2026

2026 Electric Integrated Resource Plan

Prepared by:

Electric Integrated Resource Planning

Colorado Springs Utilities®

It's how we're all connected

Final Report 2026

Electric Integrated Resource Plan

Colorado Springs Utilities®
It's how we're all connected

Prepared by:

Electric Integrated Resource Planning

Colorado Springs Utilities

Final Report | June 2026

Table of Contents

List of Figures

List of Tables

List of Acronyms and Abbreviations

Acronyms	Definition
ACAP	Accredited Capacity Planning Reserve Margin
APIP	Airport Peak Innovation Parkway
ATB	Annual Technology Baseline
CEP	Clean Energy Plan
CHP	Clean Heat Plans
CSG	Community Solar Garden
DSM	Demand-side Management
EIRP/IRP	Electric Integrated Resource Plan
ELCC	Effective load carrying capacity
ERP	Energy Resource Planning
EUE	Expected unserved energy
EV	Electric Vehicles
FPP	Fuel and Power Procurement
GHG	Greenhouse gas
kW	Kilowatt
kWh	Kilowatt-hours
LCF	Load Contributing Factors
LOLE	Loss of Load Expectation
mi/kWh	Miles per kilowatt-hour
MW	Megawatts
MWh	Megawatt-hours
NREL	National Renewable Energy Laboratory
PBA	Performance-based Accreditation
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
PV	Photovoltaic
RTO	Regional Transmission Organization
SDO	Colorado State Demography's Office
SMR	Small Modular Reactor
SPP	Southwest Power Pool
USAFA	United States Air Force Academy
WECC	Western Electricity Coordinating Council
WEIS	Western Energy Imbalance Service
WAPA	Western Area Power Administration

Executive Summary

ES.1 Purpose of the Electric Integrated Resource Plan

The Electric Integrated Resource Plan (EIRP) is a long-term planning process designed to identify the most cost-effective and reliable way to meet future electric demand in Colorado Springs. The study window for this EIRP goes 20 years out to 2045. By forecasting electric load growth within Colorado Springs Utilities' service territory, it is possible to project the generation resources required to meet these needs.

Using the advanced electric system modeling software PLEXOS, optimal build plans and strategies are created and analyzed. Additional internal stakeholder feedback, community input, and non-modeling criteria refine the plan, ultimately providing a strategic direction for future generation resource acquisitions and operation.

ES.2 Key Findings

Throughout the process, which involved hundreds of modeling runs and dozens of scenarios and sensitivities, balanced portfolios best met reliability and cost metrics. Solar, nuclear, and geothermal rose to the top consistently. Despite high upfront capital costs, nuclear's favorability can be attributed to the longevity of nuclear assets combined with high-capacity accreditation and emissions-free baseload power.

Meeting reliability requirements using only solar, wind and battery, while striving for emissions reduction targets, becomes exponentially costly and impractical. Due to accredited capacity values, explained in greater detail in **Section 5.3.2**, three to ten times more renewable resources are needed for every MW of firm capacity required.

Springs Utilities recognizes uncertainty in the market, specifically around nuclear. As such it is important to note the earliest these resources can be selected in the model is 2038. This lag time allows for careful evaluation as critical dates approach. Multiple "what-if" scenarios provide key off-ramps and pivots opportunities in the future.

ES.3 Recommended Plan

In accordance with the key findings, the following plan was the lowest-cost option within defined constraints, particularly the Planning Reserve Margin (PRM) set forth by the Regional Transmission Organization, emissions targets per Senate Bill 26-182, and projected load growth. Specific costs and modeling assumptions were reviewed by a third-party consultant, bolstering Springs Utilities' goal of providing the best possible plan for the community. The recommended resource plan includes adding 750 MW Solar, 425 MW Wind, 477 MW Nuclear and 50 MW Geothermal. This plan assumes that the Front Range Power Plant will stay online through 2045. If this plant is retired earlier than planned, additional resources will need to be built in its place.

Figure ES- 1 is an illustrative view of the balance of loads and resources for the Springs Utilities system using the system load forecast, existing Springs Utilities generation resources, and recommended new generation resources. The new resources and available capacity will be constructed based on system needs and actual project timelines. **Figure ES- 2** shows a breakdown of the new capacity by generation type. These values and the recommended portfolio are explained in more detail in **Section 7.2**.

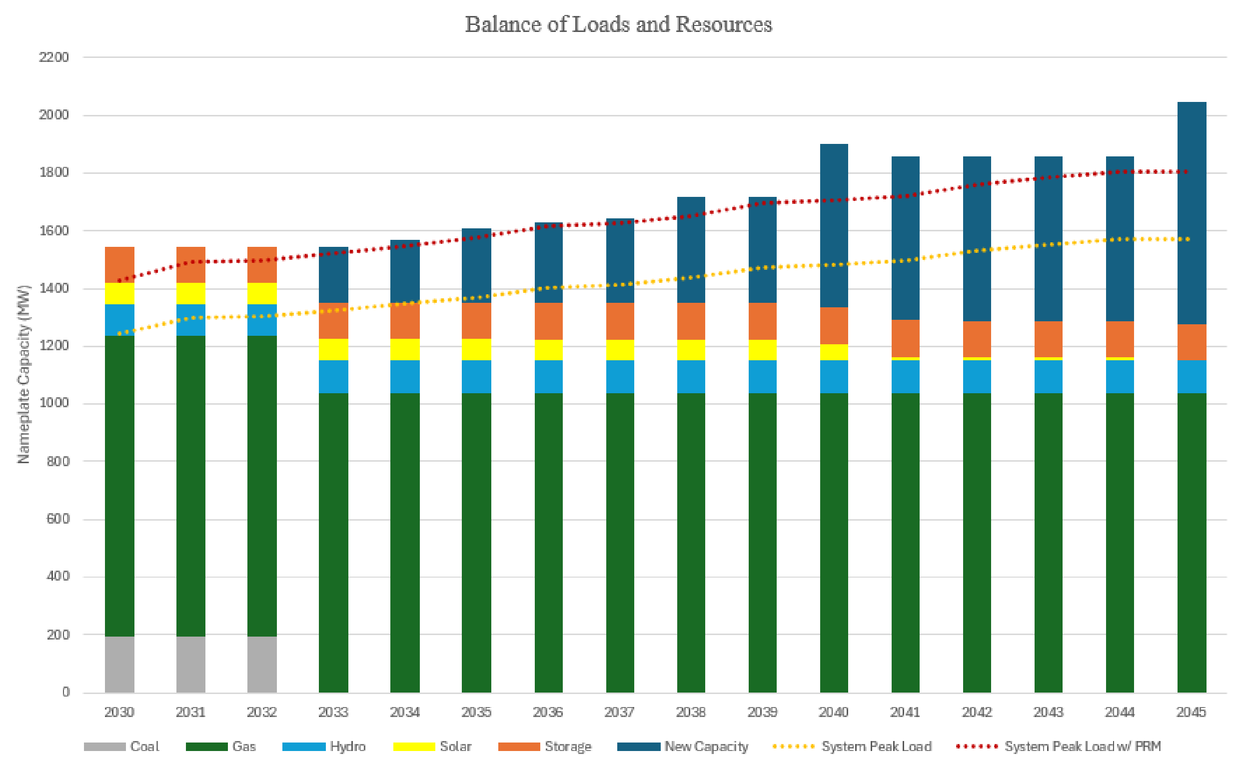


Figure ES- 1: Balance of Loads and Resources - Recommended Case

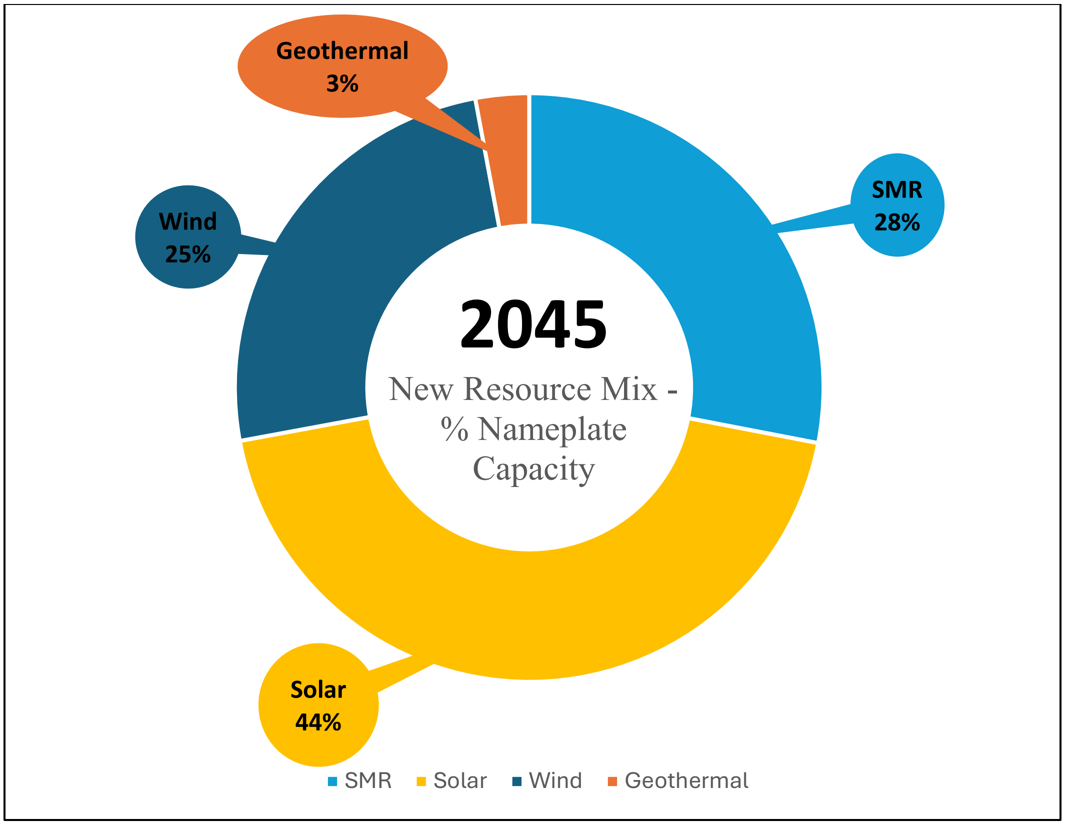


Figure ES- 2: Recommended Case - New Resource Mix by Generation Type

ES.4 Major Risks and Sensitives

Long-term planning requires several assumptions. Assumptions that are both foundational to the plan and most variable include load growth, geopolitical disruptions (supply chain and pricing shocks), regulatory/policy changes, the cost of energy in the market, and the pace of new generation technology development. These assumptions are guaranteed to change and may do so with greater severity as the study horizon lengthens.

Sensitivities in the modeling process provide guardrails to understand the degree to which a plan changes in a future state compared to our original assumptions. Examples include running the model with high-priced nuclear capital cost, increasing or decreasing the cost of energy in the market, and alternate load profiles based on electric vehicle adoption and overall load growth.

ES.5 Next Steps

To mitigate the risks and tradeoffs discussed in **Section ES.4**, Springs Utilities is taking immediate steps in the following areas:

- Annual updates to this EIRP to validate assumptions;
- A Request for Proposal for 300 MW of renewable resources, to be operational by 2030;
- Detailed feasibility study and business model evaluation on nuclear; and
- Submission of an updated Clean Energy Plan as required by Senate Bill 26-182.

Section 1: Introduction

1.1 Introduction and Background

The 2025 Colorado Springs Utilities (Springs Utilities) Electric Integrated Resource Plan (EIRP) seeks to establish long-term planning objectives while incorporating proper risk management. The EIRP was developed with the support of the Colorado Springs Utilities Board. The main goal of the EIRP is to provide Springs Utilities' customers with resilient, reliable service that is cost-effective and achieves key environmental targets. The EIRP includes public input and is typically developed every five years. The study horizon went to 2045. This horizon allows the EIRP to quantify long-term system impacts while helping to ensure short-term flexibility.

1.2 Colorado Springs Utilities Territory and System Overview

Colorado Springs is the second largest city in the state of Colorado with a population of approximately 545,000. In 1924, Colorado Springs voted to establish a four-service public utility to be owned and operated by the city.

Springs Utilities is responsible for the operation and maintenance of the system and currently serves approximately 264,000 electric service points within its 475 square mile electric service territory. As of 2025, Springs Utilities had energy requirements of 4,968,000 megawatt-hours (MWh), a system peak of 1,011 megawatts (MW), and an electric system reliability of over 99%. To serve customer load and energy requirements, Springs Utilities currently owns five active thermal generation facilities and six hydroelectric generation facilities with a max capacity of 1,001 MW during the summer season, and 624 MW of long-term PPAs comprised of 289 MW of solar, 60 MW of wind, 75 MW of hydro, and 100 MW of battery storage.

Springs Utilities maintains and operates nearly 3,800 miles of electric distribution lines and more than 200 miles of transmission lines around the city. Transmission lines deliver electricity at a high voltage from a generation source (power plants, solar arrays, windfarms, etc.) to an electric substation. Distribution lines deliver electricity at a lower voltage from a substation to a local electric distribution network that may include transformers and/or switches or overhead service lines that safely feed customers' homes and businesses with electricity.

1.3 Electric Integrated Resource Planning (EIRP) Goals

The primary objective of an EIRP is to provide an economic evaluation of a utility's power supply portfolio over both short and long-term planning horizons, with a specific focus on short-term decisions that will position the utility for long-term success. To support this objective, Springs Utilities, through a public process, developed five main goals summarized below:

Goal 1: Resilient and Reliable

- Maintain industry leading reliability and resiliency.

- Continue the ability to react to variable or extreme daily operating conditions.

Goal 2: Cost-Effective Energy

- Maintain competitive and affordable rates while avoiding stranded assets.
- Further advance energy efficiency and demand response.

Goal 3: Environmental Sustainability

- Responsibly grow the renewable portfolio.
- Establish timelines for decommissioning of assets.
- Meet environmental regulations with specific metrics, including those related to reduced carbon emission.

Goal 4: Resource Flexibility

- Maintain the ability to adapt to regulatory and market disruptions.
- Reduce reliance on fossil fuels.

Goal 5: Innovation

- Proactively and responsibly integrate new technologies.

1.4 Electric Integrated Resource Planning Process

During the EIRP process, Springs Utilities followed the procedure as is explained in Section 7 of this report. During each phase of the EIRP, Springs Utilities took a proactive approach to discuss the study with different stakeholders through a structured public stakeholder process. The process also includes analysis of numerous sensitivities and scenarios to evaluate risk and consistency in build plans. At the end of the EIRP process, Springs Utilities recommended its strategic direction to the Springs Utilities Board.

1.5 Stakeholder Engagement

The Springs Utilities' planning team worked to ensure this EIRP was thorough and involved appropriate stakeholders at each level. Multiple iterations of the model were run based on feedback, ultimately landing on an approach that appropriately weighted risks, costs and capacity for new customers.

A structured communication and engagement strategy guided outreach to customers and regional stakeholders. While the 2020 EIRP marked a major shift in local generation and the start of the utility's energy transition, this EIRP focuses on reporting progress on those commitments and updating the path forward.

Outreach efforts included a virtual community check-in in August 2025 to provide updates on the Sustainable Energy Plan and gather input on the electric and gas IRPs, as well as two customer surveys: the November 2024 Benchmark Survey and the June 2025 Rates and Incentives Survey. Additional engagement included 12 community presentations.

Together, these efforts provided multiple opportunities for customers, stakeholders and elected officials to stay informed and share input to support the planning process.

Section 2: Planning Landscape

2.1 Colorado Policy Update

2.1.1 Clean Energy Plan

Colorado House Bill 19-1261, or Colorado's Clean Energy Plan set state greenhouse gas emission target reductions relative to 2005 levels. The targets established statewide goals to reduce 2025 greenhouse gas (GHG) emissions by at least 26%, 2030 GHG emissions by at least 50%, and 2050 GHG emissions by at least 90%. Further guidance from the State recommended municipally owned electric utility companies reduce their GHG emission by at least 80% and retire coal-burning power plants by 2030 to help the State meet the above targets.

In May 2026, Colorado Senate Bill 26-182 was signed into Colorado law, which allows municipally-owned utilities to file a revised Clean Energy Plan (CEP), by the end of 2026 that extends the deadline for achieving an 80% greenhouse gas emissions reduction from 2030 to 2033. This creates a pathway for Springs Utilities to operate Nixon Unit 1 until Dec. 31, 2032.

2.1.2 Clean Heat Plan

In 2021, the General Assembly required gas distribution organizations, utilities that procure and distribute gas to retail customers such as residents and local businesses, to reduce GHG emissions by 4% by 2025 and by 22% by 2030, from a 2015 baseline.

To demonstrate compliance, gas utilities began filing Clean Heat Plans (CHPs) with the Air Pollution Control Division starting in 2023. A CHP may include a mix of supply-side resources which replace traditional gas supply and demand-side resources with electric alternatives, reducing the amount of gas customers use but increasing electric load. This increase in electric load is captured in Springs Utilities' load forecast. Clean heat resource options include:

- Energy efficiency programs, which help customers pay for energy reducing upgrades;
- Recovered methane, including the gas captured at feedlots, landfills and water purification facilities;
- Green hydrogen, where water is converted to hydrogen through electrolysis using renewable energy;
- Beneficial electrification, which is a change in energy source from gas to electric in a way that meets the following qualifications:
    - Reduction in systems costs for the Springs Utilities' customers
    - Reduction in new carbon dioxide emissions; and
- Provide for a more efficient utilization of grid resources.

Springs Utilities' plan will involve meeting the cost cap requirements, which will have a minimal impact on rates and increased electric generation requirements.

2.2 Federal Policy Update

2.2.1 Clean Energy Production Tax Credit

The Clean Electricity Production Tax Credit (PTC) under Section 45Y is a technology-neutral production tax credit that replaced the legacy Energy Production Tax Credit for facilities placed in service after December 31, 2024. The credit provides a per kilowatt hour (kWh) incentive zero emission electricity technologies sold over a 10-year period. The Clean Electricity PTC, under the Inflation Reduction Act, was scheduled to be phase-out starts beginning in the later of 2032 or when U.S. greenhouse gas emissions from electricity are 25% of 2022 levels. However, recent federal guidelines enacted in 2025 accelerated the phaseout timelines for wind and solar projects.

Recent federal policy updates, including provisions under the One Big Beautiful Bill Act (OBBBA) introduce additional eligibility and compliance requirements for certain technologies. These changes include stricter construction start and in-service timelines for wind and solar projects, revised construction start times prior to mid-2026, stronger domestic requirements, and tighter rules regarding foreign ownership or financing. These changes may reduce eligibility for projects that rely heavily on imported components or non-domestic capital.

As a result, the overall cost of wind and solar projects are expected to increase for suppliers to maintain profitability. These increases were considered in the cost of projects in Springs Utilities' model.

2.2.2 Clean Energy Investment Tax Credit

The Clean Electricity Investment Tax Credit (ITC) under Section 48E is a technology-neutral clean electricity investment tax credit under the Inflation Reduction Act that replaces the legacy Energy Investment Tax Credit. It is for qualifying facilities clean placed in service after December 31, 2024. Unlike the PTC, which is based on energy production, the ITC provides an upfront tax credit based on a percentage of a project's eligible capital cost. The credit is available to zero emission electric generation, and certain storage technologies placed in service after 2024. The ITC begins being phased out in the later of 2032 or when U.S. greenhouse gas emissions from electricity are 25% of 2022 emissions or lower. However, recent federal legislation in 2025 accelerated the phaseout timelines and additional compliance requirements for certain technologies, especially for wind and solar resources.

Recent federal policy updates under the OBBBA introduce additional eligibility constraints, including stricter construction start and placed-in-service timelines, expanded domestic material requirements, increased scrutiny on foreign ownership or involvement.

Like the PTC impact, the overall cost of wind and solar projects are expected to increase for suppliers to maintain profitability. These increases were considered in Springs Utilities' model.

2.2.3 Tariffs

In 2025, the United States significantly expanded the tariffs placed on renewable energy supply chains, primarily targeting imports from China and Southeast Asia. Section 201 tariffs were extended, which placed a 30% tariff on solar modules from some countries (since then this number has decreased to about 14%). An increase in Section 301 tariffs targeting imports from China increased the tariffs on solar cells and components to 50% and lithium-ion batteries and components to 25%. Section 232 tariffs continue to apply to steel and aluminum imports at a rate of 25%. Additional tariff measures were placed on all imported materials and equipment into the U.S. at a minimum of 10% and varying by country and products. As a result of these policies, solar project costs have increased by roughly 10%, wind project costs have increased by roughly 9%, and battery project costs have increased by roughly 14%. Where publicly available information did not reflect the impact on project costs, manual cost adders were applied within the model.

2.3 Technology Changes

2.3.1 Technology Assessment

Springs Utilities regularly evaluates new and existing generation technologies. Important factors considered include commercial availability, technology readiness, total lifecycle cost, availability information, and geographic feasibility. Based on these considerations, some technologies were eliminated before the modeling phase. The resource planning team will continue to track and evaluate emerging technologies and may incorporate them in future planning cycles as information and conditions evolve.

A list of resources that were researched can be found in **APPENDIX C**.

2.3.2 Regional Transmission Organization

In April 2026, Springs Utilities joined Southwest Power Pool (SPP), a Regional Transmission Organization (RTO). SPP centrally dispatches energy from participating resources throughout the region, enhancing both the reliability and affordability of electricity delivery from utilities to their customers. As the market’s administrator, SPP maintains reliability of the region’s transmission system and meets demand with the most cost-effective generation available, reducing wholesale electricity costs for participants.

2.4 Challenges and Critical Factors in Resource Planning

- Potential of reduced WAPA hydro allocations due to prolonged drought conditions and constrained water supply
- Shifting market dynamics and long-term planning strategy within the RTO
- Incorporating expected large load growth

- Supply chain constraints impacting equipment availability, which extends planning timelines and poses challenges in meeting in-service dates for new resources
- Economic factors, including inflation, higher interest rates, and geopolitical instability, leading to higher prices and decreased equipment and labor availability
- Meeting emissions reductions targets by 2033 while supporting city and economic growth
- Demand-side management (DSM) trends influencing net peak load, EV charging patterns, and customer usage patterns
- Multiple promising technologies are on the cusp of market viability, but it is unclear when, and if, they will be available

Section 3: System Load Forecast

3.1 Energy Resource Planning Forecast

The Energy Resource Planning (ERP) Forecast is a detailed and forward-looking load forecast. This forecast is designed to support long-term resource, transmission and distribution system planning needs over a multi-decade horizon. The ERP Forecast is updated once in January and once in July.

Springs Utilities' peak load forecast can be seen in **Table 3-1** below.

Table 3-1: Springs Utilities Peak Load Forecast

Year	Peak Load
2026	1,068
2027	1,062
2028	1,143
2029	1,196
2030	1,243
2031	1,298
2032	1,304
2033	1,325
2034	1,346
2035	1,370
2036	1,404
2037	1,413
2038	1,436
2039	1,474
2040	1,483
2041	1,497
2042	1,532
2043	1,552
2044	1,570
2045	1,570

3.1.1 Methodology

The ERP forecast begins with Springs Utilities' native load and models the drivers expected to shape future load growth or decline. These drivers are referred to as Load Contributing Factors (LCFs).

LCFs are selected based on:

- Magnitude of impact on system load; and
- Availability and quality of data to support statistical modeling.

Once individual LCF forecasts are established, they are aggregated with the native load growth to produce a system load forecast, including:

- Hourly energy usage; and
- Seasonal peaks and minimums, including:
    - Summer peak;
    - Winter peak;
    - Shoulder-season peaks; and
    - System minimums.

This approach captures both changes in total energy consumption and how and when energy is used, reflecting evolving customer behavior and technology adoption.

To reflect the uncertainty in long-term load growth, additional forecasts are developed to reflect possible real-world scenarios. These scenarios include a range of potential outcomes for each LCF. The multiple forecasts are then utilized to inform the load shape and amount of energy required in the future.

3.1.2 Load Contributing Factor Development:

To establish LCFs, Springs Utilities uses a driver-based bottom-up approach and works with subject matter experts to:

- Establish a historical baseline;
- Perform back-casting to understand observed trends;
- Identify growth drivers, including:
    - Adoption curves;
    - Technology and equipment changes;
    - Committed or announced projects and expansions; and
    - New regulatory targets.

Each LCF is then modeled independently before being combined into a comprehensive system forecast. This allows the forecast to capture structural changes in load shape, not just changes in total energy consumption and peak demand. Historical back casting ensures future projections are grounded in observed system behavior and not theoretical or national averages. The following sections provide an overview of each LCF.

3.1.2.1 Population

Population growth assumptions incorporated into the load forecast are based on data obtained from the Colorado State Demography's office (SDO). This source provides the most consistent and authoritative historical population estimates for use in long term utility planning.

Analysis of historical population trends for Colorado Springs indicates an average year over year growth rate of 1.09% from 2012 to 2023. This observed growth rate serves as the baseline population growth assumption utilized in the load forecasting model. Applying a long-term average smooths short-term volatility while remaining grounded in documented historical trends and regional demographic conditions.

The population dataset used for this forecast reflects existing customers within the current service territory and does not include population impacts associated with future annexations or economic development projects. Load impacts from these developments are evaluated separately to ensure that forecast assumptions remain consistent with confirmed service obligations and infrastructure availability.

3.1.2.2 Electric Vehicles

Electric vehicle (EV) load impacts are modeled within the ERP forecast to capture both anticipated growth in EV adoption and the resulting effects on system load shape. Estimating EV related electricity consumption requires modeling of two primary components: (1) the number of EVs in our service territory and (2) customer charging behavior, including timing and location.

To capture uncertainty in transportation electrification, Springs Utilities evaluated five distinct EV adoption scenarios spanning a wide range of potential market and policy conditions. These scenarios differ primarily in the assumed rate and ultimate maximum adoption rates of EVs over the planning horizon. The scenario set reflects varying trajectories of state and federal policy, changes to vehicle cost, charging infrastructure availability, customer adoption and fuel price dynamics. A graph of these 5 scenarios can be seen in **Figure 3-1** below.

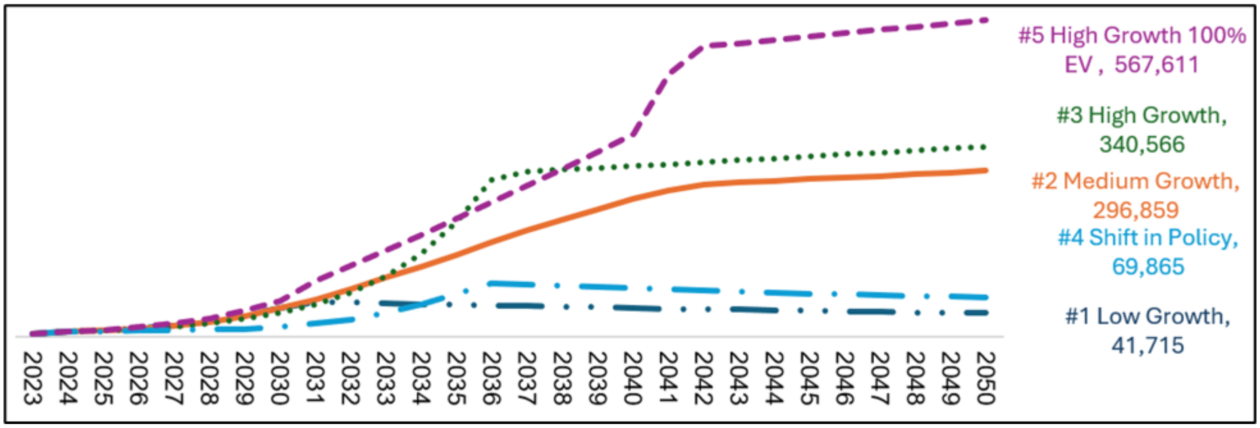


Figure 3-1: EV Charging Forecast (# of Customers)

The five scenarios modeled include:

- #1 Low Growth - low adoption trajectory, low maximum adoption percentage;
- #2 Medium Growth - expected base adoption trajectory, maximum adoption percentage;
- #3 High Growth - slightly higher than expected adoption rate trajectory, maximum adoption percentage;
- #4 Shift in Policy - slightly lower than expected adoption trajectory due to shifting policies.
- #5 Highest Growth - higher than expected adoption trajectory, maximum adoption percentage

Each adoption trajectory is internally consistent with assumptions regarding vehicle turnover rates and customer charging access. For planning purposes, the medium growth scenario is used to develop the base forecast, while the remaining scenarios are retained for risk assessment, stress testing and resource adequacy evaluation.

3.1.2.3 Energy Use per Vehicle

Annual energy consumption per EV is estimated using the following assumptions related to vehicle travel and efficiency:

- Estimated annual mileage: 11,100 miles; and
- Miles per kilowatt-hour (kWh): 2.25 to 3.5 miles per kWh, depending on vehicle size and ambient temperature, with larger vehicles toward the lower end of the range.

For modeling purposes, 2.75 miles per kWh was used as a reasonably conservative efficiency value that reflects the increasing market penetration of larger EVs.

Based on these assumptions, estimated annual energy consumption per vehicle is calculated as mileage divided by efficiency, resulting in a range of 3,171 to 4,933 kWh per year. A planning value of 4,036 kWh per vehicle was used, equivalent to approximately 11.06 kWh per day (**Table 3-2**).

Table 3-2: Estimated Annual Energy Consumption Per Vehicle

	Estimate	Used in Load Forecast
Estimated annual mileage	11,100 miles	11,100 miles
Miles per kWh	2.25 to 3.5 miles per kWh, depending on vehicle size and temperature.	2.75 miles/kWh as a reasonably conservative value incorporating larger EV’s just now coming to market.

	Larger vehicles will be toward the lower end of the range.	
Annual energy	3,171 • 4,933 kWh	4,036 kWh/year or 11.06 kWh/day

3.1.2.4 Timing of Charging

The timing of EV charging is critical to understanding impacts on hourly load and system peaks. Charging profiles were developed using output from the National Laboratory of the Rockies (NLR) EVI Pro Lite tool, representing four distinct charging scenarios. These scenarios are blended in varying proportions across future years to reflect evolving customer behavior, rate design influences and charging infrastructure availability:

- Immediate charging: Vehicles charge upon arrival at home at approximately 5:00 p.m. and continue until the battery reaches 100 percent capacity.
- Finish by departure: Charging completes by a designated departure time, assumed to be 7:00 a.m.
- Energy Wise: This scenario reflects customers adjusting charging behavior to avoid Time of Use (TOU) peak pricing between 5:00 p.m. and 9:00 p.m. on weekdays.
- Workplace charging: Charging occurs primarily during daytime hours, with the highest impact between 8:00 a.m. and 5:00 p.m.

These four charging scenarios are modeled to evolve over time, accounting for anticipated changes in customer charging preferences, workplace charging availability, and rate structures. The resulting blended charging load profiles allow the ERP forecast to capture both energy growth and potential shifts in peak demand associated with increased EV adoption.

3.1.2.5 Industrial Power

Existing industrial load data were derived from Springs Utilities’ Electric Information Administration (EIA) Form 861 filings. Historical analysis indicates substantial year-over-year variability in industrial energy demand within Colorado Springs, with observed rates of change between +/- 6%. Given this volatility, along with current population growth projections, regional employment trends and ongoing economic development activity for which Springs Utilities may not receive advance notification, a conservative planning assumption was adopted.

Specifically, Springs Utilities has assumed an average annual growth rate of 1% for industrial load not associated with municipal annexations or formally identified economic development projects, as those impacts are modeled separately. This baseline growth assumption reflects incremental demand increases from existing industrial customers as well as new customers whose electricity consumption does not exceed the 5 MW threshold that triggers mandatory notification to the utility. This approach provides a balanced and prudent representation of expected industrial load growth while maintaining consistency with historical data and current planning visibility.

3.1.2.6 Energy Efficiency

Springs Utilities actively promotes energy efficiency through a comprehensive portfolio of customer education initiatives and rebate-based incentive programs. These programs are designed to encourage the adoption of high-efficiency technologies, including building shell improvements such as insulation and air sealing, high-efficiency heat pumps and furnaces and ENERGY STAR® rated appliances. Through targeted outreach and financial rebates, customers are guided toward the most efficient products available, with rebates structured to offset incremental costs and accelerate market adoption of higher-efficiency equipment.

For planning and forecasting purposes, the impact of these energy efficiency and peak demand reduction initiatives is quantified by evaluating historical trends in annual energy consumption on a per customer basis, combined with the projected continuation of existing programs. Based on this methodology, Springs Utilities estimates that existing programs will result in an average annual load reduction of approximately 0.12%. This assumed reduction reflects the cumulative and sustained impact of ongoing investments and is incorporated into the load forecast as a persistent offset to underlying growth in the ERP forecast.

3.1.2.7 Electrification

Electrification impacts incorporated into the base load forecast exclude electric vehicles, as EV adoption and associated charging impacts are evaluated separately within the ERP forecasting framework. Excluding EVs allows for clearer attribution of load impacts across major electrification pathways and avoids double counting effects across load contributing factors.

Outside of transportation electrification, the most significant customer decision influencing electrification related load is the adoption of electric space heating technologies, particularly heat pumps. Space heating technology selection has material implications for both annual energy consumption and seasonal peak demand. As a result, heating electrification is treated as a discrete and critical component of long-term resource planning, with particular relevance for winter peak system conditions.

The electrification assumptions used in this forecast are derived from evaluating the electrical demand impacts of ENERGY STAR® heat pumps, cold climate heat pumps, and high efficiency gas furnaces across both summer and winter operating conditions. The study assessed hourly demand profiles and peak contributions associated with each technology, with specific focus on winter performance, where system constraints and reliability risks are highest. The results demonstrate that auxiliary heating configurations play a significant role in shaping overall peak load outcomes.

The study shows that ENERGY STAR® heat pumps with a gas furnace as an alternative heat source are on average having a 5.5 times lower peak electrical demand compared to electric resistance heating. This finding highlights the substantial peak demand benefits of hybrid heating configurations and underscores the importance of backup heating technology choice. In contrast, resistance-based backup systems exhibit considerably higher coincident peak demand, particularly during extreme cold weather events, amplifying system stress during critical periods.

Based on customer rebate program data, it is estimated that 29% of electric heat customers use an ENERGY STAR® heat pump, 55% use a cold climate heat pump, and 16% deploy resistance heat as a backup to heat pump heating. These market shares reflect observed customer adoption patterns influenced by climate conditions, equipment performance characteristics and incentive program design. For forecasting purposes, this distribution is assumed to persist over the planning horizon absent material changes in technology cost, efficiency, or program structure.

Given the importance of heat pump adoption to Springs Utilities' generation requirements and peak demand exposure, future heat pump adoption is assumed to follow defined trend trajectories over the forecast horizon. These adoption trends are incorporated into the load forecast to capture the evolving mix of heating technologies and their corresponding impacts on both energy consumption and peak demand. This approach ensures consistency between observed customer electrification behavior and long-term system planning assumptions.

Uncertainty in customer adoption of electric heating technologies is addressed through the evaluation of three distinct heat pump adoption scenarios. These scenarios reflect differing levels of customer willingness to electrify space heating and differing economic signals driven by technology cost trends, incentive availability and building retrofit complexity.

The three scenarios span a low, medium and high electrification adoption range, representing bounded outcomes for the pace at which heat pumps replace or displace fossil-based heating systems. The low adoption scenario reflects continued customer preference for gas heating in retrofit applications, constrained by upfront cost and building limitations. The medium adoption scenario represents observed recent adoption trends extended forward, informed by current rebate participation and market response. The high adoption scenario reflects more rapid electrification driven by improved heat pump performance, expanded incentive programs and stronger customer response to decarbonization objectives.

Across all scenarios, the mix of ENERGY STAR® heat pumps, cold climate heat pumps, and resistance-based backup systems remains aligned with observed program data unless material changes in technology performance or incentive design occur. This approach ensures that scenario differences are driven by adoption volumes rather than technology mix shifts, isolating the primary planning uncertainty associated with electrification uptake.

3.1.2.8 Distributed Photovoltaic Generation

Distributed solar generation represents the most significant customer-sited resource affecting net system load. As of the current study period, distributed solar capacity interconnected to the Springs Utilities system exceeds 50 MWs and is deployed across more than 10,000 customers. Continued customer adoption of both rooftop and community solar installations contributes to a reduction in daytime energy demand and alters the shape of the system load profile. Photovoltaic (PV) capacity and energy data used in this analysis were sourced directly from Springs Utilities' customer-level datasets.

To address uncertainty in customer-sited solar growth, three distributed solar adoption scenarios were evaluated in the load forecasting process. These scenarios reflect differing assumptions regarding customer economics, equipment cost trajectories and interconnection policy conditions. The selected adoption scenario is representative of historical adoption rates in the market today, where the low and higher adoption scenarios are used to model the impacts of shifting market conditions.

Maximum distributed solar generation is calculated using customer-reported nameplate capacity and is aligned with historical weather conditions through the application of performance data from the fixed-tilt Venetucci Solar Garden. This reference installation was selected to approximate the operational characteristics, orientation and seasonal production profile representative of distributed solar resources across the service territory. This methodology provides estimates of annual energy production as well as hourly system impacts, including both on-peak and off-peak contributions from distributed solar generation.

Distributed solar provides a reduction in net system load and overall energy requirements. However, its ability to contribute to system peak demand is more limited and may result in a shift in the timing of the system peak, particularly as distributed solar penetration increases. Customer-sited energy storage adoption remains negligible and does not materially influence the current load forecast. Adoption rates may increase following the implementation of Energy Wise rates[1]. If program design and cost structures improve the economics of pairing energy storage with distributed solar, the operational and planning impacts of distributed solar on the system could alter the operational and planning impacts over time through peak load reduction, net load smoothing and increased system flexibility.

---

[1] The Energy Wise program by Colorado Springs Utilities is designed to help customers save on their electricity bills by offering different rates based on the time of day electricity is used. This initiative aims to reduce demand during peak hours, which are typically more expensive due to higher energy consumption.

Section 4: Existing Resources

4.1 Existing Generation Resources

Springs Utilities' existing owned generation resource mix consists of five thermal generating units and six hydroelectric units totaling 1,401 MW of generation capacity with capacity ratings differing slightly between winter and summer. Most of Springs Utilities' energy requirements are generated from the 208 MW coal-fired Nixon unit and the 542 MW natural gas-fired Front Range combined cycle plant. The coal unit is typically operated as a base load (e.g., 24 hours per day, 7 days per week) resource, while natural gas and hydro units are typically used to meet intermediate and peaking load demands. An additional 400 MWs of aeroderivative natural gas units are planned to be brought online before 2030. This generation capacity is included in every scenario. A summary of Springs Utilities' generation resources is represented in **Table 4-1**. A description of each of Springs Utilities' existing plants can be found in **APPENDIX B** of this document.

Table 4-1: Springs Utilities Existing Generation Resources

Unit Name	Category	Summer Nameplate Capacity (MW)	Retirement Date
Nixon Unit 1	Coal	208	12/31/2032
Nixon Unit 2	Combustion Turbine	33	12/31/2054
Nixon Unit 3	Combustion Turbine	33	12/31/2054
Front Range	Combined Cycle	542	12/31/2050
SPAGs	Combustion Turbine	150	12/31/2052
Williams Creek	Combustion Turbine	400	12/31/2060
Manitou 1	Hydro	2.5	12/31/2054
Manitou 2	Hydro	2.5	12/31/2054
Manitou 3	Hydro	0.6	12/31/2054
Tesla	Hydro	28	12/31/2054
Ruxton	Hydro	1.0	12/31/2054
Cascade	Hydro	0.8	12/31/2054
Total Generation		1,401	

When economically beneficial, Springs Utilities also purchases market power as needed to supplement existing generation resources. Membership in the Southwest Power Pool RTO, as described in **Section 2.3.2**, will help decrease costs of these energy purchases.

4.2 Power Purchase Contracts

Springs Utilities' electric resources are supplemented with long-term power purchase agreements (PPAs). Springs Utilities currently has eleven long-term PPAs totaling 624 MW of nameplate capacity. Springs Utilities' current long-term PPAs are summarized in **Table 4-2**. These PPAs play a key role in providing additional renewable energy generation supporting Springs Utilities carbon reduction targets. A description of each of Springs Utilities' existing power purchase contracts can be found in **APPENDIX B** of this document.

Table 4-2: Colorado Springs Existing Power Purchase Agreements

Purchase Agreement	Category	Nameplate Capacity (MW)	Commission Year	Current Contract Expiration Date
WAPA – SLC	Hydro	15		9/30/2057
WAPA – LAP	Hydro	60		9/30/2054
USAFA Solar	Solar	5	2011	7/31/2036
CSG Solar	Solar	4	2011	11/10/2041
Clear Springs Ranch Solar	Solar	10	2016	11/10/2041
Palmer Solar	Solar	60	2020	4/7/2040
Grazing Yak Solar	Solar	35	2019	11/22/2044
Pike Solar	Solar	175	2023	12/18/2040
Spring Canyon	Wind	60	2020	5/31/2030
Jackson Fuller Battery	BESS	100	2025	4/29/2050
Horizon Battery	BESS	100	2027	12/31/2047
Total Power Purchase Agreements		**624**		

Section 5: Input Analysis

5.1 Potential Generation Resources

In considering new resources, Springs Utilities sourced resource inputs and assumptions from publicly available references where applicable. Fine tuning of assumptions and technology specifications will be performed once a technology type is selected during the request for proposal phase. The scope of the EIRP is to perform a broad analysis that incorporates scenarios, sensitivities, public input and regulatory requirements into a strategic path forward. Forward price trends were primarily derived from NREL's 2024 Annual Technology Baseline (ATB) report. A summary of the potential generation resources evaluated in the EIRP are highlighted in **Table 5-1**. Additional information about each of these resources can be found in **APPENDIX C** of this document.

Table 5-1: Potential Resource Summary

Resource Name	Fuel Type	Nameplate Capacity (MW)	Accredited Capacity	CAPEX ($/kW)	Design Life
H-Frame 1x1 Combined Cycle	Gas	400	400	$1,725	30
Reciprocating Internal Combustion Engine ("RICE")	Gas/Oil	17	17	$2,500	30
Aeroderivative	Gas	25	22	$2,500	30
Landfill Gas ("LFG")	LFG	10	10	$2,500	30
Solar	N/A	25	5.7*	$2,200	30
Wind	N/A	25	5.7*	$3,900	30
Battery Storage Lithium-Ion (4-Hour)	N/A	25	14.5*	$2,100	20
Battery Storage Lithium-Ion (10-Hour)	N/A	25	20.8*	$3,600	20
Nuclear: Traditional	Uranium	1000	1000	$7,600	80
Nuclear: Small Modular Reactor ("SMR")	Uranium	200	200	$7,700	80
Enhanced Geothermal	N/A	25	25	$9,400	30

*Declining Effective Load Carrying Capability (ELCC) curves applied to renewable resources and battery

5.2 Commodity Inputs

5.2.1 Coal Forecast

Coal forecasts and transportation adders were utilized for determination of coal price at Nixon. The fuel forecast was provided by Argus Media while transportation adders were assumed based on the short-term outlook and extrapolated to complete the forecasted horizon. The high, medium and low coal forecasts in one million British thermal units (MMBtu) over 12 years for the Nixon unit are presented in **Figure 5-1**.

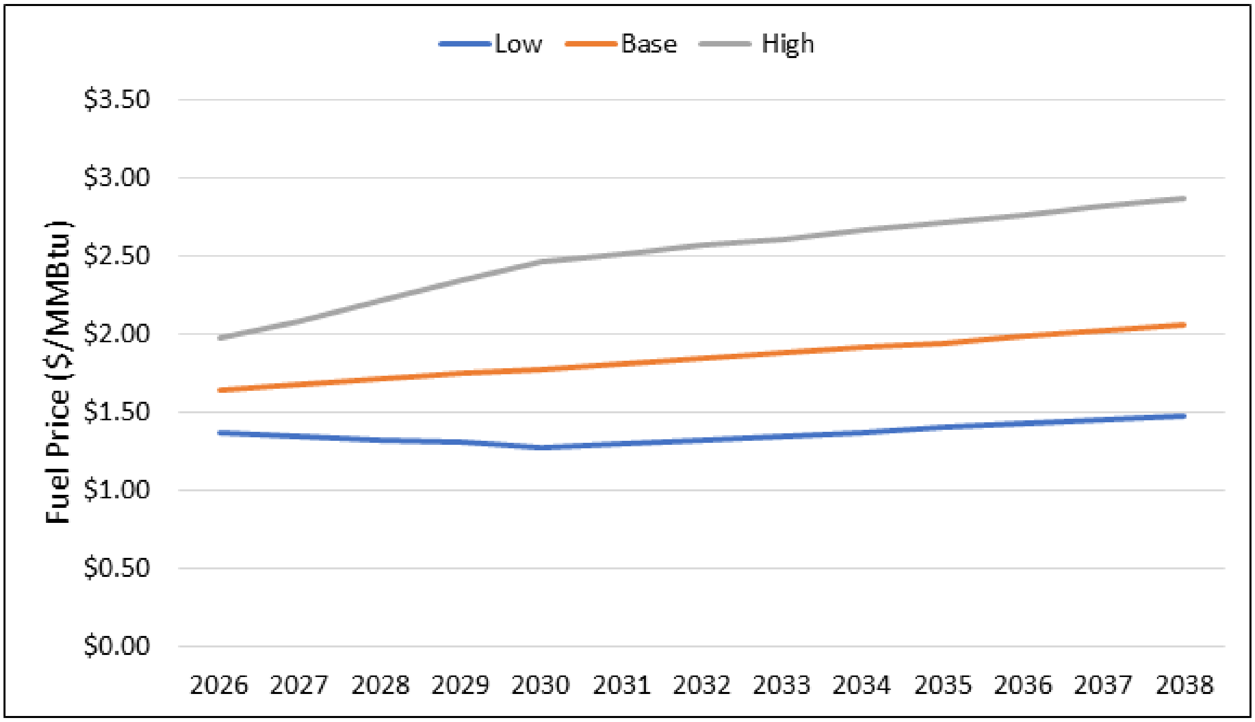


Figure 5-1: Nixon Coal Price Forecast

5.2.2 Natural Gas Forecast

Platts M2M natural gas monthly forward curves were used as a source for the 20-year natural gas forecast at the natural gas-fired generation locations. The high, medium and low natural gas forecasts are presented in **Figure 5-2**.

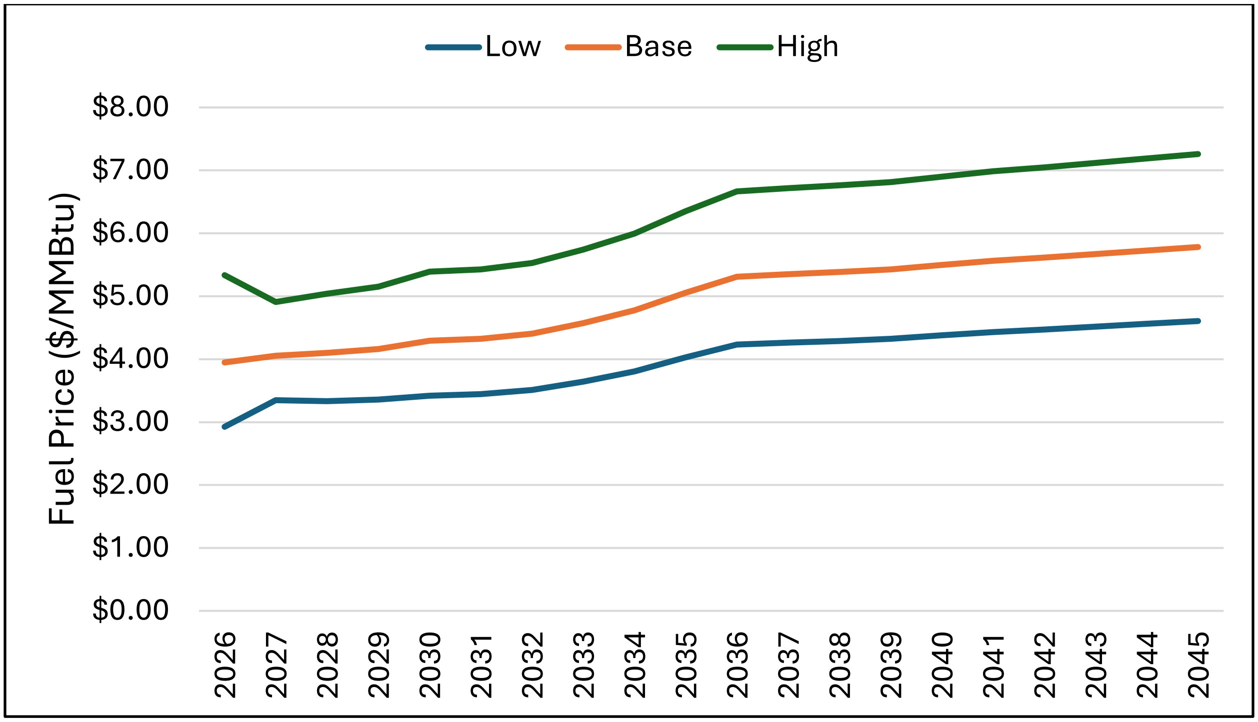


Figure 5-2: Natural Gas Fuel Forecast

5.2.3 Market Forecast

Platts M2M power monthly forward curves were used as a source for the 20-year market power forecast. The high, medium and low market forecasts are presented in **Figure 5-3**.

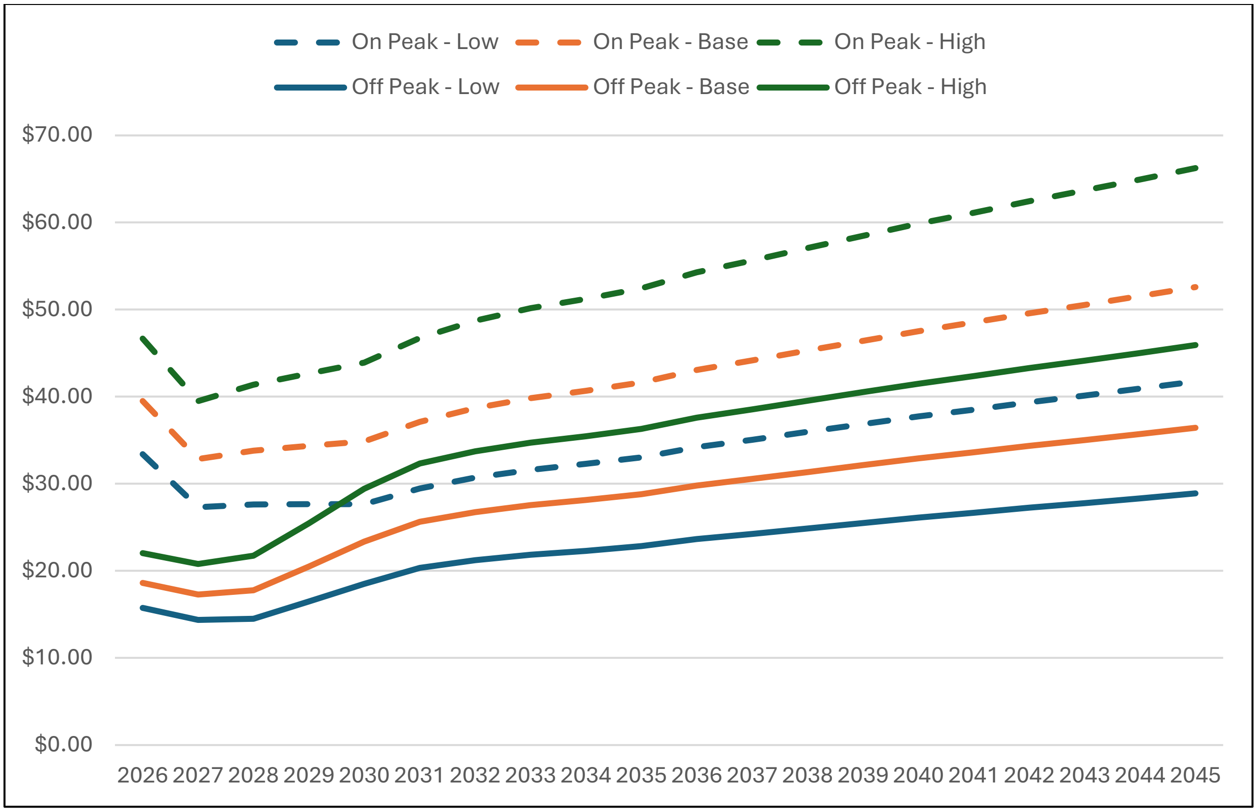


Figure 5-3: Market Price Forecast WECC- East Colorado

5.3 Resource Adequacy

5.3.1 Planning Reserve Margin

The Planning Reserve Margin (PRM) is defined as the difference between the total capacity of a system and the expected peak demand, expressed as a percentage of peak demand. This PRM provides a buffer to ensure there is enough electricity to meet unexpected increases in demand or unexpected outages in generation (See **Table 5-2**). The PRM is crucial for maintaining the reliability of the electric system and is a key component of resource adequacy. The model includes the PRM established by the RTO. The PRM is based on a Loss of Load Expectation (LOLE) of 0.1 days/per year and 1-3 parts per million expected unserved energy (EUE) (<1000 MWhs).

Table 5-2: Planning Reserve Margin

	Summer 2027	Winter 2026-2027
Accredited (ACAP) PRM	15.9%	32.2%

5.3.2 Effective Load Carrying Capability

A critical consideration in the increasing integration of renewable resources is effective load carrying capacity (ELCC). At its core, the ELCC of a generating resource is a measurement of that resource's ability to produce energy when the grid is most likely to experience electricity shortfalls. ELCC is typically expressed as a percentage of a resource's capacity, for example, a 100 MW solar plant that has an ELCC of 30% could make a 30 MW contribution towards reliability requirements during peak demand events. These ELCC values are separated into different capacity blocks (tranches), because each additional block of renewable capacity contributes less reliability value than the previous one. **Table 5-3** lists selective ELCC values for new renewable resources.

Table 5-3: Proposed ELCC Values

	Summer 2026 ELCC %	Winter 2026 ELCC %	Summer 2030 ELCC %	Winter 2030 ELCC %
Wind	27.3%	37.4%	22.9%	26.0%
Solar	25.7%	17.5%	22.9%	14.8%
Battery	63.4%	55.7%	57.9%	32.3%
Total	**31.4%**	**31.6%**	**29.8%**	**23.2%**

Section 6: Transmission and Distribution Planning

6.1 Transmission Capacity

Transmission planning is an increasingly important factor for the EIRP. Location diversity within a system is crucial to optimizing renewable resources in terms of type and size. But achieving this requires expansion of transmission capacity and infrastructure. The 2025 EIRP modified the import capacity after 2027, driven by the planned Midway to Kelker 230kV project, as shown in **Table 6-1**.

Table 6-1: Transmission Capacity

Existing Transmission Capacity	MVA
Midway to Springs Utilities	360
Fuller to Springs Utilities	170
Total Import to Springs Utilities	**530**
Transmission Capacity after new MW-KE 230kV line	**MVA**
Midway to Springs Utilities	680
Fuller to Springs Utilities	170
Total Import post 2027	**850**

6.2 Transmission Expansion Planning

To access generating resources, transmission availability must be carefully considered including the timelines associated with the development and construction of new transmission infrastructure. As resource portfolios continue to evolve, transmission expansion becomes a critical enabler for delivering reliable, clean, and cost-effective energy to the systems.

Within the RTO, the Integrated Transmission Planning (ITP) process serves as the primary framework for identifying and prioritizing regional transmission upgrades. The ITP process is a comprehensive, multi-year planning effort that evaluates Springs Utilities transmission system needs based on reliability, economic efficiency, and public policy considerations. Through detailed modeling, stakeholder input, and regional coordination, the ITP process establishes a portfolio of transmission projects designed to address congestion, voltage violations, improve system resilience, and facilitate the interconnection of new generation resources including renewables.

The next transmission study is the 2027 ITP. As illustrated in Figure 6-1, the ITP process includes multiple key phases including scoping and study development, analytical modeling and contingency assessment, competitive project selection, and subsequent project development activities. Based on the current timeline, transmission projects identified in the 2027 ITP are not expected to be placed into service until approximately 2031.

Participation in the ITP process is essential for ensuring that transmission solutions align with the visions and needs of Springs Utilities. To strengthen this alignment, outputs from the EIRP, including identified generation resource needs, load and future generation locations, and timing will directly inform ITP study assumptions, simulation scenarios, and candidate project development. This connection ensures that potential future resources identified through the EIRP are systematically evaluated within the ITP process.

By proactively engaging in planning activities and stakeholder discussions, we can help shape transmission project selection and champion critical infrastructure investments that enhance import capability, improve access to diverse generation resources, and support long-term system reliability and resilience. Ultimately, integrating EIRP inputs into the ITP provides a structured and transparent pathway for advancing transmission projects that support our operational and strategic objectives (**Figure 6-1**).

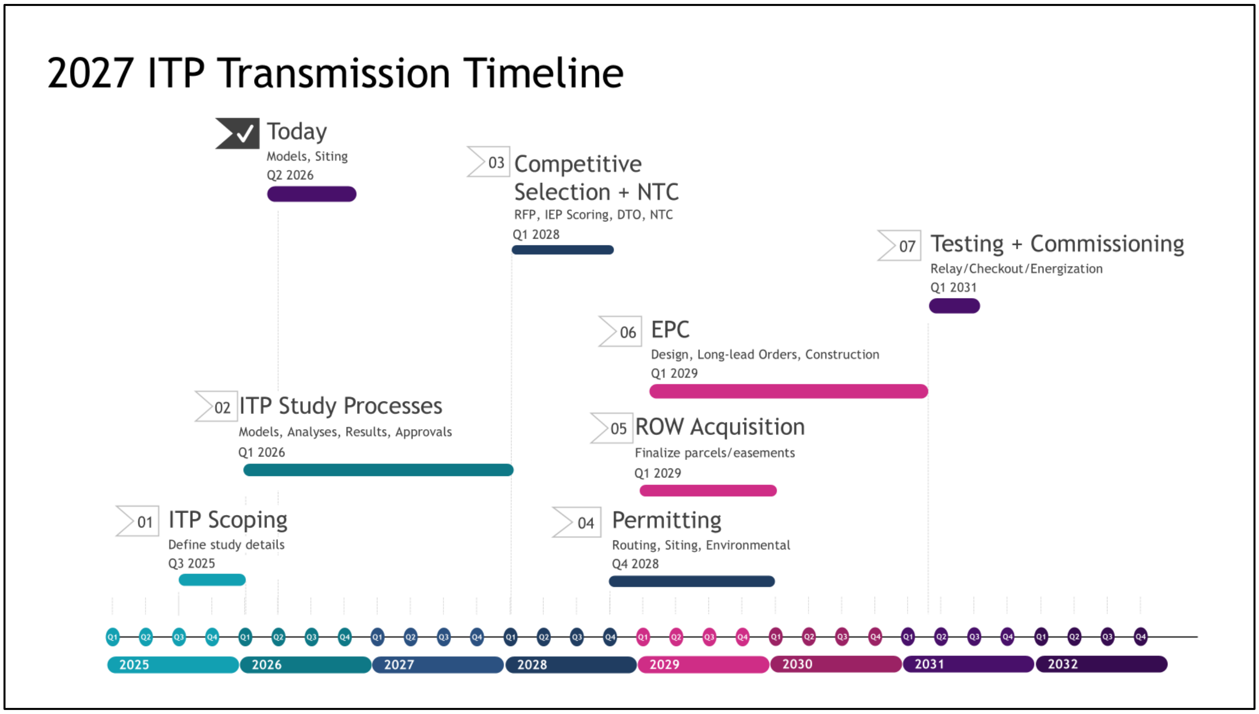


Figure 6-1: Transmission Study Timeline

6.3 RTO Planning

Several factors relating to the RTO were taken into consideration, including PRM, ELCC, existing resource accreditation, Performance-based Accreditation (PBA), and the transmission planning processes. Existing resource accreditation is expected to drop a marginal amount compared to past EIRPs due to PBA policies implemented by SPP. The purpose of these policies is to more accurately represent the reliability of generating resources by accounting for their historical forced outage rates during critical events. These impacts were considered in the resource modeling for both existing resources and resource addition options for this EIRP.

6.4 Distribution Planning

The Electric Distribution System Plan supports the EIRP by identifying where the forecasted load growth including electrification trends and customer-sited resources will most likely manifest at the local system level. While resource planning evaluates system-wide resource adequacy, distribution planning develops solutions to ensure that energy can be reliably and efficiently delivered from the substation to the customer.

The Distribution System Plan is focused on evaluating capacity and contingency needs across the 12.5 kV system over a ten-year horizon and validating the associated capital investment plan required to maintain safe, reliable, and cost-effective service.

6.4.1 Localized Load Growth and System Constraints

Forecasted system load growth, including impacts from electric vehicles, building electrification, and distributed solar, does not occur uniformly across the service territory. Distribution planning translates these system-level drivers into substation and feeder-level impacts, identifying localized capacity constraints and contingency limitations that cannot be observed in aggregate system forecasts.

These localized constraints inform the timing and location of required infrastructure investments and provide an important linkage between EIRP load forecasts and executable system improvements.

6.4.2 Integration of Distributed Energy Resources

Customer-sited distributed energy resources (DERs), including rooftop solar and emerging storage adoption, influence distribution system loading, power flows, and voltage conditions. Distribution planning evaluates these impacts to ensure safe interconnection and to identify opportunities where DERs may support system needs.

In select cases, targeted deployment of DERs and demand-side strategies may defer or reduce the need for traditional infrastructure investments, providing cost-effective alternatives while maintaining reliability.

6.4.3 Distribution Investment Outlook and EIRP Alignment

The Distribution System Plan focuses on a ten-year planning horizon, providing an actionable and near-term view of system needs and capital investment requirements. This complements the longer-term EIRP planning horizon by ensuring that near-term infrastructure decisions remain aligned with long-term resource strategies.

Distribution investments are driven by:

- Localized load growth and development patterns;
- Capacity constraints and contingency requirements;
- Asset condition and system reliability performance; and
- Integration of distributed energy resources and evolving customer demand.

These investments represent a foundational component of the overall system plan and are necessary to ensure that generation and transmission resources identified in the EIRP can be delivered reliably to customers.

Section 7: EIRP Process

7.1 Modeling and Analysis

7.1.3 The Capacity Expansion Model

Modeling software enables Springs Utilities to analyze long-term solutions given specified constraints. Long-term planning uses a capacity expansion model methodology. Within the capacity expansion model, staff upload the constraints and inputs discussed in sections 2 through 6, including emissions targets, hourly load forecasts, detailed generator operations, commodity prices, reliability requirements and transmission constraints to simultaneously evaluate different portfolios and sensitivities. The output provides the lowest-cost generation plan and associated costs to meet forecasted load.

7.1.4 The Modeling Process

The Department of Energy (DOE) issued the *Best Practices in Integrated Resource Planning* in November 2024, which describes an overview of a typical integrated resource planning process. **Figure 7-1** comes from the DOE's guide and depicts the flow from inputs to constraints, and then from modeling to a plan of action. The EIRP process flow uses an iterative approach in the modeling process that directs resource planners to reconsider inputs based on stakeholder feedback and modeling results.

For example, a model output may show repeated cycling of a thermal unit designed for baseload generation. Through iterative coordination with stakeholders in operations and reviews of technical documentation, inputs are updated to align outputs closer to what is expected in daily operations.

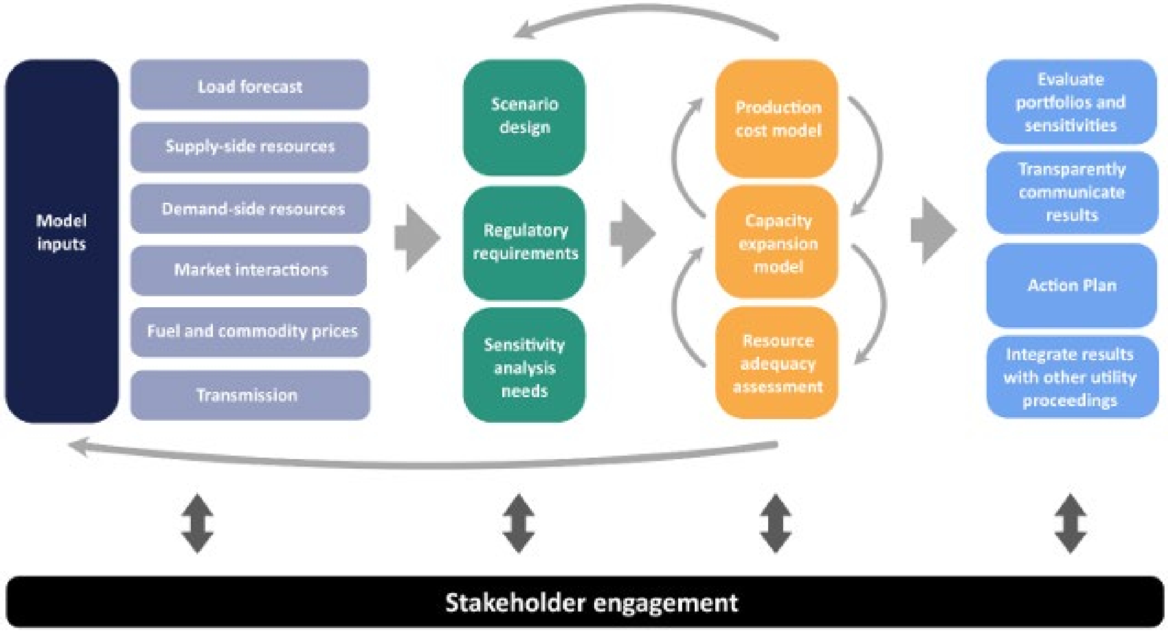


Figure 7-1: Department of Energy's Typical IRP Process Flow, November 2024

7.2 Portfolio Development

Springs Utilities evaluated a range of resource portfolios to understand how different drivers including policy targets, generation technologies, and cost assumptions affect the future electric system. Each portfolio represents a plausible pathway to meet reliability requirements while balancing affordability and emissions goals.

Across all scenarios, the analysis highlights a consistent set of tradeoffs between cost, reliability, and timing, particularly around the availability of firm, carbon-free resources such as nuclear energy.

- Firm capacity is critical to reliability.
- Renewable resources play a central role, but do not fully replace the need for firm, dispatchable generation.
- The timing of nuclear deployment materially impacts outcomes.
- Earlier availability reduces total resource build requirements and cost. Delays increase the need for additional renewable and storage investments.
- Higher renewable penetration increases overall system size and cost.
- As more renewables are added, their effective capacity contribution declines, requiring additional resources to maintain reliability.

- Gaps between retirements and replacement resources must be managed carefully to avoid overbuilding or reliability exposure.
- All viable pathways converge on a balanced portfolio, including a combination of renewables, firm capacity, and storage.

7.2.1 Reference Plan

The reference case represents the lowest-cost resource mix without emissions constraints and assumes continued operation of existing assets beyond current policy targets. This case establishes a baseline where the model was free to pick the most cost-effective portfolio before adding any restrictions. While cost-efficient, this portfolio does not meet current emission reduction targets and Nixon's required retirement date. All additional scenarios were run under the 80% by 2033 emissions restrictions and assumed a Nixon retirement at the end of 2032. **Figure 7-2** highlights the resource acquisition plan for the reference case.

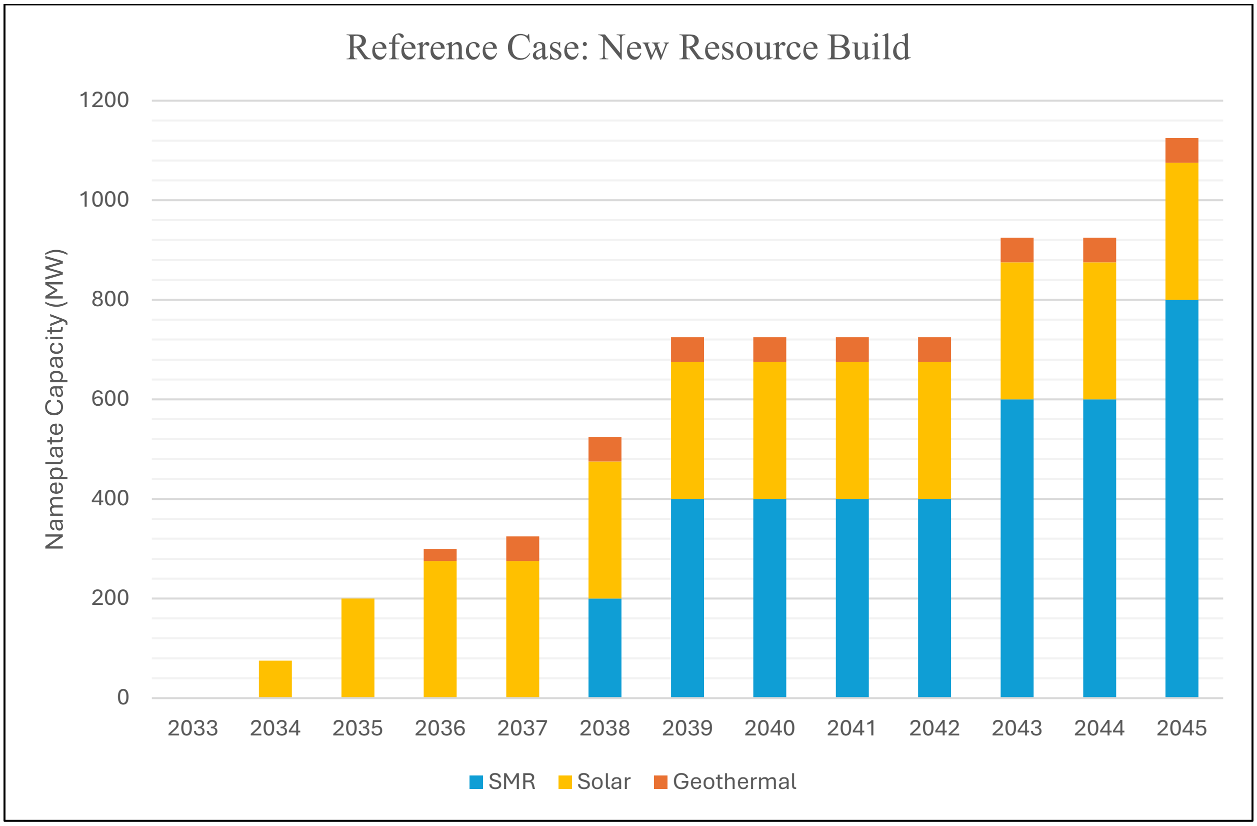


Figure 7-2: Reference Case Resource Acquisition

7.2.2 90x40, 95x45 Case

Senate Bill 26-182’s passage allows Springs Utilities to operate Nixon through 2032 and meet an 80% emissions reduction (from 2005 levels) by 2033. All subsequent modeling cases have these restrictions. This case evaluates additional emissions reductions with limited near-term firm, carbon-free resources. It considers a 90% reduction by 2040 and a 95% reduction by 2045. Nuclear is not available to be selected until 2038, so solar and wind were the primary near-term resources built by the model. This increases the total system build over the Reference Plan due to limited firm capacity. **Figure 7-3** highlights the resource acquisition plan for this emissions case.

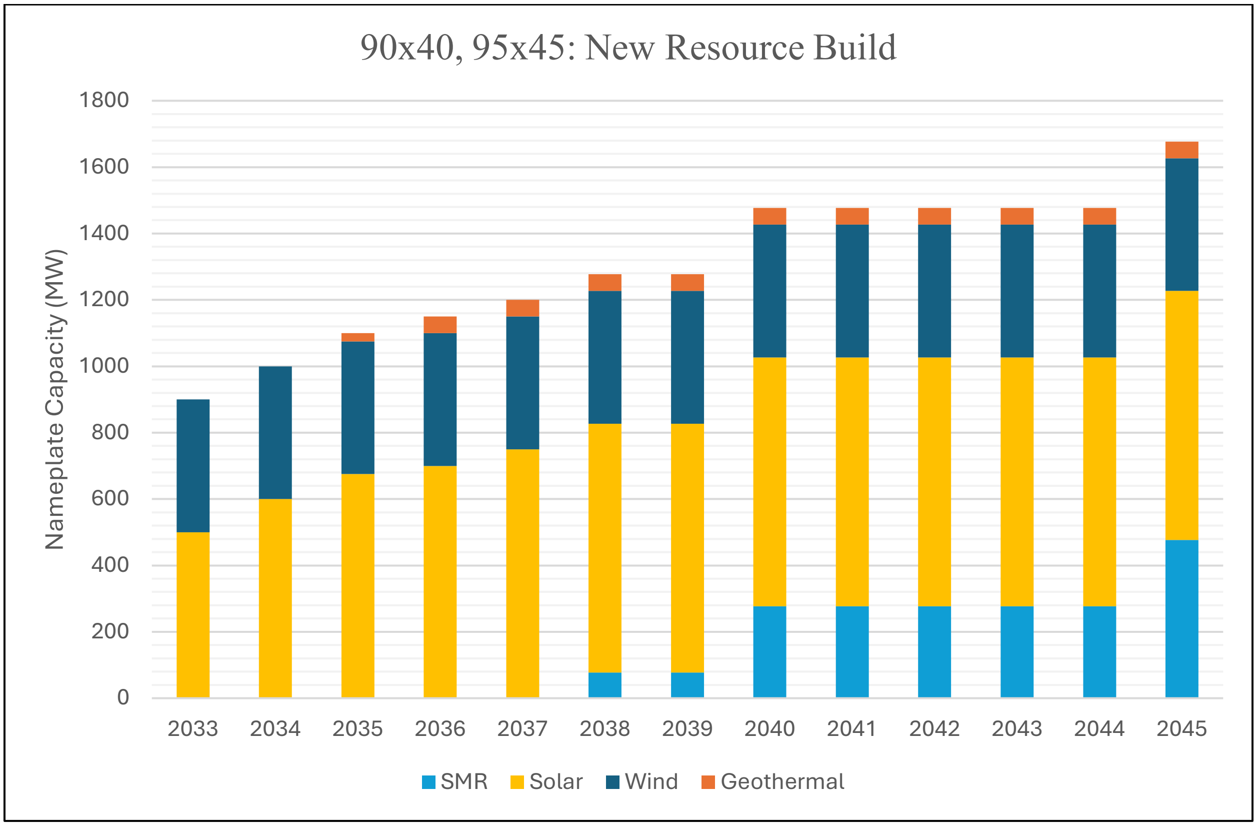


Figure 7-3: 90x40, 95x45 Resource Acquisition

7.2.3 Recommended Plan (80x33, 95x40)

This recommended case evaluates more aggressive emissions reduction. It reflects Springs Utilities' seeking to achieve a target of 95% emissions reduction by 2040. This case relies on nuclear being available before 2040. As with the previous case, nuclear is not available until 2038, so solar and wind were the primary near-term resources built. This increases the total system build over the Reference Plan and costs slightly more than the 90x40, 95x45 case. However, it provides a balance of seeking to meet emission targets and affordability. **Figure 7-4** highlights the resource acquisition plan for the recommended case.

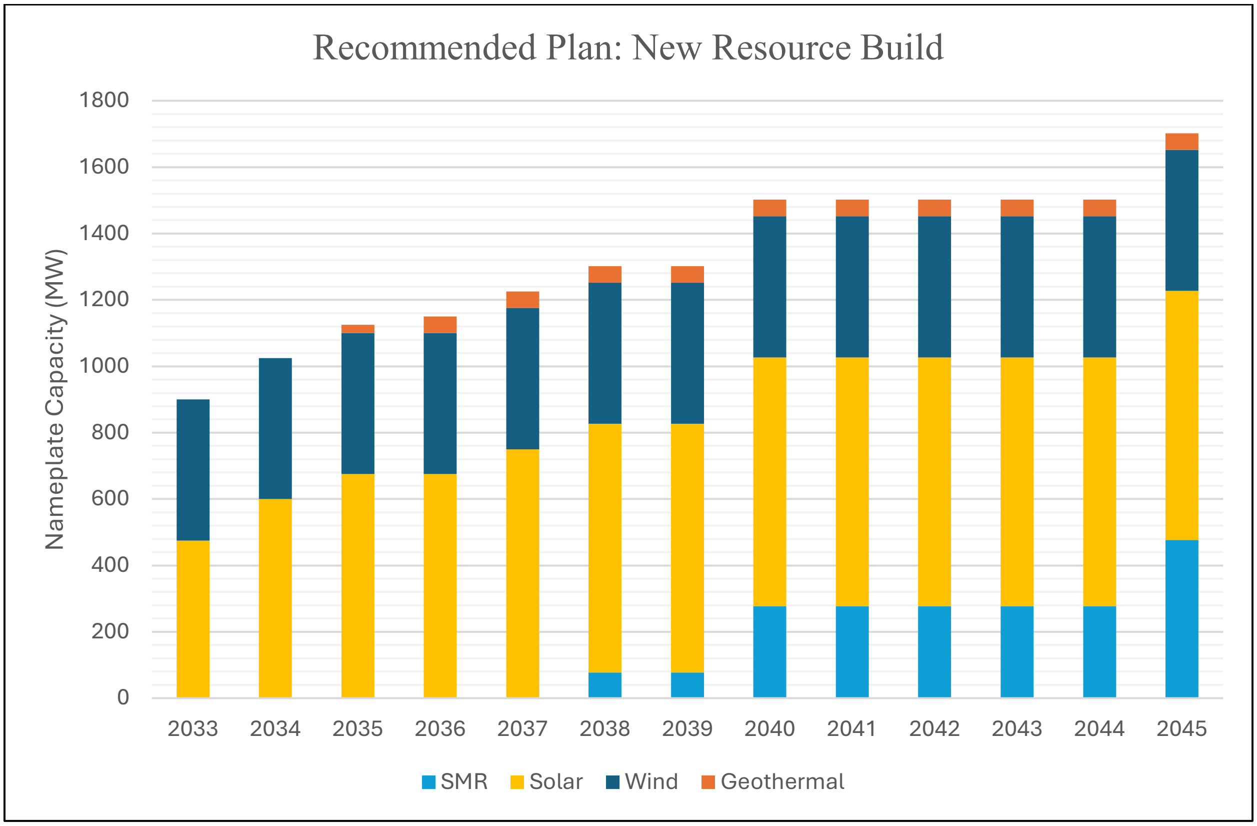


Figure 7-4: Recommended Plan Resource Acquisition

7.2.4 100x40 Case

The 100x40 case evaluates a potential future requirement for full decarbonization by 2040 to represent possible additional emissions reduction policy from the state or federal government. This case requires retiring the Front Range Power Plant 10 years earlier than the current expected date of 2050, increases reliance on nuclear and storage resources and increases the overall cost and execution risk. **Figure 7-5** highlights the resource acquisition plan for the base case.

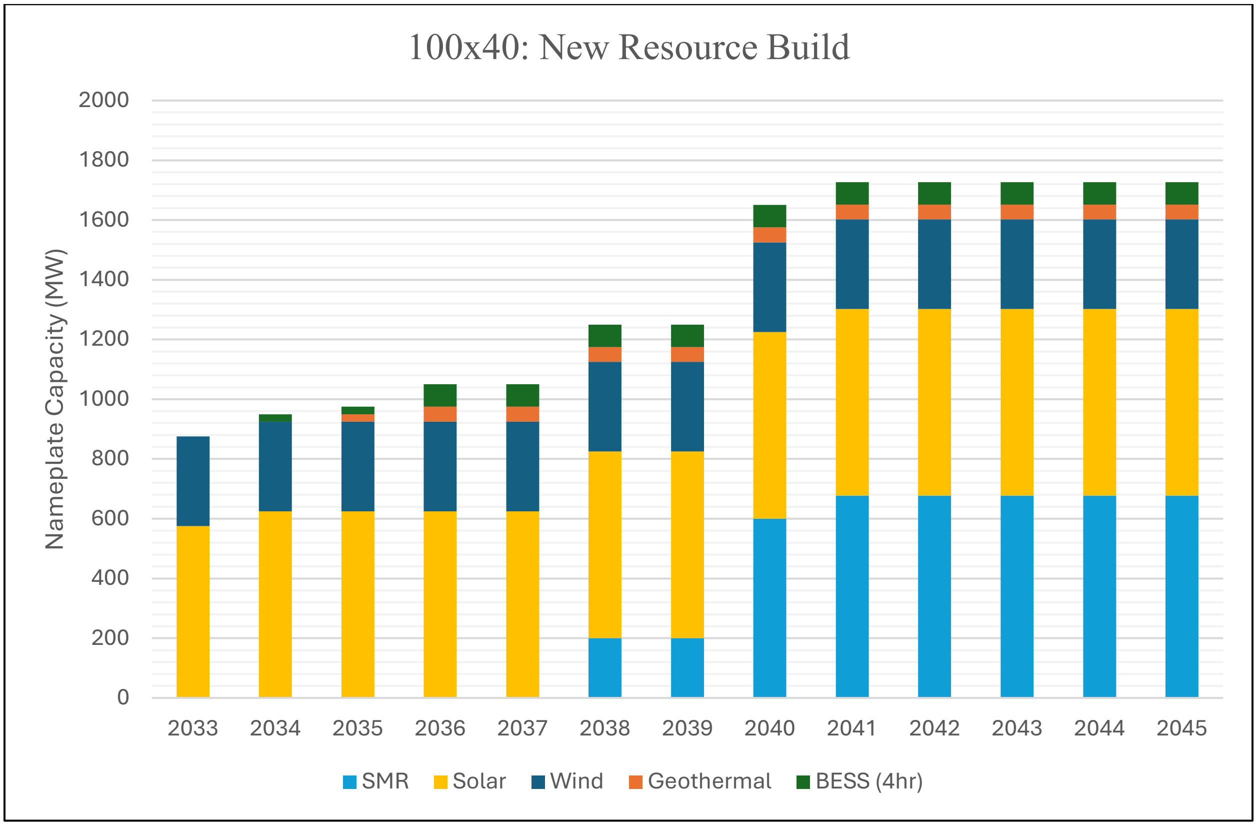


Figure 7-5: 100x40 Resource Acquisition

7.2.5 High-Cost Nuclear Case

This scenario tests the impact of significantly higher nuclear capital costs. The high-cost nuclear case doubled the cost of nuclear small modular reactors (SMRs) to determine the impacts if the cost of SMRs end up being significantly higher than projected. This increases the total system build and overall cost and creates additional reliance on renewables. **Figure 7-6** highlights the resource acquisition plan for the high-cost nuclear case.

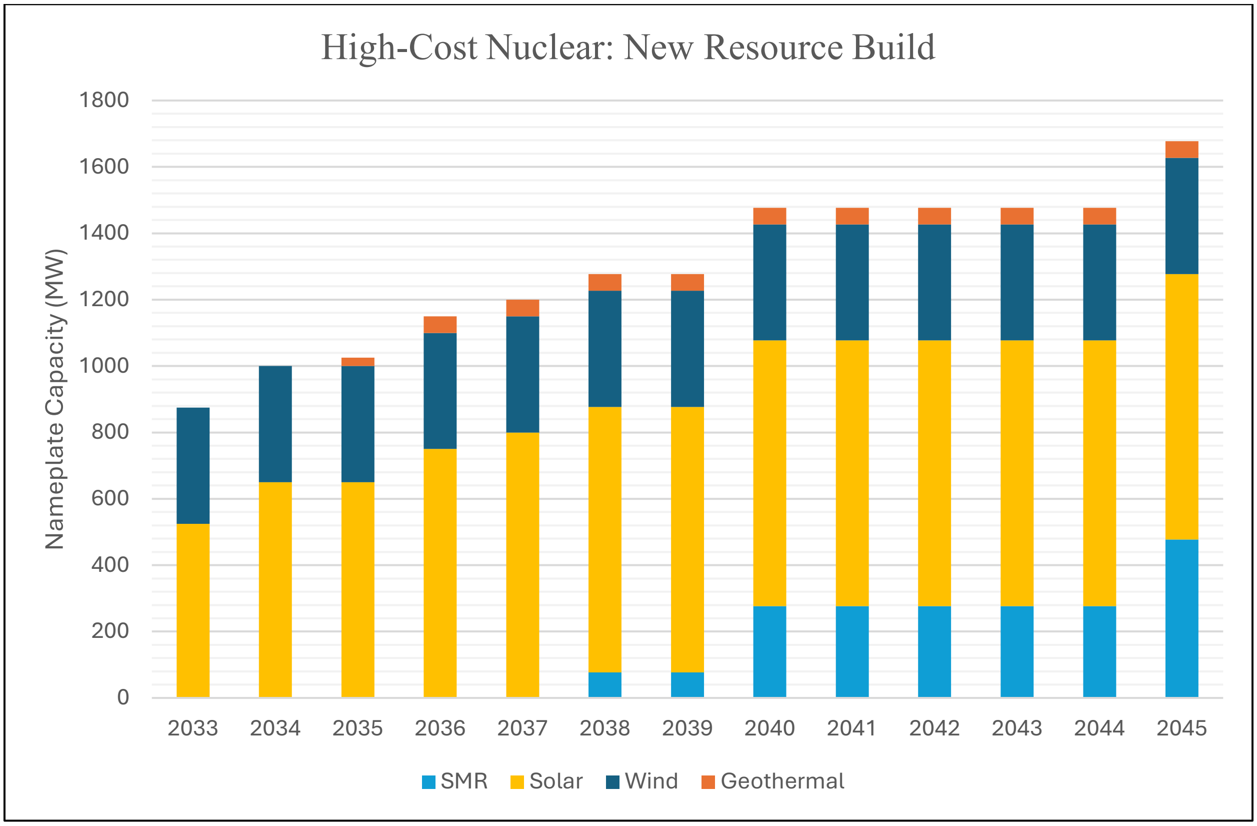


Figure 7-6: High-Cost Nuclear Resource Acquisition

7.2.6 Delayed Nuclear Case

The delayed nuclear case assumes nuclear is not available until 2042. This led to a significantly higher total system build and reliance on renewable resources. **Figure 7-7** highlights the resource acquisition plan for the delayed nuclear case.

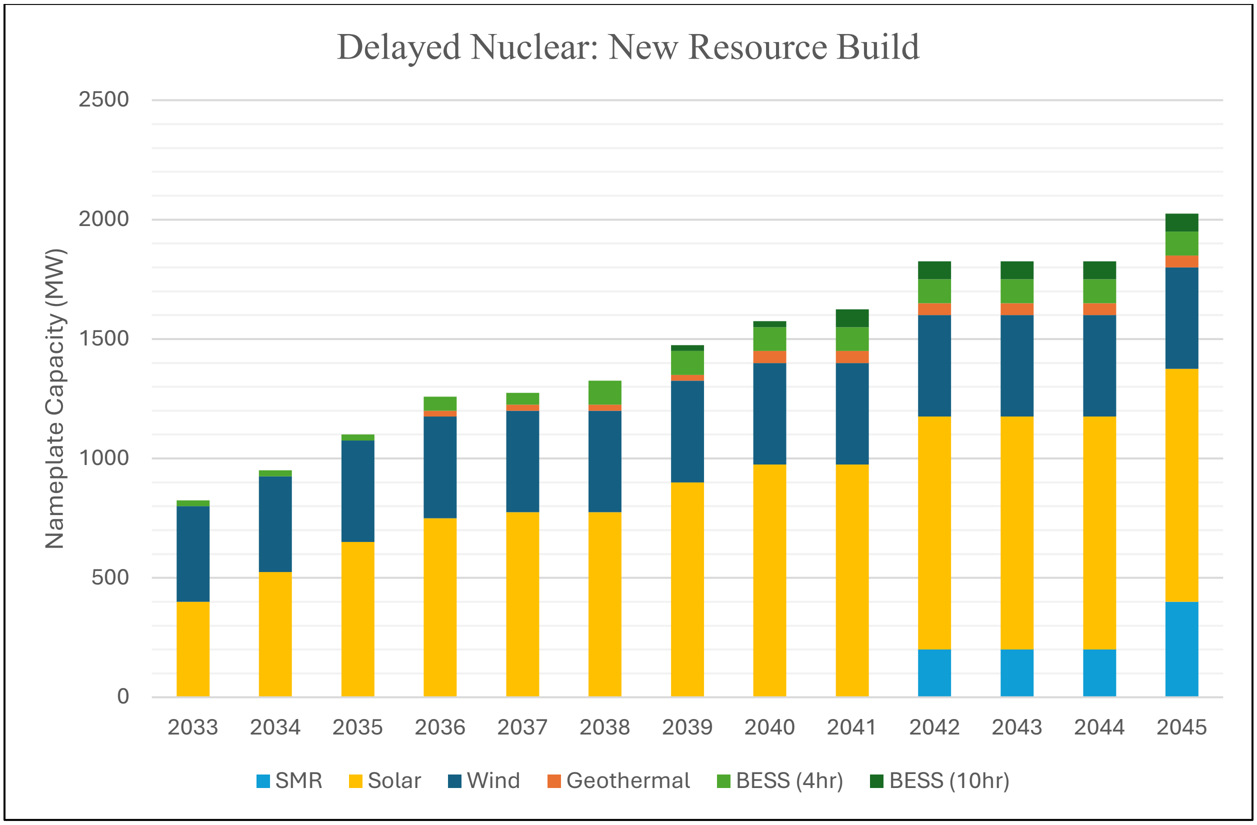


Figure 7-7: Delayed Nuclear Resource Acquisition

7.2.7 No Nuclear Case

This scenario removes nuclear as an option entirely. Since nuclear resources were consistently selected, the no nuclear case considers a portfolio where nuclear energy was not allowed to be constructed. This created the largest total system build across all portfolios, a heavy dependence on renewables and long-duration storage, and reduced effectiveness of renewable capacity as penetration increases. **Figure 7-8** highlights the resource acquisition plan for the no nuclear case.

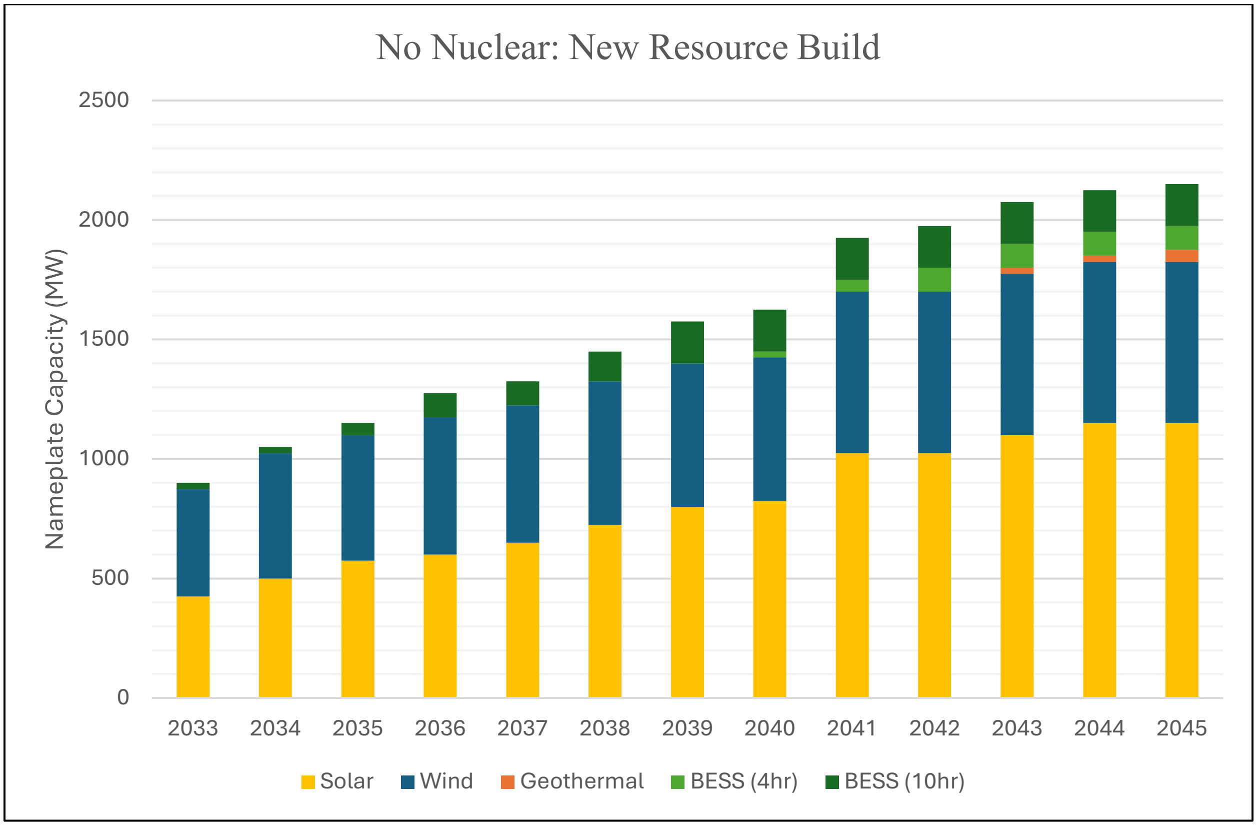


Figure 7-8: No Nuclear Resource Acquisition

7.2.8 95x45, FRPP 2045 Case

This case evaluates early retirement of existing baseload generation. The Front Range Power Plant was retired prior to 2045 in this portfolio. This led to an additional build of 400 MWs of nuclear resources to replace this retired baseload generation and highlights the importance of coordinated retirement timing. **Figure 7-9** highlights the resource acquisition plan for this emissions case.

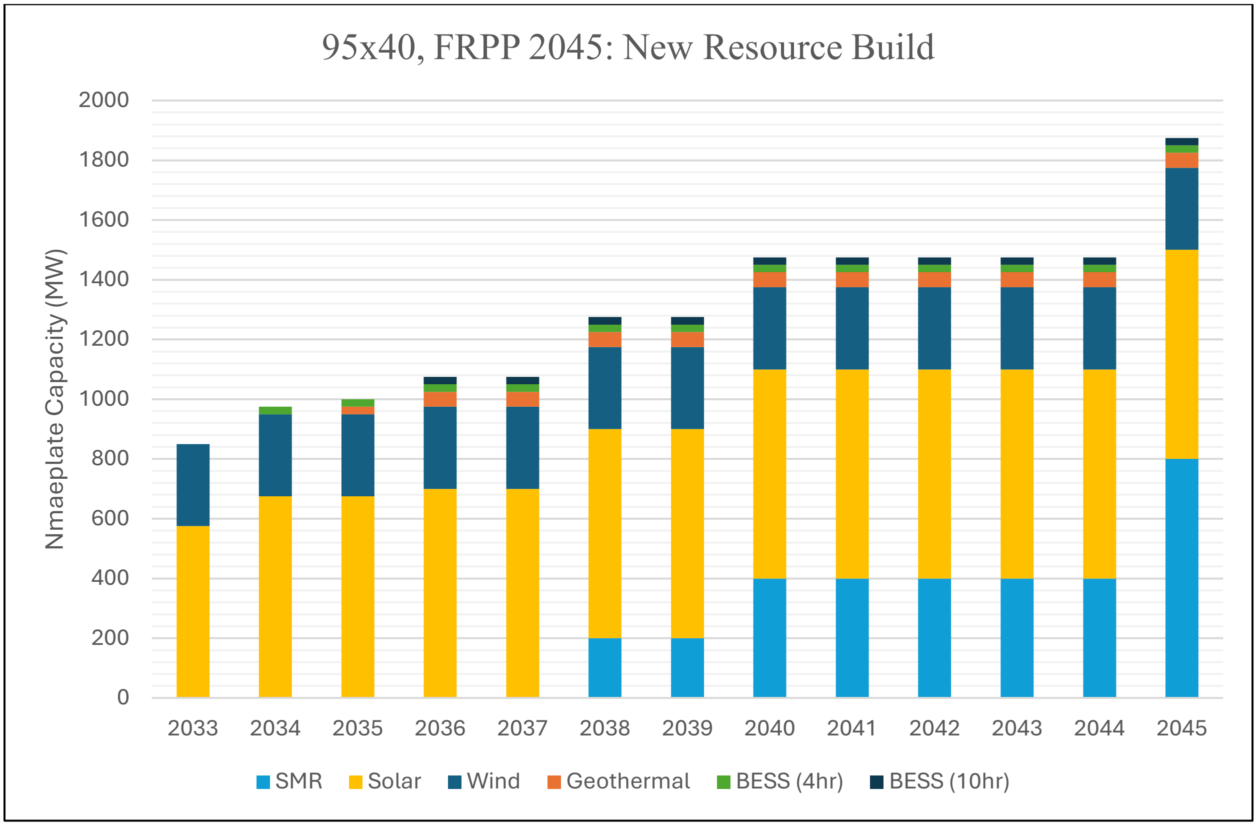


Figure 7-9: 95x40, FRPP 2045 Resource Acquisition

7.2.9 Resource Acquisition Comparison

Figure 7-10 and **Figure 7-11** highlight the amount of resources to be constructed between 2030 and 2045, and a breakdown of cost and emission reduction targets for each of the 9 portfolios. The total new resource builds are similar in many of the cases, but cost impacts occur due to overbuilding and timing mismatches. Cases with delayed, excluded or early retirement of firm resources result in the highest resource build plans of the group. Renewable-heavy cases require additional resources to be constructed and increase overall cost due to declining contribution towards peak reliability.

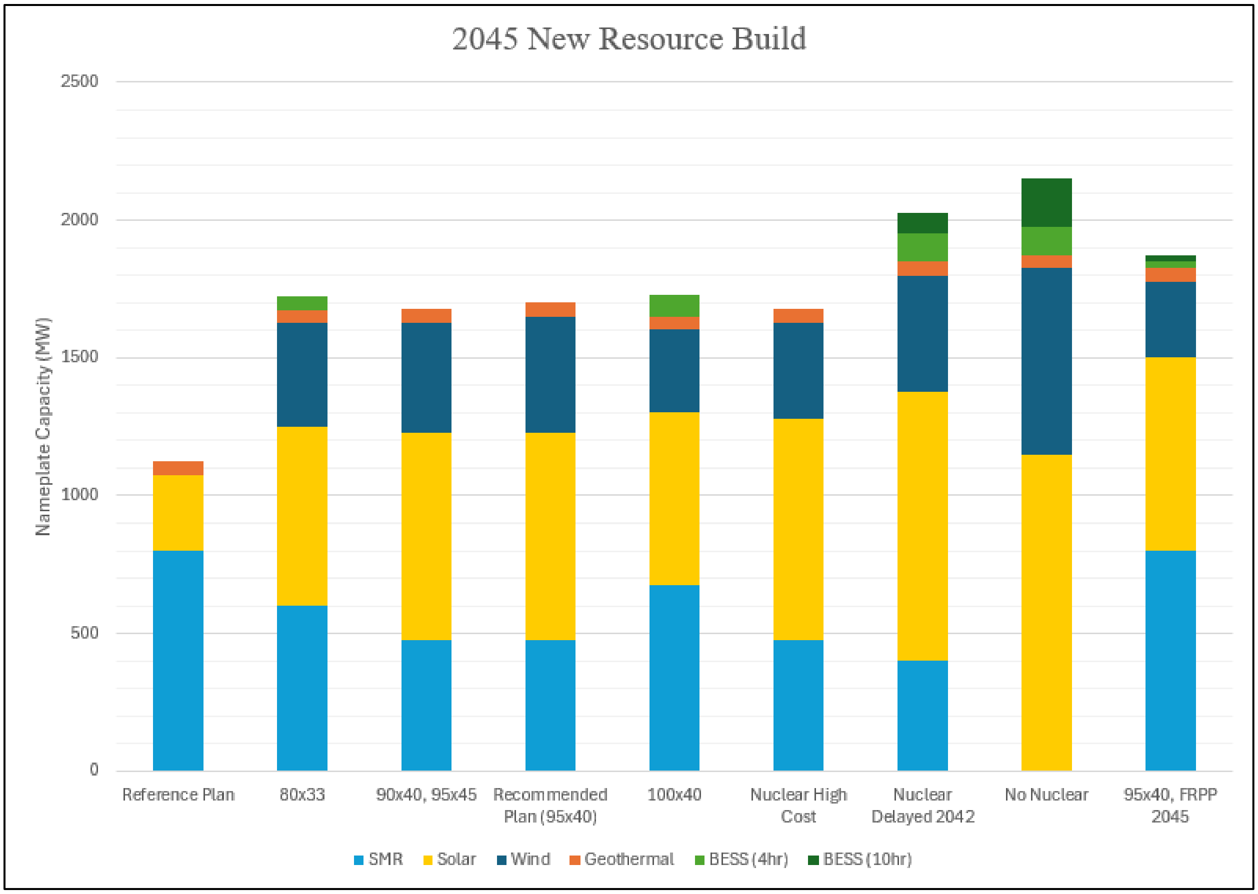
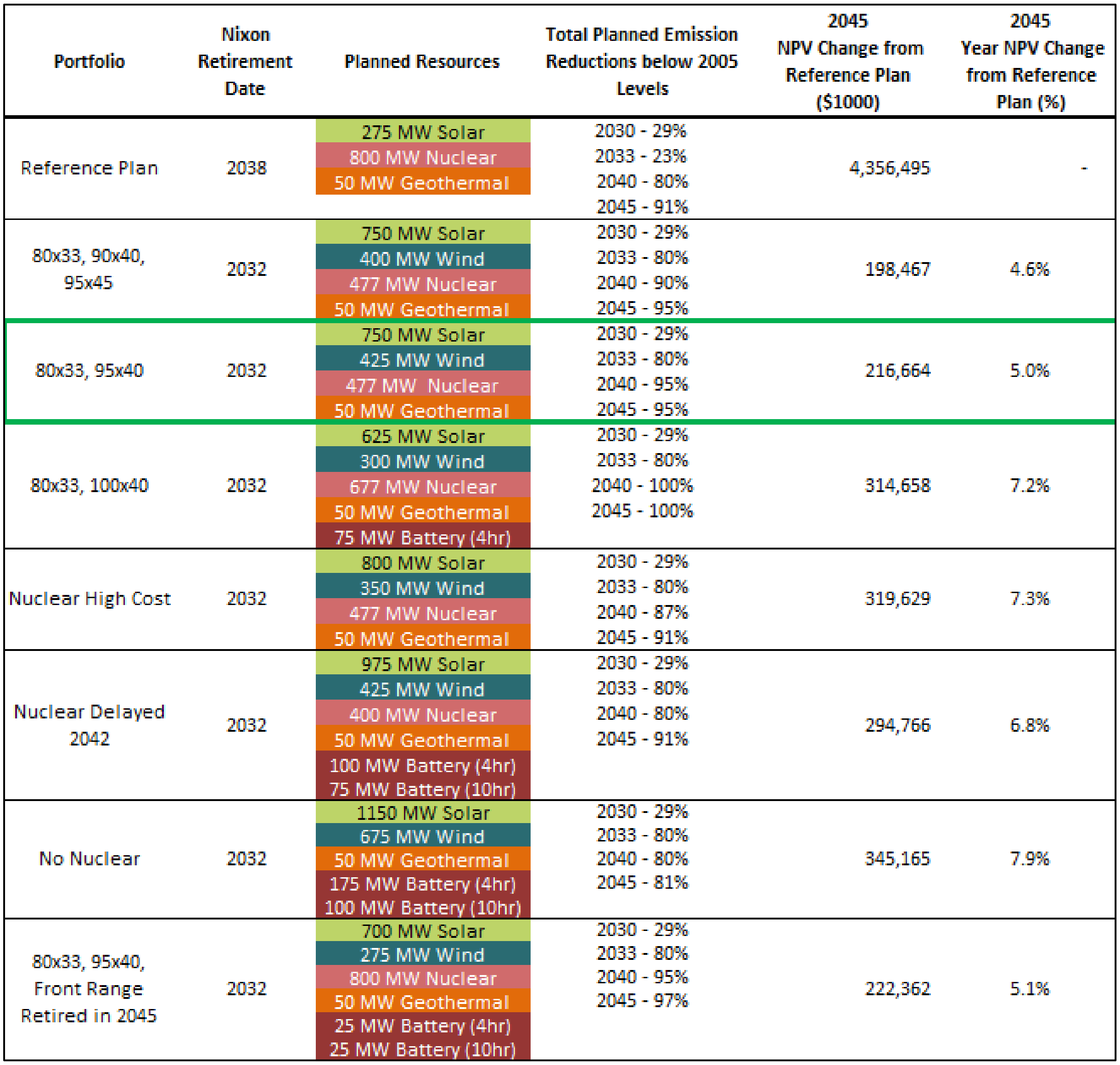


Figure 7-10: Resource Acquisitions by Case



Portfolio	Nixon Retirement Date	Planned Resources	Total Planned Emission Reductions below 2005 Levels	2045 NPV Change from Reference Plan ($1000)	2045 Year NPV Change from Reference Plan (%)
Reference Plan	2038	275 MW Solar 800 MW Nuclear 50 MW Geothermal	2030 - 29% 2033 - 23% 2040 - 80% 2045 - 91%	4,356,495	-
80x33, 90x40, 95x45	2032	750 MW Solar 400 MW Wind 477 MW Nuclear 50 MW Geothermal	2030 - 29% 2033 - 80% 2040 - 90% 2045 - 95%	198,467	4.6%
80x33, 95x40	2032	750 MW Solar 425 MW Wind 477 MW Nuclear 50 MW Geothermal	2030 - 29% 2033 - 80% 2040 - 95% 2045 - 95%	216,664	5.0%
80x33, 100x40	2032	625 MW Solar 300 MW Wind 677 MW Nuclear 50 MW Geothermal 75 MW Battery (4hr)	2030 - 29% 2033 - 80% 2040 - 100% 2045 - 100%	314,658	7.2%
Nuclear High Cost	2032	800 MW Solar 350 MW Wind 477 MW Nuclear 50 MW Geothermal	2030 - 29% 2033 - 80% 2040 - 87% 2045 - 91%	319,629	7.3%
Nuclear Delayed 2042	2032	975 MW Solar 425 MW Wind 400 MW Nuclear 50 MW Geothermal 100 MW Battery (4hr) 75 MW Battery (10hr)	2030 - 29% 2033 - 80% 2040 - 80% 2045 - 91%	294,766	6.8%
No Nuclear	2032	1150 MW Solar 675 MW Wind 50 MW Geothermal 175 MW Battery (4hr) 100 MW Battery (10hr)	2030 - 29% 2033 - 80% 2040 - 80% 2045 - 81%	345,165	7.9%
80x33, 95x40, Front Range Retired in 2045	2032	700 MW Solar 275 MW Wind 800 MW Nuclear 50 MW Geothermal 25 MW Battery (4hr) 25 MW Battery (10hr)	2030 - 29% 2033 - 80% 2040 - 95% 2045 - 97%	222,362	5.1%

Figure 7-11: Portfolio Summaries

7.3 Scenario Analysis

Multiple additional scenarios were considered throughout the modeling process to evaluate the impacts to the build plans under various potential future conditions. These scenarios provide insight into sensitivity impacts and inform planning decisions. Below is a summary of each of the additional scenarios.

7.3.1 Large Load Development Scenario

This scenario added 600 MWs of large load to represent the potential impact of additional large load development within Springs Utilities' service territory, whether that be at the Airport Peak Innovation Parkway, the Southern Colorado Rail Park annexation, or elsewhere in Colorado Springs. This load would require over 1,800 MW of additional nameplate resource capacity to be built by 2045 above what is required in the reference case. The ELCC[2] of renewable resources is the primary driver. While a total 2,600 MWs of renewable resources were built in this scenario, only 730 MW of that is accredited firm capacity. To protect the existing customer base from the impact of these potential large loads, Springs Utilities has implemented a Large Load Tariff requiring any large load to be managed through a large load process. Resources would be acquired once there was certainty in the demand requirements, and the large load customers would be responsible for the costs of this additional generation and infrastructure. **Figure 7-12** highlights the resource acquisition plan for the large load scenario.

---

[2] See **Section 5.3.2 - Effective Load Carrying Capability**

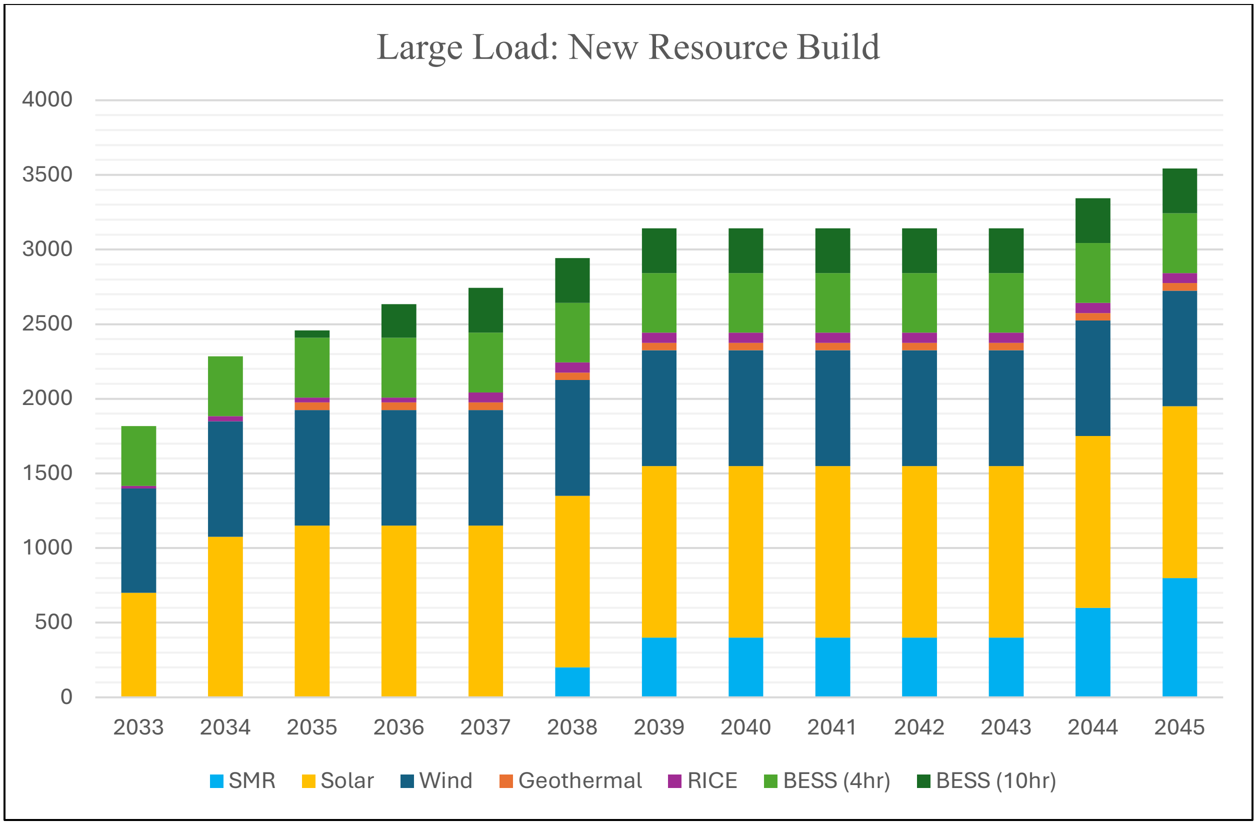


Figure 7-12: Large Load Resource Acquisition

7.3.2 Market Price Increase Scenario

This scenario increased market prices by 20% to see how market pricing affected the overall build plan. Ordinarily, the model is limited to supplying 30% of the energy requirements with market purchases, but those limits were turned off in this scenario to fully optimize usage of the market. The model built the same amount of nameplate capacity as the recommended plan. However, it selected 200 MW more nuclear, 100 MW more battery storage, and 75 MW of more solar in exchange for 375 MW of wind. The model favored baseload resources and more consistent generation profiles to take advantage of optimal pricing. Without the market limit in place, the model both bought and sold more resources from the market than in the recommended case. It is important to note for all these scenarios that the capacity expansion model is a high-level system overview. It is more valuable for determining what resources should be purchased and when, rather than exact hours for unit dispatch, battery charging, or market purchases. **Figure 7-13** highlights the resource acquisition plan for the market price increase scenario.

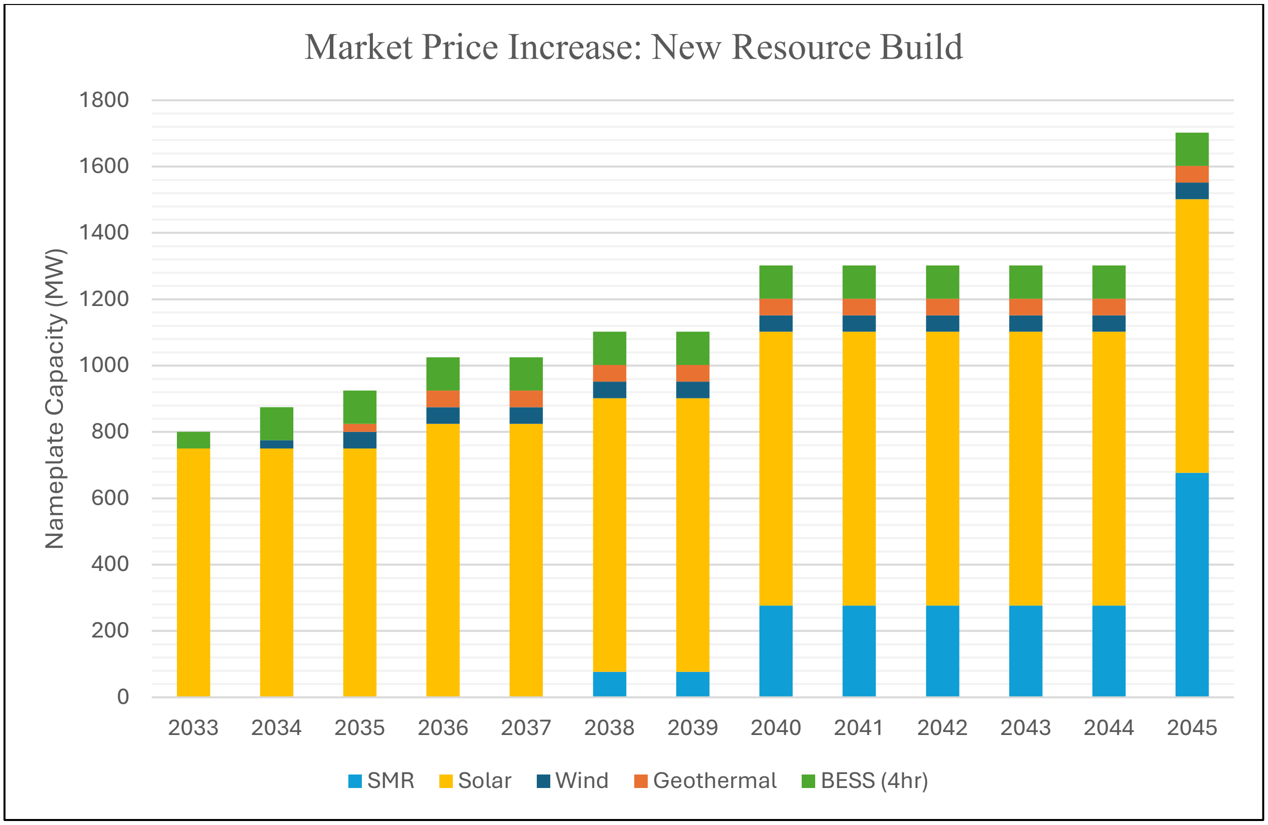


Figure 7-13: Market Price Increase Resource Acquisition

7.3.3 Market Price Decrease Scenario

This scenario decreased market prices by 20% to see how market pricing affected the overall build plan. Ordinarily, the model is limited to supplying 30% of the energy requirements with market purchases, but those limits were turned off in this scenario to fully optimize usage of the market. The model selected 500 MW fewer resources than in the recommended case as it favored purchasing low-cost energy from the market. There was also less incentive for the model to sell energy into the market at this decreased price. Springs Utilities would not use market pricing as a reason to procure fewer resources, but it provides additional intelligence on the best combination of resources in different settings. **Figure 7-14** highlights the resource acquisition plan for the market price increase scenario.

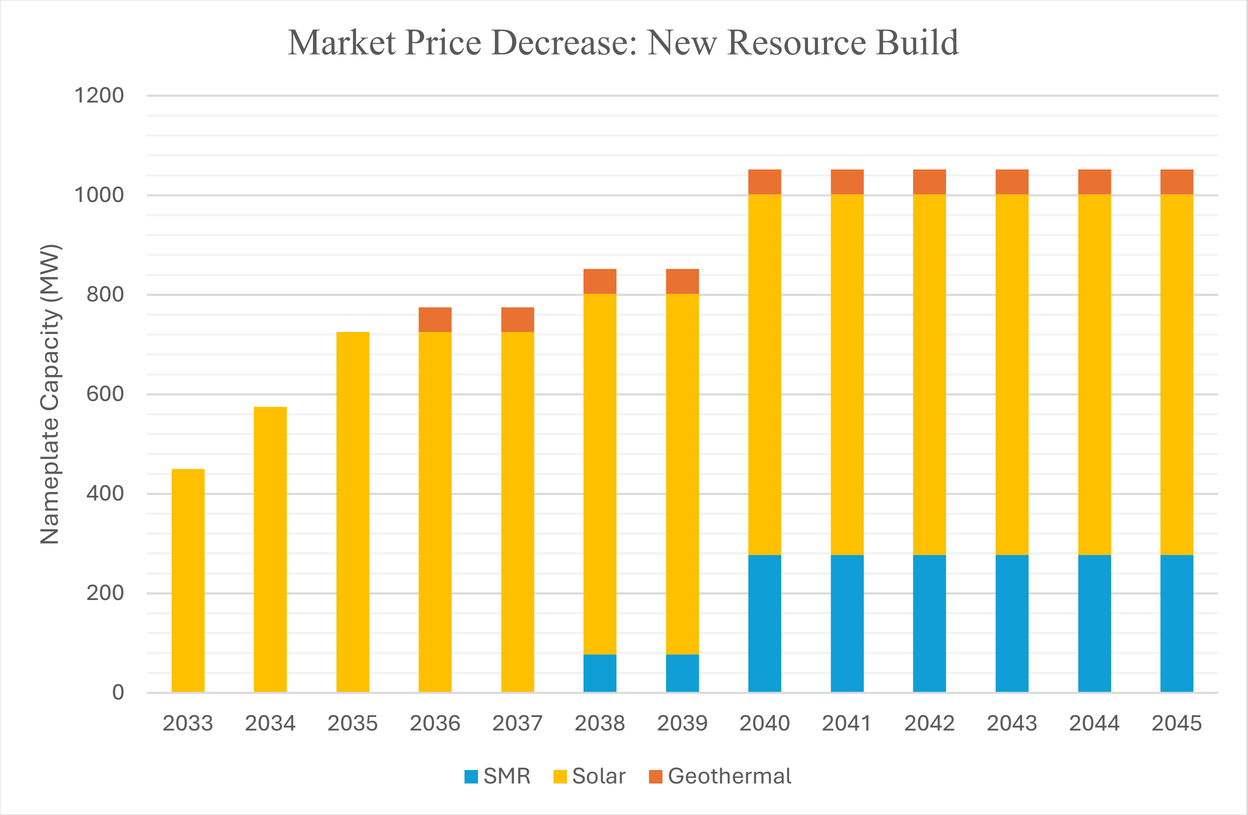


Figure 7-14: Market Price Decrease Resource Acquisition

7.3.4 Early Nuclear 2035 Scenario

This scenario considered an optimistic case where nuclear resources could be selected by 2035, rather than the current expectation of 2038. The early nuclear scenario resulted in 300 MWs less of renewable resources. While it is less likely that nuclear energy would become available by 2035, this scenario highlights the importance of emission-free, firm capacity resources being brought into Springs Utilities' service territory. If it is possible, it is beneficial to bring nuclear online sooner than the expected timeline. **Figure 7-15** highlights the resource acquisition plan for the early nuclear scenario.

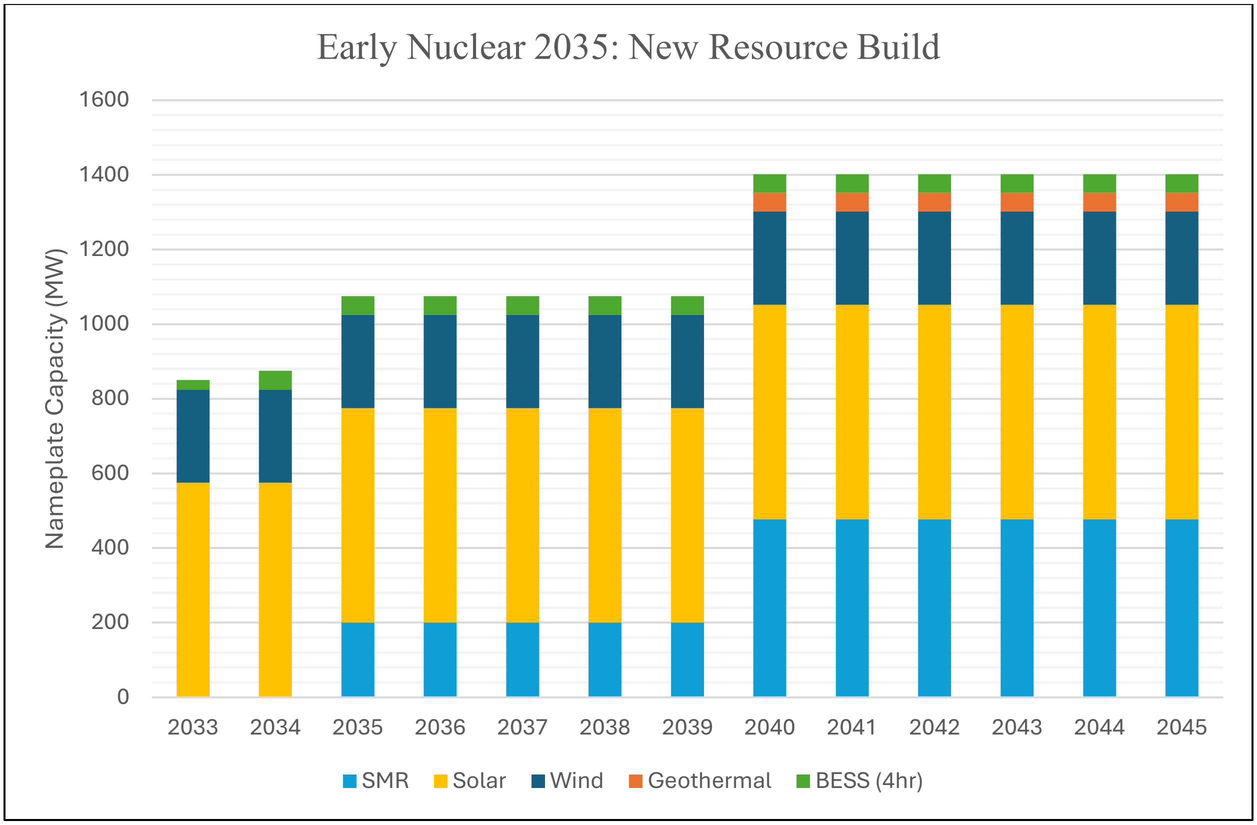


Figure 7-15: Early Nuclear 2035

7.3.5 Reference Portfolio vs Scenario Comparison

Figure 7-16 provides a comparison of the difference scenarios studies above and the reference case.

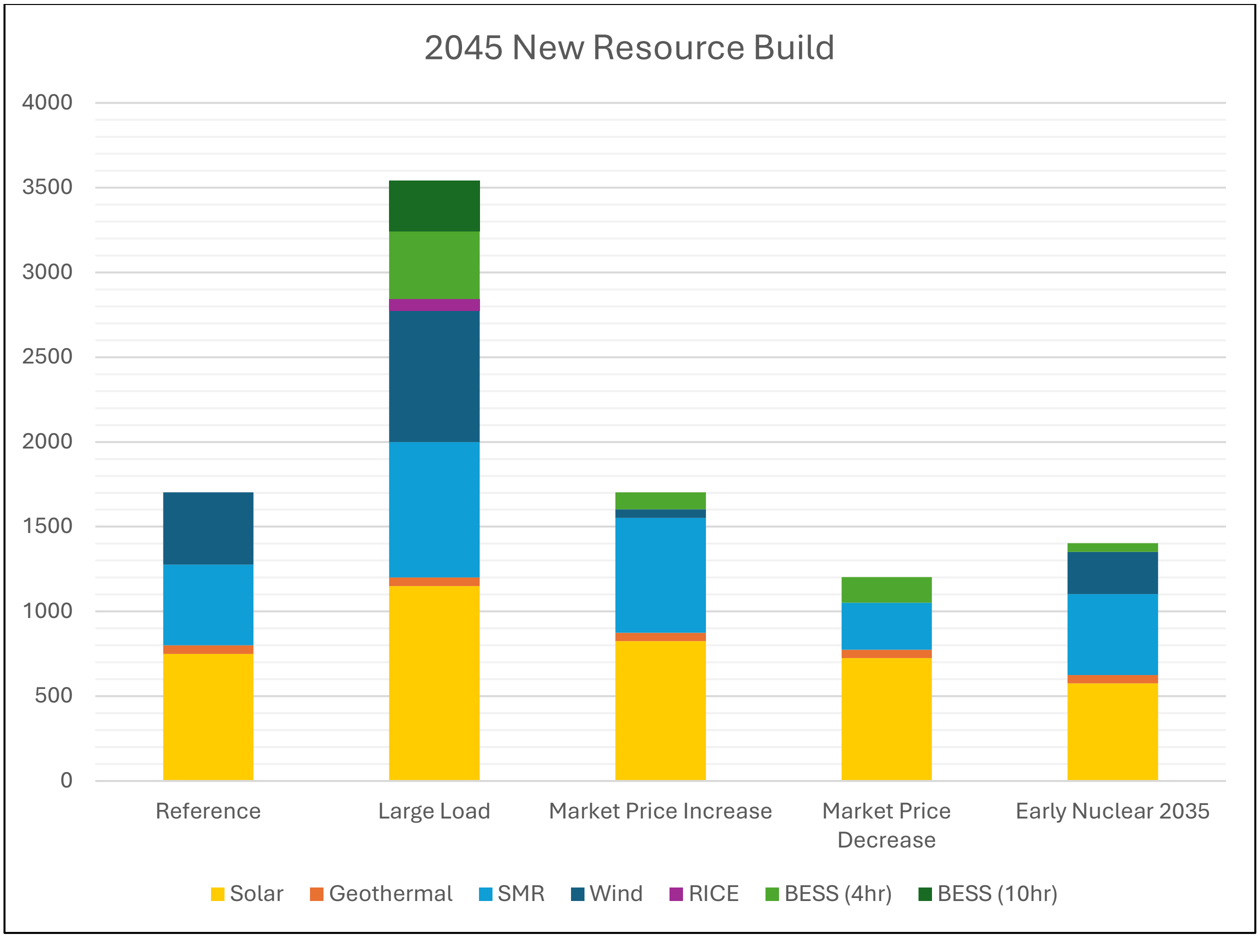


Figure 7-16: Resource Acquisition Comparison by Scenario

7.4 Risk Analysis

Springs Utilities handled risk analysis by considering the most likely sensitivities that could impact the peak load or energy required for Springs Utilities' electrical grid. There have been several state and federal policy changes regarding fossil fuels and renewable energy over the past few years that changed Springs Utilities' direction for the foreseeable future. It is possible that there will be more changes in the coming years that shift the planning landscape of the utility and energy sector. Tariffs on renewable resource components and increases in natural gas prices could potentially raise the overall cost of future generation. There are several impacts that could occur on the customer side as behind the meter resources become more commercially viable, such as increased EV adoption or behind-the-meter solar. The wide range of sensitivities considered within the modeling runs cover many of these possible risks, but Springs Utilities will continue to monitor any changes that could potentially impact the system.

Section 8: Next Steps

8.1 Resource Acquisition

Industry backlogs, supply chain instability and transmission availability have posed challenges to bringing new resources online before 2030. To meet growing demand in the short-term, Springs Utilities will look to procure capacity and energy from other power producers via term contracts.

Additionally, in April 2026, Springs Utilities issued a Request for Proposal (RFP) for 300 MWs of solar, wind and battery. This amount was chosen as a starting point because it was the minimum size of renewables built in nearly every scenario modeled. Strict requirements, such as project interconnection location and operational date, will ensure proposed projects meet cost and availability objectives.

8.2 Long-term Resource Evaluation

The EIRP is a continual process. Technological changes, local economics, or broad market conditions -to name a few- will alter core assumptions, requiring plan agility and re-evaluation. Springs Utilities will continue monitoring, modeling, and updating the long-term resource acquisition strategy.

8.3 Nuclear Feasibility Study and Community Engagement

While nuclear was selected throughout the modeling process, additional studies and review will continue to validate feasibility and the implementation strategy for Colorado Springs. Strategic partnerships are already underway with the Energy Power Research Institute (EPRI) and Gateway for Advanced Innovation in Nuclear (GAIN) to leverage their expertise as we complete the planning phase.

A comprehensive environmental justice assessment for a potential nuclear power program has been drafted based on siting at Clear Spring Ranch. A formal community engagement plan will be developed as a first step in the nuclear power feasibility study being completed in collaboration with Idaho and Oak Ridge National Labs.

The overall engagement strategy will leverage all communication channels to proactively communicate the significance of the EIRP, the importance of understanding electric rate drivers, our current projects and possible future technological solutions including nuclear power.

8.4 Submit Clean Energy Plan per Senate Bill 26-182

An updated Clean Energy Plan will be submitted by the end of 2026 in accordance with recently passed legislation. This will layout Springs Utilities plan to achieve 80% emissions reduction by 2033, replace the Nixon coal plant, and seek to reduce emissions by 95% in 2040.

APPENDICES

APPENDIX A. GENERATION PLANT DETAILS

APPENDIX A.1 Ray Nixon Power Plant

Ray Nixon Power Plant (“Nixon”) is a coal-fired generating facility located in El Paso County, Colorado that began commercial operation in 1980. It consists of one active coal-fired unit with a total of 208 MW of capacity. The fuel for the units is supplied from the Powder River Basin region. Two additional natural gas-fired combustion turbines were added at the Ray Nixon Power Plant in 1999. Both units have 33 MW of capacity for a total of an additional 66 MW at the plant.

Figure A- 1: Ray Nixon Power Plant

APPENDIX A.2 Front Range Power Plant

Front Range Power Plant (“Front Range”) is a natural gas-fired combined cycle generating facility located in El Paso County, Colorado that began commercial operation in 2003. The plant consists of two combustion turbines and steam turbine that combine for a total of 542 MW of summer capacity. Both combustion turbines are rated at 154 MW of capacity and the steam turbine is rated at 234 MW. Springs Utilities originally owned half of the generating facility and in December 2010 fully acquired the additional half of the Front Range Power Plant that it did not already own.

Figure A- 2: Front Range Power Plant

APPENDIX A.3 South Plant Aeroderivative Generators

Located in downtown Colorado Springs, The South Plant Aeroderivative Generators ("SPAGs") are natural gas-fired units and began commercial operation in 2023. The plant consists of six fast-ramping aeroderivative gas turbines that combine for 150 MWs of nameplate capacity. Adding to their reliability, they are dual fuel capable with oil as the secondary fuel.

Figure A- 3: South Plant Aeroderivative Generators

APPENDIX A.4 Tesla Hydroelectric Power Plant

Tesla Hydroelectric Power Plant ("Tesla Hydro") was built in 1997 and is in El Paso County, Colorado. The Tesla plant has a capacity of 28 MW and the water to drive the unit is supplied from the Rampart Reservoir through an underground tunnel. Electrical load on the unit varies hour to hour to help meets electrical and water consumption needs.

APPENDIX A.5 Manitou Springs Hydroelectric Plant

Manitou Springs Hydroelectric Plant ("Manitou Hydro") was built in 1905 and is in Manitou Springs, Colorado. The power plant consists of three hydraulic turbines that combine for a total of 5.5 MW of capacity. Manitou Unit 1 and Unit 2 both are rated at 2.5 MW of capacity and Manitou Unit 3 is rated at 0.6 MW of capacity. The water to drive the unit is supplied from bodies of water fed from Pike's Peak.

APPENDIX A.6 Ruxton Hydroelectric Plant

Ruxton Hydroelectric Plant ("Ruxton Hydro") was built in 1925 and is in Manitou Springs, Colorado. The power plant consists of one hydraulic turbine with a capacity of 1 MW. The plant is utilized to supply power to homes in Ruxton Park as well as to slow down the flow of water in Ruxton Creek as it flows off the mountain. The water that drives the unit is supplied from bodies of water fed from Pike's Peak similar to the Manitou Springs Hydroelectric Plant.

APPENDIX A.7 Cascade Hydroelectric Plant

Cascade Hydroelectric Plant (“Cascade Hydro”) was built in 2010 and is in Cascade, Colorado. The power plant consists of one hydraulic turbine with a capacity of 0.8 MW. The water to drive the plant is supplied from the North Slope Reservoirs of Pike’s Peak.

APPENDIX B. POWER PURCHASE CONTRACT DETAILS

APPENDIX B.1 Western Area Power Administration Purchases

Springs Utilities receives allocations of federal hydropower under contracts with WAPA's Salt Lake City Integrated Area Projects ("SLCA/IP"), and Loveland Area Projects ("LAP"). The SLCA/IP contract provides 15 MW in the summer and 60 MW in the winter. The LAP contract provides 60 MW in the summer and 57 MW in the winter. Both contracts also provide some Renewable Energy Certificates ("RECs") for energy provided from Western's small hydro facilities. These contracts currently extend to September 30, 2054.

APPENDIX B.2 United States Air Force Academy Solar Generating Station Purchase

The 5.25 MW solar contract from the USAFA Solar Project began commercial operation on July 1, 2011. SunPower owns and operates the facility, and Springs Utilities has the option to purchase the project after 10 years. Its 18,888 solar panels cover 43 acres.

APPENDIX B.3 Community Solar Gardens

In October 2011, Springs Utilities received approval from the Springs Utilities Board to offer a CSG Bill Credit (Pilot Program) Tariff for up to 2 MW total. The pilot program sold out almost immediately with four separate 500 kW installations. The Community Solar Garden Program provides an opportunity for electric customers to own a solar PV system without it being installed on their home or business. In 2014, a new CSG tariff was created, and an additional 2 MW was completed in July of 2015.

APPENDIX B.4 Clear Spring Ranch Solar

The 10 MW solar contract with NextEra Energy, Inc ("NextEra" for the Clear Spring Ranch Solar Facility ("Clear Spring Ranch") began commercial operation in 2016 and is in El Paso County, Colorado. NextEra built the solar array and will operate and maintain the facility throughout the 25-year power purchase agreement. Clear Spring Ranch Solar was the first utility-scale solar array for Springs Utilities.

APPENDIX B.5 Palmer Solar

The 60 MW solar contract with Duke Energy for the Palmer Solar Facility ("Palmer") began commercial operation in 2020 and is located on land south of Colorado Springs, Colorado. Palmer Solar is the first solar array to interconnect directly with Springs Utilities' transmission system. Duke will operate and maintain the facility throughout the 20-year power purchase agreement.

Figure B- 1: Palmer Solar

APPENDIX B.6 Grazing Yak Solar

The 35 MW solar contract with NextEra for the Grazing Yak Solar Facility ("Grazing Yak") began commercial operation in 2019 and is located near Calhan, Colorado. NextEra built the solar array and will operate and maintain the facility throughout the 25-year power purchase agreement.

Figure B- 2: Grazing Yak Solar

APPENDIX B.7 Pike Solar

The 175 MW solar contract with Pike Solar LLC for the Pike Solar Facility ("Pike") began commercial operation in 2024 and is located near Fountain, Colorado. NextEra built the solar array and will operate and maintain the facility throughout the 17-year power purchase agreement.

APPENDIX B.8 Spring Canyon Wind

The 60 MW wind contract with Invenergy for the Spring Canyon Wind Facility ("Spring Canyon") began commercial operation in 2014 and is located in Peetz, Colorado. Springs Utilities entered the into the power purchase agreement with Invenergy in 2020. Invenergy will operate and maintain the facility throughout the end of the contract on December 31, 2029.

APPENDIX B.9 Jackson Fuller Battery Storage

The 100 MW storage contract with NextEra for the Jackson Fuller Battery Storage System ("Jackson Fuller") began commercial operation in 2025 and is located near Falcon, Colorado. NextEra built the battery storage system and will operate and maintain the facility throughout the 20-year power purchase agreement.

APPENDIX B.10 Horizon Battery Storage

The 100 MW storage contract with Ameresco for the Horizon Battery Storage System ("Horizon") will begin commercial operation in 2027/28 and is located on the southeast side of Colorado Springs, Colorado. Ameresco will build the battery storage system and will operate and maintain the facility throughout the 20-year power purchase agreement.

APPENDIX C. TECHNOLOGY ASSESSMENT

APPENDIX C.1 Fossil Fuel Resource Options

Combustion Turbine

The three primary components of the gas turbine are the compressor, combustion system, and turbine. The compressor pressurizes the air and delivers it to the combustion chamber. The combustion system mixes the pressurized air with fuel to create a high-pressure, high-temperature gas mixture that is then transported to the turbine. Gas expands inside the turbine, spinning the rotating blades that connect to a generator to produce electricity. A closer look at the design of a combustion turbine can be seen in **Figure C- 1** below.

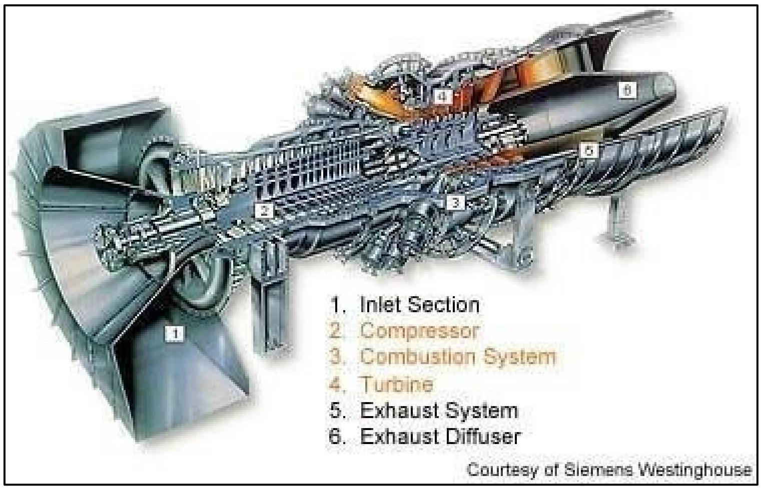


Figure C- 1: Cutaway of Combustion Gas Turbine

Source: Department of Energy ("How Gas Turbine Power Plants Work")

Combined Cycle

A combined cycle configuration improves the efficiency of a simple cycle combustion turbine by utilizing the gas exhaust from a combustion turbine. A heat recovery steam generator ("HRSG") captures the waste heat and uses a boiler to produce high-pressure steam to power through a steam turbine. The efficiency improvement will lead to a lower dispatch cost for a combined cycle than a simple cycle combustion turbine. An example of a combined cycle power plant can be seen in **Figure C- 2** below.

Figure C- 2: Combined Cycle Power Plant Layout

Source: https://electrical-engineering-portal.com/an-overview-of-combined-cycle-power-plant

Aeroderivative Gas Turbine

An aeroderivative gas turbine (“Aero”) is essentially a gas turbine that has been derived from aircraft engine technology. These turbines use the core engine from a jet engine as their basis, modified for non-aviation use. They retain much of the same mechanical design, using high-efficiency compressors, combustion chambers, and turbines, but are optimized for continuous operation and adaptability in industrial environments. These turbines run at a higher compressor ratio and tend to be more compact than a standard heavy frame combustion turbine. This technology requires a small footprint and could be portable, thus having the ability to place them at sites with specific generation needs.

Reciprocating Internal Combustion Engine

A Reciprocating Internal Combustion Engine (“RICE”) drives the standard automobile. The expansion of gas moves a piston within a cylinder which rotates a shaft to produce electricity. RICE units are similar to aeroderivative units and require a small footprint that enables them to be sited near strategic load and transmission locations. One of the main advantages of reciprocating engines is their ability to provide incremental electricity quickly. Because these units can start and stop quickly and operate at partial loads, they have become increasingly important in areas with high shares of renewable electricity generation from wind and solar.

Linear Generator

Working more like a piston in a car, the linear generator uses linear motion, as opposed to rotation, to induce electrical currents between the generator magnets and copper coils. Due to its unique design and advanced controls, the linear generator can operate at a much lower reaction temperature than traditional combustion-based generators. Precise control of the oscillators within the generator compresses a fuel air mixture until the mixture reacts uniformly without a flame. The energy from this low-temperature reaction drives the linear motion of the oscillators which is directly converted into electricity with near zero NOx emissions.

APPENDIX C.2 Renewable Resource Options

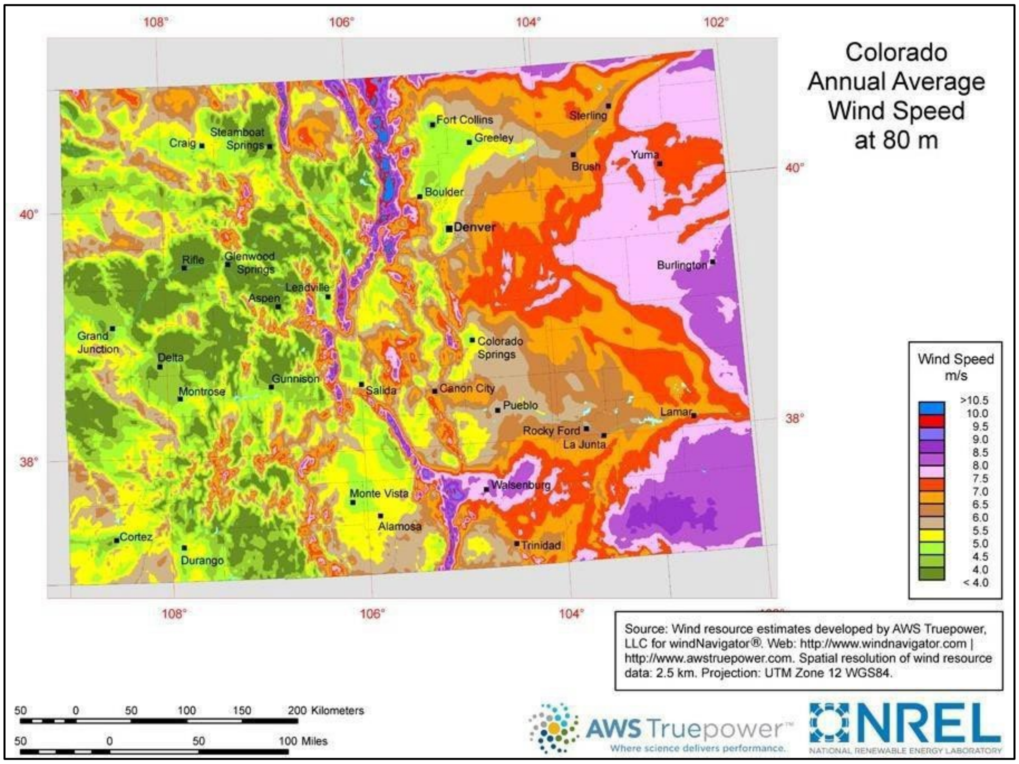
Wind, solar, and geothermal energy were considered as options in the EIRP. Renewable resources such as wind and solar typically have intermittent generation dependent on weather profiles (as described in the ELCC section of this document). Energy storage paired with renewable generation allows renewable facilities to store electricity and alter the facility's generation profile. Geothermal energy is considered a firm capacity resource and could provide base load for Springs Utilities' system.

Solar

Photovoltaic (PV) solar generation works by converting sunlight into electricity using photovoltaic cells. When the sunlight hits these cells, it creates an electric current. This direct current (DC) is converted to alternating current (AC) by an inverter, producing usable electricity. Solar energy is an abundant resource, especially in a sunny location like Colorado Springs, which makes solar a reliable renewable energy source. However, the resources cannot produce electricity during the night or in times of heavy cloud cover, so balancing it with generation resource that have different production profiles is very important.

Wind

Wind generation uses wind turbines placed in large, open fields to convert wind energy into electricity. The wind spins the turbine's large blades, which spin a rotor connected to a generator, producing electricity. Wind acts as a complimentary resource to solar generation as it has a different generation profile, often producing more electricity throughout the night than in the day. The challenge with increasing wind generation is largely due to limited access to optimum wind speeds in the Colorado Springs area. As seen in **Figure C- 3**, high wind speeds can be accessed north and east of Colorado Springs. For Springs Utilities to ramp up wind generation, a transmission strategy must be developed to interconnect to sites with high wind speeds.



Colorado Annual Average Wind Speed at 80 m

Source: Wind resource estimates developed by AWS Truepower, LLC for windNavigator®. Web: http://www.windnavigator.com | http://www.awstruepower.com. Spatial resolution of wind resource data: 2.5 km. Projection: UTM Zone 12 WGS84.

Figure C- 3: Colorado Wind Heat Map

Geothermal

Geothermal production in Colorado could be an important step in the transition towards a clean energy future. However, traditional geothermal energy relies on naturally occurring reservoirs of hot water and steam. A combination of heat, water, and permeable rock are required for traditional geothermal energy production. In Colorado, while there is substantial underground heat, there is a lack of hot water or steam pocket needed for traditional geothermal generation. The low to moderate temperature of most geothermal features in Colorado are more suitable for heating than energy production. Enhanced Geothermal Systems (EGS) are an emerging clean energy technology that allows the user to produce geothermal electricity in areas without naturally occurring underground water or permeability. Unlike traditional geothermal, which relies on naturally hot, porous, water-filled rock formations, EGS creates artificial reservoirs in deep, hot rock. **Figure C- 4** displays a heatmap of geothermal resources in the United States.

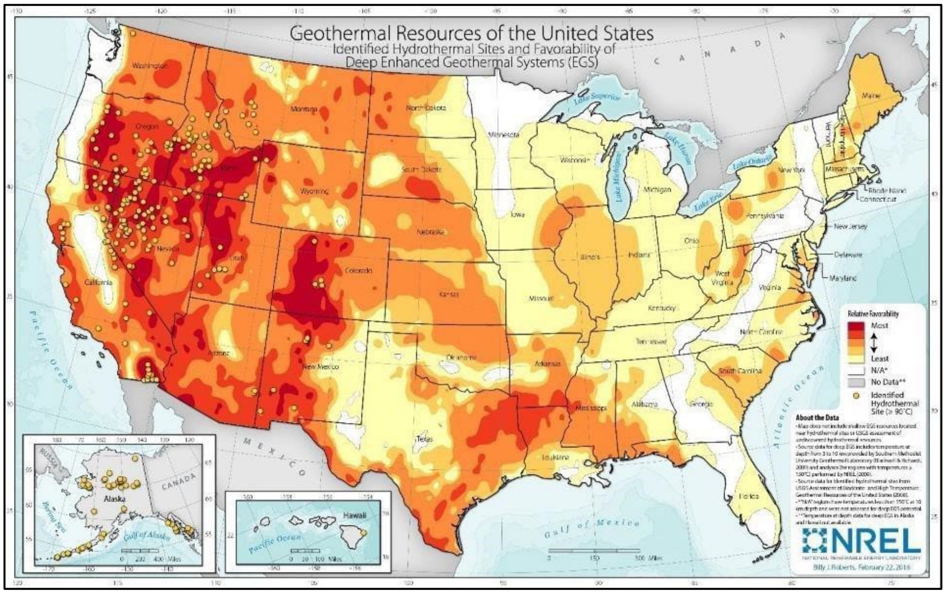


Figure C- 4: United States Geothermal Heat Map

APPENDIX C.3 Energy Storage Resource Options

Lithium-ion batters, flow batteries, fuel cells, mechanical storage, and thermal storage options were considered as potential options in the EIRP. Battery technology is quickly maturing, and costs are expected to continue to decline over the next decade. Battery storage will provide needed capacity and ancillary services that will help integrate renewable resources.

Lithium-Ion Battery

A 4-hour duration and 10-hour duration lithium-ion battery were both included in the EIRP. Lithium-ion batteries get their name from the transfer of lithium ions between the electrodes, both when energy is injected for storage purposes and when it is extracted. Unlike other batteries with electrodes that change by charging and discharging, Li-ion batteries offer better efficiency because the ion movements leave electrode structures intact. Lithium-ion batteries have the versatility to handle smaller-scale applications, such as powering electric vehicles, as well as grid-scale applications requiring megawatts of power for hours at a time. Lithium-Ion batteries have shorter duration storage compared to many other storage technologies, but the high efficiency, MW outputs, and ELCC contributions makes these batteries a reliable resource option.

Redox Flow Battery

Flow battery technology is noteworthy for its unique design. Instead of a single encased battery cell where electrolyte mixes readily with conductors, the fluid is separated into two tanks and electrons flow through electrochemical cells and a membrane which separates them. The main difference between flow batteries and other rechargeable battery types is that the aqueous electrolyte solution usually found in other batteries is not stored in the cells around the positive electrode and negative electrode. Instead, the active materials are stored in exterior tanks and pumped toward a flow cell membrane and power stack. Power sources charge electrons in the electrolyte solution in the positive anolyte tank connected to the anode through a process called “oxidation”. The charged electrons are then pushed into the catholyte tank tied to the cathode through a process called “reduction”.

Iron Air Storage

Iron-air batteries are a promising new energy storage technology designed for long-duration storage, meaning they can deliver electricity over many hours or even days—something traditional lithium-ion batteries can't do cost-effectively. They work by using iron and air as their core materials, which are abundant, low-cost, and safe to handle. This makes iron-air batteries a potentially economical solution for storing renewable energy and improving grid reliability during times when wind or solar power is unavailable. The battery operates through a process known as reversible rusting. During discharge, the battery takes in oxygen from the air and causes iron metal within the battery to rust, or oxidize, releasing electrons and generating electricity. When it's time to recharge, the process is reversed: electricity is used to convert the rust (iron oxide) back into metallic iron, releasing the oxygen back into the air. This cycle can be repeated hundreds of times and is inherently safe, as it operates at ambient temperatures and doesn't rely on flammable materials.

Compressed Air Storage

Compressed air energy storage works by using excess electricity to compress air and store it in underground caverns or pressure vehicles. When electricity is needed, the compressed air is released, heated, and expanded to drive turbines that generate power. CAES is designed to fill markets where longer duration (12-24 hours) is needed. While CAES has been demonstrated to deliver longer duration storage, its cost effectiveness is limited by the availability and design of the caverns.

Thermal Storage: Concrete

Thermal concrete storage works by using concrete as a medium to store thermal energy. During the “charging” stage, boiler steam or hot gas flows in one direction through the system, heating the concrete. The highest temperature is maintained at the charging inlet. This heat is stored due to the high thermal capacity of concrete until needed. When “discharging”, air or water is pumped in the opposite direction, and the steam exits the system at the hot end temperature (~600 degrees Celsius). Energy is drawn from the middle of the block, and the hot end temperature is maintained. This allows the system to produce consistent steam quality throughout the discharge cycle. This steam can then be converted to electricity by driving a steam turbine, which allows this technology to integrate into the infrastructure of a coal plant.

Thermal Storage: Molten Salt

Molten salt energy storage is typically used with a concentrated solar power plant. This type of power plant uses mirrors or lenses to focus a large amount of sunlight to generate heat. The salt is kept liquid at roughly 275 C in a “cold storage” tank. When the solar power plant is producing excess energy, the molten salt is pumped through the solar receiver to collect the additional heat. The concentrated solar energy heats the molten salt to over 550 C. This molten salt is then sent to a “hot storage” tank. When extra energy is needed (at night or on a cloudy day), the molten salt from the “hot storage” tank is used to produce steam that drives a turbine and generates electricity.

Hydroelectric Pumped Storage

Pumped storage hydropower (PSH) is another type of hydroelectric power. It is a configuration of two water reservoirs at different elevations that can generate power as water moves down from one to the other (discharge), passing through a turbine. The system also requires power as it pumps water back into the upper reservoir (recharge). PSH acts similarly to a giant battery, because it can store power and then release it when needed. Depending on the size of the reservoir, pumped storage hydro can provide hours or days of energy storage, both for longer and more efficiently than many other storage technologies. The flexibility of “charging” and “discharging” could also help provide power at night, when solar units are incapable of producing. An example of a pumped storage system is presented in **Figure C- 5**.

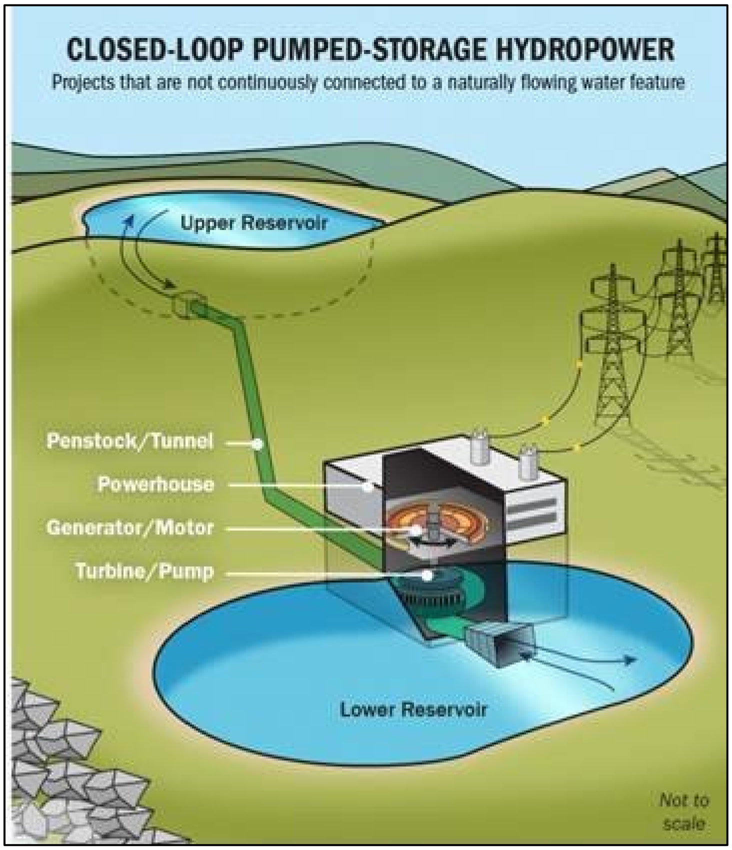


Figure C- 5: Pumped Storage System Diagram

Source: *https://www.energy.gov/eere/water/pumped-storage-hydropower*

APPENDIX C.4 Carbon-Free Resource Options

In addition to the thermal and renewable resources listed in this section, a multiple carbon-free or carbon-neutral resources were considered as options in the EIRP.

Combined Cycle with Carbon Capture

Carbon capture and storage is a technology that captures the carbon dioxide (“CO_2”) emissions from power plants instead of allowing them to be emitted into the atmosphere. This CO_2 is then compressed and stored in the earth to keep it out of the atmosphere indefinitely. This could allow units that run on fossil fuels to continue to generate electricity while producing much lower CO_2 emissions, although the cost and water consumption of this technology could be a prohibitive factor.

Traditional Nuclear Reactor

Traditional nuclear energy is generated through a process called nuclear fission, where atoms of a heavy element—usually uranium-235—are split apart inside a nuclear reactor. When these atoms split, they release a large amount of heat. This heat is used to boil water into steam, which then spins a turbine connected to a generator to produce electricity. The process takes place inside a reactor core, where fuel rods filled with uranium are arranged and controlled to sustain a steady chain reaction. To manage the reaction safely, control rods are inserted or withdrawn to absorb excess neutrons and regulate the rate of fission. The entire system is housed in a containment structure designed to protect against radiation leaks and extreme conditions. Most nuclear power plants use a design called a pressurized water reactor (PWR), where water under high pressure acts both as a coolant and as a medium to transfer heat. In these systems, the water that passes through the reactor is kept separate from the steam that turns the turbine, adding an extra layer of safety. Nuclear energy, when implemented correctly and built according to the rigorous safety codes, is a safe and dependable resource.

Small Modular Nuclear Reactor

Small modular reactors (SMRs) are advanced nuclear reactors that have a power capacity of up to 300 MW per unit, which is about one-third of the generating capacity of traditional nuclear power reactors. These advanced reactors can be used for power generation, process heat, desalination, or other industrial uses. SMR designs may employ light water as a coolant or other non-light water coolants such as a gas, liquid metal, or molten salt.

Biomass and Biogas

Biomass power plants are industrial facilities that convert organic matter into usable energy. Biomass is renewable organic material that comes from plants and animals. Biomass combustion technology converts waste to heat to produce steam. The steam is then expanded through a conventional turbine to produce electricity. Direct combustion is the most common method for converting biomass to useful energy. Biomass is used for heating, electricity generation, and as transportation fuel. Biomass sources for energy include wood and wood processing waste, agricultural crops and waste materials, biogenic materials in municipal solid waste, and animal manure and human sewage for producing biogas (renewable natural gas).

Landfill Gas

Landfill gas systems supply fuel from landfills to an associated power plant. Landfill gas is a mixture of methane and carbon dioxide and landfill gas systems. The landfill gas is typically allowed to escape into the atmosphere and so by using the gas for power generation, one can effectively use the gas instead of allowing it to escape in the air. The landfill gas can be captured from the landfill, processed through facilities, and utilized in reciprocating engines to produce electricity.

Table C- 1: Potential Resources Modeled

Item	H-Frame 1x1 CC	Aero	RICE	Solar	Wind	Geothermal	Lithium-Ion 4hr	Lithium-Ion 10hr	Landfill Gas	Traditional Nuclear	SMR
Assumed Capacity	400MW	25MW	17MW	25MW	25MW	25MW	100MW/ 400MWh	25MW/ 250MWh	10MW	1000MW	200MW
Assumed Lifespan (years)	30	30	30	30	30	30	20	20	30	80	80
Earliest Start Year	2030	2030	2030	2030	2030	2035	2030	2035	2030	2038	2038
Capex ($/kW)	$1,725	$2,500	$2,500	$0	$0	$9,400	$2,200	$3.600	$5,000	$7,600	$9,650
Fixed O&M Costs ($/kW-yr)	$39	$37	$43	$0	$0	$191	$74	$85	$164	$175	$136
Variable O&M Costs ($/MWh)	$2	$5	$7	$35	$40	$0	$0	$0	$5	$3	$3
Roundtrip Efficiency	N/A	N/A	N/A	N/A	N/A	N/A	90%	90%	N/A	N/A	N/A
Recommendation	Included	Included	Included	Included	Included	Included	Included	Included	Included	Included	Included

Table C- 2: Potential Resources Considered

Item	Linear Generator	Redox Flow Battery	Iron-Air Battery	Compressed Air Storage	Thermal Storage: Concrete	Thermal Storage: Molten Salt	Pumped Storage	Biomass/Biogas
Assumed Size	30MW	10MW/ 100MWh	10MW/ 100MWh	100MW/ 800MWh	100MW/ 1000MWh	100MW/ 1000MWh	200MW/ 1600MWh	Fuel Source
Assumed Lifespan (years)	20	12	20	25	30+	35	40	25-30
Earliest Start Year	2030	2030	2030	2032	2032	2032	2030	2030
Capex ($/kW)	N/A	3,400	N/A	1,700	N/A	4,000	3,500	3,600
Fixed O&M Costs ($/kW)	N/A	11	N/A	16	N/A	29	20	114
Variable O&M Costs ($/MWh)	N/A	2	N/A	210	N/A	3	1	6
Efficiency	46%	65%	Low	52%	Low	44%	80%	N/A
Reason for Exclusion	Lack of real-world operational data	Short lifespan and high water requirements	Lack of real-world operational data	Lack of feasible sites and real-world operational data	Lack of feasible cost information	Lack of real-world operational data	High water requirements and location concerns	Limited availability