UNITED POWER

Your Touchstone Energy® Cooperative

INTEGRATED RESOURCE PLAN

PREPARED IN COLLABORATION WITH:

TEA SOLUTIONS

JULY 22, 2026

Contents

FOREWARD BY MARK A. GABRIEL, United Power President & CEO

On May 31, 2024, United Power transitioned away from a single wholesale power supply contract, placing responsibility for power development and procurement directly with the United Power team. The cooperative moved quickly to secure the resources necessary to meet immediate system needs while continuing to advance new, local resources to support long-term growth. For members, the transition was seamless; behind the scenes, United Power was building a diversified resource portfolio designed to serve members reliably today and well into the future.

Central to this strategy is a commitment to hyper-localized resources-investing locally to develop generation and infrastructure that directly support the communities United Power serves. This approach helps reduce the costs associated with transporting power over long distances, while also creating local jobs, strengthening the tax base, and expanding access to renewable energy resources within United Power's communities.

The Integrated Resource Plan, or IRP, provides a strategic roadmap for United Power's energy future. By evaluating projected resource needs, power costs, system growth, infrastructure requirements, and operating costs, the IRP serves as a critical planning tool to ensure the cooperative can continue meeting future power requirements while anticipating cost impacts for members. Developed with a 20-year planning horizon, the IRP considers the market, regulatory, operational, environmental, and financial factors that may influence the cooperative over time. Its objective is to guide investments that maximize value, strengthen reliability, and meet the evolving needs of United Power members.

At the foundation of this plan are the cooperative principles that guide United Power's decisions and define its commitment to members. Resource investments, cost impacts, system growth, emissions, and long-term reliability were all carefully considered throughout the planning process. This report reflects a concerted effort by the United Power team to provide transparency into the cooperative's growing energy needs and to evaluate the options available to power members' lives safely, affordably, and reliably.

This report provides meaningful insight into the complex considerations involved in planning for the energy needs of a cooperative as large and dynamic as United Power. The IRP enables the cooperative's leadership to weigh the many factors affecting power costs-from fuel prices and market conditions to regulatory requirements and infrastructure needs-and identify a disciplined path forward. It is one of the many ways United Power is working to meet every member's needs, today and tomorrow.

Mark A. Gabriel
President and Chief Executive Officer, United Power

Section 1 Executive Summary

1.1 Importance of the Integrated Resource Plan (IRP)

United Power operates in one of the fastest-growing regions in Colorado. Continued residential expansion, commercial development, electrification of transportation and industry, and the emergence of large-load members are increasing both annual energy consumption and system peak demand. As a result, long-term resource planning is essential to ensure that the cooperative can reliably meet future needs while maintaining affordable rates for its members.

The electric industry across the United States is undergoing structural change. Wholesale market dynamics, transmission constraints, evolving resource adequacy requirements, fuel price volatility, and rapid technology cost shifts are reshaping how utilities procure power. These factors create both opportunity and uncertainty for electric distribution cooperatives.

In May 2024, United Power transitioned from a single wholesale power supply arrangement to a diversified power supply portfolio managed directly by the cooperative. This transition provides the cooperative with greater autonomy in shaping its resource portfolio, while increasing the importance of disciplined long-term planning and risk management. United Power now has expanded flexibility to optimize its supply mix through a combination of market purchases, bilateral agreements, renewable resources, storage technologies, and other capacity options.

As a cooperative governed by a member-elected Board of Directors, United Power must balance several core objectives:

- Maintain affordability and rate stability
- Ensure reliable service during peak demand conditions
- Manage exposure to wholesale market price volatility
- Preserve financial strength and credit quality
- Maintain flexibility to respond to changing markets and regulatory conditions

This Integrated Resource Plan provides a structured, data-driven evaluation of future load requirements and alternative resource strategies over the planning horizon. The analysis identifies portfolios that perform well across a range of economic, fuel price, and load growth scenarios, enabling United Power to make informed decisions that protect its members and support long-term system reliability.

The IRP is not a static document. Rather, it establishes a framework for ongoing monitoring and adjustment as market conditions, technology costs, and member needs evolve.

1.2 United Power Overview

United Power is a member-owned electric distribution cooperative serving more than 118,000 meters across approximately 900 square miles along Colorado's north-central Front Range. Although it serves the smallest geographic area of any Colorado electric cooperative, it has the second-highest meter count and the largest electric load among the state's cooperatives.

The cooperative's service territory includes rapidly growing suburban communities north and east of Denver, as well as historic mountain canyon areas. Strong residential and commercial development, electrification trends, and the potential addition of large-load members are expected to drive continued growth in energy and capacity requirements throughout the planning horizon.

As of 2025, United Power's system peak demand is approximately 680 MW, reflecting one of the largest loads among Colorado cooperatives. Sustained growth and evolving resource adequacy requirements will require significant planning and investment to maintain reliable and affordable service.

United Power is governed by a member-elected Board of Directors and operates under the cooperative model, which prioritizes reliability, affordability, financial strength, and long-term stewardship on behalf of its members.

This Integrated Resource Plan evaluates how United Power can meet projected load growth and future capacity needs while maintaining affordability, reliability, and flexibility under a range of potential market, regulatory, and operational conditions.

1.3 The Energy Authority Overview

TEA was established in 1997 by three public power owners to address changes in the electric utility industry. Its unique mission is to enhance the utilization of its members' electric generating assets in the wholesale energy market and to optimize power sales and purchases on their behalf. TEA distinguishes itself through its focus on creating economies of scale, reducing operating costs related to energy trading and marketing, and providing public power clients with effective risk management and settlement services. It accomplishes this through aggregated trading functions, analytical expertise, a skilled workforce, and advanced scheduling and deal capture technologies - systems that would be cost-prohibitive for most individual utilities.

TEA's unwavering commitment to public power and the communities it serves has been the cornerstone of its growth. Since its inception, TEA has expanded to include seven members and serves over 80 public power organizations across the nation. These clients represent more than 35,000 megawatts of peak demand and 30,000 megawatts of installed generation capacity. Today, TEA collaborates with these utilities to provide reliable, affordable, and sustainable energy solutions to over 1,300 communities, underscoring the scale of its operations and the trust it has earned from its stakeholders.

Strategic resource planning is a core component of TEA's services. By employing models that account for population growth, economic trends, environmental impacts, and technological advancements, TEA helps utilities identify resource portfolios that support long-term affordability and sustainability. The following exhibit highlights TEA's extensive experience and capabilities in strategic power supply planning for utilities nationwide, demonstrating its commitment to effective, forward-looking resource strategies.


FUELING CLIENT GROWTH IN
10 OUT OF THE 11
NERC REGIONS
50-80%
REDUCTIONS IN CARBON EMISSIONS
across all Integrated Resource Plans
27,000+ MWS
IN POWER PLANNING ASSESSMENTS
TEA
POWER SUPPLY PLANNING
RANGE OF RESOURCES. FULLY REVIEWED.
• CARBON-BASED TECHNOLOGIES
• NUCLEAR ENERGY
• RENEWABLE RESOURCES
• DEMAND-SIDE MANAGEMENT
• EMERGING TECHNOLOGIES
• PURCHASED POWER
TEA'S EXPERT TEAM
1 PhD
5 Bachelors
2 MASTER OF SCIENCE
OVER A DECADE OF INTEGRATED RESOURCE PLANNING TAILORED TO EACH CLIENT'S UNIQUE PORTFOLIO GOALS AND NEEDS.
50+ YEARS OF STAFF EXPERIENCE
TEA's experienced team consists of specialists in energy management, environmental science, and systems engineering. TEA uses advanced modeling software to assess long-term resource needs and optimize energy portfolios. Their comprehensive expertise allows us to develop strategic plans that meet regulatory requirements while promoting sustainable growth for clients in various regions.

1.4 IRP Methodology

United Power's IRP focuses on maintaining affordability for its members while ensuring flexibility in responding to changes in uncertain future energy markets.

To support this objective, TEA developed a comprehensive set of modeling inputs, including forecasts of electric demand across United Power's broad service footprint, natural gas prices, Southwest Power Pool (SPP) market prices, capital costs for generating resources, and projected pricing for renewable resources and bilateral power purchase agreements (PPAs).

TEA and United Power staff collaborated to define the scenarios used in the analysis. TEA then applied the PLEXOS resource planning model - an industry-recognized simulation tool - to evaluate resource portfolios that meet United Power's energy needs from 2026 through 2045. PLEXOS simulates future market conditions and optimizes resource selection based on long-term cost and system performance.

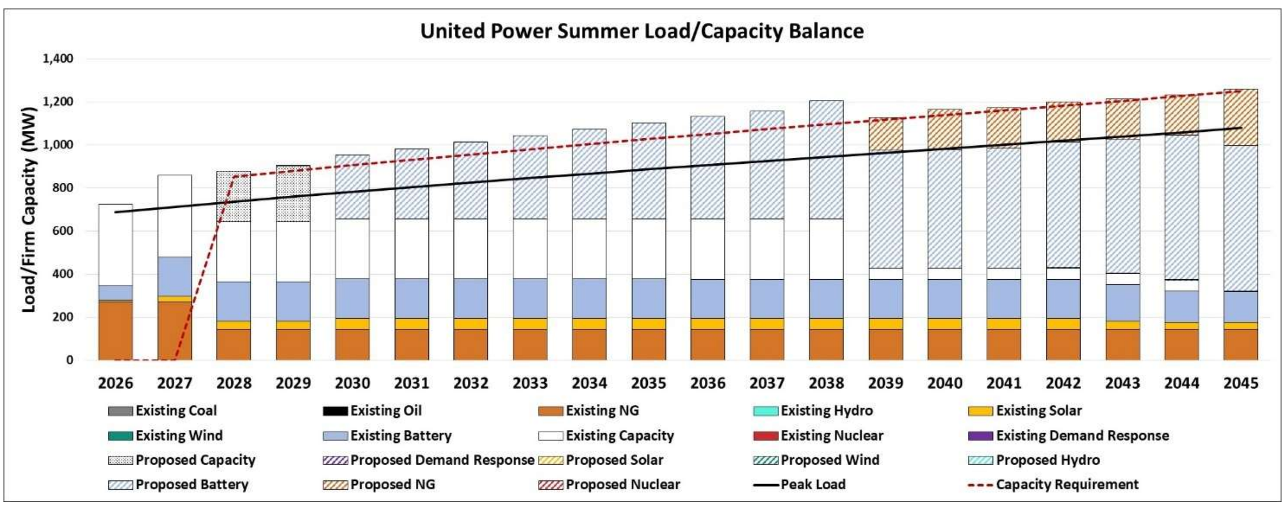
TEA compared the results of multiple scenarios to identify patterns and common solutions. This scenario-based analysis informed United Power's recommended resource strategy, which is designed to meet future energy needs while preserving adaptability and cost-effectiveness as market dynamics evolve.

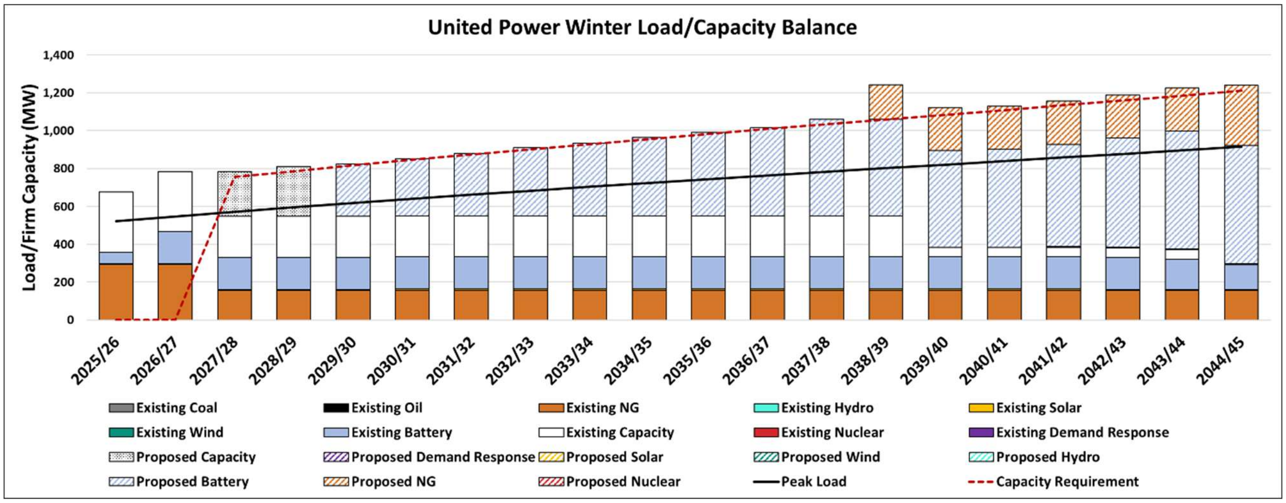
1.5 Future Electricity Needs

United Power's current power supply portfolio is diversified with natural gas thermal generation resources as well as renewable resources such as solar, battery, and landfill gas. The portfolio is further supplemented by purchased power and bilateral capacity purchase agreements. However, capacity requirements and resource distributions vary between the two balancing authorities United Power historically operated within - Public Service Company of Colorado (PSCO) and Western Area Colorado-Missouri (WACM), or what is now the SPP Regional Transmission Organization (RTO) West Expansion balancing authority. The plan seeks to optimize resources for both balancing authorities and United Power as a whole to help lower costs for all its members.

A Base Case was developed for United Power that achieves the 2030 emission limits of 80% reduction in carbon relative to 2005 levels. The figures below illustrate, for both summer and winter seasons, how existing firm capacity compares with peak load forecasts and projected capacity requirements through 2045 across the entire United Power system. In this case, most summer capacity needs are met by self-build battery resources beginning in 2030, with bilateral capacity used to bridge near-term gaps until those assets come online. Natural gas additions emerge in the late 2030s, followed by a modest amount of wind toward the end of the planning horizon.

Although winter peak load forecasts and capacity requirements are lower than in summer, the overall resource strategy is similar. Battery deployments address needs throughout the 2030s, with natural gas additions again appearing in the late 2030s and wind resources contributing later in the study period.





1.6 New Resource Options

United Power requires new resources to meet future capacity obligations and maintain system reliability under various uncertain conditions. This IRP focuses on identifying resource additions that enable each balancing authority to meet planning reserve requirements, manage risk, and support long-term cost stability.

To support these objectives, TEA evaluated a broad set of resource options including dispatchable natural gas-fired generation, solar, wind, battery storage, nuclear generation, and bilateral capacity purchases. Each option was assessed for its ability to contribute to a reliable, flexible, and cost-effective resource portfolio.

The resource types included in the analysis are:

- **Thermal Generation**: Natural gas-fired units were evaluated for their ability to provide firm, dispatchable capacity. Options include combined cycle and simple cycle combustion turbines, reciprocating internal combustion engines (RICE), and small modular reactor (SMR) nuclear generation.
- **Renewable Resources**: Solar and wind resources were considered, with cost trajectories influenced by continued technological advancements and incentives from the federal Inflation Reduction Act (IRA). Wind was modeled as both a PPA and as a self-build resource and solar was modeled as a PPA.
- **Battery Storage**: Lithium-ion battery storage was analyzed as both a PPA and a self-build option with 4-hour durations modeled to help align renewable output with system needs.
- **Bilateral Capacity**: Short-term capacity purchases of one year, typically transacted with other utilities and market participants, were included to reflect ongoing use in United Power's current portfolio and as a future option to enhance flexibility.

1.7 Scenario Results and Key Insights

To assess how varying future conditions might influence reliability, affordability, and risk, United Power's IRP evaluated a diverse set of planning scenarios. In total, ten scenarios were developed, including the

Base Case that assumes an 80% reduction in carbon emissions from 2005 levels by 2030. A corresponding scenario was also modeled without emission limits to highlight the differences between constrained and unconstrained outcomes.

Additional scenarios meeting the 2030 emission levels included high load growth, full accredited capacity for all units, and the addition of a large load such as a data center. Using the no emission limits Base Case, these same scenarios were reanalyzed, along with additional sensitivities for both high and low natural gas prices. The full set of scenarios is summarized in the table below.

Each scenario produced an optimized resource portfolio designed to meet reliability requirements while minimizing long-term system costs. Together, the results provide insight into how different resource mixes perform under a range of conditions and identify those that best balance cost, reliability, and operational flexibility. Comparisons between scenarios with and without emission limits further illustrate the cost impacts and resource requirements associated with meeting the 2030 levels.

2030 Emission Limits	No Emission Limits
Base Case	Base Case
High Load Growth Rate	High Load Growth Rate
Full Accredited Capacity	Full Accredited Capacity
Large Load Addition	Large Load Addition
	High Natural Gas Price
	Low Natural Gas Price

Key findings include:

Scenarios with Carbon Reduction Requirements:

- **Base Case**: This scenario reflects expected load growth, market conditions, resource adequacy requirements, and an 80% carbon reduction target by 2030. The preferred portfolio relies primarily on battery storage and natural gas-fired generation, supplemented by limited wind additions. The results demonstrate that a combination of battery storage and dispatchable generation provides a practical framework for maintaining reliability while meeting emissions objectives.
- **High Load Growth Rate**: This scenario evaluates sustained load growth above the Base Case forecast while maintaining carbon reduction requirements. Higher demand drives additional battery storage, natural gas-fired generation, and wind additions, increasing overall portfolio costs relative to the Base Case.
- **Full Accredited Capacity**: This scenario assumes United Power receives accredited capacity from the Brush 2 combustion turbine and Brush 4 combined cycle resources. The additional accredited capacity reduces future resource requirements, lowers portfolio costs, and decreases the amount of battery storage needed to satisfy resource adequacy requirements. The scenario highlights the potential value of securing access to this capacity.
- **Large Load Addition**: This scenario evaluates the impact of a significant new member load while maintaining carbon reduction requirements. Meeting the additional demand requires substantial

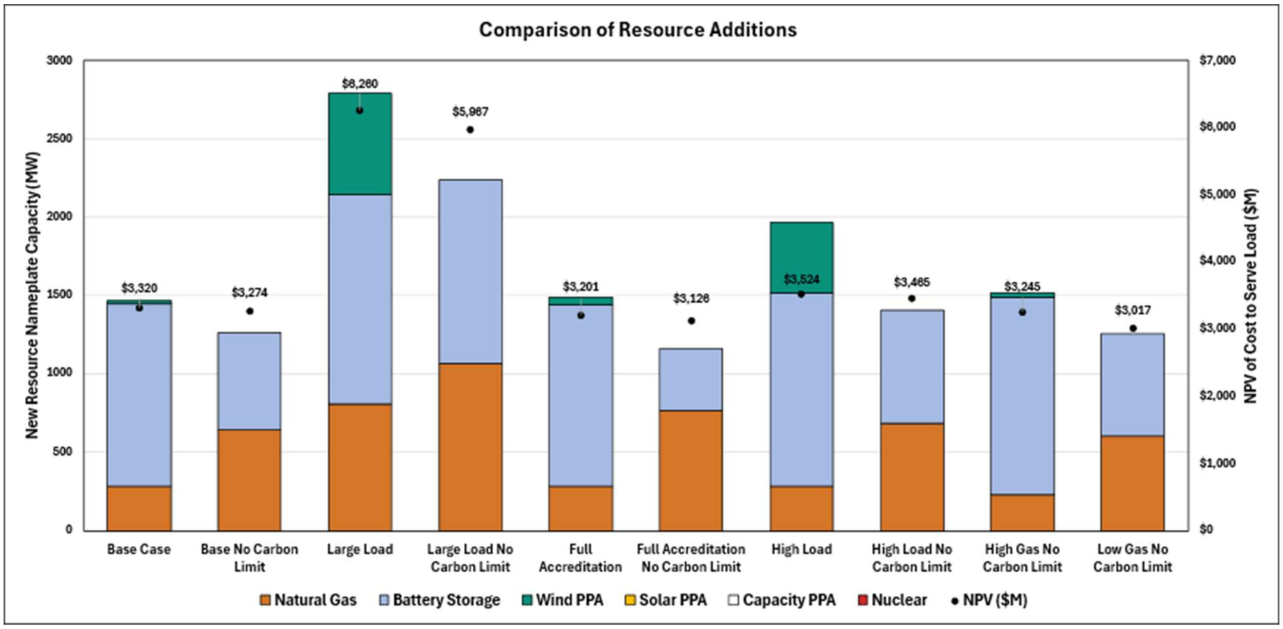
new battery storage, natural gas-fired generation, and wind resources, resulting in the largest resource additions and highest portfolio costs of all carbon-constrained scenarios.

Scenarios with No Emission Limits:

- **Base Case**: This scenario removes the 80% carbon reduction target while maintaining all other Base Case assumptions. The preferred portfolio shifts toward greater reliance on natural gas-fired generation and reduced battery storage and wind development, resulting in lower portfolio costs while continuing to satisfy reliability requirements.
- **High Load Growth Rate**: This scenario combines sustained load growth above the Base Case forecast with the removal of carbon reduction requirements. Higher demand increases future resource needs, with natural gas-fired generation playing a larger role in meeting capacity requirements and reducing portfolio costs relative to the corresponding carbon-constrained case.
- **Full Accredited Capacity**: This scenario assumes United Power receives accredited capacity from the Brush 2 combustion turbine and Brush 4 combined cycle resources while removing carbon reduction requirements. The additional accredited capacity reduces future resource requirements and portfolio costs, while the removal of carbon reduction requirements increases reliance on natural gas-fired generation.
- **Large Load Addition**: This scenario combines significant new member load with the removal of carbon reduction requirements. Meeting the additional demand requires substantial new resource additions, with natural gas-fired generation serving a larger share of future capacity needs and reducing costs relative to the corresponding carbon-constrained scenario.
- **High Natural Gas Price**: This scenario evaluates the impact of sustained increases in natural gas prices. Higher fuel costs increase portfolio costs and reduce the economic advantage of natural gas-fired generation, resulting in greater reliance on battery storage and wind resources.
- **Low Natural Gas Price**: This scenario evaluates a lower long-term natural gas price environment. Reduced fuel costs improve the economics of natural gas-fired generation, resulting in the lowest-cost portfolio of all scenarios evaluated and reducing the need for battery storage and wind additions.

Across all scenarios, the modeling results demonstrate that battery storage, natural gas-fired generation, and bilateral capacity purchases are critical components of United Power's future resource strategy. While the optimal resource mix varies under different planning assumptions, these resources consistently provide the capacity, reliability, and operational flexibility needed to support continued growth. The results reinforce the importance of maintaining planning flexibility and pursuing a diversified resource strategy capable of adapting to changing market conditions, resource adequacy requirements, and future load uncertainty.

The following figure compares resource additions and portfolio costs across the ten scenarios evaluated in this study. While the amount and timing of future resource additions vary by scenario, battery storage and natural gas-fired generation consistently form the foundation of future resource portfolios. The results demonstrate that load growth, carbon reduction requirements, natural gas prices, and resource accreditation assumptions materially influence future resource needs, portfolio costs, and resource selection. Across all scenarios, bilateral capacity purchases remain a critical near-term bridge strategy until new resources can be developed and placed into service.



1.8 Conclusions

The IRP analysis highlights the importance of maintaining a flexible, reliable, and cost-effective approach to resource planning as United Power navigates rapid load growth and an evolving energy landscape. Across all scenarios, several consistent themes emerged:

- **Battery storage is the foundation of future resource portfolios.** In nearly all scenarios, portfolios that combine thermal generation, battery storage, and bilateral capacity are preferred - even in the absence of federal storage incentives - underscoring their long-term value.

- **Natural gas-fired generation remains an important long-term reliability.** While battery storage addresses many near-term needs, dispatchable natural gas generation is consistently selected in the later years of the planning horizon to support reliability during periods of sustained load growth and changing resource adequacy requirements.

- **Load growth is the primary driver of future resource needs.** United Power's projected growth, including the potential addition of large commercial and industrial members, has a significant impact on future capacity requirements and resource acquisition timing.

- **Resource adequacy requirements and accreditation methodologies materially influence resource decisions**. Changes in accredited capacity assumptions can significantly alter future resource needs, highlighting the importance of monitoring evolving reliability frameworks.

- **Planning flexibility and resource diversification remain essential.** A balanced strategy that incorporates battery storage, natural gas-fired generation, bilateral capacity purchases, market transactions, and selective renewable development provides the most resilient path forward under a wide range of future conditions.

Overall, the IRP results indicate that a diversified portfolio emphasizing battery storage, natural gas-fired generation, bilateral capacity purchases, and selective wind development provides a practical framework for maintaining affordability, reliability, and flexibility while supporting continued member growth.

1.9 Action Plan

United Power's action plan focuses on maintaining reliability while preserving flexibility to respond to rapid load growth, evolving resource adequacy requirements, changing market conditions, and future regulatory uncertainty. Battery storage, natural gas-fired generation, bilateral capacity purchases, and selective renewable development are expected to be key components of the cooperative's future resource strategy.

Near-term priorities include advancing battery storage development, securing bilateral capacity purchases to address resource adequacy needs, evaluating opportunities to increase the accredited capacity of existing resources, and maintaining optionality for future natural gas-fired generation. United Power will also continue monitoring load growth, large member development, carbon policy, resource adequacy requirements, and market conditions to ensure future resource decisions remain aligned with system needs.

By emphasizing proactive planning, diversified procurement strategies, and regular updates to the IRP, United Power can maintain reliable and affordable service while preserving the flexibility needed to adapt to changing market, policy, and technology conditions.

Section 2 IRP Methodology

An IRP is a comprehensive and strategic planning process performed regularly by United Power to ensure the cooperative is utilizing an optimal mix of resources that weighs future costs while meeting the goals of United Power and its members. Key outputs of the process include the Net Present Value of Revenue Requirements (NPV), the Levelized Cost of Energy (LCOE), and the volume of carbon emissions.

NPV is a financial metric used by utilities to evaluate and compare the total revenues and costs of projects or scenarios over their lifespans by converting future cash flows to present-day values. The analysis includes projected market revenues, capital expenditures, fixed and variable operations and maintenance costs, fuel costs, and purchased power expenses.

LCOE is another tool used for project and scenario cost comparisons utilizing a standard basis of dollars per megawatt hour ($/MWh). LCOE is calculted by dividing the total cost of building, operating, and procurring energy resources over the study period by the total energy produced or procured during the same period. While NPV and LCOE are not inclusive of all costs to reliably serve load, they provide widely accepted benchmarks for comparing and analyzing resource scenarios.

Energy Exemplar's PLEXOS capacity planning model was utilized in the development of this 2026 IRP through the steps shown in Figure 1:

Figure 1. IRP Methodology

The PLEXOS model was used by TEA to identify optimal resource plans under various scenarios. Widely adopted in integrated resource planning by electric utilities, the model provides a flexible, data-driven platform for energy market simulation and optimization. It helps utilities analyze long-term investment decisions, forecast energy demand, and develop reliable, cost-effective resource portfolios.

Using advanced mathematical optimization, the PLEXOS model optimizes the least-cost mix of future generation resources by considering factors such as capacity accreditation, technology costs, emissions, environmental policy requirements, and energy market fluctuations, as shown in Figure 2. The model's capability to consider numerous factors makes it particularly valuable for assessing the economic impacts of different energy resource scenarios and ensuring that utilities can meet future demand under various market conditions.

In this IRP, TEA utilized the PLEXOS model to assess a range of future scenarios, including changes in fuel prices, electricity demand, market conditions, and resource availability. This scenario-based approach helps identify resource strategies that remain effective across a variety of potential futures. TEA's comprehensive approach enables United Power to ensure long-term price assurance and reliability under changing market conditions.

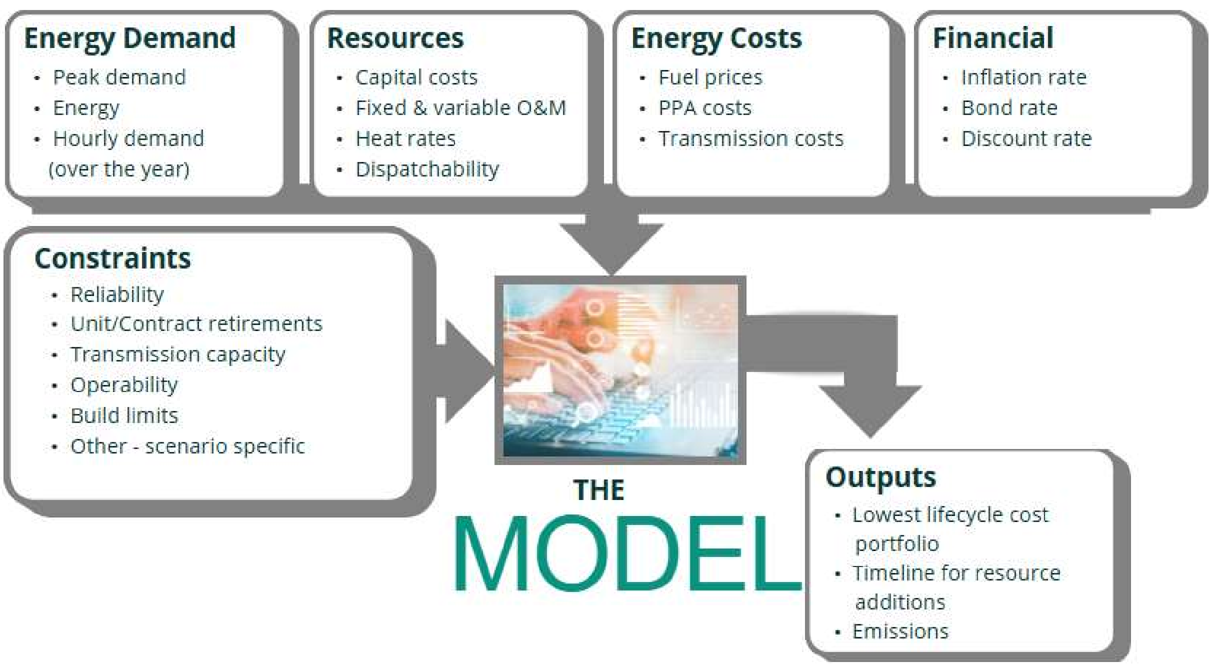


Figure 2. Model Inputs and Outputs

Section 3 Load Forecast

3.1 Load Forecast Summary

Projected system load refers to the amount of electric energy United Power's members require for air conditioning, lighting, motors, and other end uses. Over time, the system load evolves due to factors such as weather, economic growth, and shifts in member usage patterns. TEA developed United Power's load forecast using historical load, weather, and regional economic data.

To project long-term monthly load growth, a linear regression model was trained using econometric forecasts from Woods and Poole. A machine learning model was then applied to convert the monthly forecast into an hourly resolution across the study period. Hourly data is crucial as system operations and electricity demand fluctuate throughout each day and monthly averages alone do not capture intra-day variations in electric load, system peak demands, solar and wind generation profiles, or generator dispatch. The PLEXOS model utilizes hourly data to optimize resource dispatch and reliability for capacity expansion development.

To address uncertainty, the study incorporated two additional scenarios. One assumes a higher projected load driven by increased economic growth and a second with the addition of a large 600 MW load. These scenarios help assess United Power's power resource requirements under varying future conditions.

3.2 Monthly Load Forecast

The monthly load forecast incorporates the long-term impacts of economic and weather-related drivers using the steps outlined below.

1. **Load Data Collection**

   United Power provided historical monthly and non-coincident peak load data separated by balancing authority from 2023 through 2025 and previous historical data from 2014-2022 was included. Monthly non-coincident peak demand was calculated using hourly historical load data.

2. **Weather Normalization**

   Local historical weather data from January 1995 through December 2024 from the National Oceanic and Atmospheric Administration (NOAA) National Centers for Environmental Information (NCEI) database, including heating and cooling degree days and maximum and minimum temperatures were obtained. A normalized weather pattern was developed using the rank and median method and applied to both historical and forecast years. The rank and median method is a statistical approach that ranks historical weather years based on selected weather metrics and identifies the median-ranked year as representative of normalized weather conditions. This methodology avoids using unusually hot, cold, wet or mild years that could otherwise skew forecasts.

Heating and cooling degree days are designed to measure temperature differences that drive cooling or heating demand. For the forecast, heating and cooling degree days were calculated for each historical day using the following formulas:

The industry standard of 65°F is a baseline for when no heating or cooling is required for buildings to maintain adequate comfort. For hours in a day with temperatures above 65°F, heating degree days were set to zero as no heat is necessary above 65°. For hours with temperatures below 65°F, cooling degree days were set to zero as heat is only needed. From these daily degree-day calculations, several weather variables were calculated for use in the forecasting process. These variables included monthly total, monthly maximum, total squared, and maximum squared heating/cooling degree days (HDD and CDD, respectively).

Figure 3 displays monthly CDD, while Figure 4 displays monthly HDD. Each figure includes 30 years of weather history used in the analysis, along with the weather-normalized monthly degree days over the planning horizon. The total CDDs are expected to reach 317 in July for each forecasted year, the month with the most extreme cooling demand. The maximum monthly total HDDs are projected to reach 1,196 in January of each forecasted year, which is consistent with seasonal norms.

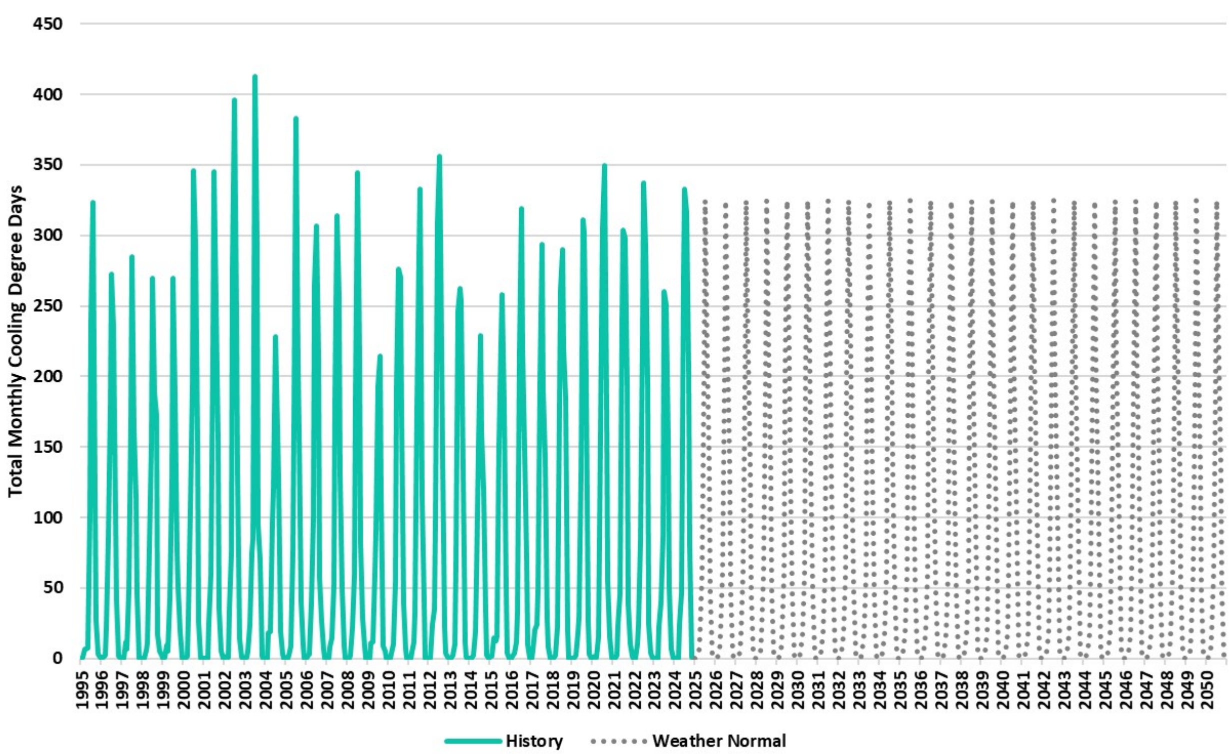


Figure 3. Historical and Projected Monthly Cooling Degree Days

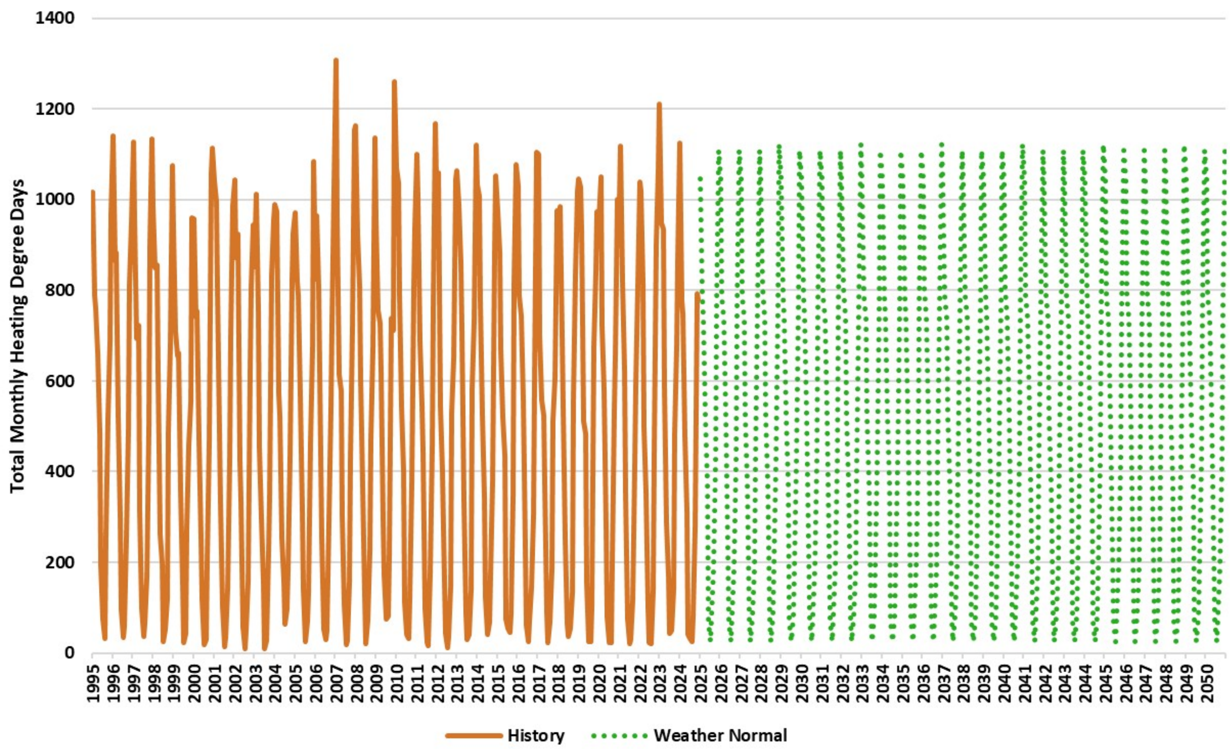


Figure 4. Historical and Projected Monthly Heating Degree Days

3. Economic and Demographic Data

TEA obtained county-level econometric data for each United Power balancing authority from Woods & Poole's 2024 Complete Economic and Demographic Data Source[1]. This dataset includes historical data from 1969 to 2024 and forecasted data from 2025 through 2050. Key economic indicators considered included population, total employment, total earnings, gross regional product, number of households, and total retail sales.

4. Forecast Model Integration

TEA enabled the forecast model to automatically select the optimal combination of weather and economic variables that best fit the historical load data. These regression models were then used to generate monthly load projections based on normalized weather conditions and forecast economic growth over the planning horizon.

[1] Woods & Poole Economics, Inc. "2024 Complete Economic and Demographic Data Source (CEDDS)®." 2024. Woods & Poole Economics, Inc. Accessed, 2024. https://www.woodsandpoole.com/our-databases/united-states/cedds/.

5. **Balancing Authority Summation**

   Monthly load forecasts were developed at the balancing authority level, Public Service Company of Colorado (PSCO) and the Southwest Power Pool's (SPP) RTO Expansion (RTOE) footprint, historically referred to as the Western Area Colorado-Missouri (WACM) balancing authority. To aggregate the forecast results for United Power's entire system, the monthly total energy for each balancing area was added together. For peak demand, each member's coincident peak demand was determined by multiplying the member's forecasted non-coincident peak by a coincidence factor. This coincidence factor is determined based on the historical ratio of coincident and non-coincident peak loads for each month. Member-level coincident peak demand was then added together for each respective pool.

3.3 Hourly Load Forecast

The hourly load forecast was developed with the following steps:

1. **Historical Load Data**
   Hourly level load data was provided by United Power for each balancing authority, covering the period from January 2023-December 2025. Previous load history was used from 2014-2022.

2. **Weather Data Collection and Normalization**
   Hourly historical weather data for the United Power system was collected from NOAA. Weather data from January 1995-December 2025 was used to calculate hourly normalized weather for the forecast horizon, applying the rank and median method.

3. **Model Training**
   A non-linear machine learning model (Gradient Boosting Machine, or GBM) was trained to predict hourly load values using historical weather data, actual system load, and time series features including hour of the day, month, and day of the week.

4. **Load Prediction**
   The trained model was then used to forecast future load values based on the normalized weather data.

5. **Reconciliation with Monthly Forecast**
   The resulting hourly load forecast was adjusted to align with the monthly total energy and peak demand projections presented in the previous section. This step ensured consistency between the hourly forecast and the broader system forecast, recognizing that the hourly model does not incorporate long-term economic growth as a direct input feature.

3.4 Combined Load Forecast

After developing the base load forecast driven by economic growth for each balancing authority, the two forecasts were combined to represent the entirety of United Power. Figure 5 below presents the Base

Case combined load forecast showing annual total energy and peak demand. Total energy consumption is forecast to increase at an average annual rate of 3.0%, rising from 3,541 GWh in 2025 to 6,440 GWh in 2045.

During the same period (2025-2045), summer peak demand is projected to grow at an average annual rate of 2.4%, reaching 1,080 MW by 2045. Winter peak demand remains lower than summer peak demand, increasing at an average annual rate of 2.9% from 514 MW in 2025 to 922 MW in 2045.

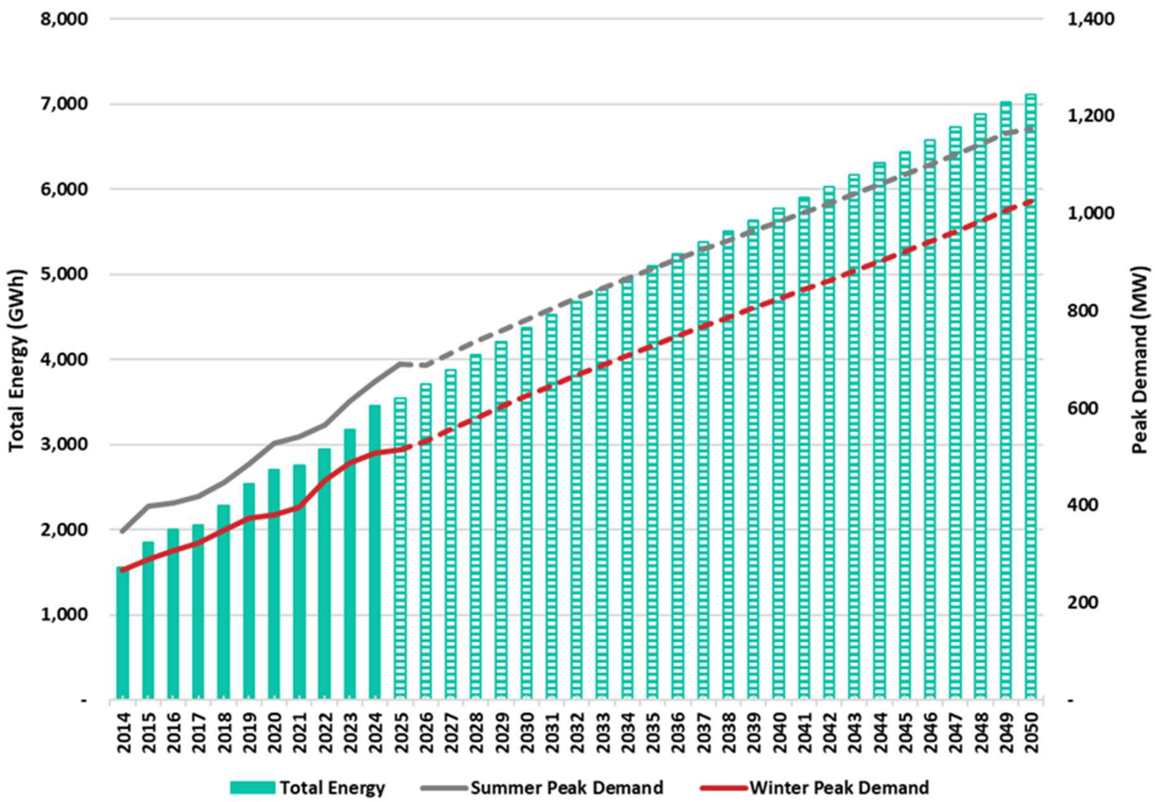


Figure 5. Base Case United Power Total Annual Load History and Forecast from 2014 - 2050

3.5 Alternative Load Projections

To account for uncertainties and potential variations in economic, technological, and demographic factors, two alternative load projections were developed in addition to the Base Case. These scenarios provide insight into how different future conditions could influence total load growth in the United Power service territory and help inform the development of an effective resource portfolio to meet future demand.

- **High Load Scenario**
  Increased demand across both balancing authorities, driven by stronger employment and population growth, pushes the load higher by 0.5% annually.

- **Large Load Addition Scenario**
  Simulation of a 600 MW large load addition coming online in 50 MW blocks every eight months starting in January 2027 leads to increased electric demand affecting the early years of the study.

These scenarios are further detailed in Section 7.1. Figure 6 and Figure 7 provide visual comparisons of the total energy and peak demand projections under the Base Case, High Load, and Large Load Addition scenarios.

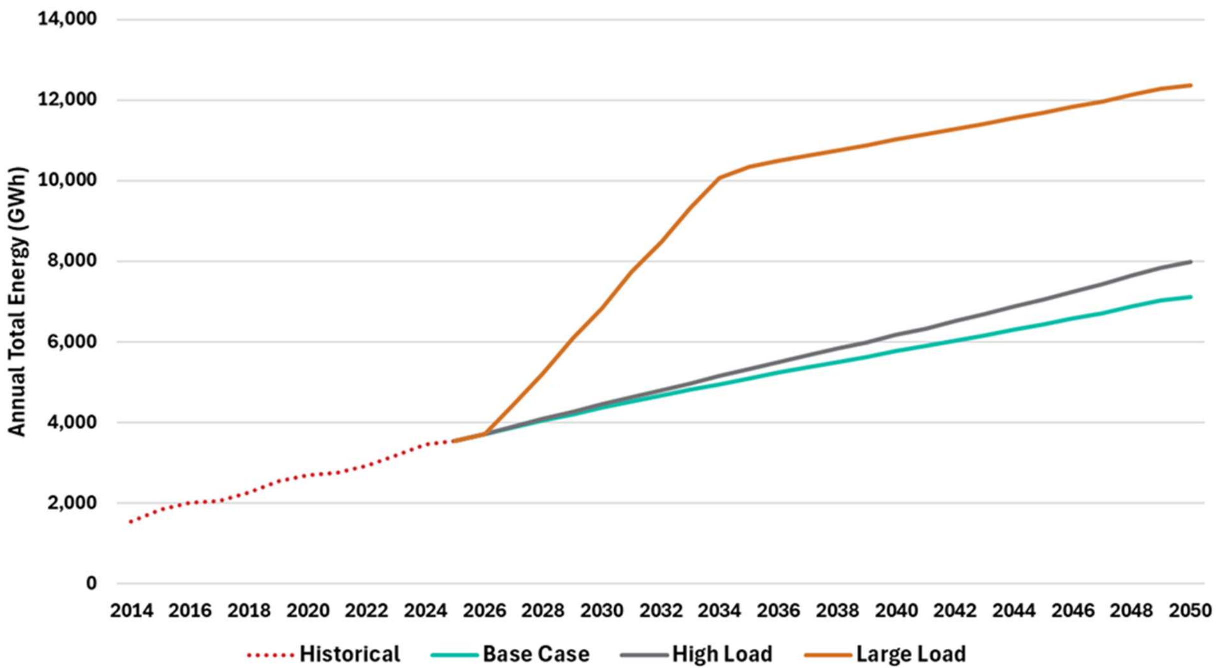


Figure 6. Total Energy Forecast - Scenario Comparison

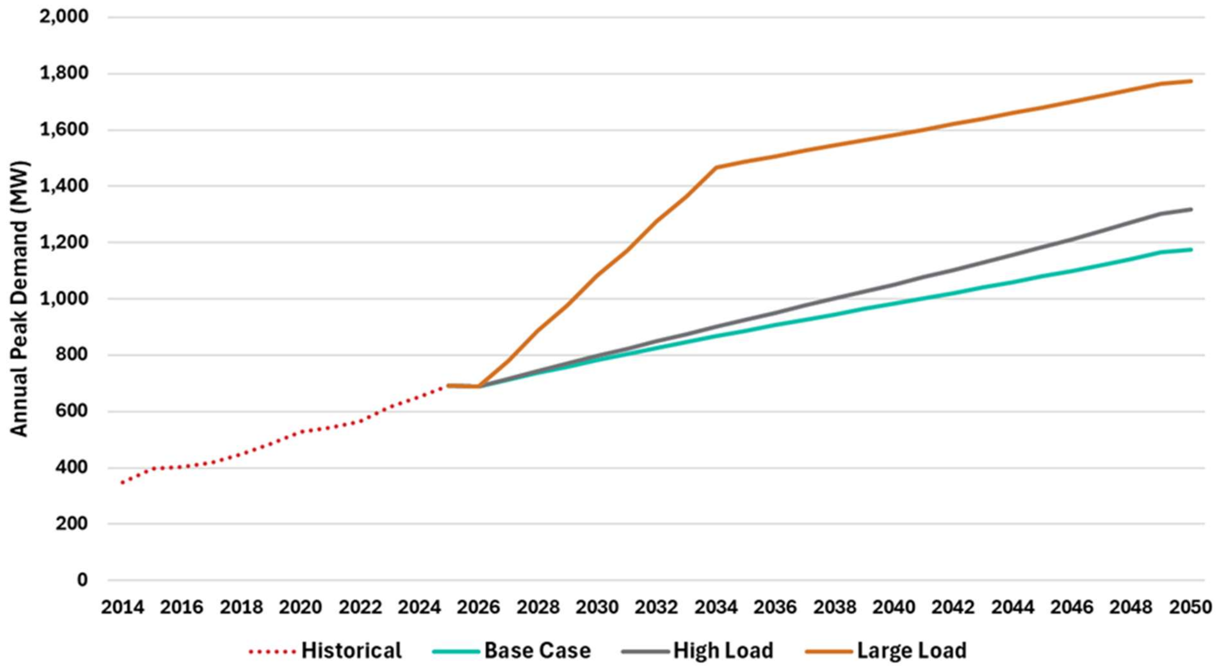


Figure 7. Peak Demand Forecast - Scenario Comparison

Section 4 Current Resources

4.1 Overview of Existing United Power Resources

United Power's electric supply portfolio comprises a diversified mix of generating resources that are intended to support reliability, cost-effectiveness, and regulatory compliance. The portfolio includes Purchase Power Agreements (PPAs), thermal generation fueled by natural gas, renewable resources including solar and landfill gas, and batteries.

PPAs provide the majority of United Power's capacity requirements with different operational choices such as call options, monthly purchases, and dispatchable products. Thermal generation is provided by gas-fired contributors such as Brush Unit 2 and 4, Knutson, and Mountain Peak Power.

In addition to PPAs and thermal generation, United Power's renewable portfolio currently provides 85 MW of summer nameplate capacity from solar energy. Batteries provide nearly 115 MW in 4- and 6-hour blocks. The Erie Landfill/Timberline and a few other projects add just under 10 MW, utilizing methane for power generation as an environmentally beneficial alternative to flaring.

Table 1 and Table 2 summarize United Power's ownership shares of existing capacity by resource type across select years of the IRP study period for summer and winter. This capacity is based on SPP's Effective Load Carrying Capability (ELCC) methodology described in Section 4.2. These summaries provide context for evaluating resource adequacy, fuel diversity, and the role of existing assets in future planning scenarios.

Table 1. Existing Firm Summer Capacity (MW) by Resource Type in Select Years

Year	Natural Gas	Solar	Battery	Bilateral Capacity	Total
2026	271	8	67	380	725
2030	142	53	183	280	658
2035	142	52	183	280	657
2040	142	52	183	50	427
2045	142	34	141	0	318

Table 2. Existing Firm Winter Capacity (MW) by Resource Type in Select Years

Year	Natural Gas	Solar	Battery	Bilateral Capacity	Total
2025-26	294	2	62	317	675
2029-30	157	5	169	217	549
2034-35	157	7	169	217	550
2039-40	157	7	169	50	383
2044-45	157	4	131	0	292

4.2 Resource Adequacy

The following figures compare the total firm capacity from existing resources from both balancing authorities with United Power's summer and winter peak load forecasts and corresponding capacity requirements through 2045.

Based on data available at the time of the IRP, United Power's mix of generation resources is expected to be short to meet peak load and capacity requirements starting the winter of 2027/2028. This is due to the end of the Knutson PPA and the Tri-State Generation and Transmission Association - Around the Clock (TSGT ATC) Block and Call options in 2028. Solar additions in the late 2020s are helpful but due to low accreditation values are not substantial enough to meet the load and capacity required. Subsequent years continue to show the system will grow shorter as demand grows and worsens starting in 2039 until the end of the study from Guzman, Brush 4, and other resource retirements.

Figure 8 below compares United Power's summer capacity by resource type with the required capacity requirement and peak load, and Figure 9 provides the corresponding winter comparison.

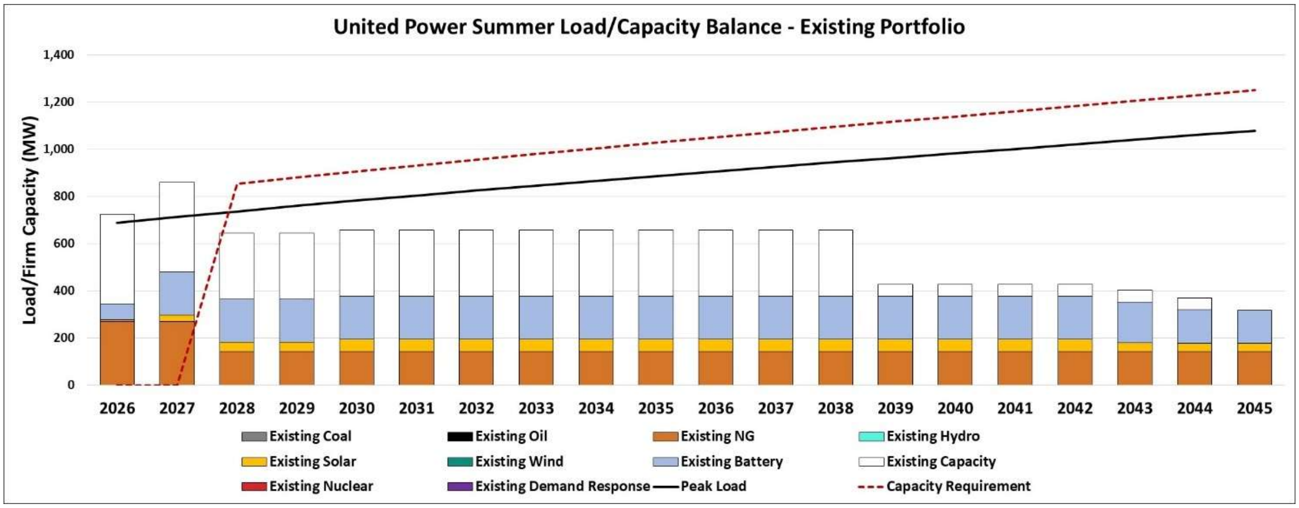


Figure 8. United Power Summer Load Capacity Balance

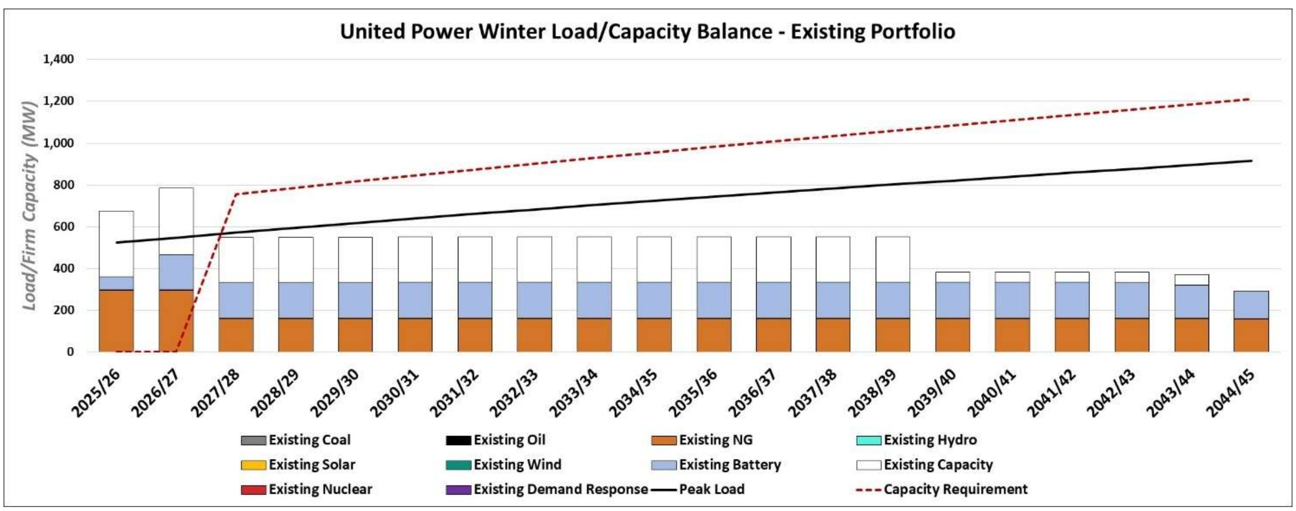


Figure 9. United Power Winter Load Capacity Balance

Accredited capacity (ACAP) represents the amount of power a generating resource can reliably contribute to the electric grid, based on factors such as forced outage rates, availability, and performance during peak demand periods. ACAP is calculated separately for different resource types in both summer and winter seasons and is expressed as a percentage of the resource's total capacity. The Planning Reserve Margin (PRM) refers to the percentage of generation capacity available above forecasted peak demand, providing a buffer to maintain system reliability. For SPP RTOE, ACAP and PRM requirements for the study were derived from a combination of Load Responsible Entity (LRE) ACAP calculations provided by United Power (a tool used by SPP), class-average performance-based accreditation from SPP, and SPP's ELCC accreditation methodology. The ACAP percentages by resource type and the PRM assumptions for both summer and winter are incorporated in the model and in all scenarios are shown in Table 3.

Table 3. SPP RTOE Accreditation and Planning Reserve Margin

Resource Type	Summer Capacity Accreditation (%)	Winter Capacity Accreditation (%)
Solar	9.0	1.1
Wind*	18.5	20.6
Storage	58.0	53.8
NG Combined Cycle**	93.1	84.7
NG Combustion Turbine**	87.0	74.7
NG Reciprocating Engine**	92.4	80.7
Coal**	90.8	77.9
Nuclear**	98.1	96.8
Hydro**	99.5	99.4

Planning Reserve Margin	Summer	Winter
Base PRM (%)	19.0	40.0
ACAP PRM (%)	15.9	32.1

* Wind accreditation based on most recently available Tier 2 ELCC results for SPP.
** Thermal accreditation reflects SPP averages for each technology type, applying to non-UPI existing thermal resources and new thermal resources. Existing UPI resource accreditation assumptions would use values from the LRE ACAP calculator.

Section 5 New Resource Options

New resource options are considered to address load growth in United Power's service territory. Due to the significant lead times required for construction and interconnecting to the electric system, timely planning is critical to ensure capacity requirements are met. These constraints are addressed by resource type in the information contained herein. In addition, new resources may be acquired through different ownership and procurement structures, including direct utility ownership and PPAs, each of which carries different cost, operational, risk allocation, financing, and long-term flexibility implications. Resource alternatives are evaluated based on capital investment requirements, fixed and variable operating costs, contractual obligations, market exposure, and potential impacts on system reliability and customer costs.

This IRP includes the following supply-side options that are currently or potentially viable within the study period.

5.1 Thermal Generating Units

Thermal generating units convert thermal energy into electrical energy, typically by producing steam through the combustion of fuels such as natural gas or coal in a boiler, directly through combustion of natural gas or oil in a combustion turbine, or through nuclear fission in a nuclear reactor. These units play a critical role in ensuring power system reliability due to their dispatchability, operational controllability, and ability to follow load. Grid operators can commit and dispatch these units as needed to maintain grid stability and ensure reliable, uninterrupted electrical service.

Thermal resources considered in this study include combined cycle and simple cycle natural gas-fired combustion turbines, reciprocating internal combustion engines (RICE), and nuclear-powered small modular reactors (SMRs). These technologies provide firm, dispatchable capacity and can also contribute to ancillary services, such as frequency regulation and spinning reserve, supporting overall system reliability.

Both industrial frame and aeroderivative small-scale combustion turbines are options for United Power's resource portfolio. Aeroderivative turbines typically offer higher efficiency, faster ramping, and a smaller footprint, making them especially suitable for peaking and flexible response applications. However, these benefits come with higher capital costs and increased operations and maintenance (O&M) expenses compared to traditional industrial frame units. Notable manufacturers of combustion turbines include GE Vernova, Mitsubishi, and Siemens.

Natural gas-fired RICE units represent another dispatchable option. While they usually involve higher upfront capital costs than combustion turbines, RICE units are modular, capable of fast starts and rapid ramping, and can be installed incrementally to match load growth or local grid needs. Notable manufacturers of RICE technologies include Wärtsilä, MAN Energy Solutions, and Caterpillar.

Both combustion turbines and RICE technologies offer load-following capabilities, positioning them to potentially earn ancillary service revenues in organized markets. However, the policy landscape is evolving, and future federal, state, or local clean energy mandates may affect the long-term viability of thermal resources that rely on fossil fuels. In response, leading manufacturers are advancing hydrogen-compatible combustion systems, enabling future operation on blended or 100% hydrogen, which could extend asset life and align with decarbonization goals.

Small modular reactors (SMRs) were included as a potential long-term resource option. SMRs are attracting growing interest due to their lower capital and operating costs relative to traditional nuclear, compact modular design that reduces siting and construction challenges, inherent safety features that enhance public acceptance, and extended refueling cycles that minimize downtime. While not yet commercially mature, SMRs could become a viable zero-emission baseload option within the planning horizon-particularly under scenarios emphasizing deep decarbonization and grid resilience.

5.1.1 Simple Cycle Combustion Turbines

The IRP evaluated a range of simple cycle combustion turbine technologies, including aeroderivative, heavy-frame, and industrial units, to capture a variety of operating characteristics and deployment scales.

Aeroderivative technologies modeled include the GE LM2500XPRESS+ G4 DLE, GE LM6000 PF+ Sprint, and GE LMS100 SAC PA+. These units provide net outputs of approximately 34 MW, 57 MW, and 113 MW, respectively, under ISO (International Organization for Standardization with operating parameters of 59°F ambient temperature, sea-level atmospheric pressure, and 60% relative humidity) conditions. Aeroderivative turbines are characterized by fast-start capability, high ramp rates, and operational flexibility, making them well-suited for peaking and cycling applications.

The study also includes larger heavy-frame combustion turbines, specifically the GE 7HA.03 and Mitsubishi Power M501JAC, with net outputs of approximately 430 MW and 453 MW, respectively, under ISO conditions. These units are typically deployed for utility-scale applications and may offer the potential for future conversion to combined cycle configurations.

In addition, Solar Turbines Titan 250 industrial gas turbine, manufactured by Solar Turbines Incorporated (a Caterpillar company), was modeled, with an output of approximately 23 MW under ISO conditions. This unit represents a smaller-scale option that may be appropriate for distributed or modular capacity additions.

5.1.2 Combined Cycle Combustion Turbines

In a combined cycle configuration, waste heat from a gas turbine is captured and used to produce steam in a heat recovery steam generator (HRSG). This steam is then used to power a steam turbine, generating additional electricity and significantly improving overall plant efficiency-typically reaching 50% to 60% or higher.

TEA modeled a range of combined cycle configurations using both heavy-frame and aeroderivative gas turbines to reflect different capacity and performance characteristics. Heavy-frame configurations include the GE 7HA.03 and Mitsubishi Power M501JAC in 1x1 arrangements, with net outputs of approximately 640 MW and 664 MW, respectively, under ISO conditions.

Aeroderivative combined cycle configurations were also evaluated, including the GE LMS100 PA+, LM6000 PF+ Sprint, and LM2500XPRESS+ G4 DLE, with net outputs ranging from approximately 47 MW to 137 MW in 1x1 configurations. These configurations offer greater flexibility and smaller unit sizes compared to heavy-frame technologies, while still achieving meaningful efficiency gains relative to simple cycle operation.

5.1.3 Reciprocating Internal Combustion Engines

RICE units are modular generation systems that convert the combustion of fuels, such as natural gas, diesel, or other gaseous fuels, into mechanical energy to produce electricity. Their modular design allows for incremental capacity additions, providing flexibility to scale installations based on system needs.

RICE technologies are characterized by relatively high thermal efficiency (typically 40% to 50%), fast startup times, rapid load-following capability, and low water requirements. These attributes make them well-suited for peaking service, grid balancing, and other flexible dispatch applications, particularly in systems with increasing variability from renewable resources.

This study evaluated multiple RICE technologies to capture a range of unit sizes and performance characteristics. Modeled units include the MAN Energy Solutions 18V51/60DF (19 MW), Wärtsilä 18V50DF (18 MW), Wärtsilä 20V34DF (9 MW), and Caterpillar CG260-16 (4 MW). These units can be deployed individually or in multi-unit configurations to achieve larger capacity additions while maintaining operational flexibility.

5.1.4 Small Modular Reactors

The use of Small Modular Reactors (SMRs) represents an emerging nuclear technology with the potential to provide carbon-free, dispatchable generation while addressing some of the financial and construction risks associated with traditional large-scale nuclear plants. Unlike conventional nuclear facilities, which typically exceed 1,000 MW, SMRs are designed as smaller, modular units that can be deployed incrementally.

SMRs are intended to be factory-fabricated and transported to site for installation, reducing on-site construction complexity and potentially shortening development timelines. Their designs also incorporate passive safety features and simplified systems, which may enhance operational safety and reliability.

This study modeled SMRs as a portion of a larger multi-module project, representing an incremental addition of approximately 60 MW. Multiple modules could be co-located to achieve larger capacity additions, allowing for phased development aligned with load growth. While SMRs remain an emerging technology with uncertainty around commercial availability, cost, and regulatory approval, they are included in this IRP to reflect their potential role as a future carbon-free resource option.

5.2 Renewable Energy Resources and Battery Storage

In recent years, renewable energy resources, particularly solar and wind, along with battery storage, have experienced significant growth across the U.S. energy sector. Within United Power's service territory, interest in these resources continues to expand as utilities seek to diversify supply portfolios, improve environmental performance, and enhance operational flexibility. This growth has been driven by declining technology costs and evolving federal policy, most notably the Inflation Reduction Act (IRA) of 2022.

The IRA established a technology-neutral framework for clean electricity incentives under Sections 45Y and 48E, providing long-term production and investment tax credits tied to emissions performance. These provisions expanded eligibility across a wide range of zero-emission resources and introduced mechanisms such as direct pay, transferability, and bonus credits for domestic content and energy community siting.

The federal policy landscape changed with the enactment of the One Big Beautiful Bill Act (OBBBA) in July 2025, along with subsequent executive actions directing federal agencies to revise implementation guidance. While the core structure of the IRA tax credits remains in place, OBBBA accelerates phase-out timelines for certain technologies, introduces foreign entity restrictions, and increases compliance requirements related to domestic sourcing and project ownership. Federal agencies have also been directed to more narrowly interpret eligibility criteria, including the definition of "beginning of construction" and associated continuity requirements.

Key implications for resource eligibility include:

- **Wind and Solar:** Eligibility for tax credits is subject to accelerated timelines. Projects must generally begin construction by mid-2026 to qualify under current policy assumptions. Projects that meet this requirement may retain eligibility if they satisfy applicable continuity requirements; however, updated guidance may narrow the ability to rely on traditional safe harbor provisions, increasing development risk for projects with longer lead times.
- **Battery Storage:** Standalone storage remains eligible for investment tax credits; however, its treatment is no longer fully aligned with the original IRA framework. Beginning in 2026, storage projects are subject to Foreign Entity of Concern (FEOC) restrictions, domestic content requirements, and additional compliance thresholds that may affect project eligibility and economics. As a result, while storage continues to benefit from federal incentives, access to those incentives is more constrained and dependent on supply chain and financing structures.
- **Foreign Entity Restrictions:** Projects may be ineligible for tax credits if they receive material assistance from designated foreign entities. Compliance is determined through a Material Assistance Cost Ratio (MACR) test, with increasing thresholds over time, requiring a greater share of project components and services to be sourced from non-restricted entities.
- **Domestic Content Requirements:** Bonus credit eligibility is tied to minimum domestic sourcing thresholds, which increase over time and may be more challenging to achieve for certain technologies, particularly storage systems with global supply chains.
- **Transferability and Recapture:** While tax credit transferability remains available, restrictions on eligible buyers and ongoing compliance requirements introduce additional transaction complexity. Projects may also face recapture risk if ownership or operational control changes in ways that violate foreign entity restrictions.

These policy changes introduce greater uncertainty into the development and financing of renewable energy projects. With reduced timeline flexibility and increased compliance requirements, project viability is expected to depend more heavily on execution timing, supply chain alignment, and regional market conditions.

Battery storage is expected to remain an important component of future resource portfolios due to its operational flexibility and ability to support renewable integration. However, its economic outlook is now more sensitive to federal policy compliance requirements than under the original IRA framework.

This IRP analysis was conducted between late 2025 and April 2026, following the enactment of the OBBBA. Wind and solar resources were modeled without federal tax incentives, reflecting constrained eligibility under current policy assumptions, while battery storage was modeled with applicable federal incentives. These assumptions provide a consistent basis for evaluating renewable and storage resources within the IRP framework.

Federal guidance related to the implementation of the OBBBA, including construction timing, domestic content, and foreign entity requirements, continues to evolve and may affect project eligibility and economics over time.

5.2.1 Solar PPA

Solar resources are based on large-scale solar photovoltaic projects and were modeled as purchase power agreements (PPAs) with block sizes of 25 MW. The rapid growth in electric generation from solar resources across the U.S. has been driven by declining costs, supportive governmental policies, and increasing demand for carbon-free renewable energy. Installed utility-scale solar capacity in the U.S. has grown from less than 1 GW in 2010 to approximately 125 GW[2] as of the end of 2024, contributing nearly 5%[3] of total U.S. electric generation during 2024.

Solar PPA resources are assumed to have a three-year construction period. Based on market data, the cost of energy from a PPA - fixed for the duration of a 15-year term - is projected to be $66.24/MWh for a project with a commercial operation date (COD) in 2029.

Prices in subsequent years reflect expected changes in construction costs and future overnight capital cost assumptions based on S&P Global Energy's (S&P) 2025 Power Crunch scenario and the National Renewable Energy Laboratory's (NREL) 2024 Annual Technology Baseline. Based on these sources, utility-scale solar capital costs are assumed to decline by an average of 1.3% per year in constant dollars between 2029 and 2035, as costs partially normalize following recent inflationary increases. Thereafter, capital costs are assumed to increase by an average of 1% per year in constant dollars through the end of the study period.

Figure 10 below shows the projected solar PPA prices, PPA offer prices, and self-build overnight capital costs assumed in the study.

[2] Energy Information Administration, Today in Energy, January 24, 2024, "New solar plants expected to support most US electric generation growth" https://www.eia.gov/todayinenergy/detail.php?id=64364

[3] Fitzgerald Weaver, John. PV Magazine USA, March 5, 2025, "US solar generation up 27% in 2024, accounting for 6.8% of all electricity" https://www.pv-magazine.com/2025/03/05/us-solar-generation-up-27-in-2024-accounting-for-6-8-of-all-electricity/

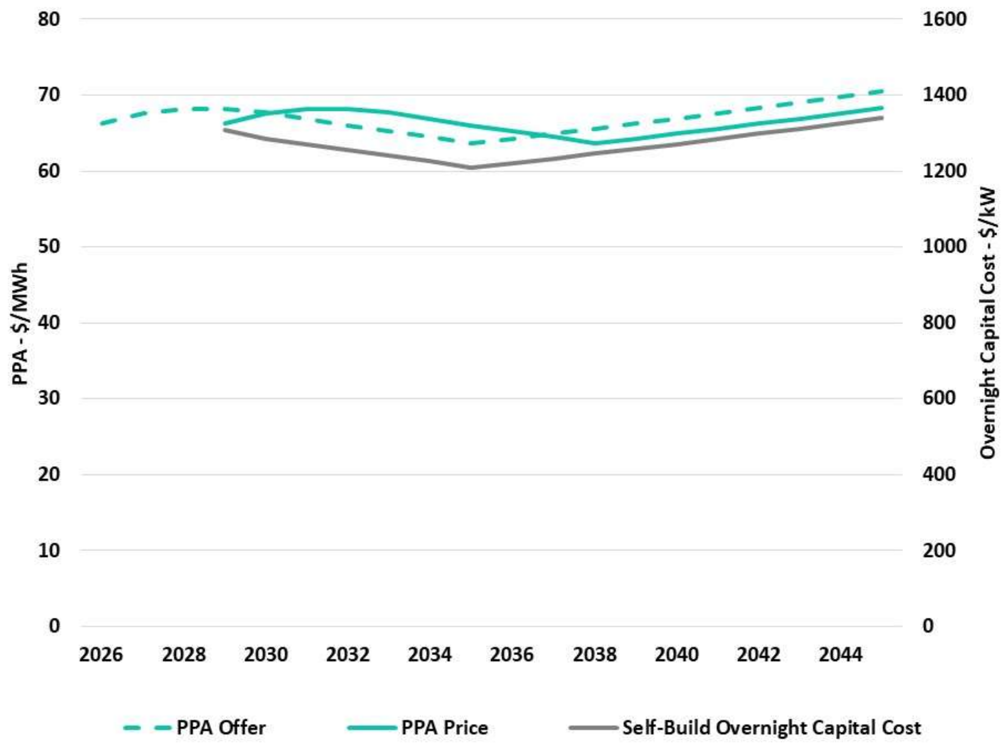


Figure 10. Fixed Price of Solar PPA and Self-Build Overnight Capital Cost

5.2.2 Wind PPA

Wind resources are modeled as 25 MW PPAs based on utility-scale on-shore wind projects. As with solar, the strong growth of wind generation has also benefited from declining costs, supportive governmental policies, and the increasing demand for carbon-free renewable energy. Installed utility-scale wind capacity in the U.S. has grown from 46 GW in 2010 to over 150 GW[4] today. In 2023, wind generation provided over 10% of the total electric generation[5,6] in the US.

[4] Buttel, Lindsey. America's Electricity Generation Capacity 2024 Update, American Public Power Association. URL: America's Electricity Generation Capacity Report, 2024 Update (publicpower.org), accessed on 7/1/2024.

[5] Morey, Mark, and Jell, Scott. "Wind generation declined in 2023 for the first time since the 1990s." U.S. Energy Information Administration (EIA), April 30, 2024. URL: https://www.eia.gov/todayinenergy/detail.php?id=61943, accessed on 7/1/2024.

[6] Form EIA-923 detailed data with previous form data (EIA-906/920). U.S. Energy Information Administration (EIA). URL: https://www.eia.gov/electricity/data/eia923/, accessed on 7/1/2024.

Wind resources are assumed to have a four-year development and construction period. Because the SPP RTOE West Hub does not have sufficient historical market data for analysis, the SPP North Hub was used as a proxy market basis for United Power. Based on recent market activity, the cost of energy for a 15-year wind PPA is estimated to range from \$50 to \$55/MWh for a project beginning construction in 2026 and achieving commercial operation in 2030. PPA prices for later in-service dates were adjusted to reflect changes in construction costs over time.

Future overnight capital cost assumptions were provided by NREL in its 2024 Annual Technology Baseline for a self-build option. NREL projects utility-scale wind capital costs to increase by an average of 1.5% per year in constant dollars between 2025 and 2044 due to additional technological advancements and efficiency improvements. Figure 11 shows the projected wind PPA prices, PPA offer prices, and self-build overnight capital costs assumed in the study.

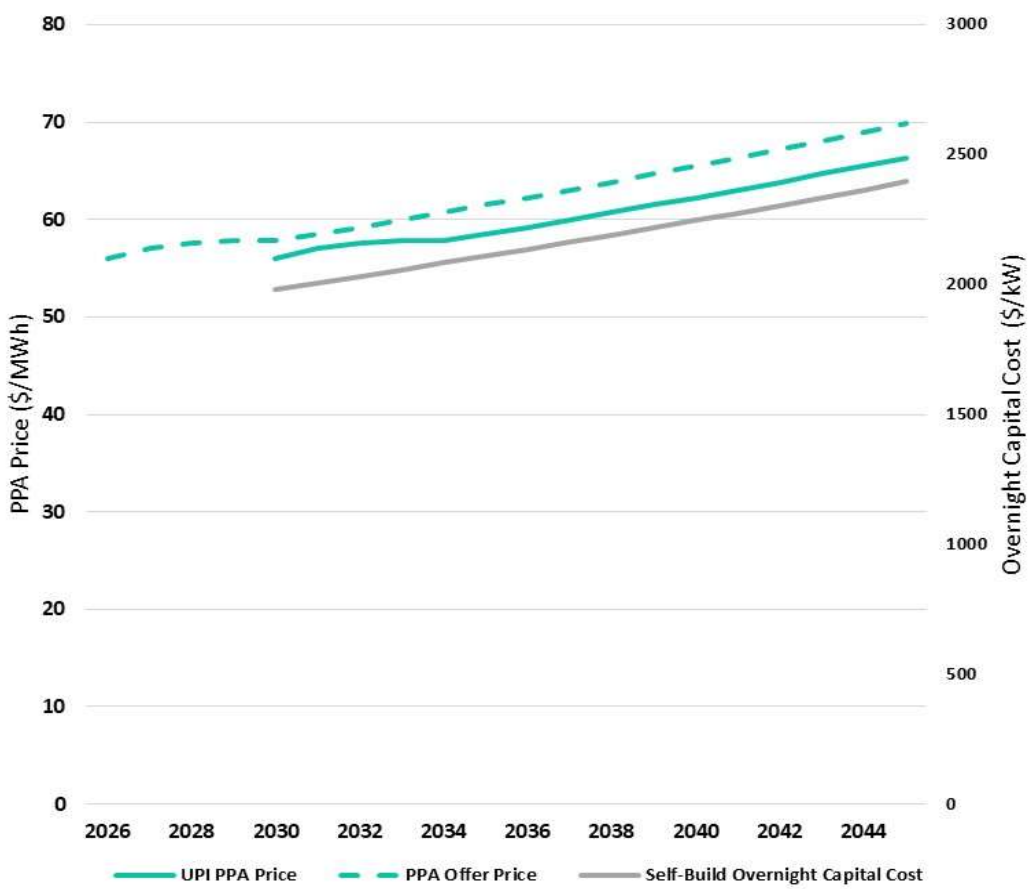


Figure 11. Fixed Price of Wind PPA and Self-Build Overnight Capital Cost

5.2.3 Battery Storage Tolling Arrangements and Self-Build Projects

Battery storage allows energy from the power grid or renewable resources such as wind or solar to be stored for later use. Enabling the storage and dispatch of power from renewable resources is vital to the transition toward cleaner, more sustainable energy systems. Currently, most utility-scale battery storage installations used for peak-shaving or load shifting applications rely on lithium-based battery chemistries, with the ability to discharge at their rated capacity for a duration of four to six hours or less.

In this IRP, battery storage systems are modeled as lithium-ion battery self-builds and tolling arrangements, with discharge durations of 4 hours. All projects are assumed to have a three-year construction period prior to commercial operation and Investment Tax Credit (ITC) subsidies through the Inflation Reduction Act for self-build projects beginning construction by 2035 were applied. Based on market data, the cost of a battery storage tolling arrangement-fixed for a 15-year contract term-is projected to be $12.42/kW-month for a 4-hour battery with a COD of 2029. For a self-build battery system, the overnight capital cost is $775/kW.

Prices in subsequent years are based on expected changes in construction costs and the availability of investment tax credits. Future overnight capital cost assumptions are based on the NREL's 2025 Annual Technology Baseline. NREL projects utility-scale battery storage capital costs to remain stable through 2036 when the ITC phase out begins and then increases through 2039 where the costs stabilize again, driven by ongoing technological advancements and efficiency improvements. Tolling costs also increase beginning in 2036 when the ITC phase out begins. Figure 12 shows the projected battery storage tolling costs and self-build overnight capital costs assumed in the study.

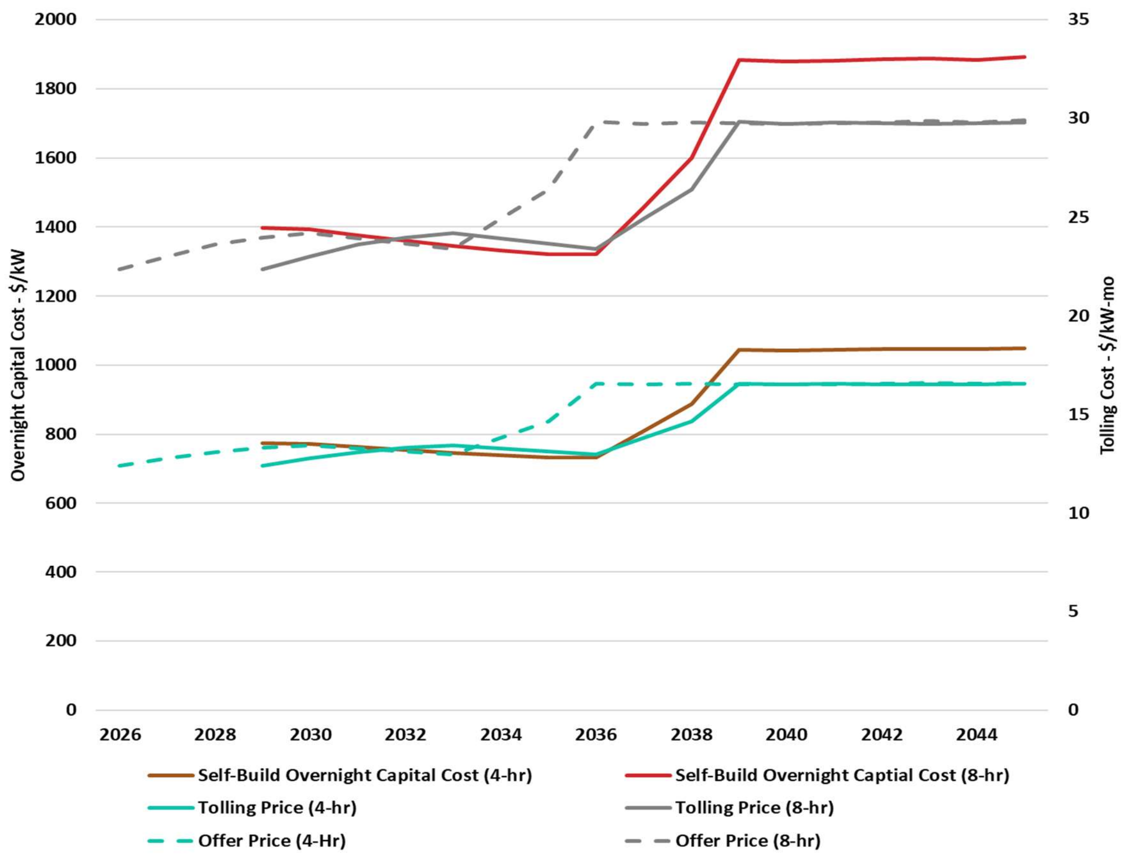


Figure 12. Battery Storage Tolling and Self-Build Costs

5.3 Bilateral Capacity Purchase

In addition to the thermal, renewable, and storage options, one-year, 5 MW bilateral capacity purchase options are included, tied to the Cost of New Entry (CONE) pricing. Bilateral capacity was only considered in the model to bridge the gap in the early years of the study (through 2029) until other resources could be constructed.

Bilateral capacity was priced at $10.05/kW-month for 2027, rising to $11.90 in 2030 then decreasing back to 2027 levels before escalating at an annual average rate of 2.5%. Figure 13 illustrates the projected capacity pricing over the entire study period despite only including it as a resource option in the initial years.

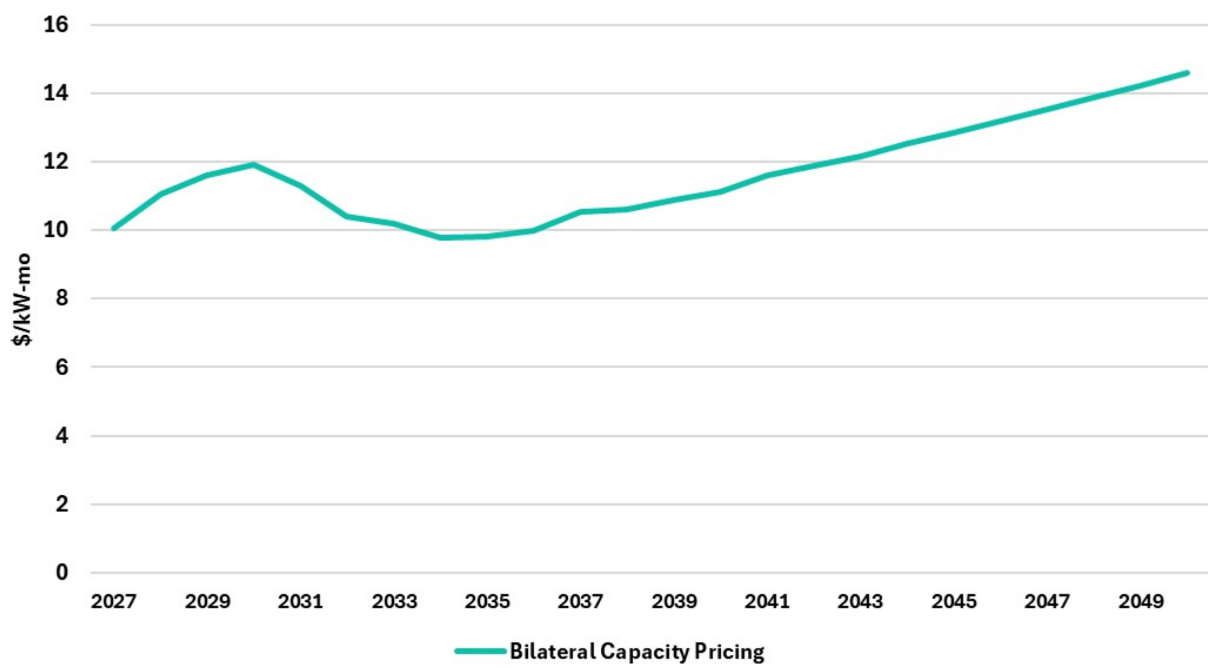


Figure 13. Bilateral Capacity Price

United Power-owned options considered in this study are summarized in Table 4 below.

Table 4. United Power-Owned Supply-Side Resource Options

	Supply-Side Resource	Description	Net Output (MW ISO)	Heat Rate (Btu/kWh HHV)	Overnight Capital Cost (2025 $/kW)	Fixed O&M (2025 $/kW-yr)	Variable O&M (2025 $/MWh)
United Power-Owned	Combined Cycle (1x1)	7HA.03	640	5,919	2,150	16.26	3.49
		M501JAC	664	5,908	2,200	16.26	3.49
		LMS100 PA+	137	7,275	2,300	23.25	4.70
		LM6000 PF+ Sprint	76	6,890	2,550	22.60	4.60
		LM2500XPRESS+G4 DLE	47	6,852	2,615	22.10	4.50
	Simple Cycle Combustion Turbine	7HA.03	430	8,735	1,650	7.20	1.30
		M501JAC	453	8,593	1,700	7.20	1.30
		LMS100 SAC PA+	113	8,792	1,850	10.50	6.10
		LM6000 PF+ Sprint	57	9,227	2,000	10.00	6.00
		LM2500XPRESS+G4 DLE	34	9,488	2,050	10.30	6.20
		Titan 250	23	9,584	2,050	8.80	5.40
	Reciprocating Internal Combustion Engine	MAN Energy 18V51/60DF	19	8,615	2,250	38.10	7.10
		Wartsila 18V50DF	18	8,528	2,385	38.10	7.10
		MAN Energy 20V32/44CR	9	8,920	2,500	45.70	8.20
		Wartsila 2V34DF	9	8,830	2,550	45.70	8.20
		Caterpillar G20CM34	10	9,050	2,700	48.00	8.60
		Caterpillar CG260-16	4	9,300	2,900	50.00	9.00
	Small Modular Reactor	Project Participant	60	10,046	9,370	128.00	3.50
	Solar PV	Single Axis Tracking	25	N/A	1,400	22.79	N/A
	Wind	Onshore Wind	25	N/A	1,766	34.06	N/A
	Battery Storage	Lithium-Ion (4-hour)	4	N/A	1,118	41.81	N/A

Section 6 Market Simulation

6.1 Methodology Overview

Long-term resource planning requires a fundamental price forecast used to value existing and future capacity resource options. Operators, participants, and other market entities utilize a production cost model to simulate future market conditions to forecast prices. The following section details the methodologies used to create a market environment outlook that can generate prospective power prices.

6.1.1 Modeling Approach

The electric price simulation was developed using a fundamental production cost model of the Western Electricity Coordinating Council (WECC) region. Figure 14 provides an overview of the process used to create the price forecast. The process can be divided into three principal phases. In the first phase, fundamental market, policy, and reliability assumptions were developed and incorporated into the model. These assumptions typically include factors such as load growth, generation fleet changes, fuel prices, environmental regulations, and resource adequacy requirements. The second phase used these inputs to perform a capacity expansion analysis across the WECC region. The capacity expansion model optimally added new resources to the existing generation fleet over a 20-year planning horizon to satisfy projected load growth and reliability requirements. In the third and final phase, the long-term production cost model simulated the operation of the resulting WECC generation portfolio to develop hourly wholesale power price forecasts for the WACM and PSCO regions. The following sections describe the model assumptions, inputs, and resulting price forecast in greater detail.

Figure 14. Electric Price Simulation Process

6.1.2 Model Structure

The primary tool used to evaluate the long-term market environment is PLEXOS, a production cost and capacity expansion modeling platform developed by Energy Exemplar. PLEXOS simulates the supply and demand fundamentals of the physical power market and produces long-term wholesale power price forecasts. Using inputs such as generation resource characteristics, regional load forecasts, fuel prices, resource adequacy requirements, and transmission constraints, the model identifies the least-cost mix of future resource additions and retirements needed to maintain reliability. The resulting generation portfolio is then dispatched chronologically to simulate market operations and develop long-term power price forecasts.

PLEXOS was utilized for three main purposes:

1. To determine a long-term view of resource additions and retirements across the WECC region.
2. To develop long-term wholesale power price forecasts for the PSCO and WACM regions.
3. To evaluate the impacts of alternative market conditions through scenario analysis.

Model inputs were developed internally and supplemented with information from reputable third-party sources for key variables such as regional load growth, resource adequacy requirements, natural gas prices, and generation capital costs. Following completion of the WECC capacity expansion analysis, the resulting generation portfolio was dispatched using a production cost simulation to develop hourly power price forecasts for the PSCO and WACM regions.

6.1.3 Market Forecast

The market forecast used in this study was developed using a WECC-wide production cost and capacity expansion model. Although the resource planning analysis focuses on United Power's service territory, market prices within the region are influenced by conditions across the broader WECC footprint. Factors such as regional load growth, generation retirements and additions, fuel prices, transmission constraints, and resource adequacy requirements can materially affect power flows and market prices throughout Colorado.

To capture these interactions, TEA developed a long-term market forecast using PLEXOS to simulate capacity expansion and market operations across the WECC region. The resulting analysis produced hourly wholesale power price forecasts for the WACM and PSCO regions, which served as key inputs to the evaluation of resource alternatives in the United Power IRP.

6.1.4 Long-term Fundamental Market Simulation

A critical component of the market forecast is the capacity expansion analysis, which identifies the types and quantities of generation resources likely to be added across the WECC region to satisfy future load growth and reliability requirements.

Using PLEXOS, TEA performed a long-term capacity expansion simulation of the WECC footprint. The model incorporated projected load growth, announced resource retirements, planned resource additions, fuel price forecasts, carbon reduction goals, transmission constraints, and regional resource adequacy requirements. Resource additions were selected by the model based on their ability to satisfy reliability requirements at the lowest overall system cost.

The capacity expansion simulation evaluated renewable generation, energy storage, and conventional thermal technologies to determine the least-cost mix of future resources needed to maintain system reliability. The resulting generation portfolio was then incorporated into a detailed production cost simulation that modeled hourly market operations and produced hourly power price forecasts for the WACM and PSCO regions.

The WACM and PSCO market forecasts developed through this WECC-wide analysis were subsequently used as inputs to a separate United Power resource planning model. Using these market price forecasts, United Power's load obligations, existing and future resources, and contractual arrangements, alternatives were evaluated to identify cost-effective resource strategies over the planning horizon.

6.2 Principal Market Assumptions

Market conditions throughout the WECC region continue to evolve due to changing load growth patterns, renewable resource deployment, fuel price uncertainty, transmission development, organized wholesale market expansion, and evolving resource adequacy requirements. These factors influence both the level and shape of future power prices and therefore impact the economics of potential resource investments.

This section summarizes the principal assumptions used to model future market conditions within the WECC region and develop the WACM and PSCO market price forecasts utilized in this study.

6.2.1 Planning Reserve Margin Standards and Accreditation Frameworks

PRM and resource accreditation methodologies are used by balancing authorities, regional transmission organizations, and resource adequacy programs to ensure sufficient generating capacity is available to meet forecast demand while maintaining reliability. These requirements establish the amount of accredited capacity that must be maintained above expected peak load to account for uncertainties such as forced outages, extreme weather conditions, forecasting errors, and variability associated with intermittent resources.

The market forecast developed for this study incorporated the resource adequacy frameworks applicable to the WACM and PSCO regions. These assumptions influenced both the capacity expansion analysis and the resulting power price forecast by affecting the quantity and types of resources required to satisfy future reliability requirements.

For the WACM region, the analysis reflected participation in SPP RTOE, which became effective in April 2026. PRM requirements were based on the resource adequacy framework adopted for RTOE participants and were held constant throughout the forecast period. The analysis assumed base planning reserve margins of 19.0% during summer and 40.0% during winter. Under the ACAP framework, equivalent reserve margin requirements of 15.9% during summer and 32.1% during winter were applied.

Resource accreditation assumptions for the WACM region were developed using the SPP ACAP framework, including ELCC-based accreditation for renewable and storage resources and performance-based accreditation concepts for thermal resources. Wind, solar, and battery storage accreditation values were based on SPP ELCC assumptions, while thermal resource accreditation values reflected seasonal performance and availability assumptions by technology type. Table 5 summarizes the WACM resource accreditation values applied in the analysis.

Table 5. WACM Resource Accreditation Assumptions

Resource Type	Summer Capacity Accreditation (%)	Winter Capacity Accreditation (%)
Solar	9.0	1.1
Wind	18.5	20.6
Battery Energy Storage	58.0	53.8
Natural Gas Combined Cycle	93.1	84.7
Natural Gas Combustion Turbine	87.0	74.7
Natural Gas Reciprocating Engine	92.4	80.7
Coal	90.8	77.9
Nuclear	98.1	96.8
Hydroelectric	99.5	99.4

For the PSCO region, the market analysis assumed participation in SPP Markets+ as a committed Phase 2 participant beginning in October 2027. Resource adequacy requirements were represented using monthly resource accreditation values for renewable, storage, hydroelectric, and thermal resources based on the Western Resource Adequacy Program (WRAP) framework. Table 6 summarizes the resource accreditation values applied in the analysis.

A 15% planning reserve margin was assumed during the capacity expansion simulation to ensure adequate capacity additions over the study horizon.

Table 6. PSCO Resource Accreditation Assumptions

Month	Capacity Accreditation (%)				
	Solar	Wind	ESR/Hybrid	Thermal	Run-of-River Hydro
January	8.7	22.2	50.3	94.3	20.9
February	18.9	14.2	39.9	94.3	22.4
March	7.7	21.4	58.5	94.3	32.1
April	0.0	0.0	0.0	0.0	0.0
May	0.0	0.0	0.0	0.0	0.0
June	34.5	13.6	80.1	95.0	49.2
July	28.8	15.0	82.7	95.0	51.5
August	27.2	13.1	84.9	95.0	44.0
September	23.2	11.7	90.8	95.0	36.5
October	0.0	0.0	0.0	0.0	0.0
November	0.9	28.2	60.7	94.3	18.5
December	7.9	26.9	49.2	94.3	21.5

For both the WACM and PSCO regions, resource adequacy assumptions influenced the quantity, timing, and technology mix of future resource additions selected by the model and were incorporated into the production cost simulation used to develop hourly power price forecasts. By explicitly representing regional resource adequacy requirements and accreditation methodologies, the market forecast captures how reliability requirements influence future resource development and wholesale power prices.

6.2.2 Natural Gas Price Forecasts

Natural gas prices are a primary driver of wholesale power prices, particularly in regions where natural gas-fired generation frequently establishes the marginal cost of electricity. As a result, natural gas price assumptions have a significant influence on the WACM and PSCO power price forecasts and on the evaluation of resource alternatives throughout this study.

To capture uncertainty in future fuel markets and evaluate the sensitivity of resource decisions to changing fuel costs, three Henry Hub natural gas price scenarios were developed:

- **Base Case** - This scenario is based on NYMEX futures prices through the near-term forecast period and a long-term natural gas market outlook developed from S&P Global Commodity Insights projections. In this scenario, nominal Henry Hub prices increase from $3.85/MMBtu in 2026 to $6.31/MMBtu in 2045, representing an average annual growth rate of 2.6%. The forecast reflects a moderate view of future natural gas prices and serves as the primary fuel price assumption used throughout the analysis.
- **High Gas Price Scenario** - This scenario is based on the U.S. Energy Information Administration's (EIA) 2025 Annual Energy Outlook Low Oil and Gas Supply case, which reflects a more constrained supply environment and higher long-term natural gas prices. The scenario was developed to evaluate the impact of sustained increases in fuel costs on wholesale power prices and resource economics. Under this scenario, the annual nominal Henry Hub price increases from $4.12/MMBtu in 2026 to $9.80/MMBtu in 2045, reflecting an average annual growth rate of 4.7%. By 2030 and throughout the rest of the study period, prices are 46 to 81% higher than those in

the Base Case. This case serves as a plausible upper bound under tighter long-term supply conditions.

- **Low Gas Price Scenario** - This scenario is based on the EIA 2025 Annual Energy Outlook High Oil and Gas Supply case, which reflects a more abundant supply environment and lower long-term natural gas prices. The scenario was developed to evaluate the impact of lower fuel costs on wholesale power prices and resource economics. Under this scenario, the annual nominal Henry Hub price increases from $2.13/MMBtu in 2026 to $3.30/MMBtu in 2045, reflecting an average annual growth rate of 2.3%. Throughout the study period, prices are 36 to 48% lower than those in the Base Case. This case serves as a plausible lower bound under higher long-term supply conditions.

Natural gas prices directly affect the operating costs of gas-fired generation and, consequently, influence wholesale power prices, resource economics, LCOE results, and the relative value of future generation and capacity investments. The alternative gas price scenarios provide a framework for evaluating the sensitivity of resource decisions to long-term fuel price uncertainty.

Figure 15 presents the annual Henry Hub natural gas price forecasts under each scenario, while Figure 16 presents the corresponding monthly forecasts and seasonal price patterns.

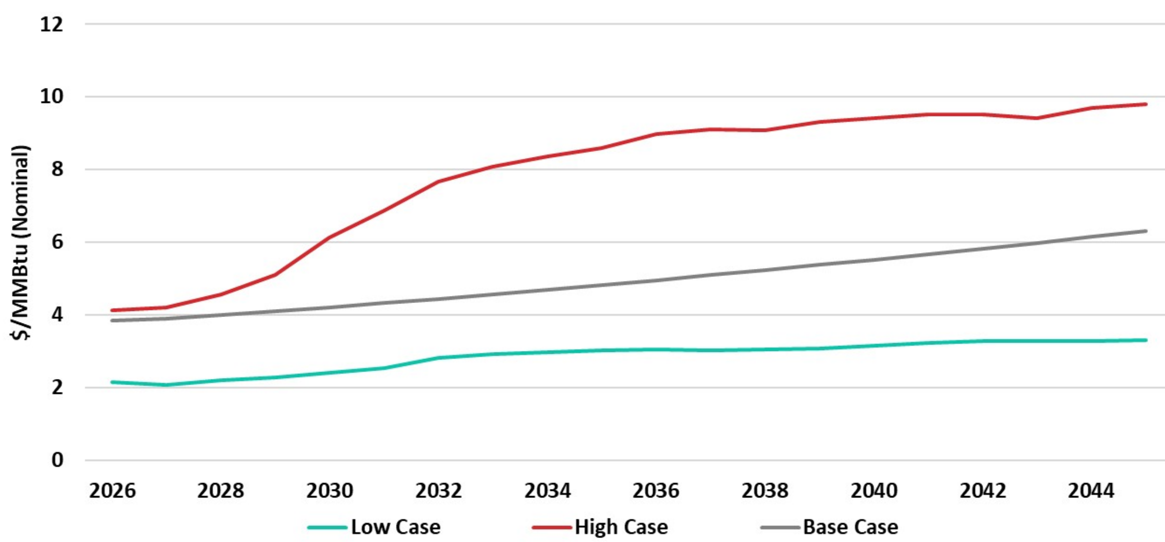


Figure 15. Annual Henry Hub Natural Gas Price Forecasts

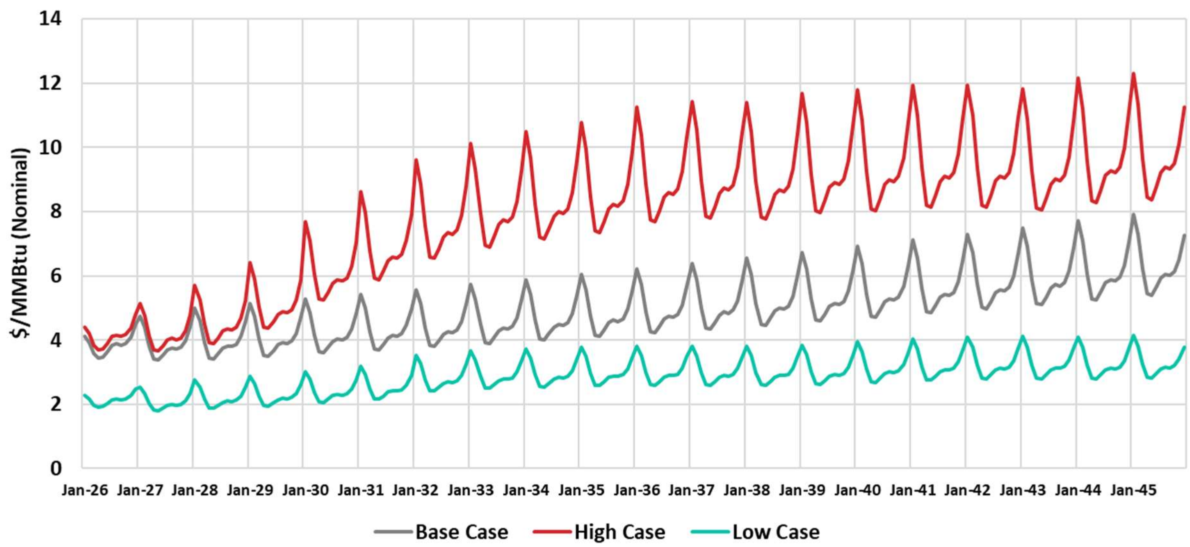


Figure 16. Monthly Henry Hub Natural Gas Price Forecasts

For modeling purposes, the Henry Hub natural gas price forecasts were adjusted to reflect estimated basis differentials, transportation charges, balancing costs, and other fuel delivery considerations. These adjustments varied by resource type and fuel supply arrangement and were incorporated directly into the PLEXOS modeling framework used to evaluate existing and future natural gas-fired generation resources.

6.3 Power Price Forecasts

The WECC-wide PLEXOS capacity expansion and production cost simulations produced hourly wholesale power price forecasts for the WACM and PSCO regions from 2026 through 2045. These forecasts reflect the combined impacts of projected load growth, generation fleet changes, fuel prices, transmission constraints, and resource adequacy requirements modeled throughout the study period.

The forecast indicates relatively stable power prices in both the PSCO and WACM regions through the late 2020s, driven by increasing renewable generation and moderate natural gas prices during this period. Longer-term price increases are primarily attributable to rising fuel costs, continued load growth, and changes in the regional generation mix.

Figure 17 and Figure 18 present the monthly average power price forecasts for the PSCO and WACM regions, respectively, from 2026 through 2045.

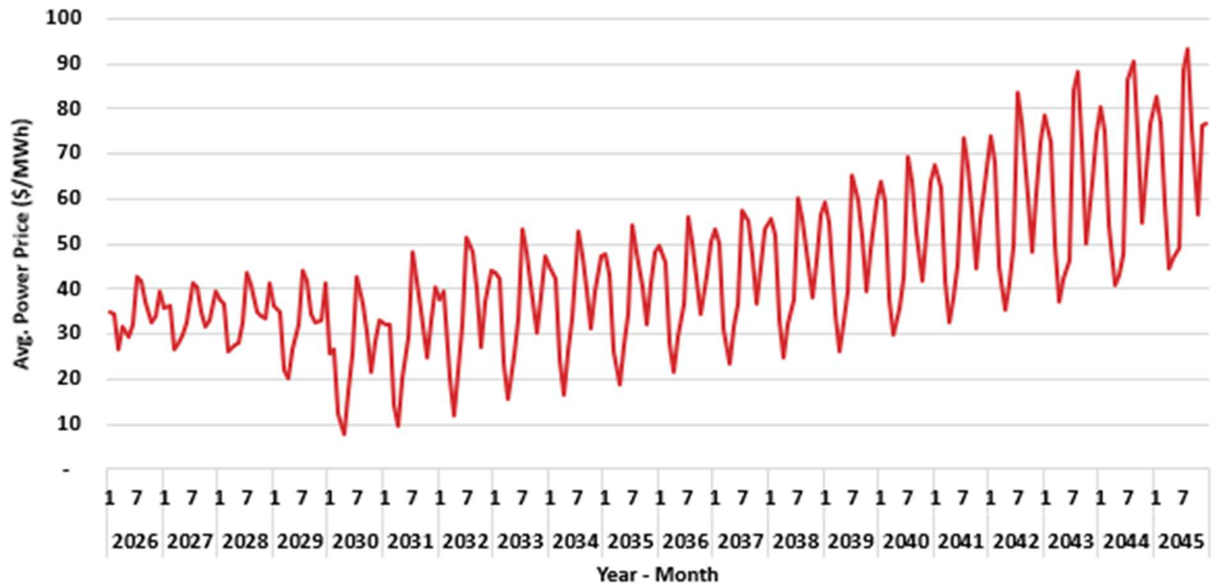


Figure 17. PSCO Monthly Power Price Forecast (nominal)

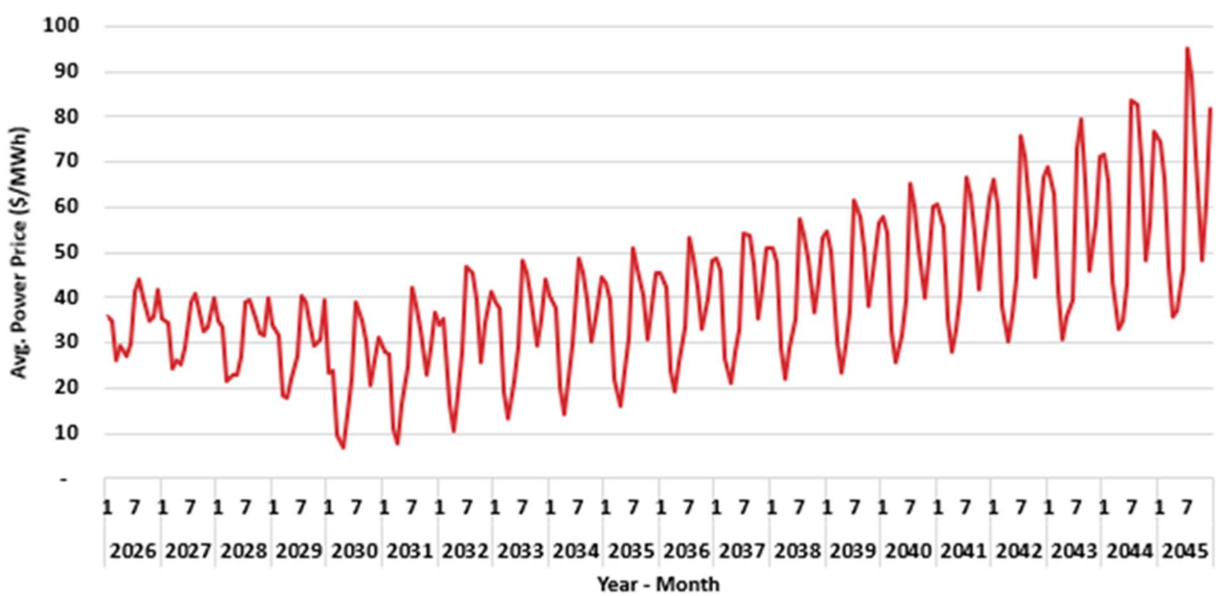


Figure 18. WACM Monthly Power Price Forecast (nominal)

Although average price trends provide a useful indicator of long-term market conditions, hourly price patterns are also important when evaluating resource alternatives. As renewable penetration increases across the WECC region, the timing and magnitude of hourly market prices become increasingly influenced by renewable generation profiles. Prices generally rise during the evening hours when solar output declines and demand remains elevated, while lower prices occur during periods of high renewable generation and reduced system demand. The forecasts also indicate increasing separation between low-price and high-price hours over time, reflecting greater intraday price volatility and more pronounced evening price peaks.

Figure 19 presents hourly price profiles for the PSCO region at five-year intervals, while Figure 20 presents the corresponding profiles for the WACM region. Together, the figures illustrate increasing average price levels, a widening range of hourly prices, and more pronounced evening peak pricing as market conditions and resource portfolios evolve across the WECC region.

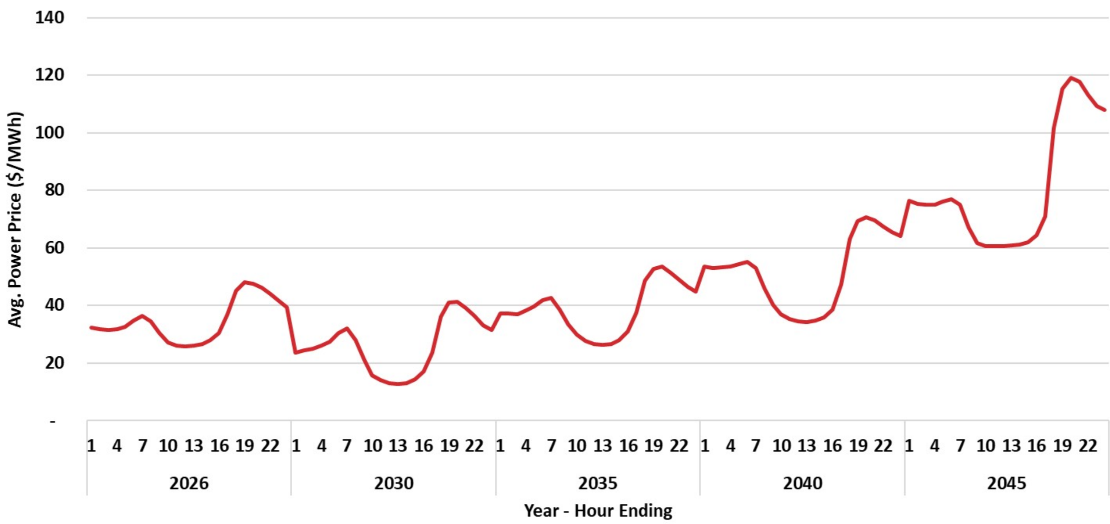


Figure 19. PSCO Average Hourly Power Price Profiles

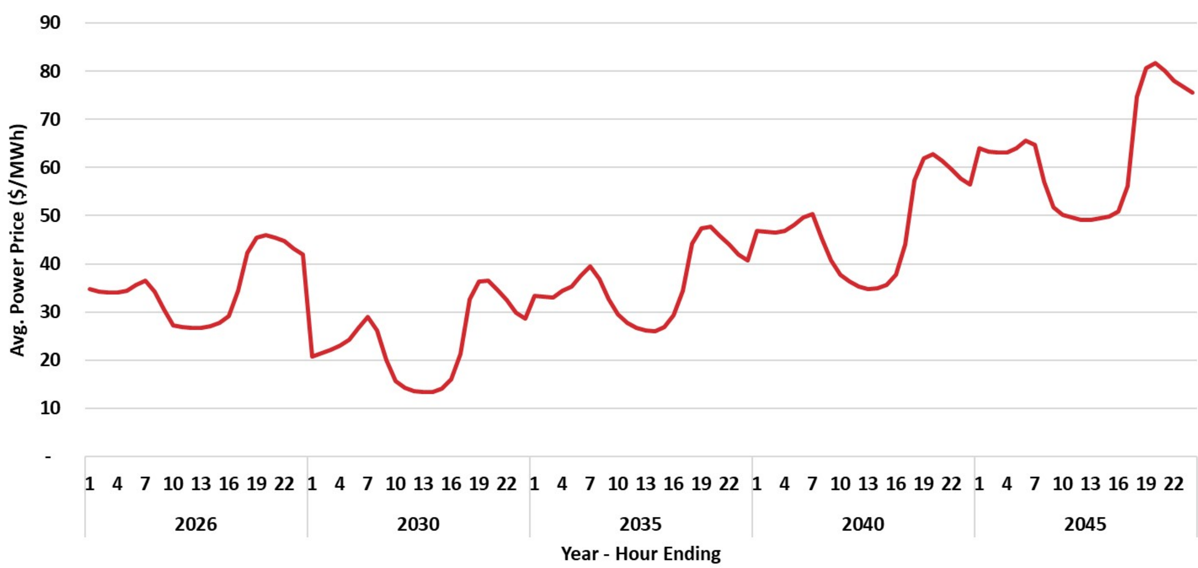


Figure 20. WACM Average Hourly Power Price Profiles

The WACM and PSCO power price forecasts developed through this analysis served as key market inputs to the United Power resource planning model. These forecasts were used to evaluate the cost, risk, and performance of alternative resource strategies under a range of future market conditions. The following section describes the portfolio evaluation methodology and presents the results of the resource planning analysis.

Section 7 Risk Analysis and Portfolio Selection

United Power's objective is to develop a resource plan that ensures affordability and reliability, while proactively managing the uncertainties of an evolving energy landscape. The IRP serves as the strategic framework guiding this effort and is built on a comprehensive analysis of technical, economic, environmental, and regulatory factors to produce a balanced and forward-looking resource strategy.

To evaluate these uncertainties, United Power applied scenario analysis to examine how changes in key assumptions may influence long-term outcomes. This approach helps identify potential planning gaps, provides insight into emerging risks and opportunities, and supports decision-making. The resulting framework is intended to remain flexible and responsive as market conditions, technologies, and policies continue to evolve.

United Power's IRP incorporates several key assumptions to guide future energy and capacity resources decision including:

- **20-year demand forecast:** A long-term projection of electricity consumption used to inform capacity planning and infrastructure investment.
- **Accredited capacity assumptions:** Resource accreditation values used to estimate the dependable contribution of generation and storage resources toward meeting system reliability and reserve margin requirements.
- **Supply-side generation resource options:** Capital and operating cost estimates, emissions, availability, and feasibility for various generating technologies.
- **Fuel, economic, and market product costs:** Forecasts of fuel prices, inflation rates, discount rates, and electricity market prices.

Together, these assumptions establish a comprehensive framework for evaluating resource options and support United Power in making strategic and informed decisions about both existing assets and future capacity needs. This foundation is essential for developing a resilient and cost-efficient plan that remains aligned with regulatory requirements and evolving market dynamics.

This study uses a long-term generation expansion model to identify the least-cost mix of replacement and expansion resources. The PLEXOS electricity production cost model is used to simulate United Power's production costs and interactions within the broader electric market. PLEXOS integrates system and resource assumptions to optimize and select the most cost-effective resource portfolio.

The primary objective of PLEXOS is to minimize the incremental Net Present Value (NPV) while meeting system reliability and regulatory constraints. NPV represents the total net cost required to support United Power's resource portfolio, adjusted for the time value of money. It includes capital expenditures for new resources, variable and fixed operating costs incurred throughout the study period, and revenues associated with market participation and system operations. As a result, NPV reflects the net financial impact of the resource portfolio over the planning horizon. Although NPV does not capture every cost associated with serving load, it provides a consistent and comparable metric for evaluating resource decisions across all scenarios.

In each scenario, PLEXOS developed an optimized future resource portfolio based on defined input assumptions, a variety of resource types and capacities, and constraints such as resource limits and import capabilities.

7.1 Scenario Descriptions

A total of ten scenarios were evaluated, including the initial Base Case. The following sections provide a brief description of each scenario.

7.1.1 Base Case

The Base Case scenario reflects the most probable set of assumptions over the planning horizon. The following are key assumptions used in developing this scenario:

- **Financial**

  United Power assumes a 4% bond rate to finance the construction of self-build resources. The same rate is also applied as the discount rate for converting future costs to present values. The average annual inflation rate is projected to be 2.1% over the study period.

- **Load**

  Total energy consumption is expected to increase at an average annual rate of 3.0% across the total United Power System (PSCO and WACM combined).

- **2030 Emission Limits**

  Carbon emission limits for 2030 are set at an 80% volumetric reduction from 2005 emission levels. This carbon emission limit is to demonstrate how the cooperative can plan to comply with Colorado state carbon reduction goals. In 2021, the Colorado State Legislature passed House Bill (HB) 21-1266 which required that electric utilities must submit a clean energy plan (CEP) that demonstrates how an electric utility will achieve an 80% reduction in greenhouse gas (GHG) emissions by 2030 compared to 2005 levels. Further, Senate Bill (SB) 23-198, expanded the definition of electric utilities subject to the requirements of CEP filing to include those electric cooperatives that “exit” their wholesale generation & transmission (“G&T”) provider after January 1, 2021. A separate CEP Guidance and Verification Workbook demonstrating compliance with the 80% reduction goals was submitted to the Colorado Air Pollution Control Division (Division) for the Division’s review and verification as required by the Colorado legislation and is reflective of the IRP modeling presented in this report.

- **Natural Gas Price**

  Natural gas commodity prices are projected to rise at an average annual nominal growth rate of 2.7% from 2026 through 2045.

- **Resource Limits**

  For all scenarios, resource limitations were restricted to bilateral capacity additions in 2028 and 2029. This approach allows the model to select alternative resource options in later years while bridging near-term capacity needs until additional resources can be developed and placed into service.

- **Key Scheduled and Assumed Resource Changes**
  - The Fortress Solar Facility and Fortress BESS Facility are included in the study with an in-service date of January 1, 2028, and operating for 20 years.
  - The Brush 4 combined cycle unit is slated to be online January 1, 2027, with a retirement date of January 1, 2040. Nameplate capacity for the summer is 133 MW and 147 MW for the winter.
  - South Platte Solar is expected to be online on January 1, 2028, with a summer/winter nameplate capacity of 150 MW.
  - SR Byers Solar is also assumed to provide 150 MW of summer and winter nameplate capacity beginning May 1, 2030.

7.1.2 Base Case with No Emission Limits Scenario

This scenario retains all Base Case assumptions but removes any carbon emission limitations. The purpose of this analysis is to evaluate how resource selection and overall system costs change in the absence of emission reduction requirements.

7.1.3 High Load Growth Rate Scenario

This scenario retains all Base Case assumptions except for load growth which is increased by an additional 0.5% annually over the study period.

7.1.4 High Load Growth Rate with No Emission Limits Scenario

This scenario is based on the Base Case with No Emission Limits and incorporates the higher annual growth assumption of 0.5% per year, consistent with the High Growth Rate scenario described in Section 7.1.3.

7.1.5 Full Accredited Capacity Scenario

PPAs for the Brush 2 combustion turbine unit and the Brush 4 combined cycle unit are given full accredited capacity for this scenario while all other Base Case assumptions remain unchanged.

7.1.6 Full Accredited Capacity with No Emission Limits Scenario

This scenario mirrors the assumptions used in the Full Accredited Capacity scenario but is evaluated using the Base Case with No Emission Limits for analysis.

7.1.7 Large Load Addition Scenario

This scenario includes a large load addition of 600 MW beyond the projected Base Case load forecast. This large load would operate at full load continually around the clock (ATC) with 50 MW blocks introduced incrementally every eight months beginning in January of 2027.

7.1.8 Large Load Addition with No Emission Limits Scenario

This scenario applies the same large load assumption described in Section 7.1.7 but is analyzed using the Base Case with No Emission Limits assumptions.

7.1.9 High Natural Gas Price with No Emission Limits Scenario

This scenario explores the impact of sustained high natural gas prices over the planning horizon. The natural gas commodity price forecast is based on the Energy Information Administration's Low Oil and Gas Availability case from its 2025 Annual Energy Outlook. In this scenario, gas prices increase at an average annual rate of 4.7% and remain approximately 59.0% above Base Case levels throughout the study period.

Because gas-fired generation frequently sets wholesale market prices, elevated gas costs place upward pressure on power prices and may reduce the economic attractiveness of new thermal resources relative to renewables, which are not exposed to fuel price volatility. This scenario was analyzed using the Base Case with No Emission Limits.

7.1.10 Low Natural Gas Price with No Emission Limits Scenario

Low natural gas prices for this scenario utilizing the Base Case with No Emission Limits are also based on the Energy Information Administration's Low Oil and Gas Availability case from its 2025 Annual Energy Outlook. The gas prices through the study remain relatively flat with a growth rate of only 2.3% and averaging 57.6% below the Base Case with No Emission Limits levels.

7.2 Scenario Results

7.2.1 Base Case Scenario

The Base Case scenario results in a total system NPV of $3,320 million for United Power. The associated cost allocation and levelized cost of energy (LCOE), reflecting the relative cost-effectiveness of the resource portfolio, is calculated to be $51.56/MWh.

In this Base Case, summer reserve margin requirements drive United Power's future capacity additions. The first resource needs occur in 2028 when 235 MW of bilateral capacity is added to address near-term reliability requirements, followed by 260 MW in 2029.

Bilateral capacity purchases are utilized as an interim solution until battery storage resources can be constructed and placed into service beginning in 2029. Battery additions continue to play a significant role through the 2030s, with natural gas-fired units added starting in 2039. The model selects 1,164 MW of battery storage, providing approximately 675 MW of accredited summer capacity, along with seven LM2500XPRESS combined cycle units between 2039 and 2045, providing approximately 282 MW of capacity and approximately 263 MW of summer accredited capacity.

The portfolio also includes a modest wind addition of 25 MW in 2042, providing approximately 5 MW of accredited summer capacity.

Figure 21 illustrates carbon emission compliance over the study period with a target of 232,980 tons/year starting in 2030, a reduction of 80% from 2005 levels. The target is achieved earlier following the expiration of the Knutson PPA and the Tri-State Generation and Transmission Association (TSGT) Around-the-Clock (ATC) Block and Call options on December 31, 2027. These agreements were part of the transitional resource adequacy arrangements supporting United Power's transition from its former wholesale power provider in 2024.

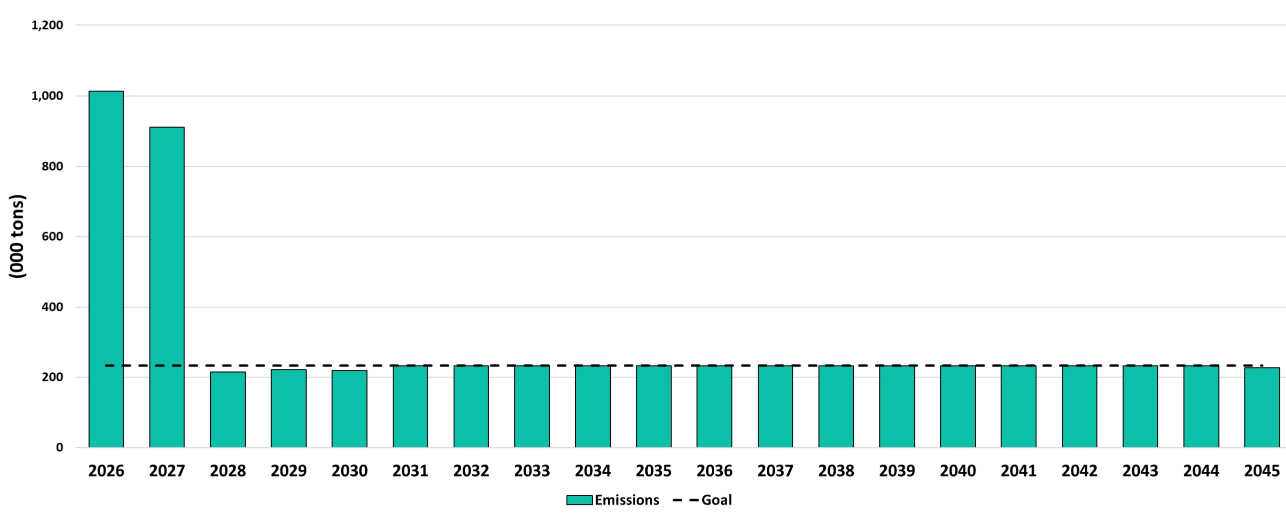


Figure 21. Carbon Emissions Over the Study Period

Table 7 summarizes United Power's summer firm capacity by resource type for each year of the forecast period, and

Table **8** presents the corresponding winter firm capacity. Figure 22 illustrates United Power's firm capacity relative to its summer peak load and capacity requirement. Figure 23 provides the corresponding comparison for the winter season.

Table 7. Base Case - United Power Firm Summer Capacity (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas	271	271	142	142	142	142	142	142	142	142	142	142	142	292	330	330	330	330	330	405
Nuclear																				
Hydro																				
Wind																	5	5	5	5
Solar	8	26	39	39	53	52	52	52	52	52	52	52	52	52	52	52	52	38	34	34
Battery Storage	67	183	183	185	480	507	540	570	598	628	658	684	732	732	735	742	765	791	814	817
Bilateral Capacity	380	380	515	540	280	280	280	280	280	280	280	280	280	50	50	50	50	50	50	
Demand Response																				
Total	**725**	**859**	**879**	**906**	**955**	**982**	**1015**	**1045**	**1073**	**1103**	**1132**	**1158**	**1207**	**1127**	**1167**	**1174**	**1201**	**1214**	**1233**	**1260**

Table 8. Base Case - United Power Firm Winter Capacity (MW)

Resource Type	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35	35/36	36/37	37/38	38/39	39/40	40/41	41/42	42/43	43/44	44/45
Coal																				
Natural Gas	294	294	157	157	157	157	157	157	157	157	157	157	157	338	384	384	384	384	384	475
Nuclear																				
Hydro																				
Wind																	5	5	5	5
Solar	2	4	5	5	5	7	7	7	7	7	7	7	7	7	7	7	7	5	5	4
Battery Storage	62	169	169	172	445	471	501	529	555	583	611	634	679	679	682	688	710	744	781	757
Bilateral Capacity	317	317	452	477	217	217	217	217	217	217	217	217	217	217	50	50	50	50	50	
Demand Response																				
Total		**785**	**784**	**811**	**824**	**851**	**881**	**909**	**935**	**963**	**991**	**1015**	**1060**	**1242**	**1122**	**1129**	**1155**	**1188**	**1225**	**1241**

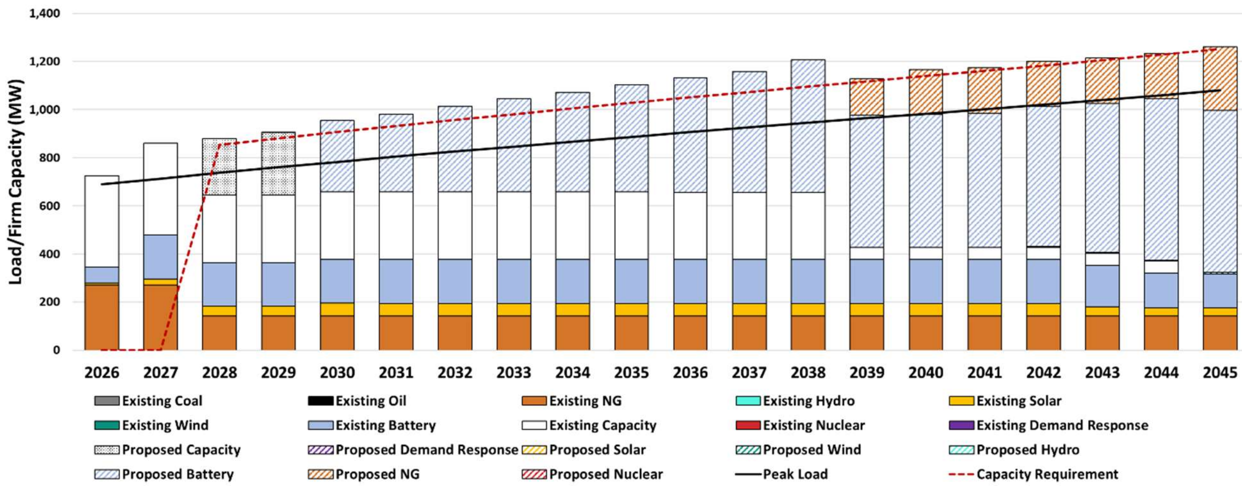


Figure 22. Base Case - United Power Summer Load/Capacity Balance

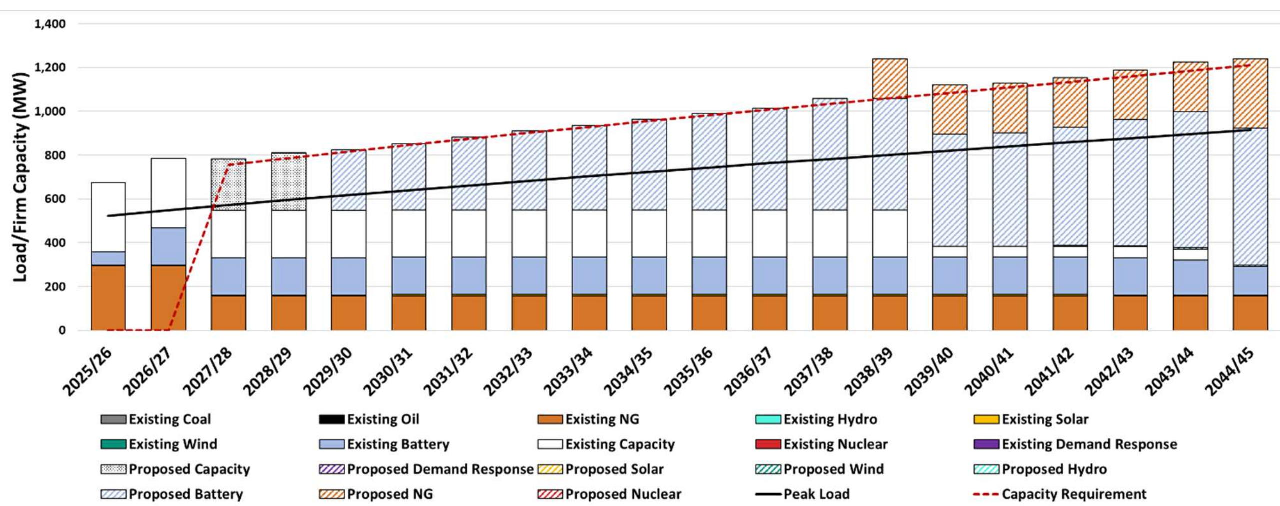


Figure 23. Base Case - United Power Winter Load/Capacity Balance

7.2.2 Base Case with No Emission Limits Scenario

Under the Base Case with No Emission Limits scenario, carbon emissions reduction requirements are removed from the analysis. NPV costs for the entire system decrease to $3,274 million, which is $46 million (1.4%) lower than the Base Case. The LCOE is $50.85/MWh or $0.71/MWh (1.4%) lower relative to the Base Case.

Compared to the Base Case, this scenario results in significantly fewer battery additions and substantially greater natural gas-fired capacity. The optimized portfolio adds 624 MW of battery storage, approximately half the battery capacity selected in the Base Case, providing approximately 362 MW of accredited summer capacity. In addition, sixteen LM2500XPRESS natural gas-fired combined cycle units are added beginning in 2032 and continuing throughout the study period, providing approximately 645 MW of summer capacity and approximately 600 MW of accredited summer capacity. Unlike the Base Case, no wind additions are selected in this scenario.

With carbon emission constraints removed, the model favors additional natural gas generation over battery and wind resources, reducing the need for storage capacity while eliminating wind development from the preferred resource portfolio.

Table 9 provides United Power's summer firm capacity by resource type for each year of the forecast period, while Table 10 summarizes the differences relative to the Base Case. Because summer is the primary planning season due to reserve margin requirements dictating capacity needs, only summer-related capacity tables are included. Figure 24 illustrates United Power's firm capacity in relation to its summer peak load and capacity requirement and Figure 25 provides the corresponding comparison for the winter season.

Table 9. Base Case with No Emission Limits Scenario - United Power Summer Firm Capacity (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas	271	271	142	142	142	142	180	180	217	217	255	255	292	518	518	555	555	593	668	743
Nuclear																				
Hydro																				
Wind																				
Solar	8	26	39	39	53	52	52	52	52	52	52	52	52	52	52	52	52	38	34	34
Battery Storage	67	183	183	350	480	507	512	521	524	528	533	538	540	540	540	540	540	533	506	503
Bilateral Capacity	380	380	515	375	280	280	280	280	280	280	280	280	280	50	50	50	50	50	50	
Demand Response																				
Total	**725**	**859**	**879**	**906**	**955**	**982**	**1024**	**1034**	**1073**	**1078**	**1120**	**1124**	**1164**	**1159**	**1159**	**1197**	**1197**	**1214**	**1258**	**1280**

Table 10. Base Case with No Emission Limits Scenario - United Power Summer Firm Capacity Difference from Base Case (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas							38	38	75	75	113	113	150	225	188	225	225	263	338	338
Nuclear																				
Hydro																				
Wind																	-5	-5	-5	-5
Solar																				
Battery Storage				165			-28	-49	-74	-100	-125	-146	-193	-193	-195	-202	-225	-258	-309	-313
Bilateral Capacity				-165																
Demand Response																				
Total				**0**			**10**	**-11**	**1**	**-25**	**-13**	**-34**	**-42**	**33**	**-7**	**23**	**-5**	**0**	**24**	**20**

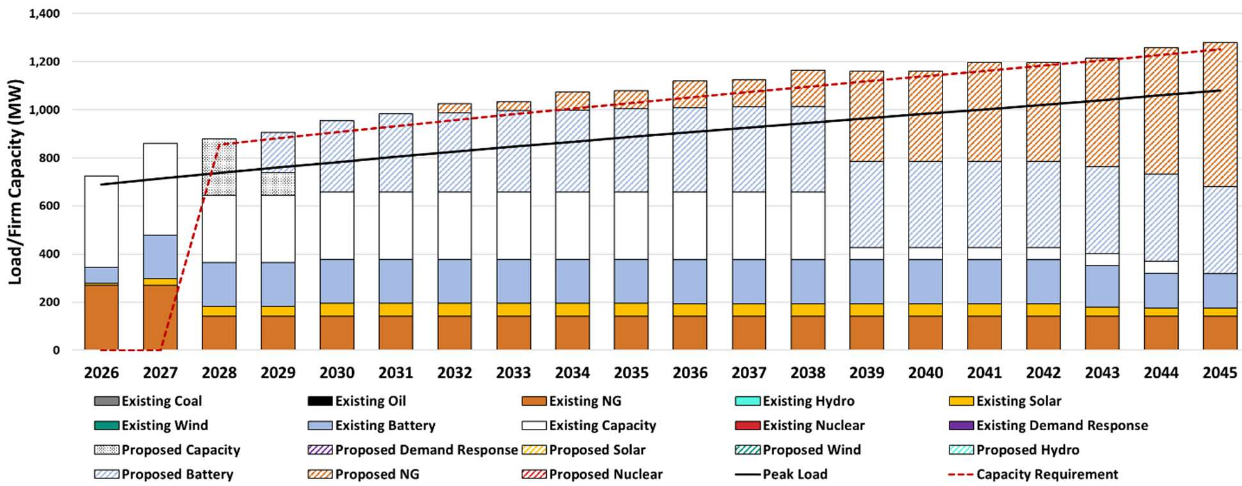


Figure 24. Base Case with No Emission Limits Scenario - United Power Summer Load/Capacity Balance

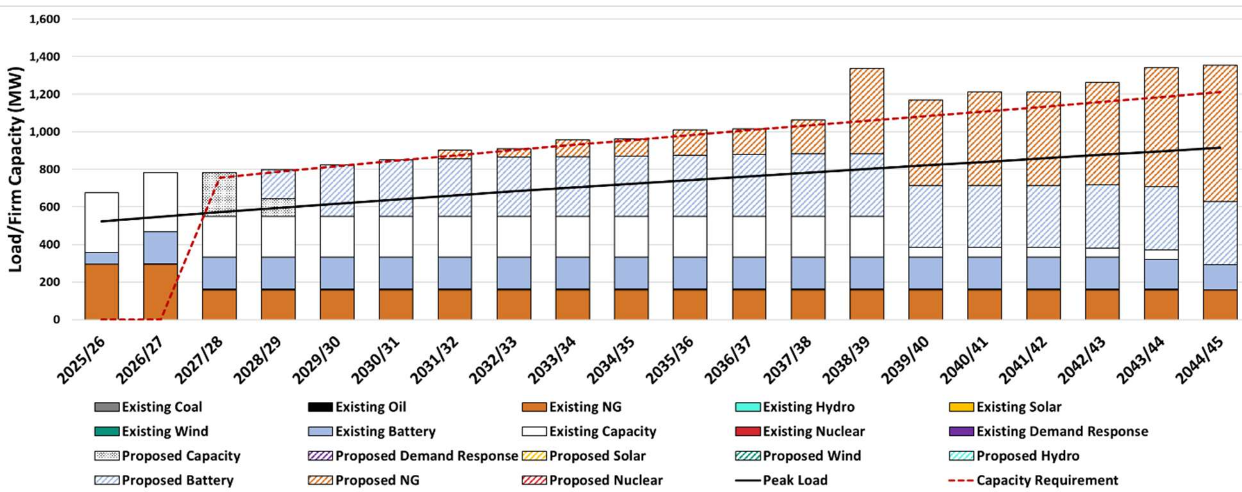


Figure 25. Base Case with No Emission Limits Scenario - United Power Winter Load/Capacity Balance

7.2.3 High Load Growth Rate Scenario

Under the High Load Growth Rate scenario, United Power's total system NPV revenue requirements increase to $3,524 million, which is $204 million (6.1%) higher than the Base Case. The corresponding Levelized Cost of Energy is $52.38/MWH, an increase of $0.82/MWh (1.6%) relative to the Base Case.

Although the annual load growth assumption increases by an additional 0.5% over the study period, the resulting resource portfolio remains generally consistent with the Base Case. Additional demand is met primarily through increased battery storage and wind additions, while the quantity of natural gas-fired combined cycle generation remains unchanged. The optimized portfolio adds 1,228 MW of battery storage, 64 MW more than in the Base Case scenario, providing approximately 712 MW of accredited summer capacity. The portfolio also adds 450 MW of wind resources, 425 more than the Base Case, providing approximately 83 MW of accredited summer capacity. As in the Base Case, seven LM2500XPRESS natural gas-fired combined-cycle units are added between 2039 and 2045, providing approximately 282 MW of summer capacity and approximately 263 MW of accredited summer capacity.

Table 11 illustrates United Power's summer firm capacity by resource type for each year of the forecast period, and Table 12 provides the difference from the Base Case. Figure 26 shows the Summer Load and Capacity Balance for this scenario.

Table 11. High Load Growth Rate Scenario - United Power Summer Firm Capacity (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas	271	271	142	142	142	142	142	142	142	142	142	142	142	292	330	368	368	368	405	405
Nuclear																				
Hydro																				
Wind																5	9	9	9	83
Solar	8	26	39	39	53	52	52	52	52	52	52	52	52	52	52	52	52	38	34	34
Battery Storage	67	183	183	183	496	531	568	603	637	674	709	742	807	807	809	809	811	849	847	856
Bilateral Capacity	380	380	520	555	280	280	280	280	280	280	280	280	280	50	50	50	50	50	50	
Demand Response																				
Total	**725**	**859**	**884**	**919**	**971**	**1005**	**1043**	**1077**	**1112**	**1149**	**1184**	**1216**	**1281**	**1201**	**1241**	**1283**	**1290**	**1314**	**1345**	**1378**

Table 12. High Load Growth Rate Scenario - United Power Summer Firm Capacity Difference from Base Case (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas																38	38	38	75	
Nuclear																				
Hydro																				
Wind																	5	5	5	79
Solar																				
Battery Storage				-2	16	23	28	32	39	46	51	58	74	74	74	67	46	58	32	39
Bilateral Capacity			5	15																
Demand Response																				
Total			**5**	**13**	**16**	**23**	**28**	**32**	**39**	**46**	**51**	**58**	**74**	**74**	**74**	**109**	**89**	**100**	**112**	**118**

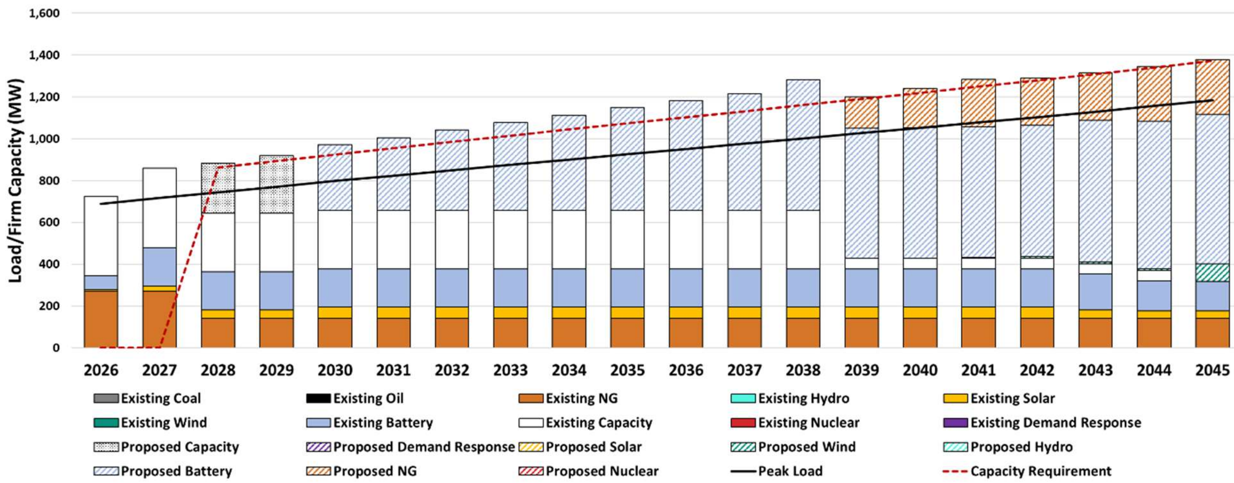


Figure 26. High Load Growth Rate Scenario - United Power Summer Load/Capacity Balance

7.2.4 High Load Growth Rate with No Emission Limits Scenario

The High Load Growth Rate with No Emission Limits scenario results in a total system NPV of $3,465 million, $191 million (5.8%) higher than the Base Case with No Emission Limits. The corresponding LCOE is $51.51/MWh, an increase of $0.66/MWh (1.3%). The optimized resource portfolio for this scenario includes 724 MW of battery storage capacity, 100 MW more than the Base Case with No Emission Limits, providing approximately 420 MW of accredited summer capacity. The portfolio also adds seventeen LM2500XPRESS natural gas-fired combined cycle units, one more unit than the Base Case with No Emissions Limits, providing approximately 685 MW of summer capacity and approximately 638 MW of accredited summer capacity.

Compared to the corresponding High Load Growth Rate scenario with carbon emission limits, this scenario produces a lower NPV by $59 million (1.7%) and a lower LCOE by $0.87/MWh (1.7%). The removal of carbon reduction requirements significantly alters the preferred resource mix, reducing battery storage additions from 1,228 MW to 724 MW while increasing natural gas-fired combined cycle capacity from approximately 282 MW to approximately 685 MW.

Table 13 provides United Power’s summer firm capacity by resource type for each year of the forecast period, while Table 14 provides the difference from the Base Case with No Emission Limits. Figure 27 shows the Summer Load and Capacity Balance for this scenario.

Table 13. High Load Growth Rate with No Emission Limits Scenario – United Power Summer Firm Capacity (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas	271	271	142	142	142	142	180	217	217	255	255	292	292	518	555	593	593	668	705	780
Nuclear																				
Hydro																				
Wind																				
Solar	8	26	39	39	53	52	52	52	52	52	52	52	52	52	52	52	52	38	34	34
Battery Storage	67	183	183	336	496	531	535	538	542	547	563	565	586	586	586	586	589	577	559	561
Bilateral Capacity	380	380	520	400	280	280	280	280	280	280	280	280	280	50	50	50	50	50	50	
Demand Response																				
Total	**725**	**859**	**884**	**917**	**971**	**1005**	**1048**	**1087**	**1092**	**1134**	**1150**	**1190**	**1211**	**1206**	**1243**	**1281**	**1283**	**1333**	**1349**	**1376**

Table 14. High Load Growth Rate with No Emission Limits Scenario – United Power Summer Firm Capacity Difference from Base Case with No Emission Limits (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas								38		38		38			38	38	38	75	38	38
Nuclear																				
Hydro																				
Wind																				
Solar																				
Battery Storage				-14	16	23	23	16	19	19	30	28	46	46	46	46	49	44	53	58
Bilateral Capacity			5	25																
Demand Response																				
Total			**5**	**11**	**16**	**23**	**23**	**54**	**19**	**56**	**30**	**65**	**46**	**46**	**84**	**84**	**86**	**119**	**91**	**96**

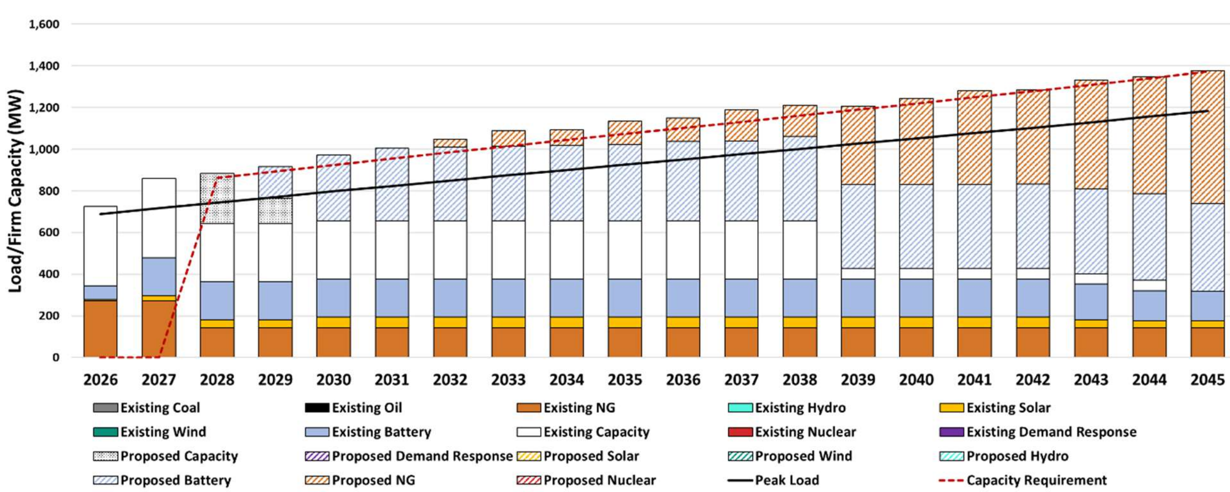


Figure 27. High Load Growth Rate with No Emission Limits Scenario - United Power Summer Load/Capacity Balance

7.2.5 Full Accredited Capacity Scenario

The Full Accredited Capacity scenario results in a total system NPV of $3,201 million, a decrease of $119 million (3.6%) from the Base Case. The corresponding LCOE declines by $1.85/MWh to $49.71/MWh, also a reduction of 3.6%.

Although United Power is assumed to receive accredited capacity from the Brush 2 combustion turbine and Brush 4 combined cycle resources in this scenario, the resulting expansion plan remains largely consistent with the Base Case. Battery storage additions decrease only slightly from 1,164 MW to 1,160 MW, wind additions increase modestly from 25 MW to 50 MW, and the quantity of natural gas-fired combined-cycle generation remains unchanged. However, the additional accredited capacity significantly reduces near-term battery storage requirements. Between 2030 and 2039, the amount of accredited battery storage capacity required is approximately 123 MW to 160 MW lower than in the Base Case. These reductions allow United Power to defer certain capacity additions during the early years of the planning horizon, resulting in an $119 million reduction in NPV despite only minor differences in the long-term expansion plan.

Table 15 shows United Power's summer firm capacity by resource type for each year of the forecast period. Table 16 provides the difference from the Base Case. Figure 28 shows the Summer Load and Capacity Balance for this scenario.

Table 15. Full Accredited Capacity Scenario – United Power Summer Firm Capacity (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas	334	457	329	329	329	329	329	329	329	266	266	266	266	416	330	330	330	330	330	405
Nuclear																				
Hydro																				
Wind																	5	5	5	9
Solar	8	26	39	39	53	52	52	52	52	52	52	52	52	52	52	52	52	38	34	34
Battery Storage	67	183	183	185	329	357	384	412	438	498	526	551	609	609	737	739	765	788	814	814
Bilateral Capacity	380	380	360	385	280	280	280	280	280	280	280	280	280	50	50	50	50	50	50	
Demand Response																				
Total	**788**	**1046**	**911**	**938**	**990**	**1018**	**1046**	**1074**	**1099**	**1097**	**1124**	**1150**	**1208**	**1128**	**1169**	**1171**	**1201**	**1211**	**1233**	**1263**

Table 16. Full Accredited Capacity Scenario – United Power Summer Firm Capacity Difference from Base Case (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas	63	186	186	186	186	186	186	186	186	124	124	124	124	124						
Nuclear																				
Hydro																				
Wind																				5
Solar																				
Battery Storage					-151	-151	-155	-158	-160	-130	-132	-132	-123	-123	2	-2		-2		-2
Bilateral Capacity			-155	-155																
Demand Response																				
Total	**63**	**186**	**31**	**31**	**36**	**36**	**31**	**29**	**26**	**-6**	**-8**	**-8**	**1**	**1**	**2**	**-2**		**-2**		**2**

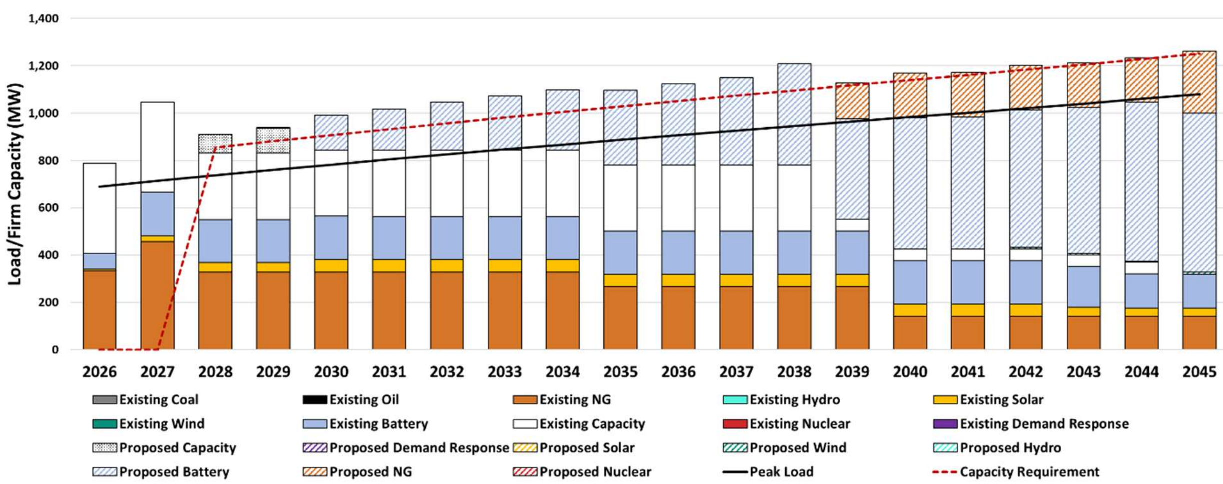


Figure 28. Full Accredited Capacity Scenario - United Power Summer Load/Capacity Balance

7.2.6 Full Accredited Capacity with No Emission Limits Scenario

Under the Full Accredited Capacity with No Emission Limits scenario, NPV decreases to $3,126 million, which is $148 million (4.5%) lower than the Base Case with No Emission Limits. The corresponding LCOE declines to $48.55/MWh, a reduction of $2.29/MWh (4.5%).

Relative to the Base Case with No Emission Limits, the additional accredited capacity from the Brush 2 combustion turbine and Brush 4 combined cycle resources further reduces future capacity requirements and portfolio costs. Battery storage additions decrease from 624 MW to 396 MW, providing approximately 230 MW of accredited summer capacity compared to approximately 362 MW in the Base Case with No Emission Limits. Natural gas-fired combined cycle capacity increases from approximately 645 MW to 766 MW, providing approximately 713 MW of accredited summer capacity. No wind additions are selected in this scenario. With carbon emission constraints lifted, the model favors lower-cost natural gas-fired generation, resulting in a greater reliance on combined cycle resources over the study horizon.

Compared to the Full Accredited Capacity scenario with carbon emission limits, this scenario produces a lower NPV by $75 million (2.3%) and a lower LCOE of $1.16/MWh (2.3%). The removal of carbon reduction requirements significantly alters the preferred resource mix, reducing battery storage from 1,160 MW to 396 MW while increasing natural gas-fired combined cycle capacity from 282 MW to 766 MW. These results illustrate the combined influence of carbon requirements and resource accreditation assumptions on future resource selection and portfolio costs.

Table 17 presents United Power's summer firm capacity by resource type for each year of the forecast period, while Table 18 provides the corresponding difference from the Base Case with No Emission Limits. Figure 29 shows the Summer Load and Capacity Balance for this scenario.

Table 17. Full Accredited Capacity with No Emission Limits Scenario – United Power Summer Firm Capacity (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas	334	457	329	329	329	329	366	366	404	379	379	416	416	641	668	668	705	743	780	855
Nuclear																				
Hydro																				
Wind																				
Solar	8	26	39	39	53	52	52	52	52	52	52	52	52	52	52	52	52	38	34	34
Battery Storage	67	183	183	206	329	357	357	364	364	366	394	394	394	394	401	403	405	399	374	371
Bilateral Capacity	380	380	360	365	280	280	280	280	280	280	280	280	280	50	50	50	50	50	50	
Demand Response																				
Total	**788**	**1046**	**911**	**939**	**990**	**1018**	**1055**	**1062**	**1100**	**1077**	**1104**	**1142**	**1142**	**1137**	**1170**	**1173**	**1212**	**1230**	**1238**	**1261**

Table 18. Full Accredited Capacity with No Emission Limits Scenario – United Power Summer Firm Capacity Difference from Base Case (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas	63	186	186	186	186	186	186	186	186	161	124	161	124	124	150	113	150	150	113	113
Nuclear																				
Hydro																				
Wind																				
Solar																				
Battery Storage				-144	-151	-151	-155	-158	-160	-162	-139	-144	-146	-146	-139	-137	-135	-135	-132	-132
Bilateral Capacity			-155	-10																
Demand Response																				
Total	**63**	**186**	**31**	**33**	**36**	**36**	**31**	**29**	**26**	**-1**	**-15**	**18**	**-22**	**-22**	**11**	**-24**	**16**	**16**	**-20**	**-20**

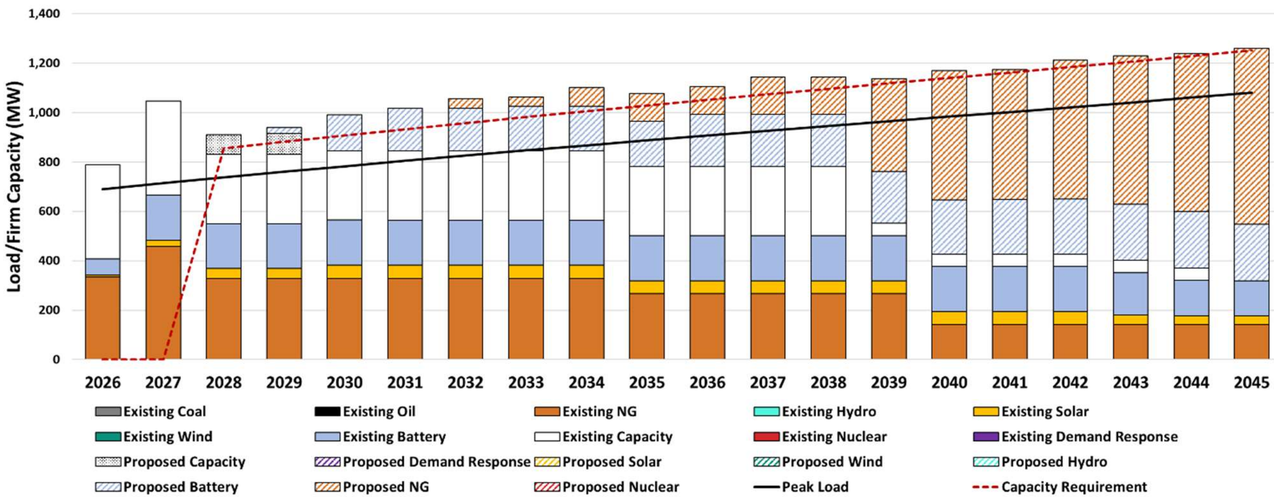


Figure 29. Full Accredited Capacity Scenario with No Emission Limits - United Power Summer Load/Capacity Balance

7.2.7 Large Load Addition Scenario

With the addition of 600 MW of large customer load, NPV increases to $6,260 million, an increase of $2,940 million (88.6%) relative to the Base Case. The corresponding LCOE rises from $51.56/MWh to $55.95/MWh, an increase of 8.5%.

Substantial additional resource development is required to serve the increased load while maintaining reliability and satisfying carbon reduction requirements. Battery storage additions increase from 1,164 MW in the Base Case to 1,332 MW, providing approximately 773 MW of accredited summer capacity. Natural gas-fired generation expands significantly, with combined cycle capacity increasing from approximately 282 MW to 605 MW, providing approximately 563 MW of accredited summer capacity, and 204 MW of simple cycle combustion turbine capacity added, providing approximately 178 MW of accredited summer capacity. Wind additions also increase substantially from 25 MW to 650 MW, providing approximately 120 MW of accredited summer capacity.

The results demonstrate that large customer load additions can materially increase future resource requirements and portfolio costs, requiring significant additions of battery storage, natural gas-fired generation, and wind resources to maintain system reliability and comply with carbon reduction requirements.

Table 19 shows United Power's summer firm capacity by resource type for each year of the forecast period, and Table 20 provides the difference from the Base Case. Figure 30 shows the Summer Load and Capacity Balance for this scenario.

Table 19. Large Load Addition Scenario – United Power Summer Firm Capacity (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas	271	271	142	142	142	295	370	482	557	632	658	695	695	808	845	845	883	883	883	883
Nuclear																				
Hydro																				
Wind																	5	5	46	120
Solar	8	26	39	39	53	52	52	52	52	52	52	52	52	52	52	52	52	38	34	34
Battery Storage	67	183	183	185	835	835	839	848	851	853	858	860	920	920	923	925	925	928	914	914
Bilateral Capacity	380	380	670	805	280	280	280	280	280	280	280	280	280	50	50	50	50	50	50	
Demand Response																				
Total	**725**	**859**	**1034**	**1171**	**1310**	**1462**	**1541**	**1663**	**1741**	**1818**	**1848**	**1887**	**1948**	**1830**	**1870**	**1872**	**1915**	**1904**	**1928**	**1951**

Table 20. Large Load Addition Scenario – United Power Summer Firm Capacity Difference from Base Case (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas						152	227	340	415	490	516	553	553	516	516	516	553	553	553	478
Nuclear																				
Hydro																				
Wind																			42	116
Solar																				
Battery Storage					355	327	299	278	253	225	200	176	188	188	188	183	160	137	100	97
Bilateral Capacity			155	265																
Demand Response																				
Total			**155**	**265**	**355**	**480**	**527**	**618**	**668**	**715**	**715**	**729**	**741**	**703**	**703**	**699**	**713**	**690**	**694**	**691**

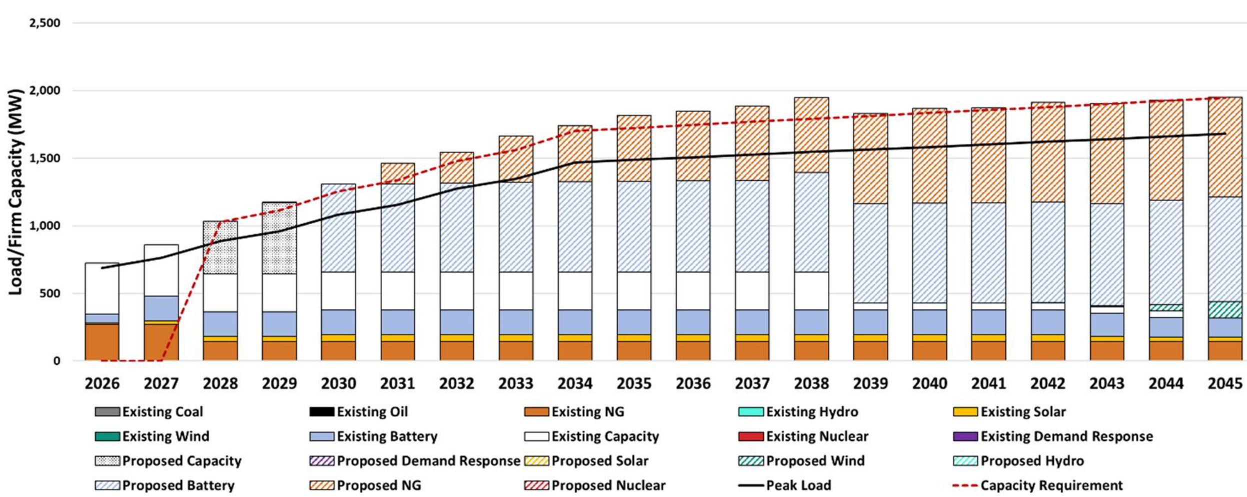


Figure 30. Large Load Addition Scenario - United Power Summer Load/Capacity Balance

7.2.8 Large Load Addition with No Emission Limits Scenario

This scenario results in an NPV of $5,967 million, which is $2,693 million (82.3%) higher than the Base Case with No Emission Limits. The corresponding LCOE increases to $53.35/MWh, an increase of $2.51/MWh (4.9%) compared to the Base Case.

As in the Large Load Addition scenario with carbon reduction requirements, substantial additional resource development is required to serve the 600 MW of large customer load. Relative to the Base Case with No Emission Limits, battery storage additions increase from 624 MW to 1,168 MW, providing approximately 677 MW of accredited summer capacity. Total natural gas generation increases from approximately 645 MW to approximately 1,074 MW through a combination of combined cycle and combustion turbine resources, providing approximately 985 MW of accredited summer capacity. No wind additions are selected in this scenario.

Compared to the corresponding Large Load Addition scenario with carbon reduction requirements, the removal of carbon reduction requirements significantly alters the preferred resource mix. Battery storage additions decrease from 1,332 MW to 1,168 MW, reducing accredited summer capacity from approximately 773 MW to approximately 677 MW, while wind additions are eliminated. Total natural gas-fired generation increases from approximately 809 MW to approximately 1,074 MW, providing approximately 985 MW of accredited summer capacity. This scenario produces an NPV that is $293 million lower and an LCOE that is $2.60/MWh lower. These results demonstrate the significant influence of carbon reduction requirements on future resource selection and portfolio costs.

Table 21 presents United Power's summer firm capacity by resource type for each year, and Table 22 provides the difference from the Base Case. Figure 31 shows the Summer Load and Capacity Balance for this scenario.

Table 21. Large Load Addition with No Emission Limits Scenario – United Power Summer Firm Capacity (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas	271	271	142	142	142	286	361	881	881	881	881	881	881	941	941	941	978	1016	1053	1128
Nuclear																				
Hydro																				
Wind																				
Solar	8	26	39	39	53	52	52	52	52	52	52	52	52	52	52	52	52	38	34	34
Battery Storage	67	183	183	688	835	835	839	841	844	846	853	855	858	858	858	858	860	849	821	819
Bilateral Capacity	380	380	670	325	280	280	280	280	280	280	280	280	280	50	50	50	50	50	50	
Demand Response																				
Total	**725**	**859**	**1034**	**1195**	**1310**	**1453**	**1533**	**2055**	**2057**	**2059**	**2066**	**2068**	**2070**	**1900**	**1900**	**1900**	**1940**	**1953**	**1959**	**1981**

Table 22. Large Load Addition with No Emission Limits Scenario – United Power Summer Firm Capacity Difference from Base Case (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas						144	181	701	663	663	626	626	588	423	423	386	423	423	386	386
Nuclear																				
Hydro																				
Wind																				
Solar																				
Battery Storage				339	355	327	327	320	320	318	320	318	318	318	318	318	320	316	316	316
Bilateral Capacity			155	-50																
Demand Response																				
Total			**155**	**289**	**355**	**471**	**508**	**1021**	**983**	**981**	**946**	**944**	**906**	**741**	**741**	**703**	**743**	**739**	**701**	**701**

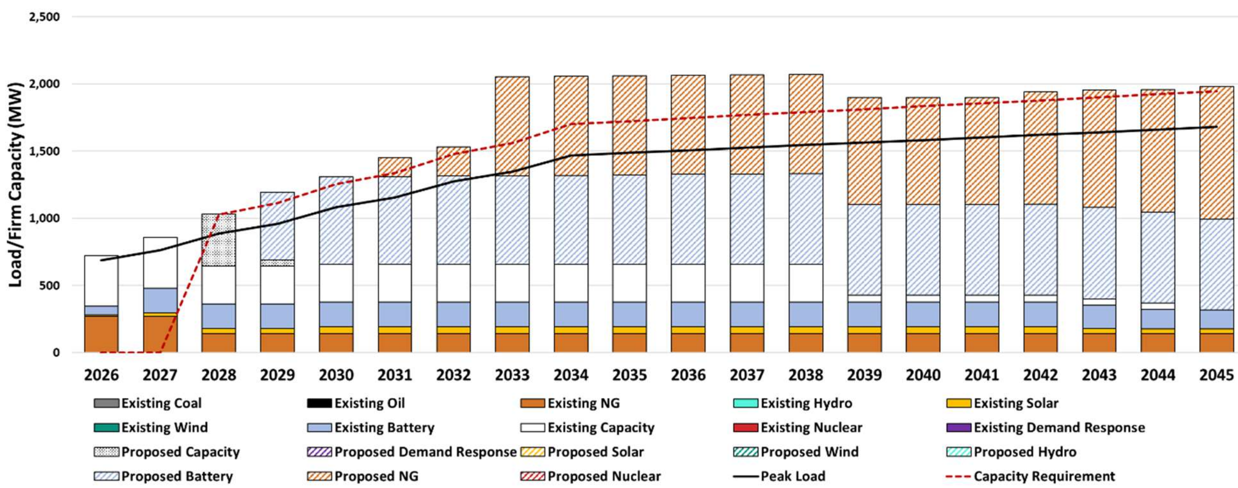


Figure 31. Large Load Addition with No Emission Limits Scenario - United Power Summer Load/Capacity Balance

7.2.9 High Natural Gas Price with No Emission Limits Scenario

With high natural gas prices for this study, NPV decreases to $3,245 million, a reduction of $29 million (0.9%) compared to the Base Case with No Emission Limits. The corresponding LCOE declines $50.40, a reduction of $0.44/MWh (0.9%).

Higher projected natural gas prices result in higher average power market prices and increased day-to-day price volatility. In response to these conditions, the model selects a resource portfolio with greater battery storage capacity, reduced natural gas-fired generation, and modest wind additions. The optimized portfolio adds 1,264 MW of battery storage, providing approximately 733 MW of accredited summer capacity, along with 25 MW of wind resources in 2045, providing approximately 5 MW of accredited summer capacity. Natural gas-fired generation decreases from approximately 645 MW in the Base Case with No Emission Limits to approximately 226 MW, providing approximately 210 MW of accredited summer capacity.

The addition of battery and wind resources allows the system to capitalize on elevated and more volatile market prices while reducing exposure to higher natural gas costs, resulting in lower overall portfolio costs than the Base Case with No Emission Limits.

Table 23 shows United Power's summer firm capacity by resource type for each year of the forecast period, and Table 24 provides the difference between the Base Case with No Emission Limits. Figure 32 shows the Summer Load and Capacity Balance for this scenario.

Table 23. High Natural Gas Price with No Emission Limits Scenario - United Power Summer Firm Capacity (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas	271	271	142	142	142	142	142	142	142	142	142	142	142	142	202	240	240	277	277	352
Nuclear																				
Hydro																				
Wind																				5
Solar	8	26	39	39	53	52	52	52	52	52	52	52	52	52	52	52	52	38	34	34
Battery Storage	67	183	183	449	480	507	540	570	598	628	883	883	883	883	883	883	883	888	875	875
Bilateral Capacity	380	380	515	285	280	280	280	280	280	280	280	280	280	50	50	50	50	50	50	
Demand Response																				
Total	**725**	**859**	**879**	**916**	**955**	**982**	**1015**	**1045**	**1073**	**1103**	**1358**	**1358**	**1358**	**1128**	**1187**	**1225**	**1225**	**1254**	**1236**	**1266**

Table 24. High Natural Gas Price with No Emission Limits Scenario - United Power Summer Firm Capacity Difference from Base Case (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas							-38	-38	-75	-75	-113	-113	-150	-375	-315	-315	-315	-315	-390	-390
Nuclear																				
Hydro																				
Wind																				5
Solar																				
Battery Storage				100			28	49	74	100	350	346	343	343	343	343	343	355	369	371
Bilateral Capacity				-90																
Demand Response																				
Total				**10**			**-10**	**11**	**-1**	**25**	**238**	**233**	**193**	**-32**	**28**	**28**	**28**	**40**	**-21**	**-14**

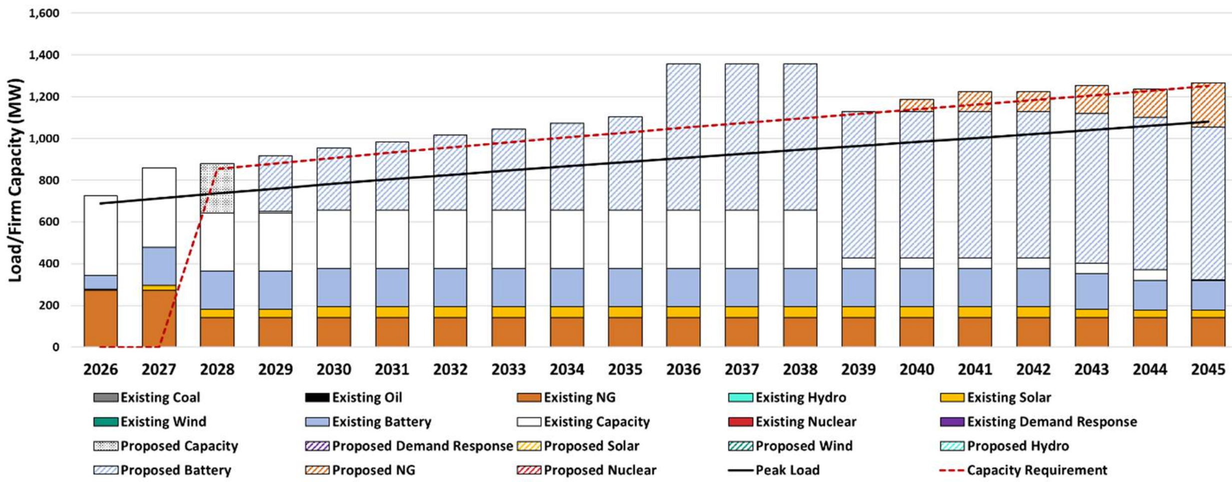


Figure 32. High Natural Gas Price with No Emission Limits Scenario - United Power Summer Load/Capacity Balance

7.2.10 Low Natural Gas Price with No Emission Limits Scenario

Under the Low Natural Gas Price with No Emission Limits scenario, NPV decreases to $3,017 million, a reduction of $258 million (7.8%) compared to the Base Case with No Emission Limits. The corresponding LCOE declines to $46.85/MWh, a reduction of $3.99/MWh (7.8%).

Lower projected natural gas prices also result in lower average power market prices throughout the study period. The resulting resource portfolio remains generally similar to the Base Case with No Emission Limits. The optimized portfolio adds 652 MW of battery storage, providing approximately 378 MW of accredited summer capacity. In addition, fifteen LM2500XPRESS natural gas-fired combined cycle units are added beginning in 2032 and continuing throughout the study period, providing approximately 605 MW of summer capacity and approximately 563 MW of accredited summer capacity. No wind additions are selected in this scenario.

With reduced fuel costs, natural gas-fired units operate more frequently and at higher capacity factors, improving operating margins across the system. These enhanced operating economics, combined with lower fuel expenses, contribute to the overall reduction in NPV and LCOE relative to the Base Case with No Emission Limits.

Table 25 shows United Power’s summer firm capacity by resource type for each year of the forecast period, and Table 26 provides the difference from the Base Case with No Emission Limits. Figure 33 shows the Summer Load and Capacity Balance for this scenario.

Table 25. Low Natural Gas Price with No Emission Limits Scenario - United Power Summer Firm Capacity (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas	271	271	142	142	142	142	180	180	217	217	255	255	292	518	518	555	555	593	630	705
Nuclear																				
Hydro																				
Wind																				
Solar	8	26	39	39	53	52	52	52	52	52	52	52	52	52	52	52	52	38	34	34
Battery Storage	67	183	183	199	480	507	512	521	524	528	533	538	540	540	540	540	540	533	520	520
Bilateral Capacity	380	380	515	525	280	280	280	280	280	280	280	280	280	50	50	50	50	50	50	
Demand Response																				
Total	**725**	**859**	**879**	**905**	**955**	**982**	**1024**	**1034**	**1073**	**1078**	**1120**	**1124**	**1164**	**1159**	**1159**	**1197**	**1197**	**1214**	**1234**	**1259**

Table 26. Low Natural Gas Price with No Emission Limits Scenario - United Power Summer Firm Capacity Difference from Base Case (MW)

Resource Type	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Coal																				
Natural Gas																			-38	-38
Nuclear																				
Hydro																				
Wind																				
Solar																				
Battery Storage				-151															14	16
Bilateral Capacity				150																
Demand Response																				
Total				**-1**															**-24**	**-21**

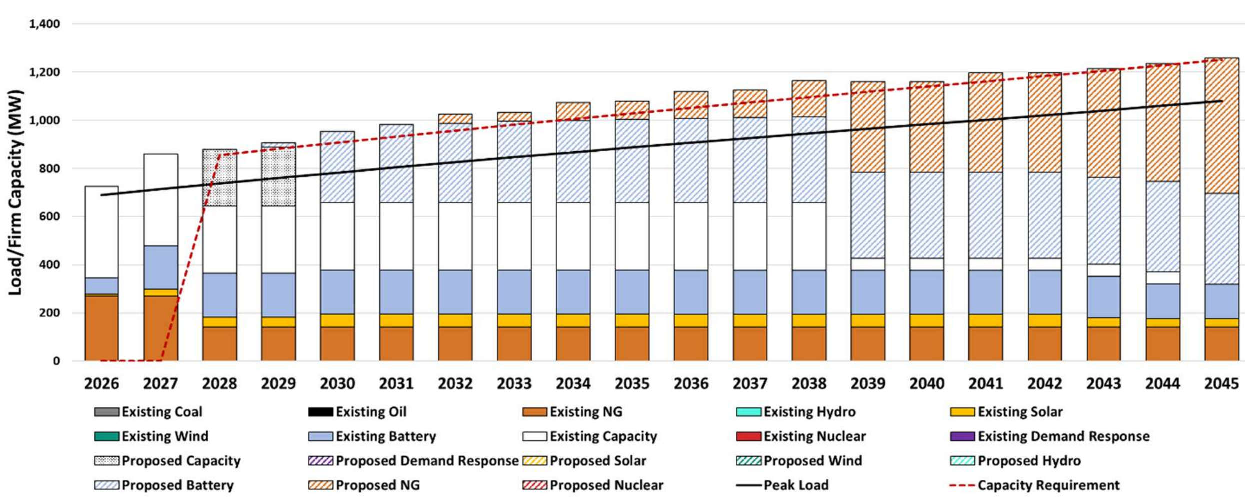


Figure 33. High Natural Gas Price with No Emission Limits Scenario - United Power Summer Load/Capacity Balance

7.3 Portfolio Comparison

7.3.1 Model Results

The resource portfolios selected under each scenario reflect differing responses to the underlying assumptions of those scenarios. However, there are notable commonalities in the types of capacity additions across the 10 modeled scenarios. This section compares these resulting portfolios based on technology selection, Net Present Value (NPV), and Levelized Cost of Energy (LCOE) for United Power's entire system.

7.3.2 Resource Additions Across Scenarios

Figure 34 illustrates the summer resource capacity additions selected by the model through 2045 by resource type including natural gas, battery storage, wind, solar, bilateral capacity, and nuclear generation. Because battery storage is the resource with the shortest development timeline, it is the first new resource type added beginning in 2029. Prior to that, bilateral capacity purchases serve as the primary short-term solution for meeting near-term capacity needs. Bilateral capacity was modelled only through 2030 and was not included in the following years of the study. For reference, the NPV for each scenario is also displayed on the right side of the chart and within each bar.

Figure 35 illustrates these same resource additions on a nameplate capacity basis, representing the maximum, full-load sustained output from each generating source under ideal conditions. Together, these figures demonstrate the difference between accredited capacity and nameplate capacity requirements. For example, wind resources, highlighted in green in both figures, require substantially greater nameplate capacity to satisfy planning reserve requirements because of the limited accreditation assigned under SPP rules. In the High Load scenario, for instance, approximately 83 MW of accredited wind capacity requires roughly 450 MW of installed nameplate wind capacity.

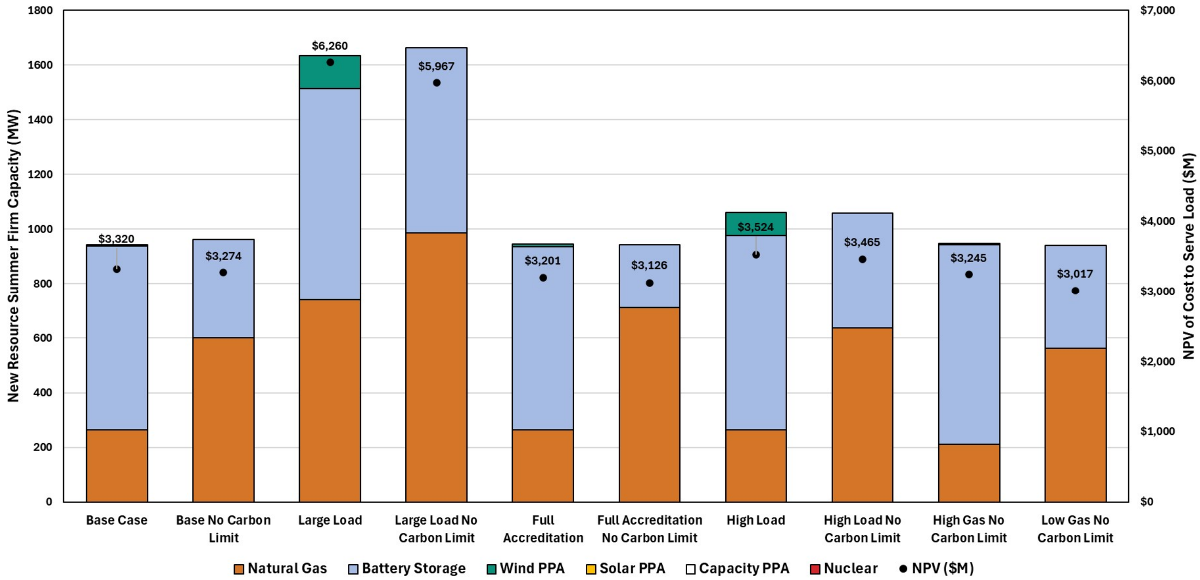


Figure 34. Comparison of Resource Capacity Additions Through 2045

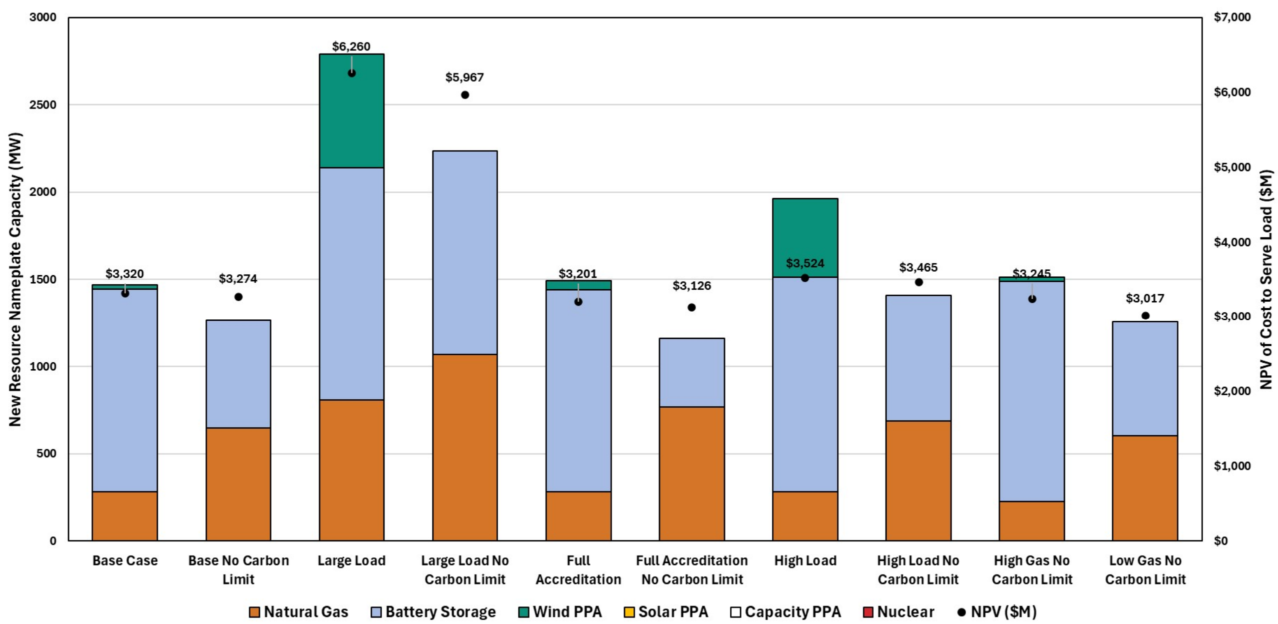


Figure 35. Comparison of Resource Nameplate Additions Through 2045

Across all scenarios, bilateral capacity is needed in the near term to address immediate reliability needs while varying amounts of batteries and natural gas resources are added throughout the study to meet projected load. In several scenarios, wind resources are also selected, however no scenarios result in the addition of solar or nuclear generation. In every scenario evaluated against a corresponding no emission limits case, additional nameplate resource capacity is required to comply with carbon emission reduction requirements.

The Base Case requires a total of 1,471 MW of additional nameplate resources across the entire study comprised of 282 MW of natural gas, 1,164 MW of batteries, and 25 MW of wind resulting in a NPV of $3,320 million. In comparison, the Base Case with No Emission Limits requires a lower total of 1,287 MW of nameplate capacity with a shift to more natural gas reliance, including 645 MW of natural gas capacity and a reduction in batteries to 642 MW. No wind additions are selected and the NPV drops to $3,274 million, a difference of $46 million (1.4%) below the Base Case.

The Large Load Addition and Large Load Addition with No Emission Limits scenarios require the greatest total resource additions of 2,791 MW and 2,268 MW of nameplate capacity, respectively. Compared to the Base Case and the Base Case with No Emission Limits, this is an increase of 1,320 and 951 MW, respectively. Conversely, the scenario with the lowest addition of resources is the Full Accreditation with No Emission Limits at 1,162 MW of nameplate capacity.

7.3.3 Financial Outcomes

Table 27 summarizes the NPV and LCOE results for each scenario providing a comparative financial assessment of the optimized resource portfolios. NPV reflects the total system cost for the entire study, while LCOE normalizes those costs on a per unit of energy served basis allowing for a more consistent comparison across scenarios with differing load trajectories.

The total NPV costs across all scenarios range from $3,017 million in the Low Natural Gas Cost with No Emission Limits scenario to $6,260 million in the Large Load Addition scenario, a spread of $3,243 million. As expected, scenarios characterized by higher load growth, significant load additions, or elevated natural gas prices generally result in higher total system costs. In addition, comparisons between corresponding cases with and without carbon reduction requirements indicate that compliance with the carbon reduction target increases overall portfolio costs, although the magnitude of the impact varies by scenario.

LCOE, which normalizes total costs by energy served, shows a similar relationship across the scenarios as compared to NPV. LCOE values range from $46.85 in the Low Natural Gas Price scenario to $55.95/MWh in the Large Load Addition scenario. Scenarios evaluated without carbon emission limitations consistently produce lower LCOE values than their corresponding emission constrained cases, further illustrating the additional cost associated with meeting emission reduction requirements.

Table 27. Comparison of NPV and LCOE by Scenario with Resource Additions

	Resource Plan Cost				Summer Nameplate Added as of 2045 (MW)			
Scenario	Net Present Value (Millions $)	Difference from Base Case* (Millions $)	Difference from Base Case* (Percent)	Levelized Cost of Energy ($/MWh)	Total	Natural Gas	Battery Storage	Wind PPA
Base Case	$3,320	$0	0.0%	$51.56	1,471	282	1,164	25
Large Load	$6,260	$2,939	88.5%	$55.95	2,791	809	1,332	650
Full Accreditation	$3,201	-$119	-3.6%	$49.71	1,492	282	1,160	50
High Load	$3,524	$204	6.1%	$52.38	1,964	282	1,232	450
Base Case No Carbon Limit	$3,274	-$46	-1.4%	$50.85	1,269	645	624	0
Large Load No Carbon Limit	$5,967	$2,693	82.2%	$53.35	2,238	1,070	1,168	0
Full Accreditation No Carbon Limit	$3,126	-$148	-4.5%	$48.55	1,162	766	396	0
High Load No Carbon Limit	$3,465	$191	5.8%	$51.51	1,409	685	724	0
High Gas No Carbon Limit	$3,245	-$29	-0.9%	$50.40	1,515	226	1,264	25
Low Gas No Carbon Limit	$3,017	-$258	-7.9%	$46.85	1,249	605	644	0

* Scenarios with Carbon Limits compared to the Base Case (Large Load, Full Accreditation, and High Load); scenarios with No Carbon Limit compared to the Base Case No Carbon Limit

Section 8 Conclusions

The IRP analysis highlights the importance of maintaining a flexible, reliable, and cost-effective approach to resource planning as United Power continues to experience significant load growth and increasing exposure to wholesale market volatility. While each scenario tested different assumptions regarding load growth, carbon regulations, resource accreditation, and market conditions, several consistent themes emerged:

Key Portfolio Insights

- **Load growth is the most significant driver of future resource needs.** United Power's service territory is projected to experience sustained growth throughout the planning horizon. Scenarios evaluating higher load growth and large new member additions require additional battery storage, wind resources, and natural gas-fired generation. These results underscore the importance of continuously monitoring load forecast trends and maintaining flexibility to accelerate resource development when necessary.
- **Near-term bilateral capacity is a critical bridge strategy.** Across all scenarios, bilateral capacity purchases are needed in the near term to help satisfy resource adequacy requirements until new resources can be developed and placed into service. Maintaining access to bilateral capacity supports reliability, preserves planning flexibility, and can defer more capital-intensive resource

investments while allowing additional time to assess load growth, market conditions, and future resource needs.

- **Battery storage plays a central role in future resource development.** Battery storage is selected in all scenarios and consistently represents one of the larger categories of future resource additions. The analysis demonstrates that battery storage provides a flexible means of meeting capacity needs while supporting system reliability and managing exposure to wholesale market volatility.

- **Natural gas-fired generation remains an important long-term reliability resource.** Natural gas-fired generation is selected in all scenarios and provides dispatchable capacity needed to maintain resource adequacy and reliability during periods of extended system stress. The amount of natural gas development varies significantly across scenarios, with substantially larger additions selected when carbon reduction requirements are relaxed. These results highlight the continued importance of natural gas as a source of firm capacity within United Power's future resource portfolio.

- **Carbon reduction requirements materially influence resource selection.** The analysis demonstrates that emission constraints affect both the timing and composition of future resource additions. Scenarios that relax carbon reduction requirements favor increased natural gas development and reduced battery storage and wind additions, while scenarios that include carbon reduction requirements require greater investment in battery storage and wind resources. These results highlight the significant influence that future carbon policies may have on portfolio composition and long-term system costs.

- **Resource accreditation assumptions can materially affect portfolio costs, timing, and resource selection.** Changes in accredited capacity assumptions influenced the quantity, timing, and mix of future resources needed to satisfy reserve margin requirements. As accreditation methodologies continue to evolve throughout the Western Interconnection, United Power will actively monitor these developments and periodically reassess future resource requirements.

- **Maintaining resource diversity reduces risk and improves long-term flexibility.** Although battery storage and natural gas generation consistently form the foundation of future resource portfolios, no single resource type provides the preferred solution under all future conditions evaluated in the IRP. Portfolios that combine storage, natural gas generation, wind resources, market purchases, and bilateral capacity agreements provide greater resilience against uncertainty in fuel prices, market conditions, carbon policies, resource adequacy requirements, and technology costs.

- **Long resource development timelines require proactive planning.** New battery storage and natural gas resources require several years for planning, permitting, procurement, and construction before they can be placed into service. Maintaining optionality across multiple resource pathways and initiating development activities early will improve United Power's ability to respond to changing market conditions, evolving reliability requirements, and future load uncertainty.

- **Maintaining planning flexibility is essential.** Given the uncertainty associated with future member growth, large member additions, market conditions, and evolving reliability requirements, United Power will continue to evaluate resource needs on a regular basis and update its plans as conditions change.

Overall, the IRP results indicate that a balanced strategy emphasizing battery storage, natural gas-fired generation, selective wind development where economic and operational conditions support it, and continued use of bilateral capacity and market purchases provides a practical framework for maintaining affordability, reliability, and flexibility. This diversified approach positions United Power to support continued member growth while maintaining the flexibility needed to adapt to changing market, regulatory, and operational conditions.

Section 9 Action Plan

United Power's action plan focuses on maintaining reliability while preserving flexibility to respond to rapid load growth, changing market conditions, evolving resource adequacy requirements, and future regulatory uncertainty. The IRP results indicate that battery storage, natural gas-fired generation, bilateral capacity purchases, and selective wind development are key components of United Power's future resource strategy. Accordingly, United Power should pursue the following:

- **Advance Battery Storage Development.** Battery storage emerged as a central component of future resource portfolios across all scenarios and should remain a primary focus of near-term resource planning efforts. United Power should continue evaluating utility-scale battery storage projects under a variety of ownership, contract, and commercial structures, with particular attention to projects capable of providing accredited capacity under applicable resource adequacy frameworks.
- **Secure Near-Term Bilateral Capacity Options.** Bilateral capacity purchases are needed in the near term to satisfy resource adequacy requirements until new resources can be developed and placed into service. United Power should continue evaluating short-term and long-term bilateral arrangements, capacity products, and market opportunities that support reliability, preserve planning flexibility, and reduce exposure to resource development delays and changing market conditions.
- **Explore Firming Up Capacity for Existing Units (Brush 2/4).** United Power should evaluate the economic feasibility of obtaining transmission services necessary for Brush 2 and Brush 4 to qualify for capacity accreditation. Accrediting these existing resources could help satisfy future resource adequacy requirements and reduce future capacity needs.
- **Prepare for Future Natural Gas-Fired Generation.** The IRP demonstrates that dispatchable natural gas-fired generation remains an important long-term reliability resource and is selected in all scenarios evaluated in this study. Given increasing equipment lead times, supply chain constraints, and development timelines, United Power should begin evaluating potential procurement pathways for future natural gas-fired generation, including ownership, partnership, and contractual structures. Activities may include identifying potential sites, assessing transmission and fuel supply requirements, engaging with developers and equipment suppliers, evaluating future solicitation opportunities, and assessing whether early participation in equipment procurement queues, development partnerships, or other reservation mechanisms is warranted. Maintaining these development options will improve United Power's ability to respond to future reliability requirements, market conditions, and load growth.
- **Monitor Load Growth and Large Member Development.** Load growth is the most significant driver of future resource requirements. United Power should regularly update its load forecast to reflect changing economic conditions, electrification trends, distributed energy resource

adoption, and the potential addition of large commercial and industrial members. The timing and magnitude of large-load member additions can significantly affect future capacity requirements and resource acquisition schedules and should be incorporated into ongoing planning efforts. Resource planning assumptions should be updated periodically to ensure future resource decisions remain aligned with actual system needs.

- **Monitor Carbon Policy and Regulatory Developments.** The IRP results demonstrate that carbon reduction requirements can materially influence future resource selection, portfolio costs, and long-term planning decisions. United Power should continue monitoring federal, state, and regional policy developments, including emission regulations, clean energy requirements, and incentive programs. Future resource decisions should maintain sufficient flexibility to adapt to changing policy requirements while preserving reliability and affordability.
- **Track Resource Accreditation and Resource Adequacy Changes.** Resource accreditation assumptions materially affect future capacity requirements and resource selection. United Power should actively monitor developments related to SPP RTOE resource adequacy requirements, accreditation methodologies, and WRAP framework. Periodic reassessment of accreditation assumptions will help ensure future resource plans remain aligned with evolving reliability requirements.
- **Maintain a Diversified Resource Portfolio.** While battery storage and natural gas-fired generation consistently form the foundation of future resource portfolios, the optimal resource mix varies across planning scenarios. United Power should continue pursuing a diversified resource strategy that balances battery storage, natural gas-fired generation, wind resources, bilateral capacity purchases, and market transactions. Maintaining multiple resource pathways improves flexibility and reduces exposure to fuel price volatility, technology risk, regulatory uncertainty, and changing market conditions.
- **Update the IRP Regularly.** Given the uncertainty associated with future load growth, large member development, market conditions, resource adequacy requirements, and regulatory policies, United Power should periodically update its Integrated Resource Plan to reflect changing assumptions and emerging developments. Regular updates will help ensure future resource decisions remain aligned with the cooperative's reliability, affordability, and flexibility objectives.

By following this action plan, United Power can maintain reliable service while preserving the flexibility needed to respond to future uncertainty. Continued monitoring of load growth, market conditions, resource adequacy requirements, regulatory developments, and emerging technologies will position the cooperative to make informed resource decisions and maintain a reliable, resilient, and adaptable power supply portfolio capable of supporting continued member growth.