PUBLIC SERVICE COMPANY OF OKLAHOMA℠

An AEP Company

2024 IRP Document

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1 Executive Summary

This Integrated Resource Plan (IRP or “Report”) is submitted by Public Service Company of Oklahoma (PSO 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. PSO is required to provide an IRP every three years that encompasses a 10-year forecast planning period (in this filing, 2025-2034). 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.

Keeping these considerations in mind, PSO analyzed various candidate portfolios and sensitivities 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 ten years.

For the 2024 PSO IRP, the Company defined four objectives that align to customer and corporate priorities including customer affordability, rate stability, maintaining reliability, and sustainability. The candidate portfolios and sensitivities were measured against these four objectives to inform the Company for the identification of its Preferred Plan. This report sets out how the Company is planning to meet the four objectives over the 10-year planning period for the benefit of its customers.

1.1 Summary of the PSO Resource Plan:

Over the next 10-year period (2025-2034), PSO’s retail sales are projected to grow at 0.9% per year with stronger growth expected from the commercial (1.9% per year) and industrial classes (1.2% per year) while the residential class declines at a rate of 0.2% per year over the forecast horizon. Load growth in the commercial and industrial sectors is affected by some customers having large load additions. Finally, PSO’s internal energy and peak demand are expected to change at an average rate of 0.9% and 0.5% per year, respectively, through 2034.

PSO started from evaluating a “going-in” capacity and energy position shown in Figure ES- 1, Figure ES- 2 and Figure ES- 3 that shows current expectations about existing owned resources and contracts. For this IRP, the Company considered the capacity needs for both SPP Summer and Winter obligations.

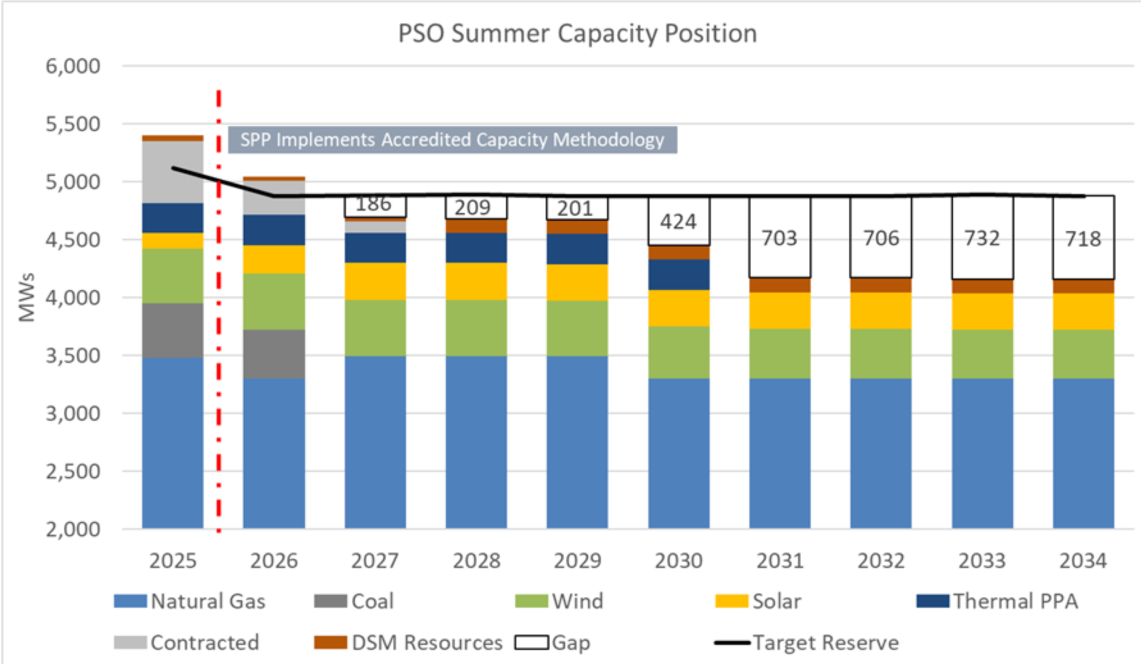


Figure ES- 1 Going-In Summer Capacity Position

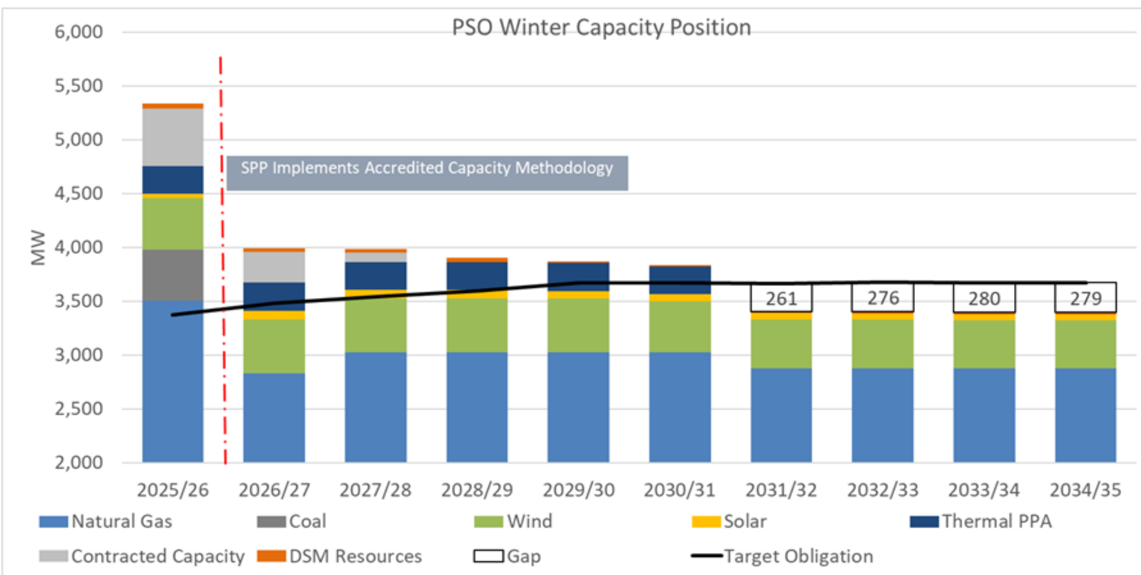


Figure ES- 2 PSO Going-In Winter Capacity Position

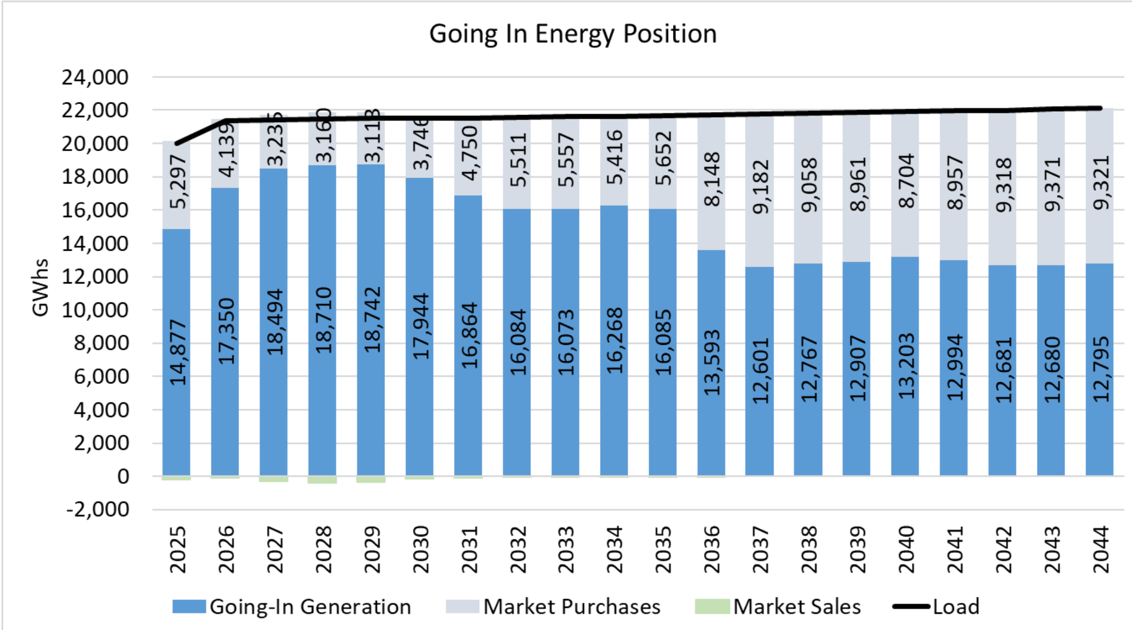


Figure ES- 3 PSO Going-In Energy Position

As a summer peaking Load Responsible Entity (LRE), PSO's capacity need begins in SPP Planning Year 2027/2028 in the summer after the Northeastern Unit 3 (NE3) ceases burning coal. The Going-In resources include a PPA contract with the Green Country Facility that expires after 2025 and the continued use of the full facility as an owned unit as noted in Section 4.2. Including the unit extends the time until the Company finds a need for additional capacity to the SPP 2027/2028 planning year. The capacity need is further widened in the SPP 2030/31 planning year after the Company's Southwestern Units 1&2 (gas) and Weleetka Units 4&5 (gas) exit the portfolio. An additional purchased power agreement set to expire in 2030 increases the capacity needs at that time.

As shown in Figure ES- 3, PSO has a significant need for energy to serve load in the future. PSO desires to lessen this market risk with the actions it is currently taking with the proposed addition of the Green Country facility, among other things.

PSO used the *Plexos*® Linear Program (LP) optimization model to evaluate a series of candidate portfolios and sensitivities to identify resources that provided the lowest expected costs to customers subject to certain constraints. The results of each candidate portfolio and sensitivity were evaluated against a series of metrics aligned to the Company's four objectives to consider the tradeoffs between portfolios to meet the broad set of requirements.

PSO's Preferred Plan:

The Preferred Plan supports the Company's objectives to provide sustainable, affordable, reliable energy and minimize risks to customers rates. The plan includes a diverse mix of resources with the least amount of capital expenditures including new solar, wind and storage resources while also leveraging the Company's existing NE3 unit to continue its operation as a gas unit. The plan provides a balanced portfolio of resources that supports the SPP summer and winter capacity obligations and maintains a fleet of dispatchable resources that can provide energy to nearly all of PSOs peak load. Figure ES- 4 and Figure ES- 5 illustrate the Company's capacity position with the new resources in both a summer and winter capacity obligation view.

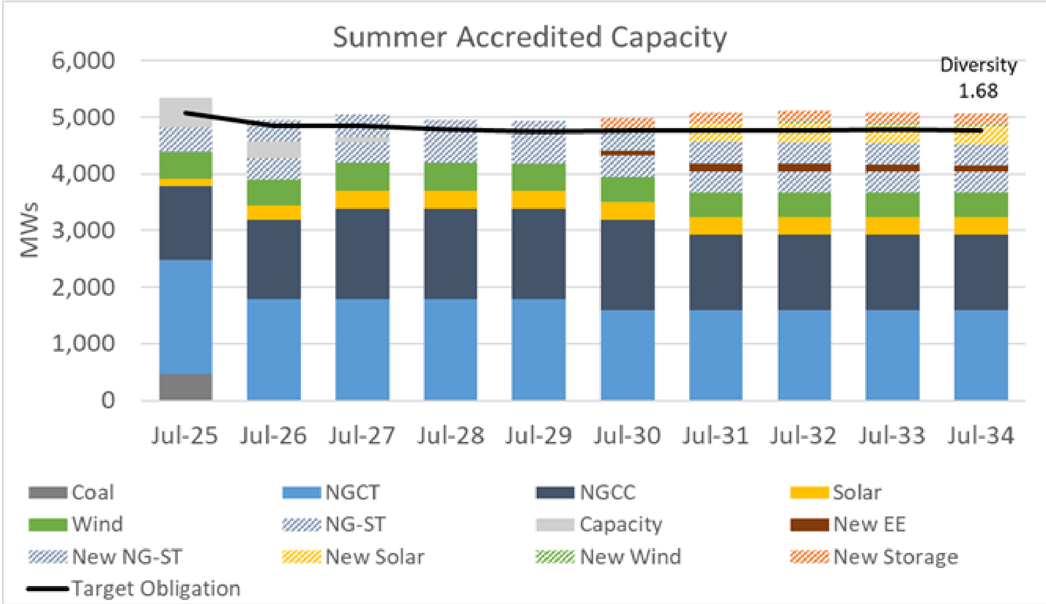


Figure ES- 4 Preferred Plan Summer Accredited Capacity

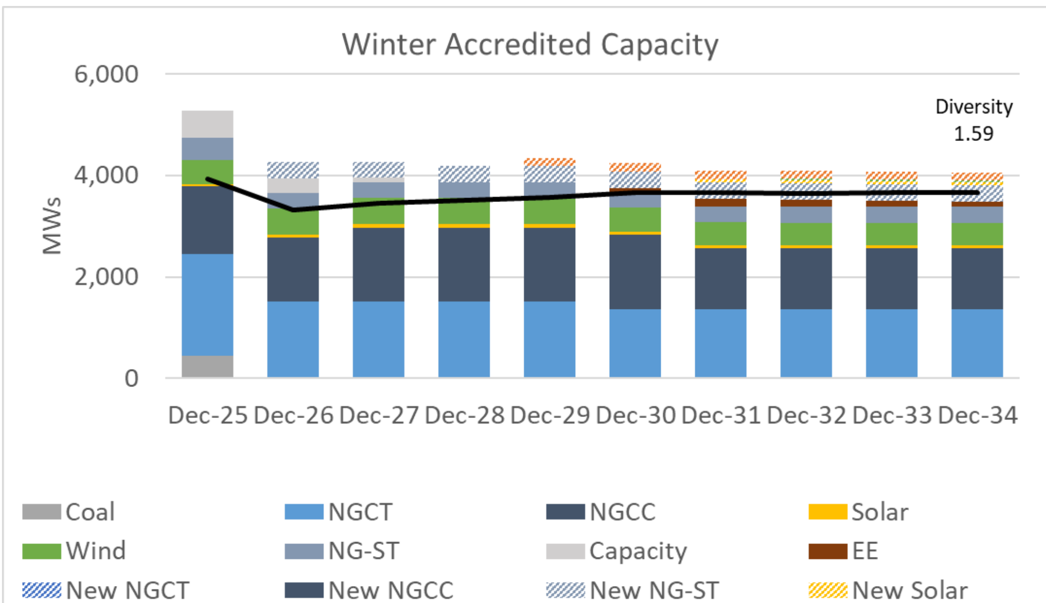


Figure ES- 5 Preferred Plan Winter Accredited Capacity

The plan includes, as shown in Table ES- 1 the selection of the Company's Northeastern Unit 3 to operate on gas in 2026 and 200MWs of additional 6hr storage in 2029. 450MWs of solar resources enter the portfolio in 2031 followed by 200MWs of additional wind resources in 2032. In total, with the recently approved renewable resources, the portfolio includes a total of 893MWs of new solar resources, 753MWs of new wind resources and 200 MWs of 6hr storage.

The portfolio also includes a peak contribution of 154MWs from incremental EE resources by 2034.

Table ES- 1 Preferred Plan New Resource Additions

Preferred Plan New Build Additions by Planning Year (Nameplate MW)							
Planning Year	New EE	New Solar	New Wind	New Storage	New CT	New CC	NE3 Gas
2025/26	0	0	0	0	0	795**	0
2026/27	0	339*	553*	0	0	0	420
2027/28	0	0	0	0	0	0	0
2028/29	0	103.5*	0	0	0	0	0
2029/30	0	0	0	200	0	0	0
2030/31	44	0	0	0	0	0	0
2031/32	95	450	0	0	0	0	0
2032/33	128	0	200	0	0	0	0
2033/34	146	0	0	0	0	0	0
2034/35	154	0	0	0	0	0	0
Total		892.5	753	200	0	795	420

* Approved new resources
** New resource seeking approval

Additionally, as discussed in Section 4.6, PSO has historically leveraged the SPP energy market to serve a measureable portion of its customer load. This plan supports the Company's desire to mitigate some of this market risk through the addition of additional energy rich resources such as wind and solar while still capturing the benefit of low cost energy from SPP during times when the market is not disrupted. Figure ES- 6 Preferred Plan Energy illustrates PSO's energy position and sources with the Preferred Plan.

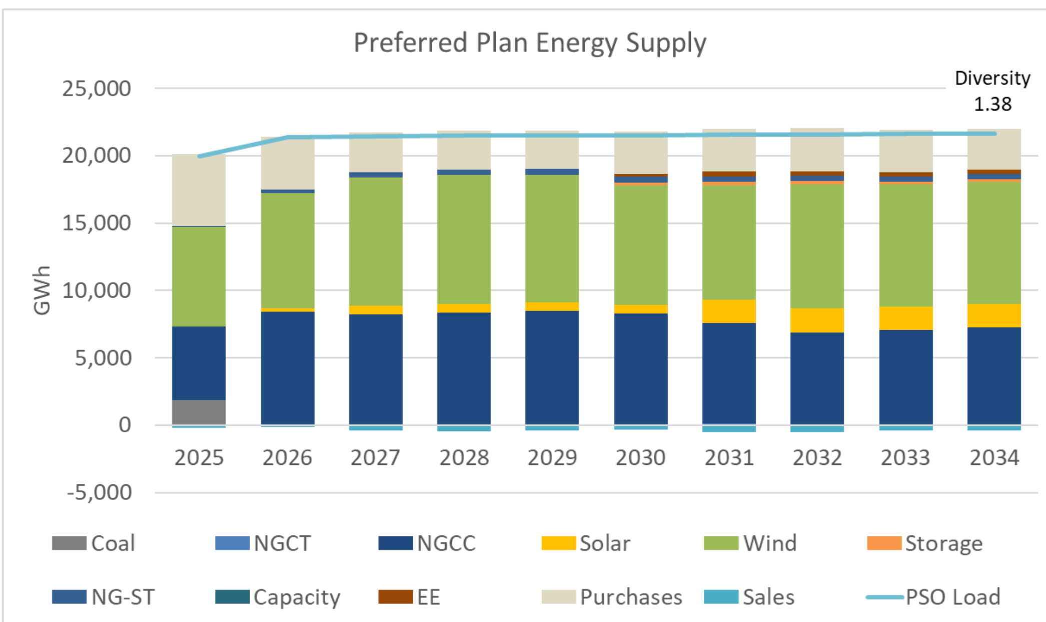


Figure ES- 6 Preferred Plan Energy

The Preferred Plan is informed by an optimized analysis to meet SPP minimum reserve margins. However, this plan is based on an uncertain future regarding events that can impact the Company's capacity position, including uncertainty around intermittent resources contribution to reserve margins, load growth and existing unit performance.

1.2 Status of 2021 IRP Five-Year Action Plan

In the 2021 IRP, the following steps were identified, and the Company provides a summarized update of each action item below.

- Continue the planning and regulatory actions to implement cost effective energy efficiency and demand response programs that reduce energy use and peak demand for PSO customers.
  - Status: PSO continues to plan, implement, and report on energy efficiency and demand response programs. PSO's current Demand Portfolio is operating under Order 720134 in PUD 202100041 that approved the 2022-2024 Demand Portfolio plan. Beginning in January 2025, PSO will begin operating under Order 743969 in PUD 2024-00013 for the approved portfolio period of 2025-2029.
- Continue to investigate opportunities to incorporate advanced technologies related to a DER technology to provide both capacity relief and improved reliability.
  - Status: PSO's current Demand Portfolio is operating under Order 720134 in PUD 202100041 that approved the 2022-2024 Demand Portfolio plan included R&D on energy storage that included a pilot on 30 residential batteries. These 30 are segmented among stand-alone batteries and solar-storage combinations.
- Conduct a Request for Proposals (RFP) to explore opportunities to add cost-effective renewable generation in the near future to take advantage of the Federal Tax Credit.
  - Status: The Company conducted an RFP in 2021 from which, three solar resources amounting to 443MWs and three wind projects amounting to 553 MWs were approved by the Commission.
- Be ready to adjust this Action Plan and future IRPs to reflect changing circumstances.

1.3 Five-Year Action Plan (2025-2029)

Steps to be taken by PSO as part of its Five-Year Action Plan include:

- Complete the evaluation of responses to the Company's November 2023 RFP, and then evaluate a potential future filing to seek approval of new resources.
- Pursue pre-approval of the purchase of the Green Country facility as part of the generation portfolio with the Oklahoma Corporation Commission. The pre-approval application was filed on September 16, 2024.
- Continue to pursue the opportunity to continue operations of the Northeastern Unit 3 using natural gas as its fuel source.
- Continue the planning and regulatory actions to implement cost effective energy efficiency and demand response programs that reduce energy use and peak demand for PSO customers.
- Monitor and evaluate the changes to SPP Resource Adequacy requirements as more information becomes available and issue subsequent RFPs as needed to meet final requirements.
- Given the timeframe to add new generation in SPP and considering the transmission interconnection queue process, PSO will continue to evaluate and implement steps as necessary to ensure a sufficient pipeline of resources consistent with the Preferred Plan that are needed beyond the five-year period.
- Remain committed to closely following developments related to environmental regulations and update our analysis of compliance options and timeliness when sufficient information becomes available.
- Be ready to adjust this Action Plan and future IRPs to reflect changing circumstances.

2 Introduction

This Report presents the 2024 Integrated Resource Plan (IRP) for Public Service Company of Oklahoma (PSO" or "Company") including descriptions of assumptions, study parameters, and methodologies. The IRP identifies the amount, timing, and type of supply- and demand-side resources required to ensure affordable and reliable energy to customers over the 10-year planning period.

2.1 IRP Objectives and Framework for Evaluation

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

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

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

- **Customer affordability** by considering broad range of resource options including renewables to take advantage of tax credits for the Company's customers, and demand-side measures including energy efficiency to empower customers with choices over how they consume energy;
- **Rate stability** by considering renewable resources to reduce uncertainties around future fuel prices, environmental policies, and ensuring an adequate energy supply to serve customers to inform portfolio choices to minimize rate risks to customers;
- **Maintaining reliability** by considering PSO's portfolio performance against seasonal reserve margins and adverse system events, in generation resource planning; and
- **Sustainability** through inclusion of renewable and advanced generation technologies as resource options to enable greener future for all.

2.2 IRP Process

This Report covers the processes and assumptions required to develop an IRP for the Company. It uses the best available information at the time of preparation, but changes that may affect its results can, and will, occur. Therefore, commitments to specific resources and actions remain subject to further review and consideration as needed. The IRP process for PSO includes the following components/steps:

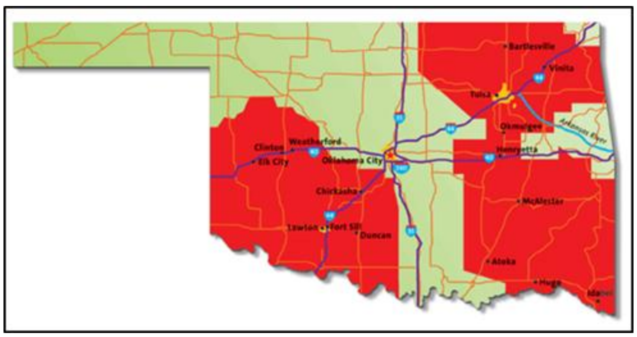
- Describe future customer needs and evaluate how those needs are likely to change over the 10-year period forecast in the 2024 IRP (see Sections 4.5 and 4.6);
- Assess the adequacy of current resources, both demand- and supply-side, in meeting future customers' needs taking into account near term changes in the portfolio and the potential impact of future regulation/legislation on the resource performance (see Section 4);
- Evaluate transmission and distribution system integration issues in meeting future customer needs and the impact on potential future resource options (see Section 5);
- Identify a list of candidate resources that could be selected by the portfolio model to meet future customer needs. Candidate resources include both supply-side (see Section 7) and demand-side options (see Section 88) including for instance, energy efficiency measures, renewables technologies and advanced generation technologies;

- Assess sources of future risks and uncertainties, and devise market scenarios to represent those risks as part of portfolio optimization (See Sections 6.3.1 and 9.2);
- Define the objectives or targets that the preferred resource plan should achieve, and evaluate all resource options to identify the portfolio options (see Sections 2.1 and 9);
- Engage with stakeholders and consider feedback received (See Appendix F); and
- Develop and evaluate the preferred resource plan and the associated five-year action plan based on all prior steps (See Sections 9.6 and 0).

2.3 Introduction to PSO

PSO's customers consist of both retail and sales-for-resale (wholesale) customers located in Oklahoma (see red area in Figure 1). Currently, PSO serves approximately 575,000 retail customers. The peak load requirement of PSO's total retail and wholesale customers is seasonal in nature, with distinctive peaks occurring in the summer and winter seasons. PSO's historical all-time highest recorded peak demand was 4,410 MW, which occurred in August 2012; and the highest recorded winter peak was 3,308 MW, which occurred in December 2022. The most recent actual PSO summer and winter peak demands were 4,287 MW and 3,263 MW, occurring on August 21, 2023 and January 16, 2024, respectively.

Figure 1 PSO's Service Territory



2.3.1 Annual Planning Process

This IRP is based upon the best available information at the time of preparation. However, changes that may impact this plan can, and do, occur without notice. Therefore, this plan is not a commitment to a specific course of action, since the future, now as much as ever before, is highly uncertain, particularly in light of economic conditions, access to capital, SPP changing requirements, 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.

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

The fundamental commodity forecasting process is ongoing as well and is continually monitored relative to ongoing activities that could potentially impact the existing commodity forecast values. Typically, the fundamental commodity forecast is updated when material changes are observed or expected. The most recent commodity forecast relied upon in this IRP was released in July of 2023.

New generation resource cost and characteristics are generally based on the assumptions used by the US Energy Information Administration (EIA) in the 2023 Annual Energy Outlook (AEO) report and informed further through the Company’s insights from market analysis of RFP results. PSO generally relies on the forecasted rate of technology cost improvements over time (i.e., “learning curves”) from the NREL Annual Technology Baseline report.

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

3 Load Forecast and Forecasting Methodology

3.1 Overview

The PSO load forecast was developed by the American Electric Power Service Corporation (AEPSC) Economic Forecasting organization and completed in April 2024.[1] The load forecast is the culmination of a series of underlying forecasts that build upon 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 10-year period (2025-2034), PSO's service territory is expected to see little population growth and non-farm employment to decline 0.1% per year. PSO is projected to see customer count growth of 0.3% annually over this period. Over the same forecast period, PSO's retail sales are projected to grow at 0.9% per year with stronger growth expected from the commercial (1.9% per year) and industrial classes (1.2% per year) while the residential class declines at a rate of 0.2% per year over the forecast horizon. Load growth in the commercial and industrial sectors is affected by some customers having large load additions. Finally, PSO's internal energy and peak demand are expected to change at an average rate of 0.9% and 0.5% per year, respectively, through 2034.

3.2 Forecast Assumptions

3.2.1 Economic Assumptions

The load forecasts for PSO and the other operating companies in the AEP System incorporate a forecast of U.S. and regional economic growth provided by Moody's Analytics. The load forecasts utilized Moody's Analytics economic forecast issued in December 2023. Moody's Analytics projects moderate growth in the U.S. economy during the 2025-2034 forecast period, characterized by a 2.2% annual rise in real Gross Domestic Product (GDP), and moderate inflation, with the implicit GDP price deflator expected to rise by 2.0% per year. Industrial output, as measured by the Federal Reserve Board's (FRB) index of industrial production, is expected to grow at 1.9% per year during the same period. Moody's projects regional employment decline of 0.1% per year during the forecast period and real regional income per-capita annual growth of 1.5% for the Company's service area.

3.2.2 Energy Price Assumptions

The Company utilizes an internally developed service area electricity price forecast. This forecast incorporates information from the Company's financial plan for the near term and the Company's fundamental forecast 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.

1 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.

3.2.3 Specific Large Customer Assumptions

PSO's customer service engineers are in frequent touch with industrial and commercial customers about their needs and activities. From these discussions, high-probability load additions or deletions are incorporated into the forecast. New large load customers, if they seek service from the Company, can also drive a significant increase in the capacity and energy requirement. For this IRP, a load forecast sensitivity was developed assuming approximately 1GW more than the Company's high load forecast to model a specific candidate portfolio sensitivity.

3.2.4 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.

3.2.5 Demand-Side Management (DSM) Assumptions

The Company's long term load forecast models account for trends in EE both in the historical data as well as the forecasted trends in appliance saturations as the result of various legislated appliance efficiency standards (Energy Policy Act of 2005 (EPAct), Energy Independence and Security Act (EISA) of 2007, etc.) modeled by the EIA. In addition to general trends in appliance efficiencies, the Company also administers multiple Demand-Side Management (DSM) programs approved by the Commission as part of its DSM portfolio. The load forecast utilizes the most current DSM programs, which either have been previously approved by or are pending currently before the Commission, at the time the load forecast is created to adjust the forecast for the impact of these programs. For this IRP, DSM programs through 2029 are included in the load forecast.

3.3 Overview of Forecast Methodology

PSO's load forecasts are based mostly on econometric, 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.

PSO utilizes two sets of econometric models: 1) a set of monthly short-term models which extends for approximately 24 months and 2) a set of monthly long-term models which extends for approximately 40 years. The forecast methodology leverages the relative analytical strengths of both the short- and long-term methods to produce a reasonable and reliable forecast used for various planning purposes.

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 long-term forecasts are used at least on an annual basis for all classes. For the typically weather sensitive classes, i.e. residential and commercial, the short-term models are leveraged to develop a monthly pattern for the annual sales forecast developed in the long-term models. This process is used as the short-term models are perceived to provide additional insight into monthly sales patterns and their relationship with heating and cooling degree-days. 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 PSO's electric load requirements as well as the major inputs and assumptions that are used in the development of the load forecast is shown in Figure 2.

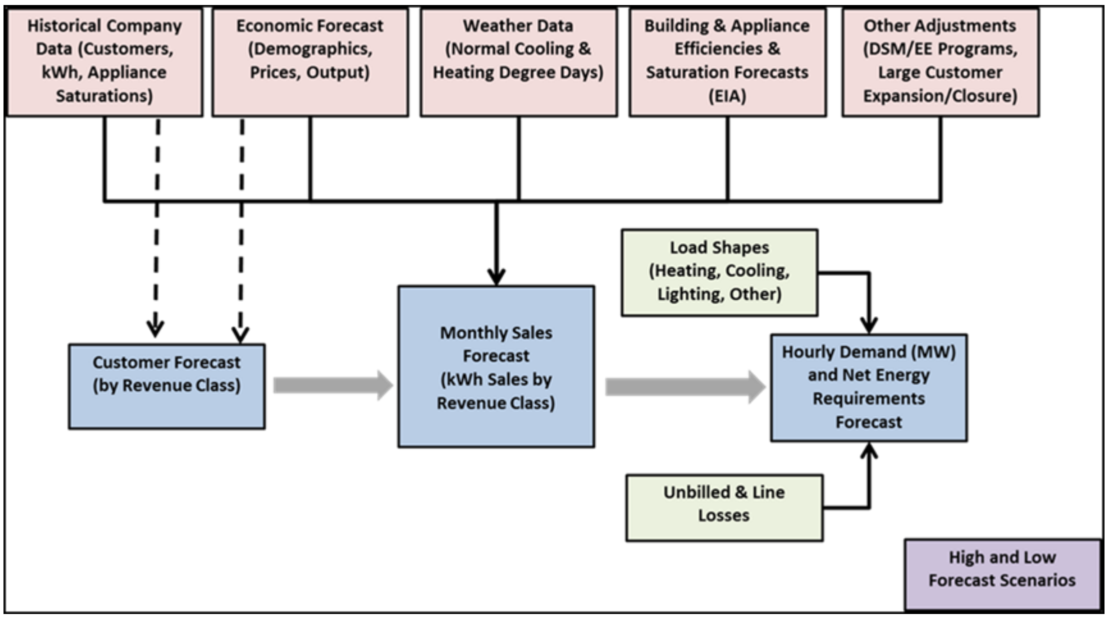


Figure 2 PSO Internal Energy Requirements & Peak Demand Forecasting Method

3.4 Detailed Explanation of Load Forecast

This section provides a more detailed description of the short-term and long-term models employed in producing the forecasts of PSO'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 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 impact 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.

3.4.1 Customer Forecast Models

The Company utilizes long-term models to develop the final customer count forecast. The long-term residential customer forecasting models are monthly and extend for 40 years. The explanatory jurisdictional economic and demographic variables may include gross regional product, employment, population, real personal income, and households used in various combinations. In addition to the economic explanatory variables, the long-term customer models employ a lagged dependent variable to capture the adjustment of customer growth to changes in the economy. There are also binary variables to capture monthly variations in customers, unusual data points and special occurrences.

The long-term customer forecasts will be used as a primary input into both short-term and long-term usage forecast models.

3.4.2 Short-term Forecasting Models

The goal of PSO's short-term forecasting models is to produce an accurate monthly load forecast shape. 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.

The estimation period for the short-term models was January 2013 through December 2023. There are models for residential, commercial, industrial, other retail, and wholesale sectors. The wholesale forecast is developed using a model for the Town of South Coffeyville. Off-system sales (OSS) and / or sales of opportunity are not relevant to the net energy requirements forecast as they are not requirements load or relevant to determining capacity and energy requirements in the IRP process.

3.4.3 Long-term Forecasting Models

The goal of the long-term forecasting models is to produce a reasonable load outlook for up to 40 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 PSO 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 2000-2023, although individual models may vary in the length of the modeling period. The annual long-term energy sales forecast is enhanced by monthly load shapes derived from the short-term models. The energy sales forecast is developed by making a billed / unbilled adjustment to derive billed and accrued values, which are consistent with monthly generation.

3.4.4 Supporting Model

In order to produce forecasts of certain independent variables used in the internal energy requirements forecasting models, a supporting model is used. This model is discussed below.

3.4.4.1 Consumed Natural Gas Pricing Model

The forecast price of natural gas used in the Company's energy models comes from an internally developed model of natural gas prices. They are first developed for Henry Hub and then developed for each state based on their historical relationship to Henry Hub. Further, they are also disaggregated in each state's primary consuming sectors: residential, commercial, and industrial. The natural gas price model is based upon 2000 through 2023 historical data.

3.4.4.2 Residential Energy Sales

Residential energy sales for PSO 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 PSO'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 model is estimated using linear regression models. This monthly model is for the period January 2001 through December 2023. It is important to note, as will be discussed later, that this modeling *has* incorporated the reductive effects of the EPAct, 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 based on analysis by the EIA regarding appliance efficiency trends. The SAE models incorporate other government legislation affecting appliance, equipment and lighting efficiency standards through the Inflation Reduction Act (IRA) that was enacted in 2022.

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

3.4.4.3 Commercial Energy Sales

Long-term commercial energy sales are forecast using SAE models. These models are similar to the residential SAE models. These models utilize efficiencies, square footage, and equipment saturations for the West South-Central Region, along with electric prices, economic drivers from Moody's Analytics, heating and cooling degree-days, and billing cycle days. As with the residential models, there are Xheat, Xcool and Xother variables derived within the model framework. The commercial SAE models are estimated similarly to the residential SAE models.

3.4.4.4 Industrial Energy Sales

The Company uses some combination of the following economic and pricing explanatory variables: service area gross regional product manufacturing, FRB industrial production indexes, and service area industrial electricity prices. 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. The last actual data point for the industrial energy sales model is December 2023.

3.4.4.5 All Other Energy Sales

The forecast of other retail sales, which is comprised of public-street and highway lighting and other sales to public authorities, relates energy sales to service households, heating and cooling degree-days, and binary variables.

Wholesale energy sales are modeled relating energy sales to economic variables such as service area households, 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.

3.4.4.6 Blending Short and Long-Term Sales

The annual energy forecasts derived from the long-term model projections. For the typically weather sensitive classes, monthly patterns are developed using the X-11 procedure. The monthly patterns for the other classes are derived from the respective forecast models. In this analysis the weather sensitive classes were defined as residential and commercial 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 Federal Energy Regulatory Commission (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.

3.4.5 Forecast Methodology for Seasonal Peak Internal Demand

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

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

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

In the end, the profiles are benchmarked to the aggregate energy and seasonal peaks through the adjustments to the hourly load duration curves of the annual 8,760 hourly values. These 8,760 hourly values per year are the forecast load of PSO 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, 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).

3.5 Load Forecast Results and Issues

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

3.5.1 Load Forecast

Exhibit A-1 presents PSO's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial, other internal sales and losses) on an actual basis for the years 2021-2023 and on a forecast basis for the years 2024-2034. The 2024 data are three months actual and nine months forecast. The exhibit also shows annual growth rates for both the historical and forecast periods.

Figure 3 provides a graphical depiction of weather normalized historic and forecast Company residential, commercial, and industrial sales for 2002 through 2034.

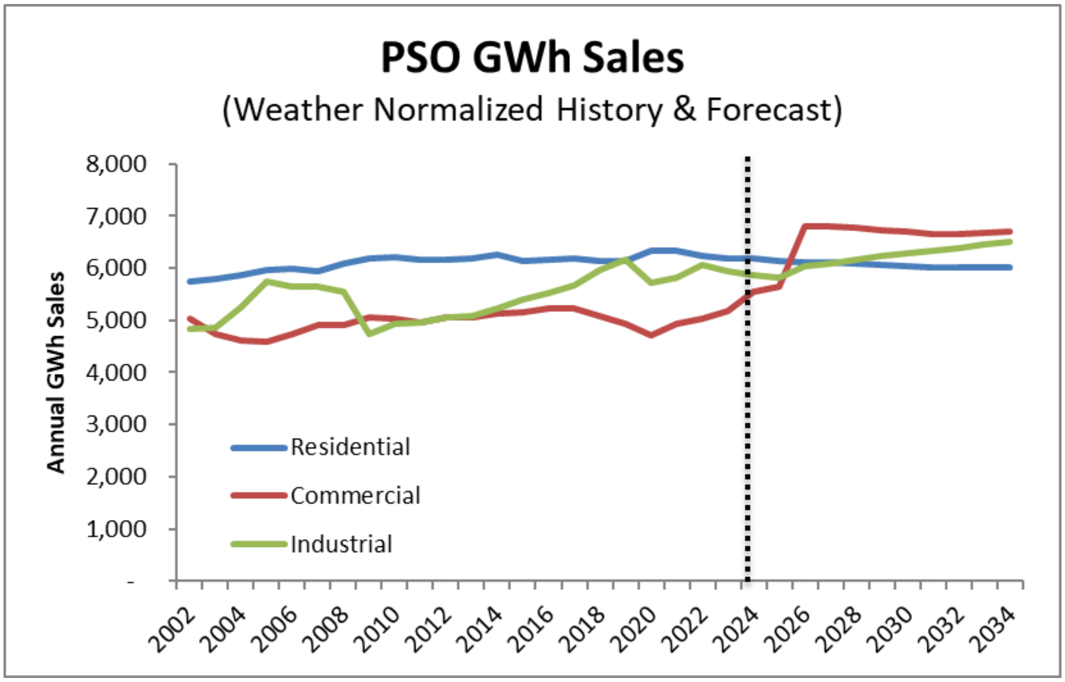


Figure 3 Weather Normalized History and Forecast of PSO's Sales by Category

3.5.2 Peak Demand and Load Factor

Exhibit A-2 provides PSO's seasonal peak demands, annual peak demand, internal energy requirements and annual load factor on an actual basis for the years 2021-2023 and on a forecast basis for the years 2024-2034. The 2024 data are three months actual and nine months forecast. 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 2034.

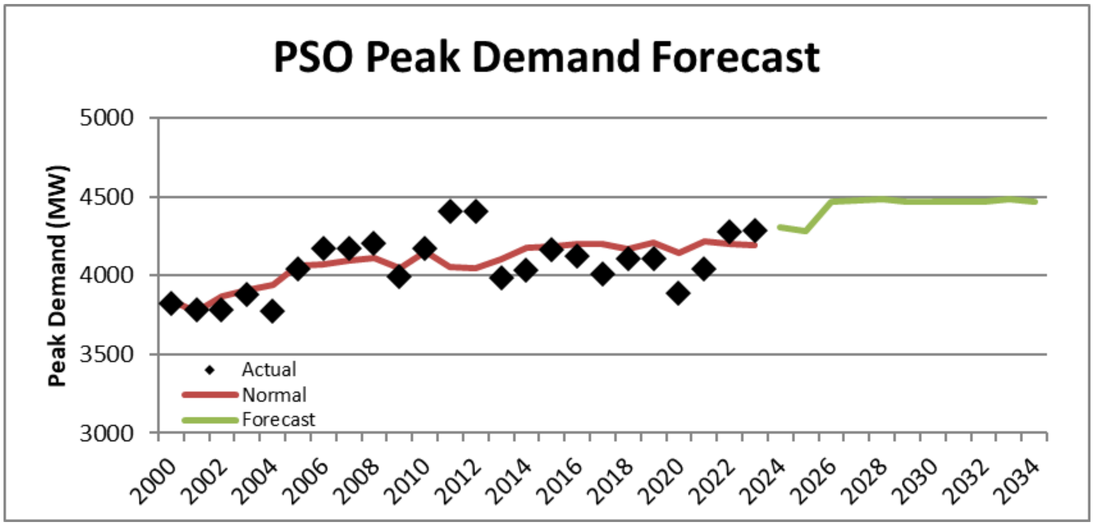


Figure 4 PSO's Peak Demand Between 2000 and 2034

3.5.3 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.

3.6 Load Forecast Trends & Issues

3.6.1 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 PSO's historical and forecasted residential and commercial usage per customer between 1991 and 2030. During the first decade shown (1991-2000), residential usage per customer grew at an average rate of 1.6% per year, while commercial usage grew by 0.1% per year. Over the next decade (2001-2010), growth in residential usage growth was at 0.6% per year while the commercial class usage decreased by 1.1% per year. In the most recent decade shown, (2011-2020) residential usage declined at a rate of 0.3% per year while commercial usage decreased by an average of 1.1% per year.

The COVID-19 Pandemic had a significant effect on usage in 2020. With more people staying at home, residential usage increased by 2.3%. Meanwhile, commercial activity curtailment played a leading role in the 5.7% decline in commercial usage. These events dampened the 2011-20 average decline in residential usage and amplified the commercial decline in usage over the period. Residential usage is projected to decline 0.9% per year over the 2021-30 actual and forecast horizon. Commercial usage is projected to grow 2.7% per year over this same horizon. However, this growth is attributed to large load additions through 2026. After 2026 through 2030, commercial usage declines by 1.2% per year as energy efficiency gains continue.

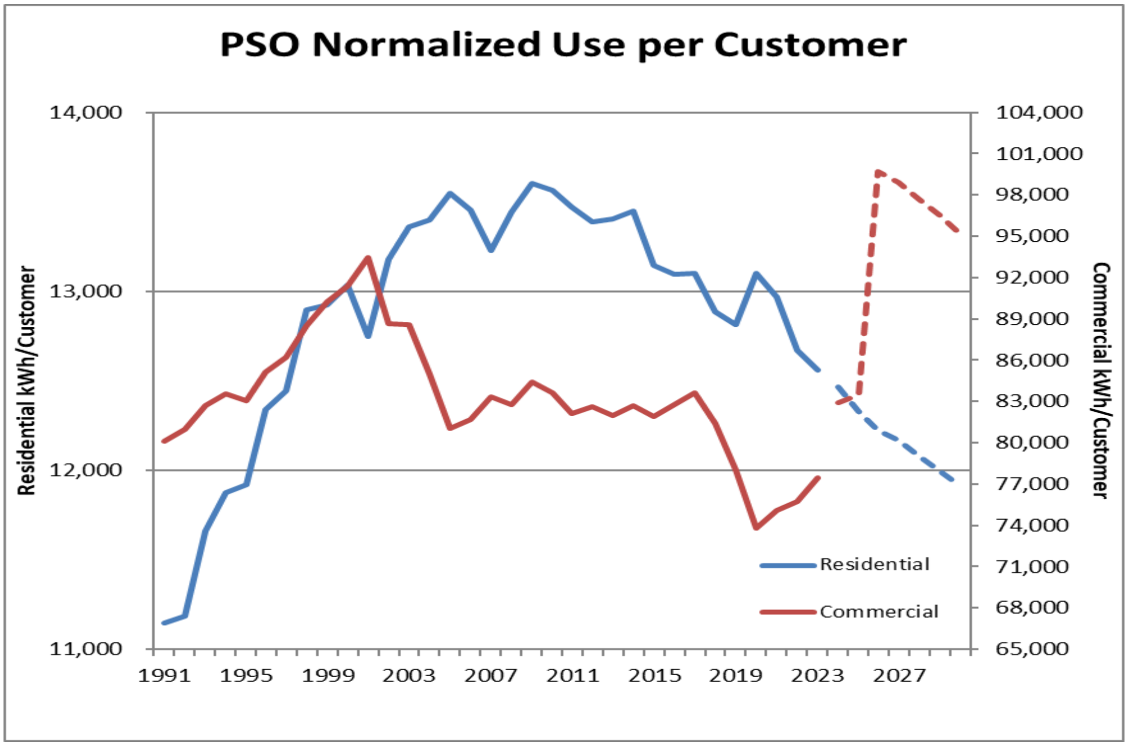


Figure 5 PSO's Normalized Usage Per Customer, by Customer Type

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

The result of this is a base load forecast that already includes some significant reductions in usage as a result of projected EE. For example, Figure 6 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 11.8 in 2010 to 15.6 by 2030. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling and room air conditioning units. Figure 7 shows similar improvements in the efficiency of lighting and refrigerators over the same period. There are not many additional efficiency gains expected from lighting for residential customers, as consumers have adopted the newer technologies and moved away from incandescent lighting.

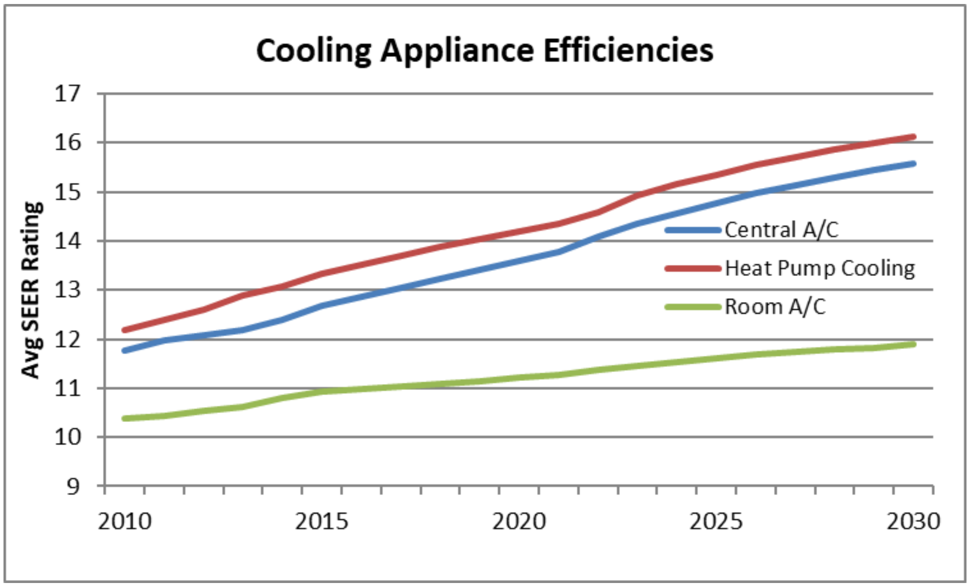


Figure 6 Projected Changes in Cooling Efficiencies, 2010 – 2030

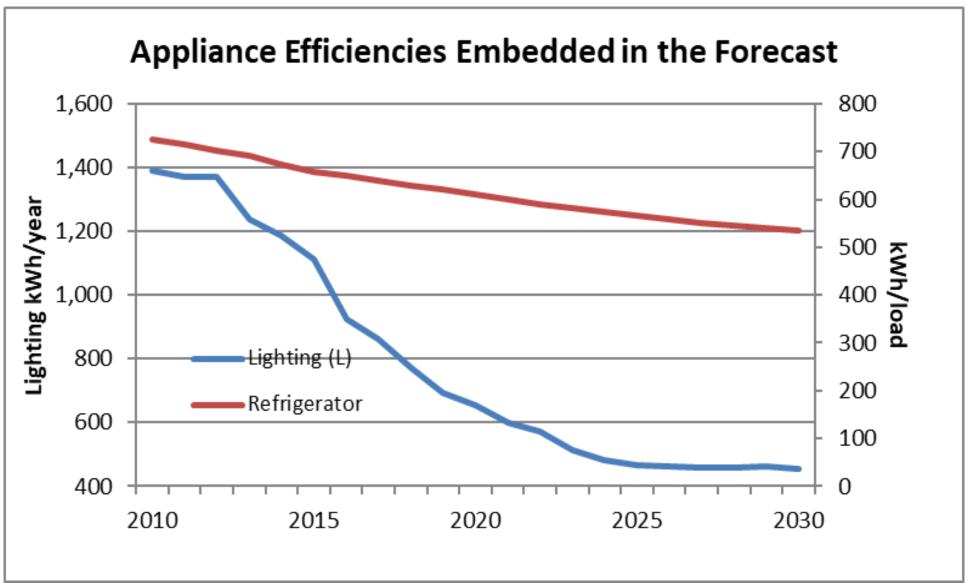


Figure 7 Projected Changes in Lighting & Clothes Washer Efficiencies, 2010-203

Figure 8 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, the historical and forecast growth in the number of PSO residential customers is provided.

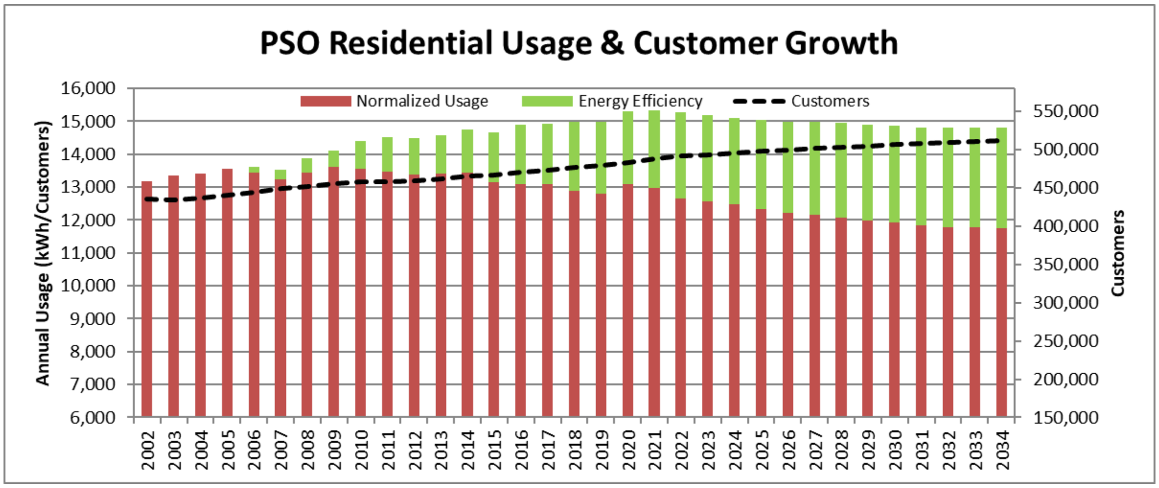


Figure 8 Residential Usage and Customer Growth, 2002 - 2031

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

The end-use load forecasting models account for changing trends and saturations of energy efficient technologies throughout the forecast horizon. However, the Company is also actively engaged in administering various commission approved DSM and EE programs which would further accelerate the adoption of energy efficient technology within its service territory. As a result, the base load forecast is adjusted to account for the impact of these programs that are not already embedded in the forecast.

For the near-term horizon (through 2029), the load forecast uses assumptions from the DSM proposed plan submitted to the Commission. For the years beyond 2029, the IRP model selected optimal levels of economic EE, which may differ from the levels currently being implemented, based on projections of future market conditions. The initial base load forecast accounts for the evolution of market and industry efficiency standards. As a result, energy savings for a specific EE program are degraded over the expected life of the program. Exhibit A-3 details the impacts of the approved EE programs included in the load forecast, which represent the cumulative degraded value of EE program impacts throughout the forecast period. The IRP process then adds the selected optimal economic EE, resulting in the total IRP EE program savings.

Exhibit A-3 provides the DSM / EE impacts incorporated in PSO's load forecast provided in this Report.

3.6.3 Interruptible Load

The Company has one customer with interruptible provisions in their contracts. This customer has interruptible contract capacity of 50 MW. However, this customer is expected to have 17 MW and 24 MW available for interruption at the time of the winter and summer peaks, respectively. An additional 1,870 customers have 72 MW available for interruption in emergency situations in DR agreements. The Company has a voluntary thermostat control program with 12,607 sites and a potential of 12 MW. 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. Further discussion of the determination of DR is included in Section 4.1.

3.6.4 Blended Load Forecast

In the typical non-weather sensitive classes, the long-term forecast is used for the entire forecast horizon. However, in order to capture the strengths of each modeling process as discussed above, elements of both the short-term and long-term forecasts are used and blended together for the typical weather sensitive classes. This is accomplished by using the X-11 procedure which breaks down each forecast into trend and seasonal components.

For the weather sensitive classes, the trend component from the long-term forecast is always used to ensure structural economic changes are captured. Since the short-term forecast better captures the monthly usage patterns, a relative ratio of the seasonal components is developed and applied to the long-term seasonal component for each month. This adjusted, long-term seasonal component is then added to the long-term trend component to arrive at a final forecast. Although a small rounding error can occur, the final forecast for the weather sensitive classes will match the original long-term forecast on an annual basis. By limiting the change to the seasonal component on a relative basis, only the monthly usage pattern is altered, with some months adjusted higher and others lowered by an equal amount of energy.

3.6.5 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 electrical service. These customers will relay information about load additions and reductions. This information will be compared with the load forecast to determine if the industrial or commercial models are adequately reflecting these changes. If the changes are different from the model results, then additional factors may be used to reflect those large changes that differ from the forecast models' output.

3.6.6 Wholesale Customer Contracts

Company representatives are in continual contact with wholesale customer representatives about their contractual needs.

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

Forecast sensitivity scenarios were established, 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 2023 AEO. While other factors may affect load growth, this analysis only considered high and low economic growth. The economy is seen as a crucial factor affecting future load growth.

The low-case, base-case and high-case forecasts of summer and winter peak demands and total internal energy requirements for PSO are tabulated in Exhibit A-4. Graphical displays of the range of forecasts, including the weather extreme scenario described below, of summer peak demand and winter peak demand for PSO are shown in Exhibit A-5.

For PSO, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2034, represent deviations of about 8.5% below and 7.9% above, respectively, the base-case forecast.

During the load forecasting process, the Company developed various other scenarios.

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

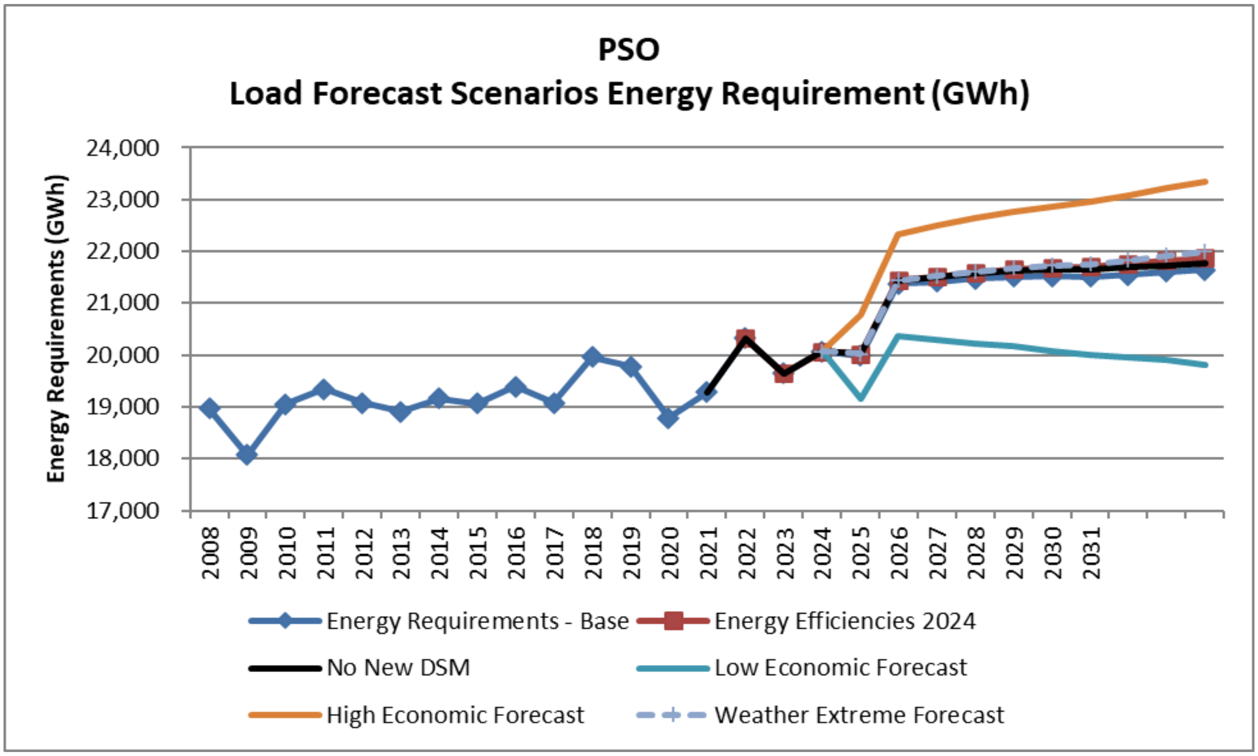


Figure 9 PSO's Load Forecast Scenarios

The no new DSM scenario extracts the DSM included in the load forecast and provides what load would be without the increased DSM activity. The energy efficiencies 2024 scenario keeps energy efficiencies at 2024 levels for the residential and commercial equipment. Both scenarios result in a load forecast greater than the base forecast.

The weather extreme forecast assumes accelerated temperatures for both the winter and summer seasons. This analysis is based on a study developed by Purdue University. This scenario results in increased load in the summer and diminished load in the winter, with the net result being a higher energy requirement forecast.

All these alternative scenarios fall within the boundary of the Company's high and low economic scenario forecasts. The Company's expectations are that any reasonable scenario developed will fall within this range of forecasts, excluding major, lower-probability events such as new large load customers.

Although the Company does not explicitly account for enhanced adoption of electric vehicles and distributed generation in the load forecast, it does continually monitor the adoption rate and will address the issue as it becomes more significant. The Company has developed high, low, and base scenarios on adoption in the service area through 2034. These scenarios a presented graphically in Figure 10. Exhibits A-6 and A-7 provide the Company's forecasts for electric vehicle and distributed generation (residential and commercial) projected adoption of these technologies.

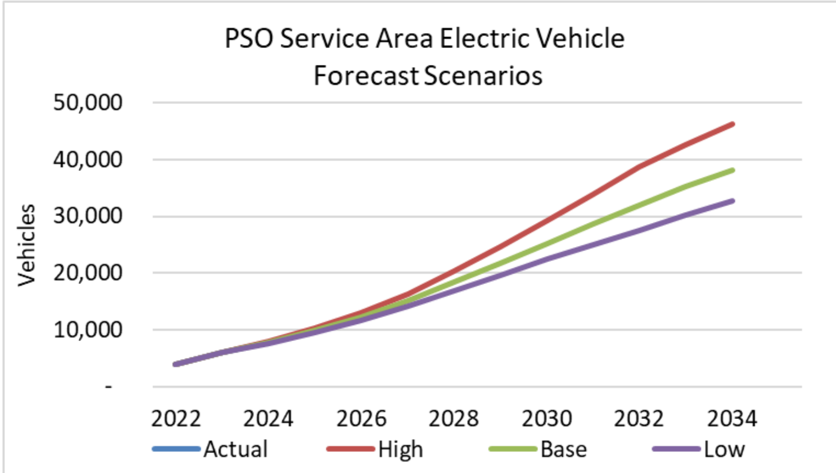


Figure 10 PSO Service Area Electric Vehicle Forecast Scenarios

3.8 Price Elasticity

The long-term load forecast models include electricity price as one of many explanatory variables. The coefficient of the electricity price variable is an estimate of the price elasticity, which is simply a measure of how responsive customers are to changes in price. The formula for price elasticity is simply the percentage change in the quantity demanded divided by the percentage change in price. If the change in demand is greater than the change in price, the elasticity estimate would be greater than 1 and described as elastic demand. If the change in demand is less than the change in price, the elasticity estimate would be less than 1 and it would be classified as inelastic demand. The demand for electricity is very inelastic. For the Residential class, the long-term elasticity estimate is approximately 0.1. For the Commercial class, the modeled price elasticity is 0.15 and the elasticity estimate for the Industrial class is 0.20. For comparison, the estimated long-term elasticity for gasoline is 0.6 while the elasticity for restaurant meals is 2.3[2]. (Note: technically each of these elasticity estimates are negative values based on the inverse relationship between price and quantity demanded. The convention by economists when describing the elasticity is to report the absolute value of these elasticity estimates.)

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

4 Current Resource Evaluation

4.1 Introduction

PSO's resource portfolio comprises a diverse set of supply- and demand-side resources that serve the Company's capacity, energy, and other reliability requirements. The generating resources include a mix of wind, solar, and fossil-fired resources. The demand-side resources include active demand response (DR) and energy efficiency (EE) programs. Customers wishing to generate their own energy can also participate in PSO's distributed generation (DG) program, which has recently seen exponential growth (https://www.psoklahoma.com/clean-energy/renewable/solar/). PSO also supports customers who are installing their own DERs and seeks rates that accurately reflect the true cost to serve them. The Company's website, https://www.psoklahoma.com/business/industry-solutions/, provides customers with ideas and links related to energy transformation solutions and energy savings. Additionally, PSO provides renewable options including ways to purchase wind and solar power equivalent to a portion or 100% of customers' monthly energy usage at https://www.psoklahoma.com/clean-energy/renewable/.

4.2 Existing PSO Generation Resources

Table 1 identifies the current PSO generating resources.

Table 1 PSO's Owned and Planned Generation Assets as of October 1, 2024

Unit Name	Primary Fuel Type	C.O.D.[1]	Planning Retirement Date [2]	Rating (MW) [3]
Owned Resources				
Comanche 1	Gas (CC)	1973	2035	220
Northeastern 1	Gas (CC)	1980	2036	422
Northeastern 2	Gas Steam	1970	2035	434
Northeastern 3	Coal	1979	2026	465
Riverside 1	Gas Steam	1974	2039	448
Riverside 2	Gas Steam	1976	2041	448
Riverside 3	Gas (CT)	2008	2056	72
Riverside 4	Gas (CT)	2008	2056	72
Southwestern 1	Gas Steam	1952	2030	56
Southwestern 2	Gas Steam	1954	2030	79
Southwestern 3	Gas Steam	1967	2037	311
Southwestern 4	Gas (CT)	2008	2056	74
Southwestern 5	Gas (CT)	2008	2056	75
Tulsa 2	Gas Steam	1956	2033	164
Tulsa 4	Gas Steam	1958	2034	158
Weleetka 4	Gas (CT)	1975	2030	47
Weleetka 5	Gas (CT)	1976	2030	49
Sundance	Wind	2021	2051	91 (A)
Maverick	Wind	2021	2051	131 (A)
Traverse	Wind	2022	2052	455 (A)
Rock Falls	Wind	2017	2047	154
Approved Future Resources				
Flat Ridge 4	Wind	2025	2055	135 (B)
Flat Ridge 5	Wind	2025	2055	153 (B)
Lazbuddie	Wind	2025	2055	265 (B)

Algodon	Solar	2025	2060	150 (B)
Pixley	Solar	2025	2060	189 (B)
Chisholm Trail	Solar	2025	2060	103.5 (B)
Proposed Future Resources				
Green Country	Gas (CC)	2025(C)	2055	795

(1) Commercial operation date

(2) Northeastern 3 will cease burning coal not later than the end of 2026. Retirement dates for company owned resources in this table are for planning purposes only. No retirement dates have formally been announced.

(3) Peak net dependable capability (Summer) as of filing.

(A) Installed capacity; Represents PSO's 45.5% ownership stake

(B) Planned installed capacity.

(C) During 2024 the Company signed an agreement to purchase the Green Country facility, subject to regulatory approval. The Company filed its application with the Oklahoma Corporation Commission (OCC) seeking approval on September 16, 2024. The Company expects to request an OCC ruling on the potential acquisition by the end of June 2025.

In addition to the owned resources, the Company also contracts for generation and capacity from various resources. Table 2 includes PSO's current contracted resources.

Table 2 PSO's Current Contracted Resources

PPA Resources	Primary Fuel Type	**PPA Expiration**	Rating (MW)
Weatherford	Wind	2025	147
Sleeping Bear	Wind	2032	94.5
Blue Canyon V	Wind	2029	99
Elk City	Wind	2029	98.9
Minco	Wind	2030	99.2
Balko	Wind	2035	199.8
Goodwell	Wind	2035	200
Seiling	Wind	2035	198.9
Oneta	Gas	2030	260
Green Country	Gas	2025	569
Confidential (C)	Gas	2025-2027	Various

(C) Individual Counterparty names and contract megawatt quantities are confidential.

4.2.1 Comprehensive Energy Hedging Program

As part of the Company's efforts to manage its fleet, a Fuel Supply Portfolio and Risk Management Plan is developed and managed annually to provide reliable and flexible sources of fuel and energy for its customers at the lowest reasonable delivered cost. This plan can be found in Appendix D.

Additionally, related to the comprehensive energy hedging program for serving load and mitigating risk with fixed-price resources, the Company is requesting approval for the use of financial hedges within that program (docket number: PUD2024-000040).

4.3 Current Demand-Side Programs

PSO utilizes cost effective demand-side programs as a tool in meeting its load obligation reliably and sustainably, while maintaining customer affordability. PSO's demand-side portfolio includes customer demand response (DR), customer energy efficiency (EE), distributed energy resources (DER) and Conservation Voltage Reduction (CVR). PSO has successfully designed, implemented, and reported on Demand Portfolio programs since 2008. PSO's current Demand Portfolio is operating under Order 720134 in PUD 202100041 that approved the 2022-2024

Demand Portfolio plan. PSO also has application PUD 2024-00013 in front of the commission, which requests approval for the portfolio period 2025-2029.

The programs for the 2022-2024 period are discussed in Section 4.3.1 and 4.3.2, recognizing some consolidation for cost savings, new technologies and market changes. The portfolio includes research and development (R&D) pilots that may lead to future programs. The R&D program includes the following pilots.

1. Demand Management Integrated Resources to research innovative and emerging technologies to enhance PSO's demand response program offerings. This will consist of two primary components:
    - Battery Storage (site solar/battery)
    - Connected Water Heaters and other devices

    PSO is testing demand, energy and bill savings of 30 residential batteries and 10 water heater control devices as part of this pilot project.
2. Efficient Homes and Communities to review and field test residential technologies:
    - A Manufactured New Homes study is reviewing possible incentives for high efficiency low-cost homes.
    - PSO is studying homes with higher level ENERGY STAR standards and near Zero-Net Energy Ready Homes (ZERH) in new construction.
    - A Solar Water Heating study is reviewing solar water heating technology for new construction homes.
3. A Non-Wires Solution is researching capacity constrained circuit(s) in PSO service territory to reduce demand through energy efficiency and other portfolio measures.
4. Virtual Diagnostics Tool to use AMI meter data to identify new energy efficiency and demand response opportunities for residential and commercial customers.

4.3.1 Customer Demand Response Programs

PSO's demand response portfolio consists of two programs: Power Hours and Peak Performers. The demand response programs sole aim is to provide load reduction capabilities during times of high demand. Because participants' voluntary load reductions during event days, there are energy savings associated with the program. These energy savings are not persistent in the same way that the installation of energy-efficient equipment provides energy savings for the life of the equipment; rather energy savings from the Business DR Program only occur during event days.

The Power Hours Program, which targets residential customers, provides ways to reduce energy usage of residential customers during peak demand periods by offering customers the option of participating in Direct Load Control (DLC) events through connected smart thermostats. PSO provides rebates for the purchase of new smart thermostats. DLC events reduce energy usage when demand is highest by communicating with registered Wi-Fi enabled thermostats installed in the homes of participants. Participating customers agreed to allow PSO to adjust the thermostat by a few degrees during an event. The customer has the option of opting out of an event through the thermostat. There is no direct penalty for opting out of specific event days. PSO calls a maximum of sixteen events per year.

The business demand response program, known as Peak Performers, targets commercial and industrial customers. In this program, customers voluntarily reduce their electricity load during

PSO-called load reduction events in exchange for paid incentives based on the average electricity usage reduction over the course of all events. There is no direct penalty for opting out of specific event days. PSO calls a maximum of sixteen events per year. The program is active during summer months when average demand typically approaches designated capacity thresholds.

4.3.1.1 Current Customer Participation

The number of residential customers participating in the Power Hours Program in 2023 was 12,953 customers with 16,513 devices participating. Peak Performers Program had 1,912 participating facilities from 238 companies.

Table 3 provides a summary of the DR program net demand and energy impacts:

Table 3 Summary of DR Program Net Impacts - 2023

Program	Net MWh	Net MW
Power Hours	228	23.89
Peak Performers	1,184	63.73
Demand Response Total	**1,412**	**87.62**

4.3.2 Customer Energy Efficiency Programs

PSO offers residential customers and commercial / industrial customers EE options designed to reduce energy usage while providing the same or improved service. Program performance is assessed on a levelized dollar per lifetime energy savings (kWh) basis and cost effectiveness test defined by the California Standard Practice Manual[3].

4.3.2.1 Current Available Energy Efficiency Programs to Customers

In 2023, PSO offered customers four energy-efficiency programs that included two residential, one commercial / industrial, and one cross-sector program. The residential programs included Home Weatherization and Residential Energy Solutions which encompasses Energy Saving Products, Home Rebates, Education, Multifamily and Manufactured Homes, and Behavioral Modification subprograms. The commercial / industrial program is Business Rebates which encompasses Custom, Prescriptive, Small Business, Midstream and Strategic Energy Management, and the cross-sector program is Conservation Voltage Reduction (CVR). The latter program, CVR, is discussed in more detail in Section 4.3.3.

4.3.2.2 Current Program Results

Table 4 provides a summary of the EE program net demand and energy impacts:

Table 4: Summary of EE Program Net Energy Impacts - 2023

Program	Net MWh	Net MW
Business Rebates	38,424	6.69
Residential Energy Solutions	56,674	12.27
Home Weatherization	4,818	2.61
Conservation Voltage Reduction	37,294	11.74
Energy Efficiency Totals	**137,210**	**33.31**

3 The California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects, 2001 edition, produced by the California Energy Commission and the California Public Utility Commission

PSO's Business Rebates Program provides a range of energy efficiency measures for small businesses, large businesses, schools, municipalities, and industrial businesses to participate in receiving an incentive to reduce energy consumption. The Business Rebates Program offers subprograms of Small Business Energy Solutions (SBES), Midstream, Strategic Energy Management, and Custom (including Agriculture and Oil and Gas industry specific subprograms) and Prescriptive (C&P). The program offers incentives for many measures including lighting, plug load & controls, insulation, windows & doors, appliance & equipment, HVAC, and refrigeration.

The Multifamily subprogram is serving properties that must be composed of three or more dwelling units within the service territory. Energy efficiency equipment is eligible within dwelling units, in common areas, and in office spaces. The Multifamily subprogram offers commercial measures in addition to the residential measures. The measures include LED lamps and fixtures, air infiltration, ceiling insulation, duct sealing, HVAC system replacements, water heaters, ENERGY STAR® windows, ENERGY STAR® pool pumps, ENERGY STAR® washing machines, ENERGY STAR® dryers, vending machine controls, and ice machines.

PSO's Home Weatherization Program objective is to generate energy savings and peak demand reduction for limited income residential customers through the direct installation of weatherization measures in eligible dwellings. The weatherization program provides no-cost energy efficiency improvements to PSO customers with household incomes of $55,000 or less a year.

PSO's Energy Saving Products (ESP) subprogram seeks to generate energy and demand savings for residential customers through the promotion of a variety of energy efficient measures. The ESP upstream program consists of retail price discounts for qualifying LED light bulbs, room air purifiers, advanced power strips, bathroom ventilation fans, water dispensers, spray foam, door sweeps and seals, room air conditioners, and air filters. The program also includes distribution of free LEDs in partnership with food banks and local food pantries within the PSO service territory. The ESP downstream program offers mail-in rebates from PSO for qualifying heat pump water heaters, clothes dryers, clothes washers, refrigerators, and level 2 electric vehicle chargers.

The Home Rebates subprogram seeks to generate energy and demand savings for residential customers through the promotion of comprehensive efficiency upgrades to building envelope measures and HVAC equipment for both new construction homes and retrofits to existing homes. Offering PSO customers direct inducements for higher efficiency measures offsets the first cost obstacle, encouraging customers to choose the upgraded products. The program has three components: New Homes, Multiple Upgrades, and Single Upgrade.

The PSO Education subprogram, known by teachers, students, and parents as the PSO Energy Saver Kits Program, provides educational materials and energy-efficient products to 5th grade students. The program annually provides approximately 16,000 students and families with the opportunity to learn about energy efficiency and provides energy efficient products to reduce home energy use.

The Behavioral Modification subprogram provides energy usage reports to approximately 200,000 residential customers. The program was designed to generate greater awareness of energy use and ways to manage energy use through energy efficiency education in the form of an energy report. The energy report provides customers with energy-saving behaviors and compares their current energy use to previous years as well as energy use in similar homes. It is expected that through this education, customers will adopt energy conservation tips that will lead to more efficient energy use in their homes. Customers can choose to opt out if they no longer want to receive the emailed energy reports. In addition to receiving a report that encourages saving energy, participants are also encouraged to go to an online portal where they could input more specific information to receive tips addressing their specific energy use.

4.3.3 Conservation Voltage Reduction

PSO's CVR Program uses a system of devices, controls, software, and communications equipment to manage reactive power flow and lower voltage level for implemented distribution circuits. With the usual system design, customers close to a substation receive voltages closer to 126 volts and customers farther from the substation receive lower voltages. Because most electric devices are designed to operate most efficiently at 115 volts, any "excess" voltage is typically wasted, usually in the form of heat. Figure 11 depicts an overview of the CVR installation.

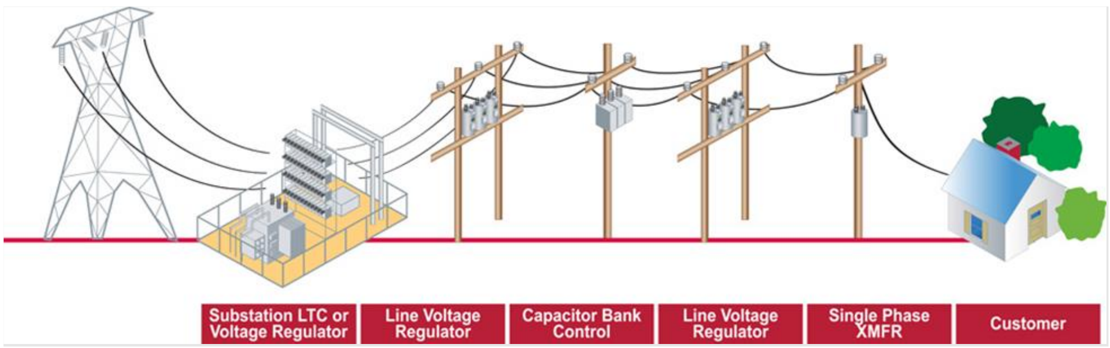


Figure 11 CVR Optimization Schematic

PSO's CVR program uses a software program called "Yukon", a control system from Eaton that monitors the voltage and power factor along the distribution circuit and lowers the voltage profile within an acceptable bandwidth. The tighter voltage regulation provided by CVR technology allows end-use devices to operate more efficiently without any action on the part of consumers. The average consumer receives a lower but still acceptable voltage and uses less energy to accomplish the same tasks. PSO has approached the implementation of CVR in a holistic, system-wide manner, to fully optimize the energy efficiency potential.

PSO has implemented CVR on 159 distribution circuits through the end of 2023 and seeks to continue implementing CVR in the 2025-2029 Demand Portfolio. This approach is consistent with PSO's commitment to CVR as shown in its Integrated Resource Plans dating back to the 2015 Integrated Resource Plan. If the 2025-2029 plan is approved with approximately 250 circuits deployed with CVR, PSO will near saturation of CVR deployment with significant energy savings.

4.4 Environmental Compliance

It should be noted that the following discussion of environmental regulations is the basis for assumptions made by the Company which are incorporated into its analysis within this IRP. Activity including but not limited to Presidential Executive Orders, litigation, 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.

4.4.1 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 AEP's existing generation, including PSO's units, are the following: (a) periodic revisions to the National Ambient Air Quality Standards (NAAQS) and the development of State Implementation Plans (SIPs) to achieve 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.

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

4.4.2 National Ambient Air Quality Standards (NAAQS)

The CAA requires the EPA to establish and periodically review NAAQS designed to protect public health and welfare. Revisions tend to increase the stringency of the standards, which in turn may require the Company to make investments in pollution control equipment at existing generating units, or, since most units are already well controlled, to make changes in how units are dispatched and operated.

In February 2024, the EPA finalized a new, more stringent annual primary PM2.5 standard. Areas with air quality that do not meet the new standard will be designated by the Federal EPA as "nonattainment," which will trigger an obligation for states to revise their SIPs to include additional requirements, resulting in further emission reductions to ensure that the new standard will be met. Areas around some of PSO's generating facilities may be deemed nonattainment, which may require those facilities to install additional pollution controls or to implement operational constraints. The nonattainment designations by the Federal EPA and the subsequent SIP revisions by the affected states will take some time to complete; therefore, management cannot reasonably estimate the impact on PSO's operations, cash flows, net income or financial condition.

4.4.3 Regional Haze Rule (RHR)

The RHR requires affected states to develop regional haze state implementation plan (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 nitrogen oxides (NOx), sulfur dioxide (SO2) and particulate matter (PM), and determine whether such controls should be deployed to improve visibility based on five factors set forth in the regulations. BART is applicable to Electric Generating Units (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 federal implementation plan (FIPs).

4.4.4 Oklahoma Regional Haze

The CAA and RHR require certain states, including Oklahoma, to develop regional haze SIPs that contain enforceable measures and strategies for reducing emissions of pollutants that can impair visibility in certain federally protected areas. Each initial SIP must require certain eligible facilities to conduct an emission control analysis, known as a BART analysis, to evaluate emissions control technologies for NOx, SO2 and particulate matter (PM), and determine whether such controls should be deployed to improve visibility based on five factors set forth in the regulations. BART is applicable to EGUs greater than 250 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.

The AEP/PSO Regional Haze Agreement and the 2013 Oklahoma RH SIP Revision required Northeastern Unit 4 to retire in 2016 and required controls be installed on Units 2 & 3.

PSO's Northeastern Unit 3 coal unit will decrease the annual capacity until the unit's planned retirement by December 31, 2026, according to the AEP/PSO Regional Haze Agreement. PSO is pursuing revisions to the Regional Haze Agreement for the continued operation of the unit on natural gas beyond 2026.

In June 2024 the United States District Court of the District of Columbia finalized a consent decree resolving a Sierra Club lawsuit alleging that the US EPA failed to take action for the second planning period regional haze state implementation plan revisions submitted by 34 states including Oklahoma. The consent decree establishes deadlines for the EPA to finalize rulemaking for each SIP included in the action, including Oklahoma. The deadline for EPA to finalize its rulemaking for Oklahoma is December 31, 2026.

4.4.5 Mercury and Air Toxics Standard (MATS) Rule

The final National Emission Standards for Hazardous Air Pollutants for Coal and Oil-Fired Electric Utility Steam Generating Units (EGUs) commonly known as the Mercury and Air Toxics Standards (MATS) became effective on April 16, 2012 and required compliance by April 16, 2015. AEP Management obtained administrative extensions for up to one year at several units, including PSO's Northeastern Units 3&4, to facilitate the installation of controls or to avoid a serious reliability problem. The rule established unit-specific emission rates for units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of non-mercury metals) and hydrogen chloride (as a surrogate for acid gases). In addition, the rule proposed work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin / furans. Compliance was required within three years. The Company obtained administrative extensions for up to one year at several units to facilitate the installation of controls or to avoid a serious reliability problem.

In addition to meeting the regional haze SIP requirements, the Northeastern Unit 3 environmental controls were installed to meet the MATS Rule requirements.

On May 7, 2024, EPA finalized revisions to the MATS Rule. The final rule establishes more stringent emission limits for particulate matter emissions from coal-based generating units. In addition, the rule requires the installation of continuous emission monitoring systems as the method for demonstrating compliance with the new particulate limit. Facilities have three years, or until May 2027, to achieve the new requirements.

4.4.6 Cross-State Air Pollution Rule (CSAPR)

CSAPR is a regional trading program designed to address interstate transport of emissions that contribute significantly to non-attainment and maintenance of the 1997 ozone and PM NAAQS in downwind states. CSAPR relies on Sulfur dioxide (SO_2) and nitrogen oxides (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 basis.

In January 2021, the Federal EPA finalized a revised CSAPR, which substantially reduced the ozone season NOx budgets for many states. PSO has been able to meet the requirements of the revised rule over the first few years of implementation and is evaluating its compliance options for later years when the budgets are further reduced. In February 2023, the Federal EPA Administrator finalized the disapproval of interstate transport SIPs submitted by 19 states, including Oklahoma, addressing the 2015 Ozone NAAQS. Disapproval of the SIPs provided the Federal EPA with authority to impose a FIP for those states, replacing the SIPs that were disapproved. In August 2023, a FIP went into effect that further revised the ozone season NOX budgets under the existing CSAPR program in states to which the FIP applies. As a result of legal challenges, the United States Court of Appeals for the Tenth Circuit granted a stay of Oklahoma's SIP denial, which means implementation of the FIP has also been stayed in Oklahoma pending completion of the legal challenges to the SIP denial. Management will continue to monitor the outcome of this litigation and the development of SIPs for any potential impact to operations.

Collectively, the installed SCR and FGD systems' respective emission reductions of NOx and SO_2, 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 position PSO well moving forward for compliance with CSAPR.

4.4.7 Clean Air Act Section 111 Greenhouse Gas Emission Standards

On May 9, 2024, EPA finalized greenhouse gas emissions standards that are applicable to existing coal and natural gas steam units, as well as new gas combustion turbine units. States will have until May 2026 to submit a state implementation plan (SIP) to EPA that details how the state will achieve the emission standards for applicable facilities. EPA will then have one year to approve the SIP (approximately May 2027). Effective dates for achieving the emission standards vary depending on the compliance option selected.

For coal units, three compliance options were finalized. The first establishes a carbon dioxide (CO_2) emission standard based on the use of a 90% carbon capture and storage (CCS) control systems. Facilities utilizing this option must have the CCS system in service by January 1, 2032. The CCS option does not have future requirement to retire coal unit operations by a specific date.

The second compliance option for existing coal units is to achieve a CO_2 emission standard that is based on the use of 40% natural gas co-firing. Facilities utilizing this option must have gas co-firing in service by January 1, 2030 and must retire coal unit operations by January 1, 2039. Finally, the third compliance option is to retire the coal unit by January 1, 2032.

Regarding gas units, EPA finalized CO_2 emissions standards for existing gas steam units and new gas combustion turbine units. Emission standards for existing gas combustion turbine units will be developed by EPA in a separate rulemaking. The emissions standard for existing gas steam units are based on the capacity factor of the unit and efficient combustion operations. The standard does not include a specific retirement date for these existing units.

For new gas combustion turbine units, EPA established three emission standards, depending on the unit's capacity factor. The low load (<20% capacity factor) and intermediate load unit (20-

40% capacity factor) standards are based on high efficiency operations. The low load and intermediate load unit standards are based on the use of low emitting fuel and high efficiency operations, respectively. The emission standards for baseload (>40% capacity factor) operations are high efficiency standards and the use of CCS technology achieving a 90% CO_2 reduction.

PSO is in the early stages of evaluating and identifying the best strategy for complying with this and other new rules, discussed herein, while ensuring the adequacy of resources to meet customer needs. The rule has been challenged by 27 states, including Oklahoma, numerous companies, trade associations and others. PSO has joined with several other utilities to challenge the rule and has asked the court to stay the rule during the litigation, and the appeals have been consolidated. In July 2024, the D.C. Circuit Court of appeals denied those motions to stay and several parties, including PSO and other utilities, have filed applications with the United States Supreme Court seeking an emergency stay. Management will continue to monitor the outcome of this litigation and consider its options for compliance should the rule stand.

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

4.4.8 Coal Combustion Residuals (CCR) Rule

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

In 2020, the EPA revised the CCR rule to include a requirement that unlined CCR storage ponds cease operations and initiate closure by April 11, 2021. On May 8, 2024, the EPA finalized an additional rulemaking, the Legacy CCR Rule. The Legacy Rule expands the requirements of the 2015 CCR Rule to ash storage locations such as surface impoundment sites at inactive facilities, previously closed landfill and pond sites not currently regulated by the 2015 CCR Rule, as well as certain beneficial use projects. Applicable locations will be subject to federal closure and post-closure care requirements, along with obligations related to groundwater monitoring and corrective measures. Closure and post-closure costs have been included in Asset Retirement Obligation (ARO) in accordance with the requirements in the final rule. Additional ARO revisions will occur on a site-by-site basis if groundwater monitoring activities conclude that corrective actions are required to mitigate groundwater impacts, which could include costs to remove ash from some unlined units.

PSO will seek cost recovery through regulated rates, including proposal of new regulatory mechanisms for cost recovery where existing mechanisms are not applicable. The rule could have an additional, material adverse impact on net income, cash flows and financial condition if PSO cannot ultimately recover these additional costs of compliance. In August 2024, AEP and PSO along with several other entities filed appeals of the rule; those appeals have all been consolidated before the D.C. Circuit Court of Appeals. Management will continue to monitor the outcome of this litigation and consider its options for compliance should the rule stand.

4.4.9 Clean Water Act Regulations

4.4.10 Clean Water Act “316(b)” Rule

The EPA’s Effluent Limitation Guidelines (ELG) rule for generating facilities establishes limits for flue gas desulfurization (FGD) wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater, which are to be implemented through each facility’s wastewater discharge permit. In 2020, the EPA revised the ELG rule to establish additional options for reusing and discharging small volumes of bottom ash transport water, an exception for retiring units, and an extension to the compliance deadline to a date as soon as possible beginning one year after the rule was published but no later than December 2025. PSO has implemented changes and has achieved compliance with the 2020 ELG Rule requirements. The Company assessed technology additions and retrofits to comply with the 2020 rule and in January 2021, permit modifications to incorporate the 2020 ELG Rule’s requirements were filed for affected facilities.

On May 9, 2024, EPA finalized additional revisions to the ELG Rule that applies to wastewater discharge from coal based generating units. The revised guidelines require facilities with wet flue gas desulfurization (FGD), to install zero liquid discharge (ZLD) technology to control wet FGD related wastes. The revised rule also established more stringent limits for landfill leachate discharge. Facilities must comply with all revised requirements by December 31, 2029. As an alternative to install ZLD technology, facilities can meet the requirements by retiring coal unit operations by December 31, 2032. Facilities that select the retirement option for compliance must notify the agency by December 31, 2025. Several appeals have been filed with various federal courts challenging the 2024 ELG rule. The various appeals have been consolidated before the United States Court of Appeals for the Eighth Circuit. Appellants have also moved the court to stay the rule during the litigation. Management cannot predict the outcome of the litigation.

4.4.11 Waters of the United States (WOTUS) Rule

On January 18, 2023, the EPA and the Army Corps of Engineers published a final rule revising the definition of “waters of the United States”, which became effective on March 20, 2023. On May 25, 2023, the Supreme Court issued a decision in the case of Sackett v. EPA which made clear that certain aspects of the 2023 rule are invalid. Consequently, in August of 2023, the agencies announced a new rule to conform the definition to the Supreme Court's decision. The new rule expands the scope of the definition, which means that permits may be necessary where none were previously required, and issued permits may need to be reopened to impose additional obligations. PSO is evaluating what impact the revised rule will have on operations.

As a result of ongoing litigation on the January 2023 Rule, the agencies are implementing the January 2023 Rule, as amended by the conforming rule, in 23 states, the District of Columbia, and the U.S. Territories. In the other 27 states – including Oklahoma -- and for certain parties, the agencies are interpreting "waters of the United States" consistent with the pre-2015 regulatory regime and the Supreme Court's decision until further notice. PSO will continue to monitor developments in rule making and litigation for any potential impact to operations.

4.5 Capacity Needs Assessment

As a member of SPP, PSO and other member utilities have an obligation to maintain a minimum level of generating capacity under SPP’s Resource Adequacy construct. If a utility falls short of these obligations, SPP may assess non-compliance charges. The current minimum SPP Planning Reserve Margin (PRM) through May 31,2026 requires an installed reserve capacity of 15% above PSO’s coincident summer peak load.

On August 6, 2024, SPP's Regional State Committee (RSC) and Board of Directors (SPP Board) approved increases to the Planning Reserve Margin (PRM) member utilities are required to maintain to support regional grid reliability[4]. The RSC and SPP Board approved minimum requirements of a 36% winter-season PRM and a 16% summer-season PRM, effective beginning summer 2026 and winter 2026/27. These actions were taken primarily based on SPP's analysis of the 2023 SPP Loss of Load Expectation Report[5]. SPP Staff has indicated that it intends to recommend further increases to the PRMs by 2029/30 and in AEP's assessment this is the most likely outcome. Based on this assessment, for AEP's system planning purposes the winter PRM is set at 36% for 2026/27, is increased by 2% annually for each of the following three winter seasons reaching 42% for winter 2029/30 and is held constant at 42% thereafter. AEP is highly engaged in the SPP stakeholder process and will continuously monitor this process.

Furthermore, SPP is modifying the basis for each LRE to meet the new PRMs by implementing an Accredited Capacity (ACAP) methodology[6]. The ACAP methodology will include an adjustment to the 16% summer and 36% winter PRMs as well as implementing a resource performance-based adjustment (PBA) for LREs existing thermal resources. The PBA will be derived from each thermal unit's past performance and result in a reduction from the installed capacity to a lower accredited capacity for meeting the Company's minimum summer ACAP PRM obligations. Additionally, the winter ACAP for the company's thermal resources will be further adjusted to account for historical performance and fuel availability during critical systems periods.

For this IRP, the Company assumed a minimum SPP summer and winter ACAP PRM estimated by SPP of 5% and 11.9% respectively in 2026[7]. The Company also included an additional 6% risk reserve to the ACAP PRM (7% risk reserve to the PRM in 2025) to mitigate risks related to complying with the fast-changing SPP reserve margin requirements and other sources of forecast uncertainties and potential unit unplanned outages. This amounts to approximately 260MW and 175MW additional reserve requirements in the summer and winter seasons respectively.

Figure 12 and Figure 13 illustrate PSO's Going-In capacity position in the summer and winter relative to the SPP ACAP PRMs and the added risk reserve described above. PSO's capacity need is the difference between the target reserve (denoted by the black line) and the accredited capacity (beginning in 2026) of the existing generation resources by year (denoted by the bars). As a summer peaking LRE, PSO's capacity need begins in SPP Planning Year 2027/2028 in the summer after the Northeastern Unit 3 (NE3) ceases burning coal. The Going-In resources include a PPA contract with the Green Country Facility that expires after 2025 and the continued use of the full facility as an owned unit after the PPA contract expires as noted in Section 4.2. Including the unit extends the time until the Company finds a need for additional capacity to the SPP 2027/2028 planning year. The capacity need is further widened in the SPP 2030/31 planning year after the Company's Southwestern Units 1&2 (gas) and Weleetka Units 4&5 (gas)

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[4] https://www.spp.org/news-list/spp-board-approves-new-planning-reserve-margins-to-protect-against-high-winter-summer-use/#:~:text=SPP%27s%20Regional%20State%20Committee%20and,2026%20and%20winter%202026%2F27

[5] https://www.spp.org/documents/71904/2023%20spp%20lole%20study%20report.pdf

[6] https://spp.org/documents/71947/mopc%20educational%20fa%20and%20acap%20prm%20overview.pdf

[7] These ACAP PRMs were informed from a preliminary SPP report provided to the Company in April 2024, however, final ACAP PRMs have not yet been communicated to LREs.

exit the portfolio. An additional purchased power agreement set to expire in 2030 increases the capacity needs at that time.

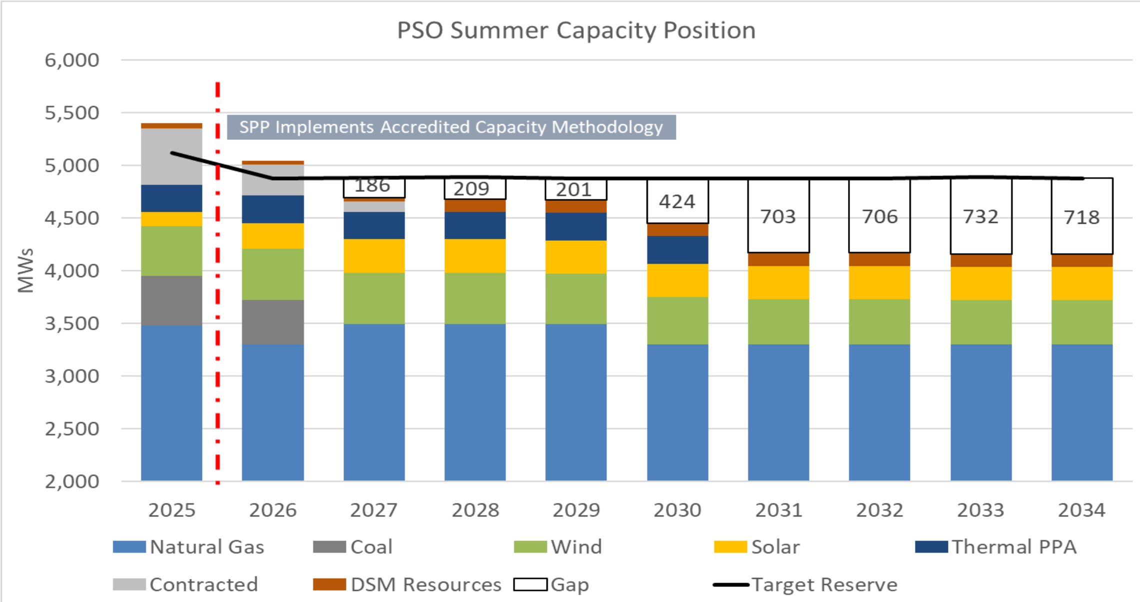

Figure 12 "Going-In" SPP Summer Capacity Position and Target Reserve Margin

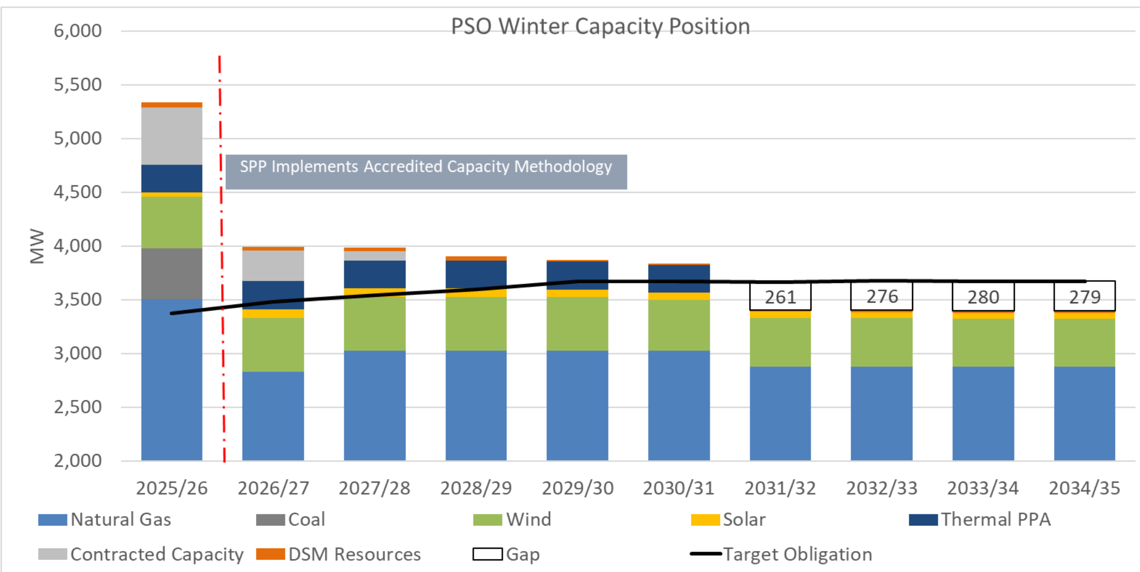

Figure 13 PSO "Going-In" SPP Winter Capacity Position and Target Reserve Margin

4.6 Energy Needs Assessment

Figure 14 illustrates the projected going-in energy position of the Company. This graphic shows how much of the Company's load is projected to be provided by Company resources, and how much will be purchased from and sold into the SPP energy market. These projections include only resources which are either already in service, under contract, or have already been approved but are not yet in service, and the expected production from the Green Country facility. PSO has historically purchased a substantial amount of energy from the market and the figure illustrates that PSO has a significant need for energy to serve load in the future. PSO desires to lessen this market risk with the actions it is currently taking with the proposed addition of the Green Country facility, among other things.

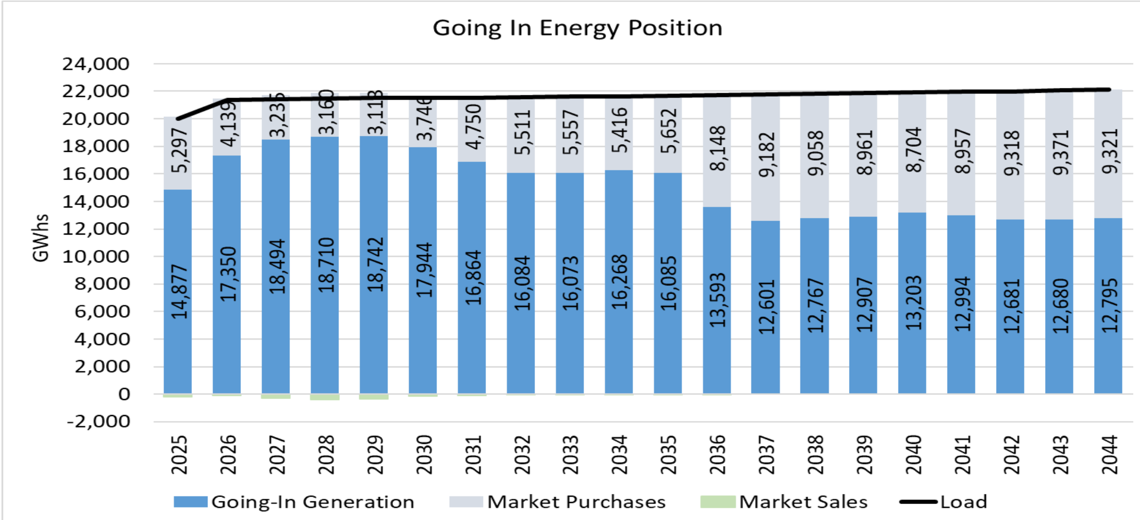

Figure 14 PSO "Going-In" Energy Position

5 Transmission and Distribution Evaluation

5.1 Transmission System Overview

AEP continues supporting the SPP Transmission Expansion Plan (STEP) and the SPP Integrated Transmission Planning Assessment (ITP) processes, which include some projects that may improve import capability. PSO has been open to such imports as evidenced by the issuing of recent Requests 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.

The portion of the AEP Transmission System operating in SPP (AEP-SPP zone, or AEP-SPP) consists of approximately 1,500 line miles of 345 kV, approximately 3,750 line miles of 138 kV, approximately 2,300 line miles of 69 kV, and approximately 390 line 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. Figure 15 shows PSO's forecasted transmission capital expenditures.

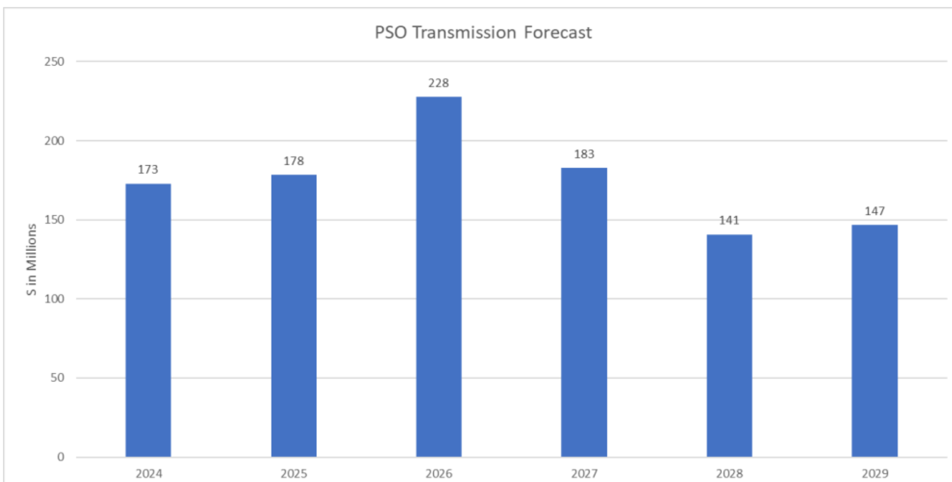

Figure 15 Transmission Forecast for PSO

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 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. 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. Moreover, a lack of seams agreements between SPP and its neighbors has significantly slowed down the process of developing new interconnections. Despite the robust nature of the AEP-SPP transmission system as originally designed, its current use is in a different manner than originally designed, in order to meet SPP requirements, which can stress the system. In addition, factors such as outages, extreme weather, and power transfers also stress the system. This has resulted in a transmission system in the AEP-SPP zone that is 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. SPP and MISO have engaged in a coordinated study process to identify transmission improvement projects which are mutually beneficial. Projects deemed beneficial by both RTOs will be pursued with joint funding, but no such projects have yet been deemed beneficial by both RTOs. Additional background on SPP's Interregional Relations, including the Regional Review Methodology and SPP's Joint Operating Agreements with MISO and AECI may be found at:http://www.spp.org/engineering/interregional-relations/

http://www.spp.org/engineering/interregional-relations/

5.3 The SPP Transmission Planning Process

Currently, SPP produces an annual SPP Transmission Expansion Plan (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 2024 STEP summarizes activities from 2023, including expansion planning and long-term SPP Open Access Transmission Tariff (OATT) studies (Tariff Studies) that impact future development of the SPP transmission grid. Key topics included in the STEP are:

1. Transmission Services,
2. Generator Interconnection,
3. Requests pursuant to Attachment AQ
4. Integrated Transmission Planning (ITP),
5. Balanced Portfolio,
6. High Priority Studies,
7. Sponsored Upgrades,
8. Interregional Coordination, and
9. Integrated Transmission Planning 20-Year Assessment
10. Generation Retirement

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

STEP projects are categorized by the following designations:

- Generation Interconnect – Projects associated with a FERC-filed Interconnection Agreement;
- High Priority – Projects identified in the high priority process; Interregional – Projects identified in SPP's joint planning and coordination processes;
- 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 2024 STEP identified 126 transmission network upgrades with a total cost of approximately $1.3 billion. At the heart of SPP's STEP process is its ITP process, which represented approximately 73% of the total cost in the 2024 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 2024 STEP is available at:
https://www.spp.org/documents/56611/2021%20step%20report.pdf
https://www.spp.org/documents/56611/2024%20spp%20transmission%20expansion%20plan%20report.pdf

5.4 Recent AEP-SPP Bulk Transmission Improvements

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

5.4.1 AEP-SPP Import Capability

Increasing the import capabilities with AEP-SPP's neighboring companies could require a large capital investment for new transmission facilities by the neighboring systems or through sponsored upgrades by SPP transmission owners. An analysis of the cost of the upgrades 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.

5.4.2 SPP Studies that may Provide Import Capability

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

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

5.4.3 Recent AEP-SPP Bulk Transmission Improvements

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

- Chisholm – Woodward/Border tie 345 kV line. This project, located in western Oklahoma, will increase bulk transfer capability from west to east across the west Texas/Oklahoma area. This project is estimated to provide between $102 million and $123 million in economic benefits over 40 years.
- Minco – Pleasant Valley – Draper 345 kV line and new station. This project creates a new Pleasant Valley 345/138 kV substation which ties into the existing Cimarron to Draper 345 kV line. A new line from Minco to Pleasant Valley and a second 345 kV line from Pleasant Valley to Draper. Overall, there are approximately 48 miles of new 345 kV transmission. The project increases transfer capability by bypassing congestion in the Oklahoma City area. This project is estimated to provide between $286 million to $804 million in economic benefits over 40 years.
- Sooner – Wekiwa 345 kV line build. This approximately 76-mile project will increase transfer capability and is estimated to provide between $17 million and $465.6 million in economic benefits over 40 years.
- South Shreveport – Wallace Lake 138 kV line rebuild. This project will improve reliability in the Shreveport / Bossier City area and will strengthen the transmission system between SPP and the Cleco area of MISO.
- 36th & Lewis – 52nd & Delaware Tap 138 kV rebuild. This 0.97-mile project was approved to address NERC TPL-001-4 criteria.
- Osage – Webb City Tap – Shidler 138 kV rebuild. This project was approved to address NERC TPL-001-4 criteria. The project includes the rebuild of 24.9 miles. The project is expected to provide up to $44.37 million in economic benefits over 40 years. The project greatly increases the west to east flow across the SPP system.
- Cleveland – Cleveland 138 kV bus tie rebuild. This tie between the SPP and AECI systems west of Tulsa has become one of the most congested points on the SPP system. This project is estimated to provide between $138.7 million and $225.3 million in economic benefits over 40 years.
- Pine & Peoria Tap – 46th Street Tap – Tulsa North 138 kV rebuild. The project includes the rebuild of 5.7 miles of 138 kV between Pine & Peoria Tap and Tulsa North. This project is estimated to provide between $390 million and $532.7 million in economic benefits over 40 years.
- Fitzgerald Creek – Kenzie 138 kV line tap at Valley. This project is located 30 miles north of Oklahoma City. The project addresses congestion between the Kenzie station owned by OG&E and the Kenzie station owned by GRDA. This project is estimated to provide between $65.1 million and $125.3 million in economic benefits over 40 years.
- Matthewson – Redbud 345 kV new line. This project assists in transferring renewable energy from western Oklahoma towards the larger load centers further to the east. The project is a new 38-mile path between the existing Matthewson and Redbud stations. This project is expected to provide between $138.6 million and $225.3 million in economic benefits over 40 years.
- Northwest Arkansas: The Siloam Springs (GRDA)-Siloam Springs (SWEPCO) 161 kV line has been upgraded to a larger conductor with improved thermal capacity. The terminal equipment upgrades were approved to further increase the rating of the path. These upgrades relieve constraints for west to east flow and improve reliability.
- Tulsa Metro, Oklahoma area: The Tulsa area upgrades include Tulsa Southeast to E. 61st St, 138 kV line, Riverside Station Upgrade, Tulsa Southeast to S. Hudson 138 kV line, Tulsa Southeast to 21st Street Tap 138 kV line. Installing larger conductor and new breakers at the Riverside station will improve capacity in the 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.

5.5 PSO Distribution System Overview

PSO serves nearly 576,000 customers in 232 cities and towns across an operational service area of 24,000 square miles of eastern and southwestern Oklahoma. This includes approximately 494,200 residential, 66,900 commercial, 6,200 industrial, and 8,600 other customers. PSO's Distribution Operations organization includes three districts: Tulsa, Lawton, and McAlester. PSO's distribution system includes approximately 15,400 overhead circuit miles and 5,400 underground circuit miles. PSO's distribution system includes approximately 16,100 primary miles and 4,700 secondary miles.

5.5.1 Distribution Investments

PSO's typical distribution investment portfolio includes projects that support employee and customer safety, new customer growth, customer requests for new service, customer satisfaction, conservation voltage reduction, as well as reliability improvements.

Since 2018, PSO has targeted additional investments on projects that support the safety, reliability, and resiliency of the distribution system. Beginning in 2024, many of these investments are included as part of PSO's Grid Enhancement and Resiliency (GEAR) rider portfolio.

In Case No. PUD 2022-000093, PSO's GEAR rider was approved for a significant investment to continue to revitalize and transform its distribution grid, with a focus on distribution grid automation and grid resiliency. Implementation of the plan includes an approximately $150 to $180 million in capital investment in PSO's distribution grid through 2026. Table 5 provides an overview of this plan.

Table 5 PSO Grid Enhancement and Resiliency Plan

Project Type	Estimated Spend (Millions $)
Distribution Automation / Circuit Reconfiguration (DA / CR) Reclosers	20.4
Distribution Automation / Circuit Reconfiguration (DA / CR) Station	20.0
Infrastructure D-Line – Circuit Ties & Upgrades	18.6
Deploy Reclosing Technology D-Line	11.4
Overhead to Underground Residential	3.1
Structural and Equipment Upgrades	46.0
Replacement of Outdated Equipment	31.5
Total	**151.0**

6 Modeling Parameters

6.1 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, conformance with applicable North American Electric Reliability Corporation (NERC) and RTO criteria. In addition, given the unique impact of fossil-fired generation on the environment, the planning effort must ultimately be in concert with anticipated long-term requirements as established by the EPA-driven environmental compliance planning process.

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

In general, assumptions and plans are continually reviewed and modified as new information becomes available. Such continuous analysis is required by multiple disciplines across PSO and AEP to ensure that market structures and governances, technical parameters, regulatory constructs, capacity supply, energy adequacy and operational reliability, and environmental mandate requirements are constantly reassessed to ensure optimal capacity resource planning.

Currently, fulfilling a regulatory obligation to serve native load customers represents one of the cornerstones of the PSO IRP process. Therefore, as a result, the objective function of the modeling applications utilized in this process is the development of a least-cost plan, with cost being more accurately described as revenue requirement under a traditional ratemaking construct.

That does not mean, however, that the most appropriate plan is the one with the absolute least cost over the planning horizon evaluated. Other factors were considered in the determination of the Plan. To challenge the robustness of the IRP, sensitivity analyses were performed to address these factors.

This overall process reflects consideration of options for maintaining affordability, rate stability, service reliability and sustainability and managing risks.

6.2 Methodology

The IRP process aims to address the gap between resource needs and current resources. Given the various assets and resources that can satisfy this expected gap, a tool is needed to sort through the myriad of potential combinations and return an optimum solution. *Plexos®* LP long-term optimization model, also known as "LT Plan®" is the primary modeling application used by PSO for identifying and ranking portfolios that address the gap between needs and current available resources. Given the cost and performance parameters around sets of potentially available proxy resources–both supply and demand side–and a scenario of economic conditions that include long-term fuel prices, capacity costs, energy costs 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 Net Present Value Revenue Requirement (NPVRR), of the resulting stream of revenue requirements. The least cost option is considered the optimum portfolio for that unique input parameter scenario.

6.3 The Fundamentals Forecast

AEP's Fundamental Forecast was developed by the AEPSC Fundamental Forecasting organization. The forecast is a long-term commodity market forecast completed July 2023. It covers the electricity market within the Eastern Interconnect. It is provided to AEPSC and all AEP operating companies for purposes such as resource planning, capital improvement analyses, fixed asset impairment accounting, and other applications. The forecast includes (in both nominal and real dollars): 1) hourly, monthly and annual regional power prices; 2) prices for various types of coals; 3) monthly and annual locational natural gas prices, including the benchmark Henry Hub; 4) nuclear fuel prices; 5) emission prices; 6) locational implied heat rates; 7) electric generation capacity values; 8) renewable energy subsidies; and 9) inflation factors; Table 6 below describes the source of the Fundamental Forecast components.

Table 6 Fundamentals Forecast Components

Category	Forecast Component	Source
FUEL	Natural gas forecast; Henry Hub	AEP Fundamentals
FUEL	Natural gas locational values	AEP Fundamentals
FUEL	Oil price, WTI	AEP Fundamentals regression model
FUEL	Uranium prices	AEP Fundamentals regression model
FUEL	Coal	Wood MacKenzie Coal Forecast
LOAD	Load Forecast and hourly shapes	AEP Economic and Load Forecasting
GENERATION	New unit costs/Technology Learning Curves	EIA AEO Build Costs/NREL
GENERATION	New, low or zero carbon dispatchable technology	AEP Engineering
GENERATION	Solar/Wind production shapes by area	NREL
GENERATION	Generating Reserve Margins	RTO Requirements
GENERATION	Announced new generation units	Velocity Suite
GENERATION	Existing generation units	Velocity Suite (EIA 860 and 923 data)
POLICY	State-mandated Renewable Portfolio Standards	AEP Fundamentals; AEP Environmental
CREDITS	REC's	Evolution Markets and Wood MacKenzie
CREDITS	PTC's, ITC's	Inflation Reduction Act
ECONOMIC	Inflation/GDP deflators/PPI	Moody's Analytics
EMISSIONS	Annual SO_2, Seasonal/Annual NO_x	AEP Commercial Operations
EMISSIONS	CO_2 -RGGI forecast	AEP Commercial Operations and Wood MacKenzie
EMISSIONS	Unit-level emission rates; CO_2, SO_2, NO_x	Velocity Suite (US EPA CEMS data)

Energy Exemplar’s Aurora energy market simulation model is the primary tool used to make the Fundamental Forecast. The Aurora model iteratively generates zonal, but not company-specific, long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions, and capital costs. The Aurora model is widely used by utilities for integrated resource and transmission planning, power cost analysis and detailed generator evaluation. The database includes approximately 22,000 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.

6.3.1 Market Scenario Drivers and Assumptions

Four scenarios, shown in Table 7, were developed to create and test PSO’s preferred plan under various long-term pricing scenarios.

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

The High scenario assumes higher load growth and higher natural gas prices than Base case.

The Low scenario assumes lower load growth and lower natural gas prices than Base case.

The Enhanced Environmental Regulation scenario is similar to Base case but assumes that adoption of the Environmental Protection Agency's proposed rule changes to CAA Section 111 (d). The proposed rule was published May 11, 2023.

Table 7 2024 IRP Scenario Assumption Matrix

Scenario	Load	Gas Price	Env. Regs
Base	Base	Base	Base
High	High	High	Base
Low	Low	Low	Base
Enhanced Environmental Regulation (EER)	Base	Base	111(d) Informed

6.3.1.1 Fuel Scenarios

Natural Gas Prices

Figure 16 illustrates the monthly Panhandle Eastern TX-OK natural gas price forecasts that are used for the SPP market modeling in the Reference scenario. This pricing point was selected for the report because it is representative of gas prices in the region.

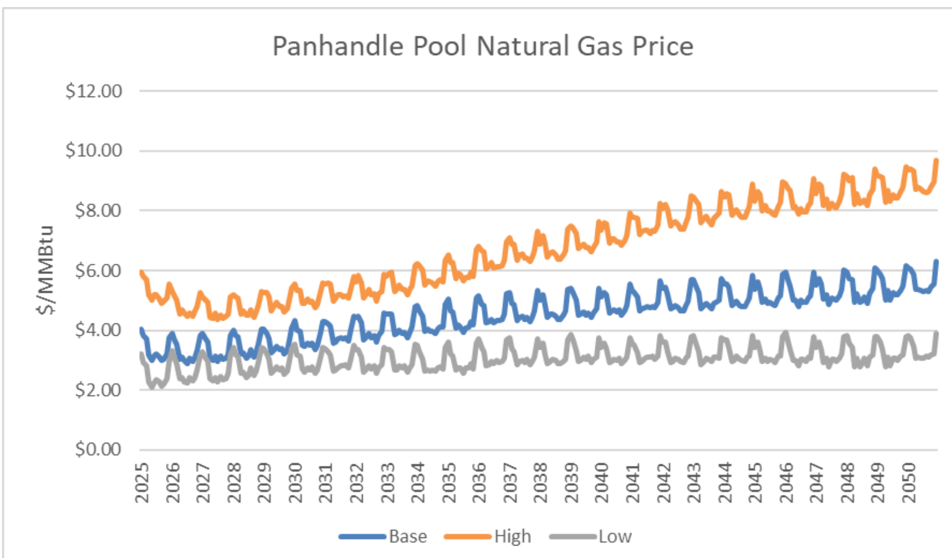

Figure 16 Panhandle Eastern TX-OK Nominal Natural Gas Prices ($ / MMBtu)

Coal Prices

PSO uses Wood MacKenzie's coal price forecast in the 2024 IRP. Figure 17 illustrates the monthly forecast of Powder River Basin (PRB) coal prices at the point of purchase (i.e., exclusive of transportation costs) used in the Base Scenario. While some coal-fired units in SPP burn coals other than PRB, this price reflects the outlook for the type of coal burned at PSO's Northeastern 3 facility.

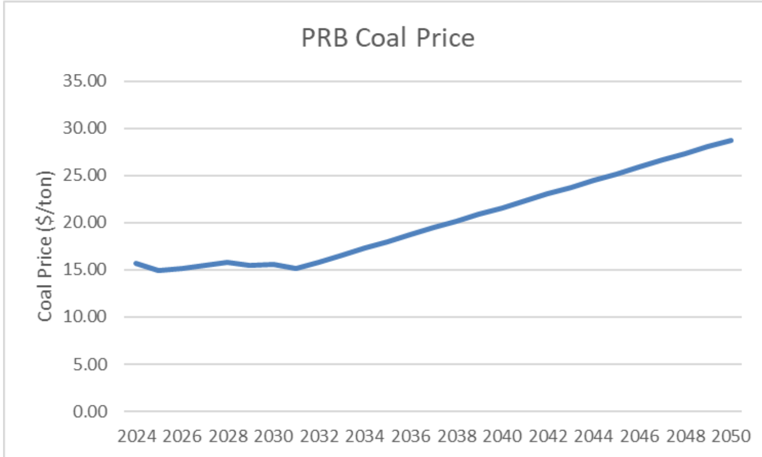

Figure 17 PRB Coal Prices (nominal $ / ton, FOB origin)

6.3.1.2 Capacity Expansion Results

PSO used the AURORA long-term capacity expansion model to forecast the least-cost combination of resource additions and retirements in SPP using the assumptions for each market scenario. While the SPP market selections do not directly impact the resources that can be selected for the PSO portfolio, they are informative for describing how different resource types might perform under certain conditions. Figure 18 and Figure 19 below illustrates the 2044 forecasted SPP capacity and generation mix (respectively) across all five market scenarios compared with the SPP resource mix in 2025.

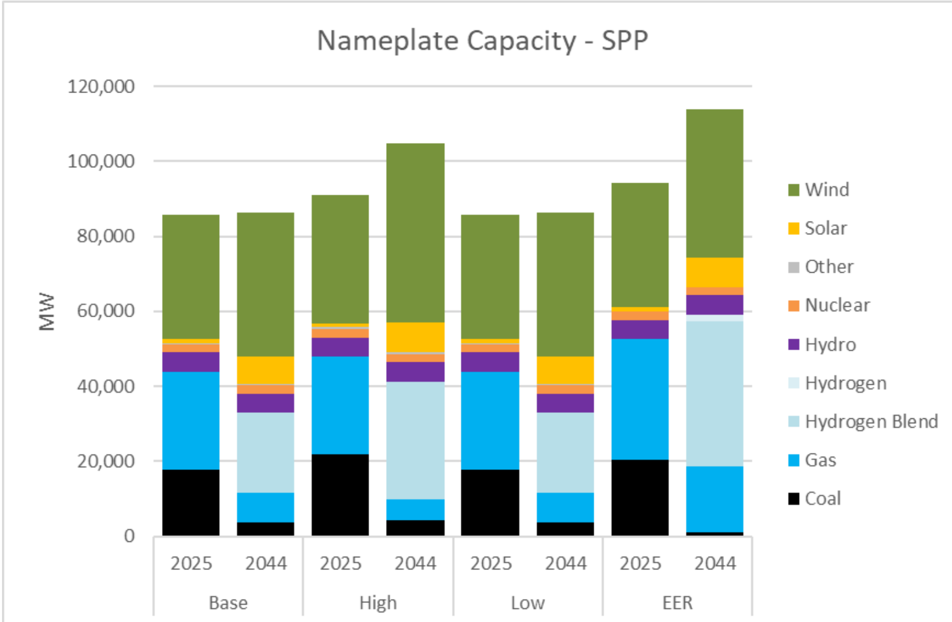

Figure 18 Comparison of 2044 Nameplate Capacity by Technology in SPP w/ 2025 Resource Mix

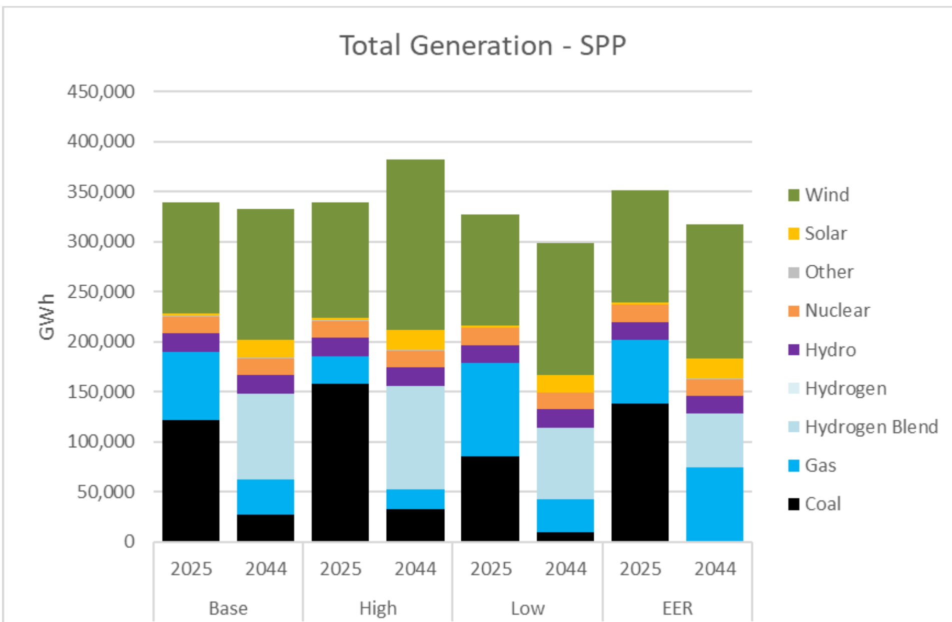

Figure 19 Comparison of 2044 Generation by Technology in SPP w/ 2025 Resource Mix

6.3.1.3 Market Price Results

The key market outputs from the scenario modeling process are the power prices illustrated below in Figure 20 and Figure 21. Shown are all four market scenarios modeled in the 2024 IRP. These figures illustrate the wide but plausible range of energy prices that emerge from the scenario modeling step that were used to develop and select the Preferred Plan.

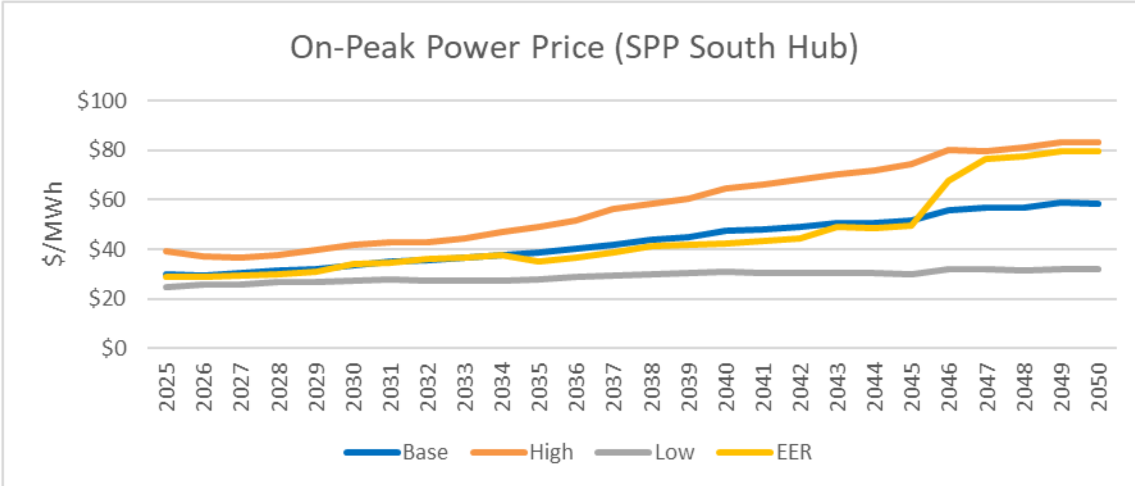

Figure 20 Annual On-Peak SPP South Hub Nominal Electricity Price ($ / MWh)

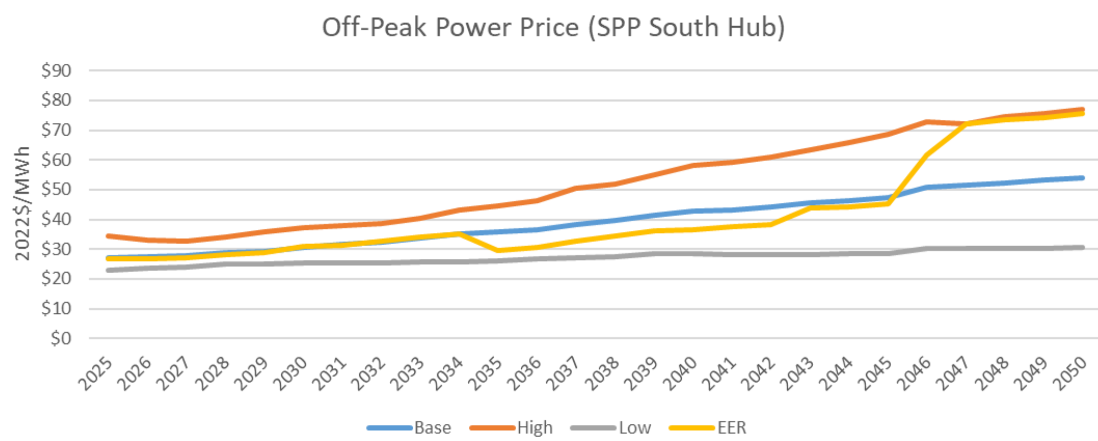

Figure 21 Annual Off-Peak SPP South Hub Nominal Electricity Price ($ / MWh)

7 Supply-Side Resource Options

7.1 Introduction

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

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

Unless stated otherwise, PSO relied on EIA's 2023 Annual Energy Outlook (AEO) as the starting point for the technology cost and performance assumptions for new utility scale generation in the

SPP footprint. Reference case changes to technology cost and performance over time are based on the medium case of the 2023 National Renewable Energy Laboratory's (NREL) annual technology baseline (NREL ATB 2023) report.[8] Cost assumptions for advanced technologies are generally based on a compilation of estimates from different external sources, reflecting uncertainties associated with cost estimates for technologies under development.

The Company included annual and cumulative capacity modeling limits for different resources informed through its analysis of the SPP queue and responses to Company RFPs. To establish the modeling limits, the Company first reviewed the potential MWs of resources that might be available through the analysis of the resources submitted in the SPP Queue. It is further assumed that of the total resources in the SPP Queue, only 20% might actually be available to the open market for development. The Company then considered the responses to recent RFPs to substantiate the estimate of potential resources that might be available to the Company to transact.

All new resources also included an assumption for additional transmission network and interconnection upgrade costs. For this IRP, a proxy cost of $32/kW was included in the cost of thermal resources informed from a study by Lawrence Berkley National Laboratory on SPP Interconnection costs through 2023[9]. Wind resources included a capital cost of $113/kW and solar resources included a capital cost of $157/kW, informed from responses to Company RFPs and are used as a proxy for potential costs of future resources.

Fixed costs for all new gas resources included an additional firm gas reservation fee of $0.2441/MMBtu based on gas distribution company published transmission rate. This cost is applied as a proxy for ensuring the availability of an adequate and reliable fuel supply.

7.1.1 Base / Intermediate Alternatives

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

Intermediate power plants adjust outputs as electricity demand fluctuates. This role is traditionally met by existing, smaller and relatively less efficient power plants. As these power plants retire, however, new capacity will be needed. Natural gas combined cycle power plants have become the typical generation resource option for intermediate power plants, and they are included in this IRP.

7.1.1.1 Natural Gas Combined Cycle (NGCC)

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

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[8] *NREL Electricity Annual Technology Baseline (ATB) 2023.* Retrieved from https://atb.nrel.gov/electricity/2023/data

[9] https://emp.lbl.gov/publications/generator-interconnection-cost-0

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

NGCCs are modeled in *Plexos*® as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. Three NGCC configurations in the model are available for selection, including the H-class turbine single shaft configuration with 418MW capacity, the H-class turbine multi-shaft configuration with 1,100 MW capacity, and the F-class turbine multi-shaft configuration with 760 MW capacity. These resources are made available in the model with a first operating year of 2032, reflective of the anticipated period required for SPP interconnection request approvals, regulatory approvals, permitting siting, engineering, and construction.

Overnight capital cost assumptions for NGCC options are shown in Figure 22. The first operating year variable operations and maintenance cost (VOM), the fixed operations and maintenance cost (FOM), firm gas reservation fees and heat rate assumptions are shown in Table 8.

Figure 22 Capital Cost Assumptions for NGCC

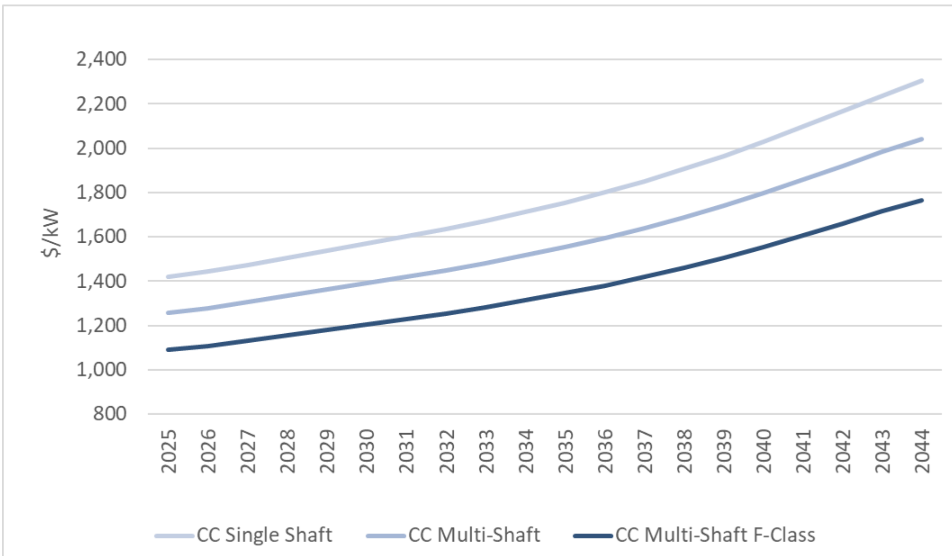


Table 8 Operating and Heat Rate Assumptions for NGCC

		H-Class Multi-Shaft (1,100 MW)	H-Class Single Shaft (418 MW)	F-Class Multi-Shaft (760 MW)
VOM	$/ MWh	2.10	2.87	2.25
FOM	$/ kW-yr	13.73	15.87	19.51
Gas Transmission Rate	$/ kW-yr	13.62	13.75	14.12
Heat Rate	Btu / kWh	6,370	6,431	6,601

7.1.1.2 Northeastern 3 Unit

The Company's existing Northeastern 3 coal unit was included as separate resource available in 2026 as a gas-fired resource, contingent upon certain environmental submissions and approvals. The continued operation of this unit as a gas-fired resource allows the Company to take advantage of existing infrastructure and retain a reliable resource to provide capacity and energy at low costs to PSO customers. For this modeling, it was assumed that the boiler will be able to produce a maximum of 420 MW of power.

7.1.2 Peaking Alternatives

Peaking sources have traditionally provided top-up generating capacity during demand peaks that typically occur a few hundred hours each year but can occur more or less. Given the low utilization of peaking generators, focus in the past has been on minimizing capital and fixed costs instead of fuel efficiency and other variable costs.

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

7.1.2.1 Simple Cycle Combustion Turbines (NGCT)

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

NGCTs are modeled in *Plexos®* as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. One NGCT configuration is available for *Plexos®* to select, i.e., the 240 MW F-Class unit. This generic resource is made available in the model with a first operating year of 2031, reflective of the anticipated period required for SPP interconnection request approvals, regulatory approvals, permitting, siting, engineering, and construction. The maximum annual capacity addition is 720 MW.

The NGCT overnight capital cost assumptions are shown in Figure 23. FOM, VOM, firm gas reservation fees and heat rate assumptions are shown in Table 9.

Figure 23 Capital Cost Assumptions for NGCT

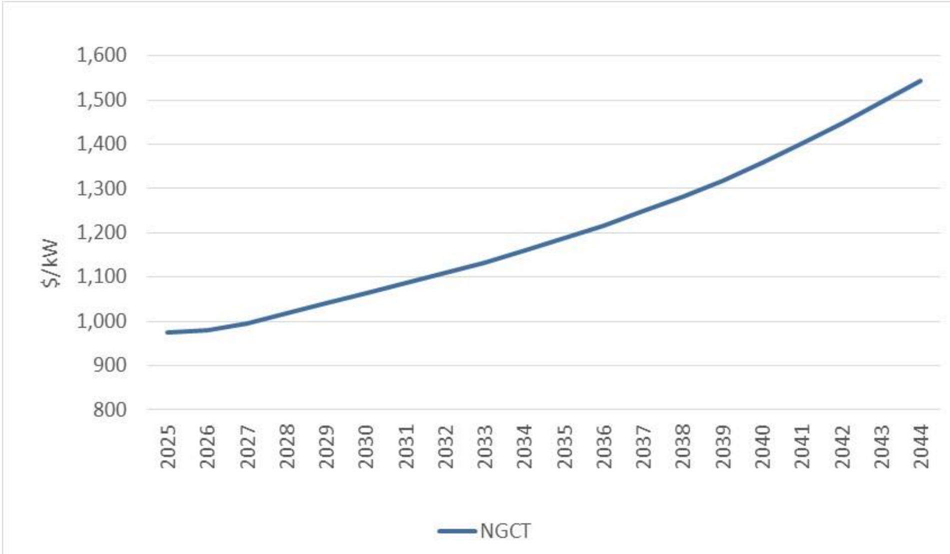


Table 9 Operating and Heat Rate Assumptions for NGCT

		F-Class CT (240 MW)
VOM	$2022 / MWh	5.06
FOM	$2022 / kW-yr	7.88
Gas Transmission Rate	$ / kW-yr	21.18
Heat Rate	Btu / kWh	9,905

7.1.2.2 Aeroderivative (AD) Turbines

Aeroderivatives turbine units are based off aircraft jet engines designs and are modified for the use in power generation. Their operating characteristics make them well suited with high renewable penetration as they can quickly respond to significant shifts in supply and demand conditions in the power system. For example, the GE 9E series NGCT requires 30 minutes to start up whereas the GE LM6000 AD unit requires only 5 minutes. This allows AD units to operate at full load even for a small amount of time. In addition, AD units are more efficient in a simple cycle operation than NGCTs for capacity less than 100 MW. However, AD units are relatively more expensive than NGCTs.

AD units are modeled in *Plexos®* in 105 MW units as a standard dispatchable resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. These resources are made available in the model with a first operating year of 2031, with a maximum annual capacity addition of 210 MW.

The AD overnight capital cost assumptions are shown in Figure 24. The first operating year FOM, VOM, firm gas reservation feeds and heat rate assumptions are shown in Table 10.

Figure 24 Capital Cost Assumptions for AD

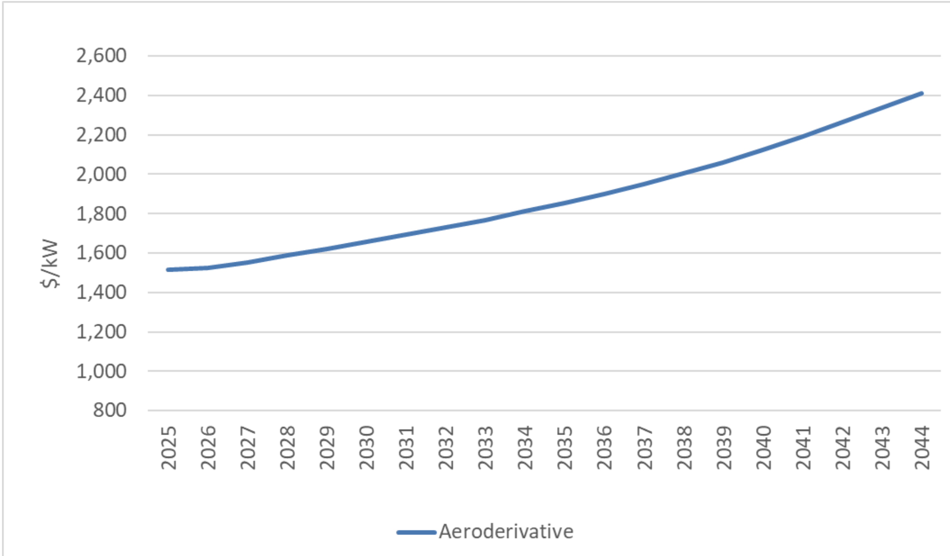


Table 10 Operating and Heat Rate Assumptions for AD

		AD (100 MW)
VOM	$2022 / MWh	5.29
FOM	$2022 / kW-yr	18.35
Gas Transmission Rate	$ / kW-yr	19.51
Heat Rate	Btu / kWh	9,124

7.1.2.3 Reciprocating Internal Combustion Engine (RICE)

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

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

RICE's are modeled in *Plexos*® in 20 MW units as a standard dispatch resource, assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. These resources are made available in the model with a first operating year of 2031, with a maximum annual capacity addition of 100 MW.

The RICE overnight capital cost assumptions are shown in Figure 25. FOM, VOM, firm gas reservation fees and heat rate assumptions are shown in Table 11.

Figure 25 Capital Cost Assumptions for RE

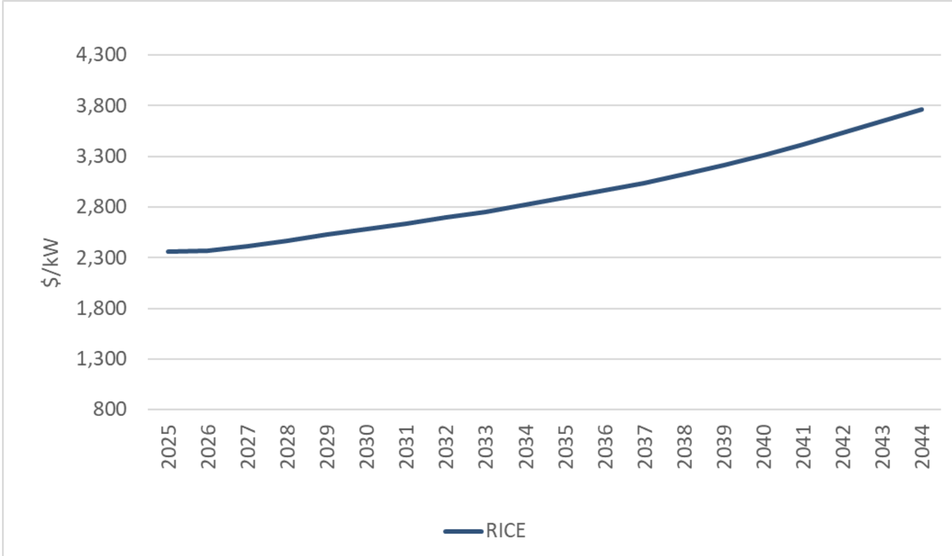


Table 11 Operating and Heat Rate Assumptions for RE

		RE (20 MW)
VOM	$2022 / MWh	6.40
FOM	$2022 / kW-yr	39.57
Gas reservation fees	$ / kW-yr	17.74
Heat Rate	Btu / kWh	8,295

7.1.3 Battery Energy Storage System (BESS) Alternatives

7.1.3.1 Lithium-Ion Battery (Li-ion)

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

Li-ion batteries are experiencing rapid growth in deployment in utility-scale storage applications. This reflects advantageous operating characteristics that include high round-trip efficiency, high energy density, low self-discharge and fast response capabilities. The batteries can also respond to dispatch signals within a second, making them well suited for primary frequency regulations, i.e., providing initial immediate response to deviations in grid frequency driven by sudden demand spikes or supply losses. However, Li-ion batteries have limited cycle life due to degradation; battery augmentation is required during the project lifetime to maintain performance. For this IRP, the modeling of storage resources in this IRP includes an additional potential value stream available to these resources of $40/MWh. This is a proxy for value associated with sub-hourly and hourly energy arbitrage and ancillary services noted above. The Company continues to explore methods to recognize additional value streams from fast responding resources like BESS.

Li-ion batteries are made available in *Plexos®* and are modeled as an energy storage option with a duration of four, six, eight and ten hours. *Plexos®* optimizes charging and discharging of the resource against projected SPP hourly day-ahead electricity prices, taking into account a round-trip efficiency of 83%.

Li-ion batteries are made available in a configuration of 50 MW. For annual limits, the 4-hour and 10-hour alternatives are limited to 50 MW/yr, and 6-hour and 8-hour alternatives are limited to 100 MW/yr. The assumed cumulative maximum capacity addition for 4-hour and 6-hour alternatives is 400 MW, while for 8-hour and 10-hour alternatives the maximum annual capacity is 200 MW. The cumulative maximum for all battery energy storage resources is 1,200 MW.

The overnight capital cost assumptions for Li-ion battery energy storage systems (BESS) are shown in Figure 27. These costs are further influenced by the availability of Federal Investment Tax Credits (ITCs) discussed in Section 7.4. Table 12 shows the assumed first year FO&M costs for BESS alternatives.

Figure 27 Capital Cost Assumptions for Li-Ion

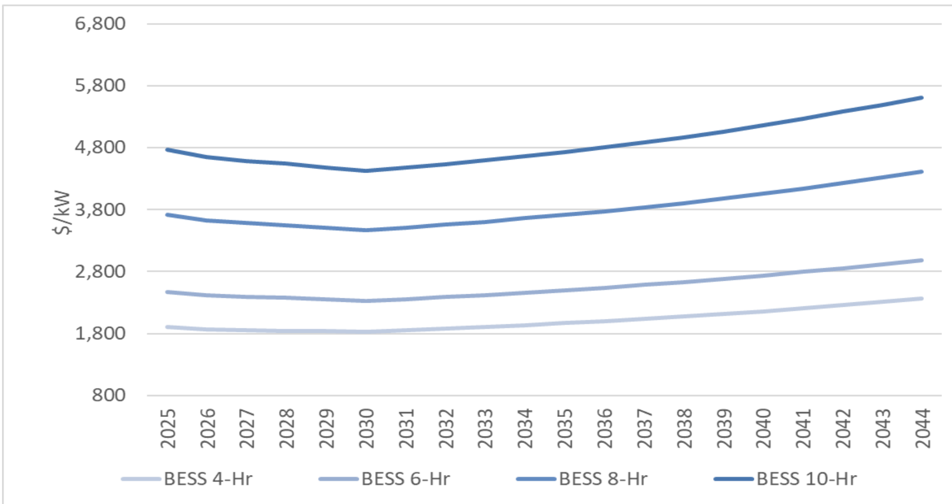


Table 12 First Year FO&M Assumptions for Li-Ion BESS

		BESS 4-Hr (50 MW)	BESS 6-Hr (50 MW)	BESS 8-Hr (50 MW)	BESS 10-Hr (50 MW)
FOM	$/ kW-yr	45.76	68.64	91.52	114.40

7.1.4 Renewable Alternatives

Renewable generation alternatives provide an opportunity to deliver affordable clean energy to address future electricity needs when cost effective. These technologies can provide a hedge against future uncertainties in fuel prices, carbon policies, and technology risks as they have zero carbon emissions and zero marginal costs. While these resources provide a reasonable hedge against several uncertainties, their intermittent nature for energy generation adds other uncertainties and variables to recognize in resource planning.

In this IRP, three renewable alternatives considered are onshore wind, utility-scale photovoltaic (solar) and hybrid solar. These technologies are made available as resource options in *Plexos*®. For the latter, *Plexos*® can choose to pair utility-scale photovoltaic with lithium-ion battery where a paired solution is economic. Additionally, wind and solar resources are further influenced in the modeling by their eligibility for Federal Production Tax Credits (PTCs) discussed in Section 7.4.

7.1.4.1 Wind

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

Wind is first made available as a resource option in *Plexos®* in 2029. It is modeled with a generic production profile representative of the region with an average capacity factor of 47%.

Wind resources are made available in a configuration of 200 MW. Because wind generation resources tend to be located electrically further from load centers, a congestion and loss cost adder of approximately $17/MWh was assumed. The maximum annual capacity additions of 400 MW were informed through an SPP queue analysis. The assumed cumulative maximum is 3,000 MW.

Capital costs were informed from responses to recent RFPs conducted in the SPP region by the Company and are used as a proxy for potential costs of future resources. The cost reduction curve from NREL ATB 2023 is applied to the capital cost in 2025 to project the capital costs through the study period and beyond, as shown in Figure 29 below.

Figure 29 Capital Cost Assumptions for Onshore Wind

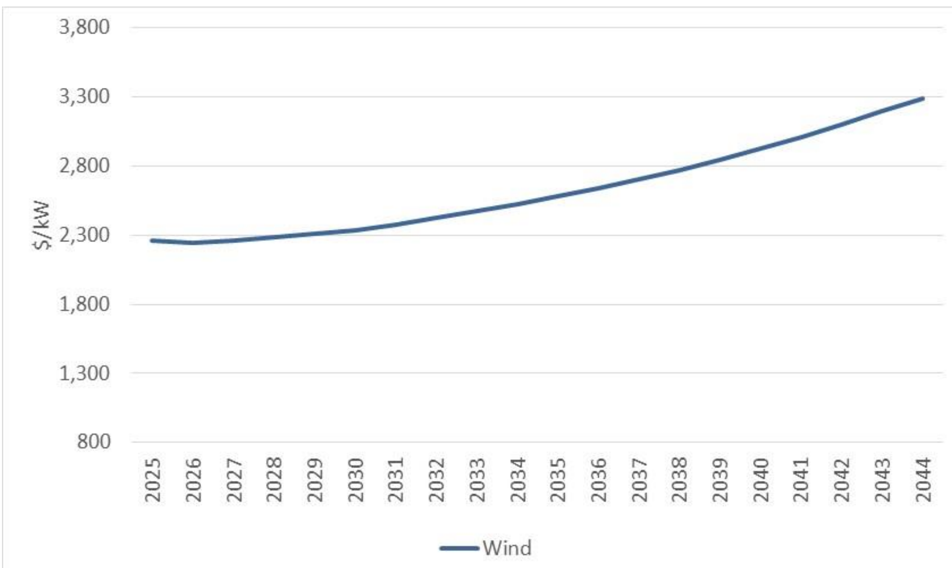


Table 13 shows the first year FO&M cost assumptions for onshore wind.

Table 13 First Year FO&M Assumptions for Onshore Wind

		Wind (200 MW)
FOM	$/ kW-yr	29.64

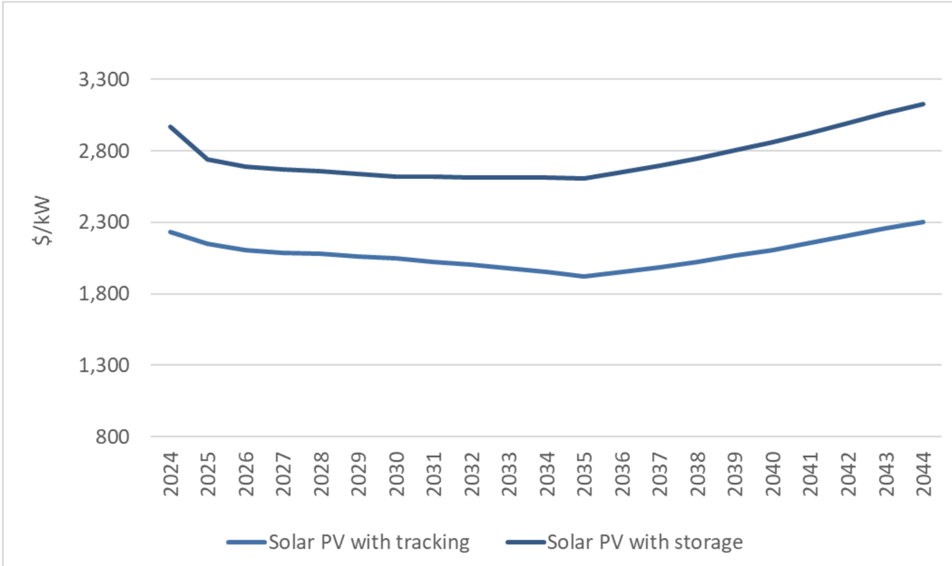
7.1.4.2 Solar

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

Utility-scale solar PV is first made available as a resource option in *Plexos®* in 2029. It is modeled with a generic production profile representative of the region with an average capacity factor of 28% assuming a single-axis tracking configuration.

The overnight capital cost assumptions for solar PV are shown in Figure 31.

Figure 31 Capital Cost Assumptions for Utility-Scale Solar PV



Solar resources are made available in a configuration of 150 MW. The maximum annual capacity additions of 600 MW were informed through an SPP queue analysis. Similar to wind resources, a congestion and loss adder was also included. For solar resources, a cost of approximately $1.80/MWh was assumed initially, rising to approximately $3/MWh by 2033. The cumulative maximum available additions over the planning horizon were modeled as 3,600 MW.

Hybrid 3:1 solar+storage systems are available in 200 MW blocks (150 MW solar plus 50 MW of 4-hour duration storage), up to 300 MW annually.

Table 14 shows the first year FOM cost assumptions for solar and solar-storage hybrid.

Table 14 First Year FO&M Assumptions for Utility-Scale Solar PV

		Solar with Tracking (150 MW)	Solar with Storage (150 MW)
FOM	$/kW-yr	17.16	32.42

7.1.5 Advanced Generation Alternatives

Advanced generation technologies are low-carbon technologies that are still in the development stage but could be commercially available during the planning horizon of this IRP. When they are available, they could potentially become the new standards of generation to complement or replace traditional resources. Including advanced generation technologies in this IRP allows PSO to consider the impact of future technology uncertainties on the Company’s generation portfolio. This informs the selection of the preferred plan that minimizes technology risks and allows PSO to continue to deliver reliable and affordable power to customers.

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

7.1.5.1 Small Modular Reactor (SMR)

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

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

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

SMR is still in the early stages of development and there remain uncertainties over the cost, performance, and availability of the technology. The cost assumptions for the First-of-a-Kind (FOAK) are based on the EIA AEO 2023, adjusted to include AEP overheads. The Nth-of-a-Kind (NOAK) cost assumptions in this IRP is based on projecting the FOAK cost forward using a learning rate from a Department of Energy (DOE) study on the learning rate for SMR[10]. The DOE study provides a learning rate as cost reduction per each doubling of installed capacity. As such, it is further assumed for the purpose of projecting SMR cost reduction that the first SMR unit with FOAK cost assumptions will be brought online in 2028 and subsequently one new SMR plant will be in service each year in the first five years, two new SMR plants for the next five years, and four new SMR plants for the five years after that. It is assumed that SMR will not be available for commercial deployment until 2036 in a block size of 600 MW and a maximum annual capacity addition of 600 MW.

Figure 26 below shows the assumed overnight capital cost of SMR cost over time. The first operating year FOM, VOM assumptions are shown in Table 15 below.

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

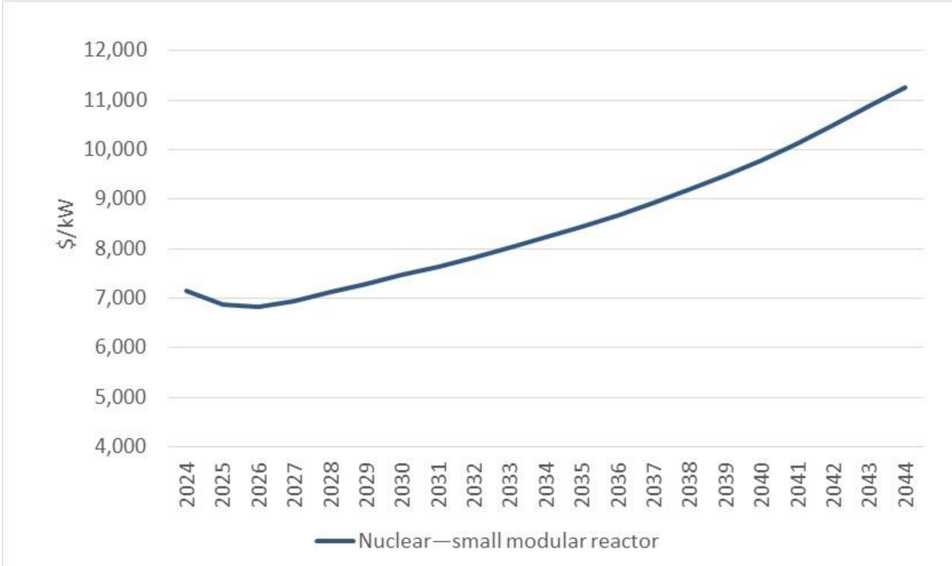


Figure 26 Capital Cost Assumptions for SMR

Table 15 Operating and Heat Rate Assumptions for SMR

		SMR
VOM	$/ MWh	3.38
FOM	$/ kW-yr	106.92
Heat Rate	Btu / kWh	10,447

7.1.5.2 Carbon Capture and Storage Technologies (CCS)

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

In *Plexos*®, CCS is modeled as new build options. CCS plants are treated as standard dispatch resources in *Plexos*®, which are assigned to run when economic on a short-run variable cost basis, subject to any operational constraints. These costs are further influenced by the availability of Federal Tax Credits for CO_2 sequestration (CCS) discussed in Section 7.4.

7.1.5.3 New build options

One new build CCS configuration is available for selection in *Plexos*®, as a 390 MW H-class single shaft, combined-cycle natural gas turbine with 90% carbon capture.

The assumption on overnight capital costs for the new build CCS is shown in Figure 27. FOM, VOM, and heat rate assumptions are shown in Table 16 below.

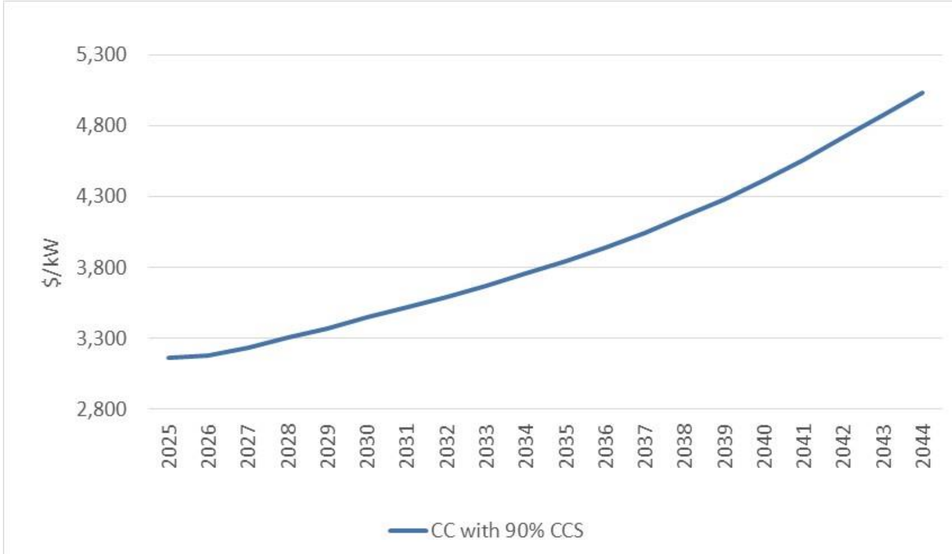


Figure 27 Capital Cost Assumptions for New Build CCS

Table 16 Operating and Heat Rate Assumptions for New Build CCS

		Gas
VOM	$/ MWh	6.57
FOM	$/ kW-yr	31.06
Gas Transmission Rate	$ / kW-yr	15.23
Heat Rate	Btu / kWh	7,124

7.2 Resource Accredited Capacities

Previously, renewable and storage resources received a reduction in their installed capacity amounts to reflect the known intermittency of their availability to serve load. This was accounted for through an Effective Load Carrying Capability (ELCC) factor informed from SPPs resource adequacy analysis. With SPPs recent move toward an Accredited Capacity (ACAP) methodology as discussed in Section 4.5, the MWs that contribute to the Company's capacity obligation to SPP for all resources, thermal, renewable and storage, will be reduced from their installed amount. Furthermore, under the seasonal construct for identifying capacity requirements, the summer and winter ELCCs and thermal resource accredited capacities are different.

Renewable and storage resources are reduced by their respective ELCCs for each SPP season. Of note with respect to BESS resources, the ability of Li-ion batteries to meet demand peaks will decline as greater amounts of renewable generation widen the length of demand peaks. Therefore, the capacity credit for different hour ranges of BESS resources are recognized to reflect their ability to serve peak loads.

For this IRP, the modeling was conducted such that the summer and winter accredited capacities were considered in the optimized resource selections. Renewable and BESS resource accredited capacities are adjusted from their nameplate ratings by the factors illustrated in Figure 28 and Figure 29.

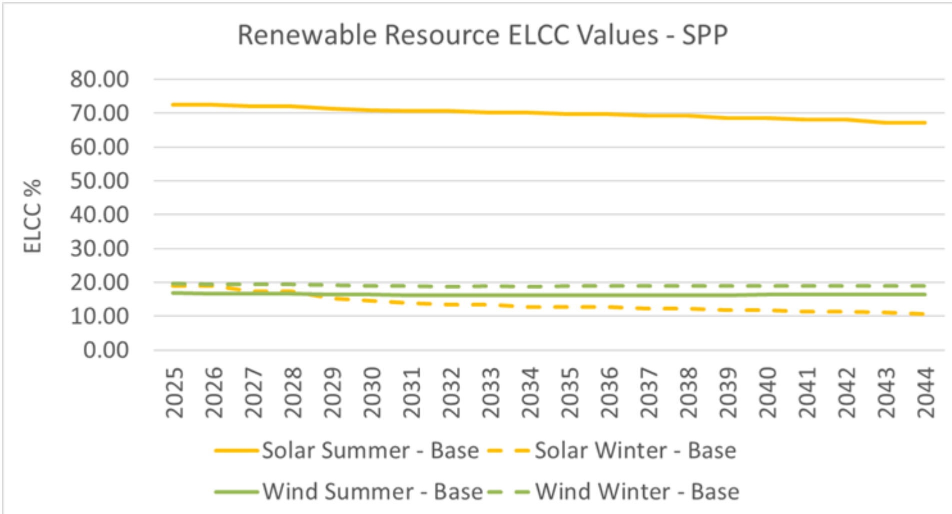


Figure 28 Renewable Resource ELCCs

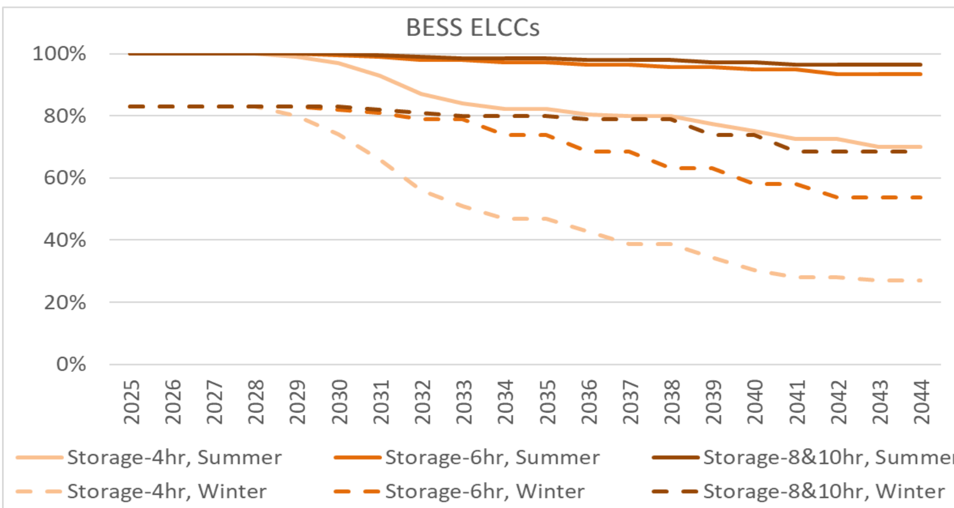


Figure 29 BESS ELCCs

Furthermore, thermal resources capacity values accredited toward the Company's SPP obligation are also reduced under SPP's ACAP methodology. Although SPP is conducting further analysis, the Company used their preliminary guidance for class average ACAP ratings for new thermal resources modeled in this IRP[11]. These are shown in Table 17.

[11] https://www.spp.org/Documents/71781/SAWG%20Meeting%20Materials%2020240618-19.zip, file 10_EFORd and EFOF Class Averages

Table 17 SPP Preliminary Guidance Thermal Resource ACAP Reductions

Fuel Type	Season	Summer Reduction (Weighted EFORd)	Winter Reduction
Natural Gas and Other Gases	Summer	8.04%	
	Winter	14.26%	22.99%
Nuclear	Summer	1.98%	
	Winter	0.64%	1.05%

7.3 Short-Term Market Purchases (STMP)

Short-Term Market Purchases are included in the modeling to support near term resource needs. The Company leverages this resource to serve as a bridge for meeting its capacity requirements until firm resources are available for selection in the model. For this IRP, STMP resources were made available up to 450MW/year in years 2025-2028.

7.4 Inflation Reduction Act (IRA)

In August 2022, the Inflation Reduction Act was enacted which, among many things, introduced additional benefits for clean energy resources. Specifically, the IRA allows for the inclusion of Production Tax Credits (PTCs) or Investment Tax Credits (ITCs) for solar and wind resources as well as for new nuclear facilities, such as SMRs. Additionally, the IRA introduced incentives for storage resources in the form of ITCs and expanded benefits for carbon sequestration solutions.

A summary of IRA benefit assumptions to specific resources included in this plan is the following:

- 10 years of 100% PTCs or ITCs for "Technology Neutral" Clean Electricity resources including solar, wind and advanced nuclear resources for projects whose construction begins by the end of 2033. After 2033, ITC tax credits reduce to 75% and 50% of their value in 2038 and 2039, respectively. In this IRP, the Company also assumed a four-year safe harbor assumption that extends the eligibility of tax credits.
- ITC benefits for storage resources for projects whose construction begins by the end of 2033. After 2033, ITC tax credits reduce to 75% and 50% of their value in 2038 and 2039, respectively. In this IRP, the Company also assumed a four-year safe harbor assumption that extends the eligibility of tax credits.
- The passage of Section 45Q legislation provides a tax credit of \$85/t of CO_2 sequestered for 12 years.
- The law also provides an opportunity for the PTCs and ITCs to extend beyond these dates although for this IRP, no further extensions were assumed beyond 2039.

Additionally, the IRA also includes opportunities for additional bonus tax credits for projects that qualify for specific siting requirements. The IRP does not include these as part of its analysis as the modeling does not include any location-specific assumptions. The analysis of any projects qualifying for bonus credits beyond what is included in the IRP analysis will be included during an RFP process for projects from developers that include the associated binding commitments.

7.5 Modeling Parameters and Resource Limits

The major system parameters that were modeled for each resource described in Section 7 are shown in Table 18. The Plexos LT Plan® models these parameters in tandem with the objective function in order to yield the least-cost resource plan for each scenario modeled.

Table 18 2024 PSO IRP - New Resource Assumptions

Resource Type	First Year Available	Life [yrs]	Block Size [MW]	Annual Limits [MW/yr]	Individual Technology Cumulative Total [MW]	Cumulative Technology Total [MW]
STMP	1/1/2025	1	25	450	450	450
Solar	1/1/2029	35	150	600	3,600	3,600
Solar Hybrid (4hr storage)	1/1/2029	35	150 MW/ 200 MWh	300 MW/ 400 MWh	300 MW/ 400 MWh	1500 MW/ 2000 MWh
Wind	1/1/2029	30	200	400	3,000	3,000
Stand Alone Storage (4Hr)	1/1/2029	20	50 MW/ 200MWh	50	400	1,200
Stand Alone Storage (6Hr)	1/1/2029	20	50 MW/ 300 MWh	100	400	
Stand Alone Storage (8Hr)	1/1/2029	20	50 MW/ 400 MWh	100	200	
Stand Alone Storage (10Hr)	1/1/2029	20	50 MW/ 500 MWh	50	200	
Combustion Turbine F Class Simple Cycle	1/1/2031	30	240	720	4560	4560
Combined Cycle F Class	1/1/2032	30	760	760	3800	3800
Combined Cycle H Class - Multi Shaft	1/1/2032	30	1100	1100	3300	3300
Combined Cycle H Class Single Shaft	1/1/2032	30	418	836	3762	3762
Combined Cycle H Class Single Shaft w/ 90% CO_2 Capture	1/1/2032	40	390	780	3510	3510
RICE	1/1/2031	20	20	100	900	900
Aeroderivative	1/1/2031	30	105	210	945	945
Small Modular Nuclear Reac-tor	1/1/2036	40	600	600	1,800	,1800
NE3 Gas Conversion	1/1/2026	15	420	420	420	420

The Company considered a variety of different constraints when establishing the annual and cumulative limits shown in the table. These included 1) Company capacity obligations and needs over the planning horizon, 2) the Company's objective to ensure reliability through a diverse mix of new resources, 3) an assessment of the resources in the SPP queue and 4) practical limits of resources informed in part, by past responses to RFPs.

While the limits are imposed in the model to provide enough capacity and energy resources to meet the necessary SPP and PSO obligations and objectives, these do not specifically suggest that these resources and amounts are in fact available and would respond to future RFPs.

8 Demand-side Resource Options

8.1 Energy Efficiency Measures

This IRP considers incremental EE programs as resource options to meet future capacity needs. These incremental EE programs, starting in 2030, are in addition to the existing demand-side programs discussed in Section 4.3 including those that were requested in PSO's 2025-2029 Demand Portfolio application to the commission (PUD 2024-00013).

8.1.1 EE Cost and Performance Assumptions

The cost and performance parameters for the incremental EE programs evaluated are based on input from PSO's internal subject matter experts and the Electric Power Research Institute's (EPRI) "2014 U.S. Energy Efficiency Potential Through 2035" report with updates from the 2019 Technical Update of this same report. The EPRI report and the PSO Energy Efficiency and Consumer Programs team provided information on a multitude of current and anticipated end-use measures including measure costs, energy savings, market acceptance ratios and program implementation factors. Table 19 provides a list of current and anticipated EE measures for both the residential and commercial sector.

Table 19 Energy Efficiency Measure Categories by Sector

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

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

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

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

8.1.2 Modeling EE measures as resource options

From this information, PSO developed proxy EE bundles for residential and commercial & industrial customer classes to be modeled within Plexos®. These bundles are based on measure characteristics identified within the EPRI report and PSO customer usage.

Table 20 and Table 21 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 21 includes potential savings for both commercial and industrial customers.

Table 20 Residential Energy Efficiency Bundles

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2030-2034	Yearly Potential Savings (MWh) 2035-2039	Yearly Potential Savings (MWh) 2040-2044	Yearly Potential Savings (MWh) 2045-2049	Bundle Life
Thermal Shell - AP	$0.30	5,890	2,666	1,982	1,832	11
Thermal Shell - HAP	$0.45	18,249	443	0	0	11
Heating/Cooling - AP	$0.85	60,255	6,543	0	0	18
Heating/Cooling - HAP	$1.17	10,774	0	0	0	18
Water Heating - AP	$0.94	10,167	2,543	1,376	1,299	15
Water Heating - HAP	$1.36	23,834	2,278	1,536	0	14
Appliances - AP	$0.41	7,299	591	0	0	16
Appliances - HAP	$0.62	862	0	0	0	16
Lighting - AP	$0.08	1,893	0	0	0	31
Lighting - HAP	$0.13	1,252	0	0	0	30

Table 21 Commercial & Industrial (C&I) Energy Efficiency Bundles

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2030-2034	Yearly Potential Savings (MWh) 2035-2039	Yearly Potential Savings (MWh) 2040-2044	Yearly Potential Savings (MWh) 2045-2049	Bundle Life
Heat Pump - AP	$10.07	38,755	5,728	5,099	6,559	19
Heat Pump - HAP	$15.41	21,501	0	0	0	19
HVAC Equipment - AP	$0.08	49,020	8,085	2,204	514	14
HVAC Equipment - HAP	$0.11	7,714	0	0	0	14
Indoor Screw-In Lighting - AP	$0.01	4,812	0	0	528	6
Indoor Screw-In Lighting - HAP	$0.02	2,043	0	0	0	6
Indoor HID/Fluor. Lighting - AP	$0.08	44,358	7,394	1,624	0	14
Indoor HID/Fluor. Lighting - HAP	$0.12	4,929	0	0	0	14
Outdoor Lighting - AP	$0.09	8,578	1,680	0	0	15
Outdoor Lighting - HAP	$0.14	9,531	0	0	0	15

Each EE bundle is a stand-alone resource within the model with its own unique cost and potential energy and demand savings.

8.2 Other DSM Resources

PSO has managed two programs as part of its Demand Response (DR) portfolio including the Power Hours and Peak Performers programs discussed in Section 4.3.1. For this IRP, the current level of DR from these programs is maintained throughout the plan.

Additionally, Conservation Voltage Reduction (CVR) has been implemented across most of the Company's distribution circuits as discussed in Section 4.3.3. With the recent 2025-2029 DSM plan submitted to the Commission for approval, the Company will near saturation of CVR deployment with significant energy savings and consequently, this was not modeled for further potential savings in this IRP.

9 Portfolio Analysis

9.1 Introduction

Portfolio analysis is conducted through the use of *Plexos*® LP long-term optimization model, also known as "LT Plan®" from which the PSO-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 Net Present Value Revenue Requirement (NPVRR) of a planning entity's generation-related variable and fixed costs over a long-term planning horizon. By minimizing NPVRR, the model will provide optimized portfolios with the lowest and most stable customer rates, while adhering to the Company's constraints.

Optimized portfolios are identified subject to a series of modeling parameters and constraints, to identify a mix of resources that 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 PSO-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 PSO generating units. This includes fuel, start-up, consumables, market replacement cost of emission allowances and/or carbon 'tax,' and variable O&M costs; and
- a 'netting' of the production revenue earned in the SPP power market from PSO's generation resource sales and the cost of energy necessary to meet PSO's load obligation.

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

- Minimum and maximum reserve margins;
- Limited energy market purchases and sales
- resource additions (i.e., maximum units built);
- age and lifetime of power generation facilities;
- 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 CO_2, SO_2 and NOx; and
- energy contract parameters such as energy and capacity.

9.2 Candidate Portfolios

For this IRP, PSO modeled a series of Candidate Portfolio Cases and Sensitivities to identify an optimal portfolio of resources to meet expected future customer needs under the different SPP market scenarios. Table 22 shows the different Candidate Portfolio Cases modeled and the respective key inputs that were modified.

Table 22 PSO Candidate Portfolio Cases

Portfolio	Scenario	PSO Load	Gas Price	Env. Regs
Base	Base	Base	Base	Base
High Load	High	High	High	Base
Low Load	Low	Low	Low	Base
Enhanced Environmental Regulations (EER)	EER	Base	Base	111(d)

The Base, High and Low load Candidate Portfolio Cases serve to inform the Company of an optimal resource mix under a condition without the recent EPA 111d GHG rules imposed. These serve to provide an important baseline for the Company to evaluate impacts for future changes to rules.

The Enhanced Environmental Regulations (EER) case is included to recognize the recent EPA's Clean Air Act Section 111 (d) rule discussed in Section 4.4.7. This rule, however, is incomplete and is subject to further development of state implementation plans (SIPs) as well as continued litigation. Although the new rule does not affect the resources assumed in the Going-In position discussed in Section 4.2., for this IRP, the Company imposed the annual capacity factor constraints on new gas resources to its existing gas CC and CT resources as a proxy for some kind of restriction the EPA might impose with an update to the rule. For the EER case, the following constraints on gas resources not equipped with CCS technology are applied:

- New and existing gas CTs, RICE and Aeroderivative resources: Operate at less than 20% annual capacity factor beginning 1/1/2032.
- New and existing gas CCs: Operate at less than 40% annual capacity factor beginning 1/1/2032.

As such, the Company will use the EER Case to understand directionally, the impacts the rule will have on the Company's fleet of resources and indicative costs to its ratepayers as well as the potential impact on the Company's ability to maintain a fleet of resources with the ability to serve customers reliably.

Additionally, PSO modeled various sensitivities to Candidate Portfolios to understand how resource selections might be affected under specific changes to a particular Candidate Portfolio case. These sensitivities are shown in Table 23.

Table 23 Candidate Portfolio Sensitivities

Sensitivity	Scenario	PSO Load	Gas Price	Env. Regs
High Gas	High	Base	High	Base
Low Gas	Low	Base	Low	Base

Large Economic Development Opportunity (LEDO)	Base	High+LEDO	Base	Base
Storage Sensitivity	Base	Base	Base	Base

The High and Low sensitivities will evaluate an optimized portfolio of resources under a condition where commodity prices such as gas and energy are high or low while serving PSO's base load forecast.

The Large Economic Development Opportunity (LEDO) sensitivity will provide the Company insight to the optimized resource selections under a base scenario condition (base commodity prices) but with a PSO load forecast that is approximately 1GW higher than the Company's high load forecast. This sensitivity will inform the company of potential resources needed to serve a higher load if a large load request is considered in PSO's territory.

The Storage Sensitivity was included to explore potential resource selections when storage is included. For this sensitivity, the Company included 200MWs of storage in 2029 and optimized the remaining portfolio. This sensitivity was included with an assumption that there are additional benefits to storage resources that might not be fully captured in the Plexos modeling.

9.2.1 Resource Additions by Portfolio

9.2.1.1 Base Case Portfolio

The Base Case was optimized under scenario conditions that represent an expected view of how load growth, commodity prices, and technology development will evolve over time and contribute to the market conditions under which PSO will operate. Resource additions in the Base Case Portfolio are shown in Table 24 and illustrated in Figure 30.

Table 24 Base Case Annual Resource Additions

Base Case New Build Additions by Planning Year (Nameplate MW)						
Planning Year	**Cumulative New EE**	**New Solar**	**New Wind**	**New CT**	**New CC**	**NE3 Gas**
2025/26	0	0	0	0	795**	0
2026/27	0	339*	553*	0	0	420
2027/28	0	0	0	0	0	0
2028/29	0	103.5*	0	0	0	0
2029/30	0	0	400	0	0	0
2030/31	44	0	200	0	0	0
2031/32	95	150	200	0	0	0
2032/33	128	0	0	0	0	0
2033/34	146	0	0	0	0	0
2034/35	154	0	0	0	0	0
Total		592.5	1,353	0	795	420
* Approved new resources ** New resource seeking approval						

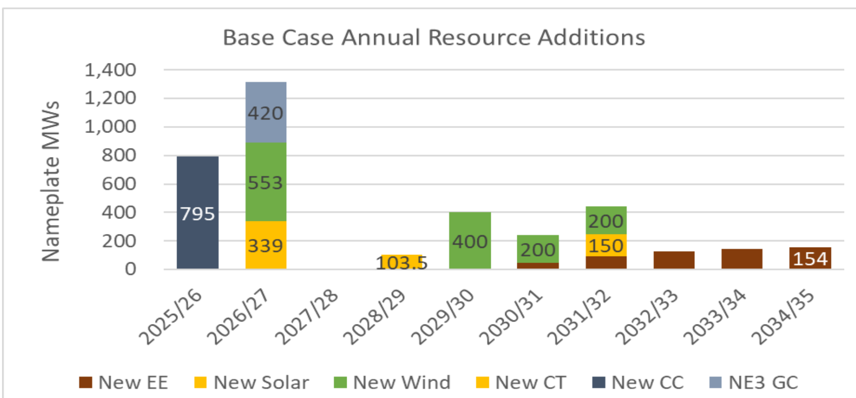


Figure 30 Base Case Annual Resource Additions

The Base Case Portfolio included the selection of the Company's Northeastern Unit 3 to operate on gas in 2026 and 800MWs of additional wind and 150MWs of additional solar resources by 2031. In total, with the recently approved renewable resources, the portfolio includes a total of 593MWs of new solar resources and 1,353MWs of new wind resources by 2031.

The portfolio also includes a peak contribution of 154MWs from incremental EE resources by 2034.

9.2.1.2 High Case Portfolio

The High Case was optimized under scenario conditions that represent a view that assumes higher load growth and higher natural gas prices than Base case. Resource additions in the High Case Portfolio are shown in Table 25 and illustrated in Figure 31.

Table 25 High Case Annual Resource Additions

High Case New Build Additions by Planning Year (Nameplate MW)							
Planning Year	**Cumulative New EE**	**New Solar**	**New Wind**	**New CT**	**New CC**	**NE3 Gas**	**STMP**
2025/26	0	0	0	0	795**	0	0
2026/27	0	339*	553*	0	0	420	125
2027/28	0	0	0	0	0	0	50
2028/29	0	103.5*	0	0	0	0	100
2029/30	0	0	800	0	0	0	0
2030/31	44	300	200	0	0	0	0
2031/32	93	0	0	240	0	0	0
2032/33	121	0	0	0	0	0	0
2033/34	135	0	200	0	0	0	0
2034/35	171	0	0	0	0	0	0
Total		742.5	1,753	240	795	420	275
* Approved new resources ** New resource seeking approval							

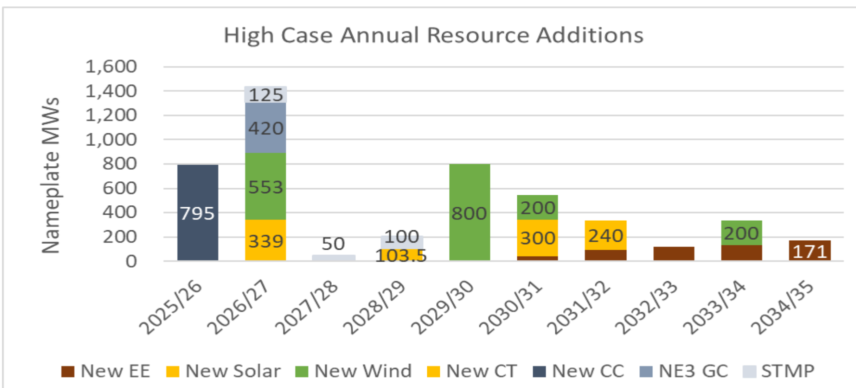


Figure 31 High Case Annual Resource Additions

The High Case Portfolio included the selection of the Company's Northeastern Unit 3 to operate on gas in 2026 and a new 240MW CT in 2031 to support the increased load. Short Term Market Purchases were selected in years 2026-2028 to bridge the time until new resources could be acquired to serve load. Also selected were new renewable resources including 1,200MWs of additional wind by 2033 and 300MWs of additional solar resources in 2031. In total, with the recently approved renewable resources, the portfolio includes a total of 743MWs of new solar resources and 1,753MWs of new wind resources.

The portfolio also includes a peak contribution of 171MWs from incremental EE resources by 2034.

9.2.1.3 Low Case Portfolio

The Low Case was optimized under scenario conditions that represent a view that assumes lower load growth and lower natural gas prices than Base case. Resource additions in the Low Case Portfolio are shown in Table 26 and illustrated in Figure 32.

Table 26 Low Case Annual Resource Additions

Low Case New Build Additions by Planning Year (Nameplate MW)							
Planning Year	**Cumulative New EE**	**New Solar**	**New Wind**	**New CT**	**New CC**	**NE3 Gas**	**STMP**
2025/26	0	0	0	0	795**	0	0
2026/27	0	339*	553*	0	0	420	0
2027/28	0	0	0	0	0	0	0
2028/29	0	103.5*	0	0	0	0	0
2029/30	0	300	400	0	0	0	0
2030/31	44	0	400	0	0	0	0
2031/32	95	0	200	0	0	0	0
2032/33	129	0	0	0	0	0	0
2033/34	156	0	0	0	0	0	0
2034/35	174	0	0	0	0	0	0
Total		742.5	1,553	0	795	420	0

* Approved new resources
** New resource seeking approval

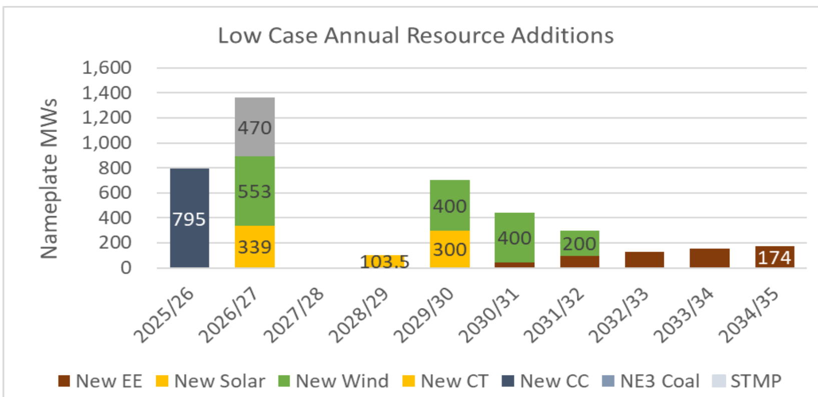


Figure 32 Low Case Annual Resource Additions

The Low Case Portfolio originally included the selection to operate the Company's Northeastern Unit 3 coal unit through calendar year 2026 and then retired. The portfolio was subsequently modified to include the NE3 unit to operate as a gas-steam unit beginning in 2026 to be consistent with other optimized portfolios herein and re-optimized. The portfolio also included 1,000MWs of additional wind by 2031 and 300MWs of additional solar resources in 2029. In total, with the recently approved renewable resources, the portfolio includes a total of 743MWs of new solar resources and 1,553MWs of new solar resources.

The portfolio also includes a peak contribution of 174MWs from incremental EE resources by 2034.

9.2.1.4 EER Case Portfolio

The EER Case was optimized under scenario conditions that represent a view that assumes that adoption of the Environmental Protection Agency's rule changes to CAA Section 111 (d). More specifically, gas resources were constrained to operate up to a maximum annual capacity factor to meet stricter emission limits. Resource additions in the EER Case Portfolio are shown in Table 27 and illustrated in Figure 33.

Table 27 EER Case Annual Resource Additions

EER Case New Build Additions by Planning Year (Nameplate MW)							
Planning Year	**Cumulative New EE**	**New Solar**	**New Wind**	**New CT**	**New CC**	**NE3 Gas**	**STMP**
2025/26	0	0	0	0	795**	0	0
2026/27	0	339*	553*	0	0	420	0
2027/28	0	0	0	0	0	0	0
2028/29	0	103.5*	0	0	0	0	0
2029/30	0	0	400	0	0	0	0
2030/31	42	0	400	0	0	0	0
2031/32	90	300	400	0	0	0	0
2032/33	118	0	200	0	0	0	0
2033/34	121	150	0	0	0	0	0
2034/35	129	0	0	0	0	0	0
Total		892.5	1,953	0	795	420	0
* Approved new resources ** New resource seeking approval							

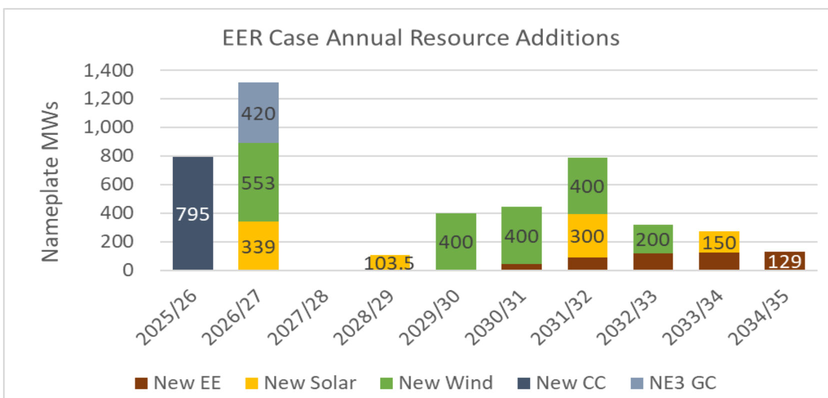


Figure 33 EER Case Annual Resource Additions

The EER Case Portfolio included the selection of the Company's Northeastern Unit 3 to operate on gas in 2026 and 1,400MWs of additional wind by 2032 and 450MWs of additional solar resources by 2033. In total, with the recently approved renewable resources, the portfolio includes a total of 893MWs of new solar resources and 1,953MWs of new wind resources.

The portfolio also includes a peak contribution of 129MWs from incremental EE resources by 2034.

9.2.1.5 High Gas, Base Load Sensitivity Portfolio

The High Gas, Base Load sensitivity was optimized to select resources to serve the Company's Base load but with higher commodity prices assumed in the High Scenario. Resource additions in the High Gas, Base Load sensitivity Portfolio are shown in Table 28 and illustrated in Figure 34.

Table 28 High Gas, Base Load Sensitivity Case Annual Resource Additions

High Gas, Base Load Sensitivity New Build Additions by Planning Year (Nameplate MW)						
Planning Year	**Cumulative New EE**	**New Solar**	**New Wind**	**New CT**	**New CC**	**NE3 Gas**
2025/26	0	0	0	0	795**	0
2026/27	0	339*	553*	0	0	420
2027/28	0	0	0	0	0	0
2028/29	0	103.5*	0	0	0	0
2029/30	0	0	400	0	0	0
2030/31	42	0	400	0	0	0
2031/32	90	150	0	0	0	0
2032/33	114	0	0	0	0	0
2033/34	121	0	200	0	0	0
2034/35	129	0	0	0	0	0
Total		592.5	1553	0	795	420
* Approved new resources ** New resource seeking approval						

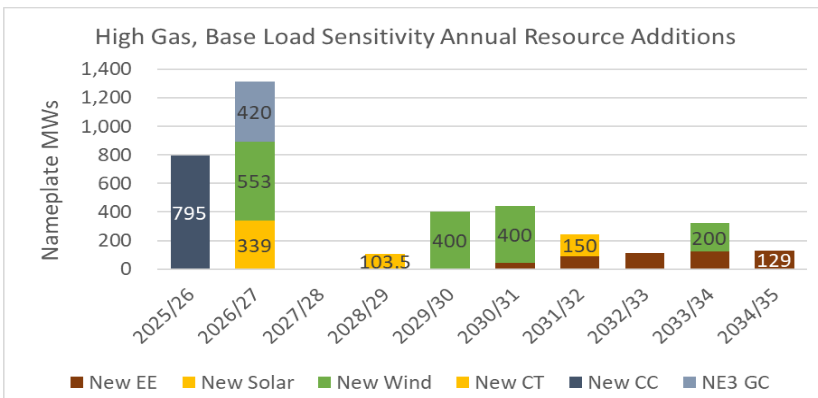


Figure 34 High Gas, Base Load Sensitivity Annual Resource Additions

Like the Base Case, the High Gas, Base Load Sensitivity Portfolio included the selection of the Company's Northeastern Unit 3 to operate on gas in 2026. The portfolio selected 200MW more wind than the Base Case as well as advancing wind selection by 2030. The portfolio includes the same 150MWs of additional solar resources by 2031. In total, with the recently approved renewable resources, the portfolio includes a total of 593 MWs of new solar resources and 1,553MWs of new wind resources.

The portfolio also includes a peak contribution of 129MWs from incremental EE resources by 2034.

9.2.1.6 Low Gas, Base Load Sensitivity Portfolio

The Low Gas, Base Load sensitivity was optimized to select resources to serve the Company's Base load but with lower commodity prices assumed in the Low Scenario. Resource additions in the Low Gas, Base Load Sensitivity Portfolio are shown in Table 29 and illustrated in Figure 35.

Table 29 Low Gas, Base Load Sensitivity Case Annual Resource Additions

Low Gas, Base Load Sensitivity New Build Additions by Planning Year (Nameplate MW)						
Planning Year	**Cumulative New EE**	**New Solar**	**New Wind**	**New CT**	**New CC**	**NE3 Gas**
2025/26	0	0	0	0	795**	0
2026/27	0	339*	553*	0	0	420
2027/28	0	0	0	0	0	0
2028/29	0	103.5*	0	0	0	0
2029/30	0	0	0	0	0	0
2030/31	37	150	200	0	0	0
2031/32	81	450	0	0	0	0
2032/33	83	0	0	0	760	0
2033/34	86	0	0	0	0	0
2034/35	93	0	0	0	0	0
Total		1,042.5	753	0	1,555	420
* Approved new resources ** New resource seeking approval						

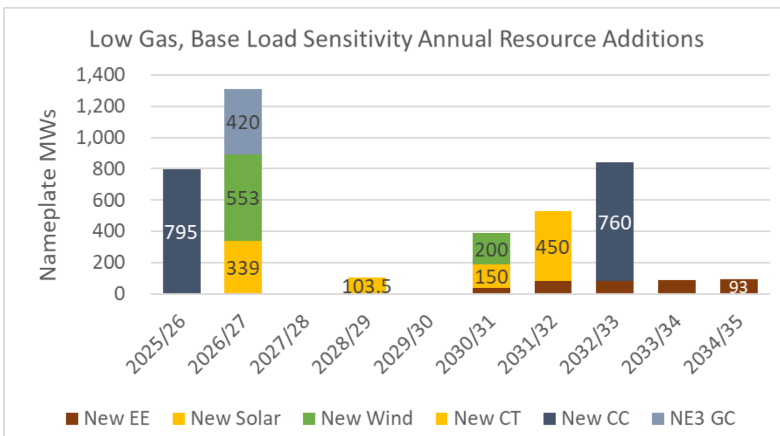


Figure 35 Low Gas, Base Load Sensitivity Annual Resource Additions

Like the Base Case, the Low Gas, Base Load Sensitivity Portfolio included the selection of the Company's Northeastern Unit 3 to operate on gas in 2026. With low gas prices, the portfolio included 760MW of NGCC in 2032, displacing the need for capacity and energy needs from 600MWs of wind resources in the Base Case. The portfolio selected 450MW more solar than the Base case for a total of 600MW of additional solar resources. In total, with the recently approved renewable resources, the portfolio includes a total of 760MWs of new NGCC resources along with 1,043MWs of new solar resources and 753MWs of new wind resources.

The portfolio also includes a peak contribution of 93MWs from incremental EE resources by 2034.

9.2.1.7 LEDO Sensitivity Portfolio

The LEDO Case was optimized under Base Scenario conditions but with a load that is almost 1GW higher than the Company's high load forecast beginning in 2030. This sensitivity will inform the company of potential resources needed to serve a higher load if a large load request is considered in PSO's territory. Resource additions in the LEDO sensitivity Portfolio are shown in Table 30 and illustrated in Figure 36.

Table 30 LEDO Sensitivity Annual Resource Additions

LEDO Sensitivity New Build Additions by Planning Year (Nameplate MW)								
Planning Year	**Cumulative New EE**	**New Solar**	**New Wind**	**New Storage**	**New CT**	**New CC**	**NE3 Gas**	**STMP**
2025/26	0	0	0	0	0	795**	0	0
2026/27	0	339*	553*	0	0	0	420	50
2027/28	0	0	0	0	0	0	0	0
2028/29	0	103.5*	0	0	0	0	0	0
2029/30	0	150	600	150	0	0	0	0
2030/31	35	1200	600	150	0	0	0	0
2031/32	38	0	0	0	960	0	0	0
2032/33	40	0	0	0	240	0	0	0
2033/34	40	0	0	0	0	0	0	0
2034/35	40	0	0	0	240	0	0	0
Total		1,792.5	1,753	300	1,440	795	420	50
* Approved new resources								
** New resource seeking approval								

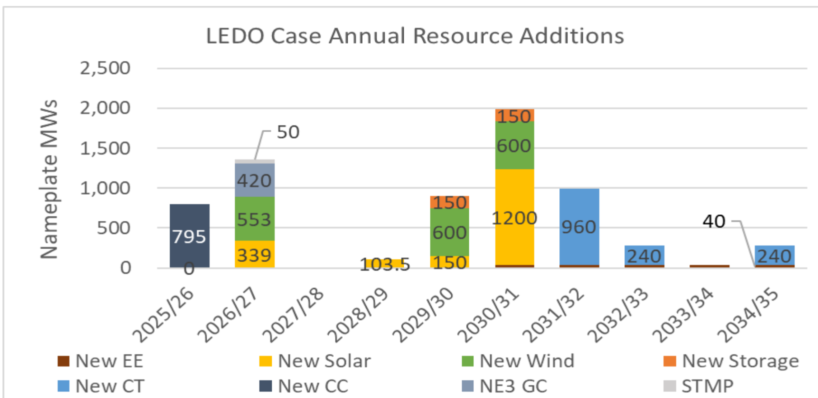


Figure 36 LEDO Sensitivity Annual Resource Additions

The LEDO sensitivity portfolio included the selection of the Company's Northeastern Unit 3 to operate on gas in 2026, 1,200MWs of additional wind and 1,350MWs of additional solar resources by 2030. In total, with the recently approved renewable resources, the portfolio includes a total of 1,793MWs of new solar resources and 1,753MWs of new wind resources by 2031 along with 300MWs of new battery storage by 2030 and 960MWs of new gas CTs in 2031 reaching a total of 1,440 MWs by 2034.

The portfolio also includes a peak contribution of 40MWs from incremental EE resources by 2034.

9.2.1.8 Storage Sensitivity Portfolio

The Storage Sensitivity was optimized under Base Scenario conditions but with 200MWs of stand-alone 6Hr storage resources assumed in 2029. This sensitivity informed the Company of potential resources economically selected to meet the remaining capacity obligations. Resource additions in the Storage Sensitivity Portfolio are shown in Table 31 and illustrated in Figure 37.

Table 31 Storage Sensitivity Annual Resource Additions

Storage Sensitivity New Build Additions by Planning Year (Nameplate MW)								
Planning Year	**Cumulative New EE**	**New Solar**	**New Wind**	**New Storage**	**New CT**	**New CC**	**NE3 Gas**	**STMP**
2025/26	0	0	0	0	0	795**	0	
2026/27	0	339*	553*	0	0	0	420	
2027/28	0	0	0	0	0	0	0	
2028/29	0	103.5*	0	0	0	0	0	
2029/30	0	0	0	200	0	0	0	
2030/31	44	0	0	0	0	0	0	
2031/32	95	450	0	0	0	0	0	
2032/33	128	0	200	0	0	0	0	
2033/34	146	0	0	0	0	0	0	
2034/35	154	0	0	0	0	0	0	
Total		892.5	753	200	0	795	420	

* Approved new resources
** New resource seeking approval

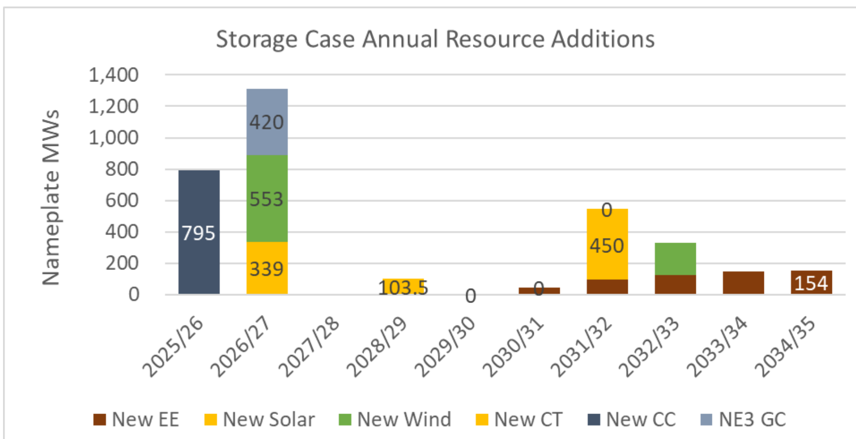


Figure 37 Storage Case Annual Resource Additions

The Storage sensitivity portfolio included, in addition to the 200MWs of battery storage, the selection of the Company's Northeastern Unit 3 to operate on gas in 2026, 200MWs of additional wind and 450MWs of additional solar resources. In total, with the recently approved renewable resources, the portfolio includes a total of 893MWs of new solar resources and 753MWs of new wind resources along with 200MWs of new battery storage.

The portfolio also includes a peak contribution of 154MWs from incremental EE resources by 2034.

9.3 Portfolio Performance Indicators

In resource planning, large amounts of data are produced, and a Portfolio Performance Indicator Matrix (PIM) can be an effective tool in decision-making. The PIM for resource planning purposes refers to a table that illustrates the performance of alternative resource plans across a set of company-defined objectives, performance indicators, and metrics. The matrix enables the Company to consider the tradeoffs between portfolios for the purposes of making decisions based on how different plans score across the metrics and how they support the Company and its customers. It provides a simple and structured means of explaining how sometimes objectives align, while other times they can conflict and be traded off as part of reaching a reasonable decision that is in the best interest of customers.

The PIM has three primary elements, illustrated in Table 32.

- **Objectives** are overarching goals that align to PSO or stakeholder priorities. The four objectives of the 2024 PSO IRP are:
    - Customer Affordability
    - Rate Stability
    - Maintaining Reliability
    - Sustainability
- **Performance indicators** measure progress towards goals and serve as measurable categories across which portfolios can be compared. There are nine performance indicators that align to the four objectives and are detailed below.
- **Metrics** are the units in which the performance indicators are measured, often they include a time element (e.g., net present value, cumulative period, future test year) in addition to numerical value or calculation.

Table 32 Elements of the 2024 PSO IRP Performance Indicator Matrix

Objective	Performance Indicator	Metric
Affordability	NPVRR	Portfolio 30yr NPVRR Portfolio 30yr Levelized Rate (MPVRR/Levelized Energy)
	Near-Term Rate Impact	7-year CAGR of Rate Impact
Rate Stability	Portfolio Resilience	Range of Portfolio NPVRR across Scenarios
	Energy Market Exposure – Purchases	Average Cost and volume exposure of market purchases (MWhs % of Internal Load) 2028- 2034
	Energy Market Exposure - Sales	Average Revenue and volume exposure of market sales (MWhs % of Internal Load), 2028-2034
Reliability	Reserve Margin	Portfolio Total Reserve Margin
	Fleet Resiliency	Dispatchable MW % of Company Peak Load
	Resource Diversity	Diversity Index inclusive of Capacity and Energy Diversity
Sustainability	Portfolio Emissions	CO_2, SO_2, NOx emissions change from 2005 Baseline

The objectives, performance indicators and metrics are further described in the following sections. The PIM is shown below in Figure 38.

	Customer Affordability		Rate Stability			Reliability			Sustainability		
Portfolio	***Short Term***	***Long Term***	***Portfolio Resilience:***	***Energy Market Risk***	***Energy Market Risk***	***Planning Reserves***	***Fleet Resiliency***	***Resource Diversity***	***Emission Reductions***		
	7-yr Rate (RR) CAGR	*Portfolio NPVRR*	*High Minus Low Scenario Range, Portfolio NPVRR*	*Purchases*	*Sales*	*% Reserve Margin*	*Dispatchable Capacity*		*% Change from 2005 Baseline CO2, NOx, SO2*		
Year Ref.	2025-2031	2025-2054	2025-2054	2028-2034	2028-2034	2034	2034	2034	2034		
Units	%	$MM Levelized Rate ($/MWh)	$MM Levelized Rate ($/MWh)	Average Cost of Market Purchases ($000) AVG MWh% of AVG PSO Demand	Average Revenue of Market Sales ($000) AVG MWh% of AVG PSO Demand	Summer % Winter % (ACAP)	Dispatchable Nameplate MW % of Company Peak Demand	Portfolio Index (Accredited Capacity+ Energy Diversity)	% Reduction CO_2	NOx	SO_2

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

Figure 38 2024 IRP Performance Indicator Matrix

9.3.1 Objective 1: Customer Affordability

Customer affordability is a primary objective for PSO. For the PSO 2024 IRP, minimizing the expected cost to customers, to the extent reasonable when evaluated against other objectives, was a clear and obvious objective to measure.

There are two performance indicators that track the customer affordability objective across the short- and long-term.

9.3.1.1 Short Term: 7-year expected growth in customer rates

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

PSO measures and considers the expected percentage growth in rates over seven years as the metric for the short-term customer affordability performance indicator. Near-term retail rate impact is measured using a 7-year Compound Annual Growth Rate (CAGR) of expected system costs for the years 2025-2031.

9.3.1.2 Long Term: Portfolio net present value of revenue requirement

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

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

NPVRR was selected as the metric for this performance indicator. NPVRR is a representation of the total long-term annual costs paid by PSO's utility customers related to power supply as described in Section 9.1. NPVRR will be measured over the long-term using a 30-year period (2025-2054) and is expressed both in terms of total and levelized rate. The levelized rate is the fixed charge per MWh needed to recover the 30-year NPVRR.

9.3.2 Objective 2: Rate Stability

Rate stability is a key component of affordability for PSO's customers. A resource plan that performs well under expected conditions may expose ratepayers during periods of volatility, extreme weather events, or extended outages. PSO understands that market fluctuations in electric and fuel commodities and other uncertainties can adversely impact customer rates under a resource plan deemed to be the most affordable.

The performance indicators of rate stability test how robust the expected costs of each portfolio are by subjecting them to different market scenario conditions. This assessment evaluates how portfolios perform under a range of market conditions, commodity prices, and policy outcomes and allows PSO to balance affordability under expected conditions with resilience to changes in the market.

The three performance indicators for rate stability are described below and include an assessment of the potential change in rates across a range of scenarios and track the amount of reliance on the SPP energy market under each candidate plan.

9.3.2.1 Portfolio Resilience: Range of Portfolio NPVRRs across the market scenarios

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

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

The portfolio NPVRR allows for all the firm resource decisions made in the optimized run to be fully reflected. Furthermore, the NPVRRs include the value of any unconstrained energy dispatch of the firm resources in the portfolio along with the ability to include additional capacity costs to meet the respective loads of each market scenario if needed. NPVRR is a representation of the total long-term annual costs paid by PSO’s utility customers related to power supply.

9.3.2.2 Market Exposure:

As a member of SPP, the Company can leverage low-cost market energy for the benefits of its customers. Under normal conditions, this is of high value to ensure access to reliable and low-cost energy. Energy markets, however, include risks both in a reliance on this resource for purchases and sales during periods of high volatility. Measuring the total portion of customer energy served by the market, or conversely, the reliance on market energy sales in certain periods of excess generation will provide insight to potential market risks of each portfolio.

9.3.2.3 Market Energy Purchases:

The metric for this performance indicator measures the portfolio costs of energy market purchases and the percent of purchases to the Company’s internal peak load. The portfolio cost metrics are calculated as the average market energy costs and % of internal peak load from 2028 through 2034.

9.3.2.4 Market Energy Sales:

The metric for this performance indicator measures the portfolio revenues of energy market sales and the percent of sales to the Company’s internal peak load. The portfolio revenue metrics are calculated as the average market energy revenues and % of internal peak load from 2028 through 2034.

9.3.3 Objective 3: Maintaining Reliability

Understanding the role that SPP plays in maintaining broader system reliability, PSO has identified maintaining reliability as an important, fundamental objective to be included on the IRP performance indicators.

Three performance indicators were selected to measure progress towards maintaining reliability. These cover the total capacity reserves maintained by PSO under each plan, the amount of dispatchable capacity included in each plan and a measure of the resource diversity in the portfolios reflecting both capacity and energy contributions.

9.3.3.1 Planning Reserves: Portfolio reserve margin

As a Load Responsible Entity (LRE), PSO must maintain a minimum amount of accredited capacity above its coincident peak load with SPP. This performance indicator measures PSO's amount of firm capacity in each candidate portfolio in 2034 relative to its coincident peak load and allows PSO to evaluate the exposure of different candidate resource plans towards meeting planning reserve margin requirements.

The metric for this performance indicator will be PSO's reserve margin measured as the ratio of firm (i.e., ACAP) supply to forecasted company peak demand. This metric is calculated by dividing the (seasonal) ACAP of the resource plan by PSO's (seasonal) peak (winter: Oct-March, summer: April-September) requirement of the resource plan in 2034.

9.3.3.2 Fleet Resiliency: Dispatchable capacity in 2034

The increase in intermittent renewable resources across SPP may create the need for more flexible resources that can provide a reliability service and balance the system during periods of low output or extreme weather. Understanding each portfolio's ability to respond to system needs is an important factor for determining the preferred plan.

This performance indicator allows management to evaluate the amount of ramping capacity or potential for continuous energy output on its system. The metric is measured as the cumulative amount of dispatchable capacity selected by the candidate portfolio in 2034 including all thermal and storage resources.

9.3.3.3 Resource Diversity: Generation mix by resource in 2034

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

This measure will evaluate the diversity of different resource contributions to their respective total accredited capacity and energy as part of the total portfolio of resource types. Diversity will be calculated based on the Shannon-Weiner Diversity Index[12] that considers the number of different types of resources and their respective contributions to the portfolio total with respect to capacity and energy. Capacity diversity will be evaluated based on accredited MWs while energy diversity will be based on modeled annual MWhs. A Portfolio Diversity index will be the sum of the Capacity Diversity Index and the Energy Diversity Index.

9.3.4 Objective 4: Sustainability

This objective also allows PSO to evaluate the relative exposure of candidate resource plans under outcomes where significant reductions in Greenhouse Gas (GHG) emissions are required in the power sector – a plausible outcome with potentially material impacts on the cost to serve PSO's customers.

12 https://www.statology.org/shannon-diversity-index/

9.3.4.1 CO_2 , NOx and SO_2 Emissions: Percent change from 2005 in 2034

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

The metric for this performance indicator is the change in emission relative to PSO's total emissions in the year 2005. Emissions are defined as the direct emissions from PSO's owned and contracted generating resources. This metric is calculated by dividing the total PSO portfolio emission in 2034 by total PSO portfolio emission from the year 2005 and evaluating the percent reduction.

9.4 Portfolio Analysis

9.4.1 Customer Affordability

PSO measures customer affordability by evaluating:

- Short-term affordability, measured as the 7-yr CAGR of growth in customer rates associated with the new demand- and supply-side resources selected under each portfolio
- Long-term affordability, measured as the 30-year NPVRR of new demand- and supply-side resources selected under each portfolio

9.4.1.1 Short-term

Table 33 shows the portfolio performance under the Customer Affordability objective. As discussed in Section 9.3.1.1, the indicators for this objective include the expected annual growth in customer generation costs over the next seven years and the NPVRR over the next 30 years.

Table 33 Portfolio Performance under Customer Affordability Metrics

Portfolio	7-Year RR CAGR, (%/annum)
Base Portfolio	-0.34%
High Portfolio	-0.14%
Low Portfolio	-0.78%
EER Portfolio	0.08%
High Gas, Base Load Sensitivity	-0.90%
Low Gas, Base Load Sensitivity	-0.39%
LEDO Sensitivity	8.13%
Storage Sensitivity	1.17%

In the short-term, customer costs are shown to be lower, driven in large part by the federal tax credits earned by new wind and solar resources. Under the Base Portfolio modeled under the conditions considered most likely by the Company, customer generation costs are estimated to decline by 0.34%. The Base Portfolio includes an estimated levelized capital cost through 2031 of approximately $660M for new resources, offset by approximately $160M in estimated PTCs. The High Portfolio includes a future with higher loads and commodity prices and results in one of the least reductions in customer costs. This portfolio includes an estimated levelized capital cost through 2031 of approximately $890M for new resources, offset by approximately $361M in estimated PTCs. The Low Portfolio that considers a future where low load and low commodity prices are in effect results in an estimated decline in customer costs of -0.78%. This portfolio includes an estimated levelized capital cost through 2031 of approximately $674M for new resources, offset by approximately $196M in estimated PTCs.

The EER Portfolio results in almost no reduction to customer costs due to the larger capital costs associated with the addition of more renewables in 2029-2031. This portfolio includes an estimated levelized capital cost through 2031 of approximately $657M for new resources, offset by approximately $189M in estimated PTCs. The High Gas, Base Load Sensitivity realized the largest reduction in near-term portfolio costs. This portfolio includes an estimated levelized capital cost through 2031 of approximately $723M for new resources, offset by approximately $238M in estimated PTCs. The Low Gas, Base Load Sensitivity resulted in a reduced cost of -0.39%. This portfolio includes an estimated levelized capital cost through 2031 of approximately $657M for new resources, offset by approximately $189M in estimated PTCs. This portfolio includes an estimated levelized capital cost through 2031 of approximately $559M for new resources, offset by approximately $93M in estimated PTCs. The LEDO Sensitivity includes the highest potential near-term costs to customers driven by the need to include significantly more resources by 2031 to serve the increased load assumed in that analysis. The Storage Sensitivity realizes a slight increase in short-term costs primarily driven by the reduced near-term wind resources and their associated PTC offsets. This portfolio includes an estimated levelized capital cost through 2031 of approximately $554M for new resources, offset by approximately $24M in estimated PTCs.

9.4.1.2 Long-term

Table 34 includes the long-term revenue requirements of each case and sensitivity considered in this IRP.

Table 34 Portfolio NPVRR (30-year)

Portfolio	Portfolio NPVRR ($MM)	Levelized Rate ($/MWh)
Base Portfolio	$16,176	$48.87
High Portfolio	$21,135	$57.56
Low Portfolio	$13,024	$44.00
EER Portfolio	$16,238	$49.05
High Gas, Base Load Sensitivity	$18,177	$54.94
Low Gas, Base Load Sensitivity	$14,310	$43.26
LEDO Sensitivity	$25,137	$55.59
Storage Sensitivity	$16,635	$50.16

In the long-term, revenue requirements align with the characteristics of the respective scenario. More specifically, as shown in Table 34, in the High Case under a scenario where gas prices and the associated energy prices are high, portfolio costs are highest. Conversely, the Low Case resulted in the lowest NPVRR where gas and energy prices are low. The LEDO sensitivity, modeled under Base Scenario conditions, had the highest NPVRR due to the higher amount of new resources required to support the large loads. The Base Load Sensitivity runs under high and low gas prices provide insight to the potential portfolio costs if only gas prices were changed. These sensitivities resulted in approximately $2B cost difference (higher and lower) from the Base Portfolio cost.

The Storage sensitivity resulted in a slightly higher cost than the Base Portfolio primarily due to the limited tax credits estimated in the portfolio and changes in market purchases and sales. The storage resources were discounted by the available 30% ITCs. Of particular note, the Storage sensitivity included approximately $6B of total levelized capital costs compared to $8-$10B of total levelized capital costs in the Base and EER portfolios. All portfolio NPVRR’s include the reduction of total costs by federal production tax credits afforded to the solar and wind resources energy production.

9.4.2 Rate Stability

PSO measures rate stability by evaluating:

- Scenario resilience as measured by the range of 30-year NPVRRs of each Candidate Portfolio Cases across the market scenarios;
- Market exposure as measured by the average sales and purchases of each portfolio between 2028 and 2043.

9.4.2.1 Portfolio Resilience

Table 35 shows the 30-year NPVRR of the Candidate Portfolio cases when dispatched across the different market scenario commodity prices. Sensitivities were excluded from this analysis as they were modeled to inform the Company on variations to the primary cases (Base, High, Low, EER). As part of this analysis, the Company also excluded any constraints on market energy resources to serve load to provide additional insight to the potential risks inherent to an overreliance on the market to serve customers. The difference between the highest and lowest value is used to populate the Portfolio Resilience Indicator on the PIM.

Table 35 The 30-Year NPVRRs of the Candidate Portfolio Cases Across Market Scenarios

Candidate Portfolio Cases	Market Scenarios				
	Base	High	Low	EER	High/Low Difference
Base	16,176	21,753	13,733	16,584	8,020
High	17,083	21,135	15,263	17,174	5,871
Low	16,005	21,176	13,024	16,588	8,153
EER	16,150	20,936	14,425	16,238	6,511
Storage	16,635	23,062	13,529	17,721	9,533

The results of the resiliency analysis indicate the High Case portfolio to have the lowest range in portfolio costs of $5,871B when evaluated across all potential market scenarios. The highest range was the Storage with a $9B range followed by the Low Case portfolio with a cost range of $8,153B, The Base Case had a cost range of $8,020B. While a low range across the scenarios is typically aligned to lower risks, for this analysis, it is important to consider the drivers of the cost range.

In general, the costs of the portfolios when dispatched under high market conditions resulted in similar costs around the $21B range. Conversely, when dispatched under the low market conditions, the costs were within $13 and $15B.

It is important to note a couple additional insights to the portfolio cost ranges in Table 35. Considering the Storage case where the range was the highest, this is driven only by the analysis when modeled under the High Scenario. The analysis showed that through the first 10 years of the analysis, the annual portfolio costs for each run were generally the same.

The High Case resulted in a range of costs that were the lowest but the series of costs that were all higher due to the extra resources the plan selected. With the extra resources, the lower bound of the analysis was generally higher across all scenarios resulting in the lower range of costs. Additionally, in this plan, the high amount of renewables included in the plan resulted in a high value of PTCs that are not entirely within the Company’s control to fully predict. This was a similar result for the EER Case.

9.4.2.2 Energy Market Risk

Table 36 shows the average energy market purchases and sales in terms of portfolio costs and revenues as well as an average percentage of PSO’s peak load between 2028 and 2034.

The Company specified this range since it relates to when material decisions could be made between portfolios for new resources.

Table 36 Average Market Energy Reliance Across All Scenarios

Case	Average Cost of Market Purchases ($000) AVG MWh% of AVG PSO Demand	Average Revenue of Market Sales ($000) AVG MWh% of AVG PSO Demand
	2028-2034	2028-2034
Base Case	$73,366 10.1%	$26,551 3.7%
High Case	$111,129 11.6%	$32,769 3.7%
Low Case	$93,365 16.4%	$13,903 2.8%
EER Case	$137,355 17.7%	$13,331 2.0%
High Gas, Base Load Sensitivity	$98,961 11.0%	$32,967 3.7%
Low Gas, Base Load Sensitivity	$125,188 22.2%	$14,146 2.1%
LEDO Sensitivity	$167,915 17.6%	$13,011 1.3%
Storage Sensitivity	$105,109 14.2%	$14,370 2.0%

PSO has relied on the SPP Market to support meeting customer energy requirements. For this IRP, the Company considered the results of the portfolios and their relative reliance on the market. The results shown in Table 36 illustrate a wide range of costs related to energy purchases while also showing an opportunity for sales to the energy market offsetting some of the costs for the benefit of PSO's customers.

The Base Case results is the lowest cost and percent of PSO demand of market energy related to market energy purchases. Additionally, the Base Case includes one of the highest percentages of energy sales revenues relative to PSO demand among all portfolios. This is driven in part, from the energy rich wind resources included in the portfolio.

The High Case includes a larger reliance on market energy resources to serve load driven by the lower capacity factors of the gas resources as a result of higher gas prices.

The Low Case relies on a higher percentage of market energy resources to serve customers. This is driven by the lower energy prices in the market analysis and consequently, a lower capacity factor from the gas resources.

The EER Case includes a high reliance on market energy resources relative to the Base Case driven primarily by reduced capacity factors from the gas resources.

The High Gas, Base Load sensitivity resulted in a slightly higher level of reliance of market energy compared to the High Case driven primarily by the slightly lower levels of wind and solar resources.

The Low Gas, Base Load sensitivity resulted in an even higher amount of market energy to serve customers as the portfolio included less wind resources and more solar resources.

The LEDO Sensitivity relies on market energy to support serving customers notably more when the large economic load is introduced in 2030. The portfolio of resources includes higher levels of renewable resources along with new storage and NGCT resources providing capacity support. For the additional load tested in this sensitivity, however, customers benefit from low-cost market energy resources while also having dispatchable resources available to hedge against market disruptions.

The Storage Sensitivity results in higher costs of market energy purchases relative to the Base Case as it included less energy rich wind resources in the near term.

9.4.3 Maintaining Reliability

PSO measures each portfolio’s contribution to maintaining reliability by evaluating:

- Planning reserves measured as the ratio of firm supply to expected peak demand for *both* the summer and winter periods in 2034;
- Operational flexibility measured as (1) the total firm capacity provided by fast-ramping technologies, and (2) the total number of units added to the resource plan designated as “dispatchable” by 2034; and
- Resource diversity measured as the percentage of total generation provided by each technology in model year 2031 under Reference Scenario conditions.

9.4.3.1 Planning Reserves

Table 37 shows the summer and winter planning reserves in 2034 for each candidate portfolio.

Table 37 Planning Reserves In 2034 by Portfolio

Case	Summer	Winter
Base Case	11.2%	35.1%
High Case	11.1%	34.4%
Low Case	24.9%	49.2%
EER Case	17.9%	39.7%
High Gas, Base Load Sensitivity	11.5%	35.7%
Low Gas, Base Load Sensitivity	31.5%	52.4%
LEDO Sensitivity	23.4%	26.1%
Storage Sensitivity	18.3%	37.5%

As discussed in Section 4.5, PSO assumed each candidate portfolio would need to meet an SPP ACAP PRM of 5% in the summer and 11.7% in the winter plus an additional 6% reserve for risk and contingencies to ensure the Company can meet SPP capacity obligations. Additionally, the portfolio of resources were optimized to stay within energy market reliance limits simultaneously which resulted in an overcompliance of several portfolio capacity reserve limits.

The Base Case, High Case and High Gas sensitivity resulted in a summer reserve margin compliance near the model limits of 11%. This also resulted in a slight overcompliance with the winter reserve margin model limits of 33% driven primarily with the variation in Effective Load Carrying Capability (ELCC) of renewable resources.

The Low and EER Cases and Low Gas and LEDO sensitivities resulted in an overcompliance to both the summer and winter reserve margin limits. The model selected renewable resources to mitigate risks of an over reliance to purchased energy from the SPP Energy market in those scenarios to serve customer load driven by the downward pressure on gas resource dispatch and associated margins. The Storage sensitivity also included additional capacity length but the relative additional length in the winter season was tempered compared to the EER Case.

9.4.3.2 Fleet Resiliency

Table 38 shows the amount of capacity in 2034 in each of the candidate portfolios considered.

Table 38 Portfolio Amount of Dispatchable Capacity and Units in 2034

Case	Dispatchable Capacity (MW)	% of Company Demand
Base Case	4,226	94.5%
High Case	4,452	92.3%
Low Case	4,226	103.27%
EER Case	4,226	94.27%
High Gas, Base Load Sensitivity	4,226	94.5%
Low Gas, Base Load Sensitivity	4,979	111.36%
LEDO Sensitivity	5,656	91.67%
Storage Sensitivity	4,426	99%

All portfolios include over 4GW of dispatchable capacity resources capable of serving over 90% of PSO's demand for the respective cases and sensitivities.

The Low Gas, Base Load sensitivity included an additional 760MW NGCC resource in 2033 increasing this particular portfolio's to dispatchable capacity along with the existing and new NGCTs. The metric resulted in more dispatchable capacity than PSO's peak load.

The LEDO Sensitivity adds a combination of different resources including 200MWs of storage by 2030 and 1,440MWs of NGCTs by 2034 to support the large load analyzed.

The Storage sensitivity resulted in an increase to the dispatchable resources relative to the Base, Low and EER cases reaching 99% of PSO's peak load.

9.4.3.3 Resource Diversity

Table 39 summarizes candidate portfolio diversity index values for both capacity and energy. The Diversity Index is calculated from the Shannon-Weiner index that takes into account, the different types and their respective contribution to the total. A higher value represents more diversity. For this metric, based on the resource selections in the different portfolios, the relative maximum diversity value for capacity is 1.95 based on a seven resource types including NGCT, NGCC, NG-ST, Solar, Wind, Storage, and EE. The relative maximum diversity value for energy is 2.08 based eight resources including NGCT, NGCC, NG-ST, Solar, Wind, Storage, EE and Market Energy. The combined maximum total diversity of capacity and energy is 4.03.

Table 39 Candidate Portfolio Resource Diversity Index

Portfolio	Summer Capacity	Energy	Total
Base Portfolio	1.56	1.2	2.76
High Portfolio	1.57	1.19	2.75
Low Portfolio	1.57	1.16	2.74
EER Portfolio	1.59	1.14	2.74
High Gas, Base Load Sensitivity	1.56	1.15	2.71
Low Gas, Base Load Sensitivity	1.51	1.30	2.86
LEDO Sensitivity	1.64	1.42	3.06
Storage Sensitivity	1.68	1.38	3.06

As shown, the summer capacity diversity index among the different portfolios indicates a consistent selection of diverse resources across the candidate portfolios except for the LEDO sensitivity. These include solar, wind, gas CTs, NGCCs, the NE3 NG-Steam resource and Energy Efficiency resources. The LEDO Sensitivity includes additional storage resources that serve to increase the relative capacity diversity index. The Storage Sensitivity includes the highest capacity diversity with the inclusion of storage resources and the relative resources to meet the planning reserve margin. The capacity diversity index is approximately 80% of a maximum diversity index potential in the summer indicating a reasonable amount of diversity in the portfolio of resources. Of note, the capacity diversity index in the winter declines to around 1.48 for the portfolios (relative to around 1.57 for summer) as a result of the reduced accredited capacity contribution from solar resources.

The Energy diversity includes a wider variance among candidate portfolios, however, with the Base Portfolio comparably high for energy diversity among the portfolios serving the respective loads except for the LEDO sensitivity. The Low Gas, Base Load Sensitivity scores higher in the energy diversity due to the additional NGCC generation. The LEDO sensitivity provides a higher energy diversity index due to the additional storage resources that are included in the Portfolio. The energy diversity index among the portfolios is approximately 55-60% of a maximum energy diversity index. The lower diversity value relative to the maximum diversity is related to the levels of wind energy in the portfolios. With over 50% of the energy being delivered from wind resources, the overweighting relative to the total energy supply reduces the overall energy diversity of the portfolios. The exception to this is the Storage Sensitivity that resulted in a higher energy diversity index. The inclusion of solar resources resulted in reduced wind resources and a more even mix of energy delivered from PSOs resources.

9.4.4 Sustainability

- PSO compares portfolio performance against the sustainability objective by evaluating the percentage reduction in CO_2, NOx and SO_2 emissions in 2034 from owned resources relative to the baseline year 2005.

9.4.4.1 CO_2 Emissions

Table 40 illustrates the reduction in emissions for CO_2, NOx and SO_2 emissions in million short tons from PSO-owned and contracted resources in 2034 for each candidate portfolio with PSO's baseline emissions from the year 2005.

Table 40 CO_2 Emission Reductions by Portfolio

Portfolio	CO_2 Emissions Reduction ($mtCO_2$)	NOx Emissions Reduction (mtNOx)	SO_2 Emissions Reduction ($mtSO_2$)
Base Portfolio	73.1%	96.0%	100%
High Portfolio	74.4%	96.3%	100%
Low Portfolio	89.0%	97.8%	100%
EER Portfolio	88.0%	98.1%	100%
High Gas, Base Load Sensitivity	74.4%	96.3%	100%
Low Gas, Base Load Sensitivity	70.8%	97.3%	100%
LEDO Sensitivity	73.1%	96.0%	100%
Storage Sensitivity	73.1%	96.0%	100%

The results demonstrate a continued pathway towards a reduction in CO_2 emissions through 2034. With the Company's previous efforts to address NOx and SO_2 emissions, the portfolios demonstrate the continued success in maintaining the reductions already achieved.

9.5 Portfolio Performance Analysis

The 2024 IRP Portfolio Performance Indicator Matrix (PIM)is displayed below in Section 9.5.1. The key results from the PIM are summarized below:

The Affordability metrics identified small cost reductions in the near term for most of the cases and sensitivities with the LEDO and Storage sensitivities identifying an increase. Overall, portfolio costs to serve customers were consistent with many relying on federal PTCs from wind resources to offset capital costs.

From a Rate Stability perspective, the potential cost ranges varied among portfolios and was dependent in part, by the amount of federal PTCs and fuel costs a portfolio might incur. Although the High Case and EER Case had lower cost ranges, they included similar high potential costs with a lower potential cost that was higher than the other portfolios.

Considering the Market Risk metrics, several portfolios including the Low Case, EER Case and the Low Gas, Base Load Sensitivity had higher levels of purchases from the SPP Market. Conversely, the Base Case, High Case and High Gas, Base Load Sensitivity all saw slightly higher levels of potential sales to the market to offset some of the portfolio costs. The Storage Sensitivity included market reliance metrics for purchases and sales that met the Company's objectives to mitigate risks for overreliance on the market and fell about in the middle for market purchases.

Reserve margins illustrated the challenge to maintain accredited capacity while also working to mitigate market energy risks. Although three of the cases and sensitivities maintained a close adherence to the summer target reserve margin, the portfolios included capacity resources that tended to over comply with the requirements.

Diversity among the resources was measured with a consistent index relative to capacity among the portfolios in 2034. The energy diversity shows some variability among the portfolios with wind being a predominant contributor to the total energy mix. The Base Case, High Case and Low Gas, Base Load Sensitivity included higher index values as a result of their energy mix providing a better balance to the overweighting of wind energy in the portfolios. The Storage Sensitivity scored well in this metric with the additional storage resources and the identification of a portfolio that provided a balance of energy from all resources.

9.5.1 Complete Performance Indicator Matrix Results

	Customer Affordability		Rate Stability			Reliability			Sustainability		
Portfolio	*Short Term*	*Long Term*	*Portfolio Resilience:*	*Energy Market Risk*	*Energy Market Risk*	*Planning Reserves*	*Fleet Resiliency*	*Resource Diversity*	*Emission Reductions*		
	7-yr Rate (RR) CAGR	*Portfolio NPVRR*	*High Minus Low Scenario Range, Portfolio NPVRR*	*Purchases*	*Sales*	*% Reserve Margin*	*Dispatchable Capacity*		*% Change from 2005 Baseline CO2, NOx, SO2*		
Year Ref.	2025-2031	2025-2054	2025-2054	2028-2034	2028-2034	2034	2034	2034	2034		
Units	%	$MM Levelized Rate ($/MWh)	$MM	Average Cost of Market Purchases ($000) AVG MWh% of AVG PSO Demand	Average Revenue of Market Sales ($000) AVG MWh% of AVG PSO Demand	Summer % Winter % (ACAP)	Dispatchable Nameplate MW % of Company Peak Demand	Portfolio Index (Accredited Capacity+ Energy Diversity)	% Reduction CO_2	NOx	SO_2
Base Portfolio	-0.34%	$16,176 $48.87	8,020	$73,364 10.1%	$26,553 3.7%	11.2% 35.1%	4,226 94.5%	1.56+1.2 = 2.76	73.1%	96.0%	100.0%
High Portfolio	-0.14%	$21,135 $57.56	5,871	$111,129 11.6%	$32,769 3.7%	11.1% 34.4%	4,824 92.3%	1.57 + 1.19 = 2.75	74.4%	96.3%	100.0%
Low Portfolio	-0.78%	$13,024 $44.	8,153	$93,365 16.4%	$13,903 2.8%	24.9% 49.2%	4,226 103.3%	1.57 + 1.16 = 2.74	89.0%	97.8%	100.0%
EER Portfolio	-0.08%	$16,238 $49.05	6,511	$137,355 17.7%	$13,331 1.97%	17.9% 39.7%	4,226 94.3%	1.59 + 1.14 = 2.74	88.0%	98.1%	100.0%
High Gas, Base Load Sensitivity	-0.90%	$18,177 $54.94	Not Evaluated	$98,961 11.%	$32,967 3.9%	11.5% 35.7%	4,226 94.5%	1.56 + 1.15 = 2.71	74.4%	96.3%	100.0%
Low Gas, Base Load Sensitivity	-0.39%	$14,310 $43.26	Not Evaluated	$125,188 22.2%	$14,146 2.1%	31.5% 52.4%	4,979 111.4%	1.51 + 1.3 = 2.81	70.8%	97.3%	100.0%
LEDO Sensitivity	8.13%	$25,137 $55.59	Not Evaluated	$167,915 17.6%	$13,011 1.3%	23.4% 26.1%	5,656 96.8%	1.64 + 1.42 = 3.06	73.1%	96.0%	100.0%
Preferred Plan (Storage Sensitivity)	1.17%	$16,635 $50.16	9,533	$105,109 14.2%	$14,370 2.02%	18.3% 37.5%	4,426 99.%	1.68 + 1.38 = 3.06	73.1%	96.0%	100.0%

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

Figure 39 Complete Performance Indicator Matrix

9.6 Preferred Plan

The IRP Performance Indicators do not specifically define a Preferred Plan on its own. Each candidate resource plan considered in the 2024 IRP represents a trade-off between the objectives defined by PSO. The purpose of the PIM is to provide PSO management with a structured tool that illustrates these trade-offs as discussed in Section 9.5 and enables the selection of the best path forward for PSO's customers. For this IRP, the Company selected the Storage Sensitivity plan as the Company's Preferred Plan.

9.6.1 Details of the Preferred Plan

The Preferred Plan supports the Company's objectives to provide sustainable, affordable, reliable energy and minimize risks to customers rates. The plan includes a diverse mix of resources including new solar, wind and storage resources while also leveraging the Company's existing NE3 unit to continue its operation as a gas unit. The plan provides a balanced portfolio of resources with the least amount of capital expenditures that supports the SPP summer and winter capacity obligations and maintains a fleet of dispatchable resources that can provide energy to nearly all of PSOs peak load. Figure 40 and Figure 41 illustrate the Company's capacity position with the new resources in both a summer and winter capacity obligation view.

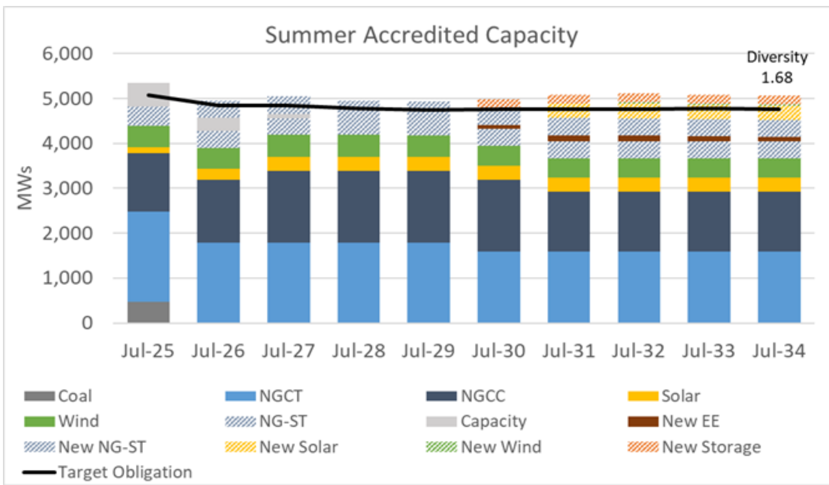


Figure 40 Preferred Plan Summer Accredited Capacity

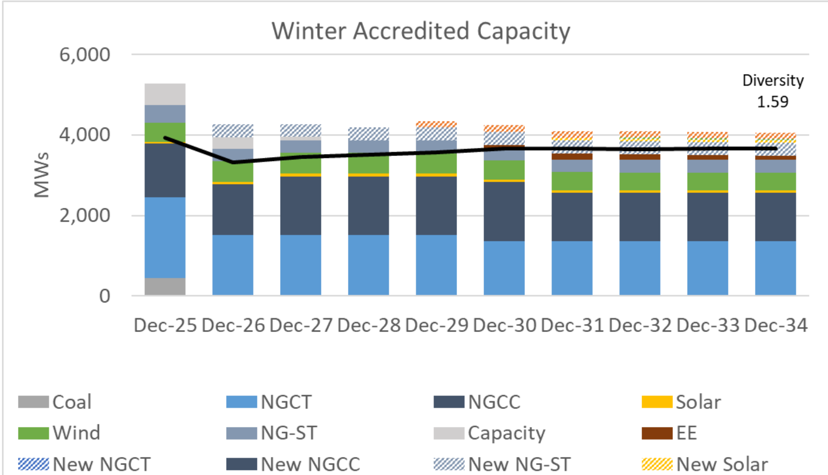


Figure 41 Preferred Plan Winter Accredited Capacity

The plan includes as shown in Table 41 the selection of the Company's Northeastern Unit 3 to operate on gas in 2026 and 200MWs of additional 6hr storage in 2029. 450MWs of solar resources enter the portfolio in 2031 followed by 200MWs of additional wind resources in 2032. In total, with the recently approved renewable resources, the portfolio includes a total of 893MWs of new solar resources, 753MWs of new wind resources and 200 MWs of 6hr storage.

The portfolio also includes a peak contribution of 154MWs from incremental EE resources by 2034.

Table 41 Preferred Plan New Resource Additions

Preferred Plan New Build Additions by Planning Year (Nameplate MW)							
Planning Year	**New EE**	**New Solar**	**New Wind**	**New Storage**	**New CT**	**New CC**	**NE3 Gas**
2025/26	0	0	0	0	0	795**	0
2026/27	0	339*	553*	0	0	0	420
2027/28	0	0	0	0	0	0	0
2028/29	0	103.5*	0	0	0	0	0
2029/30	0	0	0	200	0	0	0
2030/31	44	0	0	0	0	0	0
2031/32	95	450	0	0	0	0	0
2032/33	128	0	200	0	0	0	0
2033/34	146	0	0	0	0	0	0
2034/35	154	0	0	0	0	0	0
Total		892.5	753	200	0	795	420
* Approved new resources							
** New resource seeking approval							

Additionally, as discussed in Section 4.6, PSO has historically leveraged the SPP energy market to serve a measureable portion of its customer load. This plan supports the Company's desire to mitigate some of this market risk through the addition of additional energy rich resources such as wind and solar while still capturing the benefit of low cost energy from SPP during times when the market is not disrupted. Figure 42 illustrates PSO's energy position and sources with the Preferred Plan.

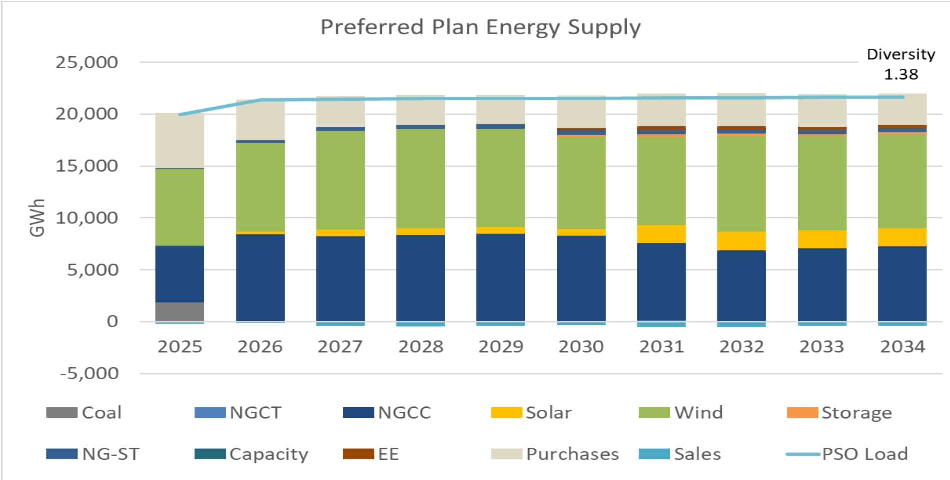


Figure 42 Preferred Plan Energy

The Preferred Plan is informed by an optimized analysis to meet SPP minimum reserve margins. However, this plan is based on an uncertain future regarding events that can impact the Company's capacity position, including uncertainty around intermittent resources contribution to reserve margins, load growth and existing unit performance.

9.6.2 The Preferred Plan Achieves PSO's IRP Objectives

9.6.2.1 Customer Affordability

The Preferred Plan supports the Company's Affordability objectives with near term rate impacts at approximately 1%. Although this was not one of the lowest rate impact metrics among the portfolios evaluated, the plan minimizes capital expenditures while also taking advantage of ITCs available to the storage resources included in the plan in 2029. Over the long-term, the plan is less than 3% more than the Base Case plan.

9.6.2.2 Rate Stability

Under the Rate Stability objective, the Preferred Plan performs well among the portfolios analyzed as shown in. Although the portfolio resiliency metric included the highest range, this was driven by the potential costs related to a scenario with high commodity prices over the long-term although these costs are not evident in the first 10 years of the planning horizon under the High Scenario conditions.

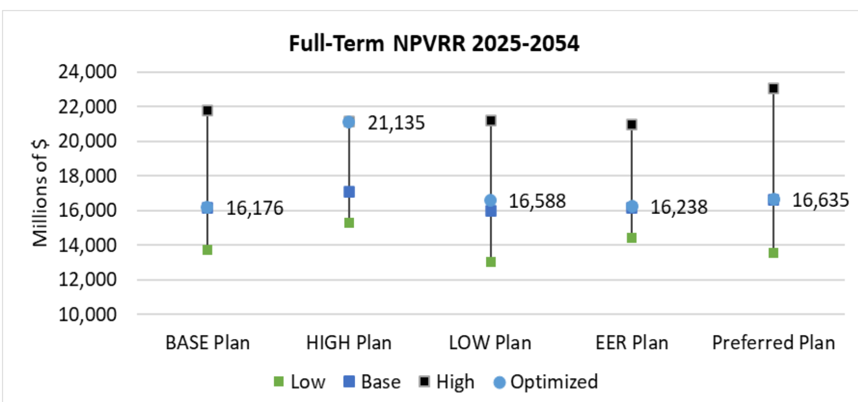


Figure 43 Portfolio Resiliency

The Preferred Plan supports the Company's desire to lessen the reliance on SPP market energy purchases to serve its customers. Under the Preferred Plan, the average market purchases from 2028 through 2034 is estimated to be around 14% of peak load. This is compared to the lowest metric of 10% and the highest metric of 22%. The Preferred Plan provides a path towards mitigating market risks while remaining flexible to leverage low-cost energy from the SPP market during times when there are no market disruptions.

The plan also includes energy resources to leverage the potential for energy sales into the market for the benefit of PSO customers.

9.6.2.3 Maintaining Reliability

The Preferred Plan scored very well among the portfolios analyzed for the Reliability objective. While the Preferred plan carried approximately 18% summer ACAP planning reserves, this was in the middle of the range of results among the plans. With the uncertainty in SPP for the near term, however, carrying this additional reserve will mitigate risks related to quickly evolving requirements by SPP. The Preferred Plan also maintained an equivalent amount of planning reserves in the winter compared to the other portfolios indicating less volatile accredited capacity differences between the seasons.

The Preferred Plan scored well in the Fleet Resiliency metric with the plan including dispatchable resources capable of serving up to 99% of the Company's peak load.

Additionally, the plan scored the highest among the portfolios in the diversity metric. Diversity of resources for both capacity and energy serve to mitigate risks of an over reliance on any one type of resource. The inclusion of storage resources provides the opportunity for PSO to take advantage of the fast-responding dispatch capabilities while the renewable resources provide benefits in terms of low cost, emission free energy that are also eligible for PTCs. Various gas resource types provide differing operating characteristics to serve load as needed when called upon.

9.6.2.4 *Sustainability*

The Preferred Plan, like all of the plans evaluated in the 2024 PSO IRP, provides a pathway towards the continued reduction of CO_2 emissions while also maintaining the reductions in NOx and SO_2 emissions already achieved.

10 Conclusion

PSO's Preferred Plan includes a diverse set of dispatchable and renewable generation resources that bring a broad set of benefits to customers. Collectively, they support the Company's objectives identified in the IRP Performance Indicator Matrix in a holistic manner including maintaining a diverse portfolio of resources that supports an expected seasonal capacity obligation construct within SPP while mitigating potential cost risks to ratepayers in the event future market conditions change.

10.1 Five-Year Action Plan (2025-2029)

Steps to be taken by PSO as part of its Five-Year Action Plan include:

- Complete the evaluation of responses to the Company's November 2023 RFP, and then evaluate a potential future filing to seek approval of new resources.
- Pursue pre-approval of the purchase of the Green Country facility as part of the generation portfolio with the Oklahoma Corporation Commission. The pre-approval application was filed on September 16, 2024.
- Continue to pursue the opportunity to continue operations of the Northeastern Unit 3 using natural gas as its fuel source.
- Continue the planning and regulatory actions to implement cost effective energy efficiency and demand response programs that reduce energy use and peak demand for PSO customers.
- Monitor and evaluate the changes to SPP Resource Adequacy requirements as more information becomes available and issue subsequent RFPs as needed to meet final requirements.
- Given the timeframe to add new generation in SPP and considering the transmission interconnection queue process, PSO will continue to evaluate and implement steps as necessary to ensure a sufficient pipeline of resources consistent with the Preferred Plan that are needed beyond the five-year period.
- Remain committed to closely following developments related to environmental regulations and update our analysis of compliance options and timeliness when sufficient information becomes available.
- Be ready to adjust this Action Plan and future IRPs to reflect changing circumstances.

11 Appendix

Exhibit A: Load Forecast Tables

Exhibit A-1
Public Service Company of Oklahoma
Annual Internal Energy Requirements and Growth Rates
2021-2034

Year	Residential Sales GWH	Residential Sales % Growth	Commercial Sales GWH	Commercial Sales % Growth	Industrial Sales GWH	Industrial Sales % Growth	Other* Energy Requirements GWH	Other* Energy Requirements % Growth	Total Internal Energy Requirements GWH	Total Internal Energy Requirements % Growth
Actual										
2021	6,243	---	4,911	---	5,830	---	2,297	---	19,280	---
2022	6,618	6.0	5,153	4.9	6,073	4.2	2,476	7.8	20,321	5.4
2023	6,138	-7.3	5,190	0.7	5,932	-2.3	2,383	-3.8	19,644	-3.3
Forecast										
2024	6,117	-0.4	5,660	9.0	5,872	-1.0	2,417	1.4	20,065	2.1
2025	6,139	0.4	5,642	-0.3	5,829	-0.7	2,377	-1.7	19,986	-0.4
2026	6,110	-0.5	6,791	20.4	6,035	3.5	2,437	2.5	21,373	6.9
2027	6,103	-0.1	6,790	0.0	6,093	1.0	2,430	-0.3	21,417	0.2
2028	6,079	-0.4	6,764	-0.4	6,162	1.1	2,465	1.4	21,470	0.2
2029	6,058	-0.4	6,736	-0.4	6,231	1.1	2,488	0.9	21,513	0.2
2030	6,034	-0.4	6,694	-0.6	6,291	1.0	2,500	0.5	21,519	0.0
2031	6,008	-0.4	6,652	-0.6	6,343	0.8	2,505	0.2	21,508	-0.1
2032	6,006	0.0	6,650	0.0	6,395	0.8	2,501	-0.2	21,551	0.2
2033	6,013	0.1	6,673	0.4	6,447	0.8	2,471	-1.2	21,605	0.3
2034	6,011	0.0	6,694	0.3	6,498	0.8	2,436	-1.4	21,639	0.2

***Other energy requirements include other retail sales, wholesale sales and losses.**
Note: 2024 data are three months actual and nine months forecast

Average Annual Growth Rates	Residential % Growth	Commercial % Growth	Industrial % Growth	Other* % Growth	Total % Growth
2021-2023	-0.8	2.8	0.9	1.9	0.9
2024-2034	-0.2	1.7	1.0	0.1	0.8

Exhibit A-2
Public Service Company of Oklahoma
Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor
2021-2034

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2021	09/01/21	4,042	---	02/14/21	3,129	---	4,042	---	19,280	---	54.4
2022	07/27/22	4,281	5.9	02/23/22	2,992	-4.4	4,281	5.9	20,321	5.4	54.2
2023	08/21/23	4,287	0.2	12/22/22	3,308	10.5	4,287	0.2	19,644	-3.3	52.3
Forecast											
2024		4,307	0.5		3,263	-1.4	4,307	0.5	20,065	2.1	53.0
2025		4,278	-0.7		2,916	-10.6	4,278	-0.7	19,986	-0.4	53.3
2026		4,471	4.5		3,109	6.6	4,471	4.5	21,373	6.9	54.6
2027		4,476	0.1		3,113	0.1	4,476	0.1	21,417	0.2	54.6
2028		4,481	0.1		3,128	0.5	4,481	0.1	21,470	0.2	54.6
2029		4,469	-0.3		3,133	0.2	4,469	-0.3	21,513	0.2	55.0
2030		4,468	0.0		3,131	-0.1	4,468	0.0	21,519	0.0	55.0
2031		4,464	-0.1		3,126	-0.2	4,464	-0.1	21,508	-0.1	55.0
2032		4,468	0.1		3,143	0.5	4,468	0.1	21,551	0.2	54.9
2033		4,482	0.3		3,160	0.6	4,482	0.3	21,605	0.3	55.0
2034		4,470	-0.3		3,148	-0.4	4,470	-0.3	21,639	0.2	55.3

Notes: 2024 data are three months actual and nine months forecast. The winter 2023/24 peak occurred on January 26, 2024.

Average Annual Growth Rates	Summer Peak % Growth	Winter Peak % Growth	Annual Peak % Growth	Energy % Growth
2021-2023	3.0	2.8	3.0	0.9
2024-2034	0.4	-0.4	0.4	0.8

Exhibit A-3
Public Service Company of Oklahoma
DSM/Energy Efficiency Included in Load Forecast
Energy (GWh) and Coincident Peak Demand (MW)

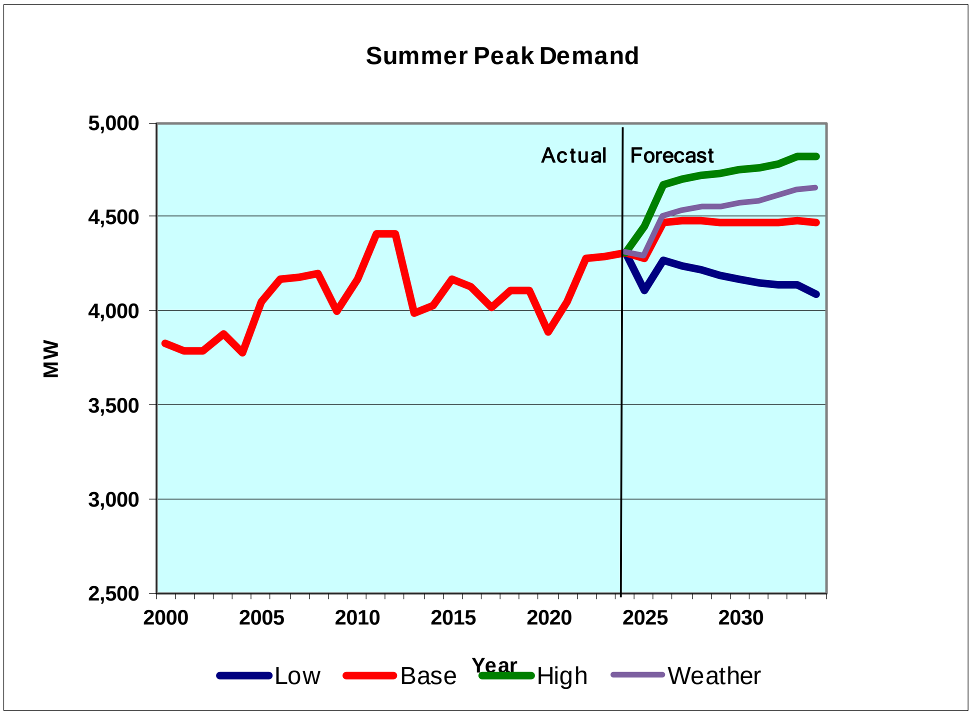
Year	Energy	Summer* Demand	Winter* Demand
2024	19.3	4.0	2.3
2025	37.6	7.8	4.5
2026	57.4	11.9	6.9
2027	77.2	16.0	9.3
2028	97.8	20.2	11.5
2029	116.5	24.0	13.5
2030	127.6	25.6	15.4
2031	148.2	28.4	18.0
2032	137.9	27.2	16.3
2033	121.4	25.1	14.3
2034	122.9	25.3	14.3

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

Exhibit A-4
Public Service Company of Oklahoma
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements

	Winter Peak Internal Demands (MW)			Summer Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	**Low Case**	**Base Case**	**High Case**	**Low Case**	**Base Case**	**High Case**	**Low Case**	**Base Case**	**High Case**
2025	2,796	2,916	3,032	4,103	4,278	4,449	19,167	19,986	20,787
2026	2,964	3,109	3,249	4,262	4,471	4,672	20,374	21,373	22,331
2027	2,949	3,113	3,269	4,239	4,476	4,699	20,285	21,417	22,486
2028	2,947	3,128	3,297	4,221	4,481	4,723	20,229	21,470	22,632
2029	2,938	3,133	3,315	4,190	4,469	4,729	20,172	21,513	22,767
2030	2,922	3,131	3,327	4,170	4,468	4,748	20,086	21,519	22,868
2031	2,906	3,126	3,335	4,150	4,464	4,763	19,995	21,508	22,949
2032	2,911	3,143	3,364	4,139	4,468	4,782	19,966	21,551	23,070
2033	2,914	3,160	3,396	4,132	4,482	4,816	19,918	21,605	23,214
2034	2,881	3,148	3,397	4,091	4,470	4,823	19,804	21,639	23,349
Average Annual Growth Rate % - 2025-2034									
	0.3	0.9	1.3	0.0	0.5	0.9	0.4	0.9	1.3

Exhibit A-5
Public Service Company of Oklahoma
Range of Forecasts



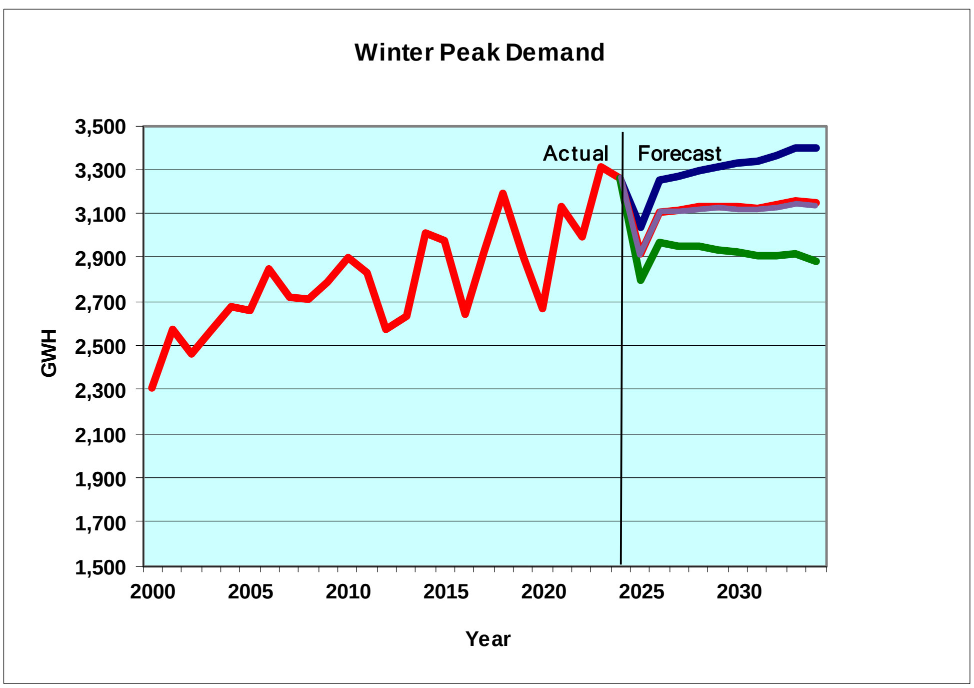


Exhibit A-6
PSO Service Area Electric Vehicle Counts

Year	Low	Base	High
2022	3,978	3,978	3,978
2023	6,050	6,050	6,050
2024	7,583	7,723	7,874
2025	9,489	9,839	10,233
2026	11,620	12,263	13,015
2027	14,058	15,095	16,355
2028	16,850	18,401	20,365
2029	19,622	21,788	24,641
2030	22,389	25,272	29,221
2031	24,936	28,603	33,832
2032	27,428	31,964	38,696
2033	30,239	35,240	42,662
2034	32,798	38,222	46,273

Exhibit A-7
PSO Service Area Solar Installation and Estimated Energy Generation (MWh)

Year	Installations	Energy
2011	30	305
2012	41	424
2013	50	493
2014	73	644
2015	102	810
2016	129	1,017
2017	139	1,089
2018	176	1,276
2019	238	1,620
2020	404	2,373
2021	909	3,975
2022	1,629	6,142
2023	2,982	10,338
2024	4,556	14,981
2025	5,505	17,977
2026	6,471	21,064
2027	7,546	24,484
2028	8,955	28,826
2029	10,596	33,827
2030	12,460	39,459
2031	14,382	45,245
2032	16,278	51,005
2033	18,008	56,376
2034	19,634	61,518

Exhibit B: Detailed Generation Technology Modeling Parameters

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

Type	Design Life (years)	Capability (MW) (e) Std. ISO	Capital Cost (d) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Firm Gas Reservation (j) ($/kW-yr)	Emission Rates SO2 (Lb/mmBtu)	Emission Rates NOx (Lb/mmBtu)	Emission Rates CO2 (Lb/mmBtu)
Base Load										
SMALL MODULAR REACTOR NUCLEAR POWER PLANT, 600 MW	40	600	8,450	10,440	4.46	141.00	-	0.000	0.000	0.0
COMBUSTION TURBINE F CLASS, COMBINED-CYCLE, F- Class	30	770	1,200	6,600	2.76	23.89	14.12	0.001	0.008	117.1
COMBUSTION TURBINE H CLASS, 1100-MW COMBINED CYCLE (RFP)	30	1,030	1,390	6,370	2.57	16.81	13.62	0.001	0.008	117.1
COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT, 430 MW (RFP)	30	420	1,570	6,430	3.51	19.43	13.75	0.001	0.008	117.1
COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT W/90% CO2 CAPTURE, 430 MW (RFP)	40	380	3,670	7,120	8.34	39.43	15.23	0.001	0.008	11.7
Peaking										
COMBUSTION TURBINE F CLASS, 240-MW SIMPLE CYCLE (RFP)	30	230	1,060	9,910	6.09	9.48	21.18	0.001	0.008	117.1
COMBUSTION TURBINES AERODERIVATIVE, 100-MW SIMPLE CYCLE (RFP)	30	110	1,660	9,120	6.36	22.07	19.51	0.001	0.008	117.1
INTERNAL COMBUSTION ENGINES, 20 MW (RFP)	30	20	2,580	8,300	7.70	47.59	17.74	0.001	0.042	110.0
Intermittent										
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 200 MWH, 4hr (RFP)	20	50	1,850	-	0.00	53.11	-	-	-	-
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 300 MWH, 6hr (RFP)	20	50	2,370	-	0.00	79.66	-	-	-	-
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 400 MWH, 8hr (RFP)	20	50	3,550	-	0.00	106.21	-	-	-	-
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 500 MWH, 10hr (RFP)	20	50	4,540	-	0.00	132.76	-	-	-	-
ONSHORE WIND, LARGE PLANT FOOTPRINT, 200 MW	30	200	2,290	-	0.00	35.86	-	-	-	-
SOLAR PHOTOVOLTAIC, 150 MWAC	35	150	2,080	-	0.00	15.86	-	-	-	-
SOLAR PHOTOVOLTAIC WITH BATTERY ENERGY STORAGE SYSTEM, 150 MWx200 MWh	35	150	2,660	-	0.00	39.54	-	-	-	-

Notes: (a) Costs and performance data informed by EIA report Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies
(b) Capital & Installed cost, capability and heat rate numbers have been rounded
(c) All costs in In Service dollars, except as noted.
(d) $/kW costs are based on summer capability
(e) All Capabilities adjusted by the Performance Adjustment Factors defined in the reference report (a)
(i) Capital costs informed through Company RFP responses
(j) Firm Gas Reservation costs assume 0.2441/MMBtu.

Exhibit C: Capacity, Demand and Reserves - "Going-in"

Public Service of Oklahoma

Capability, Demand, and Reserve Forecast

2024-2034

SUMMER

CAPABILITY - Summer	Capacity Type											
	Plant Capabilities	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
	OKLAUNION 1	0	0	0	0	0	0	0	0	0	0	0
	COMANCHE 1	173	173	149	149	149	149	149	149	149	149	149
	NORTHEASTERN 1	419	419	397	397	397	397	397	397	397	397	397
	NORTHEASTERN 2	435	435	376	376	376	376	376	376	376	376	376
	NORTHEASTERN 3	472	472	420	0	0	0	0	0	0	0	0
	RIVERSIDE 1	431	431	329	329	329	329	329	329	329	329	329
	RIVERSIDE 2	448	448	424	424	424	424	424	424	424	424	424
	RIVERSIDE 3	73	73	71	71	71	71	71	71	71	71	71
	RIVERSIDE 4	74	74	71	71	71	71	71	71	71	71	71
	SOUTHWESTERN 1	56	56	49	49	49	49		0	0	0	0
	SOUTHWESTERN 2	79	79	78	78	78	78		0	0	0	0
	SOUTHWESTERN 3	311	311	289	289	289	289	289	289	289	289	289
	SOUTHWESTERN 4	71	71	71	71	71	71	71	71	71	71	71
	SOUTHWESTERN 5	71	71	71	71	71	71	71	71	71	71	71
	TULSA 2	159	159	123	123	123	123	123	123	123	123	123
	TULSA 4	158	158	149	149	149	149	149	149	149	149	149
	WELEETKA 4	35	35	29	29	29	29		0	0	0	0
	WELEETKA 5	35	35	34	34	34	34		0	0	0	0
	WELEETKA 6	0	0	0	0	0	0	0	0	0	0	0
	SUNDANCE	22	22	22	22	22	22	22	22	22	22	22
	MAVERICK	20	20	20	20	20	20	20	20	20	20	20
	TRAVERSE	69	69	69	69	69	69	69	69	69	69	69
1 (Summer)	**TOTAL**	**3,611**	**3,611**	**3,240**	**2,820**	**2,820**	**2,820**	**2,631**	**2,631**	**2,631**	**2,631**	**2,631**
	Adjustments to Plant Capability	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
	Green Country (Owned)	0	453	596	786	786	786	786	786	786	786	786
	Rockfalls	18	26	26	26	26	25	25	25	25	25	25
	Goodyear		0	0	0	0	0	0	0	0	0	0
	Pixley		136	136	136	136	134	134	134	134	132	132
	Lazbuddie			45	45	45	42	42	42	42	42	42
	Algodon			108	108	108	107	107	107	107	105	105
	Chisholm Trail			0	75	75	73	73	73	73	72	72
	Flat Ridge IV		23	23	23	23	22	22	22	22	22	22
	Flat Ridge V		26	26	26	26	24	24	24	24	24	24
2	**TOTAL**	**18**	**664**	**960**	**1,225**	**1,225**	**1,213**	**1,213**	**1,213**	**1,213**	**1,209**	**1,209**
3 (Summer)	**Net Plant Capability (1 + 2)**	**3,629**	**4,275**	**4,200**	**4,045**	**4,045**	**4,033**	**3,844**	**3,844**	**3,844**	**3,840**	**3,840**
	Off-System Sales Without Reserves											
4	**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Purchases Without Reserves	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
	BALKO WIND	67	67	67	67	67	67	67	67	67	67	67
	GOODWELL WIND	75	75	75	75	75	75	75	75	75	75	75
	SEILING WIND	56	56	56	56	56	56	56	56	56	56	56
	MINCO WIND	19	19	19	19	19	19	19	0	0	0	0
	ELK CITY WIND	17	17	17	17	17	17	0	0	0	0	0
	BLUE CANYON V WIND Delv. Cap.	0	0	0	0	0	0	0	0	0	0	0
	BLUE CANYON V WIND Firm Cap.	15	15	15	15	15	15	0	0	0	0	0
	SLEEPING BEAR WIND	7	7	7	7	7	7	7	7	7	0	0
	WEATHERFORD WIND	30	30	0	0	0	0	0	0	0	0	0
	EXELON GREEN COUNTRY (J POWER)	569										
	CALPINE	260	260	260	260	260	260	260	0	0	0	0
	Oneta	160	300									
	Kiowa Kiamichi	75	150	150								
	Tenaska Eastman	50	50	50								
	Buckeye	10	10	10	10							
	Jayhawk	19	19	19	19							
	Upstream			42	42							
	Thunderhead			26	26							
5 (Summer)	**TOTAL**	**1,429**	**1,075**	**813**	**613**	**516**	**516**	**484**	**205**	**205**	**198**	**198**
6 (Summer)	**Total Capability (3 - 4 + 5)**	**5,058**	**5,350**	**5,013**	**4,658**	**4,561**	**4,549**	**4,328**	**4,049**	**4,049**	**4,038**	**4,038**

SUMMER

DEMAND		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
A	**Peak Demand Before Passive DSM**											
	Original Forecast	4,305	4,275	4,469	4,473	4,478	4,466	4,467	4,466	4,468	4,481	4,468
	Coffeyville, City of	2.67	2.69	2.70	2.71	2.72	2.73	2.74	2.75	2.75	2.76	2.77
		4,307	**4,278**	**4,471**	**4,476**	**4,481**	**4,469**	**4,469**	**4,469**	**4,471**	**4,483**	**4,471**
B	**Passive DSM**											
	APPROVED DSM PROGRAMS	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00
	VOLT-VAR OPTIMIZATION (VVO)	4	8	12	16	20	24	24	24	24	24	24
	AMI (METERING (DLC/TOU)	21	7	3	3	12	12	12	12	12	12	12
	TOTAL	**25**	**15**	**15**	**19**	**32**	**36**	**36**	**36**	**36**	**36**	**36**
C	**Peak Demand (A - B)**	**4,282**	**4,264**	**4,456**	**4,457**	**4,448**	**4,433**	**4,434**	**4,433**	**4,435**	**4,447**	**4,435**
D	**Active DSM**											
	APPROVED DR PROGRAMS	54	24	12	12	75	77	77	77	77	77	77
	SPECIAL CONTRACT (ABOVE FIRM)	26	7	4	4	0	0	0	0	0	0	0
	TOTAL	**80**	**32**	**16**	**16**	**75**	**77**	**77**	**77**	**77**	**77**	**77**
E	**Firm Demand (C - D)**	**4,202**	**4,232**	**4,440**	**4,441**	**4,373**	**4,356**	**4,356**	**4,356**	**4,358**	**4,370**	**4,358**
F	**Other Demand Adjustments**											
	DIVERSITY	42	42	41	39	38	38	38	37	36	36	36
	TOTAL	**42**	**42**	**41**	**39**	**38**	**38**	**38**	**37**	**36**	**36**	**36**
7	**Native Load Responsibility (E - F)**	**4,160**	**4,190**	**4,400**	**4,402**	**4,335**	**4,317**	**4,319**	**4,319**	**4,322**	**4,335**	**4,322**
	Off System Sales With Reserves											
8	**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Purchases With Reserves											
	PSO - SWPA ENTITLEMENT	39	39	39	39	39	39	39	39	39	39	39
9	**TOTAL**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**
10	**Load Responsibility (7 + 8 - 9)**	**4,121**	**4,151**	**4,361**	**4,363**	**4,296**	**4,278**	**4,280**	**4,280**	**4,283**	**4,296**	**4,283**

RESERVES - Summer		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
11 (Summer)	**Reserve Capacity (6 - 10)**	**937**	**1,199**	**652**	**295**	**265**	**271**	**48**	**-231**	**-234**	**-258**	**-245**
12 (Summer)	**% Reserve Margin ((11/10) *100)**	**22.7**	**28.9**	**15.0**	**6.8**	**6.2**	**6.3**	**1.1**	**-5.4**	**-5.5**	**-6.0**	**-5.7**
13 (Summer)	**% Capacity Margin (11/(6) *100)**	**18.5**	**22.4**	**13.0**	**6.3**	**5.8**	**6.0**	**1.1**	**-5.7**	**-5.8**	**-6.4**	**-6.1**
14 (Summer) (1	**Reserve Above Minimum SPP Reserve Margin (MW)**	**319**	**576**	**433**	**76**	**49**	**56**	**(167)**	**(446)**	**(449)**	**(474)**	**(461)**
14a (Summer)	**Reserves Above Target Reserve Margin**	**30**	**285**	**171**	**(186)**	**(209)**	**(201)**	**(424)**	**(703)**	**(706)**	**(732)**	**(718)**

WINTER

uel Typ	pacity Ty	Plant Capabilities	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
atural G	m Capac	COMANCHE 1	173	173	151	151	151	151	151	151	151	151	151
atural G	m Capac	NORTHEASTERN 1	419	419	281	281	281	281	281	281	281	281	281
atural G	m Capac	NORTHEASTERN 2	435	435	312	312	312	312	312	312	312	312	312
Coal	m Capac	NORTHEASTERN 3	472	472	0	0	0	0	0	0	0	0	0
atural G	m Capac	RIVERSIDE 1	431	431	262	262	262	262	262	262	262	262	262
atural G	m Capac	RIVERSIDE 2	448	448	301	301	301	301	301	301	301	301	301
atural G	m Capac	RIVERSIDE 3	73	73	66	66	66	66	66	66	66	66	66
atural G	m Capac	RIVERSIDE 4	74	74	65	65	65	65	65	65	65	65	65
atural G	m Capac	SOUTHWESTERN 1	56	56	46	46	46	46	46		0	0	0
atural G	m Capac	SOUTHWESTERN 2	79	79	70	70	70	70	70		0	0	0
atural G	m Capac	SOUTHWESTERN 3	311	311	276	276	276	276	276	276	276	276	276
atural G	m Capac	SOUTHWESTERN 4	71	71	66	66	66	66	66	66	66	66	66
atural G	m Capac	SOUTHWESTERN 5	71	71	67	67	67	67	67	67	67	67	67
atural G	m Capac	TULSA 2	159	159	136	136	136	136	136	136	136	136	136
atural G	m Capac	TULSA 4	158	158	132	132	132	132	132	132	132	132	132
atural G	m Capac	WELEETKA 4	35	35	19	19	19	19	19		0	0	0
atural G	m Capac	WELEETKA 5	35	35	16	16	16	16	16		0	0	0
Wind	rable Ca	SUNDANCE	22	22	22	22	22	22	22	22	22	22	22
Wind	rable Ca	MAVERICK	20	20	20	20	20	20	20	20	20	20	20
Wind	rable Ca	TRAVERSE	69	69	69	69	69	69	69	69	69	69	69
1 (Winter)		**TOTAL**	**3,611**	**3,611**	**2,374**	**2,374**	**2,374**	**2,374**	**2,374**	**2,223**	**2,223**	**2,223**	**2,223**
uel Typ	**pacity Ty**	**Adjustments to Plant Capability**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
atural G	m Capac	Green Country (owned)		476	564	764	764	764	764	764	764	764	764
Wind	m Capacity	Rockfalls	29	31	29	29	29	29	29	29	29	29	29
Solar	m Capacity	Pixley		36	36	32	32	28	28	26	25	25	25
Wind	m Capacity	Lazbuddie			50	50	50	50	50	50	50	50	50
Solar	m Capacity	Algodon			29	26	26	23	23	21	20	20	20
Solar	m Capacity	Chisholm Trail			20	18	18	16	16	14	13	13	13
Wind	m Capacity	Flat Ridge IV		27	26	26	26	26	26	26	26	26	26
Wind	m Capac	Flat Ridge V		31	29	29	29	29	29	29	29	29	29
2		**TOTAL**	**29**	**600**	**782**	**973**	**973**	**964**	**964**	**960**	**955**	**955**	**955**
3 (Winter)		**Net Plant Capability (1 + 2)**	**3,640**	**4,211**	**3,156**	**3,347**	**3,347**	**3,338**	**3,338**	**3,183**	**3,179**	**3,179**	**3,179**
		Off-System Sales Without Reserves											
4		**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
uel Typ	**pacity Ty**	**Purchases Without Reserves**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Wind	m Capacity	BALKO WIND	67	67	67	67	67	67	67	67	67	67	67
Wind	m Capacity	GOODWELL WIND	75	75	75	75	75	75	75	75	75	75	75
Wind	m Capacity	SEILING WIND	56	56	56	56	56	56	56	56	56	56	56
Wind	m Capacity	MINCO WIND	19	19	19	19	19	19	19	0	0	0	0
Wind	m Capacity	ELK CITY WIND	17	17	17	17	17	17	0	0	0	0	0
Wind	m Capacity	BLUE CANYON V WIND Firm Cap.	15	15	15	15	15	15	0	0	0	0	0
Wind	m Capacity	SLEEPING BEAR WIND	7	7	7	7	7	7	7	7	7	0	0
Wind	rable Capacity	WEATHERFORD WIND	30	30	0	0	0	0	0	0	0	0	0
ermal P	rable Ca	EXELON GREEN COUNTRY	569										
ermal P	m Capacity	CALPINE	260	260	260	260	260	260	260	0	0	0	0
ontracte	m Capacity	Oneta	160	300									
ontracte	m Capacity	Kiowa Kiamichi	75	150	150								
ontracte	m Capacity	Tenaska Eastman	50	50	50								
ontracte	m Capacity	Buckeye	9	9	9	9							
ontracte	m Capacity	Jayhawk	20	20	20	20							
ontracte	m Capacity	Upstream			26	26							
ontracte	m Capacity	Thunderhead			31	31							
5 (Winter)		**TOTAL**	**1,429**	**1,075**	**802**	**602**	**516**	**516**	**484**	**205**	**205**	**198**	**198**
6 (Winter)		**Total Capability (3 - 4 + 5)**	**5,068**	**5,285**	**3,958**	**3,949**	**3,863**	**3,854**	**3,822**	**3,388**	**3,384**	**3,377**	**3,377**

WINTER

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
DEMAND												
A	**Peak Demand Before Passive DSM**											
	Original Forecast	3,262	2,914	3,108	3,112	3,127	3,132	3,131	3,129	3,144	3,160	3,148
	Coffeyville, City of	1.49	1.22	1.23	1.23	1.38	1.28	1.28	1.29	1.29	1.41	1.67
		3,263	**2,916**	**3,109**	**3,113**	**3,128**	**3,133**	**3,132**	**3,130**	**3,145**	**3,161**	**3,149**
B	**Passive DSM**											
	APPROVED DSM PROGRAMS	0	0	0	0	0	0	0	0	0	0	0
	VOLT-VAR OPTIMIZATION (VVO)	0	5	7	9	11	13	13	13	13	14	13
	AMI (METERING (DLC/TOU)	0	7	3	3	3	0	0	0	0	0	0
	TOTAL	**0**	**11**	**10**	**13**	**15**	**14**	**13**	**13**	**13**	**14**	**13**
C	**Peak Demand (A - B)**	**3,263**	**2,904**	**3,099**	**3,101**	**3,113**	**3,119**	**3,119**	**3,117**	**3,132**	**3,147**	**3,136**
	APPROVED DR PROGRAMS	0	24	12	12	12	0	0	0	0	0	0
	SPECIAL CONTRACT (ABOVE FIRM)	0	7	4	4	4	0	0	0	0	0	0
	TOTAL	**0**	**32**	**16**	**16**	**16**	**0**	**0**	**0**	**0**	**0**	**0**
E	**Firm Demand (C - D)**	**3,263**	**2,873**	**3,083**	**3,085**	**3,097**	**3,119**	**3,119**	**3,117**	**3,132**	**3,147**	**3,136**
F	**Other Demand Adjustments**											
	DIVERSITY	-1	110	118	120	137	129	131	132	139	156	145
	TOTAL	**-1**	**110**	**118**	**120**	**137**	**129**	**131**	**132**	**139**	**156**	**145**
7	**Native Load Responsibility (E - F)**	**3,264**	**2,762**	**2,965**	**2,965**	**2,960**	**2,991**	**2,988**	**2,985**	**2,993**	**2,991**	**2,990**
	Off System Sales With Reserves											
8	**TOTAL**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Purchases With Reserves											
9	**TOTAL**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**	**39**
10	**Load Responsibility (7 + 8 - 9)**	**3,225**	**2,723**	**2,926**	**2,926**	**2,921**	**2,952**	**2,949**	**2,946**	**2,954**	**2,952**	**2,951**
RESERVES - Winter		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
11 (Winter)	**Reserve Capacity (6 - 10)**	**1,844**	**2,562**	**1,032**	**1,023**	**942**	**902**	**873**	**442**	**429**	**425**	**425**
12 (Winter)	**% Reserve Margin ((11/10) * *100*)**	**57.2**	**94.1**	**35.3**	**35.0**	**32.2**	**30.6**	**29.6**	**15.0**	**14.5**	**14.4**	**14.4**
13 (Winter)	**% Capacity Margin (11/(6) * *100*)**	**36.4**	**48.5**	**26.1**	**25.9**	**24.4**	**23.4**	**22.8**	**13.0**	**12.7**	**12.6**	**12.6**
14 (Winter)	**Reserve Above Reserve Margin (MW)**	**1360**	**2154**	**685**	**617**	**479**	**375**	**346**	**(84)**	**(98)**	**(103)**	**(102)**
14a (Winter) P	**Reserves Above Target Reserve Margin**	**1134**	**1963**	**509**	**442**	**303**	**198**	**169**	**(261)**	**(276)**	**(280)**	**(279)**

Exhibit D: 2021 PSO Fuel Supply Portfolio and Risk Management Plan

Public Service Company of Oklahoma

2024 Fuel Supply Portfolio and Risk Management Plan

May 15, 2024

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12.1.1 Introduction

Organized in Oklahoma in 1913, Public Service Company of Oklahoma (PSO or “the Company) is engaged in the generation, transmission, and distribution of electric power to approximately 578,000 retail customers in eastern and southwestern Oklahoma, and in supplying electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives, and other market participants. PSO owns 4,515 MWs of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2023, PSO had 1,062 employees. Among the principal industries served by PSO are paper manufacturing, oil and gas extraction, petroleum and coal products manufacturing, transportation equipment and pipeline transportation. PSO is a member of the Southwest Power Pool (SPP) and is part of AEP’s Vertically Integrated Utilities segment.

Under Order No. 454610, Cause No. PUD 200100096, PSO provides this Fuel Supply Portfolio and Risk Management Plan (Plan) on an annual basis. This document sets forth PSO’s plan to provide reliable and flexible sources of fuel and energy for its customers at the lowest reasonable delivered cost.

PSO is a member of the SPP, a Regional Transmission Organization (RTO) that is mandated by the Federal Energy Regulatory Commission (FERC) to provide reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity.

The SPP Integrated Market Place (IM) is a wholesale power market that consists of Day-Ahead, Real-time, and Ancillary Service markets. PSO has continued to be an active participant in all of the various SPP IM markets and continues to be an active stakeholder and advocate for its customers as it works with SPP to fine tune its market process. PSO actively manages changes in unit commitment, fuel procurement, unit dispatch, operating reserve procurement, transmission congestion management, and power settlement within the SPP IM.

In the SPP IM Day-Ahead market, market participants submit offers to sell energy and ancillary services, and load-serving entities submit day-ahead bids for load. PSO is required to offer sufficient available generating capacity into the market to cover its native load, but that capacity may or may not be selected for dispatch based on economics and reliability requirements. Available units that are not selected in the Day-Ahead market may still be called on in the Real-Time market. Additionally, market resources may choose to self-commit to ensure participation in the market. Using security-constrained economic dispatch algorithms, SPP clears the bids and offers and produces a financially binding schedule that matches generation offers with demand bids, while satisfying operating reserve requirements. The differences between the established obligations from the Day-Ahead market are settled in the Real-Time market, which balances generation with load and establishes real-time locational marginal prices every five minutes. The operating reserve market provides for Regulation Reserve, Spinning Reserve, and Supplemental Reserves. As with the energy market, the operating reserve market is also a multi-settlement market clearing in the Day-Ahead with deviations being settled in the Real-Time market. The market also allows virtual bidding, which essentially trades Day-Ahead prices with Real-Time prices. While these trades occur in the SPP market, they do not involve taking a physical position as each buy (or sell) in the Day-Ahead market will be a sell (or buy) in the Real-Time market. Such transactions have the effect of causing the Day-Ahead market and the Real-Time market prices to converge. PSO continuously works to ensure the most economic resources serve PSO's native load customers within the framework of the SPP IM.

12.1.1.1 Planning Objective

PSO's 2024 Plan is designed to ensure sufficient quantities of fuel and power are available to meet customer needs safely and reliably, under dynamic conditions, while striving to provide the over-all lowest reasonable delivered cost. In other words, PSO's fuel and purchased power procurement is first and foremost focused on the reliability of supply at the lowest reasonable delivered cost.

12.1.1.2 Resources and Capabilities

Generation

PSO's generating fleet is composed of natural gas power plants, wind resources and one coal-fired unit, as summarized in Exhibit 1.

Exhibit 1: Plant Capacity

Plant Name	Fuel Type	Net Maximum Capacity (MW)
Comanche	Natural Gas	237
Northeastern, Units 1 and 2	Natural Gas	904

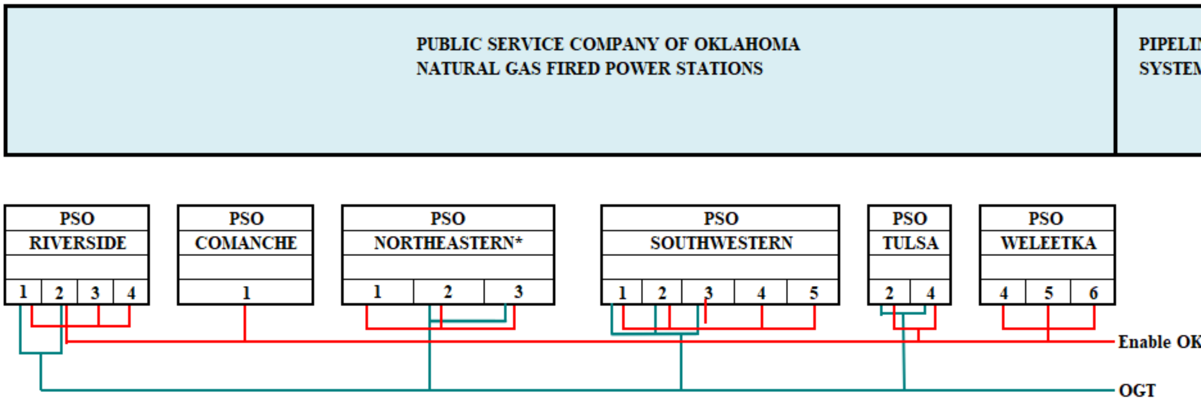
Riverside	Natural Gas	1,056
Southwestern	Natural Gas	614
Weleetka	Natural Gas	84
Northeastern, Unit 3	Coal†	472
Tulsa	Natural Gas	318
Sundance	Wind	90*
Maverick	Wind	131*
Traverse	Wind	454*
Rock Falls	Wind	155
Total		4,515

*North Central Energy Facilities (NCEF) project figures reflect only the 45.5 percent owned by PSO. The NCEF is a joint wind project with Southwestern Electric Power Company (SWEPCO) that includes Sundance (199 MW), Maverick (287 MW), and Traverse (999 MW; in-service date was March 18, 2022).

†PSO can also use natural gas to operate Northeastern Unit 3 in the event of coal unavailability or coal-related equipment outages.

Comanche, Northeastern Unit 1, Riverside Units 3 and 4, Southwestern Units 4 and 5, and Weleetka, are each connected to one pipeline system. Northeastern Units 2 and 3, Riverside Units 1 and 2, Southwestern Units 1, 2, and 3, and Tulsa Units 2 and 4 are each connected to two pipeline systems. These multiple natural gas pipeline connections provide the Company with access to reliable, flexible, and competitively priced natural gas supplies. The natural gas pipeline interconnections to each of PSO's natural gas plants are shown in Exhibit 2.

Exhibit 2: Existing Natural Gas Pipeline Interconnections to PSO



*Enable OK and OGT provide low pressure service to the Northeastern Plant Site which serves the generation needs for Unit 2, duct burner gas to Unit 1, and startup or emergency generation replacement fuel for Coal Unit 3.

Similarly, Northeastern Unit 3 has access to two competing rail carriers for coal deliveries from the Powder River Basin (PRB) in Wyoming. However, Union Pacific (UP) is contracted to provide coal deliveries to the Northeastern power plant through the end of life of the plant.

Purchased Power

PSO's purchased power activities extend beyond direct participation in the SPP IM. American Electric Power Service Corporation (AEPSC), on behalf of PSO, continues to directly engage with a variety of third-party market participants in the procurement of capacity and energy contracts. AEPSC's Commercial Operations' employees leverage a broad cross-section of operations and market knowledge to optimize the PSO system. Purchased Power Agreements (PPAs) for capacity and firm energy that are entered into by PSO also utilize primarily Oklahoma resources.

Renewable Energy

Wind energy provides PSO's customers with a power supply that has very little correlation to fossil fuel prices and a hedge against current as well as future environmental compliance requirements related to fossil-fired generation.

12.1.2 Procurement Strategy

12.1.2.1 Background and Strategy

PSO's overall procurement strategy is to assure reliable, adequate, flexible, and competitively priced fuel supplies and transportation, as well as purchased power, at the lowest reasonable delivered cost to PSO's customers. To accomplish this objective, PSO maintains a portfolio of fuel and power supply contracts with varying contract terms.

Even within the context of the SPP IM, the flexibility in PSO's fuel supply plan and the diversity of its generating fleet continue to allow the Company to optimize its generation resources to take advantage of spot market fuel and purchased power opportunities, while maintaining reliability of service to its customers. PSO's diversified generation and balanced fuel supply portfolio has been an important part of its risk management plan for many years. Throughout PSO's history, fuel diversity has primarily been achieved through the traditional use of both coal and natural gas. However, with changes in environmental regulations, the SPP IM, and the PSO generation fleet, PSO is addressing the positive attributes of fuel diversity in a more comprehensive way. Mitigating price risk includes renewables, more efficient generation, demand side resources, and other programs. PSO continues to monitor its coal, natural gas, and purchased power pricing risk and takes steps such as those described later in Section III subpart A. Hedging, to mitigate risk and ensure adequate resources.

12.1.2.2 Coal Procurement Plan

PSO's strategy is to assure reliable, flexible, and competitively priced fuel supply and transportation agreements. The coal and transportation procurement process for PSO uses a competitive bidding process from which the offers are evaluated and selected. PSO strategically layers in long-term and short-term agreements to meet the coal requirements at the time of each evaluation and as market conditions dictate. The transportation agreement with the UP Railroad for PSO's Northeastern Plant was amended in 2023 and was extended through 2026.

PSO maintains coal inventory at the Northeastern Plant to assure the plant is available to operate during disruptions of coal supply, transportation, or unloading equipment. In addition to mitigating supply risks, inventory allows PSO the flexibility to take advantage of favorable market conditions when present. Lastly, the inventory serves as a physical hedge during times of coal market volatility. PSO establishes an inventory target aimed at balancing cost and reliability. Inventory targets are reviewed on an annual basis to assure the target meets the current conditions of both the market and PSO.

12.1.2.3 Natural Gas Procurement Plan

The SPP IM has increased its utilization of PSO's natural gas-fired generating units in each of the last two calendar years. While PSO expects to experience similar levels of natural gas consumption going forward, it also recognizes the potential for change, associated with adding renewables to its portfolio, along with the overall shifting generation mix.

As a result of recent market volatility, PSO has shifted strategy and is purchasing greater quantities of forward-month, fixed price, baseload natural gas supply. These purchases aim to better insulate customers from sharp natural gas price increases. PSO continually reviews expected natural gas requirements and issues forward-month request for proposals (RFP) to secure baseload supply. In addition to forward-month baseload supply, prompt month natural gas supply agreements will also be considered and pursued in 2024. Prompt month baseload natural gas supply will be secured through an RFP process as well and will be based on a fixed price or a first-of-month index price. PSO remains active in the daily natural gas market, and supplements baseload supply, as needed, with daily spot market purchases. PSO will continue to stay abreast of market changes, including any new potential natural gas suppliers that can be solicited.

PSO uses competitive bidding and competitive market offers for natural gas transportation services. PSO negotiates transportation arrangements with connected pipelines for swing service beyond its daily nominations to meet its peak instantaneous, hourly, and daily demands. For 2024, PSO has a firm transportation agreement with Enable Oklahoma Intrastate Transmission, LLC (Enable OK) that can serve all of PSO's natural gas units. In addition, PSO has interruptible transportation agreements with both Enable OK and ONEOK Gas Transportation, LLC (OGT" or "ONEOK). If the economics are favorable, PSO will explore the possibility of procuring seasonal firm transportation from OGT during the peak summer months.

PSO also uses competitive bidding and competitive market offers for natural gas storage services. For 2024, PSO has a firm storage agreement in place with Enable OK. This agreement expires on March 31, 2025, thus PSO will be issuing an RFP to solicit bids for storage service beyond that date. PSO will endeavor to optimize the value of its natural gas storage contract throughout each calendar year, based on prompt market conditions. However, regardless of the injection and withdrawal strategy that is ultimately pursued, PSO will seek to maximize its total storage capacity by December 15 of each year.

12.1.2.4 Purchased Power Plan

The purchased power strategy is to have a diverse mix of transactions with a wide range of counterparties. PPAs, along with PSO's wind Renewable Energy Purchase Agreements (REPAs), demonstrate PSO's utilization of cost-effective, long-term purchased power opportunities. PSO will continue to be actively engaged in all areas of the SPP IM and pursue activities to optimize its participation in those markets. The holistic and active management of the whole range of purchased power opportunities will provide the operational flexibility to effectively respond to a wide range of possible market scenarios.

12.1.2.5 Consumables (Reagents) Plan

PSO utilizes consumables, also known as environmental reagents, at Northeastern Unit 3. Reagents are products that are introduced into the flue gas stream to reduce emissions from the process to levels that adhere to environmental regulations.

Northeastern Unit 3 uses two consumable products. Brominated activated carbon (AC) is utilized for the capture of mercury. Sodium Bicarbonate (SBC) is employed for SO_2 and hydrogen chloride (HCl) mitigation.

As with the procurement of fuels, PSO purchases reagents through a competitive bid process to ensure that products with the required specifications are purchased at the lowest reasonable delivered cost.

12.1.3 Risk Management

12.1.3.1 Hedging

The primary objective of PSO's hedging strategy is to reduce fuel and purchased power price volatility experienced by customers. In many respects, a hedging strategy is similar to insurance. A successful hedging program can effectively mitigate the risk of fuel cost and power price volatility, but it also comes with a cost and can limit potential fuel cost decreases if prices fall or remain unchanged.

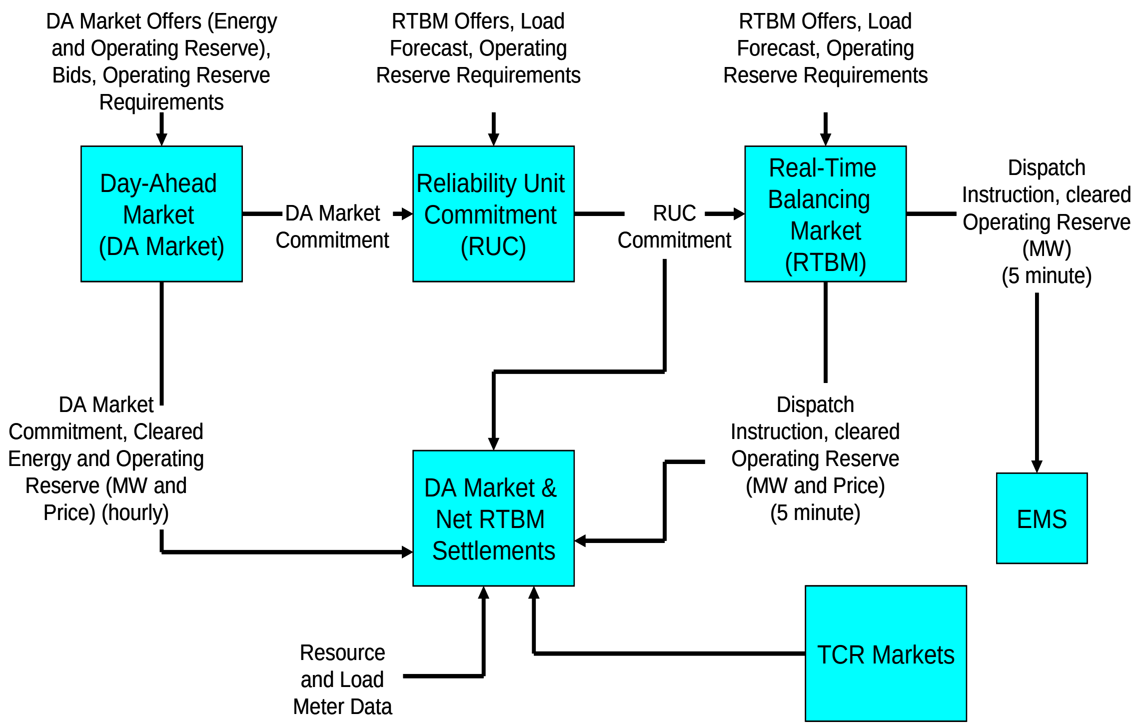
PSO's primary means of hedging to reduce fuel price volatility is through a portfolio of renewable energy, physical coal, and natural gas supply agreements of various durations. All such physical transactions are secured through a competitive RFP process.

Financial hedging, through the use of forward market contracts, is aimed at reducing volatility but could potentially increase the overall fuel cost based on transaction costs and premiums required to lock in pricing. Pursuant to Case No. 2022-000093, Order No. 738226, part 12 of the stipulation states: "The stipulating parties agreed to work together to develop a financial hedging pilot program to be proposed within 180 days of the final order in this case. PSO agreed to work with all parties in this proceeding to make this filing." PSO has been developing a comprehensive hedging strategy that incorporates financial products, in addition to the physical products identified in the previous paragraph. On April 3, 2024, PSO hosted a stakeholder meeting discussing the details of its plan to incorporate such financial products. PSO plans to draft testimony, going into even greater detail, during the upcoming, annual fuel review filing.

12.1.3.2 Resource Optimization

AEPSC's purchased power and optimization activities are instrumental in how PSO manages fuel and energy price risks and minimizes costs for its customers. The SPP IM has expanded the range and impact of that role. The SPP IM requires a significant level of attention to detail and market intelligence to optimize PSO's resources and serve its load. Exhibit 3 illustrates the process design relationship between the market processes in which AEPSC participates on behalf of PSO.

Exhibit 3: Integrated Marketplace Process Design Relationships



SPP's Day-Ahead Market is a financially binding market whose purpose is to match the set of market supply and market demand made available, which clears for the next Operating Day. The Reliability Unit Commitment (RUC) is an operationally binding process whose purpose is to ensure there are adequate resources to satisfactorily cover the RTO load and reliability forecasts. There is a Day-Ahead RUC that exists for the same time period as the Day-Ahead Market as well as an Intra-Day RUC that exists for the balance of the operating day. The Real-Time Balancing Market is a financially and operationally binding market clearing every 5 minutes with a purpose of ensuring that market resources committed through the RUC process are dispatched according to Real-Time load requirements. The Reserve Market, which is integrated within the Day-Ahead Market, RUC process and the Real-Time Balancing Market through co-optimization, ensures that adequate ancillary service products are procured so that the system can smoothly respond to contingencies. The Auction Revenue Rights (ARR) Process/Transmission Congestion Rights (TCR) Market, which clears annually and monthly, provides market participants with a mechanism to be pro-active and hedge against anticipated Day-Ahead market congestion, or increase financial benefits. Finally, the Settlement Process provides market participants with a measure of the financial benefits associated with their participation in the Day-Ahead and Real-Time Balancing Markets.

Congestion occurs in situations where the desired amount of electricity is unable to flow due to either physical or effective limitations. This impairs SPP's ability to use the least cost electricity to meet demand. The cost of congestion is included in the locational marginal prices (LMPs) and can be seen in the price difference between source (generation point) and sink (load point). The continued rise in wind generation within the SPP footprint is one of the major drivers of increased congestion costs. AEPSC is tasked with optimizing source-sink path selections in the ARR and TCR market in order to financially hedge day-ahead congestion and reduce the net congestion costs charged to PSO.

PSO actively optimizes its SPP IM participation by maintaining the efficiency and availability of its generators, securing low-cost fuel, performing proper scheduling of down times, and responding to price signals established by the market. Commitment of generating units through the SPP IM will likely continue to create additional uncertainties from a resource and fuel procurement standpoint, which creates more risks in arranging bilateral sales. The ability of the Commercial Operations personnel to get the most value for PSO's generating resources also enables them to maximize the off-system sales margins for the benefit of PSO's customers.

An additional issue that increasingly impacts resource optimization is the lack of harmonization between the natural gas and electric industries. Due to coal generation retirements in response to environmental regulations, as well as shale gas developments, U.S. reliance on gas-fired electric generation has grown over the last several years. This increased reliance on natural gas amplifies the need for continued improvements in coordination between the electric and natural gas industries. Although some coordination issues have been addressed by the FERC, challenges remain including market scheduling and fuel security. For example, once a unit has been committed to the SPP IM market, SPP has the ability to extend unit awards with only minutes notice impacting the amount of fuel required. The timing of the notice (duration or time of day) may not allow the unit operator to purchase and schedule additional needed fuel supply possibly forcing the unit offline. AEP continues to work with SPP (and others) on these market protocol issues.

12.1.3.3 Contract Provisions

As mentioned previously, PSO procures fuel with a variety of contract provisions that serve as a hedge against fuel price volatility. Fuel contracts can utilize either fixed or indexed prices. The contract lengths also vary and are staggered to increase flexibility.

12.1.4 Prior Period – 2023

PSO's generating plants, combined with purchased power and wind energy, offered a diverse fleet to PSO's customers. Exhibit 4 below offers a comparison of the total generation resource mix in 2022 and 2023.

Exhibit 4: Resource Percentage Comparison

ration Resource (MWh Basis)	2022	2023
Natural Gas	20.0%	25.0%
Coal	11.2%	9.7%
rchased Power[1]	41.2%	38%
Wind Energy[2]	27.7%	27.3%

[1]Includes market purchases and non-renewable PPAs.
[2]Includes owned and PPA wind resources.

In 2023, PSO's total average delivered cost of fossil fuel varied from a low of $2.02 per MMBtu in May to a high of $4.10 per MMBtu in February. Throughout the calendar year, the price of natural gas was lower than the volatile prices seen in 2022. The Company experienced increases in the percentage of Natural Gas (5.0%) while Coal (-1.4%), Wind (-0.4%), and Purchased Power (-3.2%) experienced a decrease when compared to 2022.

12.1.4.1 PSO's Demand

PSO realized an actual weather normalized peak of 4,192 MW in 2023.

12.1.4.2 2023 Coal Procurement Summary

PSO purchases low sulfur PRB coal and has a Dry Sorbent Injection system to meet the emission rate of 0.40 lb. SO_2/MMBtu required for Northeastern Unit 3. Shipments of coal from the PRB to the Northeastern plant during 2023 were made pursuant to a transportation arrangement with UP. Exhibit 5 summarizes the contracts used by PSO to purchase coal in 2023 for its Northeastern Generation Station.

Exhibit 5: List of Coal Contracts in effect in 2023

Vendor	Agreement Number	Tons Purchased
Peabody COALSALES, LLC	08-81-18-4M4	184,826
Peabody COALSALES, LLC	08-81-22-4M2	184,260
Peabody COALSALES, LLC	08-81-23-4M1	306,176
Peabody COALSALES, LLC	08-81-23-4M2	504,535
Thunder Basin Coal Company LLC	08-81-21-4M3	367,072

12.1.4.3 2023 Natural Gas Procurement Summary

As mentioned earlier in the document, the SPP IM has increased its utilization of PSO's gas-fired generating units in each of the last two calendar years. Consistent with history, PSO's gas-fired generating units were dispatched on-line and off-line by SPP on relatively short notice, resulting in daily natural gas demand that was highly variable. The mode of system operation and unit dispatch required a flexible procurement strategy in a dynamic marketplace. Throughout 2023, PSO pursued forward and prompt month baseload natural gas supply agreements, which were supplemented with daily spot market purchases.

To transport natural gas supplies to PSO gas plants as necessary, transportation contracts with Enable OK and OGT were used. PSO employed a mix of firm and interruptible agreements to provide reliable, flexible natural gas transportation at the lowest reasonable delivered cost. Refer to Exhibit 2 for an illustration of the pipeline connections at each plant.

Effective April 1, 2023, PSO began utilizing natural gas storage services, also provided by Enable OK. PSO injected natural gas into storage when demand and market prices were low and withdrew natural gas from storage when demand and market prices were high.

12.1.4.4 2023 Purchased Power Summary

On an energy basis, purchased power, including wind purchases, accounted for approximately 61% percent of the resource mix in 2023, a decrease of 5% percent from the prior year. On average, year-over-year SPP IM prices decreased for both on-peak and off-peak hours from 2022 to 2023. The average decrease for on-peak hours was approximately by 50.6% and 51% for off-peak hours. The average SPP IM day-ahead market prices for SPP South Hub for 2022 and 2023, shown in Exhibit 6 below, are based on the daily trading results as reported by Platts.

Exhibit 6: 2022-2023 Average SPP South Hub Prices

Month	age On-Peak $/MWh)	age Off-Peak ($/MWh)	Month	age On-Peak $/MWh)	age Off-Peak $/MWh)
Jan-22	$35.87	$29.17	Jan-23	$34.26	$20.67
Feb-22	$35.71	$21.07	Feb-23	$34.68	$20.81
Mar-22	$33.90	$14.40	Mar-23	$34.81	$19.42
Apr-22	$31.24	$21.90	Apr-23	$34.34	$19.79
May-22	$88.32	$36.30	May-23	$34.74	$18.77
Jun-22	$99.31	$52.32	Jun-23	$34.65	$18.82
Jul-22	$114.26	$58.03	Jul-23	$34.16	$18.43

Aug-22	$115.01	$62.61	Aug-23	$33.99	$18.11
Sep-22	$92.85	$46.62	Sep-23	$33.61	$17.56
Oct-22	$64.96	$38.04	Oct-23	$32.11	$17.65
Nov-22	$50.34	$41.81	Nov-23	$31.70	$17.30
Dec-22	$57.27	$38.01	Dec-23	$31.69	$18.09
Monthly Average	**$68.25**	**$38.36**	**Monthly Average**	**$33.73**	**$18.78**

12.1.5 Current Period – 2024 Expectations

12.1.5.1 Forecast

PSO forecasts market conditions, weather patterns, unit outages, and purchased power opportunities in order to anticipate both short-term and long-term fuel supply needs. Exhibit 7 below illustrates PSO's forecasted energy source mix for 2024, which will help determine purchases of fuel and other sources of power. In 2024, PSO estimates that approximately 36 percent of its energy to serve customers will come from Oklahoma wind generation resources.

Exhibit 7: Energy Source Percentages

Generation Resource (MWh Basis)	2024
Natural Gas	18.7%
Coal	9.8%
Wind	36.3%
Purchase Power	4.8%
SPP Market Purchases	30.5%

12.1.5.2 Demand Forecast

PSO's 2024 peak native load responsibility is forecasted to be at 4,278 MW.

12.1.5.3 Fuel

PSO's fuel planning forecast is generally based on existing fuel and fuel-related contracts and anticipated market prices for any non-committed fuel. The fuel cost for each of PSO's generating plants is based on the cost of fuel sourced for each plant and the related transportation costs to deliver the fuel to the plant.

Coal

Northeastern Unit 3 uses sub-bituminous coal from the Powder River Basin in Wyoming that typically has a heat content of 8,500 to 8,900 Btu per pound. Projections of coal supply needs must consider railroad delivery constraints and cycle time performance. Currently, PSO has an arrangement with the UP to deliver coal to Northeastern. PSO's 2024 delivered costs for Northeastern are expected to be slightly lower than those seen in 2023.

Natural Gas

PSO currently utilizes a linear regression methodology for near-term Henry Hub price forecasting. The inputs for the regression model are degree days, natural gas dry production, and consumption. The natural gas forecast is adjusted for estimated transportation costs and basis differentials that are applicable to PSO's geographic region and delivery points. These delivered prices are used in the Plexos generation dispatch model that projects PSO's natural gas consumption. The natural gas forecast methodology is separate and distinct from the methods used for operational purposes. Weather, generating unit availability, economic power purchase opportunities, and the SPP IM will all impact natural gas purchases in 2024.

12.1.5.4 Purchased Power

Conventional Purchased Power

It is expected that SPP IM market prices in 2024 will be similar to those seen in 2023.

Purchase Power Contracts (PPAs)

In 2024, PSO will purchase capacity and energy through long-term PPAs from facilities listed below in Exhibit 8. The associated megawatts and start dates are also listed below.

Exhibit 8: Purchased Power Contracts

2024 Purchased Power Contracts	ract Maxi- n Quantity (MW)	tract Start	ntract End
ta[1]	260	une 2016	May 2031
en Country[2]	569	une 2022	May 2027
ta[3]	75	une 2023	May 2024
ta[3]	160	une 2024	May 2025
awk Wind[4]	19	une 2023	May 2028
keye Wind[4]	9	une 2023	May 2028
man Cogen[5]	10	une 2023	May 2027
nichi[6]	75	une 2023	May 2027
Total[7]	1,177		

[1]Natural gas with energy option

[2]Deliverable capacity only contract effective 06/01/2022: Planning Year (PY) 2024/2025: 569 MW; PY 2025/2026: 390 MW; PY 2026/2027: 520 MW

[3]Deliverable capacity only contract

[4]Firm Capacity

[5]Capacity effective 06/01/2023; 2023/2024: 10 MW; 2024/2025: 50 MW; 2025/2026: 50 MW; 2026/2027: 50 MW

[6]Capacity effective 06/01/2023; 2023/2024: 75 MW; 2024/2025: 75 MW; 2025/2026: 150 MW; 2026/2027: 150 MW

[7]Represents total capacity included in the SPP resource adequacy plan for PY 2024/2025

Wind Energy

PSO's commitment to a diversified generation portfolio, combined with its support of developing environmentally beneficial forms of energy production, is supported by PSO's portfolio of wind energy contracts. Exhibit 9 below shows PSO's wind resources that are in effect during 2024.

Exhibit 9: Wind Contracts

PSO 2024 Wind Projects	ntract Maximum Quantity (MW)	Delivery Start Date (Month/Year)
ıtherford Wind Energy	147	May 2005
ping Bear Wind Energy	94.5	September 2007
e Canyon V Wind Energy	99	October 2009
City Wind Energy	98.9	January 2010
co Wind Energy	99.2	December 2010
ko Wind Energy	199.8	January 2016
dwell Wind Energy	200	January 2016
ing Wind Energy	198.9	January 2016
Total	1137.3	

12.1.6 Customer Programs and Tariffs

12.1.6.1 Managing Energy Usage and Costs

PSO offers a wide variety of programs to assist customers in managing their energy usage and cost. PSO customer programs are established to encourage reduced energy consumption, either at times of peak consumption or throughout the day or year. Programs or tariffs that support reduce consumption at the system peak are Demand Response (DR) programs, while around-the-clock measures are typically categorized as Energy Efficiency (EE) programs. PSO's Demand Portfolio programs were most recently approved by the Commission in Cause No. PUD 202100041 for the 2022-2024 program years. The Demand Portfolio includes energy efficiency and demand response program options for customers to save energy and money. The portfolio includes extensive education approaches to further customer understanding of energy use and ways to not waste energy but use energy wisely. PSO is deploying Conservation Voltage Reduction technology across circuits to manage voltage and lower energy consumption for customers. A complete listing of PSO's Demand Side Management (DSM) programs can be found in Exhibit 10 below.

Exhibit 10: PSO Demand Side Management Programs

ential	nercial & Industrial
e Weatherization	ness Rebates
ervation Voltage Reduction	ervation Voltage Reduction
er Hours	Performers
dential Energy Services	

Enabled by Advanced Metering Infrastructure (AMI), PSO offers Time of Day Pricing options for residential customers to manage energy use during the day. The most recent Time of Day pricing option allows customers to save money and PSO to minimize peak impact of electric vehicle charging including commercial charging and fleet charging tariffs. With AMI, customers are able view their 15-minute energy usage when logged onto PSOklahoma.com/account. Interacting with your energy usage data introduces insights to help better manage your energy usage. Simply navigate within an account to discover new insights into how your home or business uses energy and find ways to save. PSO also offers a residential pre-pay program called Power Pay to provide payment convenience and daily notifications to bring awareness to their daily energy costs.

PSO offers Green Energy Choice Tariffs, which provide customers with a variety of options to achieve their sustainability goals through wind and solar resources. The voluntary options include a range of prices and timeframes, allowing customers to choose an option that best fits their needs. The options are:

- **Option A - Green Energy Choice Flex** - Formerly known as WindChoice, this option allows both residential and commercial customers to purchase up to 100% of their monthly usage in Renewable Energy Certificates (RECs). The price is adjusted annually based on current market conditions. The initial commitment is one year, and then month-to-month thereafter.
- **Option B – Green Energy Choice Blocks –** This option allows customers to purchase a fixed quantity of RECs in 1,000 kWh blocks. It is the perfect option for commercial customers that may also have facilities outside of PSO's

service territory that are looking to purchase RECs to offset their carbon footprint. There is no long-term commitment with this option, and the price is adjusted annually based on market conditions.

- **Option C - Green Energy Choice –** The Green Energy Choice option allows customers to get a 10-year fixed price on RECs generated from local renewable resources including PSO's North Central Wind facility. Customers subscribe based on a percentage of usage and may choose RECs from renewable generation that is already operational, or from new generation sources that will be coming online in the near future.
- **Option D – Green Energy Choice Plus -** This option allows customers an option to lock in a 10-year fixed price on RECs and cap fuel costs at the same time.

12.1.6.2 Retail Energy Usage and Cost Projections

Exhibit 11 below provides monthly bill projections for summer 2024 and winter 2024, as well as a comparison to the previous year for illustrative purposes.

Exhibit 11: Monthly Bill Projections

r Bill

mer Class and Usage**	**Bill* 2023**	**–¢/kWh 2023**	**jected Bill* 2024**	**cted Price–¢/kWh 2024**	**ojected % ge Per kWh**
tial- Wh	136.55	2.76	$128.32	11.99	-6.03%
Commercial- Wh	210.22	1.94	$202.46	11.50	-3.69%

er Bill

mer Class and Usage**	**Bill* 2023**	**–¢/kWh 2023**	**jected Bill* 2024**	**cted Price–¢/kWh 2024**	**ojected % ge Per kWh**
tial- Wh	206.08	4.21	$199.76	13.78	-3.07%
Commercial- Wh	310.19	3.49	$319.25	13.88	2.92%

*Actual and projected bill amounts include base service charges, seasonal energy charges, and the most recent fuel factors and all applicable riders. Actual and projected bill amounts do not include franchise fees or taxes.

**Class kWh levels are based on prior FSP Table levels.

12.1.7 Summary

PSO's risk management plan has a diversified resource portfolio, which includes coal generation, natural gas generation, wholesale energy purchases, renewable energy, and EE/DR. Each of the commodities is procured under a competitive bidding or competitive market offer process. This includes energy purchases in lieu of PSO's generation when it can be arranged both economically and reliably. PSO's fuel supply plan allows PSO to appropriately respond to changes in the SPP IM and assists in ensuring a reliable fuel supply at the lowest reasonable delivered cost. Recognizing the dynamic market, PSO will continue to review and adapt its fuel procurement activities to ensure that the fuel procurement and risk management plan continues to meet the standards of providing the lowest reasonable delivered cost to PSO's customers.

Contact Information

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Exhibit E: Portfolio Annual Revenue Requirement

Public Service Company of Oklahoma
2024 IRP Base Scenario Optimal Plan
Base Portfolio

	Utility Costs (Nominal$000)									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)			(9)=(1)thru(7)-(8)
	Off System Sales	Off System Purchases	Fuel Costs	Emission Costs	Existing + New System FOM and OGC + ST Market Purchases	Variable O&M (new and existing)	Levelized Return, Taxes, and Depreciation - New Owned Resources	Contract Cost	*Less:* Tax Credit Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2025	5,344	151,374	177,138	1,274	199,576	144,253	52,724	2,335	0	723,329
2026	3,167	112,224	214,523	0	153,339	138,078	75,397	2,375	0	692,769
2027	11,491	87,260	217,693	0	177,979	140,898	80,495	2,420	0	695,255
2028	14,267	88,649	229,729	0	155,176	144,662	80,495	2,472	0	686,917
2029	16,152	78,178	238,215	0	165,287	150,681	101,397	2,517	18,563	701,560
2030	23,886	64,765	247,608	0	167,464	135,028	189,005	2,559	78,765	703,778
2031	35,488	57,970	236,287	0	176,553	138,572	278,352	2,606	146,005	708,846
2032	34,439	75,566	221,289	0	182,593	138,939	286,922	2,661	158,992	714,536
2033	28,432	73,765	235,910	0	184,519	135,465	282,510	2,707	158,355	728,089
2034	33,205	74,659	249,502	0	188,856	137,340	276,060	2,751	162,956	733,006
2035	51,946	68,669	251,504	0	186,497	141,446	339,823	2,800	208,089	730,704
2036	40,210	84,666	254,393	0	201,785	107,147	492,593	2,857	294,097	809,133
2037	85,058	58,453	229,394	0	199,420	139,443	733,558	2,906	434,203	843,913
2038	111,117	47,165	247,561	0	202,341	143,053	798,927	2,950	473,539	857,342
2039	115,477	47,069	257,361	0	206,394	144,102	804,926	3,001	488,762	858,616
2040	149,775	44,911	292,531	0	213,406	148,903	819,941	3,061	498,424	874,553
2041	126,404	49,427	276,320	0	223,735	147,497	881,015	3,111	465,078	989,622
2042	122,447	56,092	272,626	0	220,204	147,639	951,091	3,158	475,845	1,052,518
2043	156,007	57,480	305,934	0	228,210	152,659	974,486	3,212	486,570	1,079,405
2044	168,196	51,037	327,868	0	232,390	156,246	974,331	3,273	498,453	1,078,496
2045	156,307	54,010	324,533	0	235,693	155,206	973,955	3,322	471,042	1,119,370
2046	145,642	68,831	336,294	0	239,506	152,198	973,946	3,379	337,814	1,290,697
2047	136,662	69,146	335,926	0	243,397	152,065	973,935	3,436	26,015	1,615,228
2048	124,346	80,658	323,126	0	247,862	150,145	973,923	3,501	0	1,654,869
2049	126,914	87,044	330,239	0	251,422	150,727	974,739	3,554	0	1,670,810
2050	123,314	87,023	341,383	0	258,960	152,440	983,562	3,614	0	1,703,668
2051	136,018	91,141	379,126	0	267,864	157,571	1,012,840	3,676	0	1,776,199
2052	63,456	172,815	341,937	0	247,177	152,551	1,012,840	3,745	0	1,867,608
2053	56,085	213,081	351,477	0	234,269	153,913	1,030,477	3,802	0	1,930,933
2054	54,709	205,253	362,430	0	234,195	155,020	1,048,114	3,866	0	1,954,170
TOTAL Utility Cost, Net Present Value										16,175,982

Public Service Company of Oklahoma
2024 IRP High Scenario Optimal Plan
HIGH Portfolio

	Utility Costs (Nominal$000)									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)			(9)=(1)thru(7)-(8)
	Off System Sales	Off System Purchases	Fuel Costs	Emission Costs	Existing + New System FOM and OGC + ST Market Purchases	Variable O&M (new and existing)	Levelized Return, Taxes, and Depreciation - New Owned Resources	Contract Cost	*Less:* Tax Credit Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2025	1,407	283,415	189,763	1,274	199,576	141,239	52,724	2,335	0	868,919
2026	0	224,395	256,429	0	159,071	135,295	75,397	2,375	0	852,962
2027	1,926	178,679	254,992	0	186,055	138,268	80,495	2,420	0	838,983
2028	1,004	184,792	264,889	0	162,281	141,854	80,495	2,472	0	835,778
2029	29,863	99,037	282,938	0	185,695	196,228	247,711	2,517	134,320	849,943
2030	43,280	80,281	294,059	0	182,225	172,602	344,180	2,559	197,799	834,826
2031	33,750	102,968	285,887	0	186,203	152,599	368,764	2,606	203,733	861,546
2032	34,450	107,406	291,721	0	194,368	154,572	374,575	2,661	210,428	880,425
2033	42,077	99,668	302,949	0	201,204	165,261	414,878	2,707	245,218	899,371
2034	44,963	103,753	324,120	0	205,770	167,215	421,280	2,751	252,305	927,621
2035	70,159	80,863	339,345	0	206,293	172,588	499,342	2,800	313,425	917,647
2036	27,842	156,650	349,638	0	210,805	109,216	575,579	2,857	327,088	1,049,815
2037	152,284	65,103	347,487	0	219,968	185,502	931,016	2,906	570,426	1,029,271
2038	182,802	60,759	366,484	0	231,265	188,861	1,010,365	2,950	609,859	1,068,024
2039	170,820	70,856	368,247	0	235,744	188,201	1,016,973	3,001	625,550	1,086,652
2040	194,847	69,672	405,535	0	241,817	191,554	1,024,722	3,061	614,132	1,127,381
2041	185,620	81,632	395,989	0	250,984	191,156	1,092,587	3,111	619,380	1,210,461
2042	205,424	85,783	411,270	0	252,680	193,199	1,205,498	3,158	643,183	1,302,981
2043	207,261	94,081	420,088	0	257,235	193,814	1,212,695	3,212	616,789	1,357,076
2044	207,932	101,305	438,467	0	263,491	195,496	1,220,946	3,273	632,029	1,383,017
2045	223,038	101,972	462,723	0	272,723	197,690	1,261,182	3,322	549,892	1,526,682
2046	229,888	123,689	481,921	0	278,103	197,301	1,276,505	3,379	562,250	1,568,759
2047	200,004	131,810	475,334	0	282,582	196,314	1,276,494	3,436	26,359	2,139,609
2048	198,312	144,348	488,006	0	287,757	197,437	1,276,482	3,501	0	2,199,218
2049	185,819	160,332	490,106	0	291,822	197,209	1,276,480	3,554	0	2,233,684
2050	183,389	163,633	506,157	0	302,891	198,949	1,302,838	3,614	0	2,294,694
2051	199,255	190,246	547,068	0	309,927	203,060	1,348,834	3,676	0	2,403,556
2052	114,074	297,506	539,390	0	293,465	202,582	1,359,182	3,745	0	2,581,796
2053	87,482	375,338	551,944	0	284,723	203,009	1,390,226	3,802	0	2,721,559
2054	90,342	411,901	570,753	0	284,214	204,556	1,390,226	3,866	0	2,775,174
TOTAL Utility Cost, Net Present Value										21,134,546

Public Service Company of Oklahoma
2024 IRP LOW Scenario Optimal Plan
Low Portfolio with NE3 Gas

	Utility Costs (Nominal$000)									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)			(9)=(1)thru(7)-(8)
	Off System Sales	Off System Purchases	Fuel Costs	Emission Costs	Existing + New System FOM and OGC + ST Market Purchases	Variable O&M (new and existing)	Levelized Return, Taxes, and Depreciation - New Owned Resources	Contract Cost	*Less:* Tax Credit Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2025	12,708	119,582	138,150	719	199,576	144,656	52,724	2,335	0	645,034
2026	9,102	123,253	135,709	0	153,339	135,590	75,397	2,375	0	616,561
2027	18,220	108,233	130,271	0	177,979	137,493	80,495	2,420	0	618,670
2028	18,458	112,164	135,073	0	155,176	140,643	80,495	2,472	0	607,565
2029	24,960	106,607	130,699	0	166,388	146,298	121,587	2,517	30,594	618,542
2030	18,479	99,862	106,703	0	170,093	132,560	223,817	2,559	103,693	613,422
2031	11,680	88,242	86,680	0	178,459	135,126	299,165	2,606	163,254	615,344
2032	12,762	81,403	72,420	0	188,471	146,833	343,956	2,661	207,371	615,610
2033	6,561	83,329	70,824	0	190,871	142,583	344,882	2,707	209,651	618,983
2034	4,419	81,948	69,017	0	195,317	143,777	344,907	2,751	215,686	617,611
2035	3,055	85,705	65,463	0	187,979	144,767	346,305	2,800	221,664	608,301
2036	7,399	109,479	71,219	0	188,413	88,362	448,059	2,857	286,766	614,225
2037	4,687	120,098	21,386	0	176,108	105,510	604,586	2,906	373,908	651,999
2038	11,747	92,660	22,737	0	187,848	126,899	698,194	2,950	441,083	678,459
2039	7,377	92,629	21,966	0	191,342	126,745	696,976	3,001	451,958	673,323
2040	28,963	63,474	58,109	0	201,552	132,676	724,259	3,061	430,314	723,854
2041	90,098	17,629	133,967	0	220,593	144,448	816,003	3,111	376,590	869,064
2042	85,788	21,076	127,535	0	211,294	143,957	855,882	3,158	379,229	897,886
2043	82,507	21,678	123,696	0	214,951	143,760	855,882	3,212	387,825	892,846
2044	89,362	25,208	127,960	0	219,130	145,047	855,882	3,273	397,204	889,934
2045	84,567	29,676	121,457	0	222,511	144,150	855,904	3,322	404,923	887,531
2046	67,830	33,761	116,875	0	226,372	140,724	855,902	3,379	229,998	1,079,183
2047	67,489	33,517	116,196	0	230,307	141,071	855,899	3,436	0	1,312,937
2048	64,693	40,830	107,371	0	234,784	140,541	855,896	3,501	0	1,318,230
2049	63,067	42,399	106,676	0	238,427	140,310	855,905	3,554	0	1,324,205
2050	59,655	43,624	105,089	0	242,611	140,134	855,882	3,614	0	1,331,298
2051	53,053	52,992	103,312	0	246,851	140,049	855,882	3,676	0	1,349,709
2052	22,410	89,283	91,369	0	227,933	138,828	855,882	3,745	0	1,384,629
2053	14,049	109,743	92,247	0	218,364	138,880	864,700	3,802	0	1,413,687
2054	16,427	99,946	95,889	0	218,897	140,563	891,156	3,866	0	1,433,890
TOTAL Utility Cost, Net Present Value										13,023,535

Public Service Company of Oklahoma
2024 IRP EER Scenario Optimal Plan
EER Portfolio

	Utility Costs (Nominal$000)									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)			(9)=(1)thru(7)-(8)
	Off System Sales	Off System Purchases	Fuel Costs	Emission Costs	Existing + New System FOM and OGC + ST Market Purchases	Variable O&M (new and existing)	Levelized Return, Taxes, and Depreciation - New Owned Resources	Contract Cost	*Less:* Tax Credit Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2025	7,717	136,944	188,469	1,274	199,576	144,834	52,724	2,335	0	718,439
2026	1,718	133,778	190,597	0	153,339	136,433	75,397	2,375	0	690,201
2027	6,348	119,486	180,746	0	177,979	138,271	80,495	2,420	0	693,050
2028	5,667	132,475	177,772	0	155,176	141,065	80,495	2,472	0	683,787
2029	7,959	109,935	198,618	0	165,287	147,845	101,397	2,517	18,563	699,077
2030	3,396	196,608	116,278	0	168,612	129,687	197,655	2,559	88,329	719,674
2031	7,917	173,679	87,865	0	180,410	137,832	322,807	2,606	182,326	714,956
2032	21,187	125,849	104,664	0	194,787	165,987	406,412	2,661	256,226	722,948
2033	20,719	116,364	100,043	0	201,673	172,759	450,987	2,707	293,796	730,017
2034	26,475	106,573	119,106	0	206,706	175,338	457,461	2,751	305,466	735,993
2035	17,710	114,927	77,751	0	202,062	179,503	488,579	2,800	337,876	710,035
2036	32,273	103,849	86,214	0	215,679	158,233	696,116	2,857	478,796	751,879
2037	61,738	67,280	82,657	0	209,786	179,963	900,382	2,906	595,174	786,062
2038	104,181	46,098	109,465	0	221,185	197,803	994,995	2,950	664,270	804,045
2039	108,117	39,672	104,148	0	229,291	207,687	1,032,185	3,001	710,401	797,467
2040	113,527	40,126	111,032	0	238,364	209,326	1,053,983	3,061	727,817	814,549
2041	124,498	42,823	122,372	0	252,074	210,319	1,129,271	3,111	678,920	956,552
2042	127,355	37,742	132,856	0	244,735	211,275	1,176,898	3,158	648,947	1,030,361
2043	157,198	42,050	150,287	0	253,312	213,506	1,200,140	3,212	655,391	1,049,918
2044	152,568	39,393	153,432	0	258,150	214,975	1,200,140	3,273	671,788	1,045,006
2045	150,105	45,719	152,609	0	261,982	213,960	1,200,293	3,322	605,007	1,122,774
2046	75,099	134,136	65,553	0	266,396	203,394	1,200,284	3,379	396,478	1,401,565
2047	164,428	104,488	184,285	0	270,897	207,686	1,200,158	3,436	76,968	1,729,554
2048	181,324	107,839	199,935	0	276,067	209,075	1,200,155	3,501	0	1,815,247
2049	172,802	112,677	200,616	0	280,190	208,440	1,200,164	3,554	0	1,832,838
2050	168,613	114,317	208,859	0	284,981	209,157	1,200,140	3,614	0	1,852,456
2051	160,197	133,083	224,249	0	289,823	210,536	1,200,140	3,676	0	1,901,311
2052	95,870	214,560	228,842	0	274,845	211,693	1,220,836	3,745	0	2,058,652
2053	74,719	268,431	245,073	0	264,510	212,520	1,241,532	3,802	0	2,161,148
2054	264,147	195,511	281,857	0	263,943	222,793	1,241,532	3,866	0	1,945,356
TOTAL Utility Cost, Net Present Value										16,238,463

Public Service Company of Oklahoma
2024 IRP High Gas Base Load Scenario Optimal Plan
HIGH Gas Base Load Portfolio

	Utility Costs (Nominal$000)									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)			(9)=(1)thru(7)-(8)
	Off System Sales	Off System Purchases	Fuel Costs	Emission Costs	Existing + New System FOM and OGC + ST Market Purchases	Variable O&M (new and existing)	Levelized Return, Taxes, and Depreciation - New Owned Resources	Contract Cost	*Less:* Tax Credit Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2025	1,887	253,986	189,763	1,274	199,576	141,239	52,724	2,335	0	839,010
2026	171	187,138	260,388	0	157,937	135,456	80,495	2,375	0	823,619
2027	4,891	144,263	254,992	0	177,979	138,268	80,495	2,420	0	793,527
2028	3,169	144,679	264,889	0	155,176	141,854	80,495	2,472	0	786,396
2029	20,684	102,541	282,938	0	171,981	168,412	164,103	2,517	67,160	804,649
2030	38,706	79,303	294,059	0	175,427	157,155	261,165	2,559	138,404	792,557
2031	34,121	95,792	285,887	0	176,931	137,059	281,312	2,606	150,801	794,665
2032	36,589	96,265	291,721	0	182,591	138,771	281,773	2,661	158,973	798,220
2033	46,485	86,433	302,949	0	189,323	149,523	321,519	2,707	193,982	811,987
2034	51,014	87,717	324,120	0	193,749	151,482	320,006	2,751	199,636	829,176
2035	72,410	67,506	339,345	0	191,484	155,981	384,448	2,800	245,815	823,340
2036	68,405	80,873	349,638	0	204,006	122,671	556,834	2,857	345,495	902,980
2037	148,719	54,993	345,691	0	200,874	154,940	784,729	2,906	476,301	919,113
2038	167,984	53,117	360,127	0	206,318	156,951	824,660	2,950	498,998	937,142
2039	160,377	59,110	364,471	0	210,025	156,361	824,452	3,001	511,382	945,662
2040	193,547	52,832	396,802	0	219,498	159,650	858,018	3,061	515,317	980,997
2041	192,262	65,290	393,054	0	227,628	159,831	942,048	3,111	519,213	1,079,487
2042	191,360	70,850	402,889	0	224,466	160,075	986,987	3,158	531,354	1,125,712
2043	194,414	76,111	411,523	0	228,154	160,474	987,139	3,212	499,799	1,172,401
2044	209,711	74,208	428,699	0	233,395	162,480	1,002,290	3,273	517,748	1,176,885
2045	228,864	75,396	444,500	0	237,778	163,986	1,017,210	3,322	470,971	1,242,357
2046	243,323	84,111	465,813	0	242,725	163,887	1,033,217	3,379	294,049	1,455,759
2047	235,908	84,487	462,488	0	248,778	163,772	1,054,197	3,436	0	1,781,250
2048	244,149	87,872	478,429	0	256,457	165,141	1,073,180	3,501	0	1,820,430
2049	239,491	94,040	481,470	0	260,192	165,131	1,073,178	3,554	0	1,838,073
2050	234,378	96,087	495,621	0	264,533	166,159	1,073,059	3,614	0	1,864,695
2051	231,529	108,776	525,257	0	268,919	168,690	1,073,059	3,676	0	1,916,848
2052	140,770	180,879	527,767	0	253,420	169,066	1,093,755	3,745	0	2,087,861
2053	97,016	228,930	533,267	0	242,676	168,943	1,114,451	3,802	0	2,195,053
2054	102,511	241,267	551,858	0	241,620	170,515	1,114,451	3,866	0	2,221,066
TOTAL Utility Cost, Net Present Value										18,176,628

Public Service Company of Oklahoma
2024 IRP High Gas Base Load Scenario Optimal Plan
HIGH Gas Base Load Portfolio

	Utility Costs (Nominal$000)									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)			(9)=(1)thru(7)-(8)
	Off System Sales	Off System Purchases	Fuel Costs	Emission Costs	Existing + New System FOM and OGC + ST Market Purchases	Variable O&M (new and existing)	Levelized Return, Taxes, and Depreciation - New Owned Resources	Contract Cost	*Less:* Tax Credit Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2025	1,887	253,986	189,763	1,274	199,576	141,239	52,724	2,335	0	839,010
2026	171	187,138	260,388	0	157,937	135,456	80,495	2,375	0	823,619
2027	4,891	144,263	254,992	0	177,979	138,268	80,495	2,420	0	793,527
2028	3,169	144,679	264,889	0	155,176	141,854	80,495	2,472	0	786,396
2029	20,684	102,541	282,938	0	171,981	168,412	164,103	2,517	67,160	804,649
2030	38,706	79,303	294,059	0	175,427	157,155	261,165	2,559	138,404	792,557
2031	34,121	95,792	285,887	0	176,931	137,059	281,312	2,606	150,801	794,665
2032	36,589	96,265	291,721	0	182,591	138,771	281,773	2,661	158,973	798,220
2033	46,485	86,433	302,949	0	189,323	149,523	321,519	2,707	193,982	811,987
2034	51,014	87,717	324,120	0	193,749	151,482	320,006	2,751	199,636	829,176
2035	72,410	67,506	339,345	0	191,484	155,981	384,448	2,800	245,815	823,340
2036	68,405	80,873	349,638	0	204,006	122,671	556,834	2,857	345,495	902,980
2037	148,719	54,993	345,691	0	200,874	154,940	784,729	2,906	476,301	919,113
2038	167,984	53,117	360,127	0	206,318	156,951	824,660	2,950	498,998	937,142
2039	160,377	59,110	364,471	0	210,025	156,361	824,452	3,001	511,382	945,662
2040	193,547	52,832	396,802	0	219,498	159,650	858,018	3,061	515,317	980,997
2041	192,262	65,290	393,054	0	227,628	159,831	942,048	3,111	519,213	1,079,487
2042	191,360	70,850	402,889	0	224,466	160,075	986,987	3,158	531,354	1,125,712
2043	194,414	76,111	411,523	0	228,154	160,474	987,139	3,212	499,799	1,172,401
2044	209,711	74,208	428,699	0	233,395	162,480	1,002,290	3,273	517,748	1,176,885
2045	228,864	75,396	444,500	0	237,778	163,986	1,017,210	3,322	470,971	1,242,357
2046	243,323	84,111	465,813	0	242,725	163,887	1,033,217	3,379	294,049	1,455,759
2047	235,908	84,487	462,488	0	248,778	163,772	1,054,197	3,436	0	1,781,250
2048	244,149	87,872	478,429	0	256,457	165,141	1,073,180	3,501	0	1,820,430
2049	239,491	94,040	481,470	0	260,192	165,131	1,073,178	3,554	0	1,838,073
2050	234,378	96,087	495,621	0	264,533	166,159	1,073,059	3,614	0	1,864,695
2051	231,529	108,776	525,257	0	268,919	168,690	1,073,059	3,676	0	1,916,848
2052	140,770	180,879	527,767	0	253,420	169,066	1,093,755	3,745	0	2,087,861
2053	97,016	228,930	533,267	0	242,676	168,943	1,114,451	3,802	0	2,195,053
2054	102,511	241,267	551,858	0	241,620	170,515	1,114,451	3,866	0	2,221,066
TOTAL Utility Cost, Net Present Value										18,176,628

Public Service Company of Oklahoma
2024 IRP Low Gas Base Load Scenario Optimal Plan
Low Gas Base Load Portfolio

	Utility Costs (Nominal$000)									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)			(9)=(1)thru(7)-(8)
	Off System Sales	Off System Purchases	Fuel Costs	Emission Costs	Existing + New System FOM and OGC + ST Market Purchases	Variable O&M (new and existing)	Levelized Return, Taxes, and Depreciation - New Owned Resources	Contract Cost	*Less:* Tax Credit Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2025	9,709	136,295	138,150	719	199,576	144,656	52,724	2,335	0	664,746
2026	5,303	144,278	135,709	0	153,339	135,591	75,397	2,375	0	641,385
2027	11,611	130,024	130,271	0	177,979	137,493	80,495	2,420	0	647,071
2028	11,160	137,363	135,073	0	155,176	140,643	80,495	2,472	0	640,062
2029	11,100	147,787	130,699	0	163,031	138,079	80,495	2,517	0	651,508
2030	8,966	163,924	106,703	0	162,881	110,425	153,442	2,559	46,998	643,970
2031	9,964	167,146	86,680	0	167,926	90,769	240,451	2,606	96,231	649,382
2032	8,692	143,892	104,252	0	178,692	94,676	251,178	2,661	98,960	667,698
2033	27,910	58,416	192,269	0	197,618	102,865	318,013	2,707	98,502	745,477
2034	21,228	57,787	188,480	0	202,018	104,213	318,039	2,751	101,087	750,972
2035	16,113	63,960	185,271	0	194,630	105,215	318,657	2,800	103,630	750,789
2036	6,991	119,647	193,582	0	188,743	41,188	331,320	2,857	103,440	766,905
2037	10,454	152,585	144,331	0	173,369	41,857	467,529	2,906	164,804	807,320
2038	13,277	151,979	146,659	0	182,494	43,077	527,054	2,950	179,075	861,860
2039	7,270	154,766	149,000	0	185,626	43,284	527,054	3,001	183,048	872,412
2040	8,152	156,183	148,727	0	190,607	44,034	534,320	3,061	145,038	923,742
2041	20,172	123,985	179,741	0	198,467	49,443	594,758	3,111	110,006	1,019,327
2042	93,435	38,771	293,131	0	200,089	66,794	720,876	3,158	112,177	1,117,207
2043	86,514	42,328	286,239	0	203,286	66,752	720,876	3,212	114,321	1,121,858
2044	89,329	43,378	295,182	0	206,954	68,387	720,876	3,273	116,689	1,132,031
2045	81,594	48,498	286,735	0	209,883	68,255	720,898	3,322	118,523	1,137,474
2046	66,368	86,415	284,715	0	213,255	61,970	720,896	3,379	120,582	1,183,679
2047	62,747	89,758	280,489	0	216,695	62,378	720,894	3,436	0	1,310,903
2048	57,416	103,385	268,432	0	220,623	61,188	720,891	3,501	0	1,320,604
2049	54,486	105,544	267,787	0	223,784	61,879	720,900	3,554	0	1,328,962
2050	49,559	112,903	265,472	0	227,439	61,685	720,876	3,614	0	1,342,431
2051	43,188	126,962	264,027	0	231,138	62,023	720,876	3,676	0	1,365,513
2052	21,091	182,409	241,259	0	213,859	59,573	745,521	3,745	0	1,425,275
2053	17,407	203,657	238,665	0	205,503	61,170	811,255	3,802	0	1,506,644
2054	17,459	199,257	246,537	0	204,359	63,165	820,074	3,866	0	1,519,798
TOTAL Utility Cost, Net Present Value										14,309,862

Public Service Company of Oklahoma
2024 IRP Large Economic Development Opportunity (LEDO) Scenario Optimal Plan
LEDO Portfolio with NE3 Gas

	Utility Costs (Nominal$000)									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)			(9)=(1)thru(7)-(8)
	Off System Sales	Off System Purchases	Fuel Costs	Emission Costs	Existing + New System FOM and OGC + ST Market Purchases	Variable O&M (new and existing)	Levelized Return, Taxes, and Depreciation - New Owned Resources	Contract Cost	*Less:* Tax Credit Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2025	3,749	172,718	177,138	1,274	199,576	144,253	52,724	2,335	0	746,269
2026	1,491	136,399	214,523	0	155,632	138,078	75,397	2,375	0	720,914
2027	5,828	110,935	217,693	0	180,275	140,898	80,495	2,420	0	726,890
2028	6,838	114,407	229,729	0	155,176	144,662	80,495	2,472	0	720,103
2029	12,659	93,915	238,215	0	171,197	155,646	138,278	2,517	39,876	747,235
2030	24,598	161,858	247,608	0	217,351	200,105	590,075	2,559	322,149	1,072,811
2031	18,236	173,429	237,838	0	246,705	184,541	711,515	2,606	345,804	1,192,595
2032	12,849	201,615	221,289	0	258,658	186,192	729,969	2,661	356,375	1,231,159
2033	8,728	213,273	235,910	0	265,534	182,368	740,810	2,707	354,822	1,277,051
2034	7,172	216,911	249,502	0	272,356	184,933	746,061	2,751	364,576	1,300,765
2035	7,175	236,298	251,504	0	273,062	186,352	779,035	2,800	374,205	1,347,671
2036	6,891	225,385	302,682	0	290,353	156,337	936,245	2,857	450,124	1,456,844
2037	89,532	89,131	414,841	0	294,315	214,399	1,162,897	2,906	577,010	1,511,947
2038	105,319	88,542	444,144	0	301,306	218,226	1,189,965	2,950	591,848	1,547,965
2039	107,192	89,702	462,902	0	310,745	220,636	1,210,108	3,001	606,571	1,583,331
2040	153,133	83,376	520,403	0	318,169	229,955	1,217,074	3,061	394,044	1,824,860
2041	117,755	98,882	492,513	0	326,890	226,640	1,263,845	3,111	392,624	1,901,501
2042	116,825	110,654	494,847	0	327,877	228,426	1,348,662	3,158	402,440	1,994,359
2043	152,141	116,060	535,765	0	334,618	235,418	1,356,614	3,212	412,255	2,017,290
2044	167,351	100,988	576,839	0	345,261	242,384	1,380,559	3,273	423,598	2,058,355
2045	149,019	111,665	573,190	0	350,014	241,748	1,380,280	3,322	431,887	2,079,313
2046	128,136	145,369	599,196	0	355,593	238,812	1,380,271	3,379	292,813	2,301,671
2047	116,204	156,335	598,044	0	361,285	239,178	1,380,260	3,436	0	2,622,334
2048	89,042	175,808	577,412	0	367,918	236,069	1,380,248	3,501	0	2,651,913
2049	91,811	194,830	589,022	0	369,163	236,365	1,383,759	3,554	0	2,684,881
2050	105,291	179,597	650,588	0	355,672	232,708	1,407,248	3,614	0	2,724,137
2051	185,997	129,054	791,991	0	360,375	246,396	1,474,450	3,676	0	2,819,944
2052	93,786	224,568	739,435	0	343,043	239,378	1,474,450	3,745	0	2,930,833
2053	77,730	275,680	758,521	0	329,953	241,462	1,474,450	3,802	0	3,006,138
2054	65,762	287,911	769,262	0	330,009	242,082	1,474,450	3,866	0	3,041,819
TOTAL Utility Cost, Net Present Value										25,136,647

Public Service Company of Oklahoma
2024 IRP Proposed Preferred Plan
Preferred Plan

	Utility Costs (Nominal$000)									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)			(9)=(1)thru(7)-(8)
	Off System Sales	Off System Purchases	Fuel Costs	Emission Costs	Existing + New System FOM and OGC + ST Market Purchases	Variable O&M (new and existing)	Levelized Return, Taxes, and Depreciation - New Owned Resources	Contract Cost	*Less:* Tax Credit Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2025	5,344	151,374	177,138	1,274	199,576	144,253	52,724	2,335	0	723,329
2026	3,167	112,224	214,523	0	153,339	138,078	75,397	2,375	0	692,769
2027	11,491	87,260	217,693	0	177,979	140,898	80,495	2,420	0	695,255
2028	14,267	88,649	229,729	0	155,176	144,662	80,495	2,472	0	686,917
2029	13,394	88,121	238,215	0	168,385	143,839	89,472	2,517	0	717,155
2030	11,390	102,037	247,608	0	178,829	108,904	166,083	2,559	0	794,631
2031	18,947	112,503	236,287	0	182,677	89,207	208,659	2,606	37,192	775,800
2032	13,855	123,248	221,289	0	190,395	92,948	207,624	2,661	57,338	766,971
2033	14,082	111,449	235,910	0	196,023	100,158	239,818	2,707	82,893	789,090
2034	14,656	109,753	249,502	0	200,556	102,576	239,843	2,751	85,098	805,228
2035	42,148	89,627	301,098	0	199,211	108,758	263,388	2,800	87,270	835,465
2036	82,518	70,345	430,463	0	209,917	56,554	341,248	2,857	87,164	941,703
2037	104,481	60,412	406,206	0	195,008	74,795	494,407	2,906	176,453	952,801
2038	120,482	57,955	429,091	0	203,807	77,738	540,959	2,950	184,203	1,007,815
2039	124,267	56,165	445,043	0	207,466	79,625	540,959	3,001	188,495	1,019,497
2040	151,423	53,161	478,205	0	213,052	84,348	548,461	3,061	193,091	1,035,774
2041	124,643	56,695	460,714	0	225,121	83,137	587,749	3,111	166,400	1,125,485
2042	128,421	63,733	464,669	0	230,718	85,010	673,337	3,158	161,493	1,230,710
2043	157,158	65,159	495,799	0	229,418	90,294	712,145	3,212	164,988	1,273,882
2044	166,369	56,075	520,766	0	233,635	94,004	712,193	3,273	168,951	1,284,627
2045	158,189	60,325	520,653	0	236,971	94,251	711,913	3,322	171,913	1,297,334
2046	152,319	77,432	555,982	0	240,827	93,002	711,905	3,379	175,344	1,354,862
2047	139,828	74,481	556,892	0	244,760	93,514	711,894	3,436	0	1,545,150
2048	125,051	81,758	549,389	0	249,270	91,846	711,881	3,501	0	1,562,594
2049	127,315	91,705	557,732	0	244,966	90,925	702,903	3,554	0	1,564,469
2050	121,029	96,748	576,815	0	228,202	83,369	695,372	3,614	0	1,563,091
2051	129,856	97,596	607,897	0	236,064	88,014	731,909	3,676	0	1,635,300
2052	70,201	166,590	577,814	0	218,824	84,862	766,256	3,745	0	1,747,891
2053	61,387	204,354	590,623	0	207,019	87,613	787,203	3,802	0	1,819,227
2054	55,037	200,343	603,447	0	210,071	90,602	798,063	3,866	0	1,851,355
TOTAL Utility Cost, Net Present Value										16,634,658

Exhibit F: 2024 PSO IRP Technical Conference Minutes

2024 PSO IRP Technical Conference

9/4/2024

Attendees:

Matt Horeled, Amy Brown, Greg Soller, Kelly Pearce, Tracy Harper, Mark Becker, Ismael Martinez, Jack Fite, Kenneth Tillotson, Shelli Sloan, Trenton Feasel, Paul McCurtain, Mark O'Brein, Scott Ritz, Paul Demmy, Jeff Brown, Jim Martin, Dan White, Jason Baker, Chase Snodgrass (AG), Todd Bohrmann (AG), Greg Matejcic (AG), Mike Ryan (PUD), Mike Valez (PUD), Natasha Scott (PUD), Fairo Mitchell (PUD), Nicole King (Commissioner Heitt's Office), Jeff Kline (Commissioner David's Office), Eric Davis (OSN), Montelle Clark (OSN), David Jacobson (Petroleum Alliance), Tom Schroedter (OIEC), Scott Norwood (OIEC), Kikhil Kumar (Gridlab), Taylor McNair (Gridlab)

Start: 10:02 am

Greg Soller, Resource Planning Manager (Facilitator): Covers meeting guidelines and agenda.

Matt Horeled, PSO VP Regulatory & Finance: Introduces team and discusses 5-year plan.

Greg: 2024 IRP Objectives – we want to make sure that not only is the plan affordable, but that we have rate stability, a portfolio with resiliency to react to unexpected events, and a portfolio that maintains a focus on sustainability.

On customer affordability, we looked at this over 30 years (not 20). This is our long-term view. We also look at this over a 7-year/short term view. There are three metrics to rate stability: 1. Portfolio Resilience. 2. Energy Market Exposure – sales and last, Energy Market Exposure - purchases. For us to mitigate the risks, we have to know how much we rely on sales into the market and purchases from the market.

For Reliability, we have three metrics: 1. Reserve Margin – we have a minimum reserve margin. In this IRP, we introduced a summer and a winter reserve margin. 2. Fleet resiliency. This is our ability to deliver energy or be called on to deliver energy in critical times. How many megawatts (MW) of our portfolio are dispatchable or fast ramping. 3. Another metric we introduced this year is Resource Diversity. We need to look at this in terms of capacity and energy. Our capacity has been a key factor for us in the past and we've reliedon the SPP market for energy. Energy diversity is becoming more of a factor for us as more wind resources come online. We are using a Shannon-Weiner diversity index to measure capacity and energy diversity. 4. Sustainability – We continue to measure the reductions of CO_2, NOx, and SO2 because it's still important.

The chart on slide 9 is showing how SPP's reserve margin is declining. This calls on organizations like PSO to change their reserve margins. It was approved this past August to increase planning reserve margins. They added the winter peak of 36%. We expect that 36% to be increased by SPP even further. In addition, SPP is looking to have a more robust planning process by transitioning to an Accredited Capability – ACAP – to not only adjust for load carrying capability of renewables but also accredited capacity of its thermal resources. This IRP assumes a winter Peak Reserve Margin that will grow to 42% by 2029. We have also added an additional 6% to the SPP Reserve Margins to account for uncertainties of where SPP may end up landing.

Regarding the Going-In Position shown on slide 10, we assumed that by the end of 2026, Northeastern Station 3 will cease burning coal. We have also incorporated the additional assumption of RFP resources that have been approved (Pixley, Lazbuddie, Algodon, Chisholm Trail, Flat Ridge IV, Flat Ridge V) as well as the Green Country Plant (combined cycle). We co-optimized the summer and the winter periods so the model could select the resources to serve both periods simultaneously.

Montelle asks: Does PSO think it's likely that SPP will propose or adopt a higher summer PRM by 2030? It's my understanding that SPP’s analysis has discussed a possible 21% PRM. Greg responds: things certainly suggest they could get there but we don’t know. That is part of the reason we wanted to add an additional risk reserve to the obligations and incorporate that on our side, because we just don’t know. Per Matt, the reserve margin continues to go up, we don’t know where they will land.

Scott Norwood: Explain why the ACAP in 2026. Greg goes to slide 9 and explains that the ACAP is something that SPP is defining for the LREs. We have been accustomed to a RM around 12% and now SPP is moving it to 15-16%. Because SPP is now looking at past performance of the thermal units, and ELCC amounts for renewable and storage, all the resources will now get a “haircut” in capacity that will count towards the minimum obligation.

Scott Norwood: Did the modeling assume the ACAP? Greg, yes. SPP gave us a view of the accredited capacity amount for both the summer and winter amounts, so we applied that to our resources.

Scott Norwood asks: What is the net effect to our resources? Does SPP say either or? Greg responds, no, SPP has moved to the ACAP methodology. The Net Dependable PRM is not the controlling factor now, the ACAP is. In some units it helps us, per Greg, and in some units, it is adjusted down, and that will change year over year based on how the units perform. Norwood asks if it is a positive for us in our position, and Greg said not necessarily, in theory – the 16 and 5 percents should be aligned, but some LREs would have poor performing units which could be impacted.

Trenton Feasel, manager Economic Forecasting:

Peak Demand Forecast on slide 11 – attributes increase to the expectation that more data centers are expected to come online in the next few years. Then as we move out into the next 10 years, load growth is more concentrated in manufacturing relative to the other classes.

Slide 12: Residential growth has been flat since the pandemic. We see about a .3% decline over the next decade. Commercial load has been increasing and will continue to jump up as we see more data centers come online over the next few years. We are expecting to see continued commercial growth going forward and this forecast comes from Moody’s Analytics data. Industrial continues to grow going forward based on industries in and around Tulsa such as aerospace, manufacturing, etc.

In terms of the load scenarios that were used for this IRP, the two primary ones are the High and Low Economic Forecasts in terms of GDP. These are the bounds of our forecasts.

We also look at load forecasts in terms of heating trends.

Focusing now on the EV forecast, which is included in this forecast overall. There are currently 5-7k electric vehicles in the PSO area. The base scenario doesn't assume any EV mandates. We assume an electric vehicle mandate that takes effect in 2035 (Slide 14), and a price decline which will also drive EV sales.

Slide 15 – Customer owned solar generation. We currently have about .5% of our peak.

Montelle: Residential energy sales expected to decline, partly as a result of appliance efficiencies. Does this forecast reflect expected trends in electrification, including EV charging? Trenton says yes, it does.

Mark O'Brien, director Gen & Market Simulation, discusses pricing forecasts. On slide 16, we are forecasting SPP prices, natural gas prices, things like that. The Base scenario is close to what we expect. The high is higher gas prices and higher load growth, and the low is lower gas prices and lower load growth. The EER (Enhanced Environmental Regulation) is a proxy for what the EPA published.

Scott Norwood: Is Carbon tax or prices included in this? Mark says the IRP takes the place of that burden. Norwood asks how we are modeling high congestion costs. Mark says that congestion is not part of the forecast modeling, it is captured in another part. Norwood asks if congestion is captured zonally? Mark says we do use zonal. Greg says we will discuss how we incorporate congestion factors in the later slides.

Slide 17: The EER is similar to the rules the EPA published in April. The one big factor here is that the scenario does include treatment for natural gas units, which we expect them to publish later this year.

Slide 18: What we are showing here is the installed name-plate capacity for each of the 4 scenarios. Natural gas decreases by a significant amount as you go out to 2044. We expect natural gas generation to switch to a blend of natural gas and hydrogen. Solar increases a lot between 2025 and 2044. We do increase wind in the base case scenario. There is more of the hydrogen/natural gas blend in the EER case. The left-hand chart is name plate capacity and right-hand side shows how much of the generation dispatches in our model. You can see over time where coal is being replaced by natural gas generation.

The purpose is to give a wide enough band for meaningful, purposeful portfolio planning. On slide 19, you can see how gas prices start at various points and increase over time.

Slide 20: The yellow prices are EER and we wanted to take that out to 2050 – this scenario is heavily dependent on IRA credits/requirements tied to environmental regulations.

Greg discussed the resource alternatives beginning on slide 21. Storage and renewables become available in 2029 (as shown on slide 22) – this gives us 4 years to get through the regulatory process and get the resources online. We have incorporated some short-term marketing purchases until 2028, to allow time to get some resources online. Finally, Northeastern Unit 3 fuel conversion was made available for economic selection in 2026.

Montelle: SPP is restudying or expects it will need to restudy the 2018 to 2023 clusters to reflect projects exiting the interconnection process. Is this something that could affect the renewable resources in your Plan? Regarding battery storage, can you explain the 50-100 limits on batteries? Greg says if you combined all three, you get up to 300 MW per year. We wanted diversity in that storage. 300 MW a year helps us balance the portfolio and be there to react to serving peak loads. We wanted to be sure we didn't over-rely on this to allow other resources to be selected. Montelle says that batteries and CTs have similarities, and Greg says that CTs have some capabilities that storage doesn't. Montelle asks if the storage could be available before 2029, and Greg says we chose 2029 for time to conduct RFP, select resources, get through regulatory approval, and get resources online…plus the timing of the SPP planning year is another thing to consider.

Can you explain ATB annual technology baseline on slide 23? Greg says orange line declines quick through 2030, then starts to flatten out. This incorporates learning curve and PPI inflation index. That is what is driving the price of battery storage prices to increase after 2030. ATB is done on real dollars, no inflationary dollars. Montelle asks if advanced geothermal was considered and why not? Greg says the cost of these resources is less conducive as you move east from areas such as Nevada. Montelle says if you have SMRs (Small Modular Nuclear Reactor) then why not geo-thermal.

Slide 25: Several cost adjustments are included to various technologies. These include adjustments for IRA tax credits for solar and wind as well as carbon sequestration credits. Additionally, network and interconnection costs associated with wind and solar resources are included in addition to capital costs. Gas resources include a gas reservation fee to ensure we have costs assumed for frim gas availability. The chart on the right shows congestion with wind and solar, to try to account for congestion costs those resources might incur as part of the modeling.

Slide 26: Wind and solar ELCCs are informed from SPP. Solar resources do not provide a lot of capacity value in the winter while the wind is pretty steady through the summer and the winter seasons. Storage accreditation is shown in the middle chart. The 4-hour storage has a significant drop. The 6-hour has a better capacity value than the 4-hour. Batteries will be less effective in the winter, reflected by a drop in the winter.

Thermal resources are impacted with accredited ratings informed from SPPs class average of recent performance. For this IRP, gas resources are impacted and include a 22.99% reduction of nameplate capacity for winter accredited capacity.

Slide 27: CVR is well saturated at this point. We have assumed continuation of current DR programs which are included in the model. The plan assumed the potential that was submitted in the recent plan to the Commission that for energy efficiency programs for through 2029 which is incorporated and accounted for in the load forecast. Beginning in 2030, we made a series of Energy Efficiency (EE) bundles available for the model to select.

Montelle: Regarding the Northeastern 3 conversion, has this been cleared under the Regional Haze Settlement? Matt says this is pending, and that we are in the final stages of working through that with parties. It won't be finalized until OkDEQ presents their plan to the EPA and it is accepted by the EPA federally. We probably won't have an answer until next year.

What is the lifespan? Around 15 years.

What if it is not approved and how would it affect our preferred plan? Per Matt, we would have to reevaluate options if it isn't approved, but that is a tricky question for us to address until we have a final answer.

Montelle re: Green Country – does the plant have SCR installed? It was confirmed that GC does have SCR.

Montelle wants to know the costs given the Good Neighbor Rule.

Montelle: with conversion of NE3 unit and acquisition of Green Country which seems like more a baseload plant, this seems like PSO is moving towards a less flexible plan that what I saw in 2023? Greg responded that in alignment with key objectives, we are trying to address our market-risk reliance in terms of energy as well as capacity.

Montelle asks for update on wind facilities. Matt responded that three were given notice to proceed and moving forward. The company is working towards steps of issuing a notice to proceed on the other three projects. Chisholm Trail has some uncertainty related to local opposition. Montelle inquired further on contingency plans related to RFP resource approval success. Matt responded that PSO would need to go back to looking at the current RFP.

Slide 28: Candidate Portfolios modeled align to the Market Scenarios discussed earlier. Three Portfolios with regulations prior to the proposed and the final greenhouse gas rules and then the enhanced environmental regulation (EER) that considers a portfolio with the 111d regulations imposed. In the EER portfolio, we imposed the rules for new gas resources on our existing gas resources. More specifically, the combined cycle resources included a 40% capacity factor constraint.

A Large Economic Development (LEDO) sensitivity was modeled that considered a future where the company might pursue or have customers coming in with a very high load, much higher than what our high load forecast is estimating. Our LEDO sensitivity included a GW of energy load above the Company's High load forecast to let the model to optimize the selection of resources to serve that kind of load.

Finally, a storage sensitivity was considered to understand the balance of resources when storage resources are included. The company is learning through continued studies and analysis, there's that storage resources they have not only their ability to serve loads of peak loads that might get extended, but the company is assuming additional value at the sub hourly level.

Slide 30: Our diversity mix on the capacity contributions goes down in the winter largely because the solar isn't contributing as much. There is a stable amount of gas resources that underpin these plans. The gas capacity does includes Green Country, and this helps us by giving us different resources. The solar amounts increase over time. All plans include a reasonable amount of wind, some include a higher level. On the winter capacity mix, solar is significantly reduced. In the high portfolio and the LEDO, there is an increase in combustion turbine resources to serve the load. The Company is looking to identify some resources that can mitigate the risk of what you saw with a winter storm Uri. Many of these plans have a fundamental amount of gas energy that is being provided, but there is a large part that relies on wind energy which can be intermittent, and we wanted to mitigate some of that risk.

Slide 31: Cumulative Resource Addition Comparisons- The Preferred Plan includes 450 MW of solar in 2031, which is higher than other plans. Wind was preferred in many of the portfolios due to large amounts of federal tax credits based on performance. In the LEDO sensitivity, the 6-hour storage was selected and provides a longer duration to cover peak times and added more value on the capacity side. The Preferred Plan also includes 6-hour storage. The combined cycle resource was selected in the early 2030s in the Low Gas Base Load sensitivity portfolio.

Slide 35: Customer Affordability: The cost difference from year 1 to year 7 was considered in the short term and in the long-term, we looked at the total portfolio costs. In the short-term, high levels of wind resources in the first six portfolios are included and earned large amount of federal tax credits as offsets to capital costs. The Preferred Plan does not have the level of wind resources and the associated federal tax credit offsets. From a long-term view, when you look at the levelized rates on a $/MWh basis, the plans are consistent with each other as this reflects the expiration of tax credits in the different plans as well. On the PTCs, the preferred plan is very competitive when you start to eliminate some of the tax credits. Tax credits amount to between 11 & 15% of the total portfolio direct costs where the PP included tax credits of about 4% of the total portfolio direct costs. More specifically, the PP includes significantly less fixed costs of about $2-4B than the other portfolios.

Slide 37: Rate Stability: Three metrics are included including portfolio resiliency and market energy exposure. For portfolio resiliency, the range of costs was lowest in the High Case while the Proposed PP had the highest range of costs. The high cost range of the portfolios, however, was similar in the $21-22B range. The variation between portfolios shows up in the low cost potential. The Proposed PP has one of the lowest potential costs.

The Market Exposure risks identified market purchases between 10 and 22% of customer load between 2028 and 2034. Average costs of these purchases ranged from $73M to $137M. The PP allows the Company to leverage the market and mitigate some of the current levels of market energy purchases. The Proposed PP also includes some resources to capture upwards of 2% of the peak demand in energy sales for the benefit of customers.

Slide 39: Reliability: Three different metrics including Planning Reserves, Fleet Resiliency and Resource Diversity. Planning reserves for the Base portfolio of 11.2% was right at the minimum that the Company is comfortable to go give the uncertainty around SPP and where they may go with future requirements. Other portfolios include significantly higher planning reserves. The Proposed PP, while above the minimum target summer reserve margin, provides the Company the ability to serve its customers and its obligations.

In the winter, the portfolios show a consistent winter reserve margin. Although PSO in recent years, has not been driven by its winter reserve obligations, recent SPP changes has elevated this to pay closer attention.

Fleet resiliency is consistent among the portfolios in the high 90% of the fleet being dispatchable. It doesn't mean that these resources are actually going to serve customers but they have the ability to serve if needed to be called on by SPP. The resource included in this metric include all thermal resources as well as storage resources.

The Diversity index is our effort to quantify the value. The index looks at the capacity and energy and the Proposed PP has the highest level of diversity across the different portfolios.

Slide 41: Sustainability: NOx and SO2 reductions among the portfolios is consistent and is a testament to the investments the Company has already made.CO_2 reductions are consistent in the mid70% except for the low portfolio and the EER portfolio. It needs to be recognized that those portfolios include additional capital costs to achieve those reductions. For example, the EER includes resources with $4B in additional fixed costs over the Proposed PP while also estimating approximately $3B in production tax credits.

Slide 41: NOx and SO_2, current investments have resulted in reductions that continue over time. With the CO_2, those are reduced through 2034.

Tom S. Thanks Greg for the comprehensive presentation. What is the status of PSO's pending RFP and has a selection been made for resources and is that taken into account in the IRP? Matt says the RFP is still on-going, but we have a short list and will then move into negotiations with the parties. But some market data and intelligence has been utilized. Greg says we used some of the costs from the RFP responses i.e. technology costs. Tom – is the Northeastern 3 conversion a result of the IRP or part of RFP? Matt says it is extremely economical option, so it wasn't bid into the RFP but was by far a lowest cost option. Tom asks – what about Green Country? Was this bid into the RFP or a separate transaction and what is the status of the acquisition of the unit? Matt says we have signed a purchase agreement with the seller of Green Country and we are putting forth a regulatory filing to put before the OCC this year, and will be able to close that pending final OCC approval next year. Per Matt, Green Country was a separate transaction and was not bid into the RFP. Tom asks if IRP group can share the slides? Greg will get that to Tracy and Tracy will send that out.

Montelle: On page 67 of the report, the solar says zero for made annually, Greg says it should be 300 and will correct it. Montelle asks, "Why wasn't the hybrid resource chosen?" Greg says it is more expensive, and hybrid storage wasn't rising to the economic level of others. Utilities such as PSO can take advantage of storage more as stand alone. As a matter of economic selection, the hybrid resource didn't rise to be competitive against the other alternatives. Montelle also asks about LEDO sensitivity – and does the base load include project anthem? Greg says yes. We wanted to make sure we optimized the portfolio under a large enough load, so the LEDO is a proxy for a load like that. Montelle is asking about large load tariffs, and if PSO is considering something like what Ohio is doing with tariffs to protect customers. Greg brings up slide 42 and discusses the big capital expenditures of bringing in large loads. The point is, should those things arise, this must be part of the conversation in the negotiations about the impact on levelized rates.

Montelle asks if we can attach our transcript to the presentation prior to the 9/23 meeting. Greg says we will have notes in the final IRP ahead of the public meeting. IRP Technical Conference Presentation to be sent out this week by Tracy (sent via email on 9/4)

Other action items:

Tracy to send slides to stakeholders (done 9/4)

Greg to update page 67 of the report to reflect 300MW.

Montelle asked the status of North Central wind resources.