate LCOE for utility-scale solar, including capital cost, capacity factor, regional differences, etc.
RESPONSE: The LCOE shown for utility-scale solar is for discussion purposes, the model does not utilize this value to make resource decisions. The LCOE values shown include the Company's WACC, the installed capital cost, the ongoing O&M and the expected output for the resource configuration. The detailed assumptions can be provided in the draft IRP update.

24. Why does the 300 MW annual limit exist?
RESPONSE: The 300MW annual limit is a planning assumption that the Company believes is a reasonable for this IRP. It is based on historical RFPs, regulatory approvals, and the fact that the Company currently does not have any utility-scale solar.

25. Why does the 1,300 MW total limit exist?
RESPONSE: The cumulative 1,300MW limit is also a planning assumption that recognizes an overall penetration limit to intermittent resources within SPP. A further description of these planning assumptions is provided in Section 4.5.5.1.1, page 85 of the DRAFT IRP.

26. Explain how the ITC was factored into the solar energy pricing.
RESPONSE: The ITC is reflected in the overall cost of the solar resource.

ELECTRIC VEHICLES

27. Explain SWEPCO's assumptions on electric vehicle adoption.
RESPONSE: SWEPCO has created 3 different electric vehicle (EV) adoption scenarios (high, medium, and low). The medium EV scenario assumes the number of EVs in SWEPCO territory increases at a rate of 30% per year through 2030. The high adoption scenario assumes an average increase of 40% per year and the low scenario assumes a rate of growth of 25% per year. The total number of EV's in SWEPCO's territory as of Dec 2017 was only 303 (88% of those are in AR). Even with the relatively aggressive growth assumptions on EV's, the impact of EV's on SWEPCO's load by 2030 is well within the High and Low Economic scenarios that are modeled in the IRP analysis.

TRANSMISSION

28. How will SWEPCO evaluate potential transmission opportunities?

RESPONSE: Transmission opportunities generally are not in the scope of an IRP process. Such solutions would or could surface in an RFP process soliciting additional resources.

SWEPCO IRP
2nd Set of Stakeholder Committee Requests
Submitted on October 16, 2018
Responded on October 31, 2018

1) SWEPCO should reduce wind energy prices and solar energy prices to align with the NREL Annual Technology Baseline.

2) SWEPCO should evaluate several types of wind energy resources at several different price points and performance levels, as provided below:

		2019	*2020*	*2021*	*2022*	*2023**	*2024**	*2025**
TRG1	Overnight $/kW	$730	$687	$739	$787	$1,133	$1,075	$730
	Capacity Factor	50%	50%	51%	51%	52%	52%	53%
	LCOE $/MWh	$19	$21	$22	$23	$27	$26	$24
TRG5	Overnight $/kW	$840	$803	$839	$874	$1,208	$1,142	$1,075
	Capacity Factor	44%	45%	45%	46%	47%	48%	48%
	LCOE $/MWh	$25	$26	$27	$28	$31	$29	$28
TRG7	Overnight $/kW	$1,013	$991	$1,023	$1,054	$1,384	$1,313	$1,241
	Capacity Factor	35%	36%	37%	38%	38%	39%	40%
	LCOE $/MWh	$39	$40	$39	$39	$41	$39	$36

PTC included through 2022. *Excludes PTC

3) SWEPCO should increase its cap on wind energy to beyond 60% and consider increasing its annual limit to 1,000 MW per year or higher.

4) SWEPCO should update its solar power pricing, as provided below:

		2019	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*
Mid	Overnight $/kWdc	$707	$707	$707	$707	$707	$784	$775
	Capacity Factor AC	20%	20%	20%	20%	20%	20%	20%
	LCOE $/MWhAC	$32	$32	$32	$$32	$32	$38	$38

ITC incorporated with step-down through 2023.

5) SWEPCO should increase the amount of solar allowed in the model to at least 25% of its total energy, with annual additions of up to 1,000 MW annually.

6) SPP uses 20% capacity value for wind and 70% capacity value for solar in their ITP process. SWEPCO should use these same values for new generation.

RESPONSE TO REQUESTS 1-6: In response to the Stakeholders' first 6 requests contained in its 2nd request for information, the Company has performed an analysis with increased levels of wind and solar resources available for the model to select from during the optimization process. It is important to note the Company does not believe the Stakeholder recommended input assumptions are realistic or achievable, or that such a plan would result in an acceptable level of risk allocation for the Company and the commissions that regulate SWEPCO to execute and approve such a plan.

In addition to the 1,400 MW of wind capacity allowed in the Company's original optimization runs, the Company allowed an additional 1,000 MW of wind capacity in the Stakeholder optimization run. The additional 1,000 MW wind capacity had the following characteristics:

- An additional 600 MW of wind was available at the Company's wind prices which are comparable to the Stakeholders' TRG1 wind prices.
- An additional 200 MW of wind was available at the Stakeholders' TRG5 wind prices.
- An additional 200 MW of wind was available at the Stakeholders' TRG7 wind prices.
- All wind resources could be added beginning in 2022 and 1,000 MW of wind capacity could be added in a single year.
- A 48% capacity factor and 30% capacity credit was assumed for all Company and Stakeholder wind alternatives.

Also, in addition to the 1,300 MW of utility solar capacity allowed in the Company's original optimization runs, the Company allowed an additional 850 MW of solar in the Stakeholder optimization run. The additional 850 MW solar capacity had the following characteristics:

- The LCOE cost curve provided by the Stakeholders was assumed for the Stakeholder solar resource.
- All solar resources could be added beginning in 2021 and 1,000 MW of solar capacity could be added in a single year.
- The Company assumed a 28% capacity factor for all solar resources, not the 20% capacity factor suggested by the Stakeholders.
- A capacity credit of 70% was assumed for both the Company's solar alternative and the Stakeholder alternative.

The following table provides a summary of the wind and solar installed capacity for the Stakeholder optimization run:

Installed Capacity (MW)

	AEP Wind	Stakeholder Wind TRG5	Stakeholder Wind TRG7	Stakeholder Solar	AEP Solar
2018	0	0	0	0	0
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	1,000	0	0	0	0
2023	2,000	0	0	850	0
2024	2,000	0	0	850	0
2025	2,000	200	0	850	150
2026	2,000	200	200	850	300
2027	2,000	200	200	850	450
2028	2,000	200	200	850	600
2029	2,000	200	200	850	750
2030	2,000	200	200	850	900
2031	2,000	200	200	850	1,050
2032	2,000	200	200	850	1,200
2033	2,400	200	200	850	1,300
2034	2,400	200	200	850	1,300
2035	2,400	200	200	850	1,300
2036	2,400	200	200	850	1,300
2037	2,400	200	200	850	1,300

The Stakeholder optimization run produces the following capacity expansion plan:

	302 MW (25% Share of 1500 MW) GE 7HA.02 CC Firm Capacity (MW)	Commercial DSM Firm Capacity (MW)	Residential DSM Firm Capacity (MW)	Distributed Solar Firm Capacity (MW)	Utility Solar Firm Capacity (MW)	CVR Firm Capacity (MW)	Wind Firm Capacity (MW)	Firm Generation Capacity with New Capacity Additions (MW)	Capacity Reserves Above Required Generation with New Capacity Additions (MW)	Reserve Margin with New Capacity Additions (%)
2018	0	0	0	3.30	0	0	0	5,745	627	25.7
2019	0	0	0	3.30	0	0	0	5,679	472	22.2
2020	0	5	3	3.30	0	24	0	5,636	573	24.7
2021	0	9	6	3.63	0	24	0	5,588	482	22.6
2022	0	13	8	3.63	0	24	300	5,894	754	28.4
2023	0	11	9	3.96	595	24	600	6,679	1,520	45.0
2024	0	16	10	3.96	595	24	600	6,684	1,504	44.5
2025	0	15	9	4.29	700	37	660	6,753	1,554	45.5
2026	0	13	7	4.62	805	37	720	6,805	1,584	46.0
2027	0	12	6	4.62	910	37	720	6,907	1,607	46.0
2028	0	8	4	4.95	1,015	37	720	7,007	1,688	47.6
2029	0	9	4	4.95	1,120	37	720	7,112	1,768	49.0
2030	0	7	4	5.28	1,225	37	720	7,041	1,671	46.8
2031	0	6	4	5.61	1,330	37	720	7,145	1,748	48.3
2032	0	4	3	5.94	1,435	37	720	7,248	1,823	49.6
2033	0	3	2	5.94	1,505	48	780	7,299	1,846	49.9
2034	0	1	2	6.27	1,505	58	840	7,367	1,891	50.7
2035	0	1	1	6.60	1,505	58	840	7,367	1,860	49.8
2036	0	1	1	6.93	1,505	67	840	7,016	1,475	41.8
2037	0	0	1	7.26	1,505	67	840	6,662	1,090	33.9

The Company does not believe the Stakeholders' recommended assumptions are reasonable or would result in an acceptable level of risk allocation for the Company or the commissions that regulate SWEPCO. An example of this risk results from using the Stakeholder's lower price resource assumptions which result in a portfolio that is $1.9 billion less expensive than the Company's base plan (or about 5.5% less expensive). These assumptions create capacity reserves of approximately 1,900 MW above what is needed to meet the SPP required minimum reserve margin of 12%, and reserve margins of more than 50% in some years. While this exercise does validate the Company's conclusion that the forecasted value of both wind and solar within the IRP modeling construct is significant, the Company continues to support its Preferred Portfolio as being more realistic and achievable over the planning period.

SWEPCO should develop a 500 MW renewable energy corporate procurement scenario for evaluation.
Response: Currently, renewable resources are projected to be lower cost than market energy and therefore, the Company would not readily assign this lower cost generation to benefit a specific customer. The Company plans to offer a Renewable Energy Credit tariff for customers that are interested in supporting renewable energy.

We request methodology and metrics regarding transmission costs, including multiple configuration types (e.g., point-to-point, network integration transmission service, self-build, etc.) and costs, and possible capacity, energy, ancillary or any other benefits to those types.
Response: These calculations are generally not performed during IRP development but instead could be appropriate when analyzing responses to RFPs.

SWEPCO should perform the same analysis it performed for the Pirkey unit as for the Dolet Hills unit, with retirement taking place in 2025.
Response: SWEPCO will take this request under advisement in preparing the final IRP.

SWEPCO should provide the data inputs associated with the energy storage "value stack".
Response: The Company agrees there may be additional value to all resources versus what is modeled within the IRP, which is predominately focused on day-ahead energy and capacity value, when "ancillary services" are included in a resource evaluation. These values or "value stack" in SPP at this time include day-ahead energy, regulation up, regulation down, spinning reserves and non-spinning reserves and real time energy, regulation up, regulation down, spinning reserves and non-spinning reserves. The current characteristics of electrochemical energy storage appear to allow this type of resource to be effective in participating in all of these markets, if the resource is designed to respond to these market products. The Company is currently monitoring this value; however, at this time is not comfortable assigning a monetary value to these market products other than day-ahead capacity and energy. This current view does not prevent the Company from choosing to pursue adding energy storage in the future based on all of its characteristics.

SWEPCO should provide an estimate at what value and/or what cost energy storage would begin to be selected in the current model.
Response: Below is a simulation of the breakeven cost needed for the battery storage resource that the Company has included in this IRP. The Company has assumed for the purposes of this calculation that Ancillary Services revenue may range from zero to 50% of the energy revenue earned, ultimately the Ancillary Services revenue will be dependent on the storage design as well as the market. For Scenarios 1, 2 & 3, the Company modified the installed cost to get a breakeven NPV for each Scenario. In

Scenarios 2 & 3, the value of Ancillary Services was changed to gain a relative understanding of Ancillary Services revenue on breakeven installed cost. In conclusion, based on current conditions the storage resource installed cost would need to be reduced by approximately 80%.

Summary

		Break-Even Cost		
	Today's Cost	Scenario 1	Scenario 2	Scenario 3
Intalled Cost ($/kWh)	457	85	100	70
Capacity (kWh)	40,000	40,000	40,000	40,000
Installed Cost ($)	18,280,000	***3,410,002***	***4,011,965***	***2,808,038***
Fixed O&M ($/kW-yr.)	39	39	39	39
Ancillary Svs Rev. as % of Energy	25%	25%	***50%***	***0%***
Fixed Charge Rate (FCR) for 20 Yr. Asset (%)	13%	13%	13%	13%
Discount to Today's Cost(%)		***-81%***	***-78%***	***-85%***
NPV ($)	(22,104,995)	0	0	0

SWEPCO should provide a narrative of lessons learned from the Windcatcher deal, and recommendations and steps it plans to take to improve the likelihood of a positive outcome of future projects.

Response: "A narrative of lessons learned from the Windcatcher deal" is not an appropriate topic for the Arkansas IRP, particularly given that the Arkansas Public Service Commission approved the Application in APSC Docket No. 17-038-U.

Exhibit D Long-Term Commodity Price Forecast

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

	Natural Gas (Henry Hub) $/mmBTU				Coal (PRB 8800 0.8#) $/Ton FOB				CO_2 $/short ton			
	Base	Low Band	High Band	No Carbon	Base	Low Band	High Band	No Carbon	Base	Low Band	High Band	No Carbon
2018	3.22	2.79	3.65	3.22	12.18	12.18	12.18	12.2	0	0	0	0
2019	3.88	3.36	4.4	3.89	11.84	10.5	13.1	11.8	0	0	0	0
2020	4.59	3.97	5.21	4.6	11.89	9.24	14.44	11.86	0	0	0	0
2021	4.69	4.06	5.32	4.69	12.18	8.05	16.35	12.21	0	0	0	0
2022	4.82	4.17	5.47	4.83	12.32	8.14	16.52	12.35	0	0	0	0
2023	4.96	4.29	5.63	4.97	12.38	8.14	16.52	12.35	0	0	0	0
2024	5.12	4.43	5.81	5.13	12.68	8.38	17	12.71	0	0	0	0
2025	5.22	4.52	5.92	5.23	12.91	8.51	17.27	12.91	0	0	0	0
2026	5.32	4.6	6.04	5.32	13.15	8.67	17.61	13.17	0	0	0	0
2027	5.41	4.68	6.14	5.41	13.34	8.85	17.97	13.43	0	0	0	0
2028	5.99	5.18	6.8	5.69	13.19	8.67	17.61	14.07	13.61	13.61	13.61	0
2029	6.15	5.32	6.98	5.83	13.32	8.78	17.82	14.3	14.29	14.29	14.29	0
2030	6.48	5.6	7.36	6.17	13.42	8.94	18.14	14.49	15	15	15	0
2031	6.71	5.8	7.62	6.37	13.1	8.51	17.27	13.78	15.75	15.75	15.75	0
2032	6.91	5.98	7.84	6.57	13.81	9.19	18.67	14.91	16.54	16.54	16.54	0
2033	7.12	6.16	8.08	6.76	13.8	9.14	18.56	14.88	17.37	17.37	17.37	0
2034	7.33	6.34	8.32	6.99	13.49	8.86	18	14.41	18.24	18.24	18.24	0
2035	7.55	6.53	8.57	7.21	13.59	8.96	18.18	14.58	19.15	19.15	19.15	0
2036	7.78	6.73	8.83	7.43	13.85	9.13	18.55	14.89	20.11	20.11	20.11	0
2037	8.01	6.93	9.09	7.67	14.44	9.32	18.92	15.15	21.11	21.11	21.11	0

	Power On-Peak (SPP) $/MWh				Power Off-Peak (SPP) $/MWh			
	Base	Low Band	High Band	No Carbon	Base	Low Band	High Band	No Carbon
2018	29.05	27.54	31.04	29.15	23.41	21.87	24.77	23.63
2019	32.89	29.99	36.23	33.12	26.18	24.19	28.48	26.5
2020	37.99	33.42	42.25	38.09	29.25	26.03	32.5	29.54
2021	39.11	33.99	43.71	39.08	30.28	26.24	33.94	30.4
2022	40.68	35.21	45.35	40.5	31.32	27.1	35.24	31.4
2023	42.24	36.32	46.95	41.84	32.48	27.8	36.35	32.32
2024	44.12	37.66	48.76	43.37	34.19	28.7	37.69	33.46
2025	45.27	38.75	49.87	44.67	35.15	29.44	38.76	34.48
2026	46.55	39.82	51.21	46.01	36.3	30.34	39.86	35.51
2027	47.22	40.64	52.15	46.67	37.28	31.04	40.97	36.53
2028	58.67	52.48	64.38	48.81	49.18	43.42	53.33	38.2
2029	59.97	53.88	66.19	50.44	50.26	44.41	54.93	39.5
2030	63.23	57.53	69.93	53.02	52.56	46.98	57.94	41.5
2031	65.71	59.75	72.51	55.49	54.61	48.9	60.04	43.11
2032	66.8	61.27	74.04	56.44	56.68	50.75	62.44	44.59
2033	68.01	62.93	75.98	57.61	57.93	52.44	64.03	46.01
2034	69.72	64.54	76.11	58.5	60.38	54.64	66.05	47.58
2035	72.56	67.51	79.46	60.34	62.78	57.19	68.85	49.83
2036	74.76	69.96	80.5	61.12	63.88	59.19	70.26	50.77
2037	76.24	70.59	81.45	61.73	65.93	60.56	72.12	52.23

Exhibit E Cost of Capital

Southwestern Electric Power
Annual Investment Carrying Charges
For Economic Analyses
As of 12/31/2017

	Investment Life (Years)											
	2	3	4	5	10	15	20	25	30	33	40	50
Return (1)	7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45	7.45
Depreciation (2)	49.01	31.84	23.25	18.10	7.95	4.71	3.17	2.31	1.77	1.54	1.16	0.84
FIT (3) (4)	1.10	0.79	0.84	0.70	0.66	0.80	0.83	0.72	0.65	0.62	0.56	0.51
Property Taxes, General & Admin Expenses	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41
Carrying Cost Per Year	58.96	41.49	32.95	27.66	17.48	14.37	12.86	11.89	11.28	11.01	10.58	10.21

(1) Based on a 100% (as of 12/31/2017) and 0% incremental weighting of capital costs

(2) Sinking Fund annuity with R1 Dispersion of Retirements

(3) Assuming MACRS Tax Depreciation

(4) @ 21% Federal Income Tax Rate

Exhibit F Acronyms

ACRONYM	DEFINITION
A/C	Air Conditioning
AC	Alternating Current
ACI	Activated Carbon Injection
AD	Aeroderivative
ADEQ	Arkansas Department of Environmental Quality
AECC	Arkansas Electric Cooperative Corporation
AEP	American Electric Power
AMI	Advanced Metering Infrastructure
AP	Achievable Potential
APC&EC	Arkansas Pollution Control and Ecology Commission
APSC	Arkansas Public Service Commission
ARIMA	Autoregressive Integrated Moving Average
ARRA	American Recovery and Reinvestment Act
BART	Best Available Retrofit Technology
BNEF	Bloomberg New Energy Finance
BSER	Best System of Emission Reduction
BTU	British Thermal Unit
CAA	Clean Air Act
CAFE	Corporate Average Fuel Economy
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals
CD	Compact Disc
CDR	Capacity Demand and Reserves
CERA	Cambridge Energy Research Associates
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
COS	Cost of Service
CPP	Clean Power Plan
CPW	Cumulative Present Worth
CSAPR	Cross-State Air Pollution Rule
DC	Direct Current
DG	Distributed Generation
DOE	Department of Energy
DR	Demand Reduction
DSI	Dry Sorbent Injection
DSM	Demand-side Management
EE	Energy Efficiency
EGU	Electric Generating Units
EHV	Extra High Voltage
EIA	Energy Information Administration
EIEA2008	Energy Improvement and Extension Act of 2008
EISA	Energy Independence and Security Act
ELG	Effluent Limitation Guidelines
EPA	Environmental Protection Agency
EPAct	Energy Policy Act
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas

ESP	Electrostatic Precipitator
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FRB	Federal Reserve Board
GDP	Gross Domestic Product
GE	General Electric
GHG	Greenhouse Gas
GWh	Gigawatt-hour
HAP	High Achievable Potential
HCl	Hydrochloric Acid
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Cooling
HVDC	High Voltage Direct Current
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
ITP	Integrated Transmission Planning
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
lb	Pound
LCOE	Levelized Cost of Energy
LHV	Lower Hating value
LNB	Low NO_x Burner
MAR	Market Acceptance Ratio
MATS	Mercury and Air Toxics Standard
mmBTU	Million BTU
MW	Megawatt
MWac	Alternating Current Megawatts
MWh	Megawatt-Hour
MWh-g	Megawatt-Hour, Gross
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combines Cycle
NGCT	Natural Gas Combustion Turbine
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
O&M	Operations and Maintenance
OATT	Open Access Transmission Tariff
OCC	Oklahoma Corporation Commission
OFA	Overfire Air
OG&E	Oklahoma Gas and Electric Energy Corporation
PCT	Participant Cost Test

PIF	Program Implementation Factor
PIRA	Petroleum Industry Research Associates
PM	Particulate Material
PPA	Power Purchase Agreement
PSIG	Pounds per Square Inch, Gage
PSO	Public Service Company of Oklahoma
PTC	Production Tax Credit
PV	Photovoltaic
PY	Program Year
RE	Reciprocating Engine
REPA	Renewable Energy Purchase Agreement
RFP	Request for Proposal
RHR	Regional Haze Rule
RIM	Ratepayer Impact Measure
RRaR	Revenue Requirement at Risk
RTO	Regional Transmission Organization
SAE	Statistically Adjust End-Use
SCR	Selective Catalytic Reduction
SD	Standard Deviation
SEER	Seasonal Energy Efficiency Ratio
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool
STEP	SPP Transmission Expansion Plan
SWEPCO	Southwestern Electric Power Company
TCEQ	Texas Commission on Environmental Quality
TRC	Total Resource Cost
UCT	Utility Cost Test
VVO	Volt VAR Optimization

Exhibit G Capability, Demand and Reserve (CDR) – "Going-In"[14,15]

[14] Represents SWEPCO-owned installed capacity.

[15] Exhibit includes the Turk Power Plant which is not used or recoverable in Arkansas.

SOUTHWESTERN ELECTRIC POWER COMPANY
CAPABILITY, DEMAND AND RESERVES FORECAST
2019 - 2051
(MW)

CAPABILITY

	Plant Capabilities	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
12	ARSENAL HILL # 5	110	110	110	110	110	110	110	0	0	0	0	0	0	0	0	0	0	0	0	0
11	J.L. STALL CC	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511
10	DOLET HILLS #1	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
9	FLINT CREEK # 1	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258
8	TURK	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477	477
7	KNOX LEE # 2, 3, 4, 5	398	398	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342
6	LIEBERMAN # 2, 3, 4	242	217	217	217	108	108	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	LONE STAR # 1	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	PIRKEY #1	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580
3	MATTISON CTs	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284
2	WELSH # 1, 3	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	528
1	WILKES # 1, 2, 3	877	877	877	877	877	877	877	877	877	877	877	713	713	713	713	713	713	353	0	0
1	TOTAL	5,097	5,022	4,966	4,966	4,857	4,857	4,749	4,639	4,639	4,639	4,639	4,475	4,475	4,475	4,475	4,475	4,475	4,115	3,762	3,237
	Adjustments to Plant Capability																				
2	TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Net Plant Capability (1 + 2)	5,097	5,022	4,966	4,966	4,857	4,857	4,749	4,639	4,639	4,639	4,639	4,475	4,475	4,475	4,475	4,475	4,475	4,115	3,762	3,237
	Sales Without Reserves																				
	Backup contracts (Eastman, Domtar, & Internat'l Paper)	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
4	TOTAL	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
	Purchases Without Reserves																				
	NTEC - HCPP	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	NTEC GEN - PIRKEY/DOLET HILLS/TURK	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171
	NTEC - ENTERGY ISES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	NTEC - SPA NARROWS	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
	TEX-LA - HCPP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ETEC - HCPP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CUSTOMER GENERATION - MINDEN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	EXELON GREEN COUNTRY (2)	0	0																		
	MAJESTIC WIND PROJECT	13	13	13	13	13	13	13	13	13	13	0	0	0	0	0	0	0	0	0	0
	HIGH MAJESTIC WIND PROJECT	21	21	21	21	21	21	21	21	21	21	21	21	21	21	0	0	0	0	0	0
	FLAT RIDGE WIND PROJECT	11	11	11	11	11	11	11	11	11	11	11	11	11	11	0	0	0	0	0	0
	CANADIAN HILLS WIND PROJECT	35	35	35	35	35	35	35	35	35	35	35	35	35	35	0	0	0	0	0	0
	WHOLESALE PURCHASE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	TOTAL	578	578	578	578	578	578	578	578	578	578	565	565	565	565	498	498	498	498	498	498
6	Total Capability (3 - 4 + 5)	5,656	5,581	5,525	5,525	5,416	5,416	5,308	5,198	5,198	5,198	5,185	5,021	5,021	5,021	4,955	4,955	4,955	4,595	4,242	3,717

DEMAND	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Original Forecast	3,773	3,751	3,781	3,801	3,810	3,825	3,838	3,853	3,869	3,886	3,901	3,919	3,940	3,961	3,982	3,999	4,023	4,049	4,072	4,096
Bentonville, City of	143	144	147	150	153	155	157	160	163	165	168	170	173	175	178	181	183	186	188	191
East Texas EC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hope, City of	57	58	58	58	58	59	59	59	59	59	59	60	60	60	60	60	60	61	61	61
Minden, City of	33	33	33	33	33	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
North Texas EC	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660
Prescott, City of	15	15	15	15	15	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Rayburn Country EC	109	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
A Peak Demand Before Passive DSM	4,799	4,668	4,704	4,732	4,746	4,765	4,782	4,802	4,823	4,842	4,863	4,885	4,910	4,935	4,961	4,980	5,009	5,039	5,067	5,095
B Passive DSM																				
Approved Passive DSM	9	8	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	9	8	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C Peak Demand (A - B)	4,789	4,660	4,700	4,730	4,746	4,765	4,782	4,802	4,823	4,842	4,863	4,885	4,910	4,935	4,961	4,980	5,009	5,039	5,067	5,095
D Active DSM																				
Interruptible	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29
DLC/ELM	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
TOTAL	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
E Firm Demand (C - D)	4,744	4,614	4,654	4,684	4,700	4,719	4,736	4,756	4,777	4,797	4,817	4,839	4,864	4,889	4,915	4,934	4,963	4,993	5,021	5,049
F Other Demand Adjustments																				
DIVERSITY	23	22	23	24	23	23	23	24	23	25	23	23	23	23	24	24	24	25	24	25
TOTAL	23	22	23	24	23	23	23	24	23	25	23	23	23	23	24	24	24	25	24	25
7 Native Load Responsibility (E - F)	4,721	4,592	4,631	4,660	4,677	4,696	4,714	4,733	4,753	4,771	4,793	4,816	4,841	4,866	4,890	4,911	4,939	4,969	4,997	5,025
Sales With Reserves																				
TEX-LA ERCOT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NTEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchases With Reserves																				
NTEC SPA HYDRO PEAKING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LOUISIANA GENERATION (FORMERLY CAJUN)	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0
SPA HYDRO-B'VILLE/R'BURN/MINDEN/TEXLA	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
9 TOTAL	72	72	72	72	72	72	72	72	22	22	22	22	22	22	22	22	22	22	22	22
10 Load Responsibility (7 + 8 - 9)	4,649	4,520	4,559	4,588	4,605	4,624	4,642	4,661	4,731	4,749	4,771	4,794	4,819	4,844	4,868	4,889	4,917	4,947	4,975	5,003

RESERVES	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
11 Reserve Capacity (6 - 10)	1,008	1,061	967	937	811	792	667	538	467	449	414	227	202	178	86	66	38	-352	-733	-1,286
12 % Reserve Margin ((11/10) * 100)	21.7	23.5	21.2	20.4	17.6	17.1	14.4	11.5	9.9	9.5	8.7	4.7	4.2	3.7	1.8	1.4	0.8	-7.1	-14.7	-25.7
13 % Capacity Margin (11/(6) * 100)	17.8	19.0	17.5	17.0	15.0	14.6	12.6	10.3	9.0	8.6	8.0	4.5	4.0	3.5	1.7	1.3	0.8	-7.7	-17.3	-34.6
14 Reserves Above Minimum 12.0% Reserve Margin	450	519	419	386	258	237	110	(22)	(101)	(121)	(159)	(348)	(376)	(403)	(498)	(520)	(552)	(946)	(1,330)	(1,886)

Exhibit H Capability, Demand and Reserve (CDR) – Preferred Plan[16],[17]

[16] Represents SWEPCO-owned installed capacity.

[17] Exhibit includes the Turk Power Plant which is not used or recoverable in Arkansas.

SOUTHWESTERN ELECTRIC POWER COMPANY
CAPABILITY, DEMAND AND RESERVES FORECAST
2019 - 2038
(MW)

CAPABILITY

#	Plant Capabilities	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
	ARSENAL HILL # 5	110	110	110	110	110	110	110	0	0	0	0	0	0	0	0	0	0	0	0	0
	J.L. STALL CC	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511
	DOLET HILLS #1	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
	FLINT CREEK # 1	258	258	258	258	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	477	477	477	477
	KNOX LEE # 2, 3, 4, 5	398	398	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342
	LIEBERMAN # 2, 3, 4	242	217	217	217	108	108	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	LONE STAR # 1	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	PIRKEY #1	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580
	MATTISON CTs	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284
	WELSH # 1, 3	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	528
	WILKES # 1, 2, 3	877	877	877	877	877	877	877	877	877	877	877	713	713	713	713	713	713	353	0	0
1	**TOTAL**	**5,097**	**5,022**	**4,966**	**4,966**	**4,857**	**4,857**	**4,749**	**4,639**	**4,639**	**4,639**	**4,639**	**4,475**	**4,475**	**4,475**	**4,475**	**4,475**	**4,475**	**4,115**	**3,762**	**3,237**
	Adjustments to Plant Capability																				
	New CC1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	373	1,119
	VVO	0	24	24	24	24	24	37	37	37	37	37	37	37	37	48	48	48	48	48	48
	EE	0	8	15	21	20	25	23	20	17	13	12	11	10	7	5	3	3	2	2	1
	Distr Solar	3	3	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
	IRP Wind	0	0	0	30	60	70	220	370	420	420	450	450	450	600	600	600	600	600	600	600
	IRP Solar	0	0	0	0	0	0	15	30	45	95	144	204	253	303	360	395	429	429	429	429
2	**TOTAL**	**3**	**35**	**43**	**79**	**108**	**123**	**300**	**462**	**524**	**569**	**648**	**707**	**755**	**952**	**1,019**	**1,052**	**1,086**	**1,086**	**1,459**	**2,205**
3	**Net Plant Capability (1 + 2)**	**5,100**	**5,056**	**5,008**	**5,044**	**4,965**	**4,980**	**5,048**	**5,100**	**5,162**	**5,207**	**5,287**	**5,182**	**5,230**	**5,427**	**5,494**	**5,526**	**5,561**	**5,200**	**5,220**	**5,442**
	Sales Without Reserves																				
	Backup contracts (Eastman, Domtar, & Internat'l Paper)	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
4	**TOTAL**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**
	Purchases Without Reserves																				
	NTEC - HCPP	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	NTEC GEN - PIRKEY/DOLET HILLS/TURK	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171	171
	NTEC - SPA NARROWS	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
	MAJESTIC WIND PROJECT	13	13	13	13	13	13	13	13	13	13	0	0	0	0	0	0	0	0	0	0
	HIGH MAJESTIC WIND PROJECT	21	21	21	21	21	21	21	21	21	21	21	21	21	21	0	0	0	0	0	0
	FLAT RIDGE WIND PROJECT	11	11	11	11	11	11	11	11	11	11	11	11	11	11	0	0	0	0	0	0
	CANADIAN HILLS WIND PROJECT	35	35	35	35	35	35	35	35	35	35	35	35	35	35	0	0	0	0	0	0
	WHOLESALE PURCHASE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	**TOTAL**	**578**	**578**	**578**	**578**	**578**	**578**	**578**	**578**	**578**	**578**	**565**	**565**	**565**	**565**	**498**	**498**	**498**	**498**	**498**	**498**
6	**Total Capability (3 - 4 + 5)**	**5,660**	**5,616**	**5,568**	**5,604**	**5,524**	**5,539**	**5,608**	**5,660**	**5,722**	**5,767**	**5,834**	**5,728**	**5,776**	**5,974**	**5,974**	**6,006**	**6,041**	**5,680**	**5,700**	**5,922**

	DEMAND	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
	Original Forecast	3,773	3,751	3,781	3,801	3,810	3,825	3,838	3,853	3,869	3,886	3,901	3,919	3,940	3,961	3,982	3,999	4,023	4,049	4,072	4,096
	Bentonville, City of	143	144	147	150	153	155	157	160	163	165	168	170	173	175	178	181	183	186	188	191
	Hope, City of	57	58	58	58	58	59	59	59	59	59	59	60	60	60	60	60	60	61	61	61
	Minden, City of	33	33	33	33	33	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
	North Texas EC	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660
	Prescott, City of	15	15	15	15	15	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
	Rayburn Country EC	109	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
A	Peak Demand Before Passive DSM	4,799	4,668	4,704	4,732	4,746	4,765	4,782	4,802	4,823	4,842	4,863	4,885	4,910	4,935	4,961	4,980	5,009	5,039	5,067	5,095
B	Passive DSM																				
	Approved Passive DSM	9	8	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	9	8	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C	Peak Demand (A - B)	4,789	4,660	4,700	4,730	4,746	4,765	4,782	4,802	4,823	4,842	4,863	4,885	4,910	4,935	4,961	4,980	5,009	5,039	5,067	5,095
D	Active DSM																				
	Interruptible	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29
	DLC/ELM	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	TOTAL	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
E	Firm Demand (C - D)	4,744	4,614	4,654	4,684	4,700	4,719	4,736	4,756	4,777	4,797	4,817	4,839	4,864	4,889	4,915	4,934	4,963	4,993	5,021	5,049
F	Other Demand Adjustments																				
	DIVERSITY	23	22	23	24	23	23	23	24	23	25	23	23	23	23	24	24	24	25	24	25
	TOTAL	23	22	23	24	23	23	23	24	23	25	23	23	23	23	24	24	24	25	24	25
7	Native Load Responsibility (E - F)	4,721	4,592	4,631	4,660	4,677	4,696	4,714	4,733	4,753	4,771	4,793	4,816	4,841	4,866	4,890	4,911	4,939	4,969	4,997	5,025
	Sales With Reserves																				
8	TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Purchases With Reserves																				
	LOUISIANA GENERATION (FORMERLY CAJUN)	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0
	SPA HYDRO-B'VILLE/R'BURN/MINDEN/TEXLA	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
9	TOTAL	72	72	72	72	72	72	72	72	22	22	22	22	22	22	22	22	22	22	22	22
10	Load Responsibility (7 + 8 - 9)	4,649	4,520	4,559	4,588	4,605	4,624	4,642	4,661	4,731	4,749	4,771	4,794	4,819	4,844	4,868	4,889	4,917	4,947	4,975	5,003

	RESERVES	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
11	Reserve Capacity (6 - 10)	1,011	1,096	1,009	1,016	919	915	966	999	991	1,018	1,062	934	958	1,130	1,105	1,118	1,124	734	726	919
12	% Reserve Margin ((11/10) * 100)	21.7	24.3	22.1	22.1	20.0	19.8	20.8	21.4	20.9	21.4	22.3	19.5	19.9	23.3	22.7	22.9	22.9	14.8	14.6	18.4
13	% Capacity Margin (11/(6) * 100)	17.9	19.5	18.1	18.1	16.6	16.5	17.2	17.7	17.3	17.7	18.2	16.3	16.6	18.9	18.5	18.6	18.6	12.9	12.7	15.5
14	Reserves Above Minimum 12.0% Reserve Margin	453	554	462	465	367	360	409	440	423	448	490	359	379	549	521	531	534	140	129	319

Exhibit I Modeled Scenario Results

SOUTHWESTERN ELECTRIC POWER COMPANY

INTEGRATED RESOURCE PLAN

'Base' Commodity Pricing - Preferred Plan & Base Optimization

Utility Costs (Nominal$)

	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) Less: Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	$562,185	$546,635	$9,169	$152,104	$34,379	$0	$18,737	$524,106	$799,103
2019	$631,562	$476,432	$9,193	$180,379	$33,528	$0	$13,116	$563,728	$780,482
2020	$700,811	$499,190	$9,561	$213,911	$35,408	$4,869	$5,994	$658,173	$811,571
2021	$727,680	$505,205	$10,179	$238,949	$36,400	$5,173	$4,359	$671,899	$856,046
2022	$761,338	$514,897	$10,671	$255,023	$49,054	$72,374	$2,477	$800,954	$864,880
2023	$793,783	$522,181	$11,128	$280,110	$61,113	$152,949	$449	$924,630	$897,083
2024	$836,234	$565,416	$11,715	$304,653	$66,295	$188,074	($2,229)	$1,031,617	$938,541
2025	$861,177	$535,459	$27,718	$356,929	$67,430	$204,790	($3,690)	$1,033,336	$1,016,478
2026	$891,171	$580,477	$29,201	$373,595	$75,679	$220,768	($5,416)	$1,125,295	$1,040,179
2027	$912,597	$618,909	$31,080	$377,475	$82,778	$236,583	($6,472)	$1,199,368	$1,053,582
2028	$1,167,064	$599,430	$293,862	$388,914	$87,228	$252,065	($27,873)	$1,498,969	$1,261,721
2029	$1,199,721	$651,248	$316,757	$425,090	$111,279	$382,985	($35,463)	$1,730,285	$1,321,334
2030	$1,266,020	$609,663	$315,469	$451,667	$116,700	$409,713	($40,004)	$1,776,356	$1,352,873
2031	$1,321,936	$648,570	$348,263	$474,306	$126,955	$425,137	($43,393)	$1,926,260	$1,375,514
2032	$1,362,981	$672,047	$366,811	$495,091	$134,785	$441,792	($44,697)	$2,009,670	$1,419,140
2033	$1,393,187	$656,699	$369,578	$516,523	$141,646	$444,502	$0	$2,000,669	$1,521,466
2034	$1,447,270	$685,685	$401,020	$538,205	$147,248	$444,697	$0	$2,113,136	$1,550,988
2035	$1,513,297	$679,002	$404,596	$557,235	$149,581	$445,412	$0	$2,149,894	$1,599,228
2036	$1,557,369	$715,177	$443,099	$572,259	$154,675	$445,402	$0	$2,247,103	$1,640,878
2037	$1,605,333	$798,957	$474,212	$583,773	$166,171	$492,367	$0	$2,407,330	$1,713,482
2038	$1,683,036	$839,374	$408,288	$559,682	$177,510	$588,165	$0	$2,420,750	$1,835,305
2039	$1,701,219	$816,626	$389,653	$539,893	$176,690	$588,175	$0	$2,328,919	$1,883,337
2040	$1,763,370	$899,303	$413,270	$528,798	$188,258	$639,233	$0	$2,497,187	$1,935,045
2041	$1,828,634	$934,442	$442,574	$526,739	$193,398	$639,154	$0	$2,600,159	$1,964,782
2042	$1,855,855	$1,025,638	$478,858	$520,934	$206,087	$691,290	$0	$2,737,626	$2,041,036
2043	$1,926,686	$1,009,813	$384,980	$466,218	$211,029	$744,525	$0	$2,644,949	$2,098,302
2044	$1,986,403	$1,040,646	$416,500	$454,707	$222,188	$744,525	$0	$2,736,858	$2,128,111
2045	$2,035,296	$1,063,420	$434,941	$440,394	$226,651	$744,525	$0	$2,785,675	$2,159,551
2046	$2,104,364	$1,128,142	$361,961	$387,750	$240,679	$857,954	$0	$2,804,194	$2,276,657
2047	$2,170,053	$1,118,288	$306,045	$341,594	$246,766	$987,390	$0	$2,809,825	$2,360,310
Cumulative Present Worth $000 (2018$)									
Utility CPW 2018-2045	$12,735,404	$7,451,990	$1,980,839	$4,210,111	$1,115,551	$3,130,111	-$44,910	$16,298,285	$14,280,812
CPW of End Effects beyond 2045									$3,669,613
TOTAL Utility Cost, Net CPW (2018$)									$17,950,425

Resource (Capacity) Additions / Energy & Capacity Positions

	(10) Supply-Side (Thermal) Ann MW	(11) Supply-Side (Thermal) Cum MW	(12) (Increm) Energy Efficiency + VVO Ann MW	(13) (Increm) Energy Efficiency + VVO Cum MW	(14) Distributed Solar Ann MW	(15) Distributed Solar Cum MW	(16) Generic Wind Ann MW	(17) Generic Wind Cum MW	(18) Utility Solar Ann MW	(19) Utility Solar Cum MW	(12) Thermal Generation GWh	(13) (Current) Purchased Energy GWh	(14) (New) Wind, EE, Solar, IVV GWh	(15)=(12)+(13)+(14) = Market Sales GWh	(16) = Net Load Requirements GWh	(17)=(16)-(15) ENERGY Surplus GWh	(17) Capacity MW	(18) Peak + Reserves MW	(19)=(17)-(18) CAPACITY Surplus MW	(20) Reserve Margin %
2018	0	0	0.0	0.0	0.0	3.30	0.0	0	0	0	19,129	1,874	19	21,022	20,820	202	5,745	5,118	627	25.7
2019	0	0	0.0	0.0	0.0	3.30	0.0	0	0	0	18,351	1,874	19	20,244	20,808	(564)	5,659	5,207	452	21.7
2020	0	0	31.5	31.5	0.0	3.30	0.0	0	0	0	18,842	1,880	158	20,879	20,326	554	5,616	5,062	553	24.2
2021	0	0	7.4	39.0	0.3	3.63	0.0	0	0	0	18,629	1,874	196	20,699	20,457	241	5,568	5,106	462	22.1
2022	0	0	6.2	45.2	0.0	3.63	30.0	30	0	0	18,952	1,874	2,749	23,575	20,589	2,985	5,604	5,139	465	22.1
2023	0	0	(1.1)	44.1	0.3	3.96	30.0	60	0	0	18,899	1,874	5,298	26,071	20,684	5,387	5,524	5,158	366	20.0
2024	0	0	5.0	49.1	0.0	3.96	10.0	70	0	0	19,651	1,880	6,167	27,698	20,750	6,948	5,539	5,179	360	19.8
2025	0	0	11.1	60.3	0.3	4.29	150.0	220	15	15	18,433	1,874	6,557	26,864	20,803	6,061	5,608	5,199	409	20.8
2026	0	0	(3.2)	57.1	0.3	4.62	150.0	370	15	30	19,671	1,874	6,906	28,452	20,869	7,583	5,660	5,220	439	21.4
2027	0	0	(3.1)	54.0	0.0	4.62	50.0	420	15	45	20,584	1,874	7,255	29,713	20,943	8,770	5,722	5,299	423	20.9
2028	0	0	(4.7)	49.4	0.3	4.95	0.0	420	50	95	19,627	1,880	7,623	29,130	21,036	8,094	5,767	5,319	448	21.4
2029	0	0	(0.0)	49.3	0.0	4.95	30.0	450	50	144	20,294	1,591	10,483	32,369	21,130	11,239	5,833	5,344	490	22.3
2030	0	0	(1.2)	48.1	0.3	5.28	0.0	450	60	204	18,950	1,569	11,093	31,613	21,206	10,407	5,728	5,369	359	19.5
2031	0	0	(1.7)	46.4	0.3	5.61	0.0	450	50	253	19,951	1,569	11,452	32,973	21,290	11,683	5,776	5,397	379	19.9
2032	0	0	(2.4)	44.0	0.3	5.94	150.0	600	50	303	20,112	1,528	11,835	33,474	21,379	12,095	5,973	5,425	548	23.3
2033	0	0	9.1	53.1	0.0	5.94	0.0	600	58	360	19,370	0	11,849	31,218	21,475	9,743	5,974	5,452	522	22.7
2034	0	0	(2.2)	50.9	0.3	6.27	0.0	600	35	395	20,035	0	11,846	31,881	21,582	10,299	6,007	5,476	531	22.9
2035	0	0	(0.4)	50.5	0.3	6.60	0.0	600	35	429	19,316	0	11,845	31,160	21,694	9,466	6,041	5,507	534	22.9
2036	0	0	(0.6)	49.9	0.3	6.93	0.0	600	0	429	20,094	0	11,867	31,961	21,806	10,155	5,681	5,541	140	14.8
2037	373	373	(0.5)	49.4	0.3	7.26	0.0	600	0	429	21,506	0	11,845	33,351	21,922	11,429	5,701	5,572	129	14.6
2038	746	1,119	(0.4)	49.0	0.3	7.59	0.0	600	0	429	20,267	0	11,845	32,112	22,038	10,074	5,922	5,603	318	18.4
2039	0	1,119	(0.2)	48.8	0.3	7.92	0.0	600	0	429	18,801	0	11,846	30,647	22,159	8,488	5,664	5,635	29	12.6
2040	373	1,492	(0.2)	48.6	0.3	8.25	0.0	600	0	429	19,922	0	11,862	31,784	22,281	9,503	5,695	5,667	28	12.5
2041	0	1,492	(0.3)	48.3	0.3	8.58	0.0	600	0	429	20,319	0	11,848	32,168	22,388	9,780	5,695	5,692	3	12.1
2042	373	1,865	(0.2)	48.1	0.3	8.91	0.0	600	0	429	21,554	0	11,849	33,403	22,504	10,900	6,068	5,724	344	18.7
2043	373	2,238	(0.1)	48.0	0.3	9.24	0.0	600	0	429	19,363	0	11,851	31,214	22,629	8,584	5,913	5,758	155	15.0
2044	0	2,238	(0.1)	47.9	0.3	9.57	0.0	600	0	429	19,621	0	11,866	31,487	22,759	8,728	5,913	5,787	126	14.4
2045	0	2,238	(0.0)	47.9	0.3	9.90	0.0	600	0	429	19,612	0	11,854	31,466	22,893	8,573	5,835	5,817	17	12.3
2046	746	2,984	0.0	47.9	0.7	10.56	0.0	600	0	429	18,903	0	11,858	30,761	23,052	7,709	5,963	5,942	22	12.4
2047	373	3,357	0.0	47.9	0.3	10.89	0.0	600	0	429	18,097	0	11,860	29,957	23,186	6,771	6,080	5,937	143	14.7

SOUTHWESTERN ELECTRIC POWER COMPANY
INTEGRATED RESOURCE PLAN
'High Band' Commodity Pricing

Utility Costs (Nominal $)

	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) Less: Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	$596,541	$575,758	$9,447	$152,104	$35,061	$0	$15,596	$568,311	$816,196
2019	$690,465	$484,030	$9,317	$180,379	$33,536	$0	$7,977	$618,035	$787,668
2020	$777,753	$507,524	$9,615	$213,911	$35,449	$4,869	($940)	$731,663	$816,518
2021	$813,858	$515,327	$10,244	$238,949	$36,540	$5,173	($3,241)	$754,302	$862,547
2022	$850,695	$547,505	$10,713	$255,023	$49,473	$74,601	($5,474)	$897,693	$884,843
2023	$883,754	$556,070	$11,171	$280,110	$61,364	$155,176	($7,446)	$1,029,955	$910,244
2024	$922,352	$593,094	$11,739	$304,653	$68,658	$206,795	($9,711)	$1,145,090	$952,491
2025	$947,878	$565,196	$27,842	$356,929	$69,438	$221,113	($11,255)	$1,146,319	$1,030,821
2026	$978,308	$610,369	$29,239	$373,595	$77,789	$237,091	($12,931)	$1,244,067	$1,049,393
2027	$1,005,051	$654,347	$31,129	$377,475	$85,006	$252,906	($14,392)	$1,331,323	$1,060,199
2028	$1,274,137	$642,559	$295,989	$388,914	$91,882	$279,918	($36,893)	$1,675,119	$1,261,386
2029	$1,318,217	$692,110	$319,150	$425,090	$115,790	$410,838	($43,849)	$1,935,382	$1,301,965
2030	$1,398,614	$653,129	$318,930	$451,667	$120,372	$429,750	($49,193)	$1,996,680	$1,326,591
2031	$1,455,664	$694,075	$351,767	$474,306	$131,268	$447,046	($52,732)	$2,160,696	$1,340,698
2032	$1,507,028	$717,707	$370,093	$495,091	$136,605	$450,023	($54,335)	$2,234,385	$1,387,827
2033	$1,551,288	$701,003	$373,310	$516,523	$143,544	$452,733	$0	$2,237,454	$1,500,948
2034	$1,575,994	$728,842	$404,579	$538,205	$148,936	$452,927	$0	$2,312,898	$1,536,585
2035	$1,655,938	$726,319	$407,773	$557,235	$151,604	$453,643	$0	$2,370,782	$1,581,730
2036	$1,687,528	$751,890	$446,137	$572,259	$156,260	$453,633	$0	$2,445,242	$1,622,465
2037	$1,723,640	$829,216	$474,685	$583,773	$166,765	$501,596	$0	$2,576,449	$1,703,226
2038	$1,770,843	$849,474	$401,217	$559,682	$176,551	$597,394	$0	$2,499,139	$1,856,023
2039	$1,817,375	$834,001	$384,565	$539,893	$176,186	$597,404	$0	$2,451,528	$1,897,897
2040	$1,865,050	$896,369	$403,313	$528,798	$187,018	$647,387	$0	$2,563,962	$1,963,973
2041	$1,907,782	$928,188	$431,108	$526,739	$191,999	$651,613	$0	$2,634,643	$2,002,786
2042	$1,972,783	$965,840	$458,597	$520,934	$196,833	$654,189	$0	$2,734,613	$2,034,563
2043	$2,033,741	$1,008,317	$369,741	$466,218	$209,268	$753,777	$0	$2,693,799	$2,147,264
2044	$2,105,964	$1,050,071	$402,627	$454,707	$220,974	$753,777	$0	$2,814,399	$2,173,721
2045	$2,157,097	$1,119,148	$428,545	$440,394	$226,465	$751,130	$0	$2,918,406	$2,204,373
2046	$2,245,525	$1,124,162	$339,384	$387,750	$236,091	$861,847	$0	$2,837,569	$2,357,189
2047	$2,308,145	$1,197,388	$294,687	$341,594	$244,051	$988,503	$0	$2,920,039	$2,454,329
Cumulative Present Worth $000 (2018$)									
Utility CPW 2018-2045	$13,874,489	$7,765,009	$1,971,957	$4,210,111	$1,127,698	$3,230,615	-$108,775	$17,717,134	$14,353,969
CPW of End Effects beyond 2045									$3,815,785
TOTAL Utility Cost, Net CPW (2018$)									$18,169,754

Resource (Capacity) Additions / Energy & Capacity Positions

	(10) Supply-Side (Thermal) Ann MW	(11) Supply-Side (Thermal) Cum MW	(12) (Increm) Energy Efficiency + VVO Ann MW	(13) (Increm) Energy Efficiency + VVO Cum MW	(14) Distributed Solar Ann MW	(15) Distributed Solar Cum MW	(16) Generic Wind Ann MW	(17) Generic Wind Cum MW	(18) Utility Solar Ann MW	(19) Utility Solar Cum MW	(12) Thermal Generation GWh	(13) (Current) Purchased Energy GWh	(14) (New) Wind, EE, Solar, IVV GWh	(15)=(12)+(13)+(14) = Market Sales GWh	(16) = Net Load Requirements GWh	(17)=(16)-(15) ENERGY Surplus GWh	(17) Capacity MW	(18) Peak + Reserves MW	(19)=(17)-(18) CAPACITY Surplus MW	(20) Reserve Margin %
2018	0	0	0.0	0.0	0.0	3.30	0.0	0	0	0	19,761	1,874	19	21,655	20,820	835	5,745	5,118	627	25.7
2019	0	0	0.0	**0.0**	0.0	3.30	0.0	0	0	0	18,497	1,874	19	20,390	20,808	(418)	5,659	5,207	452	21.7
2020	0	0	31.5	**31.5**	0.0	3.30	0.0	0	0	0	18,949	1,880	158	20,986	20,326	661	5,616	5,062	554	24.2
2021	0	0	7.4	**39.0**	0.3	3.63	0.0	0	0	0	18,787	1,874	196	20,857	20,457	400	5,568	5,106	462	22.1
2022	0	0	19.2	**58.2**	0.0	3.63	30.0	30	0	0	19,005	1,874	2,803	23,682	20,589	3,093	5,617	5,139	478	22.4
2023	0	0	(1.1)	**57.1**	0.3	3.96	30.0	60	0	0	18,898	1,874	5,352	26,124	20,684	5,440	5,537	5,158	379	20.2
2024	0	0	5.0	**62.1**	0.0	3.96	10.0	70	15	15	19,398	1,880	6,589	27,867	20,750	7,117	5,567	5,179	388	20.4
2025	0	0	(1.9)	**60.3**	0.3	4.29	150.0	220	15	30	18,304	1,874	6,925	27,103	20,803	6,300	5,623	5,199	424	21.1
2026	0	0	(3.2)	**57.1**	0.3	4.62	150.0	370	15	45	19,471	1,874	7,274	28,619	20,869	7,750	5,675	5,220	455	21.8
2027	0	0	(3.1)	**54.0**	0.0	4.62	50.0	420	50	95	20,422	1,874	7,623	29,919	20,943	8,976	5,771	5,299	472	22.0
2028	0	0	(4.7)	**49.4**	0.3	4.95	0.0	420	60	154	19,670	1,880	8,236	29,786	21,036	8,750	5,826	5,319	507	22.7
2029	0	0	(0.0)	**49.3**	0.0	4.95	30.0	450	50	204	20,282	1,591	11,096	32,969	21,130	11,839	5,893	5,344	549	23.5
2030	0	0	9.0	**58.3**	0.3	5.28	0.0	450	50	253	19,120	1,569	11,501	32,190	21,206	10,984	5,788	5,369	419	20.7
2031	0	0	7.9	**66.2**	0.3	5.61	0.0	450	73	326	20,126	1,569	11,900	33,595	21,290	12,305	5,868	5,397	471	21.8
2032	0	0	5.9	**72.1**	0.3	5.94	150.0	600	35	360	20,202	1,528	11,949	33,679	21,379	12,300	6,059	5,425	634	25.1
2033	0	0	8.9	**81.0**	0.0	5.94	0.0	600	35	395	19,471	0	11,963	31,434	21,475	9,958	6,036	5,452	584	24.0
2034	0	0	(2.4)	**78.6**	0.3	6.27	0.0	600	35	429	20,126	0	11,960	32,086	21,582	10,504	6,069	5,476	593	24.1
2035	0	0	(0.6)	**78.0**	0.3	6.60	0.0	600	0	429	19,441	0	11,958	31,399	21,694	9,705	6,069	5,507	562	23.4
2036	0	0	(0.7)	**77.3**	0.3	6.93	0.0	600	0	429	20,079	0	11,980	32,060	21,806	10,254	5,708	5,541	167	15.4
2037	373	373	(0.6)	**76.7**	0.3	7.26	0.0	600	0	429	21,198	0	11,957	33,156	21,922	11,234	5,728	5,572	156	15.1
2038	746	1,119	(0.5)	**76.2**	0.3	7.59	0.0	600	0	429	19,363	0	11,958	31,321	22,038	9,283	5,949	5,603	346	18.9
2039	0	1,119	(0.3)	**75.9**	0.3	7.92	0.0	600	0	429	18,134	0	11,959	30,093	22,159	7,934	5,691	5,635	56	13.1
2040	373	1,492	(0.2)	**75.7**	0.3	8.25	0.0	600	0	429	18,725	0	11,974	30,699	22,281	8,418	5,722	5,667	55	13.1
2041	0	1,492	0.7	**76.4**	0.3	8.58	0.0	600	0	429	19,035	0	11,962	30,998	22,388	8,609	5,723	5,692	31	12.6
2042	0	1,492	1.0	**77.4**	0.3	8.91	0.0	600	0	429	19,343	0	11,965	31,308	22,504	8,805	5,724	5,724	(0)	12.0
2043	746	2,238	(1.4)	**76.0**	0.3	9.24	0.0	600	0	429	17,965	0	11,965	29,929	22,629	7,300	5,941	5,758	183	15.6
2044	0	2,238	(0.8)	**75.2**	0.3	9.57	0.0	600	0	429	18,389	0	11,979	30,368	22,759	7,609	5,941	5,787	154	15.0
2045	0	2,238	(9.2)	**66.0**	0.3	9.90	0.0	600	0	429	19,028	0	11,929	30,957	22,893	8,064	5,853	5,817	36	12.7
2046	746	2,984	(9.7)	**56.3**	0.7	10.56	0.0	600	0	429	17,072	0	11,893	28,965	23,052	5,913	5,972	5,942	30	12.6
2047	373	3,357	(8.4)	**47.9**	0.3	10.89	0.0	600	0	429	17,219	0	11,860	29,078	23,186	5,893	6,080	5,937	143	14.7

SOUTHWESTERN ELECTRIC POWER COMPANY
INTEGRATED RESOURCE PLAN
'Low Band' Commodity Pricing

Utility Costs (Nominal $)

	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) Less: Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	$529,443	$516,393	$8,741	$152,104	$34,037	$0	$21,655	$483,008	$779,365
2019	$578,922	$468,812	$9,010	$180,379	$33,880	$0	$17,628	$519,281	$769,351
2020	$618,203	$484,178	$9,406	$213,911	$34,933	$4,869	$13,123	$574,475	$804,149
2021	$630,313	$488,477	$9,952	$238,949	$35,747	$4,466	$12,742	$574,362	$846,285
2022	$656,706	$476,577	$10,584	$255,023	$48,701	$71,958	$11,292	$687,439	$843,401
2023	$679,390	$472,757	$10,963	$280,110	$59,937	$152,530	$10,131	$780,636	$885,182
2024	$706,729	$504,079	$11,501	$304,653	$64,560	$187,041	$8,741	$852,745	$934,559
2025	$728,748	$478,527	$27,196	$356,929	$62,688	$186,226	$7,515	$842,725	$1,005,103
2026	$753,559	$524,506	$28,589	$373,595	$71,291	$202,204	$6,292	$922,416	$1,037,619
2027	$773,385	$554,690	$30,351	$377,475	$77,891	$218,019	$5,335	$980,363	$1,056,784
2028	$1,037,323	$537,050	$281,550	$388,914	$82,511	$233,501	($16,719)	$1,283,996	$1,260,134
2029	$1,067,500	$583,626	$303,902	$425,090	$106,181	$364,421	($26,017)	$1,484,883	$1,339,822
2030	$1,143,028	$557,908	$308,083	$451,667	$113,456	$396,100	($31,188)	$1,573,499	$1,365,554
2031	$1,194,048	$600,797	$340,823	$474,306	$123,926	$412,225	($34,364)	$1,713,542	$1,398,218
2032	$1,236,736	$613,370	$357,308	$495,091	$131,739	$431,729	($36,009)	$1,786,594	$1,443,371
2033	$1,278,418	$607,911	$362,111	$516,523	$141,292	$445,630	$0	$1,824,146	$1,527,738
2034	$1,324,713	$644,338	$395,863	$538,205	$147,329	$445,824	$0	$1,934,026	$1,562,246
2035	$1,395,700	$653,356	$403,080	$557,235	$150,808	$446,539	$0	$2,007,469	$1,599,251
2036	$1,454,870	$687,414	$442,523	$572,259	$155,990	$446,530	$0	$2,120,004	$1,639,581
2037	$1,479,963	$750,423	$469,909	$583,773	$166,732	$493,495	$0	$2,229,192	$1,715,103
2038	$1,524,872	$796,590	$410,178	$559,682	$179,251	$589,293	$0	$2,236,706	$1,823,161
2039	$1,556,664	$775,403	$390,446	$539,893	$178,214	$589,303	$0	$2,166,179	$1,863,744
2040	$1,604,627	$846,233	$414,400	$528,798	$189,900	$639,286	$0	$2,309,595	$1,913,649
2041	$1,610,633	$845,757	$435,566	$526,739	$192,881	$639,206	$0	$2,288,546	$1,962,236
2042	$1,657,055	$936,393	$472,894	$520,934	$206,019	$691,343	$0	$2,449,991	$2,034,647
2043	$1,716,971	$911,453	$382,889	$466,218	$210,886	$744,577	$0	$2,361,021	$2,071,973
2044	$1,759,320	$946,722	$415,184	$454,707	$222,356	$744,577	$0	$2,438,145	$2,104,721
2045	$1,809,789	$990,719	$438,658	$440,394	$228,021	$744,577	$0	$2,522,703	$2,129,456
2046	$1,888,781	$998,316	$359,595	$387,750	$240,874	$858,007	$0	$2,525,520	$2,207,803
2047	$1,954,347	$1,006,994	$312,812	$341,594	$247,644	$984,593	$0	$2,577,369	$2,270,615
Cumulative Present Worth $000 (2018$)									
Utility CPW 2018-2045	$11,352,149	$6,909,876	$1,952,412	$4,210,111	$1,099,484	$3,071,186	$29,793	$14,425,590	$14,199,421
CPW of End Effects beyond 2045									$3,530,162
TOTAL Utility Cost, Net CPW (2018$)									$17,729,583

Resource (Capacity) Additions / Energy & Capacity Positions

	(10) Supply-Side (Thermal) Ann MW	(11) Supply-Side (Thermal) Cum MW	(12) (Increm) Energy Efficiency + VVO Ann MW	(13) (Increm) Energy Efficiency + VVO Cum MW	(14) Distributed Solar Ann MW	(15) Distributed Solar Cum MW	(16) Generic Wind Ann MW	(17) Generic Wind Cum MW	(18) Utility Solar Ann MW	(19) Utility Solar Cum MW	(12) Thermal Generation GWh	(13) (Current) Purchased Energy GWh	(14) (New) Wind, EE, Solar, IVV GWh	(15)=(12)+(13)+(14) = Market Sales GWh	(16) = Net Load Requirements GWh	(17)=(16)-(15) ENERGY Surplus GWh	(17) Capacity MW	(18) Peak + Reserves MW	(19)=(17)-(18) CAPACITY Surplus MW	(20) Reserve Margin %
2018	0	0	0.0	0.0	0.0	3.30	0.0	0	0	0	18,346	1,874	19	20,239	20,745	(506)	5,745	5,118	627	25.7
2019	0	0	0.0	0.0	0.0	3.30	0.0	0	0	0	18,233	1,874	19	20,126	20,746	(620)	5,659	5,207	452	21.7
2020	0	0	31.5	31.5	0.0	3.30	0.0	0	0	0	18,468	1,880	158	20,506	20,264	242	5,616	5,062	554	24.2
2021	0	0	5.8	37.4	0.3	3.63	0.0	0	0	0	18,172	1,874	192	20,238	20,395	(157)	5,566	5,106	460	22.1
2022	0	0	5.2	42.6	0.0	3.63	30.0	30	0	0	18,725	1,874	2,742	23,341	20,527	2,814	5,601	5,139	462	22.1
2023	0	0	(1.2)	41.4	0.3	3.96	30.0	60	0	0	18,436	1,874	5,288	25,598	20,622	4,976	5,521	5,158	363	19.9
2024	0	0	2.8	44.2	0.0	3.96	10.0	70	0	0	18,927	1,880	6,153	26,960	20,688	6,272	5,534	5,179	355	19.7
2025	0	0	(1.3)	42.9	0.3	4.29	150.0	220	0	0	17,809	1,874	6,124	25,806	20,741	5,065	5,575	5,199	376	20.1
2026	0	0	(2.3)	40.7	0.3	4.62	150.0	370	15	15	19,087	1,874	6,476	27,437	20,807	6,630	5,628	5,220	408	20.7
2027	0	0	(2.3)	38.4	0.0	4.62	50.0	420	15	30	19,854	1,874	6,827	28,555	20,881	7,674	5,691	5,299	392	20.3
2028	0	0	(3.6)	34.7	0.3	4.95	0.0	420	15	45	18,834	1,880	7,196	27,910	20,974	6,936	5,703	5,319	384	20.1
2029	0	0	0.1	34.8	0.0	4.95	30.0	450	50	95	19,420	1,591	10,058	31,070	21,068	10,001	5,769	5,344	425	20.9
2030	0	0	(1.2)	33.6	0.3	5.28	0.0	450	65	159	18,532	1,569	10,789	30,890	21,144	9,746	5,669	5,369	300	18.3
2031	0	0	(1.4)	32.3	0.3	5.61	0.0	450	50	209	19,617	1,569	11,149	32,335	21,228	11,107	5,717	5,397	320	18.6
2032	0	0	9.0	41.3	0.3	5.94	150.0	600	50	258	19,581	1,528	11,578	32,687	21,317	11,370	5,926	5,425	501	22.3
2033	0	0	11.3	52.6	0.0	5.94	0.0	600	79	337	19,069	0	11,846	30,915	21,413	9,502	5,951	5,452	499	22.2
2034	0	0	(2.0)	50.6	0.3	6.27	0.0	600	35	372	19,937	0	11,845	31,782	21,520	10,262	5,983	5,476	507	22.4
2035	0	0	(0.3)	50.3	0.3	6.60	0.0	600	35	406	19,569	0	11,844	31,412	21,632	9,780	6,018	5,507	511	22.4
2036	0	0	(0.5)	49.8	0.3	6.93	0.0	600	23	429	20,363	0	11,866	32,230	21,744	10,486	5,681	5,541	140	14.8
2037	373	373	(0.4)	49.3	0.3	7.26	0.0	600	0	429	21,538	0	11,844	33,382	21,860	11,522	5,701	5,572	129	14.6
2038	746	1,119	(0.4)	48.9	0.3	7.59	0.0	600	0	429	20,775	0	11,845	32,620	21,976	10,643	5,922	5,603	319	18.4
2039	0	1,119	(0.2)	48.8	0.3	7.92	0.0	600	0	429	19,228	0	11,846	31,074	22,097	8,977	5,664	5,635	29	12.6
2040	373	1,492	(0.2)	48.6	0.3	8.25	0.0	600	0	429	20,339	0	11,862	32,201	22,219	9,981	5,695	5,667	28	12.5
2041	0	1,492	(0.3)	48.3	0.3	8.58	0.0	600	0	429	20,067	0	11,848	31,915	22,326	9,589	5,695	5,692	3	12.1
2042	373	1,865	(0.2)	48.1	0.3	8.91	0.0	600	0	429	21,500	0	11,849	33,350	22,442	10,908	6,068	5,724	344	18.7
2043	373	2,238	(0.1)	48.0	0.3	9.24	0.0	600	0	429	19,300	0	11,851	31,150	22,567	8,583	5,913	5,758	155	15.0
2044	0	2,238	(0.1)	47.9	0.3	9.57	0.0	600	0	429	19,668	0	11,866	31,534	22,697	8,837	5,913	5,787	126	14.4
2045	0	2,238	(0.0)	47.9	0.3	9.90	0.0	600	0	429	20,090	0	11,854	31,944	22,831	9,113	5,835	5,817	18	12.3
2046	746	2,984	0.0	47.9	0.7	10.56	0.0	600	0	429	18,857	0	11,858	30,715	22,990	7,725	5,963	5,942	22	12.4
2047	373	3,357	(11.0)	36.8	0.3	10.89	0.0	600	0	429	18,657	0	11,814	30,471	23,124	7,348	6,069	5,937	132	14.5

SOUTHWESTERN ELECTRIC POWER COMPANY
INTEGRATED RESOURCE PLAN
'Status Quo (No Carbon)' Commodity Pricing

Utility Costs (Nominal$)

	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) Less: Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	$563,589	$550,864	$9,232	$152,104	$34,524	$0	$18,402	$529,125	$799,591
2019	$635,678	$480,005	$9,225	$180,379	$33,820	$0	$12,625	$572,318	$779,415
2020	$702,335	$504,109	$9,574	$213,911	$35,750	$4,869	$5,597	$666,829	$809,315
2021	$726,612	$505,781	$10,185	$238,949	$36,435	$5,173	$4,231	$673,092	$854,274
2022	$757,496	$515,115	$10,678	$255,023	$49,058	$72,374	$2,519	$799,566	$862,698
2023	$784,960	$520,094	$11,127	$280,110	$60,930	$152,530	$894	$915,286	$895,357
2024	$817,390	$551,915	$11,690	$304,653	$65,332	$188,074	($902)	$997,671	$940,481
2025	$845,189	$526,571	$27,567	$356,929	$63,557	$186,226	($2,546)	$990,203	$1,013,289
2026	$875,190	$575,874	$29,017	$373,595	$72,136	$202,204	($4,135)	$1,084,878	$1,039,003
2027	$896,258	$611,460	$30,952	$377,475	$78,855	$218,019	($5,300)	$1,154,776	$1,052,943
2028	$940,516	$443,443	$225,516	$388,914	$72,616	$233,333	($8,373)	$986,916	$1,309,050
2029	$979,232	$495,288	$246,308	$425,090	$96,198	$364,091	($19,320)	$1,184,340	$1,402,547
2030	$1,032,165	$469,625	$251,650	$451,667	$100,903	$379,145	($23,414)	$1,230,646	$1,431,096
2031	$1,082,156	$514,594	$283,254	$474,306	$112,236	$398,050	($26,409)	$1,363,978	$1,474,208
2032	$1,115,129	$513,843	$290,359	$495,091	$118,841	$417,555	($27,552)	$1,397,240	$1,526,026
2033	$1,147,906	$498,893	$291,021	$516,523	$128,160	$434,129	$0	$1,415,957	$1,600,675
2034	$1,176,569	$527,528	$321,066	$538,205	$135,495	$445,529	$0	$1,498,797	$1,645,594
2035	$1,230,432	$521,960	$326,395	$557,235	$138,312	$446,447	$0	$1,533,094	$1,687,687
2036	$1,253,129	$537,009	$350,202	$572,259	$141,726	$446,438	$0	$1,560,460	$1,740,303
2037	$1,279,230	$553,374	$366,369	$583,773	$149,982	$493,402	$0	$1,598,660	$1,827,471
2038	$1,299,550	$496,576	$303,558	$559,682	$157,868	$589,201	$0	$1,474,211	$1,932,225
2039	$1,338,678	$475,794	$289,517	$539,893	$157,893	$589,211	$0	$1,443,884	$1,947,102
2040	$1,376,200	$482,558	$297,926	$528,798	$166,490	$639,194	$0	$1,478,123	$2,013,043
2041	$1,413,675	$501,287	$318,308	$526,739	$170,820	$639,114	$0	$1,521,935	$2,048,009
2042	$1,448,652	$519,396	$335,926	$520,934	$180,289	$691,251	$0	$1,561,983	$2,134,465
2043	$1,491,085	$447,027	$270,683	$466,218	$184,486	$744,485	$0	$1,456,231	$2,147,753
2044	$1,538,847	$473,610	$296,138	$454,707	$195,462	$744,485	$0	$1,521,918	$2,181,330
2045	$1,593,618	$472,680	$307,184	$440,394	$198,925	$744,485	$0	$1,550,127	$2,207,159
2046	$1,653,945	$338,837	$191,405	$387,750	$204,178	$859,161	$0	$1,350,082	$2,285,194
2047	$1,703,952	$245,591	$121,057	$341,594	$207,769	$969,894	$0	$1,250,510	$2,339,347
Cumulative Present Worth $000 (2018$)									
Utility CPW 2018-2045	$11,169,747	$6,071,354	$1,519,418	$4,210,111	$1,020,212	$3,050,259	-$8,832	$12,370,477	$14,661,792
CPW of End Effects beyond 2045									$3,637,021
TOTAL Utility Cost, Net CPW (2018$)									$18,298,813

Resource (Capacity) Additions / Energy & Capacity Positions

	(10) Supply-Side (Thermal)	(11) Supply-Side (Thermal)	(12) (Increm) Energy Efficiency + VVO	(13) (Increm) Energy Efficiency + VVO	(14) Distributed Solar	(15) Distributed Solar	(16) Generic Wind	(17) Generic Wind	(18) Utility Solar	(19) Utility Solar	(12) Thermal Generation	(13) (Current) Purchased Energy	(14) (New) Wind, EE, Solar, IVV	(15)=(12)+(13)+(14) = Market Sales	(16) = Net Load Requirements	(17)=(16)-(15) ENERGY Surplus	(17) Capacity	(18) Peak + Reserves	(19)=(17)-(18) CAPACITY Surplus	(20) Reserve Margin
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018	0	0	0.0	0.0	0.0	3.30	0.0	0	0	0	19,241	1,874	19	21,135	20,745	390	5,745	5,118	627	25.7
2019	0	0	0.0	**0.0**	0.0	3.30	0.0	0	0	0	18,474	1,874	19	20,367	20,746	(379)	5,659	5,207	452	21.7
2020	0	0	31.5	**31.5**	0.0	3.30	0.0	0	0	0	19,015	1,880	158	21,052	20,264	789	5,616	5,062	554	24.2
2021	0	0	7.4	**39.0**	0.3	3.63	0.0	0	0	0	18,644	1,874	196	20,714	20,395	319	5,568	5,106	462	22.1
2022	0	0	6.2	**45.2**	0.0	3.63	30.0	30	0	0	18,968	1,874	2,749	23,591	20,527	3,063	5,604	5,139	465	22.1
2023	0	0	(2.1)	**43.1**	0.3	3.96	30.0	60	0	0	18,860	1,874	5,294	26,029	20,622	5,407	5,523	5,158	365	19.9
2024	0	0	5.2	**48.4**	0.0	3.96	10.0	70	0	0	19,305	1,880	6,164	27,350	20,688	6,662	5,538	5,179	359	19.8
2025	0	0	(1.7)	**46.7**	0.3	4.29	150.0	220	0	0	18,201	1,874	6,133	26,208	20,741	5,467	5,579	5,199	380	20.2
2026	0	0	(3.0)	**43.7**	0.3	4.62	150.0	370	15	15	19,515	1,874	6,483	27,873	20,807	7,065	5,631	5,220	411	20.8
2027	0	0	(2.9)	**40.8**	0.0	4.62	50.0	420	15	30	20,386	1,874	6,833	29,093	20,881	8,212	5,693	5,299	394	20.3
2028	0	0	(4.8)	**36.0**	0.3	4.95	0.0	420	15	45	14,429	1,880	7,200	23,508	20,974	2,534	5,704	5,319	385	20.1
2029	0	0	(0.7)	**35.3**	0.0	4.95	30.0	450	50	95	15,152	1,591	10,059	26,802	21,068	5,734	5,770	5,344	426	20.9
2030	0	0	(1.7)	**33.6**	0.3	5.28	0.0	450	50	144	14,540	1,569	10,421	26,531	21,144	5,386	5,654	5,369	285	17.9
2031	0	0	11.6	**45.2**	0.3	5.61	0.0	450	50	194	15,697	1,569	10,835	28,101	21,228	6,873	5,715	5,397	318	18.6
2032	0	0	8.9	**54.1**	0.3	5.94	150.0	600	50	243	15,247	1,528	11,263	28,038	21,317	6,721	5,924	5,425	499	22.3
2033	0	0	(1.7)	**52.4**	0.0	5.94	0.0	600	50	293	14,603	0	11,601	26,204	21,413	4,791	5,906	5,452	454	21.3
2034	0	0	(2.3)	**50.1**	0.3	6.27	0.0	600	45	337	15,393	0	11,843	27,236	21,520	5,715	5,948	5,476	472	21.7
2035	0	0	(0.2)	**49.9**	0.3	6.60	0.0	600	35	372	14,897	0	11,842	26,740	21,632	5,107	5,983	5,507	476	21.7
2036	0	0	(0.4)	**49.5**	0.3	6.93	0.0	600	35	406	15,155	0	11,866	27,021	21,744	5,277	5,657	5,541	116	14.4
2037	373	373	(0.3)	**49.2**	0.3	7.26	0.0	600	23	429	15,297	0	11,844	27,141	21,860	5,281	5,700	5,572	128	14.6
2038	746	1,119	(0.3)	**48.9**	0.3	7.59	0.0	600	0	429	12,845	0	11,845	24,689	21,976	2,713	5,921	5,603	318	18.3
2039	0	1,119	(0.1)	**48.7**	0.3	7.92	0.0	600	0	429	11,769	0	11,846	23,615	22,097	1,518	5,664	5,635	29	12.6
2040	373	1,492	(0.1)	**48.6**	0.3	8.25	0.0	600	0	429	11,658	0	11,862	23,520	22,219	1,300	5,695	5,667	28	12.5
2041	0	1,492	(0.3)	**48.3**	0.3	8.58	0.0	600	0	429	11,878	0	11,848	23,726	22,326	1,400	5,695	5,692	3	12.1
2042	373	1,865	(0.2)	**48.1**	0.3	8.91	0.0	600	0	429	12,006	0	11,849	23,856	22,442	1,414	6,068	5,724	344	18.7
2043	373	2,238	(0.1)	**48.0**	0.3	9.24	0.0	600	0	429	9,890	0	11,851	21,741	22,567	(826)	5,913	5,758	155	15.0
2044	0	2,238	(0.1)	**47.9**	0.3	9.57	0.0	600	0	429	10,270	0	11,866	22,135	22,697	(561)	5,913	5,787	126	14.4
2045	0	2,238	(0.0)	**47.9**	0.3	9.90	0.0	600	0	429	10,084	0	11,854	21,938	22,831	(893)	5,835	5,817	18	12.3
2046	746	2,984	0.0	**47.9**	0.7	10.56	0.0	600	0	429	6,518	0	11,858	18,376	22,990	(4,614)	5,963	5,942	22	12.4
2047	248	3,232	(11.0)	**36.8**	0.3	10.89	0.0	600	0	429	4,781	0	11,814	16,595	23,124	(6,529)	5,944	5,937	7	12.1

SOUTHWESTERN ELECTRIC POWER COMPANY
INTEGRATED RESOURCE PLAN
'Base' Commodity Pricing - High Load

Utility Costs (Nominal $)

	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) Less: Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	$564,379	$546,635	$9,169	$152,104	$34,379	$0	$18,737	$523,583	$801,820
2019	$636,935	$476,432	$9,193	$180,379	$33,528	$0	$13,116	$563,138	$786,444
2020	$710,725	$499,190	$9,561	$213,911	$35,408	$4,869	$5,994	$652,661	$826,997
2021	$741,937	$505,205	$10,179	$238,949	$36,400	$5,173	$4,359	$664,847	$877,356
2022	$778,505	$514,897	$10,671	$255,023	$49,054	$72,374	$2,477	$703,170	$979,830
2023	$813,736	$522,181	$11,128	$280,110	$61,113	$152,949	$449	$729,196	$1,112,470
2024	$860,130	$565,416	$11,715	$304,653	$66,295	$188,074	($2,229)	$793,544	$1,200,509
2025	$888,674	$535,459	$27,718	$356,929	$67,430	$204,790	($3,690)	$772,451	$1,304,858
2026	$923,057	$580,477	$29,201	$373,595	$75,679	$220,768	($5,416)	$841,134	$1,356,227
2027	$948,049	$618,909	$31,080	$377,475	$82,778	$236,583	($6,472)	$893,845	$1,394,557
2028	$1,218,725	$599,430	$293,862	$388,914	$87,228	$252,065	($27,873)	$1,087,866	$1,724,485
2029	$1,256,186	$651,248	$316,757	$425,090	$111,279	$382,985	($35,463)	$1,153,476	$1,954,608
2030	$1,335,403	$609,663	$315,469	$451,667	$116,700	$409,713	($40,004)	$1,134,880	$2,063,732
2031	$1,399,382	$648,570	$348,263	$474,306	$126,955	$425,137	($43,393)	$1,237,408	$2,141,812
2032	$1,450,277	$672,047	$366,811	$495,091	$134,785	$441,792	($44,697)	$1,277,146	$2,238,960
2033	$1,490,602	$656,699	$369,578	$516,523	$141,646	$444,502	$0	$1,252,059	$2,367,492
2034	$1,554,855	$685,685	$401,020	$538,205	$147,248	$444,697	$0	$1,339,448	$2,432,261
2035	$1,637,555	$679,002	$404,596	$557,235	$149,581	$445,412	$0	$1,346,046	$2,527,335
2036	$1,698,724	$791,187	$454,718	$572,259	$163,098	$491,349	$0	$1,423,070	$2,748,265
2037	$1,764,204	$955,799	$498,666	$583,773	$183,327	$585,241	$0	$1,449,193	$3,121,817
2038	$1,867,730	$920,033	$421,103	$559,682	$186,265	$633,131	$0	$1,188,021	$3,399,923
2039	$1,905,975	$978,906	$415,867	$539,893	$194,396	$682,077	$0	$1,089,178	$3,627,936
2040	$1,994,925	$1,064,533	$440,574	$528,798	$206,275	$733,135	$0	$1,101,167	$3,867,072
2041	$2,095,719	$1,193,399	$486,363	$526,739	$221,133	$784,094	$0	$1,154,084	$4,153,364
2042	$2,154,822	$1,198,641	$508,901	$520,934	$224,755	$784,094	$0	$1,160,940	$4,231,207
2043	$2,270,546	$1,279,909	$432,721	$466,218	$239,752	$890,563	$0	$878,733	$4,700,976
2044	$2,373,379	$1,316,352	$466,825	$454,707	$251,525	$890,563	$0	$923,515	$4,829,837
2045	$2,467,993	$1,439,976	$505,096	$440,394	$266,446	$946,110	$0	$939,391	$5,126,625
2046	$2,593,858	$1,517,705	$436,319	$387,750	$281,459	$1,059,540	$0	$622,610	$5,654,022
2047	$2,726,417	$1,508,412	$382,406	$341,594	$287,932	$1,188,976	$0	$455,218	$5,980,519
Cumulative Present Worth $000 (2018$)									
Utility CPW 2018-2045	$13,669,173	$7,891,752	$2,057,948	$4,210,111	$1,162,665	$3,371,324	-$44,910	$10,557,818	$21,760,247
CPW of End Effects beyond 2045									$9,298,010
TOTAL Utility Cost, Net CPW (2018$)									$31,058,257

Resource (Capacity) Additions

	(10) Supply-Side (Thermal) Ann MW	(11) Supply-Side (Thermal) Cum MW	(12) (Increm) Energy Efficiency + VVO Ann MW	(13) (Increm) Energy Efficiency + VVO Cum MW	(14) Distributed Solar Ann MW	(15) Distributed Solar Cum MW	(16) Generic Wind Ann MW	(17) Generic Wind Cum MW	(18) Utility Solar Ann MW	(19) Utility Solar Cum MW
2018	0	0	0.0	0.0	0.0	3.30	0.0	0	0	0
2019	0	0	0.0	0.0	0.0	3.30	0.0	0	0	0
2020	0	0	31.5	31.5	0.0	3.30	0.0	0	0	0
2021	0	0	7.4	39.0	0.3	3.63	0.0	0	0	0
2022	0	0	6.2	45.2	0.0	3.63	30.0	30	0	0
2023	0	0	(1.1)	44.1	0.3	3.96	30.0	60	0	0
2024	0	0	5.0	49.1	0.0	3.96	10.0	70	0	0
2025	0	0	11.1	60.3	0.3	4.29	150.0	220	15	15
2026	0	0	(3.2)	57.1	0.3	4.62	150.0	370	15	30
2027	0	0	(3.1)	54.0	0.0	4.62	50.0	420	15	45
2028	0	0	(4.7)	49.4	0.3	4.95	0.0	420	50	95
2029	0	0	(0.0)	49.3	0.0	4.95	30.0	450	50	144
2030	0	0	(1.2)	48.1	0.3	5.28	0.0	450	60	204
2031	0	0	(1.7)	46.4	0.3	5.61	0.0	450	50	253
2032	0	0	(2.4)	44.0	0.3	5.94	150.0	600	50	303
2033	0	0	9.1	53.1	0.0	5.94	0.0	600	58	360
2034	0	0	(2.2)	50.9	0.3	6.27	0.0	600	35	395
2035	0	0	(0.4)	50.5	0.3	6.60	0.0	600	35	429
2036	373	373	(0.6)	49.9	0.3	6.93	0.0	600	0	429
2037	746	1,119	(0.5)	49.4	0.3	7.26	0.0	600	0	429
2038	373	1,492	(0.4)	49.0	0.3	7.59	0.0	600	0	429
2039	373	1,865	(0.2)	48.8	0.3	7.92	0.0	600	0	429
2040	373	2,238	(0.2)	48.6	0.3	8.25	0.0	600	0	429
2041	373	2,611	(0.3)	48.3	0.3	8.58	0.0	600	0	429
2042	0	2,611	(0.2)	48.1	0.3	8.91	0.0	600	0	429
2043	746	3,357	(0.1)	48.0	0.3	9.24	0.0	600	0	429
2044	0	3,357	(0.1)	47.9	0.3	9.57	0.0	600	0	429
2045	373	3,730	(0.0)	47.9	0.3	9.90	0.0	600	0	429
2046	746	4,476	0.0	47.9	0.7	10.56	0.0	600	0	429
2047	373	4,849	0.0	47.9	0.3	10.89	0.0	600	0	429

Energy & Capacity Positions

	(12) Thermal Generation	(13) (Current) Purchased Energy	(14) (New) Wind, EE, Solar, IVV	(15)=(12)+(13)+(14) = Market Sales	(16) = Net Load Requirements	(17)=(16)-(15) ENERGY Surplus	(17) Capacity	(18) Peak + Reserves	(19)=(17)-(18) CAPACITY Surplus	(20) Reserve Margin
	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018	19,129	1,874	19	21,022	20,914	108	5,745	5,119	626	25.7
2019	18,351	1,874	19	20,244	20,994	(750)	5,659	5,252	407	20.7
2020	18,842	1,880	158	20,879	20,622	257	5,616	5,133	483	22.5
2021	18,629	1,874	196	20,699	20,872	(174)	5,568	5,211	357	19.7
2022	18,952	1,874	2,749	23,575	21,070	2,505	5,604	5,265	339	19.2
2023	18,899	1,874	5,298	26,071	21,216	4,855	5,524	5,300	224	16.7
2024	19,651	1,880	6,167	27,698	21,353	6,345	5,539	5,336	203	16.3
2025	18,433	1,874	6,557	26,864	21,477	5,387	5,608	5,370	237	16.9
2026	19,671	1,874	6,906	28,452	21,624	6,828	5,660	5,411	249	17.2
2027	20,584	1,874	7,255	29,713	21,773	7,940	5,722	5,509	212	16.3
2028	19,627	1,880	7,623	29,130	21,983	7,147	5,767	5,559	208	16.2
2029	20,294	1,591	10,483	32,369	22,133	10,235	5,833	5,608	225	16.5
2030	18,950	1,569	11,093	31,613	22,378	9,236	5,728	5,671	57	13.1
2031	19,951	1,569	11,452	32,973	22,548	10,425	5,776	5,720	56	13.1
2032	20,112	1,528	11,835	33,474	22,762	10,712	5,973	5,780	193	15.7
2033	19,370	0	11,849	31,218	22,994	8,224	5,974	5,843	131	14.5
2034	20,035	0	11,846	31,881	23,197	8,684	6,007	5,892	114	14.2
2035	19,316	0	11,845	31,160	23,484	7,677	6,041	5,967	74	13.4
2036	21,619	0	11,867	33,486	23,797	9,689	6,054	6,050	4	12.1
2037	24,564	0	11,845	36,409	24,100	12,309	6,447	6,132	314	17.7
2038	21,797	0	11,845	33,642	24,475	9,167	6,295	6,231	64	13.1
2039	21,797	0	11,846	33,643	24,845	8,798	6,410	6,330	80	13.4
2040	22,889	0	11,862	34,751	25,219	9,531	6,441	6,434	7	12.1
2041	24,853	0	11,848	36,701	25,663	11,038	6,814	6,534	280	16.8
2042	24,505	0	11,849	36,354	26,137	10,217	6,814	6,662	152	14.6
2043	23,853	0	11,851	35,704	26,675	9,029	7,032	6,800	232	15.8
2044	24,098	0	11,866	35,964	27,213	8,751	7,032	6,933	99	13.6
2045	25,576	0	11,854	37,430	27,770	9,660	7,327	7,079	247	15.9
2046	24,924	0	11,858	36,782	28,422	8,360	7,455	7,291	165	14.5
2047	23,984	0	11,860	35,843	29,137	6,706	7,572	7,529	42	12.6

SOUTHWESTERN ELECTRIC POWER COMPANY
INTEGRATED RESOURCE PLAN
'Base' Commodity Pricing - Low Load

Utility Costs (Nominal $)

	(1) Load Cost	(2) Fuel Costs	(3) Emission Costs	(4) Existing System FOM and OGC	(5) (Incremental) Fixed & (All) Var Cap Charges Costs	(6) (Incremental) Capital + Renewable+EE+VVO Program Costs	(7) Contract (Revenue)/Cost	(8) Less: Market Revenue	(9)=(1)thru(7)-(8) GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	$557,995	$546,635	$9,169	$152,104	$34,379	$0	$18,737	$524,106	$794,912
2019	$621,569	$476,432	$9,193	$180,379	$33,528	$0	$13,116	$563,728	$770,488
2020	$685,151	$499,190	$9,561	$213,911	$35,408	$4,869	$5,994	$658,170	$795,914
2021	$707,183	$505,205	$10,179	$238,949	$36,400	$5,173	$4,359	$671,895	$835,553
2022	$734,879	$514,897	$10,671	$255,023	$49,054	$72,374	$2,477	$800,994	$838,380
2023	$761,153	$522,181	$11,128	$280,110	$61,113	$152,949	$449	$924,486	$864,597
2024	$798,142	$565,416	$11,715	$304,653	$66,295	$188,074	($2,229)	$1,031,755	$900,310
2025	$817,729	$535,459	$27,718	$356,929	$67,430	$204,790	($3,690)	$1,033,314	$973,052
2026	$842,216	$580,477	$29,201	$373,595	$75,679	$220,768	($5,416)	$1,125,389	$991,131
2027	$857,627	$618,909	$31,080	$377,475	$82,778	$236,583	($6,472)	$1,199,110	$998,870
2028	$1,092,097	$599,430	$293,862	$388,914	$87,228	$252,065	($27,873)	$1,498,891	$1,186,831
2029	$1,115,821	$651,248	$316,757	$425,090	$111,279	$382,985	($35,463)	$1,730,421	$1,237,297
2030	$1,173,159	$609,663	$315,469	$451,667	$116,700	$409,713	($40,004)	$1,776,547	$1,259,820
2031	$1,217,228	$648,570	$348,263	$474,306	$126,955	$425,137	($43,393)	$1,926,078	$1,270,988
2032	$1,248,724	$672,047	$366,811	$495,091	$134,785	$441,792	($44,697)	$2,009,538	$1,305,016
2033	$1,268,151	$656,699	$369,578	$516,523	$141,646	$444,502	$0	$2,000,545	$1,396,554
2034	$1,306,613	$685,685	$401,020	$538,205	$147,248	$444,697	$0	$2,113,058	$1,410,410
2035	$1,355,463	$679,002	$404,596	$557,235	$149,581	$445,412	$0	$2,149,865	$1,441,424
2036	$1,385,356	$715,177	$443,099	$572,259	$154,675	$491,349	$0	$2,246,879	$1,515,035
2037	$1,418,274	$720,535	$461,986	$583,773	$157,593	$585,241	$0	$2,293,941	$1,633,461
2038	$1,478,366	$678,054	$382,658	$559,682	$160,000	$633,131	$0	$2,183,224	$1,708,667
2039	$1,485,518	$654,347	$363,439	$539,893	$158,983	$682,077	$0	$2,093,687	$1,790,571
2040	$1,528,322	$734,073	$385,966	$528,798	$170,242	$733,135	$0	$2,256,954	$1,823,582
2041	$1,577,082	$761,804	$413,381	$526,739	$174,907	$784,094	$0	$2,348,568	$1,889,440
2042	$1,588,847	$766,135	$433,795	$520,934	$178,084	$784,094	$0	$2,364,580	$1,907,309
2043	$1,635,423	$829,750	$353,153	$466,218	$191,880	$890,563	$0	$2,384,119	$1,982,869
2044	$1,667,635	$856,841	$382,950	$454,707	$202,630	$890,563	$0	$2,469,201	$1,986,126
2045	$1,687,209	$875,141	$399,863	$440,394	$206,754	$946,110	$0	$2,514,567	$2,040,904
2046	$1,724,095	$835,970	$306,192	$387,750	$210,094	$1,059,540	$0	$2,384,484	$2,139,157
2047	$1,756,302	$825,696	$248,773	$341,594	$215,891	$1,188,976	$0	$2,387,809	$2,189,423
Cumulative Present Worth $000 (2018$)									
Utility CPW 2018-2045	$11,703,040	$7,109,169	$1,920,962	$4,210,111	$1,078,794	$3,371,324	-$44,910	$15,801,336	$13,547,155
CPW of End Effects beyond 2045									$3,403,932
TOTAL Utility Cost, Net CPW (2018$)									$16,951,087

Resource (Capacity) Additions

	(10) Supply-Side (Thermal) Ann MW	(11) Supply-Side (Thermal) Cum MW	(12) (Increm) Energy Efficiency + VVO Ann MW	(13) (Increm) Energy Efficiency + VVO Cum MW	(14) Distributed Solar Ann MW	(15) Distributed Solar Cum MW	(16) Generic Wind Ann MW	(17) Generic Wind Cum MW	(18) Utility Solar Ann MW	(19) Utility Solar Cum MW
2018	0	0	0.0	0.0	0.0	3.30	0.0	0	0	0
2019	0	0	0.0	0.0	0.0	3.30	0.0	0	0	0
2020	0	0	31.5	31.5	0.0	3.30	0.0	0	0	0
2021	0	0	7.4	39.0	0.3	3.63	0.0	0	0	0
2022	0	0	6.2	45.2	0.0	3.63	30.0	30	0	0
2023	0	0	(1.1)	44.1	0.3	3.96	30.0	60	0	0
2024	0	0	5.0	49.1	0.0	3.96	10.0	70	0	0
2025	0	0	11.1	60.3	0.3	4.29	150.0	220	15	15
2026	0	0	(3.2)	57.1	0.3	4.62	150.0	370	15	30
2027	0	0	(3.1)	54.0	0.0	4.62	50.0	420	15	45
2028	0	0	(4.7)	49.4	0.3	4.95	0.0	420	50	95
2029	0	0	(0.0)	49.3	0.0	4.95	30.0	450	50	144
2030	0	0	(1.2)	48.1	0.3	5.28	0.0	450	60	204
2031	0	0	(1.7)	46.4	0.3	5.61	0.0	450	50	253
2032	0	0	(2.4)	44.0	0.3	5.94	150.0	600	50	303
2033	0	0	9.1	53.1	0.0	5.94	0.0	600	58	360
2034	0	0	(2.2)	50.9	0.3	6.27	0.0	600	35	395
2035	0	0	(0.4)	50.5	0.3	6.60	0.0	600	35	429
2036	0	0	(0.6)	49.9	0.3	6.93	0.0	600	0	429
2037	0	0	(0.5)	49.4	0.3	7.26	0.0	600	0	429
2038	373	373	(0.4)	49.0	0.3	7.59	0.0	600	0	429
2039	0	373	0.7	49.6	0.3	7.92	0.0	600	0	429
2040	373	746	(1.0)	48.6	0.3	8.25	0.0	600	0	429
2041	0	746	(0.3)	48.3	0.3	8.58	0.0	600	0	429
2042	0	746	(0.2)	48.1	0.3	8.91	0.0	600	0	429
2043	746	1,492	(0.1)	48.0	0.3	9.24	0.0	600	0	429
2044	0	1,492	(0.1)	47.9	0.3	9.57	0.0	600	0	429
2045	0	1,492	(0.0)	47.9	0.3	9.90	0.0	600	0	429
2046	373	1,865	0.0	47.9	0.7	10.56	0.0	600	0	429
2047	373	2,238	0.0	47.9	0.3	10.89	0.0	600	0	429

Energy & Capacity Positions

	(12) Thermal Generation	(13) (Current) Purchased Energy	(14) (New) Wind, EE, Solar, IVV	(15)=(12)+(13)+(14) = Market Sales	(16) = Net Load Requirements	(17)=(16)-(15) ENERGY Surplus	(17) Capacity	(18) Peak + Reserves	(19)=(17)-(18) CAPACITY Surplus	(20) Reserve Margin
	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018	19,129	1,874	19	21,022	20,677	345	5,745	5,118	627	25.7
2019	18,351	1,874	19	20,244	20,488	(244)	5,659	5,122	537	23.8
2020	18,842	1,880	158	20,879	19,880	999	5,616	4,943	673	27.2
2021	18,629	1,874	196	20,699	19,895	804	5,568	4,961	606	25.7
2022	18,952	1,874	2,749	23,575	19,889	3,685	5,604	4,963	641	26.5
2023	18,899	1,874	5,298	26,071	19,845	6,226	5,524	4,951	573	25.0
2024	19,651	1,880	6,167	27,698	19,814	7,884	5,539	4,944	595	25.5
2025	18,433	1,874	6,557	26,864	19,763	7,101	5,608	4,933	675	27.3
2026	19,671	1,874	6,906	28,452	19,730	8,722	5,660	4,927	733	28.7
2027	20,584	1,874	7,255	29,713	19,697	10,017	5,722	4,978	743	28.7
2028	19,627	1,880	7,623	29,130	19,699	9,431	5,767	4,975	792	29.8
2029	20,294	1,591	10,483	32,369	19,660	12,708	5,833	4,974	860	31.4
2030	18,950	1,569	11,093	31,613	19,659	11,954	5,728	4,974	754	29.0
2031	19,951	1,569	11,452	32,973	19,613	13,360	5,776	4,968	808	30.2
2032	20,112	1,528	11,835	33,474	19,599	13,875	5,973	4,967	1,006	34.7
2033	19,370	0	11,849	31,218	19,563	11,656	5,974	4,961	1,013	34.9
2034	20,035	0	11,846	31,881	19,493	12,388	6,007	4,941	1,066	36.2
2035	19,316	0	11,845	31,160	19,438	11,722	6,041	4,928	1,113	37.3
2036	20,094	0	11,867	31,961	19,407	12,554	5,681	4,922	758	29.3
2037	19,977	0	11,845	31,822	19,374	12,448	5,328	4,916	411	21.4
2038	17,207	0	11,845	29,052	19,373	9,680	5,176	4,919	256	17.8
2039	15,806	0	11,848	27,654	19,364	8,289	4,919	4,919	0	12.0
2040	16,956	0	11,862	28,818	19,321	9,497	4,949	4,912	37	12.8
2041	17,297	0	11,848	29,145	19,312	9,833	4,949	4,900	49	13.1
2042	17,128	0	11,849	28,977	19,272	9,705	4,949	4,894	55	13.3
2043	16,369	0	11,851	28,220	19,213	9,007	5,167	4,878	290	18.6
2044	16,637	0	11,866	28,503	19,121	9,382	5,167	4,849	318	19.3
2045	16,630	0	11,854	28,484	18,985	9,500	5,089	4,817	272	18.3
2046	14,388	0	11,858	26,245	18,892	7,354	4,844	4,821	23	12.5
2047	13,682	0	11,860	25,542	18,769	6,772	4,961	4,824	137	15.2