



2026 Integrated Resource Plan



FOREWORD

Building Greater Energy Independence for Our Communities

Energy providers have a responsibility to look ahead clearly and carefully so we can deliver the safe, reliable and affordable power our communities will need. That requires balancing system reliability with evolving realities, including changing weather, affordability pressures and increasing demand across the Desert Southwest.

UNS Electric's 2026 Integrated Resource Plan (IRP) outlines how we will meet our customers' energy needs over the next 15 years while remaining focused on reliability and affordability. At the same time, it advances an important objective for our company and the communities we serve: increasing our energy independence by developing more of the resources needed to meet our customers' needs.

Today, approximately half of the energy we deliver to customers is purchased through regional markets. Those markets provide important benefits, but growing demand across the West, increasing resource adequacy concerns, and rising power costs highlight the value of developing additional resources that we can depend on directly. By investing in a more balanced portfolio of generation and storage resources, we can strengthen reliability, reduce exposure to market volatility and better control long-term costs for customers.

This technology-neutral preferred portfolio emerged from a transparent evaluation of multiple resource options, informed by community input, stakeholder engagement and extensive modeling. After examining a range of possible futures, we selected a portfolio that meets projected energy needs at the lowest overall cost while maintaining reliability and limiting environmental impacts. Our analysis found that this portfolio performs better and at lower cost than alternatives that rely exclusively on renewable resources and storage.

The plan calls for significant investment in resources that will serve our customers for decades to come through the addition of more than 500 MW of generating capacity. It includes 321 megawatts of new natural gas generation, 190 megawatts of new solar resources and 190 megawatts of energy storage, representing UniSource's first utility-scale battery storage resources. Together, these additions more than double the capacity of our existing production resources and provide a stronger foundation for meeting future energy needs close to home.

In the near term, the IRP reflects decisions already underway, advancing projects that will help us serve growing communities in both northern and southern Arizona while enhancing the resiliency of our system.

While there is significant discussion about future growth opportunities, including data centers, mining operations and other large customers, we have developed a resource strategy based on demonstrated needs and realistic assumptions while preserving the flexibility to adapt as conditions evolve. That flexibility will remain equally important as technologies advance and customer needs change. We are particularly encouraged by the long-term potential of technologies such as advanced geothermal, long-duration energy storage and advanced nuclear energy, which could play a larger role in future resource plans.

We appreciate the contributions of our Resource Planning Advisory Council, whose members represent residential customers, businesses, advocacy organizations and other stakeholders. Their thoughtful engagement throughout this process provided valuable insight into the priorities and expectations of the communities we serve and helped ensure that this plan reflects more than a utility perspective alone.

Our customers expect energy that is safe, reliable, affordable and responsible for future generations. By increasing our energy independence while maintaining a balanced approach, this plan puts us on a path toward meeting those expectations and serving our communities well into the future.

Susan Gray

Chief Executive Officer



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SECTION 1

EXECUTIVE SUMMARY

UNS Electric's (UNSE's) 2026 Integrated Resource Plan (IRP) describes how the company anticipates meeting customers' energy needs reliably and affordably over the next 15 years. The plan considers increasing regional demand, uncertainties about the availability and cost of wholesale power, potential need for new energy infrastructure from large-load customers, and other changing market conditions. Changes in federal tax incentives, environmental requirements and technology costs have altered the relative economics of available resources.

UNSE incorporated these changes into updated load forecasts, resource-cost assumptions and reliability analyses. After evaluating seven potential resource portfolios, UNSE has selected the Least-Cost, Technology Neutral (LCTN) portfolio to serve projected customer needs through 2041. This portfolio offers the best balance of UNSE's core planning principles: reliability, affordability and sustainability.

A balanced, diversified resource strategy

UNSE's preferred portfolio would add 321 MW of new natural gas capacity, 190 MW of solar generation and 190 MW of battery storage during the planning period. Solar and storage additions are expected to be developed together, allowing solar energy produced during the day to be stored for later use during periods of higher customer demand.

This diversified portfolio reduces reliance on market power while adding flexible new resources that can respond to changing conditions. Some resources in the preferred portfolio are already under development, including Dandelion Energy Park, which adds 140 MW of solar paired with 140 MW four-hour battery storage system beginning in 2028, and the Black Mountain Expansion Project, which adds 196 MW of natural gas combustion-turbine capacity in 2030.

These investments would improve UNSE's ability to meet growing demand, reduce exposure to volatile wholesale energy markets and maintain reliable service during extreme heat and other periods of system stress.

Maintaining Reliability

Reliable electric service is the foundation of UNSE's resource strategy. Every portfolio evaluated in the IRP was required to satisfy an 18 percent Planning Reserve Margin and an industry-standard loss-of-load expectation of no more than one day in 10 years. The updated reserve margin, increased from 16.5 percent in the 2023 IRP, reflects additional analysis of generator outages, weather variability, forecast demand and operating reserve requirements. UNSE also applied updated capacity values to solar, wind and storage resources to reflect how much dependable capacity they can provide to satisfy customers' peak energy demands.

UNSE's modeling confirms the value in creating a diverse resource portfolio. Solar provides low-cost energy during daylight hours, while batteries can shift that energy into higher-demand periods. Flexible natural gas resources can respond quickly and provide sustained output when renewable production is limited or stored energy has been depleted. The preferred portfolio improves reliability while allowing renewable generation and battery storage to serve an increasing share of customer needs.

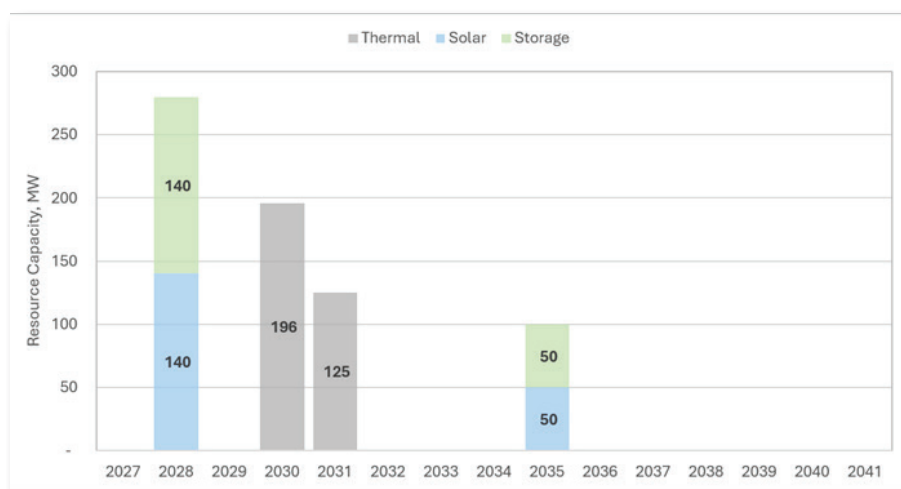
Affordability for Customers

Affordability is considered throughout the IRP, from portfolio design and competitive resource solicitations to participation in regional energy markets and customer energy-efficiency programs.

UNSE's preferred model provides the lowest-cost option evaluated for the base-load forecast. It is expected to cost \$40 million to \$225 million less in cumulative capital investment costs than other portfolios considered while reducing net present value revenue requirements by approximately \$25 million to \$140 million.

UNSE will continue using all-source requests for proposals to identify potential projects with cost, performance and delivery characteristics that meet or exceed resource assumptions in the IRP. Participation in real-time and day-ahead regional markets also can help UNSE obtain cleaner, lower-cost energy and use its generating resources more efficiently.

Figure 1.1 - Preferred Portfolio Capacity Additions by Year



Expanding Resources with Energy Storage

Although the preferred portfolio was not designed around a specific emissions-reduction mandate, the least-cost analysis selected a diverse mix that includes new solar and energy storage resources.

UNSE considered solar, wind, storage, geothermal, nuclear, and natural gas resources while developing potential portfolios. New renewable generation and storage, alongside efficient and flexible natural gas resources, supports reliable service while improving the environmental performance of the energy supply. UNSE will continue evaluating emerging technologies, including longer-duration storage, enhanced geothermal and advanced nuclear generation, as their costs and commercial readiness evolve.

Preparing responsibly for future growth

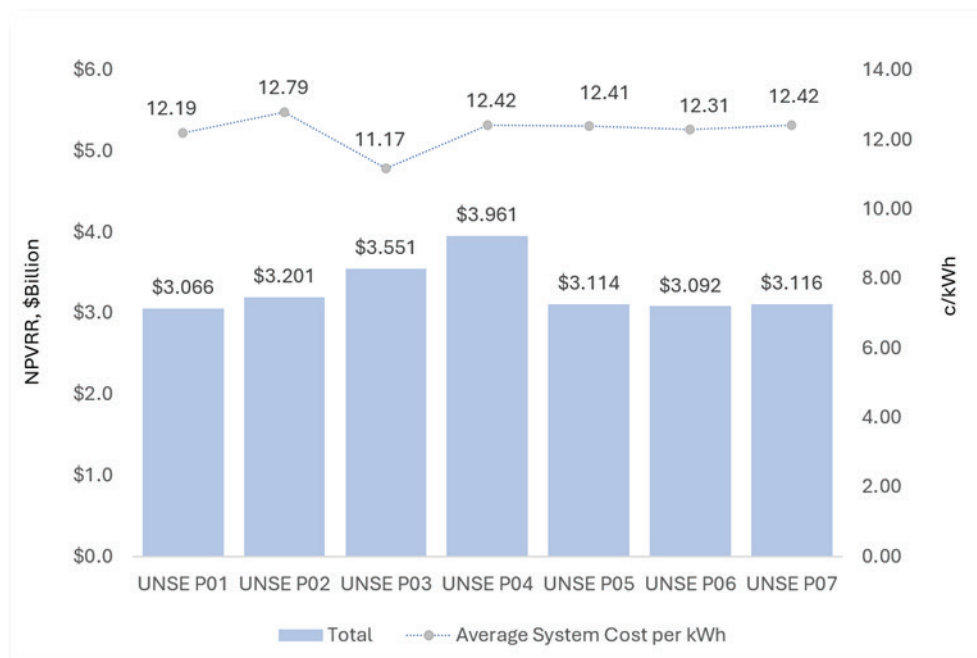
The 2026 IRP considers the potential for adding large, energy-intensive customers including mining, data center, industrial, and manufacturing facilities. UNSE's guiding principle is that growth should pay for growth. New customers must appropriately support the generation, transmission and other infrastructure required to serve them, without transferring unreasonable costs or risks to existing customers.

UNSE uses a disciplined, case-by-case process before incorporating them into its official load forecast. Prospective customers are included only after reaching an advanced stage of development or providing sufficient contractual certainty that their demand is likely to materialize. UNSE also requires interconnection studies to determine potential effects on the local and regional transmission system and to identify any facilities needed to serve the new load.

To evaluate the potential impacts, UNSE modeled two dedicated scenarios. Portfolio P03 adds 150 MW of high-load-factor demand beginning in 2030 and allows the model to choose from all available technologies. It called for an additional 125 MW of natural gas, 50 MW of solar and 100 MW of storage relative to the preferred portfolio. P03 offered the lowest modeled average system cost per kilowatt-hour among the seven portfolios, although its total resource requirements and revenue requirements were higher.

Portfolio P04 assumes the same additional energy demand but limits new selections to carbon-free resources. It required a substantially larger solar and storage buildout, along with advanced nuclear capacity.

Figure 1.2 – NPVRR by Portfolio



The modeling demonstrates that large-load growth would require significant new infrastructure and increase total system investment. It also shows that customers with high and steady electricity use can spread fixed system costs across a larger volume of energy, which could promote bill savings for other customers. Through early engagement, interconnection studies, conservative forecasting, competitive resource procurement and careful investment decisions, UNSE is prepared to support beneficial economic development while protecting reliability and affordability for the customers it serves today.

Conclusion

The 2026 IRP is a flexible, forward-looking plan based on current assumptions, not a set of rigid directives. UNSE will continue monitoring load growth, market conditions, policy developments, and emerging technologies, and will communicate significant updates to the Arizona Corporation Commission. This balanced approach positions UNSE to meet current customer needs, accommodate responsible growth and build a more reliable, affordable and sustainable energy future.

SECTION 2

A CHANGING ENERGY LANDSCAPE

2.1. UNSE's Near-Term Economic Development Opportunities

UNS Electric's (UNSE) role in supporting regional economic development is guided by a core commitment to reliable and affordable service for existing customers, while responsibly supporting new growth. Economic expansion in Northern and Southern Arizona is being driven by accelerating trends in digitalization, electrification, decarbonization, and resilience. These trends are increasing demand for electricity while elevating expectations around grid performance, sustainability, and long-term cost certainty. UNSE's ability to balance opportunity with affordability and prudent risk management will be critical to long-term success.

Arizona continues to benefit from a diverse economic base. Economic development pipelines are expanding, with both a growing number of projects and increasing project scale.

Prospective development is increasingly larger and more energy-intensive. Large-scale projects with potential demand above 100 megawatts, such as data centers, are emerging more frequently. Many customers seek high reliability, fast delivery, long-term cost predictability, and pathways to lower-carbon or carbon-free energy. If realized, these projects will materially affect UNSE's load forecasts, resource planning, and infrastructure investment requirements.

Capturing opportunity and supporting this growth presents significant challenges. Future development will require consensus around new and evolving generation resources, timely shared investment in major transmission and substation infrastructure, and sustained coordination across planning, permitting, and regulatory processes.

Equally important is strong alignment around regional strategic priorities and infrastructure development, including efforts by the Arizona Governor's Energy Promise Task Force, the Arizona Commerce Authority, Mohave and Santa Cruz counties, and support from regional economic development organizations such as the chambers of commerce. These efforts underscore the importance of coordinated decision-making among utilities, municipalities, counties, state agencies, water providers, and economic development organizations.

A foundational principle for UNSE during this period is that growth will pay for growth. New customers and incremental load must appropriately support the generation, transmission, and other infrastructure required to serve them. Economic development should proceed without shifting costs or risks to existing customers, and without compromising affordability or reliability system-wide.

Through early engagement, disciplined evaluation of system impacts, transparent coordination, and alignment with regulatory and community expectations, UNSE is positioned to support economic development that strengthens the region while protecting existing customers and advancing long-term community prosperity.



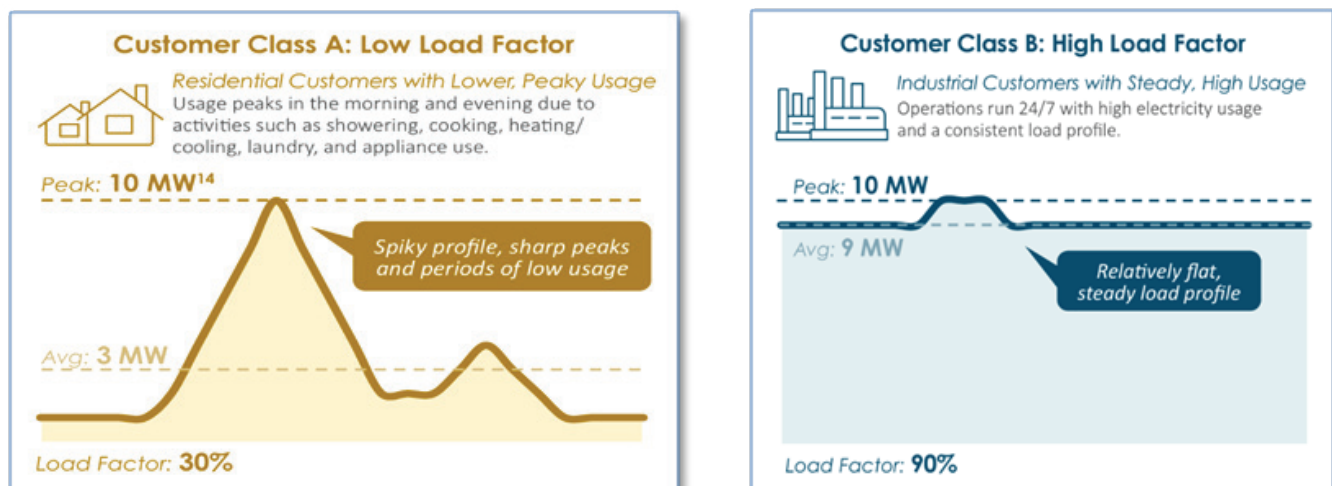
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2.1.1. High Load Factor Customers

Utilities across the country have seen a proliferation in service requests by extra-high load factor (XHLF) customers. While there is no uniform industry definition for these customers, they are typically defined by the higher magnitudes of their proposed power usage and load factor.

In E3's June 2026 report, "Beyond the Headlines: An Empirical Analysis of Data Center Grid Utilization, Cost-of-Service and Revenue Contributions," load factor is described as "a measure of how efficiently electricity capacity is used. It is defined as the ratio of the average demand to the peak demand over a given period (e.g. a month or year). In other words, load factor indicates how steadily electricity is used relative to the customer's max demand."¹ **Figure 2.1** below shows a typical hourly load shape for a group of average residential customers, compared to a typical large load customer.

Figure 2.1: Residential vs. Large Load Customer Load Factor²



XHLF customers include many types of industrial and commercial usage, including data centers, mining facilities, and different types of manufacturing and processing plants.³ In recent years, Arizona utilities have also reported an increase in requests from XHLF customers.^{4,5} Between 2025 and 2026, UNSE received inquiries from potential XHLF customers whose combined capacity needs exceeds 4,000 MW.

UNSE requires interconnection studies before large customers may interconnect to the distribution or transmission system. Transmission interconnection studies evaluate new customers' impacts on the local and remote transmission system, including whether new transmission facilities are needed. UNSE's resource capacity to serve the load is evaluated in concert with its ability to deliver the energy to the customer.

¹ Energy and Environmental Economics, Inc. (E3), Beyond the Headlines: An Empirical Analysis of Data Center Grid Utilization, Cost-of-Service and Revenue Contributions (June 2026), 4, [Beyond the Headlines](#).

² E3, Beyond the Headlines, 13.

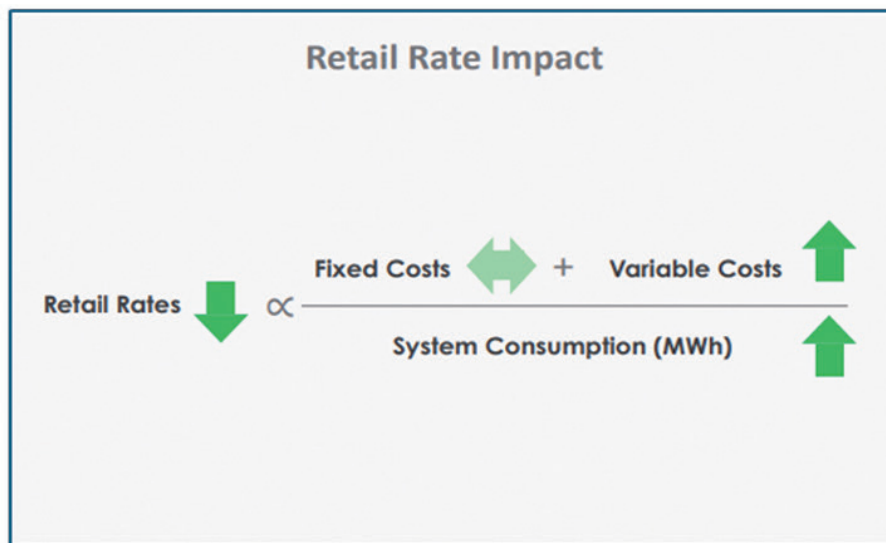
³ North American Electric Reliability Corporation (NERC), Characteristics and Risks of Emerging Large Loads: Large Loads Task Force White Paper (July 2025), 8, [Characteristics and Risks of Emerging Large Loads](#).

⁴ Arizona Public Service, "APS Uses 'Growth Pays For Growth' Model to Develop New Natural Gas Plant" (October 30, 2025), [APS Uses 'Growth Pays For Growth' Model to Develop New Natural Gas Plant](#).

⁵ Salt River Project (SRP), "Data Centers and SRP" (2026), [Data Centers and SRP](#).

While there has been public concern over the effect of XHLF customers on customer rates, XHLF customers can provide system benefits by sharing existing system costs and helping to offset the costs of necessary grid upgrades.⁶ Increased power consumption spreads system costs over a larger volume of energy which drives down the average cost of energy system-wide. **Figure 2.2** illustrates this relationship.⁷

Figure 2.2 – Retail Rate Impact



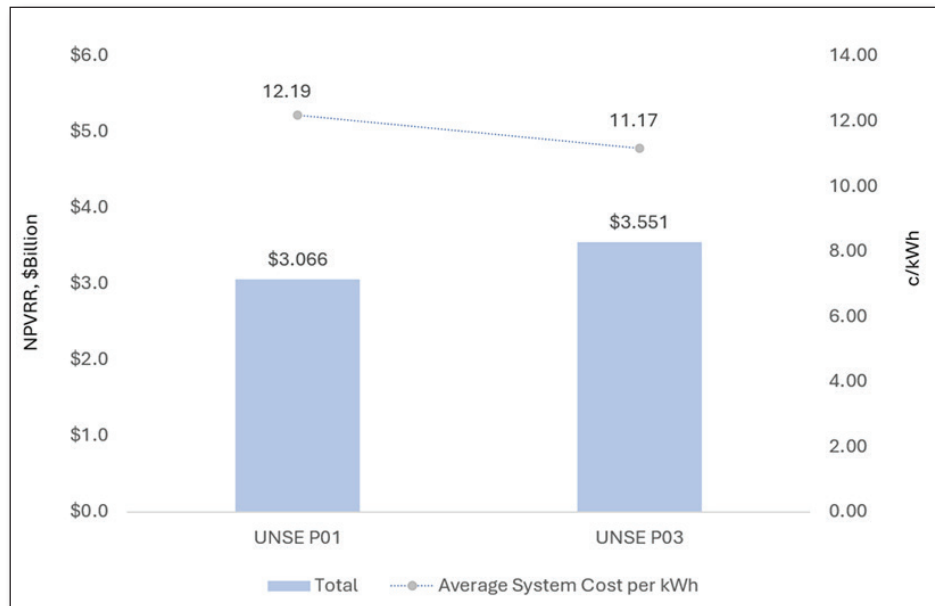
⁶ Energy and Environmental Economics, Inc. (E3), Tailored for Scale: Designing Electric Rates and Tariffs for Large Loads: A Guidebook of Industry Best Practices and Examples from Real-World Amazon Data Center Case Studies (December 2025), 7, [Ratepayer Study](#).

⁷ E3, Beyond the Headlines, 17.

This is demonstrated between UNSE portfolios P01 – Least-Cost, Technology Neutral and P03 – High Load Factor Customer Growth. These two portfolios contain the same inputs, assumptions, and constraints with the exception of the load forecast. P01 assumes a typical UNSE retail load increase over the fifteen-year study period (see section 4.2.1 for more on UNSE’s load forecast). P03 takes the P01 load forecast and adds 150 MW of generic high load-factor load beginning in 2030. The P03 portfolio requires the development of additional resources to supply the additional capacity and energy needed to adequately serve the new load, but the average system cost per kWh to serve all customers across the portfolio is lower than that of P01. This demonstrates how a portfolio with a higher load forecast and higher quantity of new resources can result in lower average energy costs for all customers.

This demonstrates how a portfolio with a higher load forecast and higher quantity of new resources can result in lower average energy costs for all customers.

Figure 2.3 - Portfolio NPVRR vs Average System Cost per kWh



2.2. Resource Adequacy and Reliability

The chief purpose of the Integrated Resource Plan is to outline resource portfolios that address multiple possible futures, such as different load forecasts and different resource mixes. The characteristic that all these portfolios must have in common is resource adequacy (RA). Resource adequacy is the ability of a utility to meet system demand and required reserves under varying system conditions. Meeting RA requirements positions the utility to be able to respond to meet its customers’ needs under real-time operating conditions (see Appendix I for more information on real-time operations and reliability standards).

Until recent years, utilities could typically evaluate resource adequacy based on capacity to meet net peak demand. Resource portfolios built primarily or entirely on thermal resources that were able to provide energy on-demand meant that the ability to serve peak demand implied the ability to meet load at any other time of year or hour of the day. Since the addition of intermittent resources, such as solar and wind, as well as energy-limited resources, such as lithium-ion batteries (i.e. Battery Energy Storage Systems, or BESS), resource adequacy has become increasingly complex.

To ensure resource adequacy, power providers rely on a capacity margin, called the Planning Reserve Margin (PRM), which is the required amount of capacity above expected peak loads that will enable them to meet customers' power needs. This additional capacity is available in case the load exceeds the forecast, or there are plant or transmission outages that prevent the delivery of energy to the service territory.



A newer consideration when evaluating resources against the PRM is their accreditation value, usually called Effective Load-Carrying Capability (ELCC). Each type of resource, whether thermal, intermittent, or energy-limited, is evaluated within the system it serves and assigned a capacity value which can be applied to meet the PRM. ELCCs are dependent on a utility system's load characteristics and historical weather patterns, as well as quantities and types of generation. As variables within each utility's system change, so may the ELCCs for each resource type. This results in resource accreditation which is much more dynamic than when most resources across the grid had uniform operational characteristics.

Another aspect of resource adequacy is the loss of load expectation, or LOLE. Utilities design RA requirements and portfolios around meeting a 1-day-in-10-year LOLE. ELCC and PRM studies that model LOLE over long time frames are able to identify which hours of the day, and during which months of the year, loss of load events are most likely to occur. Utilities can then design portfolios with resources that are able to supply energy during those at-risk hours.

2.2.1. Regional Resource Adequacy Studies

In 2021, Energy & Environmental Economics, Inc. (E3) conducted a study of resource adequacy in the Desert Southwest. The study was conducted with input from Arizona Public Service Company (APS), Arizona Electric Power Cooperative (AEP), El Paso Electric Company (EPE), Public Service Company of New Mexico (PNM), Salt River Project (SRP), Tucson Electric Power Company (TEP), and UNS Electric, Inc. (UNSE) and focused primarily on evaluating load growth, resource retirements in the region, and the need for aggressive resource development against reliability. It also recognized that the resource plans developed at the time by the utilities resulted in regional resource adequacy over the following decade.⁸

⁸ Energy and Environmental Economics, Inc. (E3), Resource Adequacy in the Desert Southwest: Final Report (2022), 9, [Resource Adequacy in the Desert Southwest](#).

In 2025, the same group elected to have E3 refresh the 2021 study and conduct an independent assessment of regional resource adequacy.⁹ Each utility provided updated load forecasts and resource plans to E3, who then enacted a two-pronged approach to the study:

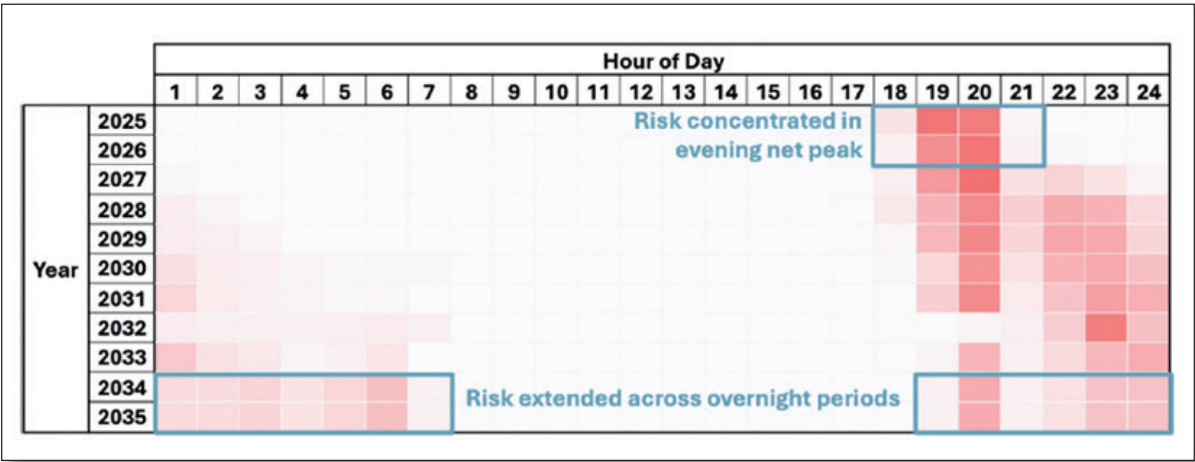
- A near-term, ten-year assessment to evaluate the loads and resources provided by participants and determine whether resource plans prove adequate, and
- A long-term, twenty-year assessment which constructed multiple future scenarios and developed multiple resource portfolios based on long-term capacity expansion (LTCE).

The near-term assessment used the criteria of the 1-day-in-10-year (0.1 days per year) LOLE and determined that utility plans result in a resource adequate system over the 2025 to 2035 study period.¹⁰ This, in concert with the original 2021 study, validates that “the utilities’ collective planning practices are effective in their identification of resource portfolios with the technical ability to maintain regional resource adequacy.”¹¹ However, the need for new resources is urgent, and the success of those resource plans is dependent on their swift implementation.

Another important result of the near-term study is the identification of shifts in reliability risks over the 10-year study period. As the Desert Southwest utilities continue to increase the amount of solar and BESS on the system, reliability challenges shift away from typical peak times, towards the evening and then into the overnight hours. This shift “increases the relative value of resources that can provide longer duration services to the grid... without limits on their use.”¹²

Figure 2.4 below from E3’s study illustrates the relative loss-of-load risk by hour of day over the 2025-2035 period.

Figure 2.4 – Relative Loss-of-Load risk¹³



⁹ Energy and Environmental Economics, Inc. (E3), 2025 Resource Adequacy Assessment: Desert Southwest (2025), [2025 Resource Adequacy Assessment](#).

¹⁰ E3, 2025 Resource Adequacy Assessment, 12.

¹¹ E3, 2025 Resource Adequacy Assessment, 17.

¹² E3, 2025 Resource Adequacy Assessment, 13.

¹³ E3, 2025 Resource Adequacy Assessment, 13.

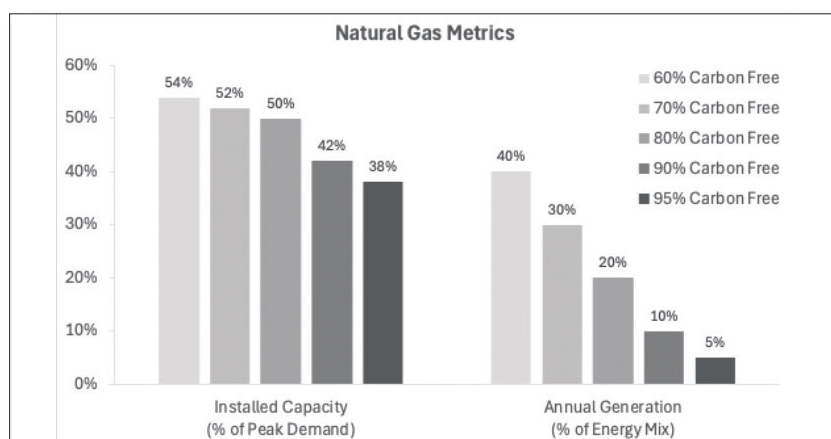
2.2.2. Resource Adequacy into the Future

The remaining key findings from the 2025 E3 study are results of the long-term analysis. For the long-term analysis, E3 developed multiple portfolios of varying levels of renewable penetration. Each portfolio was designed to meet the 1-day-in-10 LOLE requirement, and each includes some quantity of firm (gas and nuclear), renewable (wind and solar), and energy-limited (BESS) resources. Key findings include that “resource adequacy can be met with a wide range of resource mixes,”¹⁴ as portfolios between 60 to 95% carbon-free were studied and found to meet the LOLE requirement.

The long-term assessment also identified firm resources as critical to reliability, regardless of the quantity of renewable and energy-limited resources on the system. “In all long-term portfolios, nuclear and natural gas resources play a critical role in ensuring reliability when electric demand is high, renewable availability is low, and energy storage resources have been depleted...” Because gas resources are available around-the-clock and on demand, they are instrumental in providing reliability when the system experiences periods of low renewable output. The study notes that even as renewable penetration increases and the amount of energy served by natural gas resources drops, the installed capacity of gas resources needed does not decrease. In fact, even in the 95% renewable portfolio, the installed capacity of natural gas remains around 40% of the system peak to maintain resource adequacy and reliability.¹⁵

Figure 2.5 from E3’s RA study presents the key metrics for natural gas resources in the long-term adequacy assessment.

Figure 2.5 – Natural Gas Metrics¹⁶



The study finds that increasing the energy served by renewable resources drives down how often gas resources are run, but doesn't reduce how much flexible, firm capacity is needed to maintain reliability.

The study finds that increasing the energy served by renewable resources drives down how often gas resources are run, but doesn't reduce how much flexible, firm capacity is needed to maintain reliability. These results highlight that natural gas can act as a facilitator of regional plans to drive towards net-zero direct emissions.

¹⁴ E3, 2025 Resource Adequacy Assessment, 14

¹⁵ E3, 2025 Resource Adequacy Assessment, 11

¹⁶ E3, 2025 Resource Adequacy Assessment, 16

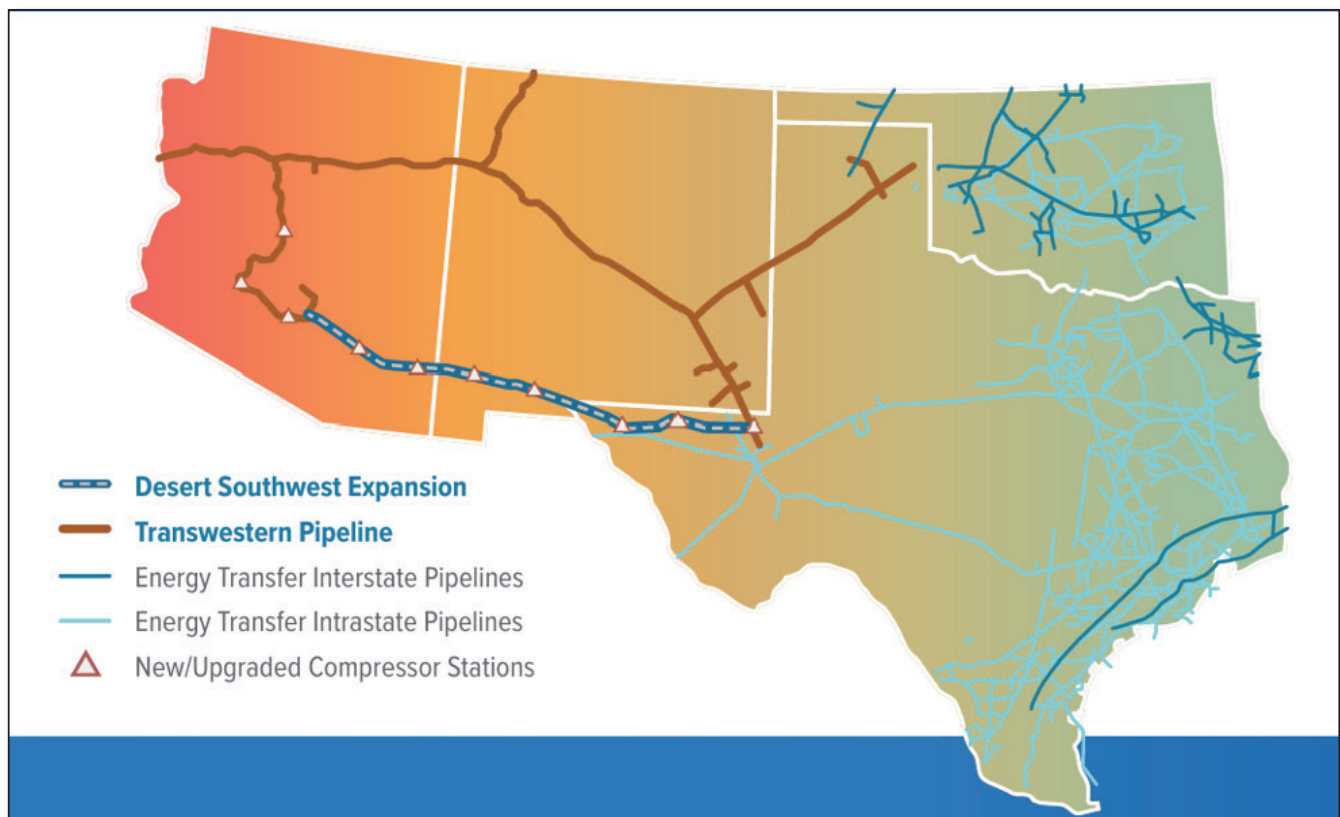
2.3. Desert Southwest Pipeline Expansion Project

Project Overview

In August 2025, Transwestern Pipeline Company announced plans to develop the Desert Southwest Pipeline Expansion project. This interstate pipeline project is intended to increase gas delivery from the Permian Basin into Arizona and New Mexico to support growing customer demand and electric grid reliability.

The Desert Southwest Expansion is planned to originate in Winkler County, Texas, and traverse approximately 520 miles through New Mexico and Arizona to an end point in Coolidge, Arizona. The 48-inch underground pipeline will be powered by new compressor stations strategically situated along the pipeline route to deliver up to 2.3 billion cubic feet per day of natural gas to customers in Texas, New Mexico and Arizona.¹⁷ Moreover, the Desert Southwest Expansion will make Transwestern's natural gas flows on the Phoenix Lateral bi-directional, adding flexibility to move natural gas in both directions based on customer needs.

Figure 2.6 – Desert Southwest Pipeline Expansion Proposed Route



¹⁷ <https://desertsouthwest.com/>

Arizona’s Demand for New Natural Gas

Today, Arizona’s existing natural gas pipelines are fully subscribed. The Desert Southwest Pipeline Expansion project will strengthen the Southwest’s energy backbone by increasing natural gas supply and enabling Arizona electric utilities to secure natural gas transportation to fuel new and existing generation facilities, enhancing grid reliability during periods of high demand.

Arizona Governor Katie Hobbs emphasized that the project is essential for reliable, affordable energy and long-term economic growth. “The Desert Southwest Pipeline will significantly increase our state’s energy capacity and diversify our energy resources. Arizona’s all-of-the-above energy strategy is ensuring we have the energy we need to expand our economy and deliver for working people in this state.”¹⁸ The Desert Southwest Pipeline Expansion project plays a critical role in supporting the Company’s plans to supply the Gila River and Black Mountain Generating Stations and expand natural gas generation resources for UNSE.

Project Timeline

The four-year project has an estimated construction start date in the second quarter of 2028, resulting in an expected in-service date of the fourth quarter of 2029.

Figure 2.7 – Desert Southwest Pipeline Expansion Project Timeline



UNSE’s Need for New Natural Gas Resources

UNSE’s 2023 IRP acknowledged by the Arizona Corporation Commission in October 2024 identified the Company’s need for new natural gas resources.¹⁹ UNSE’s 2023 Balanced Portfolio which included new natural gas resources was shown to be the most cost-effective way to maintain reliable, affordable service while reducing long-term environmental compliance risks for UNSE’s customers.

¹⁸ <https://azgovernor.gov/office-arizona-governor/news/2026/05/governor-katie-hobbs-announces-support-transwesterns-desert>

¹⁹ See ACC Decision 79589 - <https://docket.images.azcc.gov/0000212120.pdf?i=1779468799809>

SECTION 3

THE RESOURCE PLANNING PROCESS AND CONSIDERATIONS

3.1 Overview of UNSE's Planning Process

3.1.1 Reliability, Affordability, Sustainability

UNSE's core planning principles are reliability, affordability, and sustainability. Each of these are guiding values, and they must be weighed against each other in any planning scenario or investment decision. In the IRP, the needs of customers and the system must be balanced in order to arrive at portfolios that achieve the required reliability metrics while keeping costs low and minimizing carbon emissions.

Reliability

A power utility's most important function is to provide power to its customers 24 hours per day without interruption. UNSE's customers depend on a reliable power supply to cool their homes and run their businesses. Integrated resource planning ensures that all future scenarios the company may operate in provide this reliability. In order to do so, each resource portfolio is required to meet minimum resource adequacy metrics, as based on industry standards. The most significant of these is the Planning Reserve Margin, which is the required amount of capacity above expected peak loads that will enable them to meet customers' power needs, and is designed to meet the industry standard 1-day-in-10-year LOLE criteria (see section 2.2). Effective Load Carrying Capabilities are also applied to renewable and energy-limited resource types to ensure that the addition of these resources to the system does not result in a degradation of reliability.

The resources included in each portfolio must work in concert to serve the system's demand at any given time. Large thermal facilities tend to operate as 'base load,' where they operate at the top of their capability and are usually most efficient. Those resources may ramp up in the morning and down in the evening to accommodate afternoon peaks. Wind and solar resources are not dispatchable in this way, although weather forecasting can prepare system operators for potential changes in output. Small thermal resources, such as internal combustion turbines (ICTs) serve as fast-ramping resources that can respond quickly to changes in load or renewable output.

The addition of Li-ion battery resources to the UNSE system, as discussed in section 3.1.2, enables the storage of excess morning solar energy for dispatch later in the day. The capture of this energy for use during peak helps achieve reliability metrics while also improving affordability and sustainability by reducing the amount of thermal generation needed to meet those peaks. While batteries do not themselves generate energy, they are an important part of a resource portfolio due to their ability to store excess or low-cost energy and provide access to that capacity on demand.

Affordability

In developing resource portfolios, UNSE recognizes the broad affordability challenges that many customers face, and the need to pursue least-cost resource additions to provide power responsibly. UNSE's participation in Energy Imbalance and Day-Ahead Markets optimizes the efficient dispatch of UNSE's generators, helping UNSE capture the benefits of low-cost market energy and pass those savings on to customers (see Appendix F). Energy efficiency programs enable customers to reduce their overall energy consumption and therefore costs, while demand response programs can help reduce the need for expensive peaking resources (see Appendix J).

UNSE also must acquire new capacity and energy resources to satisfy retail load requirements. To ensure that UNSE can acquire the most cost-effective resources, All-Source Requests for Proposals are issued and bids are evaluated according to cost as well as other criteria (see section 3.2.1). Factors affecting resource costs include fluctuations in federal tax incentive policies and increases in capital and operations and maintenance (O&M) costs due to inflation, supply chain delays and other market factors.

Sustainability

UNSE considers all types of resources in its integrated resource planning including carbon-free resources such as solar, wind, geothermal, and nuclear. UNSE also conducts ASRFPs which allow for bidding of all types of resources. This enables the Company to evaluate how carbon-free and storage resources will interact with the existing UNSE system from a reliability perspective, and how competitive they are with fossil-fueled generation types. UNSE intends to continue its consideration and evaluation of renewable and storage resources, assessing potential investments for their contribution to system reliability and customer affordability.



3.1.2. Risk Management

Energy Resource Risk Management

Electric resource planning requires balancing cost, reliability, resilience, and environmental objectives under uncertain future conditions. Geopolitical events, shared infrastructure dependencies, cybersecurity vulnerabilities, and extreme weather events can disrupt fuel supply, generation, transmission, and distribution systems. These disruptions may result in power outages affecting homes, businesses, and essential services.

UNSE manages resource risk through a diversified portfolio that includes renewable generation, energy storage, dispatchable thermal resources, demand-side resources and market participation. Resource diversification reduces reliance on any single technology, fuel source, or market mechanism while improving the system's ability to respond to changing load growth, technology developments, regulatory requirements, and market conditions.

In addition, UNSE leverages regional diversity through market participation in the California Independent System Operator's Western Energy Imbalance Market and, in the future, Southwest Power Pool (SPP)'s Markets+, providing access to a broader pool of regional resources and market opportunities. Membership in Western Power Pool's Western Resource Adequacy Program, through its affiliation with Tucson Electric Power, contributes to increased reliability across the broader Western Interconnection (see Section 3.4.1). UNSE also utilizes the ASRFP process to identify cost-effective resource options that support resource adequacy, resilience, environmental objectives, and customer affordability.

Fuel Price Volatility and Fuel Supply Availability Risk Management

UNSE employs a diversified fuel procurement and risk management strategy to mitigate fuel price volatility and maintain reliable fuel supply for generating resources.

Natural gas supply is primarily procured through short term supply agreements to manage natural gas price volatility. UNSE implements a structured hedging program utilizing a rolling 36-month layered execution strategy, resulting in approximately 90% of forecast natural gas requirements being hedged one month prior to delivery (primarily through fixed-for-floating financial swap transactions). UNSE relies on long-term natural gas transportation agreements through its sister companies with multiple pipeline providers, providing access to diverse supply basins, including the Permian and San Juan basins. While natural gas deliveries may be affected by extreme weather, pipeline outages, or changing market conditions such as liquefied natural gas export demand, supply diversity and transportation flexibility help reduce exposure to localized disruptions and support reliable fuel delivery.

Wholesale Power Market Risk Management

The Desert Southwest wholesale power market has experienced increasing price volatility and tightening resource adequacy conditions in recent years, particularly during summer peak demand periods. To mitigate exposure to wholesale market price volatility and potential capacity shortages, UNSE implements a capacity hedging program designed to secure firm resource capacity in advance.

The Company procures fixed price physical power transactions and maintains a Planning Reserve Margin (PRM) target to support reliable service during peak demand periods. In 2026, UNSE increased its PRM target to 18% to further strengthen resource adequacy and address evolving reliability risks. UNSE utilizes a four-season laddering strategy under which approximately 25% of projected open summer-season capacity requirements are secured two years in advance, with additional purchases layered in over time as delivery approaches. This strategy reduces exposure to short-term market volatility, enhances resource adequacy, and increases certainty regarding future capacity costs.

Power System Operational Risk Management

UNSE incorporates redundancy across generation, transmission, and distribution systems to ensure power reliability. The systems involve duplicating critical components, data, or functions, ensuring that if one fails, another can seamlessly take over. This redundancy minimizes disruptions, improves reliability, and enhances the ability to withstand unexpected events, such as equipment failures, natural disasters, and cyberattacks.

UNSE incorporates redundancy within its Energy Management System (EMS), Outage Management System (OMS), and the communication infrastructure connecting the remote substations and generation facilities to these operational systems. Critical applications that support interconnected system operations are designed with independent primary and backup control centers to maintain operational continuity in the event of equipment or facility outages. These systems are routinely maintained, tested, and updated by the EMS personnel and system operators. In addition, both the primary and backup control centers are supported by redundant utility power feeds and backup generators to enhance system resilience during emergency conditions. Beyond internal redundancy measures, UNSE is contained within Tucson Electric Power's (TEP) balancing authority. TEP's participation in the Southwest Power Pool (SPP) as its Reliability Coordinator (RC) provides an additional layer of operational reliability through regional monitoring, reliability assessments and coordination across the interconnected grid.

Demand Risk Management

Demand risk represents the uncertainty that actual electricity consumption and peak demand will differ from forecasted levels, particularly over the long-term horizon. Key sources of uncertainty include demographic and economic trends, customer behavior, technological innovations, energy efficiency, distributed energy resource adoption, electrification, and the magnitude of large load customer growth. As a result, forecasts that include large load customers inherently contain a higher degree of uncertainty than forecasts based solely on traditional retail customer growth. If demand grows more rapidly than anticipated, the utility may face reliability risks and the need for additional capacity investments or market purchases. Conversely, slower-than-expected growth may result in underutilized assets and increased costs for customers.

UNSE mitigates demand forecast risk through the procurement of a diversified portfolio of energy resources, maintenance of planning reserve margins, access to wholesale markets and participation in regional real-time and day-ahead markets. Resource diversity and market access provide flexibility to respond to changes in customer demand, including uncertainty associated with large load growth. UNSE's capacity hedging program and phased execution approach allow the Company to gradually secure future resource needs as the planning period shortens and forecast uncertainty declines.

3.1.3. Resource Planning Advisory Council

Stakeholder feedback is a critical input to UNSE’s planning process. Since the 2020 IRP process, UNSE has convened a Resource Planning Advisory Council (RPAC) intended to provide UNSE with a diverse set of views from community groups. The goal is to ensure that customer and community needs are heard, understood, and reflected in long-term planning outcomes.

Through a series of regular meetings in the year leading up to the IRP’s submission to the Arizona Corporation Commission, UNSE and RPAC members exchanged information on the development of the IRP. UNSE representatives offered detailed insight into the UNSE planning process, discussing UNSE’s planning objectives, methodology, internal and external considerations, and modeling outcomes. In turn, RPAC members provided critical feedback on IRP methodology and outcomes, raised questions and concerns, shared knowledge on industry best practices and key customer insights, and kept UNSE informed of important events in the community that affect long-term utility planning.

Early meetings focused on utility planning basics. Several meetings also featured presentations from external industry experts on a variety of related topics. As the IRP analysis matured, the content of meetings shifted to discussion of the portfolios under review and preliminary results.

As a result of the process, RPAC members recommended the inclusion of portfolios that would add increased large load customers to UNSE’s load forecast. The interest stems from a desire to understand the impacts of large loads on UNSE resource portfolios and associated cost impacts. Accordingly, UNSE included two high-load portfolios as part of its seven main portfolios.

Six meetings were held between August 2025 and September 2026, as described in the table below.

Table 3.1 – RPAC Meetings

Meeting	Topic
August 2025	RPAC Purpose & Ground Rules, Utility Basics and UNSE Overview
October 2025	Technical Session: IRP Basics, Key Assumptions, and Inputs
January 2026	Technical Session: Portfolios and Modeling
February 2026	Focus On: Resource Adequacy and Portfolios
June 2026	IRP Base Case
September 2026	IRP Preliminary Portfolio Results Review

Membership

The RPAC included 12 members, representing a diverse set of stakeholders across a range of customer classes, advocacy groups, and community businesses.

Table 3.2 – RPAC Membership

Category	Organization
Public interest group	Lake Havasu Chamber of Commerce
Consumer advocacy group	AARP AZ Public Interest Resource Group River Cities United Way Wildfire
Residential customers	AZ Residential Utility Consumer Office
Large commercial/industrial customers	Fresh Produce Association of the Americas
Mining	South32
Environmental advocate	Sierra Club
Renewable power representative	Arizona Solar Energy Industry Association
Energy efficiency representative	Southwest Energy Efficiency Project
Regulator	Arizona Corporation Commission

Modeling Software License and Data Dashboards

In accordance with ACC Decision No. 81495, UNSE offered RPAC members the option to purchase and be reimbursed for a modeling software license (Energy Exemplar's Aurora platform) in order to perform planning analysis. In lieu of the modeling software, UNSE also offered RPAC members a data dashboard that included extensive modeling information. While none of the RPAC members opted for the modeling license, several selected to receive the data dashboard, which allowed them to compare long-term planning inputs and outputs of the portfolios using UNSE's IRP data. The dashboard was provided subject to a UNSE non-disclosure agreement.

Public Workshop

In addition to the RPAC meetings, UNSE held a public workshop in October 2026, near the culmination of the 2026 IRP activities. The workshop provided a deep dive into the IRP planning process, including planning goals and objectives, methodology, selection of portfolios, and modeling outcomes. It was held virtually and provided a forum for attendees to engage with the Company regarding the 2026 IRP.

The presentations and minutes of all RPAC meetings and the public workshop are posted on UNSE's RPAC webpage: <https://www.uesaz.com/rpac/>.



3.2. Actions Taken Since the 2023 IRP

3.2.1. All-Source Request for Proposals

UNSE issues All-Source Request for Proposals (ASRFPs) to solicit bids for capacity and energy resources on an as-needed basis. ASRFPs are administered according to the requirements established in Arizona Administrative Code. The resources solicited in ASRFPs are informed by the results of Integrated Resource Planning. Although the IRP is used as a guiding document, the resources procured may not be exactly as outlined in the IRP. The timing of each ASRFP is also informed by the most recent IRP and considers the results of the previous ASRFPs.

ASRFP Process

UNSE works with an Independent Monitor, which acts as an independent third-party on behalf of the Company to conduct an initial evaluation of proposals. Proposals are scored based on their cost, interconnection progression, bidder experience, and the likelihood of meeting proposed project in-service dates. Projects with the highest score are selected for a shortlist.

An evaluation of the commercial operating date is a priority for the Company in order to meet increasing summer demand and avoid unusually high summer capacity and energy prices. The timeline for executing an interconnection agreement is a critical element in the project development process, as the status of an interconnection request can significantly impact the development timeline of a project. The expectation is that proposed facilities must be constructed and interconnected to meet proposed capacity and energy deliveries by the in-service date requirements established in the ASRFP.

Deliverability is an important evaluation criterion for ranking the projects' interconnection status, regulatory status, and available transfer capability at the time and point of interconnection such that the energy and capacity will be fully available to UNSE retail customers. Projects having obtained or deemed well into the process of obtaining a Certificate of Environmental Compatibility (CEC) and those which are in advanced stages of the interconnection process ranked highest. Prices are also a major factor, but the ability to bring a project into service at the time proposed is vital to maintaining reliability and avoiding potentially expensive summer purchase power.

A summary of ASRFPs conducted since the 2023 IRP is provided below:

2024 ASRFP

UNSE issued an ASRFP on December 21, 2024. The in-service dates preferred by UNSE were indicated in the solicitation as May 1, 2026, but no later than May 1, 2027. The need for these resources was based primarily on the Company's 2023 IRP and a Needs Assessment performed in 2023 prior to the release of the ASRFP.

2025 ASRFP

UNSE issued an ASRFP on March 3, 2025. The in-service dates preferred by UNSE were indicated in the solicitation as May 1, 2028, but no later than May 1, 2029. The need for these resources was based on the 2023 IRP and the 2024 ASRFP.

2026 ASRFP

UNSE issued an ASRFP to solicit bids for capacity and clean energy resources on May 12, 2026. The in-service dates preferred by UNSE were indicated in the solicitation as May 1, 2028, but no later than December 2029. The need for these resources was based on the 2023 IRP and previous ASRFPs. As of October 2026, UNSE is evaluating the 2026 ASRFP project bids.

For a detailed review of resource additions that have come online since the 2023 IRP, please see section 3.2.3.

3.2.2. Development Timelines

The timeline for executing an interconnection agreement is a critical element in the project development process. For purposes of an ASRFP, bidders are not necessarily required to have entered the interconnection queue process. However, the status of an interconnection request can significantly impact the development timeline of a project. Application processing time for interconnection requests vary by queue position, queue workload, and the location on the transmission network. The expectation is that proposed facilities must be constructed and interconnected to meet proposed capacity and energy deliveries by the in-service dates established in the ASRFP.

UNSE studies large generator interconnection projects on an annual cluster basis. Applications for the annual cluster open on January 15th of each year, and assuming no delays occur, the study and interconnection agreement contracting process can be expected to take until April of the following year at the earliest. More information on UNSE's interconnection process can be found on its Open Access Sametime Information System website.²⁰

UNSE is also a Network Integrated Transmission Service ("NITS") customer of the Western Area Power Administration ("WAPA") in Mohave County. Proposed facilities with adequate interconnection agreements with WAPA for connection in that region may also be considered in the ASRFP process.

In addition, projects proposed in the ASRFP may require a CEC for a project to be constructed. The Arizona Power Plant and Transmission Line Siting Committee, created by the state legislature, has jurisdictional purview of proposed conventional generating plants greater than or equal to 100 megawatts and transmission lines greater than or equal to 115 kV. The Committee considers the application for a CEC through a public process relative to a series of factors specified in Section 40-360.06 of the Arizona Revised Statutes.

Upon conclusion of review, the Committee makes a recommendation to the ACC regarding the CEC. The ACC makes a final determination on the CEC application and votes in a public proceeding to accept, reject, or modify the Committee's recommendations. The ACC has 180 days after the application is filed to decide on the CEC.

The application for a CEC requires additional time for site plans and multiple environmental and archeological studies to be performed. The CEC process may run concurrently to the interconnection process, but the timeline is similar in duration – at least two years.

²⁰ <https://www.oasis.oati.com/UNST/index.html>

3.2.3. Resource Additions and Developments

Since the filing of UNSE's 2023 Integrated Resource Plan, the company has continued to advance a resource strategy focused on strengthening reliability, diversifying its resource portfolio, and supporting long-term customer load growth. Consistent with the objectives identified in the 2023 IRP, UNSE has executed agreements for new utility-scale renewable and energy storage resources that support its evolving supply requirements. These additions are expected to enhance UNSE's ability to serve customers while addressing changing system needs.

Dandelion Energy Park Solar and Storage Project (2028)

In March 2026, UNSE executed a solar power purchase and storage agreement with Dandelion Energy Park, LLC for a solar and battery energy storage project in Maricopa County, Arizona. Under the agreement, UNSE will purchase the output from a 140 MW solar generation facility paired with a 140 MW / 560 MWh battery energy storage system. The battery storage system is designed to provide four hours of dispatchable storage capability, allowing energy produced during daylight hours to be shifted to periods of higher customer demand. The project is expected to achieve commercial operation in 2028.

Resource Portfolio Progress

Upon commercial operation, Dandelion Energy Park will become a significant long-term supply resource for UNSE. As the project advances toward its expected 2028 in-service date, it represents a tangible transition from planning to execution.

The combination of solar generation and four-hour battery storage illustrates the increasing role of integrated solar and storage facilities in utility resource planning. By pairing renewable generation with storage capability, the project is designed to better align energy delivery with customer demand patterns and contribute to meeting UNSE's future energy needs.

3.3. Federal Tax Policy and Its Impacts

On July 4, 2025, the One Big Beautiful Bill Act (OBBBA) was signed into law, significantly accelerating the phaseout of wind and solar tax credits and reversing several clean energy incentives under the Inflation Reduction Act (IRA). New Foreign Entity of Concern restrictions also potentially limit the ability for projects to qualify.

Under OBBBA, wind and solar projects must have begun construction by July 4, 2026 to remain eligible for full tax credits. Other technology neutral resources such as battery storage, geothermal, pumped hydro storage and nuclear remain under the IRA framework and are not subject to an accelerated timeline. These technologies continue to be eligible for a 100% tax credit for projects that begin construction by 2033, with the credit phasing down to 75% in 2034, 50% in 2035, and expiring thereafter. UNSE has incorporated the changes into its resource modeling. Please refer to section 4.2.4 for more information.

Figures 3.1 and 3.2 show how the removal of tax incentives in the 2026 IRP affects the levelized costs of solar and wind resources relative to the 2023 IRP assumptions that included full applicable tax credits through 2036 before phasing out.

Figure 3.1 - Utility Solar Levelized Costs, Nominal \$/MWh

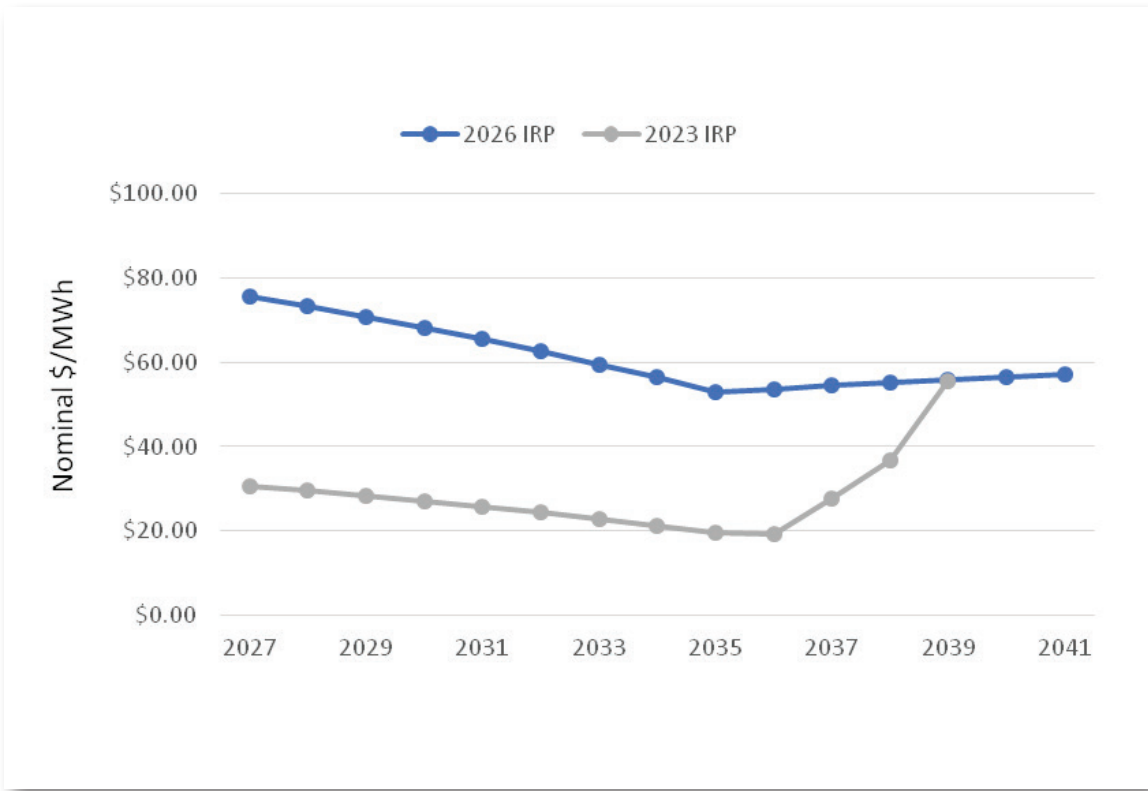
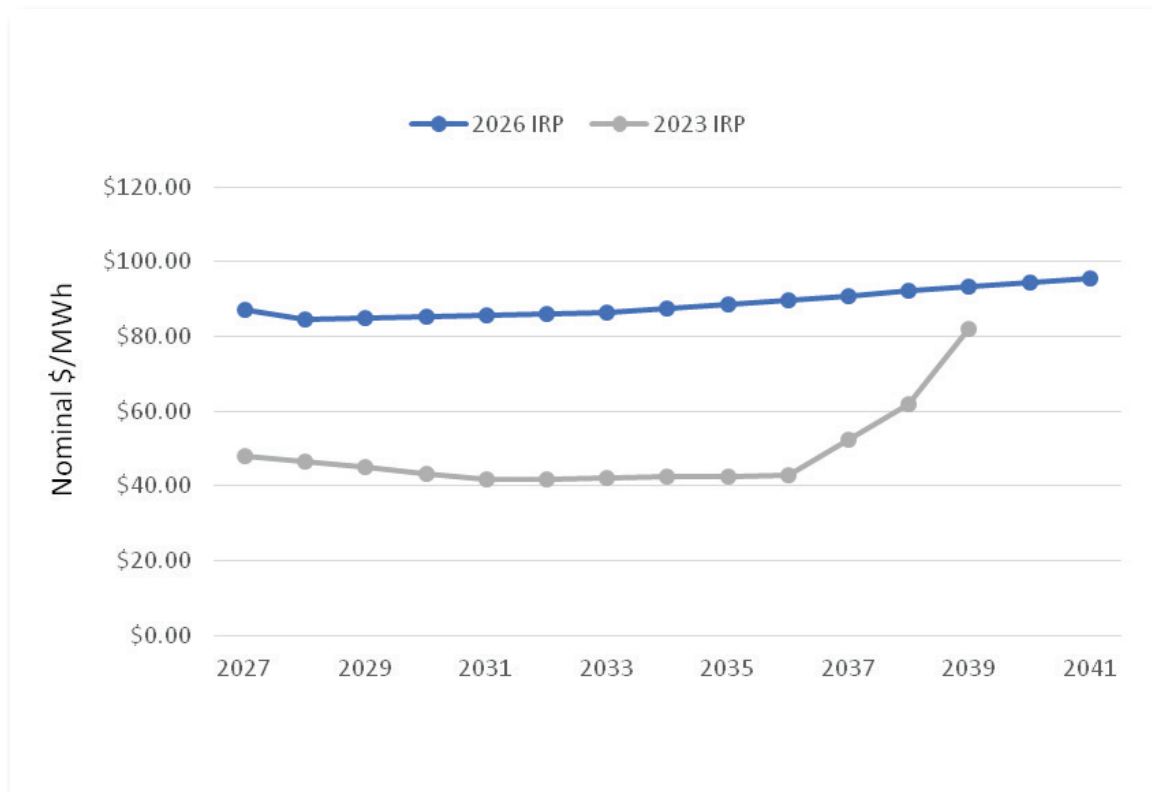


Figure 3.2 - Wind Levelized Costs, Nominal \$/MWh

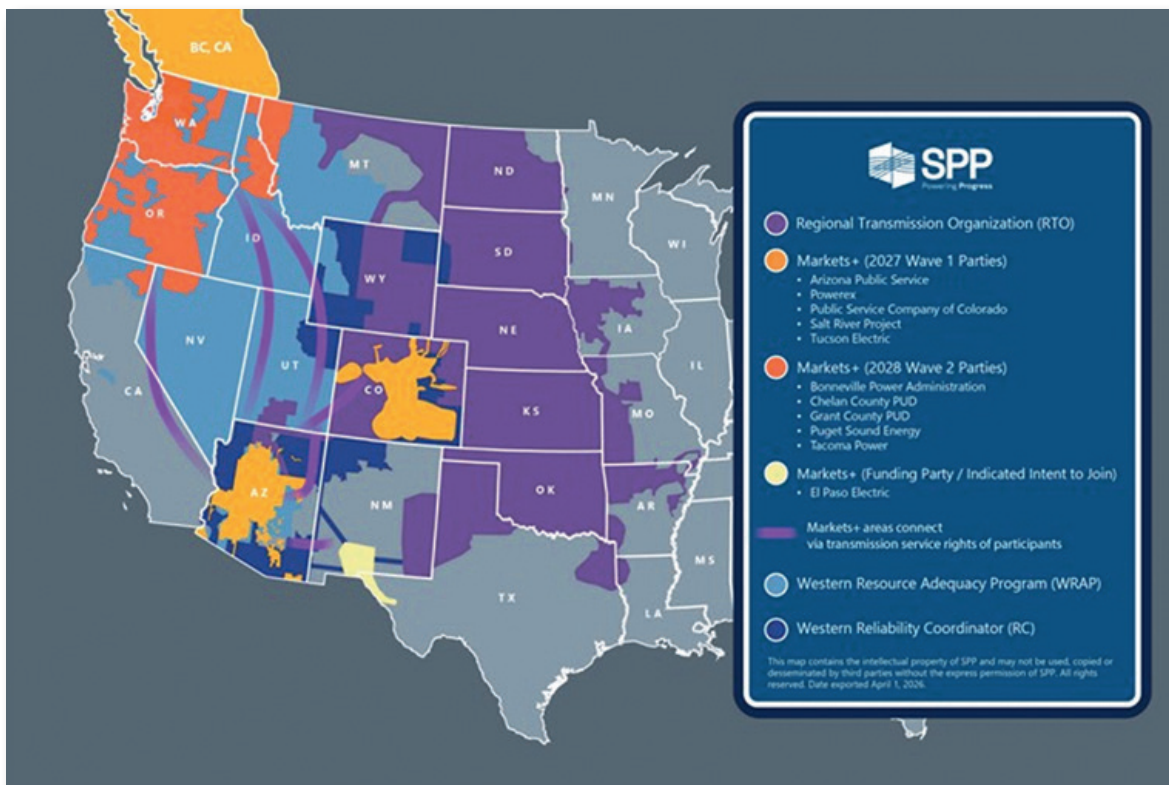


3.4. Day-Ahead Market Participation

In November 2024, Tucson Electric Power announced its intent to join Markets+ alongside Arizona Public Service, Salt River Project, and other western utilities when the market becomes operational in 2027. As part of TEP's balancing authority, UNSE has the ability to participate in Markets+ to take advantage of its benefits. Markets+ builds on SPP's operational experience managing organized electricity markets, including the Western Energy Imbalance Service (WEIS) and SPP's Integrated Marketplace. The WEIS market currently provides real-time economic dispatch across participating western entities, while the Integrated Marketplace has demonstrated the value of coordinated day-ahead and real-time market operations through more than a decade of successful implementation.

Markets+ will improve visibility into regional resource availability and support more effective coordination of generation resources during periods of high demand and changing system conditions. Participation in Markets+' organized day-ahead and real-time markets will benefit customers through improved reliability, greater access to diverse and lower-cost energy supplies, greater access to low-carbon resources and more efficient use of the western transmission network. The company expects Markets+ to enhance its ability to respond to changing system conditions, market prices, and weather events while maintaining control of its transmission system and resource portfolio. Participation aligns with the Company's broader strategic goals as western energy markets become increasingly interconnected, offering western utilities a framework emphasizing voluntary participation and stakeholder governance.

Figure 3.3 – SPP Markets+ Map



3.4.1. Western Resource Adequacy Program

The Western Resource Adequacy Program (WRAP) is a regional reliability planning and compliance program administered by the Western Power Pool (WPP) with program operator services provided by the Southwest Power Pool (SPP). WRAP is the designated resource adequacy program of SPP's Markets+. UNSE participates in WRAP through its affiliation with Tucson Electric Power, which serves as UNSE's designated WRAP participant and compliance entity. Through this relationship, UNSE benefits from regional resource adequacy coordination while continuing to conduct its own utility-specific resource planning and reliability assessments.

WRAP is the first region-wide resource adequacy framework in the Western Interconnection and is designed to provide a coordinated approach for ensuring sufficient generation and transmission capacity to meet demand during periods of system stress. The program establishes common reliability metrics and introduces compliance obligations to ensure that participating entities contribute to regional reliability while maintaining their independent planning and operational responsibilities.²¹

WRAP Reliability Metrics and Relationship to UNSE Planning

While UNSE participates in WRAP and incorporates WRAP requirements into its compliance planning, UNSE continues to use its own IRP reliability assessments and planning reserve margin targets as the primary basis for long-term resource planning. WRAP planning reserve margins are designed to demonstrate compliance within the WRAP footprint and reflect assumptions regarding regional diversity benefits, participant resource adequacy performance, transmission deliverability, and the continued availability of capacity sharing through the binding operational program. These assumptions may evolve as participation levels, accreditation methodologies, and program rules mature.

For long-term utility planning, UNSE must ensure reliable service to its retail customers under a wide range of future conditions, including scenarios in which regional assistance may be constrained by transmission limitations, widespread extreme weather events, or changes in WRAP participation. UNSE's IRP evaluates resource adequacy using company-specific reliability analyses and reserve margin requirements that reflect UNSE's load characteristics, resource portfolio, operational experience, and planning objectives. WRAP compliance requirements are viewed as a supplemental regional reliability obligation rather than the sole determinant of UNSE's capacity planning needs. As WRAP transitions to its binding phase and additional operational experience is gained, UNSE will continue to assess how WRAP metrics and regional diversity benefits should be incorporated into future planning processes. For more information, refer to Appendix F.

²¹ <https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program>

3.5. Environmental Regulations and Uncertainty

Environmental policy and regulations play an important role in utility planning. UNSE is tracking and complying with multiple environmental regulations implemented at the local, state and federal levels. As detailed in Appendix G, this includes the regulation of greenhouse gases, criteria pollutants such as ozone, and water consumption.

All IRP modeling was performed according to current regulations in effect at that time. For example, portfolios were designed under existing greenhouse gas rules, published by the U.S. Environmental Protection Agency in 2024, which limit the allowable emissions of new natural gas facilities based on their thermal efficiency and capacity factor. To comply with that rule, new natural gas facilities in the portfolios were limited to 40% or less in 2032 and later. However, as of September 2026, EPA partially repealed the 2024 greenhouse gas rules, and several other regulations remain under EPA's review. UNSE cannot predict the outcomes of these actions.



SECTION 4

PORTFOLIO DEVELOPMENT AND INPUTS

4.1. Methodology

4.1.1. Resource Adequacy Study

In 2025, UNSE retained E3 to complete a new resource adequacy (RA) study (see Appendix E). The study incorporated updated UNSE load forecasts, thermal generator performance assumptions, and resource plans, as well as historical weather and renewable generation profiles to perform a statistical analysis and calculate the required Planning Reserve Margin (PRM) to ensure resource adequacy. E3 evaluated system reliability using the industry standard Loss of Load Expectation (LOLE) target of 0.1 days per year and identified the PRM needed to maintain that level of reliability.

The study concluded that the UNSE system will require an 18% PRM, a slight increase from the 16.5% PRM used in the 2023 IRP. The increased requirement is primarily driven by E3's enhanced modeling of thermal generator forced outages. While the thermal fleet has an average forced outage rate of approximately 5%, the analysis shows that loss of load events are most likely to occur when multiple large generating units are unavailable at the same time. During these periods, average thermal fleet availability decreases to about 85%, requiring additional reserve capacity to maintain reliability. The updated analysis also reflects higher load forecasts, greater weather variability, and updated operating reserve requirements. Based on these inputs, the modeling process iteratively adds or removes capacity until the LOLE target of 0.1 days per year is achieved. The resulting 18% PRM was applied to each UNSE portfolio evaluated in the 2026 IRP.

E3 also updated the Effective Load Carrying Capability (ELCC) study that was conducted for UNSE in 2022. Building on the PRM study that was conducted, E3 analyzed increasing levels of wind, solar, 4-hour storage and 8-hour storage to develop updated ELCCs for UNSE. ELCC represents the effective capacity that renewable and storage resources can provide toward meeting system reliability requirements such as the PRM. The updated study developed ELCC curves for individual technologies and resource combinations reflecting how the effective capacity value changes as penetration levels increase. **Figure 4.1** illustrates the diversity benefit of combining solar and 4-hour battery storage. As storage is added with increasing solar penetration, the combined ELCC increases because battery storage shifts excess daytime solar generation to high demand evening hours when solar output decreases, and reliability needs are greatest. As a result, the combined capacity value of solar and storage exceeds the sum of their individual contributions when evaluated individually.



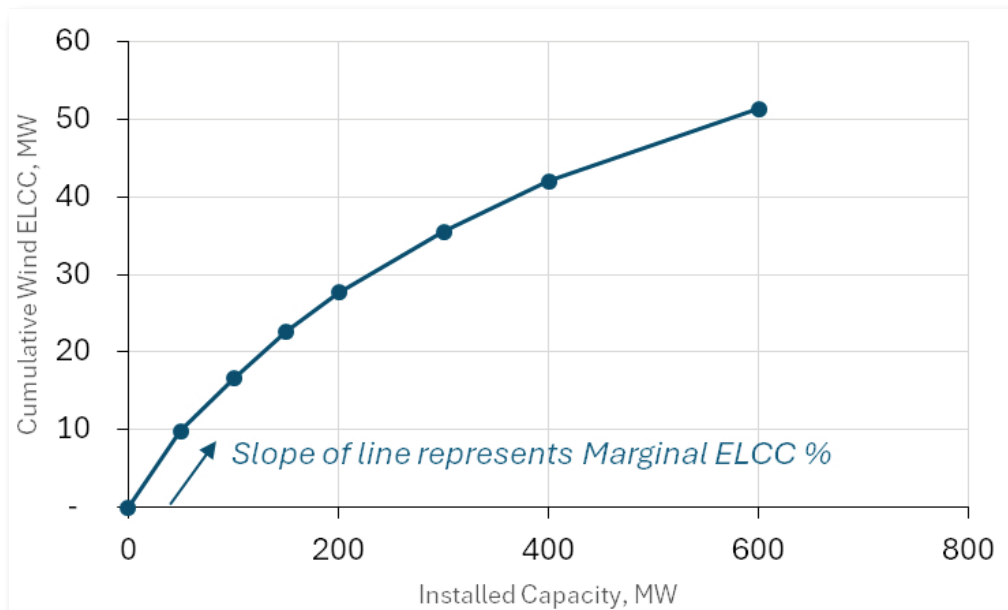
The resulting 18% PRM was applied to each UNSE portfolio evaluated in the 2026 IRP.

Figure 4.1 - Portfolio ELCC Incremental Solar and Battery Storage Additions²²

Cumulative ELCCs (MW)		4-hour Battery Storage Capacity (MW)						
		-	100	200	300	400	500	600
Solar Capacity (MW)	-	-	92	175	202	212	219	227
	100	13	105	194	231	243	250	258
	200	17	110	198	252	267	276	283
	300	19	112	201	268	288	296	305
	400	20	114	203	276	303	316	325
	500	22	115	204	280	311	325	336
	600	24	117	206	281	314	332	343

The ELCC analysis confirms that the marginal capacity value of solar and wind resources declines as their proportion on the system increases. As shown in **Figure 4.2**, the marginal ELCC of wind declines as installed capacity increases, illustrating the diminishing contribution of additional wind resources at higher penetration levels. Similarly, as solar capacity is added to the system, the net system peak is pushed into the evening when solar generation is reduced or unavailable, resulting in lower marginal ELCC values. This effect, commonly referred to as resource saturation, means that while the initial additions of solar or wind provide significant reliability benefits, each subsequent addition contributes progressively less capacity.

Figure 4.2 - Cumulative ELCC for Incremental Wind Additions²³



²² Energy and Environmental Economics, Tucson Electric Power PRM and ELCC Study (2025).

²³ Ibid

Battery Storage helps offset the resource saturation effects of solar generation by shifting excess generation to evening periods when reliability needs are greatest. While battery storage provides one of the highest marginal ELCC values among the evaluated technologies, its marginal capacity value also declines with growth. As battery storage capacity increases, reliability events tend to become longer in duration. The updated analysis indicates that 8-hour battery storage generally provides approximately 1.5 times the ELCC of comparable 4-hour storage resources. Similarly, this advantage gradually decreases as overall storage penetration increases.

Thermal resources can also be assigned Effective Load Carrying Capability (ELCC) values based on their forced outage characteristics. For this study, UNSE did not develop thermal ELCC values separately. Instead, the impacts of thermal outages were incorporated directly into the Planning Reserve Margin (PRM), effectively assigning thermal resources an ELCC of 1 while increasing the PRM to account for outage risks.

The ELCC results were incorporated into the portfolio modeling process and applied consistently across all portfolios evaluated in the 2026 IRP. ELCC values are used to determine the capacity contribution when evaluating resource additions. The model increasingly selects solar and battery storage paired together to utilize the diversity benefit and, in some cases, longer-duration storage to meet the 18% PRM (see section 5 for detailed portfolio analysis).



4.1.2. Long-Term Capacity Expansion Modeling

UNSE utilizes Aurora, an energy market simulation and forecasting platform developed by Energy Exemplar, to perform its Long-Term Capacity Expansion (LTCE) modeling. The LTCE model identifies the least-cost portfolio of resource additions needed to meet future energy and capacity requirements while satisfying planning constraints for each specific portfolio. Resource expansion decisions are determined through economic optimization, allowing the model to identify the combination of resources that minimizes total system costs while maintaining reliable service.

For the 2026 IRP, UNSE engaged Siemens Power Technologies International (Siemens PTI) to support the development of LTCE modeling assumptions and offer insights into industry best practices. While UNSE first incorporated LTCE modeling into its 2023 IRP process, the Company sought to further strengthen its modeling approach and leverage additional modeling capabilities through collaboration with Siemens PTI.

Aurora's LTCE process uses an iterative optimization approach. Beginning with UNSE's existing resource portfolio, the model evaluates system operations and determines the quantity and type of additional resources needed to satisfy planning reserve margin requirements and other planning constraints. During each iteration, candidate resources are assessed based on their costs, operating characteristics, capacity contributions, and overall value to the system. Key inputs include capital costs, fixed and variable operating costs, fuel costs, resource performance characteristics, and Effective Load Carrying Capability (ELCC) values.

Through each iteration, Aurora simulates system dispatch, calculates system economics, and evaluates the contribution of candidate resources. Based on these results, the model selects the combination of resource additions that provides the greatest overall benefit to the system while minimizing total portfolio costs. The updated portfolio is subsequently re-evaluated, and the process continues until the model reaches a stable solution and satisfies predefined convergence criteria.

The final LTCE results identify the resource additions and timing that best meet UNSE's projected load growth, resource adequacy requirements, and planning objectives at the lowest overall system cost.

4.1.3. Production Cost Modeling

While Aurora's LTCE model identifies the least-cost resource portfolio that satisfies planning objectives and constraints, Aurora's Production Cost Model (PCM) provides a more detailed assessment of operational performance. Following the LTCE analysis, UNSE applies its planning and operational expertise to further evaluate and refine the modeled resource additions to ensure resource adequacy requirements are met and implementation constraints are considered. The PCM then incorporates the refined resource additions and performs a chronological hourly simulation of UNSE's system operations across the 15-year IRP timeframe.

The PCM economically commits and dispatches available generating resources, energy storage assets, and market purchases and sales to meet customer demand and reliability requirements at the lowest total system cost. Dispatch decisions are based on resource economics and market conditions while accounting for operational characteristics and constraints, including minimum generation levels, startup costs, ramp rates, minimum up/down times, transmission limitations, reserve requirements, and storage operating parameters.



4.2. Inputs and Assumptions

4.2.1. Load Forecast

This section summarizes UNSE's customer base and load forecast methodology and subsequently details some of the major forecast components. It concludes with a summary of forecast results. Detailed forecast results can be found in Appendix C.

4.2.1.1. Service Territory and Customer Base

UNSE currently provides electricity to more than 100,000 customers in Santa Cruz and Mohave counties.

Figure 4.3 shows UNSE's service territory, and that of its sister company, TEP. The number of historic and projected residential customers is shown in **Figure 4.4**, while the current sales by customer class are shown in **Figure 4.5**.

Figure 4.3 - TEP and UNSE Service Territories

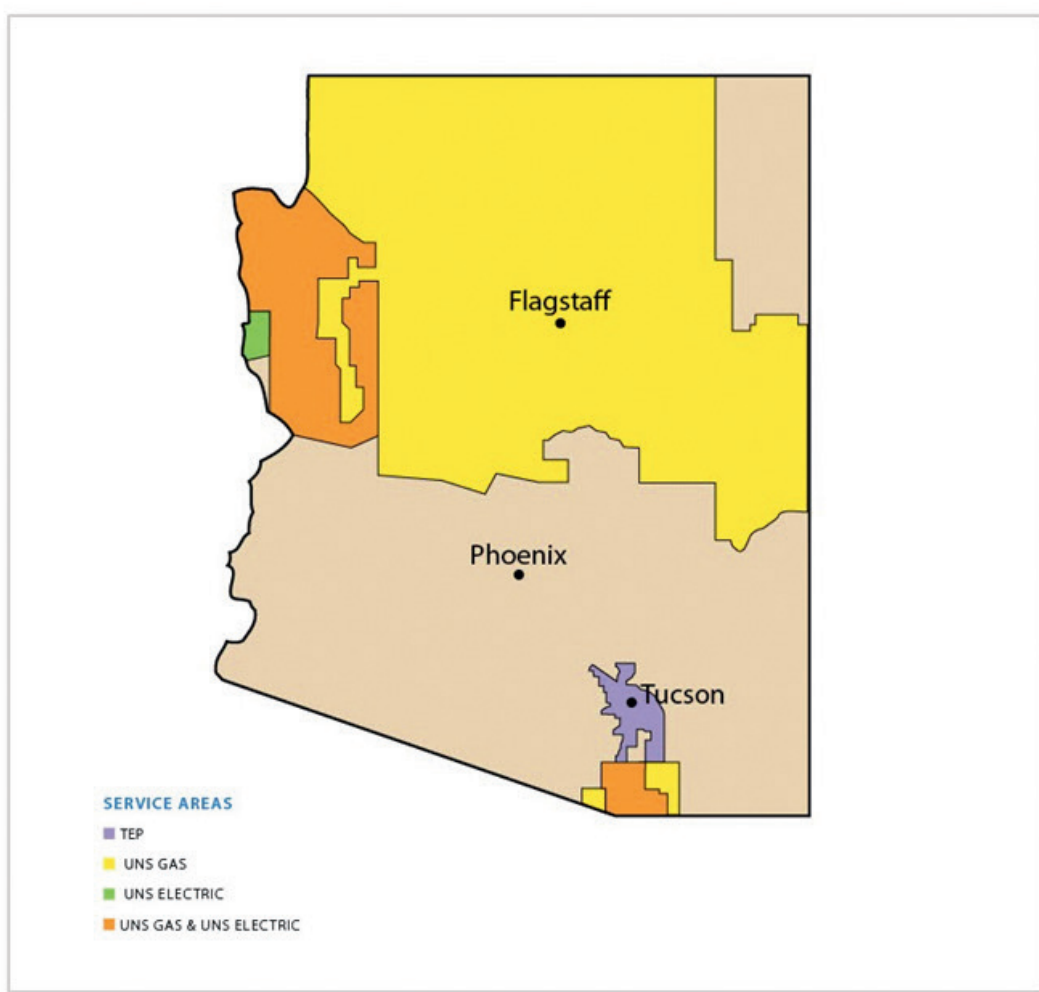


Figure 4.4 - Historic and Projected Number of Residential Customers

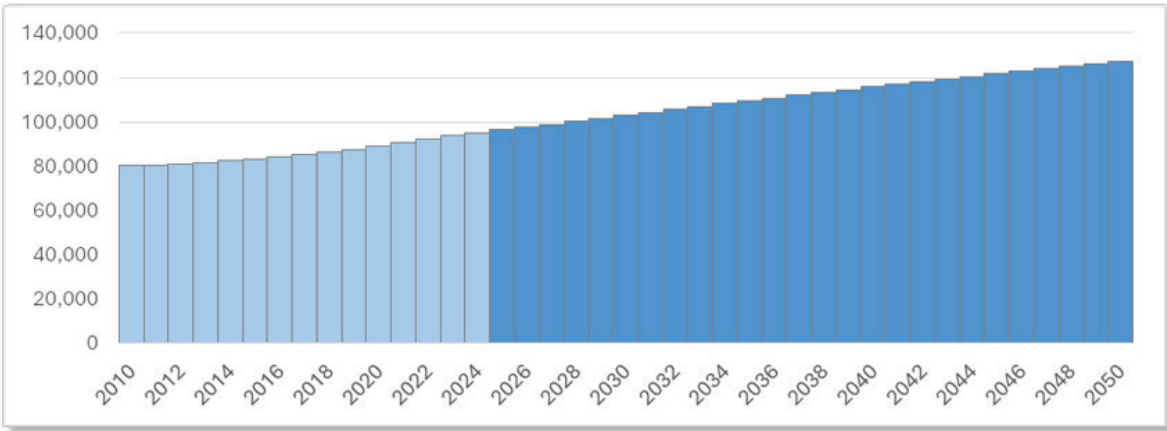
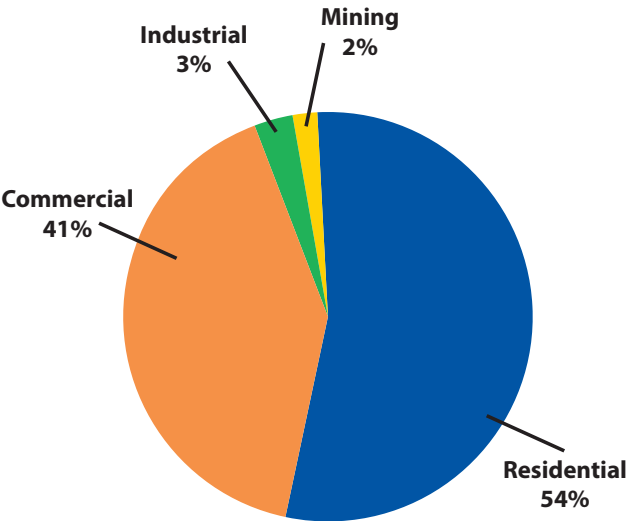


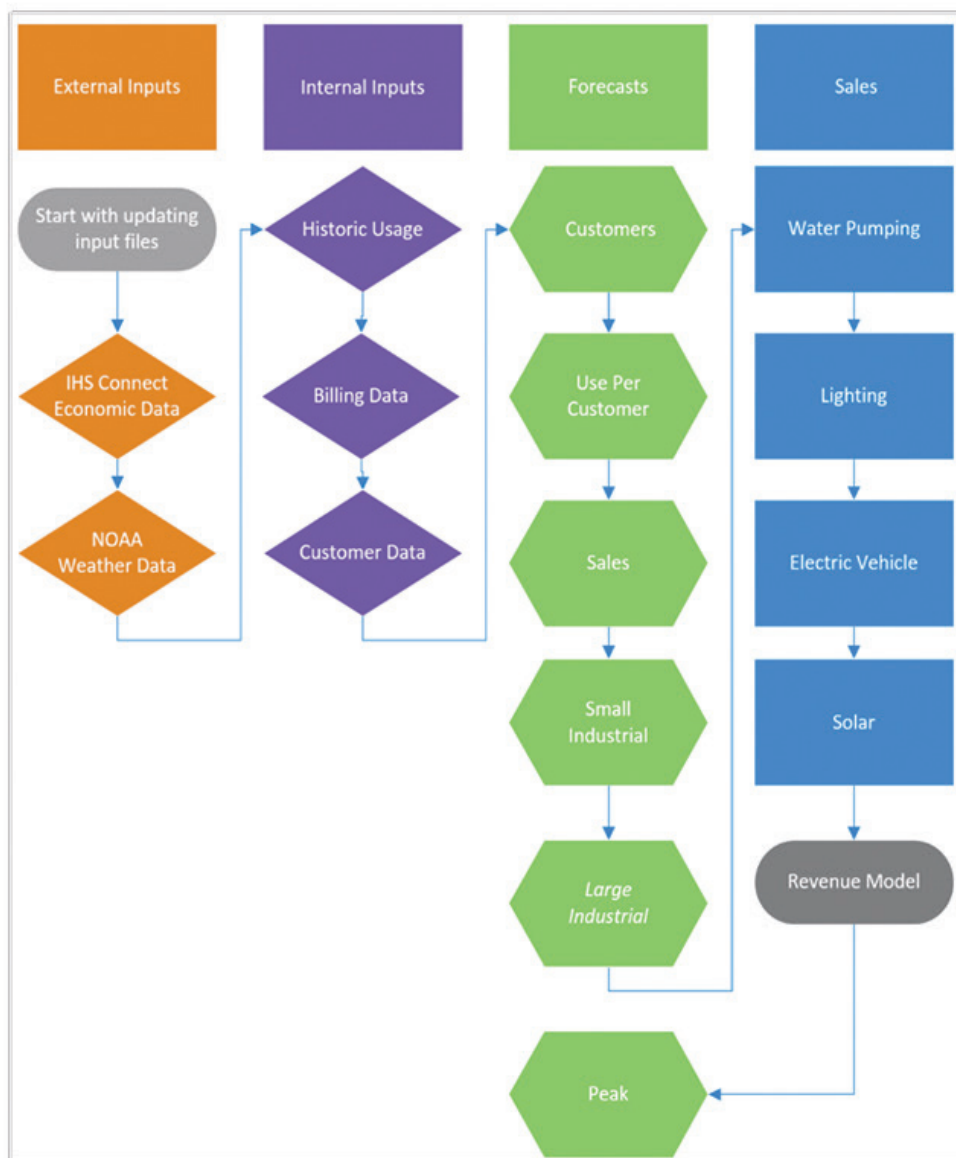
Figure 4.5 - 2025 Retail Sales by Customer Class



4.2.1.2. Methodology, Data Sources, and Uncertainties

UNSE's load forecast methodology is illustrated in **Figure 4.6**. Residential, commercial, and small industrial customer sales are forecasted monthly using statistical models based on factors such as historical usage, weather, demographic forecasts, and economic conditions. Large industrial and mining sales are likewise forecasted monthly; however, these forecasts are developed at the individual customer level, drawing on historical consumption patterns and insights from UNSE's Key Account Managers who maintain close engagement with these customers.

Figure 4.6 - Load Forecast Process



New Large Load Customers

In addition, new large load customers are incorporated into the forecast once they have either been formally contracted or have advanced to a stage at which service delivery is considered effectively certain. The timing of inclusion is determined based on the level of confidence in project execution and the anticipated realization of load. Each prospective large load addition is evaluated on an individual basis, with consideration given to its unique circumstances, contractual status, and stage of development. This case-by-case approach supports the development of forecast assumptions that are both accurate and appropriately conservative.

Peak Forecast

Following the development of monthly sales forecasts by customer class, the results are aggregated and used as inputs into a separate statistical model designed to estimate retail peak demand. This peak demand model is based on historical relationships among hourly load, weather variables, calendar effects, and overall sales growth. Greater weight is given to more recent weather years to include the impact of rising temperatures.

Data Sources and Other Considerations

Data sources used in the forecast include:

- IHS Global Insights (S&P Global)
- The University of Arizona Forecasting Project
- Arizona Department of Commerce
- U.S. Census Bureau
- National Oceanic and Atmospheric Administration (NOAA)

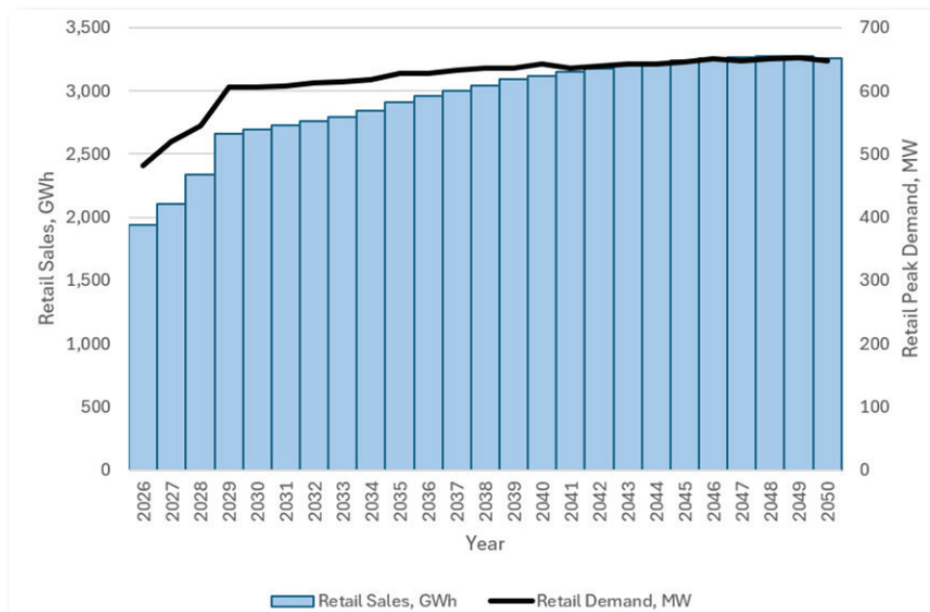
As always, projected load growth is subject to a wide range of variables and assumptions. While not all inclusive, some of the key risks to the current forecast are:

- Strength and timing of business cycle fluctuations
- Structural changes to customer behavior
- Volatility in industrial metal prices and associated shifts in mining consumption
- Efficacy of energy efficiency programs
- Technological innovations
- Volatility in demographic assumptions

4.2.1.3. Load Forecast Results

Figure 4.7 summarizes UNSE’s forecasted annual retail sales and peak demand. The average annual growth rate of sales and demand over the planning period is 2.25% and 1.29% respectively. This load forecast was used to develop all portfolios. Detailed forecast results are provided in Appendix C.

Figure 4.7 - UNSE Forecasted Annual Retail Sales and Peak Demand



Because of the large amount of uncertainty underlying the load forecast, it is crucial to consider the implications to resource planning if UNSE experiences significantly lower or higher load growth than projected. For this reason, load growth is one of the fundamental factors considered in the risk analysis process undertaken as part of this IRP. Specifically, the performance of select potential resource portfolios is analyzed with the use of Monte Carlo load simulations. See Appendix D for Stochastic results.

4.2.2. Demand Side Management and Distributed Generation

Customer-sited resources and demand management play an increasingly important role in UNSE’s resource mix, and accordingly in long-term resource planning. As part of the load forecasting methodology, all distributed generation (DG) and demand-side management (DSM) impacts present within the system are initially added back to the forecast to establish a gross load basis. Upon completion of the forecast, the embedded DG and DSM components are subsequently removed, and independent forecasts for DSM, DG, and electric vehicles (EVs) are then incorporated as layered adjustments to produce the final net load forecast. In the 2026 IRP, demand response (DR) is modeled as a dispatchable demand-side resource in the portfolio optimization process. See Appendix J – UNSE Customer Programs, for more detailed information on each of these resources.

Energy Efficiency and Demand Response

UNSE's demand-side management portfolio includes energy efficiency programs serving residential, commercial, and industrial customers. These programs reduce system peak demand, lower customer bills, improve grid reliability and resilience, and support a cleaner energy future.

Between 2024 and 2025, UNSE's energy efficiency portfolio continued delivering measurable customer and system benefits through a diverse mix of residential, commercial, and income-qualified programs. Key highlights include:

- In 2025, residential programs delivered 12,588 MWhs and commercial programs delivered 10,320 MWh of energy savings.
- Multifamily Program Relaunch – This program expanded direct install offerings and increased property manager engagement. In 2025, the program achieved approximately 139 MWh in annual savings while serving more than 260 multifamily units and delivering over 1,400 energy-saving measures.
- Existing Homes Program – UNSE expanded residential Existing Homes offerings through enhanced HVAC measures, streamlined participation pathways, and expanded trade ally engagement in 2025. The program achieved approximately 3,620 MWh in annual savings while supporting nearly 3,000 participating customers.

UNSE achieved cumulative annual savings equivalent to 24.3% of the retail sales in 2024 and 24.6% in 2025, exceeding Arizona's cumulative energy efficiency standard of 22%.

In July 2026, the ACC formally repealed Arizona's Electric Energy Efficiency Standard (EEES) rules. UNSE's approved three-year DSM plan is still tied to the EEES requirements and will remain in effect until further order of the Commission. In the absence of new rules, future DSM program development will be at the discretion of individual utilities, subject to Commission review and approval.

While UNSE does not currently have any active demand response programs, the Company is actively pursuing the foundational activities to establish a portfolio of dispatchable demand-side resources.

The IRP incorporates energy efficiency and demand response projections based on the results of the Demand-Side Resources Market Potential Study conducted by a third party in 2025. The study quantified the energy savings and peak demand reduction that could potentially be captured through demand-side programs over a 2026–2040 planning horizon. For the IRP, UNSE utilizes the achievable potential results, assuming continuation of existing program designs, incentive structures, delivery approaches, participation trends, and budget levels. Detailed study results are available in Appendix J.

Distributed Generation

UNSE offers a number of programs to support the use of customer-sited distributed generation, specifically rooftop solar and battery storage. UNSE’s DG adoption trajectory reflects steady growth driven by technology advancement, electrification trends, and evolving program design, with relatively limited volatility associated with policy or economic shifts. The number of customers and total capacity deployment through 2025 is shown in **Table 4.1**.

Table 4.1 – DG Customer Adoption

DG Category	Total All-Time Customers Through 2025	Total MW
3rd Party Residential DG	11,315	91
3rd Party Non-Residential DG	268	20
Storage Residential	549	6

Transportation Electrification

UNSE’s three-year Transportation Electrification Implementation Plan (2023-2025) increased awareness and adoption of transportation electrification, recognizing the benefits to the Company and the community of beneficial electrification. Highlights include:

- 22 residential EV charging ports installed
- 24 commercial EV charging ports contracted

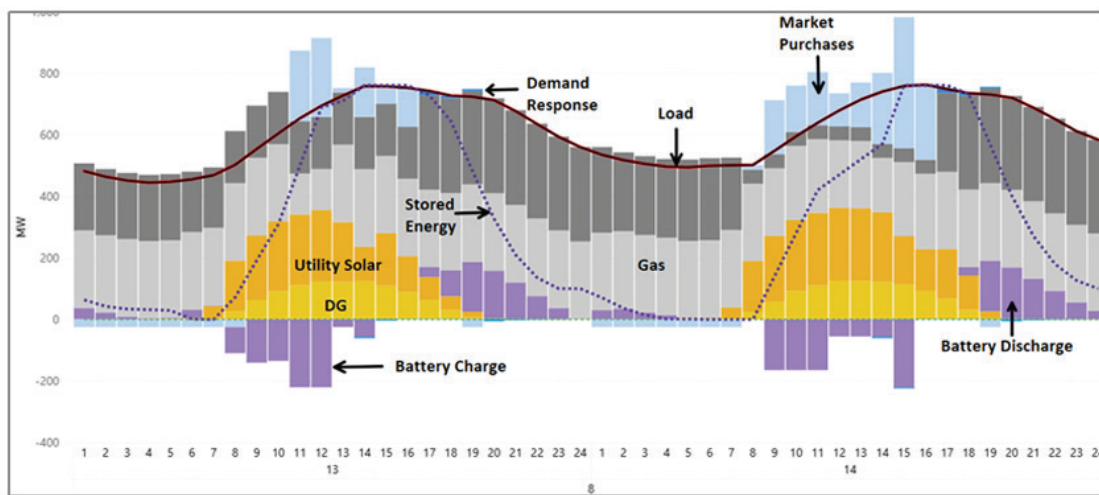
4.2.3. Resource Adequacy in the Portfolios

The Resource Adequacy (RA) of each portfolio was determined through a two-step process. First, each year was required to meet a Planning Reserve Margin (PRM) of 18%, updated from a value of 16.5% used in the prior IRP. The updated PRM was derived using a Loss of Load Probability model designed to achieve a Loss of Load Expectation (LOLE) target of 0.1 days in a given year. To determine whether the PRM is met, solar, wind, and storage resources are given a capacity value based on their Effective Load Carrying Capability (ELCC), as described in section 4.1.1. Given the lead times associated with the procurement, development and construction of new resources, UNSE plans to rely on market purchases to meet the PRM requirements during the first four years of the planning period, until additional resources become available.

Second, UNSE performed a “stress test” on each portfolio beginning in year 5 of the planning period. Under this assessment, market purchases are not permitted during summer evenings, and UNSE must meet extended hours of peak loads exclusively with its own resources. Because UNSE uses Aurora as an hourly, security-constrained dispatch model, this process inherently accounts for and enforces limits on system operations. Such limits include minimum and maximum fuel restrictions, commitment decisions needed for thermal resources that are not fast-start and fast-ramping, variability of renewable resources, energy and charging limitations of storage resources, market depth and volatility, and other factors that can affect the costs and reliability on an hour-by-hour basis. Hourly results for the entire 15-year period are then examined for any shortfalls.

An example of the hourly results used to verify RA is provided in **Figure 4.8**, which shows not only that each hour can be adequately served for the period illustrated, but how they are expected to be served. Load, shown in the black line, is met or exceeded each hour by a stack of resources. Generation exceeding load is used to make economy market sales or replenish energy storage resources. Total stored energy is shown in the dashed purple line. The load and resource stack shown in **Figure 4.8** are typical of summer days, and the daily charging and discharging of the storage fleet cycles are as expected.

Figure 4.8 - Example of Hourly Load and Dispatch Results Used to Ensure Resource Adequacy (August 13-14, 2035)



4.2.4. Resource Costs

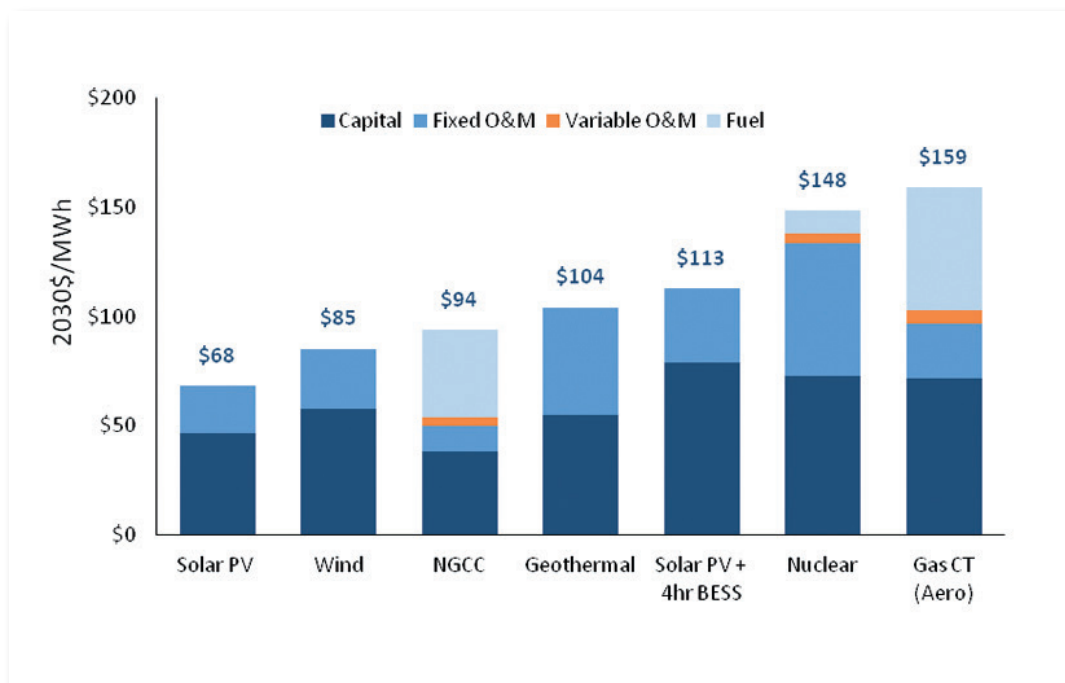
Capital cost assumptions for future resources are primarily based on Siemens PTI Spring 2025 National Forecast Model Reference Case. This outlook reflects expectations that near-term cost pressures will persist through 2030, driven by projected load growth and increasing reliability needs that are elevating demand for new generating resources. Capital costs were also benchmarked against other industry sources including the National Laboratory of the Rockies' Annual Technology Baseline, Wood Mackenzie, the U.S. Energy Information Administration, and Lazard, as well as special project studies and UNSE's ASRFP.

In the IRP modeling, UNSE assumed that solar and wind projects would not receive tax credits under the OBBBA. Resources such as storage, geothermal, pumped storage, and nuclear are assumed to meet the prevailing wage and apprenticeship requirements and qualify for the full Investment Tax Credit if the construction begins by 2033. Project construction timeframes, domestic content requirements associated with tax credit eligibility, project location and other factors are also considered. Please refer to Appendix C for more information.

Levelized Cost of Energy

The levelized cost of energy (LCOE) is commonly used to compare the cost of energy produced by different resource technologies. LCOE is calculated as the net present value of a project's cost over its lifetime divided by the net present value of the energy produced over its lifetime (\$/MWh). Costs include construction, financing, fuel, and operation and maintenance (O&M). However, LCOE has limitations as a benchmarking metric, as it does not adequately capture key risk factors such as fuel volatility, regulatory uncertainty, and differences in system value across resources.

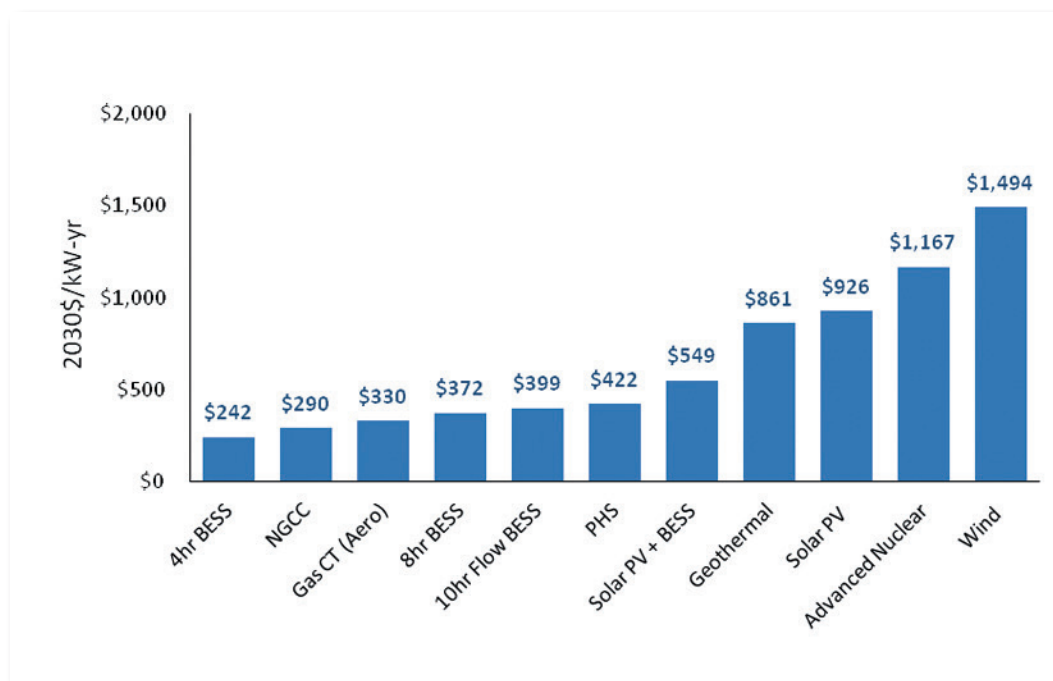
Figure 4.9 - Levelized Cost of Energy



Levelized Cost of Capacity

Another metric commonly used to compare resource costs is the levelized cost of capacity (LCOC). It measures the net present value of total cost over a project's lifetime relative to accredited capacity (\$/kW-year). LCOC generally includes capital and fixed O&M costs but excludes variable costs such as fuel and variable O&M. As a result, it does not capture fuel price risk and ignores differences in energy production across resources. However, LCOC is a useful metric for evaluating the cost of reliable capacity and aligns with planning objectives related to resource adequacy and reserve margin requirement.

Figure 4.10 - Levelized Cost of Capacity (ELCC Adjusted)



Note: ELCC assumptions applied - Wind and Solar PV (20%), Solar PV+BESS (60%), 4Hr BESS (85%) and all other resources 90%

4.2.5. Market and Fuel Prices

Desert Southwest Wholesale Power Markets

Wholesale power markets in the Desert Southwest historically have provided an efficient mechanism for utilities to buy and sell power, enabling optimization of resource portfolios and reducing costs for customers. Annual trends in wholesale power prices are strongly influenced by natural gas prices, as gas-fired generation often sets the marginal cost of energy in the region. However, market prices are also impacted by increasing renewable penetration and system conditions. The extreme weather events in recent years have increased market volatility and exposed capacity shortfalls across much of the Western Interconnection. While participation in regional markets is expected to improve access to resources, utilities continue to prioritize firm resource additions to reduce exposure to higher market prices and ensure reliable service during periods of system stress.

As power demand is expected to grow at an unprecedented pace with surges in large loads, long-term wholesale power prices are projected to be volatile while trending upward. Including these dynamics in UNSE’s portfolio modeling is important to account for how wholesale market opportunities are likely to affect UNSE’s dispatch and operating costs.



Wholesale Power and Natural Gas Price Forecasts

UNSE develops its fuel and wholesale power price forecasts using independent third-party sources to ensure alignment with current market conditions and long-term fundamentals. Near-term natural gas and wholesale power price projections are based on S&P Global Platts’ forward curves. These forward curves are derived from Intercontinental Exchange settlement data reflecting market-based pricing and current market expectations. UNSE applies Platts forward natural gas and wholesale

power prices for 2027 through 2029, the first three years of the IRP study period. From 2030 through 2033, prices reflect a blend of Platts forward market data and a long-term fundamental outlook based on Wood MacKenzie’s 2025 North America Long-Term Power Market Outlook (moderate case). Beyond 2033, prices are derived entirely from the Wood Mackenzie report. This outlook assumes continued strength in natural gas supply, supported by sustained demand growth. **Figure 4.11** presents average historical and forecasted Palo Verde hub power prices, while **Figure 4.12** presents historical and forecasted San Juan Basin natural gas prices.

Figure 4.11 - Palo Verde Average Wholesale Power Prices

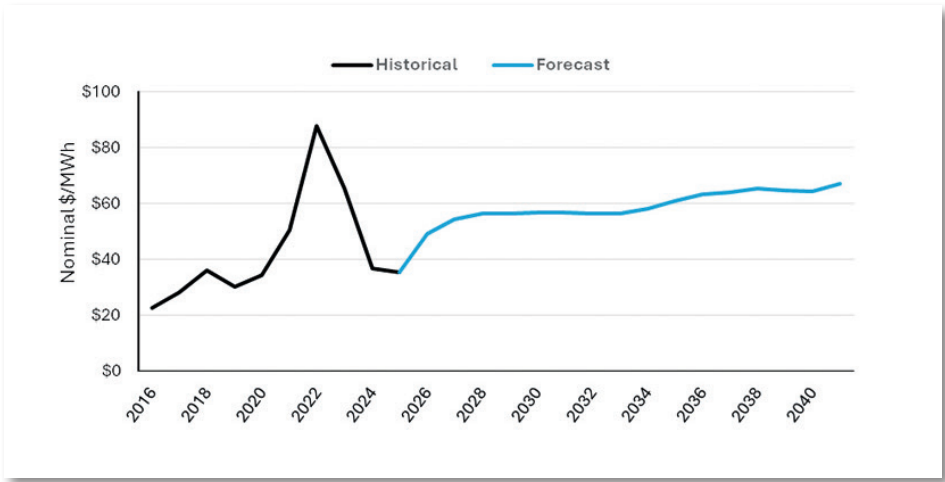
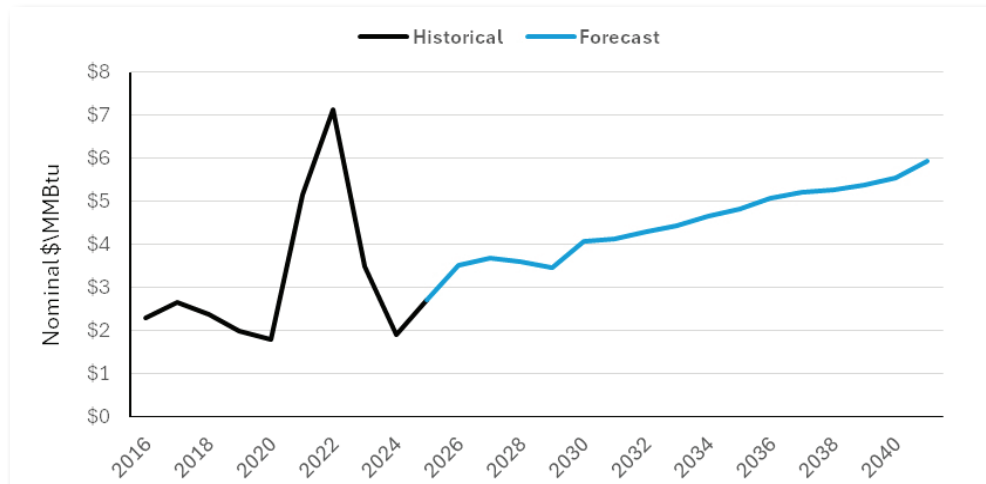


Figure 4.12 - San Juan Basin Natural Gas Prices



4.2.6. New Transmission Development

Currently, the Unisource system in Santa Cruz County is served by a single 138kV transmission line from Tucson Electric Power's Vail substation. Because there is no alternate power route, a fault on this transmission line could result in a sustained outage for customers across Santa Cruz county. In order to improve reliability for customers in this area, UNSE is developing the Santa Cruz Reliability Project, which will provide an alternate source of power to Santa Cruz customers by creating a new connection to the regional TEP 138kV system near Green Valley, Arizona and then constructing a new 138kV circuit to a new substation in Nogales, Arizona. The resulting looped transmission system will provide power to substations in Santa Cruz county from more than one source, greatly increasing reliability for UNSE customers.

In 2024, the Department of Energy announced that UNSE would be a recipient of funds through the Grid Resilience and Innovations Partnerships (GRIP) program. All funds received from the GRIP program will go towards the cost of the Santa Cruz Reliability Project, ultimately reducing costs reflected in future rates.

The expected in-service date for all three phases of this project is 2031.²⁴

²⁴ For details on the Santa Cruz Reliability Project, see the project website: <https://www.uesaz.com/santa-cruz-reliability/>.

4.2.7. Retirement Analysis

Firm and dispatchable resources play a critical role in meeting reliability in the Desert Southwest, particularly during periods of extreme weather. In considering whether generating resources should be retired, UNSE looks at whether the resources still have a useful life, state and federal regulations and their associated risks, availability of fuel supply, and overall cost impacts to customers. At the same time, given the projected load growth and future capacity needs, the resources required to replace the retired capacity and maintain resource adequacy are also considered.

Gila River Power Block 3 is a natural gas combined cycle (NGCC) facility built in 2006. This resource is a large unit capable of baseload dispatch with a reasonably fast ramp rate, making this generator a key component of UNSE's resource adequacy.

Replacing this unit's capacity like-for-like or with the required quantity of intermittent and energy-limited resources would result in additional capital expense, even as recovery on assets continued. Fuel transport contracts are in place, and Gila River has the capability to receive gas from both the San Juan and Permian basins, which lowers fuel risk. Given these factors and the useful life still ahead of this unit, UNSE does not plan to retire them within the window of this IRP.



SECTION 5

PORTFOLIO RESULTS AND ANALYSIS

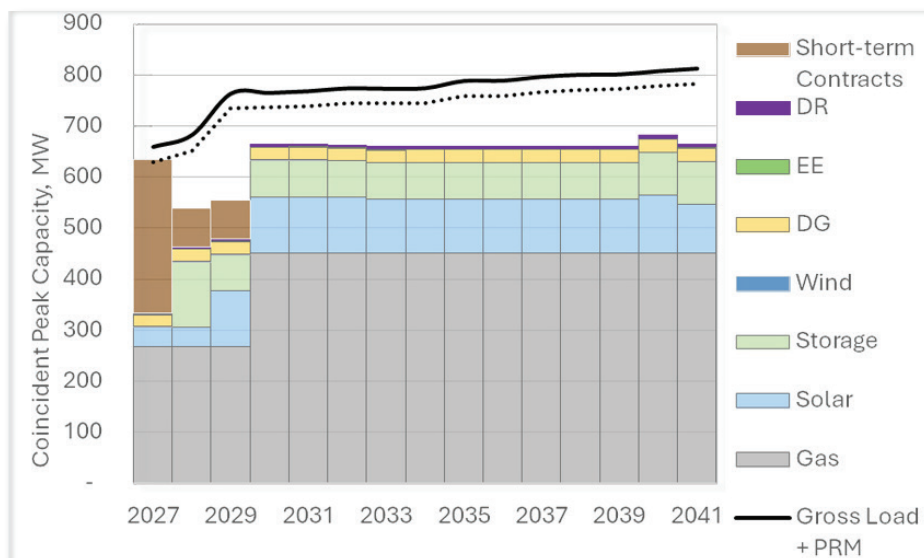
5.1. Existing Loads and Resources

This IRP covers the study period 2027 through 2041. **Figure 5.1** shows UNSE's forecasted gross and net peak demand including the accredited capacity of existing and committed resources available to serve customer demand. Gross peak demand reflects forecasted load plus the PRM requirement. Net peak demand reflects forecasted load after the impacts of Energy Efficiency (EE) and Distributed Generation (DG), plus the PRM requirement. The coincident peak capacity for DG, utility-scale solar, wind, and storage are based on their ELCC values.

The resources shown in **Figure 5.1** include all existing generating resources and committed resource additions in 2028, including the Dandelion facility of 140 MW solar paired with 140 MW/560 MWh of battery storage. The study period also includes the Black Mountain Expansion Project that adds 196MW of new simple cycle combustion turbines. No future resource additions beyond those already committed are assumed in this timeframe. The gap between gross load and the top of the resource stack represents the additional capacity required over the planning horizon to meet UNSE's resource adequacy requirements. The portfolio development in this IRP is informed by the timing and magnitude of the capacity needed.

Following the completion of portfolio development, UNSE procured approximately 275MW of additional purchased capacity that will contribute to meeting peak demand across 2027-2029. The balance of near-term capacity needs is expected to be met through UNSE's capacity hedging program. **Figure 5.1** includes these market purchase additions.

Figure 5.1 - Annual Loads and Resources with No Future Resource Additions



5.2. Portfolio Evaluation, Results and Analysis

As summarized in **Table 5.1**, UNSE developed several portfolios covering a range of future customer loads, resources, costs, and market and fuel price assumptions. This allows UNSE to evaluate its adaptability to changing load and market conditions while achieving least-cost outcomes and meeting reliability objectives. These portfolios incorporate long-term capacity expansion results, two-step RA tests, and price sensitivities, and are intended to meet the requirements outlined in Appendix A.

Table 5.1 - 2026 UNSE IRP Portfolios

Portfolio Number and Name	Description/Design Objectives ³³	Sensitivity Tests
P01 – Least-Cost, Technology Neutral Base Case	A least-cost, technology neutral portfolio required by the ACC. Allows the LTCE to select any resources available.	High/Low Market Prices
P02 - Clean Energy Buildout	A portfolio that only allows the LTCE to choose carbon-free resources (solar, wind, storage, pumped hydro, geothermal, nuclear).	High/Low Market Prices
P03 - High Load Factor Customer Growth (HLFCG)	A least-cost, technology neutral portfolio that adds 150 MW of high load factor customers to the base forecast beginning in 2030.	High/Low Market Prices
P04 - High Load Factor Customer Growth (HLFCG) / Clean Energy Buildout	A portfolio that adds 150 MW of high load factor customers to the base forecast beginning in 2030 and only allows the LTCE to select carbon-free resources.	High/Low Market Prices
P05 - Pumped Hydro	A least-cost portfolio that adds 25 MW of pumped hydro storage in 2033.	High/Low Market Prices
P06 – Geothermal	A least-cost portfolio that adds 25 MW of geothermal resources in 2034.	High/Low Market Prices
P07 – Nuclear	A least-cost portfolio that adds 25 MW of large nuclear resources in 2038.	High/Low Market Prices

Portfolios Using the Base Forecast

UNSE developed seven portfolios for the 2026 IRP in accordance with ACC Order No. 79589. The annual resource additions and retirements for each portfolio are presented in Appendix B: Portfolio Summaries.

P01 – Least-Cost, Technology Neutral serves as the least-cost, technology-neutral portfolio and UNSE’s reference case.²⁵ The portfolio assumes the 140 MW Dandelion hybrid solar plus storage project enters into service in 2028. It also includes the Black Mountain Expansion consisting of four 49 MW gas combustion turbines in 2030, and the retirement of wind and solar resources over the planning horizon.

In addition, P01 adds 50 MW solar and 50 MW 4-hour energy storage resources. The LTCE model also selected 125 MW of new natural gas combined-cycle capacity in 2031. Because the portfolio was not subject to emissions reduction targets, renewable energy requirements, or other carbon-related constraints, natural gas resources remained available for selection and were identified by the model as part of the least-cost resource mix.

P02 – Clean Energy Buildout represents a variation of P01 in which the model was restricted to selecting only carbon-free resources. The resource options were comprised of solar, wind, advanced geothermal, and nuclear generation types, as well as four-, eight-, and ten-hour battery and pumped hydro storage types. This portfolio illustrates the least-cost resource plan in the absence of new gas-fired resource options. Relative to P01, the LTCE model selected an additional 225 MW of 4-hour energy storage and 225 MW of solar to replace the capacity and reliability contribution provided by the 125 MW of gas selected in the Least-Cost, Technology Neutral portfolio.

The need for approximately 450 MW of additional solar and storage resources to offset 125 MW of gas capacity reflects, in part, the declining Effective Load Carrying Capability (ELCC) of solar and storage resources as their penetration increases on the system in comparison to gas, consistent with the findings of E3’s ELCC study (see Appendix E). In addition to declining ELCC values, resource adequacy, operational flexibility, and reserve margin requirements also influence the amount of clean energy capacity required. It is interesting to note that the LTCE did not add wind as a resource for P02 or any of the other portfolios. Increased capital cost assumptions, reduced tax credit benefits, and minimal peak credit value decreased the competitiveness of new wind resources. Solar plus storage and new natural gas resources provide a more cost-effective combination of capacity value.

In addition to the reference portfolios, UNSE evaluated several technologies: pumped hydro storage, enhanced geothermal, and advanced large nuclear resources. While these resources were available as candidate technologies in the LTCE model for both P01 and P02, none were economically selected under the modeled assumptions. To evaluate their potential impacts on future resource needs, UNSE developed portfolios in which 25 MW of each technology was set in the earliest feasible in-service year, taking into consideration expected procurement, permitting, and construction timelines.

²⁵ This portfolio also meets the requirement in Decision No. 79589 to model a least cost, technology neutral portfolio.

P05 – Pumped Hydro includes 25 MW of pumped hydro storage placed in service in 2033 in addition to the assumptions in P01. Relative to P01, the resulting least-cost resource plan includes 200 MW more solar capacity and 50 MW less storage capacity. Because pumped hydro provides energy shifting and capacity value but does not generate energy on a net basis, the LTCE model selected additional solar resources to provide the energy required to charge the facility while maintaining reliability and reserve margin requirements. The resulting resource mix represents the least-cost portfolio identified by the model under these revised assumptions.

P06 – Geothermal includes 25 MW of enhanced geothermal resources entering into service in 2034. Relative to P01, the addition of geothermal increases solar capacity by 50 MW and decreases storage capacity by 50 MW. Unlike pumped hydro storage, geothermal provides both energy and capacity and can operate at high capacity factors throughout the year. As a result, geothermal can directly offset a portion of the storage capacity that would otherwise be required to maintain reliability.

P07 – Nuclear includes 25 MW of large advanced pressurized water reactor nuclear resources entering service in 2038. Relative to P01, the portfolio includes 25 MW less natural gas while resulting in an otherwise similar resource build. One of the primary drivers of this differing resource mix is the later in-service date of the nuclear resource. Because nuclear capacity is not available until 2038, the LTCE model selects additional resources earlier in the planning horizon to maintain reserve margin requirements and reliably meet projected load growth prior to the nuclear resource becoming operational.

Portfolios Using the Base Forecast Plus Additional Growth

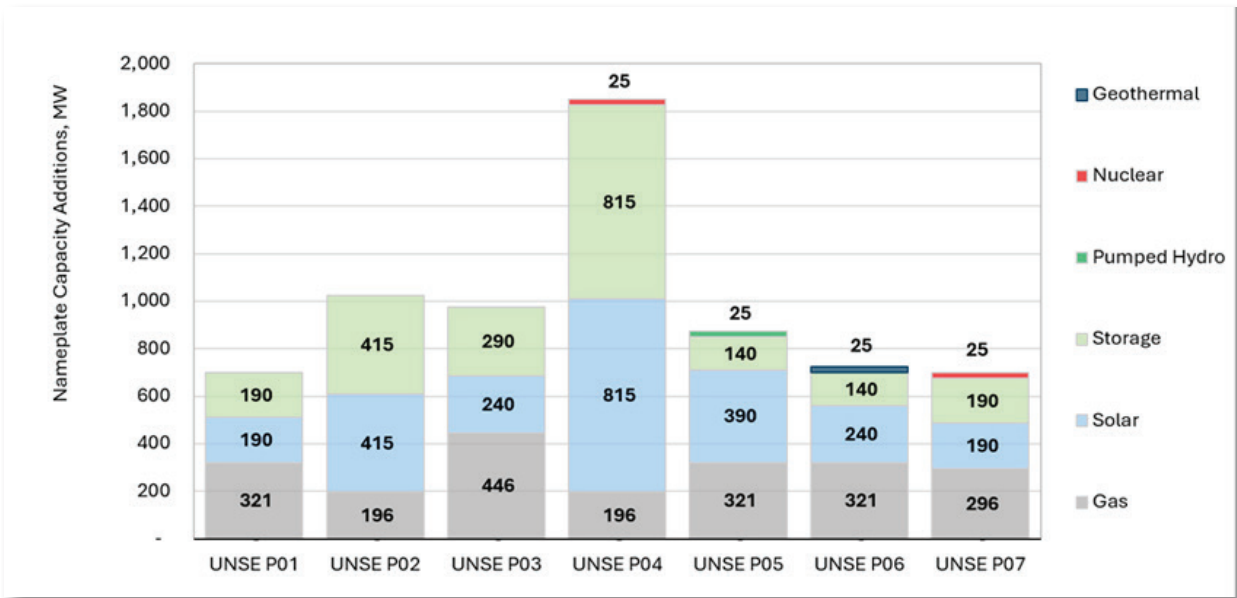
P03 – HLFCG Technology Neutral represents a variation of P01 in which UNSE evaluated a High Load Factor Customer Growth (HLFCG) scenario that includes 150 MW of additional high load factor load. Relative to P01, the LTCE model selected an additional capacity of 125 MW of natural gas, 50 MW of solar, and 100 MW of energy storage to meet the increased demand associated with the higher load forecast (see Appendix B). Similar to P01, the model continued to select a combination of natural gas, solar, and storage resources as the least-cost portfolio under technology-neutral assumptions.

P04 – HLFCG Clean Energy represents a variation of P03 in which the same HLFCG assumptions are applied but only carbon-free resources are available for selection by the model. Relative to P03, the portfolio adds an additional 575 MW of solar, 525 MW of energy storage, and 25 MW of advanced nuclear (see Appendix B). Similar to P02, restricting the model to carbon-free resources results in substantially greater solar and storage deployment to satisfy reliability and resource adequacy requirements. The clean energy constraints, combined with the additional load requirements, also drive the selection of advanced nuclear as part of the least-cost resource portfolio.

Portfolio Resource Buildouts

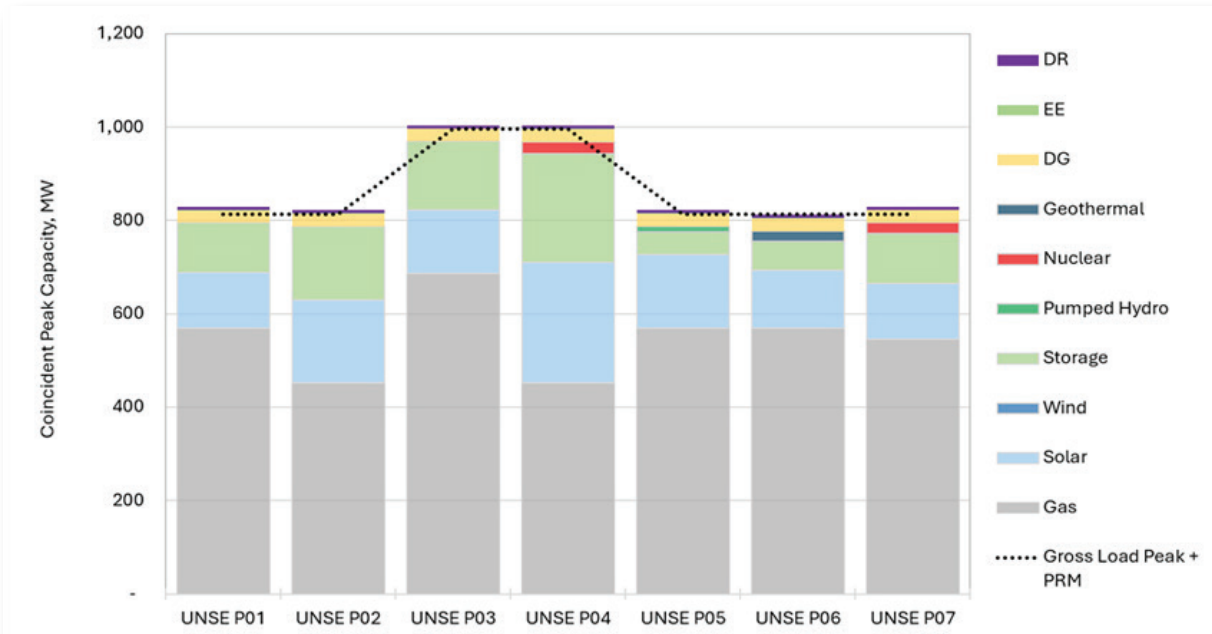
Figure 5.2 illustrates total resource additions throughout the study period by portfolio. Portfolios P02, P03, and P04 exhibit the largest cumulative resource additions. The increased additions in P02 are driven by the carbon-free resource constraint, while P03 reflects the impact of higher load growth. Portfolio P04 combines both factors and therefore has the largest overall buildout.

Figure 5.2 – Total Resource Additions for Each Portfolio



When ELCC values are applied to determine the coincident peak contribution of all resources in service by 2041, the relative differences among portfolios narrow. As shown in Figure 5.3, the resulting coincident peak capacity across the portfolios aligns more closely with each portfolio’s gross load requirement, indicating that ELCC-adjusted capacity provides a more comparable measure of each portfolio’s contribution to reliability than installed capacity alone.

Figure 5.3 - 2041 Coincident Peak Capacity



Portfolio Costs

Figure 5.4 presents the Net Present Value of Revenue Requirements (NPVRR) and average system cost per kWh for each of the seven portfolios evaluated. Among the portfolios using the base load forecast, P02 exhibits the highest NPVRR and total system cost per retail load, while P01 represents the least-cost portfolio. **Figure 5.5** illustrates the incremental NPVRR of portfolios under the same load assumption relative to portfolio P01.

The range of costs across these portfolios is consistent with the resource additions shown in **Figure 5.2**. Although the portfolios differ in their mix of gas, solar, storage resources, and emerging technologies, total nameplate capacity additions are generally comparable, resulting in similar levels of capital investment and fixed costs.

The most significant driver of cost variation is the scale of resource additions required to meet projected demand. As shown in **Figure 5.2**, Portfolios P03 and P04 require substantially larger resource buildouts than the other portfolios. The increased additions in P03 are driven primarily by higher load growth, while P04 reflects the combined effects of higher load growth and the clean energy resource constraint. These larger buildouts increase NPVRR through higher capital expenditures, fixed operating costs, and the additional energy production required from the expanded resource fleet. Consequently, P03 and P04 exhibit the highest overall revenue requirements among the portfolios evaluated.

Despite their higher total system costs, P03 and P04 benefit from greater energy sales associated with higher load growth. The ability to recover fixed costs over a larger sales base results in lower total system cost per kWh, with P03 having the lowest average system cost per kWh among the portfolios evaluated, while P04 has a lower average system cost per kWh than P02. This outcome illustrates that while higher load growth necessitates greater investment in resources and increases total revenue requirements, the resulting increase in sales volumes can offset those costs on a per-unit basis.

Figure 5.4 - NPVRR by Portfolio

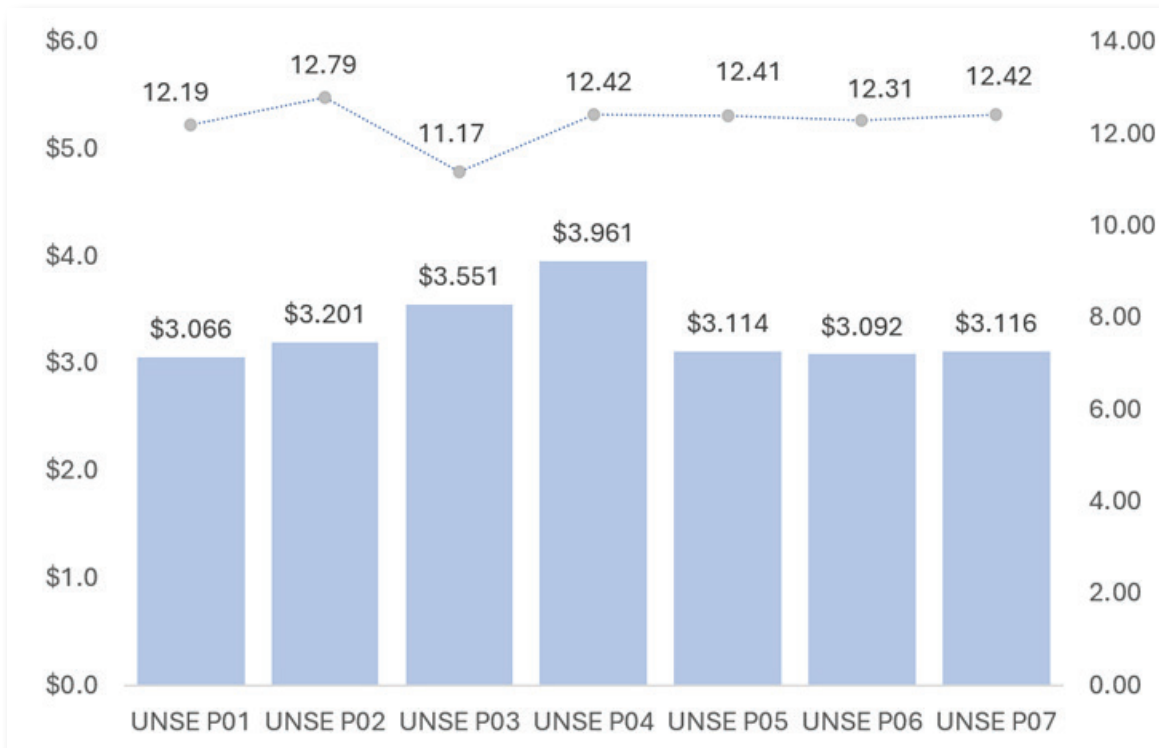
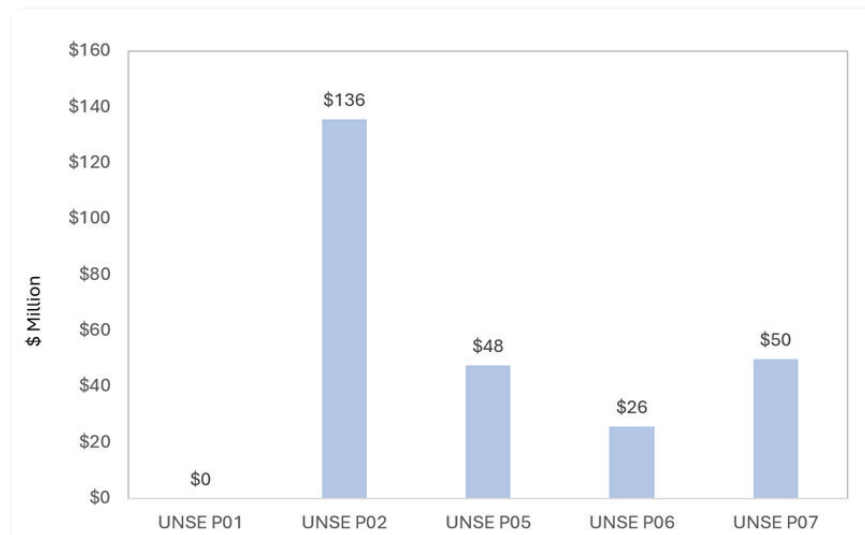


Figure 5.5 - Comparison of NPVRR Relative to P01 Tech Neutral Portfolio



Environmental Performance

Figure 5.6 through Figure 5.8 compare the environmental performance of each portfolio based on carbon dioxide (CO₂), nitrogen oxides (NO_x), and water use intensity, where intensity measures emissions or water consumption per unit of electricity generated. While most portfolios include new natural gas resources to maintain resource adequacy, changes in the overall generation mix result in similar or lower emissions intensity across all portfolios. Water use intensity remains relatively consistent throughout the study period, with minimal difference among portfolios despite changes in the generation fleet. The additional resources in these portfolios, particularly renewables, increase the total generation while reducing emissions intensity. P01 demonstrates environmental performance comparable to other evaluated portfolios.

Figure 5.6 - CO₂ Intensity

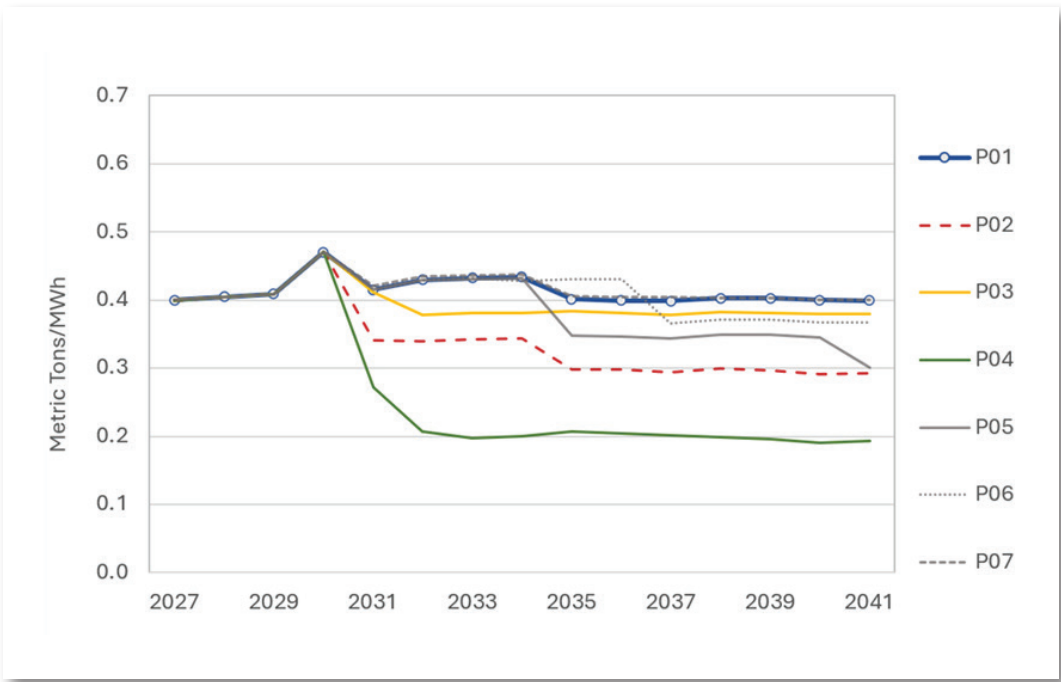


Figure 5.7 - NO_x Intensity

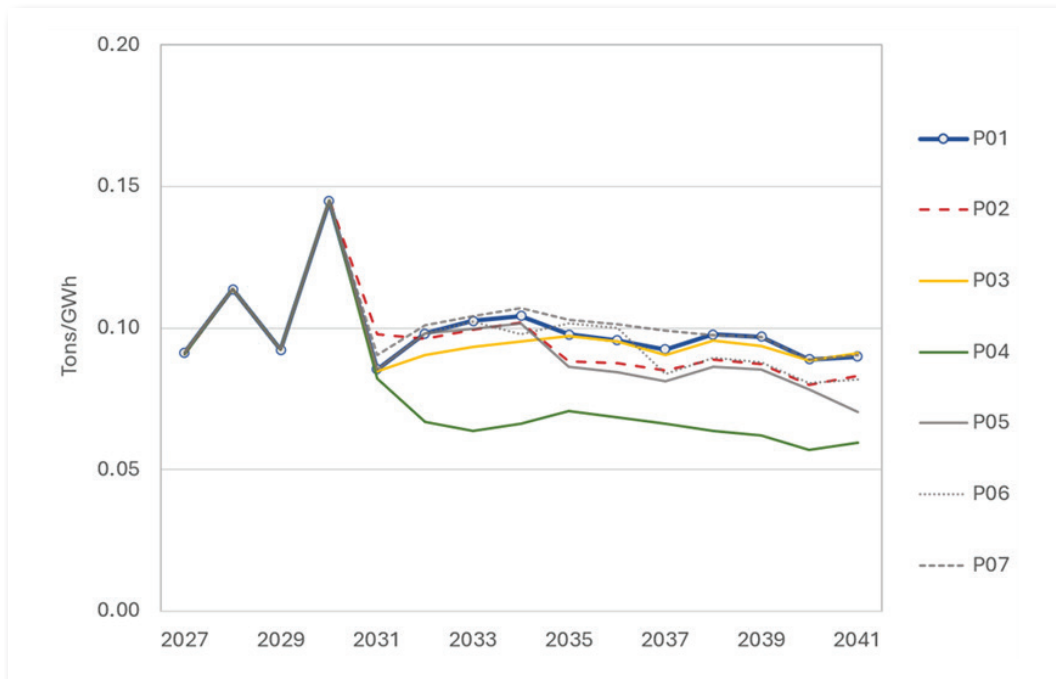
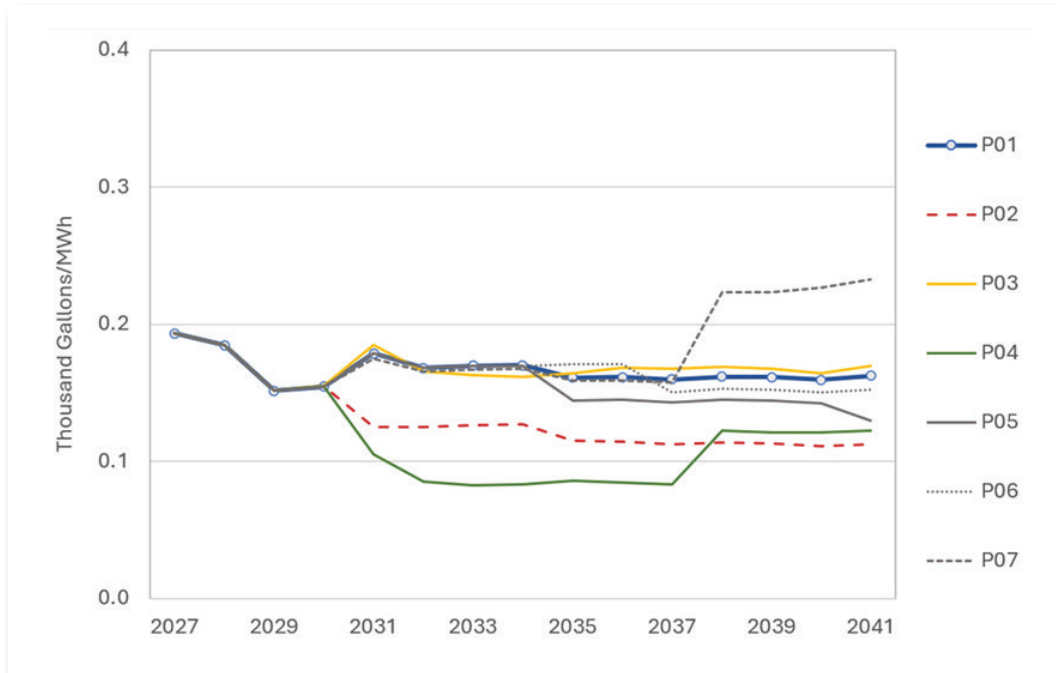


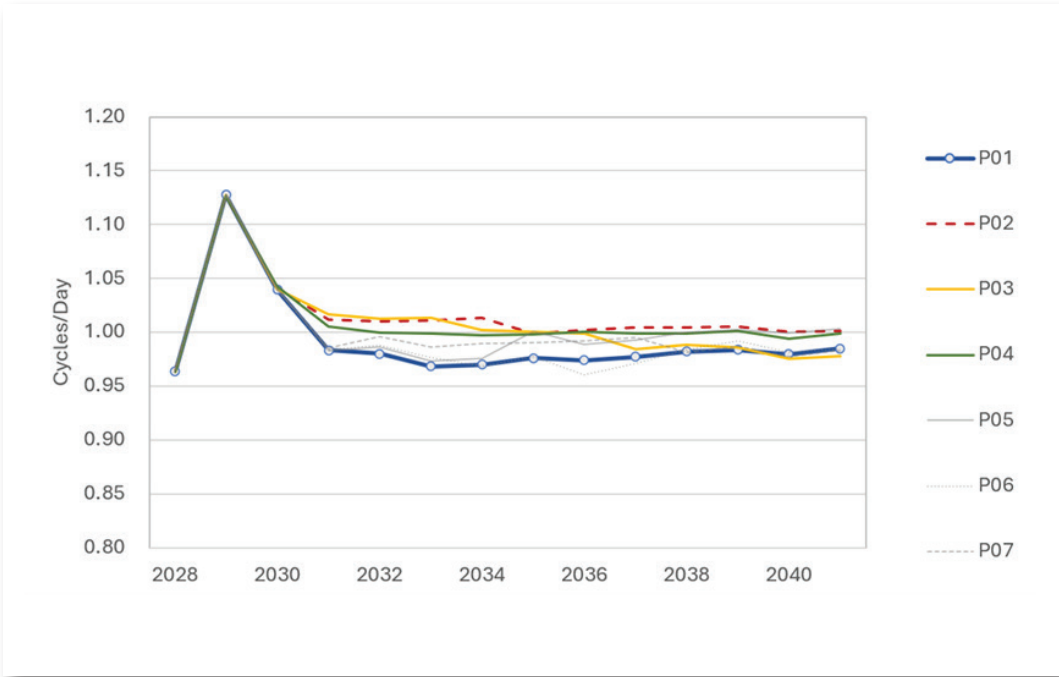
Figure 5.8 - Water Use Intensity



Battery Storage Cycling

Figure 5.9 shows the capacity-weighted, average daily cycling of each portfolio's battery storage fleet. Although the size of the battery storage fleet is driven by the need for capacity, it serves an important function of storing excess renewable generation or low-cost market energy for later use during peak hours. This energy shifting maximizes the use of solar and wind power and reduces the reliance on natural gas generation as well as market purchases over peak. Unless otherwise needed for capacity, UNSE designed its portfolios to target an average daily cycle of approximately one. Cycling levels below this target indicate underutilized storage capacity, while levels above the target indicate the need for additional storage capacity to support the system's needs, as battery warranties often have limits on the number of annual cycles.

Figure 5.9 - Battery Storage Fleet Average Daily Cycles



Portfolio Comparison

UNSE developed and analyzed seven different resource portfolios as part of the 2026 IRP. A summary of the 15-year net present value, average system cost and cumulative capacity additions are shown in **Table 5.2** below.

Table 5.2 - Portfolio Case Matrix Details

Portfolio #	Portfolio Name	Cumulative Additions (2027-2041)					
		Solar (MW)	Storage (MW)	Gas (MW)	Pumped Hydro (MW)	Geothermal (MW)	Nuclear (MW)
UNSE P01	Technology Neutral	190	190	321	0	0	0
UNSE P02	Clean Energy	415	415	196	0	0	0
UNSE P03	HLFC Growth - Tech Neutral	240	290	446	0	0	0
UNSE P04	HLFC Growth - Clean Energy	815	815	196	0	0	25
UNSE P05	Pumped Storage Hydro	390	140	321	25	0	0
UNSE P06	Geothermal	240	140	321	0	25	0
UNSE P07	Nuclear	190	190	296	0	0	25

Portfolio #	Portfolio Name	NPV (\$ Millions)	Fuel NPV (\$ Millions)	Non-Fuel NPV (\$ Millions)	Avg System Cost (¢/kWh)
UNSE P01	Technology Neutral	\$3,066	\$1,670	\$1,396	12.19
UNSE P02	Clean Energy	\$3,201	\$1,585	\$1,617	12.79
UNSE P03	HLFC Growth - Tech Neutral	\$3,551	\$1,810	\$1,742	11.17
UNSE P04	HLFC Growth - Clean Energy	\$3,961	\$1,608	\$2,353	12.42
UNSE P05	Pumped Storage Hydro	\$3,114	\$1,642	\$1,471	12.41
UNSE P06	Geothermal	\$3,092	\$1,639	\$1,452	12.31
UNSE P07	Nuclear	\$3,116	\$1,677	\$1,439	12.42

5.3. Sensitivity Analysis

Modeling the performance of a resource portfolio requires assumptions regarding future conditions such as economic growth, fuel and wholesale power markets, regulatory requirements, and the pace of technological development. UNSE seeks to identify a robust portfolio that delivers strong performance under these assumptions while preserving the flexibility to adapt to evolving market, policy, and operational conditions. Given the inherent uncertainty associated with long-term planning, each resource portfolio is evaluated across a range of future scenarios to assess its performance and resilience under a variety of potential outcomes. Because key market drivers do not move independently, alternative future scenarios must capture a range of plausible futures while maintaining internally consistent relationships among economic, market, regulatory, and technological assumptions.

Sensitivity analysis for market prices includes both low and high cases for natural gas and wholesale energy prices.

The low market case is based on E3's Southwest Region Market Price Forecast Core Case 2025 edition, which reflects increased renewable and storage deployment, as well as the impacts of the anticipated regional day-ahead market configuration. Under this outlook, energy prices are expected to remain relatively low in the near to medium term due to the increasing penetration of low-marginal-cost resources. Over the longer term, steady load growth from data centers and other factors with escalating gas prices contribute to higher energy market prices.

The high market case is derived from Siemens PTI's Fall 2025 Power Market Outlook. This outlook assumes natural gas will continue to serve as a critical firming and dispatchable resource, with its role reinforced by the reduction of renewable energy tax incentives and growing reliability needs from rising data center demand. The forecast also incorporates expanding U.S. liquid natural gas exports through the early 2030s, driven by sustained global demand and other geopolitical factors. These assumptions contribute to higher natural gas prices, which in turn increase wholesale energy prices. In addition, strong load growth and a slower pace of renewable resource additions further contribute to upward pressure on energy market prices.

Figure 5.10 - Palo Verde Wholesale Power Prices

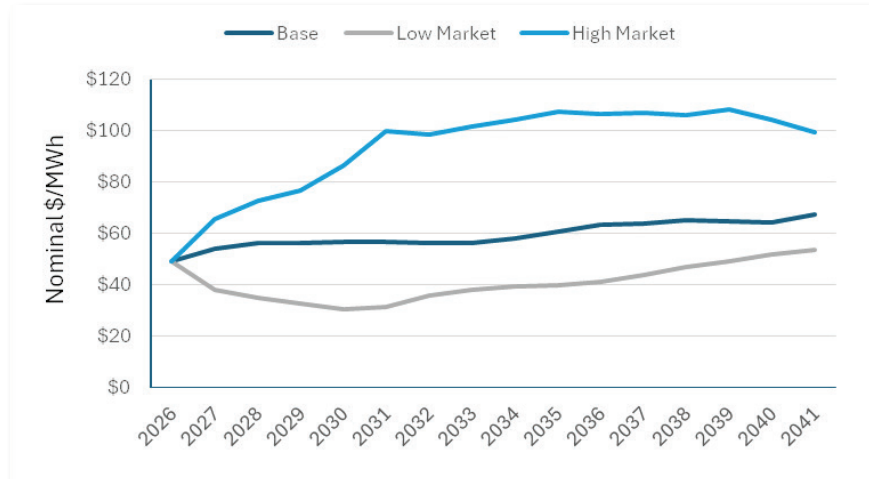


Figure 5.11 - San Juan Basin Natural Gas Prices

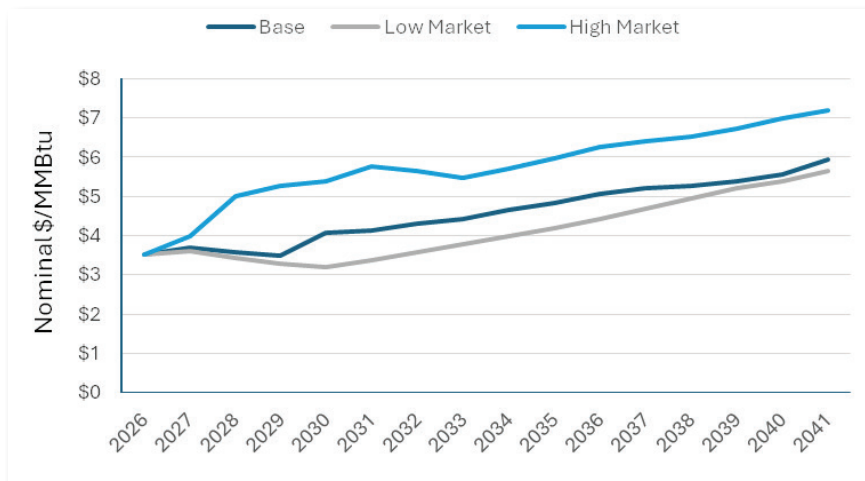
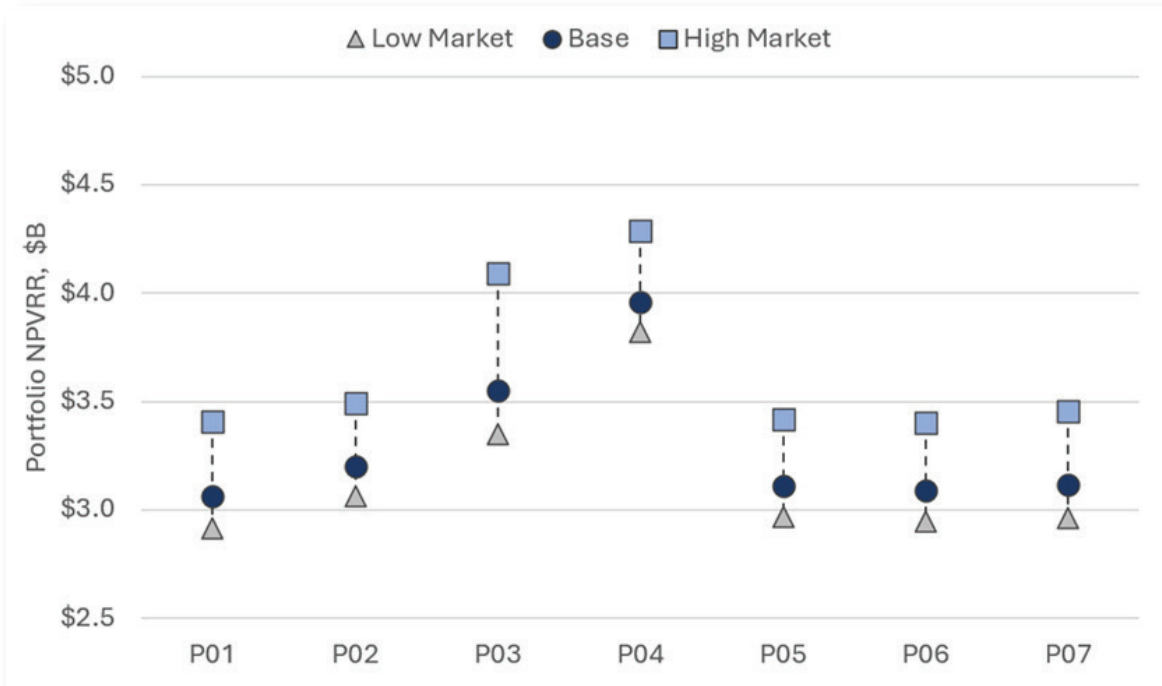


Figure 5.12 shows each portfolio's NPVRR and the range of results of the sensitivity tests. The impacts of changes in wholesale energy and natural gas prices are generally consistent across portfolios, indicating the uncertainty in future market and gas prices does not place one portfolio at a particularly higher risk than any others.

Figure 5.12 - Portfolio NPVRR Sensitivity to Market Conditions



Additionally, UNSE observed that total natural gas consumption is relatively insensitive to the lower market price assumptions. However, under higher market price scenarios, all portfolios exhibit increased utilization of UNSE's natural gas-fired generation resources. This outcome is driven by wholesale energy prices remaining above the marginal cost of UNSE's natural gas generation, creating additional opportunities for economic dispatch and market sales. **Figure 5.13** and **Figure 5.14** illustrate this behavior for Portfolio P01.

Figure 5.13 - Total Natural Gas Consumption Across P01 Sensitivity Analysis

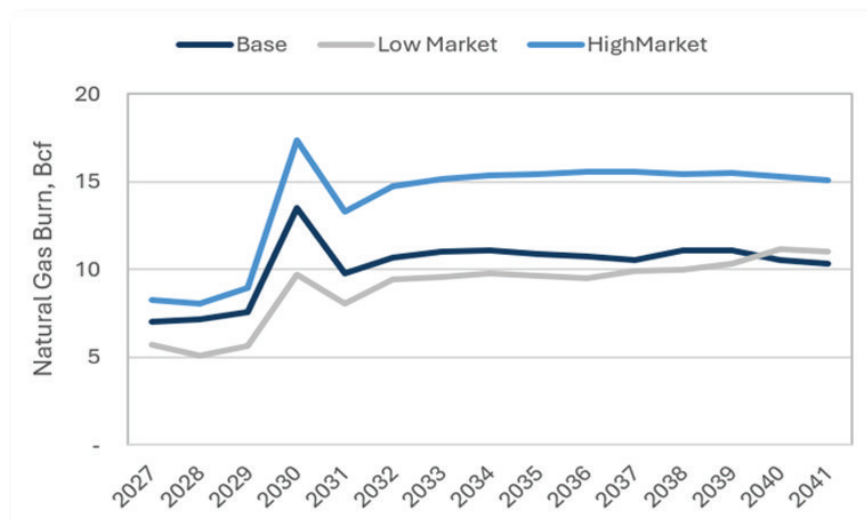


Figure 5.14 - Total Market Sales Across P01 Sensitivity Analysis



ACC Decision No. 79589 requires each LSE to 'include in future IRPs portfolios which capture the benefits of joining a day-ahead market.' Day-ahead market frameworks in the Western Interconnection continue to evolve and the actual benefits will depend on factors including market participation levels, market design, transmission availability and operational performance. As such, UNSE elected to incorporate the assumed benefits of joining a day-ahead market through sensitivity analysis.

UNSE performed a sensitivity analysis using E3 market pricing based on the Southwest Region Market Price Forecast E3 Core Case 2025 edition on all the portfolios. E3's forecast models the Western Electricity Coordinating Council region as an integrated market and reflects the expected benefits of regional market participation based on expected CAISO Extended Day-Ahead Market and SPP Markets+ configurations and frameworks. These benefits arise from increased access to regional resources, broader economic dispatch across participating utilities and optimized transmission usage.

SECTION 6

UNSE'S 2026 PREFERRED PORTFOLIO

6.1 Portfolio Results

Project Overview

UNSE's 2026 preferred portfolio is the P01 – Least-Cost, Technology Neutral (LCTN) portfolio. This base case portfolio establishes an updated resource strategy that prioritizes affordability and reliability.

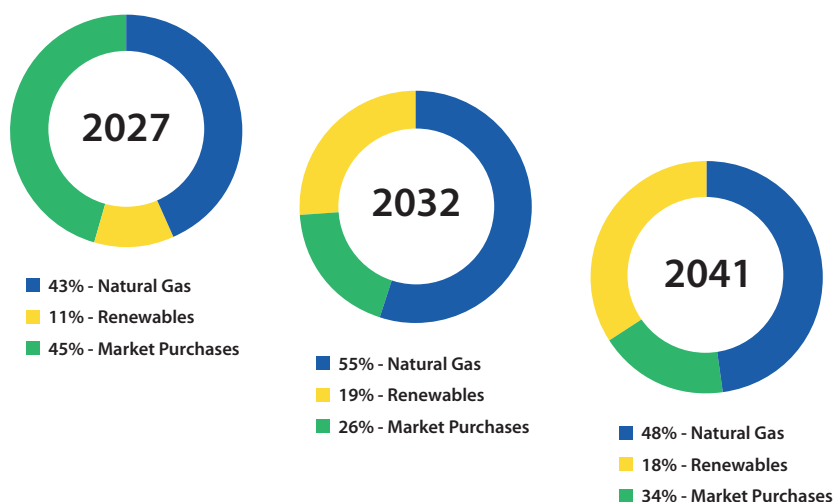
As compared to the 2023 IRP, the 2026 IRP reflects significant changes in environmental regulations, federal tax incentives, capital cost projections, load forecasts, and updates to UNSE's planning methodology. These methodological enhancements include revised Planning Reserve Margin (PRM) requirements and updated Effective Load Carrying Capability (ELCC) study results, which affect the reliability value and relative economics of available resource options and contribute to the different resource mix selected in the optimization. As a result, UNSE reassessed its planning objectives and resource strategy to ensure customers continue to receive reliable and affordable electric service under a wide range of future conditions.

The Least-Cost, Technology Neutral Portfolio represents the least-cost portfolio evaluated in this planning cycle while maintaining system reliability (see **Figure 6.1**). The portfolio balances new resource additions and market purchases to meet projected load growth and reliability needs, resulting in a generation mix that increases the contribution of natural gas, renewable resources, and energy storage.

Among the portfolios evaluated under the same load growth scenario in the 2026 IRP, the Least-Cost, Technology Neutral Portfolio requires approximately \$40 million to \$225 million less in cumulative capital investment over the 2027-2041 planning horizon. On a NPVRR basis, the portfolio is projected to reduce customer costs by approximately \$25 million to \$140 million relative to the other resource portfolios considered.

 The Least-Cost, Technology Neutral Portfolio represents the least-cost portfolio evaluated in this planning cycle while maintaining system reliability and achieving additional direct emissions reductions.

Figure 6.1 - LCTN Portfolio Energy Mix



6.2. Least-Cost, Technology Neutral Portfolio Plan Attributes

The primary objective of the preferred portfolio is to reliably meet our customers’ energy needs at affordable rates, while mitigating potential risks to future costs. To meet projected load growth and replace capacity lost from future resource retirements, UNSE’s preferred portfolio adds 511 MW of generating capacity and 190 MW of battery energy storage over the 15-year planning horizon. As shown in **Figure 6.2**, these additions include 190 MW of solar generation, 190 MW of energy storage, and 321 MW of new natural gas combustion turbines and combined cycle generation in 2030 and 2031.

The Least-Cost, Technology Neutral Portfolio assumes that all 190 MW of solar capacity will be paired with 190 MW of battery energy storage in a hybrid configuration. Co-locating solar and storage resources is expected to provide construction and operational efficiencies, maximize available battery storage tax incentives, and efficiently utilize available transmission infrastructure.

Figure 6.2 - LCTN Portfolio Future Capacity Additions, MW

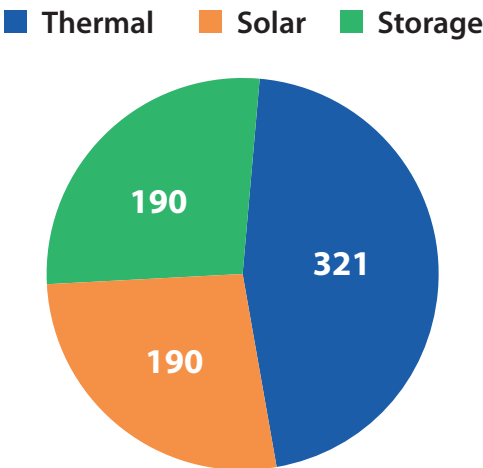


Figure 6.3 - LCTN Portfolio Capacity Additions by Year

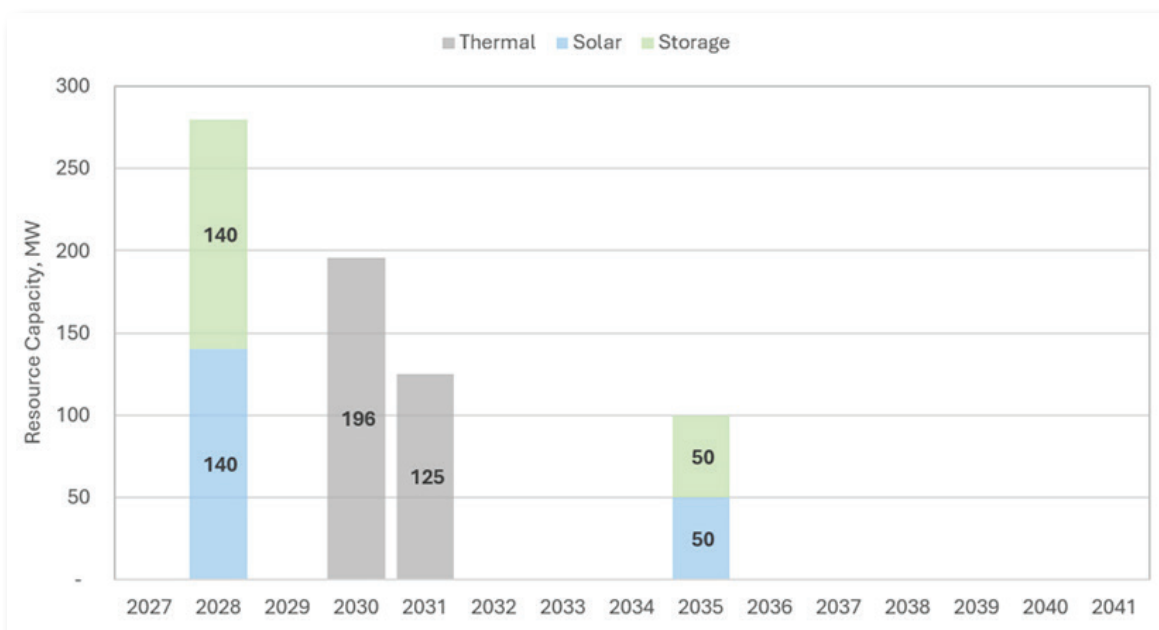


Figure 6.3 shows the Least-Cost, Technology Neutral Portfolio resource capacity additions through the planning period. These additions are needed to replace expiring Power Purchase Agreements (PPAs) and support increasing demand from customers. The portfolio includes 321 MW of natural gas capacity additions, of which 196 MW is associated with the Black Mountain Expansion Project. Although the portfolio includes 190 MW of new solar and 190 MW of battery storage, the net additions shown in **Figure 6.4** are lower due to the expiration of existing PPAs.

Figure 6.4 - LCTN Portfolio Net Additions and Retirements (2027 – 2041)

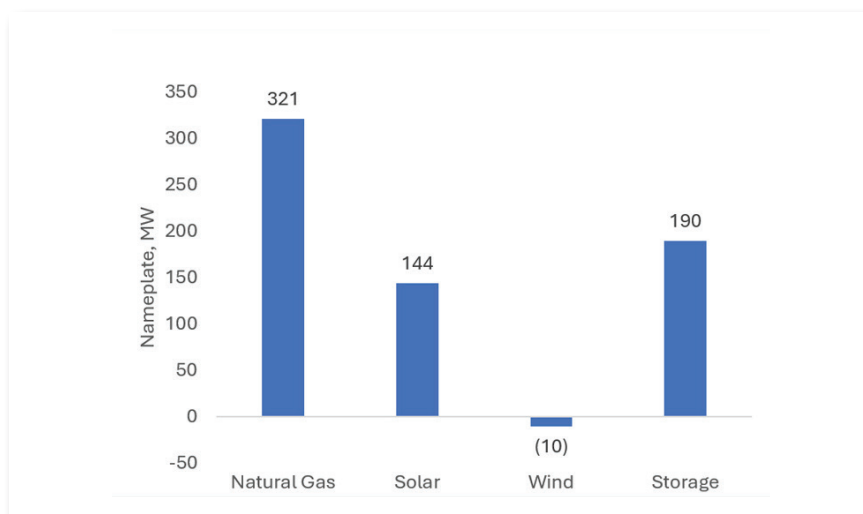


Figure 6.5 below shows the shift in energy mix over the planning period. New gas facilities serve as both base load and peaking units. Renewable generation increases over the study period as additional solar capacity is added to the portfolio. Market purchases support the resource mix by providing a flexible source of energy when it is more economical than dispatching available resources or when additional energy is needed to meet demand.

Figure 6.5 - LCTN Portfolio Annual Energy by Resource Type

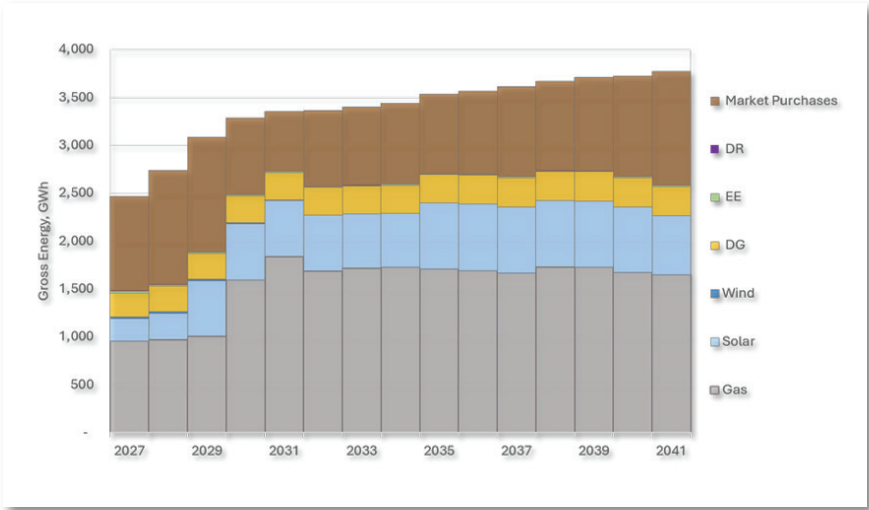


Figure 6.6 and **Table 6.1** below show the Load and Resources assessment of the Least-Cost, Technology Neutral Portfolio. While renewables and energy storage contribute significant nameplate capacity, only their ELCC values are reflected for resource adequacy purposes, representing the amount of capacity contributing towards meeting peak demand. As additional solar and storage resources are added over the study period, their incremental ELCC values decline due to diminishing capacity contribution at high levels of renewable penetration.

Figure 6.6 - LCTN Portfolio Loads and Resources Forecast

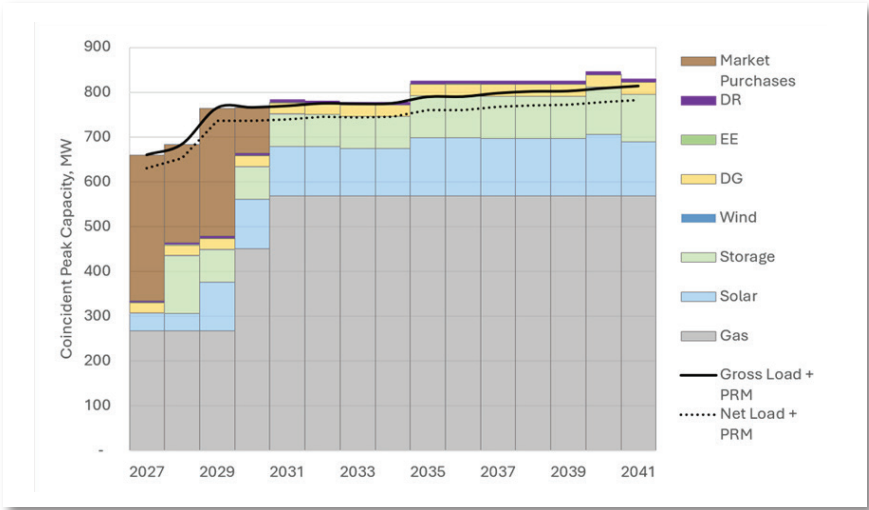


Table 6.1 - LCTN Portfolio Loads and Resources, MW

	2027	2028	2029	2030	2031	2032	2033	2034
Firm Load Obligation, MW	630	652	736	737	739	745	744	745
Retail	534	553	623	624	626	632	630	632
Retail Reserve Requirement	96	99	112	112	113	114	113	114
Coincident Peak Capacity, MW	485	438	453	638	757	755	751	751
Gas - Combined Cycle	133	133	133	133	251	251	251	251
Gas - Combustion Turbines	134	134	134	318	318	318	318	318
Wind	2	2	2	2	2	0	0	0
Solar	39	39	110	110	110	110	106	106
Storage	0	128	71	71	71	71	71	71
Demand Response	2	3	4	4	5	6	6	6
Short-Term Contract Purchases	175	0	0	0	0	0	0	0
Retail Reserve Margin, MW	-50	-114	-170	14	131	124	121	120
Retail Reserve Margin, %	-9%	-21%	-27%	2%	21%	20%	19%	19%
Net Position	-146	-214	-282	-98	18	10	7	6

	2035	2036	2037	2038	2039	2040	2041
Firm Load Obligation, MW	760	760	767	771	772	778	783
Retail	644	644	650	653	654	659	663
Retail Reserve Requirement	116	116	117	118	118	119	119
Coincident Peak Capacity, MW	798	798	798	798	798	819	802
Gas - Combined Cycle	251	251	251	251	251	251	251
Gas - Combustion Turbines	318	318	318	318	318	318	318
Wind	0	0	0	0	0	0	0
Solar	129	129	128	128	128	137	120
Storage	94	94	94	94	94	106	106
Demand Response	6	6	7	7	7	7	7
Short-Term Contract Purchases	0	0	0	0	0	0	0
Retail Reserve Margin, MW	154	154	148	145	144	160	139
Retail Reserve Margin, %	24%	24%	23%	22%	22%	24%	21%
Net Position	38	38	31	27	26	41	19

6.3. Environmental Attributes

Although the Least-Cost, Technology Neutral portfolio was developed without specific emissions reduction criteria or renewable energy standards, the least-cost optimization selected a diverse mix of resources, including solar generation, battery energy storage, and natural gas-fired generation. The resulting environmental attributes reflect the resource additions of the portfolio over the planning period. **Figure 6.7** through **Figure 6.9** represent the projected carbon dioxide and nitrogen oxides emissions along with total water consumption. Emissions reductions beyond those reflected in P01 would require additional investment in renewables and other low emitting resources.

Figure 6.7 - LCTN Portfolio CO₂ Emissions

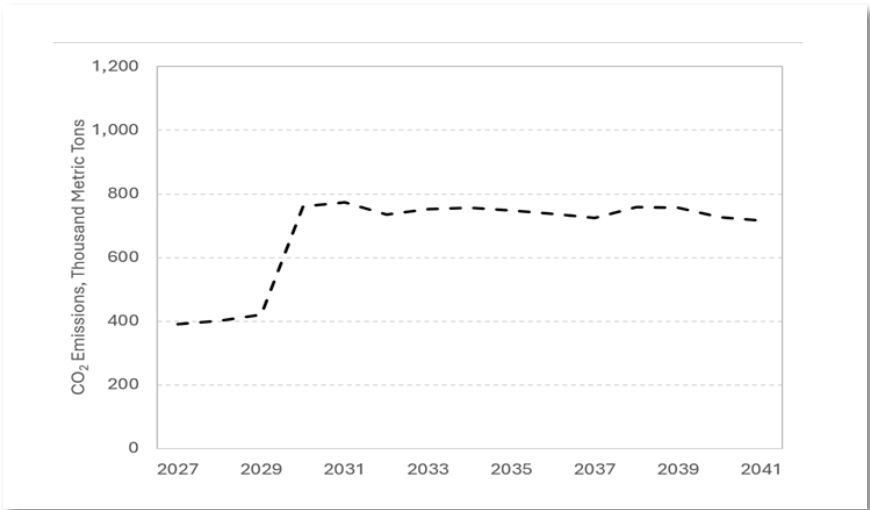


Figure 6.8 - LCTN Portfolio NO_x Emissions

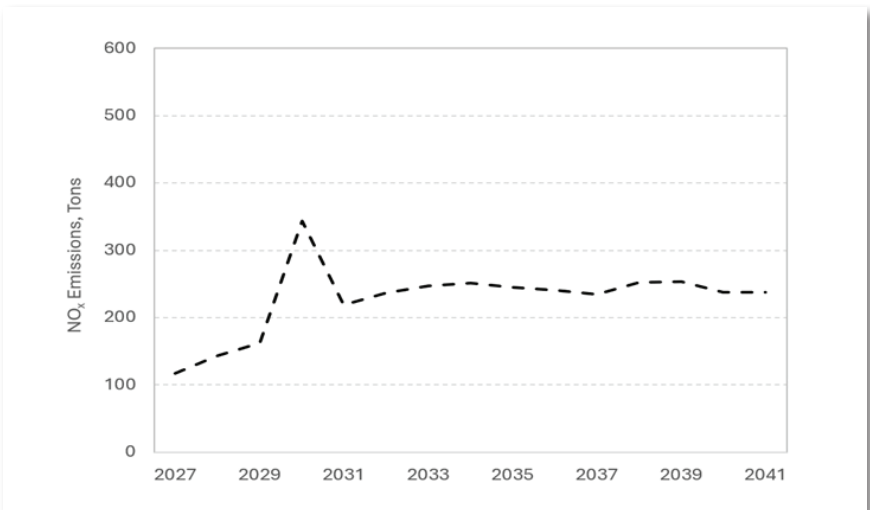
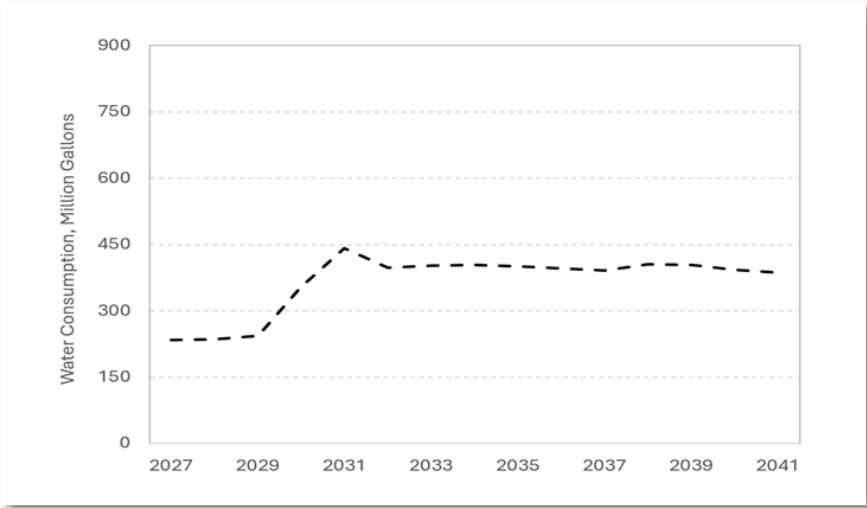


Figure 6.9 - LCTN Portfolio Water Usage

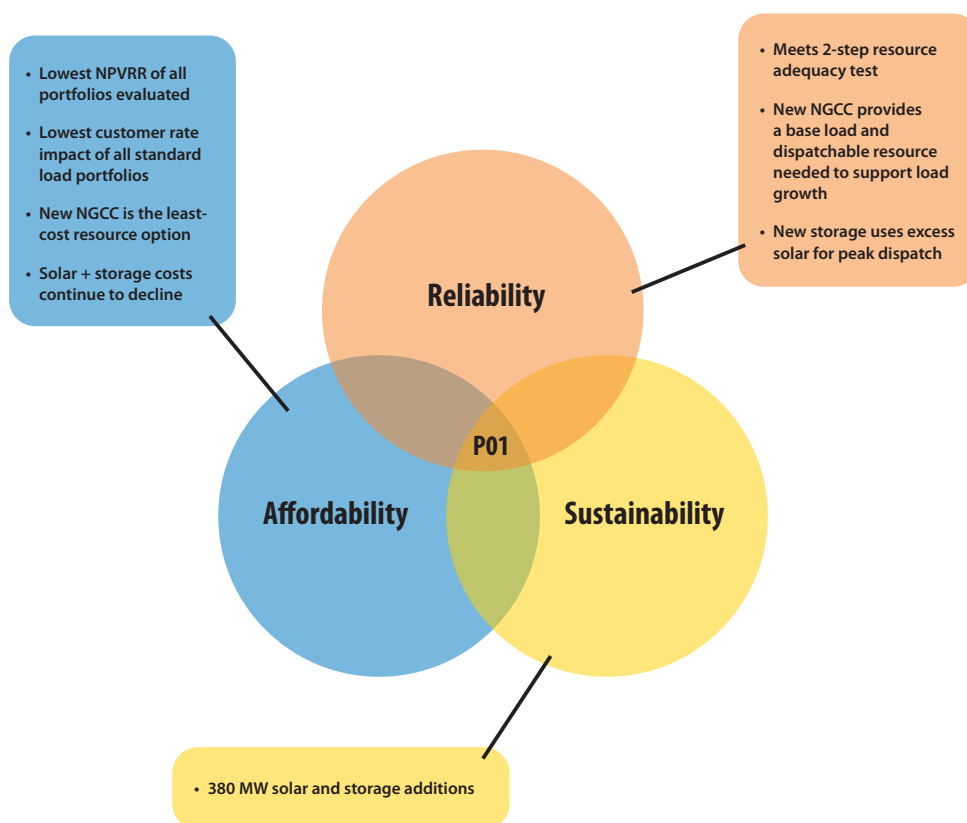


6.4. UNSE's Preferred Portfolio: Balanced Priorities

As discussed in section 3.2.1, UNSE has a responsibility to provide power that is reliable, affordable, and sustainable. Achieving the correct balance between these guiding principles is essential for long-term planning, and depends on many factors including resource constraints, current and projected market conditions, economic outlooks, and technological breakthroughs. Based on the modeling outcomes for current load projections, the P01 Least-Cost, Technology Neutral portfolio provides the best balance of reliability, affordability, and sustainability, supporting each principle in concrete ways:

The P01 Least-Cost, Technology Neutral portfolio provides the best balance of reliability, affordability, and sustainability

Figure 6.10 - Reliability, Affordability and Sustainability



Section 7

FIVE-YEAR ACTION PLAN

Since the 2023 IRP, UNSE has advanced development of the natural gas combustion turbines and entered into a PPA for solar plus storage resources called for in that IRP.

With the results of this 2026 IRP, UNSE will continue to pursue power that is reliable and affordable for all customers in its service territory. UNSE has developed a five-year action plan based on the cost and load growth assumptions within this IRP. Under this plan, UNSE will pursue new resources through future ASRFPs to monitor and validate resource costs, development timelines, and operational parameters prior to future decisions on acquisition. UNSE's action plan also includes overseeing the items as outlined below.

UNSE will monitor the development of Transwestern's Desert Southwest Expansion natural gas pipeline, projected to be in service in late 2029. Development of the new combustion turbines will continue, with a projected 2030 in-service date. UNSE will also oversee the completion of the Dandelion 140 MW solar plus storage facility, set to be in service in 2028.

To increase import capability and improve reliability in the Santa Cruz County portion of UNSE's service territory, UNSE will pursue the development of the Santa Cruz Reliability Project. This transmission is expected in service in 2031.

UNSE plans to enter SPP's Markets+ day-ahead market in the fall of 2027 as part of TEP's Balancing Authority. UNSE will continue its engagement in the Markets+ stakeholder working groups and task forces to ensure market alignment with UNSE's needs. UNSE will also monitor resource adequacy standards established by WPP's WRAP to ensure compliance.

UNSE recognizes that an IRP represents a snapshot based on a certain set of planning assumptions, and that these assumptions are subject to volatility and uncertainty. As UNSE evaluates and refines its plans moving forward, the Company will analyze the impact of new changes to its assumptions before making final resource decisions. The Company will also engage with the Arizona Corporation Commission to communicate major changes to anticipated plans. UNSE requests that the Commission acknowledge its 2026 IRP, and the associated actions herein, as provided in A.A.C. R14-2-704.B.

Section 8

APPENDICES

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Appendix A

RESPONSE TO RULES INDEX

Appendix A (cont.)

Response to Rules Index (Resource Planning Rule A.A.C. R14-2-703)

Rule	Description	IRP Location
C	A load-serving entity shall, by April 1 of each even year, file with Docket Control a compilation of the following items of load data and analyses, which may include a reference to the last filing made under this subsection for each item for which there has been no change in forecast since the last filing:	
C.1	Fifteen-year forecast of system coincident peak load (megawatts) and energy consumption (megawatt-hours) by month and year, expressed separately for residential, commercial, industrial, and other customer classes; for interruptible power; for resale; and for energy losses;	See Appendix C
C.2	Disaggregation of the load forecast of subsection (C)(1) into a component in which no additional demand management measures are assumed, and a component assuming the change in load due to additional forecasted demand management measures; and	See Appendix C
C.3	Documentation of all sources of data, analyses, methods, and assumptions used in making the load forecasts, including a description of how the forecasts were benchmarked and justifications for selecting the methods and assumptions used	See Section 4.2.1
D	A load-serving entity shall, by April 1 of each even year, file with Docket Control the following prospective analyses and plans, which shall compare a wide range of resource options and take into consideration expected duty cycles, cost projections, other analyses required under this Section, environmental impacts, and water consumption and may include a reference to the last filing made under this subsection for each item for which there has been no change since the last filing:	
D.1	A 15-year resource plan, providing for each year:	See 2026 IRP
D.1.a	Projected data for each of the items listed in subsection (B)(1), for each generating unit and purchased power source, including each generating unit that is expected to be new or refurbished during the period, which shall be designated as new or refurbished, as applicable, for the year of purchase or the period of refurbishment;	See Section 5 and Appendix B & C
D.1.b	Projected data for each of the items listed in subsection (B)(2), for the power supply system;	See Section 3.1.2 and Appendix B & C
D.1.c	The capital cost, construction time, and construction spending schedule for each generating unit expected to be new or refurbished during the period;	See Section 4.2.4 and Appendix C
D.1.d	The escalation levels assumed for each component of cost, such as, but not limited to, operating and maintenance, environmental compliance, system integration, backup capacity, and transmission delivery, for each generating unit and purchased power source;	See Appendix C
D.1.e	If discontinuation, decommissioning, or mothballing of any power source or permanent derating of any generating facility is expected:	See Section 4.2.7
D.1.e.i	Identification of each power source or generating unit involved;	See Section 4.2.7 and Appendix H
D.1.e.ii	The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating; and	See Section 4.2.7
D.1.e.iii	The reasons for each discontinuation, decommissioning, mothballing, or derating;	See Section 4.2.7
D.1.f	The capital costs and operating and maintenance costs of all new or refurbished transmission and distribution facilities expected during the 15-year period;	See Appendix I
D.1.g	An explanation of the need for and purpose of all expected new or refurbished transmission and distribution facilities, which explanation shall incorporate the load-serving entity's most recent transmission plan filed under A.R.S. § 40-360.02(A) and any relevant provisions of the Commission's most recent Biennial Transmission Assessment decision regarding the adequacy of transmission facilities in Arizona; and	See Appendix I
D.1.h	Cost analyses and cost projections;	See Appendix I

Appendix A (cont.)

D.2	Documentation of the data, assumptions, and methods or models used to forecast production costs and power production for the 15-year resource plan, including the method by which the forecast was benchmarked;	See Section 4
D.3	A description of each potential power source that was rejected; the capital costs, operating costs, and maintenance costs of each rejected source; and an explanation of the reasons for rejecting each source;	See Section 6 and Appendix C
D.4	A 15-year forecast of self-generation by customers of the load-serving entity, in terms of annual peak production (megawatts) and annual energy production (megawatt-hours);	See Section 4.2.2 and Appendix B & J
D.5	Disaggregation of the forecast of subsection (D)(4) into two components, one reflecting the self-generation projected if no additional efforts are made to encourage self-generation, and one reflecting the self-generation projected to result from the load-serving entity's institution of additional forecasted self-generation measures;	See Section 4.2.2 and Appendix B & J
D.6	A 15-year forecast of the annual capital costs and operating and maintenance costs of the self-generation identified under subsections (D)(4) and (D)(5);	See Section 4.2.2 and Appendix B & J
D.7	Documentation of the analysis of the self-generation under subsections (D)(4) through (6);	See Section 4.2.2 and Appendix B & J
D.8	A plan that considers using a wide range of resources and promotes fuel and technology diversity within its portfolio;	See Sections 4, 5 and 6
D.9	A calculation of the benefits of generation using renewable energy resources;	See Sections 4, 5 and 6
D.10	A plan that factors in the delivered cost of all resource options, including costs associated with environmental compliance, system integration, backup capacity, and transmission delivery;	See Sections 4, 5 and 6 and Appendix I
D.11	Analysis of integration costs for intermittent resources;	See Section 4.2
D.12	A plan to increase the efficiency of the load-serving entity's generation using fossil fuel;	See Section 6
D.13	Data to support technology choices for supply-side resources;	See Sections 4, 5 and 6 and Appendix C & K
D.14	A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure:	See Sections 4.2.2 and Appendix J
D.14.a	How and when the program or measure will be implemented,	See Sections 4.2.2 and Appendix J
D.14.b	The projected participation rate by customer class for the program or measure;	See Sections 4.2.2 and Appendix J
D.14.c	The expected change in demand resulting from the program or measure;	See Sections 4.2.2 and Appendix J
D.14.d	The expected reductions in air emissions and water consumption attributable to the program or measure;	See Sections 4.2.2 and Appendix J
D.14.e	The expected societal benefits, societal costs, and cost-effectiveness of the program or measure	See Sections 4.2.2 and Appendix J
D.14.f	The expected life of the measure; and	See Sections 4.2.2 and Appendix J
D.14.g	The capital costs, operating costs, and maintenance costs of the measure;	See Sections 4.2.2 and Appendix J
D.15	For each demand management measure that was considered but rejected:	See Sections 4.2.2 and Appendix J
D.15.a	A description of the measure;	See Sections 4.2.2 and Appendix J
D.15.b	The estimated change in peak demand and energy consumption from the measure;	See Sections 4.2.2 and Appendix J
D.15.c	The estimated cost-effectiveness of the measure;	See Sections 4.2.2 and Appendix J
D.15.d	The capital costs, operating costs, and maintenance costs of the measure; and	See Sections 4.2.2 and Appendix J
D.15.e	The reasons for rejecting the measure; and	See Sections 4.2.2 and Appendix J
D.16	Analysis of future fuel supplies that are part of the resource plan;	See Sections 2.2 to 2.3, 3.1.2 and 4.2.5
D.17	A plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption.	See Section 6.4 and Appendix G
E	A load-serving entity shall, by April 1 of each even year, file with Docket Control a compilation of the following analyses and plan:	
E.1	Analyses to identify and assess errors, risks, and uncertainties in the following, completed using methods such as sensitivity analysis and probabilistic analysis:	See Sections 4.2.5, 5.3 and Appendix D
E.1.a	Demand forecasts;	See Sections 4.2.1, 5 and Appendix C
E.1.b	The costs of demand management measures and power supply;	See Appendix I & J
E.1.c	The availability of sources of power;	See Sections 3, 4, 5, 6 and Appendix E, H and K

Appendix A (cont.)

F.7	Will effectively manage the uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors;	See Sections 4, 5, 6 and Appendix J
F.8	Will achieve a reasonable long-term total cost, taking into consideration the objectives set forth in subsections (F)(2)-(6) and the uncertainty of future costs; and	See Sections 4, 5, 6
F.9	Contains all of the following:	
F.9.a	A complete description and documentation of the plan, including supply and demand conditions, availability of transmission, costs, and discount rates utilized;	See Sections 4, 5, 6, Appendix I & J
F.9.b	A comprehensive, self-explanatory load and resources table summarizing the plan;	See Section 5.1
F.9.c	A brief executive summary;	See Section 1
F.9.d	An index to indicate where the responses to each filing requirement of these rules can be found; and	See Appendix A
F.9.e	Definitions of the terms used in the plan.	See Appendix L
G.1	An outline of the contents of the resource plan the load-serving entity is developing to be filed the following year as required under subsection (F);	See Contents and Appendix sections
G.2	The load-serving entity's method for assessing potential resources;	See Sections 3 and 4
G.3	The sources of the load-serving entity's current assumptions; and	See Sections 3 and 4
G.4	An outline of the timing and extent of public participation and advisory group meetings the load-serving entity intends to hold before completing and filing the resource plan.	See UNSE website: https://www.uesaz.com/rpac/
H.1	Includes a summary of actions to be taken on future resource acquisitions;	See Sections 3.2 and 7
H.2	Includes details on resource types, resources capacity, and resource timing; and	See Section 6.2
H.3	Covers the three-year period following the Commission's acknowledgment of the resource plan.	See Section 7
Response to Rules: Other Compliance Requirements		
79589	Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include in future Integrated Resource Plans an analysis of a technology neutral resource portfolio, which is the least-cost method of safely and reliably meeting customers' energy needs without regard for their emissions reduction goals or any renewable or carbon emissions standards.	See Section 5 and 6
79589	Arizona Public Service Company, Tucson Electric Power Company and UNS Electric, Inc. include in the next IRP cycle an analysis of, at minimum, seven resource portfolios that are designed to evaluate the range of resource procurement actions.	See Section 5 and 6
79589	Arizona Public Service Company, Tucson Electric Power Company and UNS Electric, Inc. shall: provide modeling input and output files, for the preferred portfolio in the RP tilings to Staff and stakeholders who hold modeling licenses. Provide data in tabular form, similar to the D tables in APS's 2023 IRP, for the preferred portfolio they have modeled. Provide a robust inventory (candidate resource information and cost for each of the portfolios) listed in their IRPs.	See Appendix B & C
79589	Arizona Public Service Company, Tucson Electric Power Company and UNS Electric, Inc. shall include in future Integrated Resource Plans an analysis of cost savings and other benefits resulting from their participation in western regional markets. The analysis shall also include a discussion of how their participation in a real-time and/or day-ahead market has impacted their portfolio development and selection, and how market participation has impacted their reserve margin, resource adequacy, reliability during extreme weather events, transmission planning, and capacity needs.	See Sections 3.4, 5.3 and Appendix F
79589	Language in Decision No. 78499 that states "In future IRPs" be amended to "In the next IRP cycle", notwithstanding the foregoing, in all future Integrated Resource Plans APS, TEP and UNSE shall discuss their natural gas price assumptions, the impact of those assumptions on resource acquisition decisions, and the implications of declining gas usage as the utilities resource mixes shift and shall continue to include capacity expansion modeling in their IRPs. Furthermore, in all future Integrated Resource Plans APS, TEP and UNSE shall closely monitor federal legislation relating to a carbon tax and discuss relevant impacts of any such legislation on the development of their Integrated Resource Plans.	See Sections 2, 3, 4 and 5
79589	Arizona Public Service, Tucson Electric Power Company and UNS Electric, Inc shall include in future IRPs portfolios which capture the benefits of joining a day-ahead market. Provide market enrollment assumptions in their preferred portfolios and specifically identify those	See Sections 3.4, 5.3 and Appendix F

Appendix A (cont.)

	assumptions in future IRPs. File ongoing, periodic reporting on activities relating to joining a day-ahead market, as well as metrics and other decision-making elements at a minimum semiannually, beginning November 1, 2024.	
79589	Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include a retirement analysis in future Integrated Resource Plans including specific estimated retirement dates for each resource. The retirement analysis shall include a dedicated and comprehensive analysis describing how the load-serving entity evaluated the operations of its current resources, how retirement dates were selected, and why, and what the economic impact to ratepayers will be due to the retirements. The retirement analysis shall discuss plans to replace retired capacity to ensure resource adequacy.	See Section 4.2.7
79589	Arizona Public Service Company, Tucson Electric Power Company and UNS Electric, Inc. share base case input data and modeling information to the stakeholders at least 90 days before the LSEs final Integrated Resource Plans are due.	Section 3.1.3

Appendix B

PORTFOLIO SUMMARY DASHBOARDS

Appendix B (cont.)

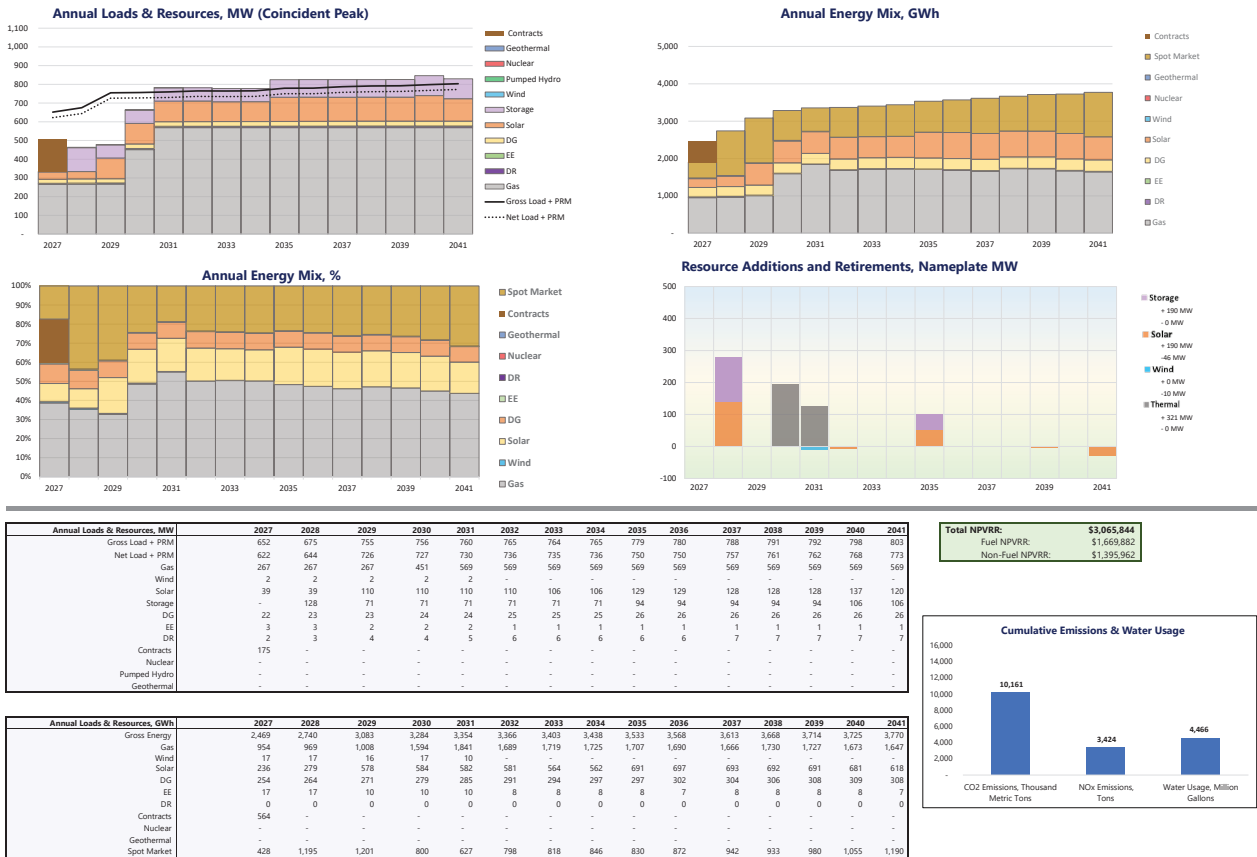


2026 Integrated Resource Plan

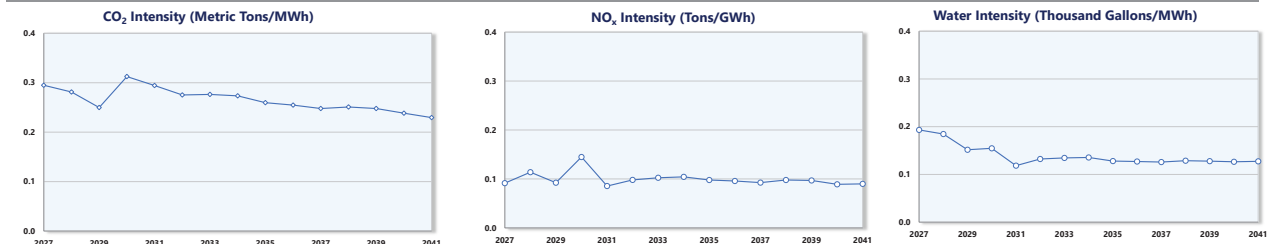
Portfolio ID - P01

Portfolio Description - Technology Neutral

Loads & Resources Dashboard



Environmental Dashboard



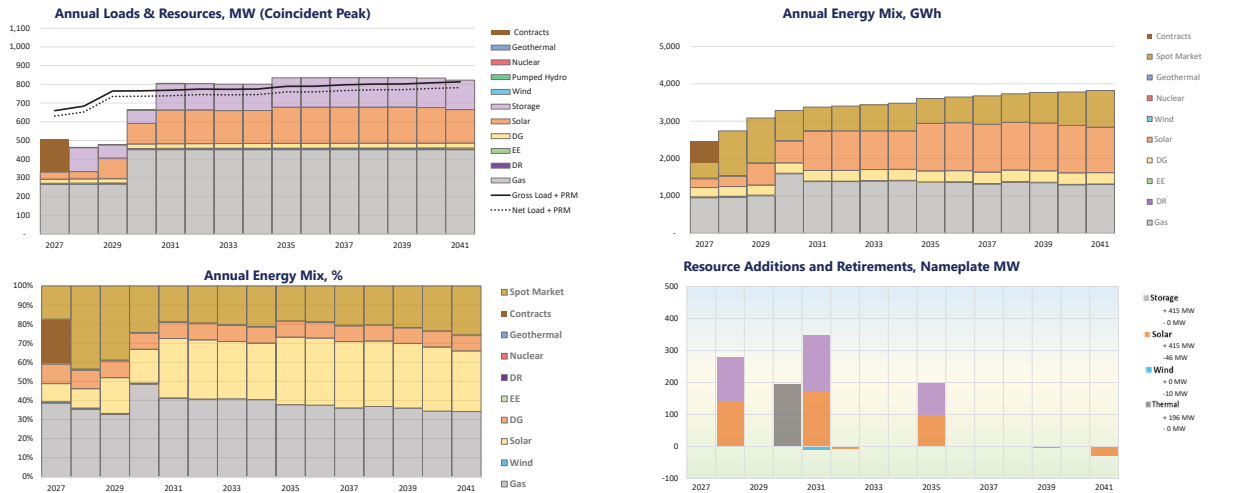
Appendix B (cont.)



2026 Integrated Resource Plan

Portfolio ID - P02
Portfolio Description - Clean Energy

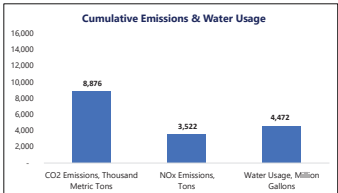
Loads & Resources Dashboard



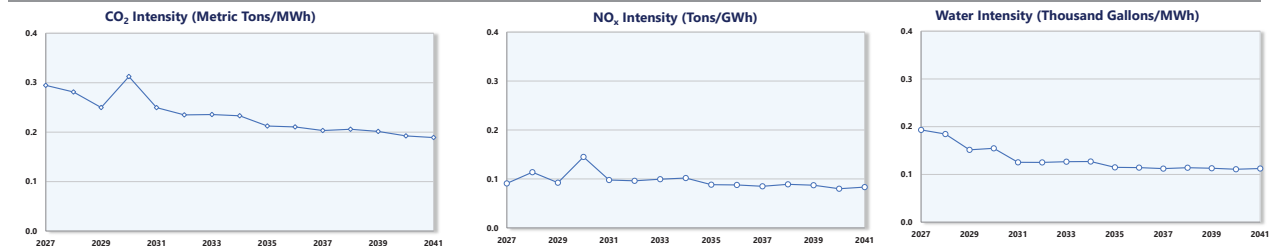
Annual Loads & Resources, MW	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Load + PRM	660	683	764	766	769	775	774	775	789	790	797	801	802	808	813
Net Load + PRM	630	652	736	737	739	745	744	745	760	760	767	771	772	778	783
Gas	267	267	267	451	451	451	451	451	451	451	451	451	451	451	451
Wind	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-
Solar	39	39	110	110	180	180	176	176	193	193	193	193	193	190	179
Storage	-	128	71	71	141	141	141	141	157	157	157	157	157	157	157
DG	22	23	23	24	24	25	25	25	26	26	26	26	26	26	26
EE	3	3	2	2	2	1	1	1	1	1	1	1	1	1	1
DR	2	3	4	4	5	6	6	6	6	6	7	7	7	7	7
Contracts	175	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Total NPVRR: \$3,201,390
Fuel NPVRR: \$1,584,818
Non-Fuel NPVRR: \$1,616,572

Annual Loads & Resources, GWh	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Energy	2,469	2,740	3,083	3,284	3,377	3,403	3,437	3,480	3,606	3,645	3,676	3,732	3,768	3,780	3,822
Gas	953	969	1,007	1,595	1,384	1,384	1,403	1,407	1,363	1,366	1,324	1,375	1,355	1,299	1,306
Wind	17	17	16	17	10	-	-	-	-	-	-	-	-	-	-
Solar	236	279	578	583	1,052	1,057	1,034	1,029	1,275	1,284	1,280	1,279	1,278	1,270	1,216
DG	254	264	271	279	285	291	294	297	302	304	304	306	308	309	308
EE	17	17	10	10	10	8	8	8	7	7	8	8	8	8	7
DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contracts	564	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Market	429	1,195	1,201	801	636	663	698	740	664	686	761	764	819	894	985



Environmental Dashboard



Appendix B (cont.)

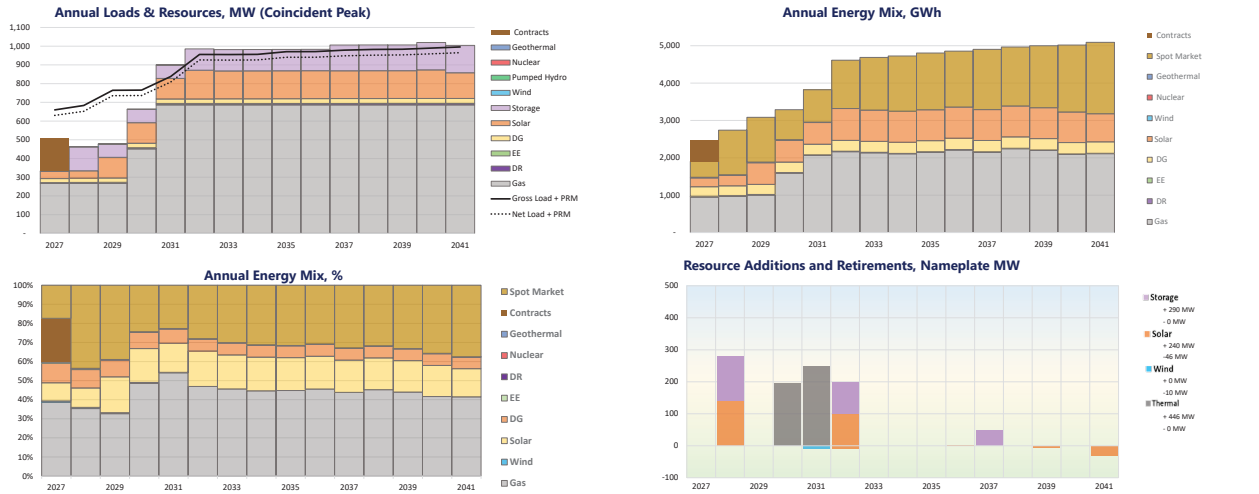


2026 Integrated Resource Plan

Portfolio ID - P03

Portfolio Description - High Load Factor Customer Growth Technology Neutral

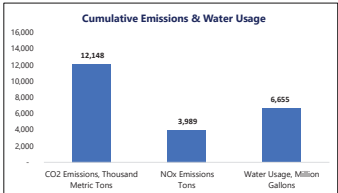
Loads & Resources Dashboard



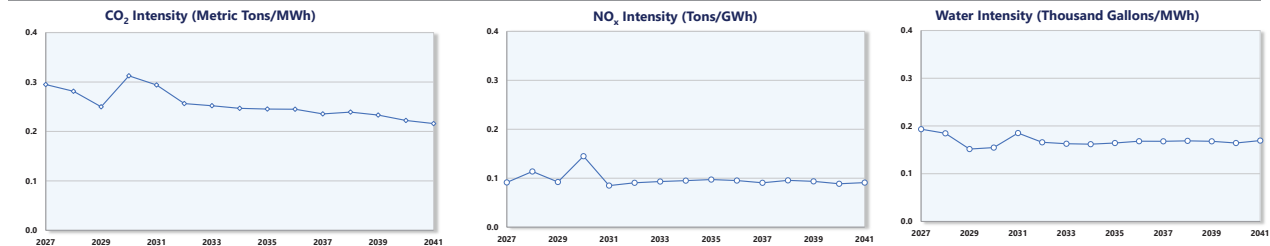
Annual Loads & Resources, MW	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Load + PRM	660	683	764	766	838	956	955	956	971	971	979	983	983	990	996
Net Load + PRM	630	652	736	737	808	927	925	927	941	941	948	952	953	959	965
Gas	267	267	267	451	686	686	686	686	686	686	686	686	686	686	686
Wind	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-
Solar	39	39	110	110	110	153	149	149	149	149	148	148	148	152	137
Storage	-	128	71	71	71	114	114	114	114	114	138	138	138	146	146
DG	22	23	23	24	24	25	25	25	26	26	26	26	26	26	26
EE	3	3	2	2	2	1	1	1	1	1	1	1	1	1	1
DR	2	3	4	4	5	6	6	6	6	6	7	7	7	7	7
Contracts	175	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Annual Loads & Resources, GWh	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Energy	2,469	2,740	3,083	3,287	3,822	4,612	4,686	4,725	4,803	4,855	4,904	4,965	5,000	5,019	5,091
Gas	954	969	1,008	1,596	2,067	2,166	2,137	2,109	2,153	2,213	2,151	2,245	2,199	2,092	2,112
Wind	17	17	16	17	10	-	-	-	-	-	-	-	-	-	-
Solar	236	279	578	584	582	855	836	834	827	835	827	827	825	817	752
DG	254	264	271	279	285	291	294	297	297	302	304	306	308	309	308
EE	17	17	10	10	10	8	8	8	8	7	8	8	8	8	7
DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contracts	564	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Market	428	1,195	1,201	802	868	1,293	1,411	1,477	1,518	1,498	1,615	1,579	1,660	1,794	1,910

Total NPVRR: \$3,551,311
Fuel NPVRR: \$1,809,553
Non-Fuel NPVRR: \$1,741,757



Environmental Dashboard



Appendix B (cont.)

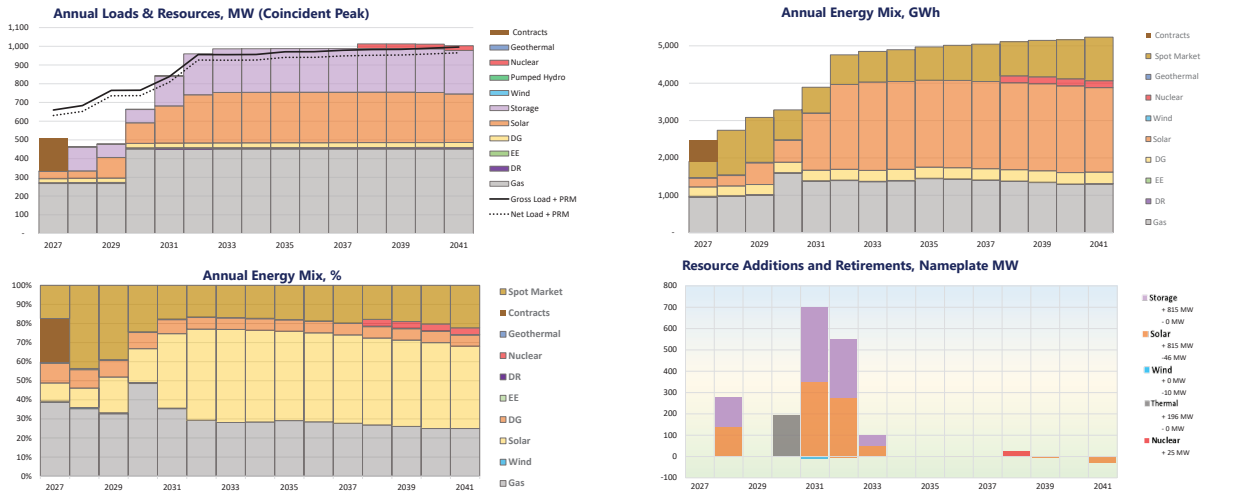


2026 Integrated Resource Plan

Portfolio ID - P04

Portfolio Description - High Load Factor Customer Growth Clean Energy

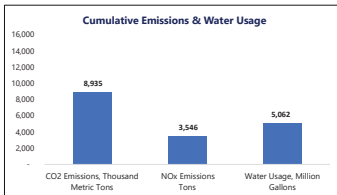
Loads & Resources Dashboard



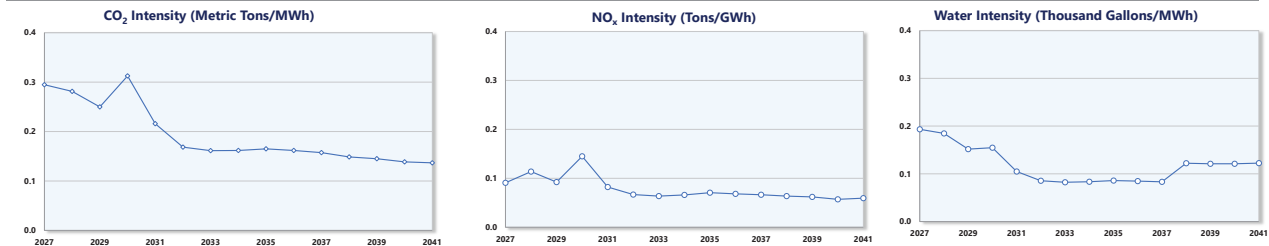
Annual Loads & Resources, MW	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Load + PRM	660	683	764	766	838	956	955	956	971	971	979	983	983	990	996
Net Load + PRM	630	652	736	737	808	927	925	927	941	941	948	952	953	959	965
Gas	267	267	267	267	451	451	451	451	451	451	451	451	451	451	451
Wind	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-
Solar	39	39	110	110	198	258	270	270	270	270	269	269	269	268	259
Storage	-	128	71	71	159	219	233	233	233	233	233	233	233	233	233
DG	22	23	23	24	24	25	25	25	26	26	26	26	26	26	26
EE	3	3	2	2	2	1	1	1	1	1	1	1	1	1	1
DR	2	3	4	4	5	6	6	6	6	6	7	7	7	7	7
Contracts	175	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	25	25	25	25
Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Annual Loads & Resources, GWh	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Load	2,469	2,740	3,084	3,286	3,891	4,759	4,850	4,895	4,970	5,013	5,045	5,109	5,147	5,163	5,232
Gas	953	969	1,007	1,595	1,375	1,395	1,364	1,388	1,447	1,427	1,398	1,370	1,340	1,290	1,305
Wind	17	17	16	17	10	-	-	-	-	-	-	-	-	-	-
Solar	236	279	578	583	1,520	2,272	2,365	2,353	2,327	2,338	2,335	2,328	2,329	2,322	2,260
DG	254	264	271	279	285	291	294	297	297	302	304	306	308	309	308
EE	17	17	10	10	10	8	8	8	8	7	8	8	8	8	7
DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contracts	564	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	186	185	188	186
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Market	429	1,195	1,201	802	691	794	819	849	892	939	1,000	913	977	1,047	1,165

Total NPVRR:	\$3,961,388
Fuel NPVRR:	\$1,608,157
Non-Fuel NPVRR:	\$2,353,232



Environmental Dashboard



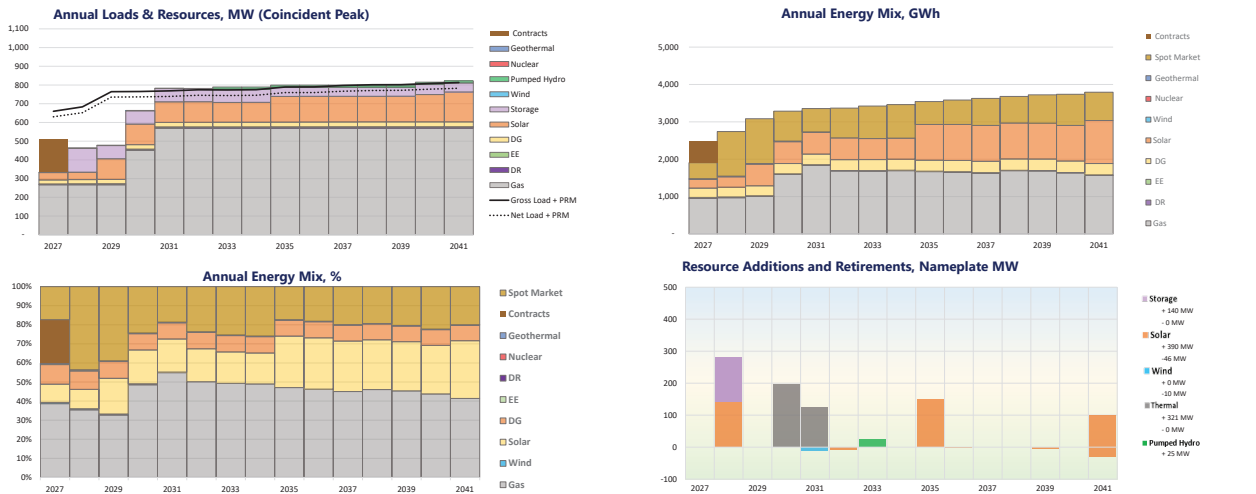
Appendix B (cont.)



2026 Integrated Resource Plan

Portfolio ID - P05
Portfolio Description - Pumped Hydro

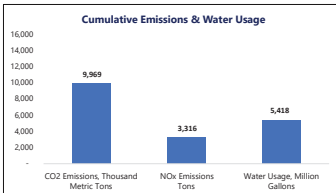
Loads & Resources Dashboard



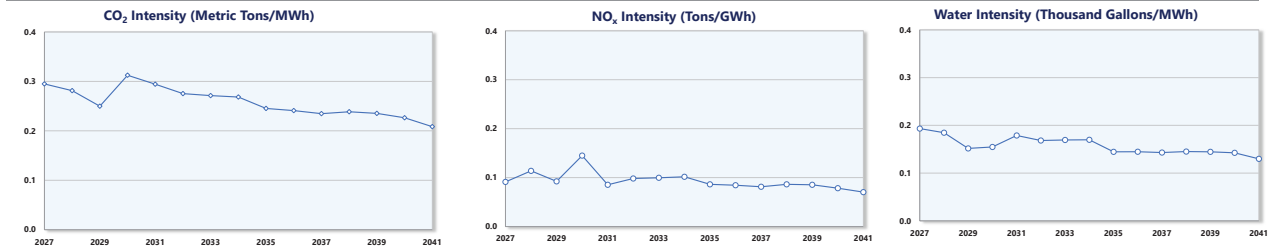
Annual Loads & Resources, MW	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Load + PRM	660	683	764	766	769	775	774	775	789	790	797	801	802	808	813
Net Load + PRM	630	652	736	737	739	745	744	745	760	760	767	771	772	778	783
Gas	267	267	267	451	569	569	569	569	569	569	569	569	569	569	569
Wind	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-
Solar	39	39	110	110	110	110	106	106	137	137	137	137	137	146	159
Storage	-	128	71	71	71	71	71	71	49	49	49	49	49	55	49
DG	22	23	23	24	24	25	25	25	26	26	26	26	26	26	26
EE	3	3	3	2	2	2	1	1	1	1	1	1	1	1	1
DR	2	3	4	4	5	6	6	6	6	6	7	7	7	7	7
Contracts	175	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	-	-	-	-	-	-	12	12	12	12	12	12	12	12	12
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Annual Loads & Resources, GWh	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Energy	2,469	2,740	3,084	3,284	3,354	3,366	3,423	3,461	3,543	3,582	3,627	3,680	3,724	3,737	3,793
Gas	954	970	1,008	1,594	1,841	1,688	1,687	1,694	1,668	1,656	1,632	1,694	1,688	1,635	1,569
Wind	17	17	16	17	10	-	-	-	-	-	-	-	-	-	-
Solar	236	279	578	584	582	581	564	562	956	965	961	960	960	951	1,149
DG	254	264	271	279	285	291	294	297	302	304	304	306	308	309	308
EE	17	17	10	10	10	8	8	8	8	7	8	8	8	8	7
DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contracts	564	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Market	428	1,195	1,201	801	627	797	871	900	614	652	723	712	760	835	759

Total NPVRR: \$3,113,500
Fuel NPVRR: \$1,642,491
Non-Fuel NPVRR: \$1,471,009



Environmental Dashboard



Appendix B (cont.)



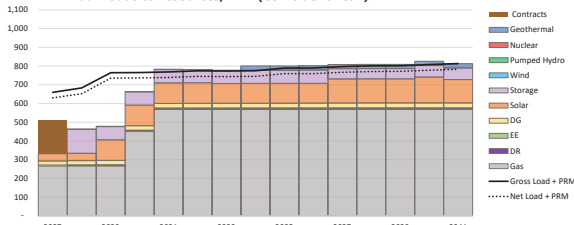
2026 Integrated Resource Plan

Portfolio ID - P06

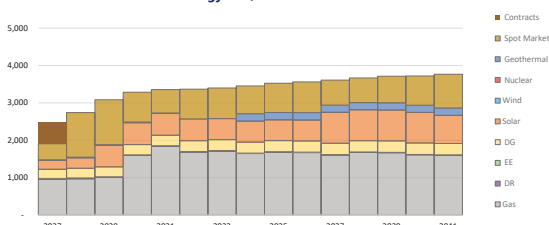
Portfolio Description - Geothermal

Loads & Resources Dashboard

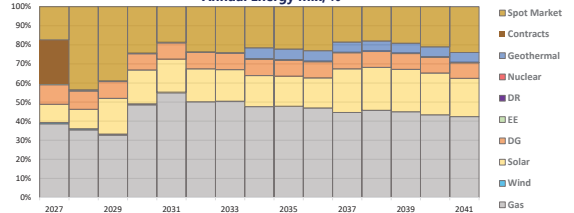
Annual Loads & Resources, MW (Coincident Peak)



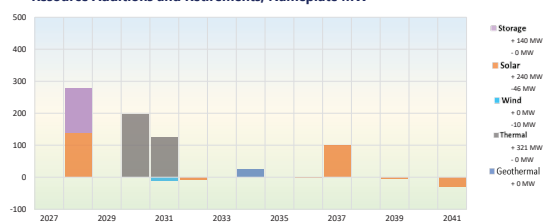
Annual Energy Mix, GWh



Annual Energy Mix, %



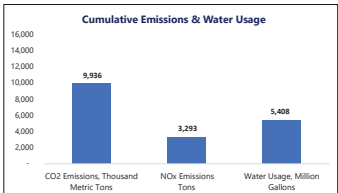
Resource Additions and Retirements, Nameplate MW



Annual Loads & Resources, MW	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Load + PRM	660	683	764	766	769	775	774	775	789	790	797	801	802	808	813
Net Load + PRM	630	652	736	737	739	745	744	745	760	760	767	771	772	778	783
Gas	267	267	267	451	569	569	569	569	569	569	569	569	569	569	569
Wind	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-
Solar	39	39	110	110	110	110	106	106	106	106	129	129	129	138	125
Storage	-	128	71	71	71	71	71	71	71	71	55	55	55	62	62
DG	22	23	23	24	24	25	25	25	26	26	26	26	26	26	26
EE	3	3	2	2	2	1	1	1	1	1	1	1	1	1	1
DR	2	3	4	4	5	6	6	6	6	6	7	7	7	7	7
Contracts	175	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	23	23	23	23	23	23	23

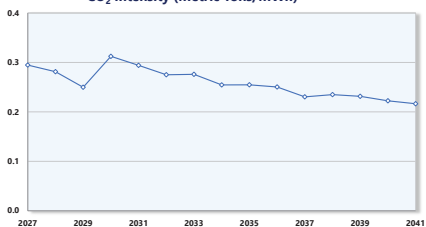
Total NPVRR:	\$3,091,580
Fuel NPVRR:	\$1,639,314
Non-Fuel NPVRR:	\$1,452,267

Annual Loads & Resources, GWh	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Energy	2,469	2,740	3,083	3,284	3,354	3,366	3,399	3,453	3,525	3,561	3,611	3,668	3,712	3,721	3,766
Gas	953	970	1,007	1,594	1,840	1,688	1,714	1,644	1,684	1,671	1,608	1,675	1,667	1,612	1,596
Wind	17	17	16	17	10	-	-	-	-	-	-	-	-	-	-
Solar	236	279	578	584	582	581	564	562	556	561	826	826	825	816	754
DG	254	264	271	279	285	291	294	297	302	302	304	306	308	309	308
EE	17	17	10	10	10	8	8	8	7	7	8	8	8	8	7
DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contracts	564	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Market	429	1,195	1,201	801	627	798	820	745	783	822	671	660	711	784	805

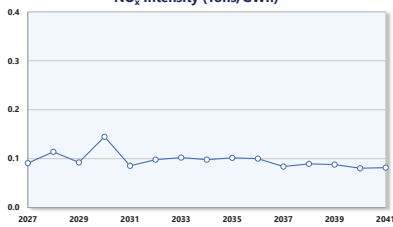


Environmental Dashboard

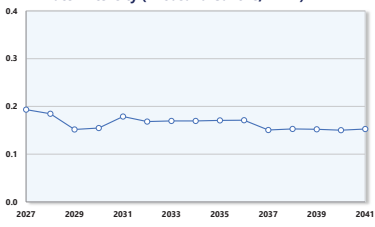
CO₂ Intensity (Metric Tons/MWh)



NO_x Intensity (Tons/GWh)



Water Intensity (Thousand Gallons/MWh)



Appendix B (cont.)

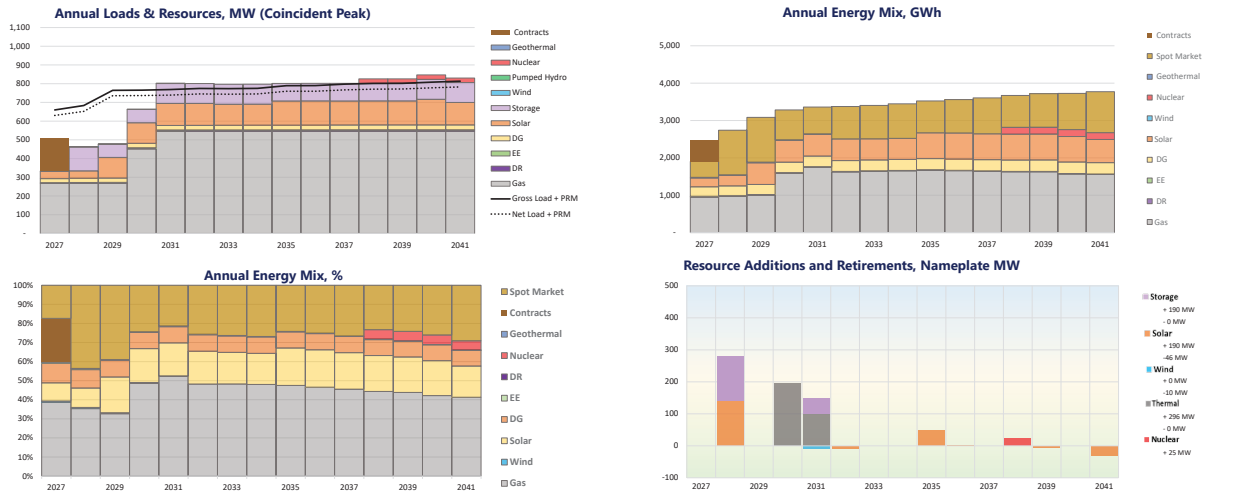
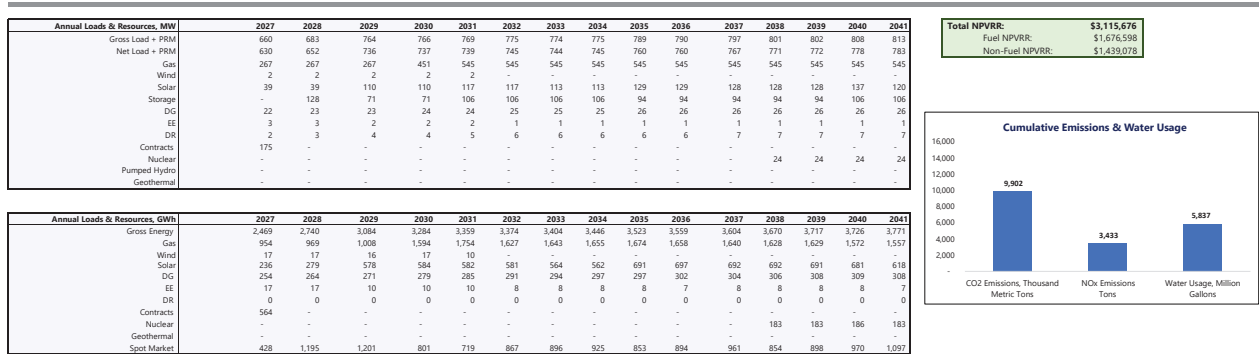
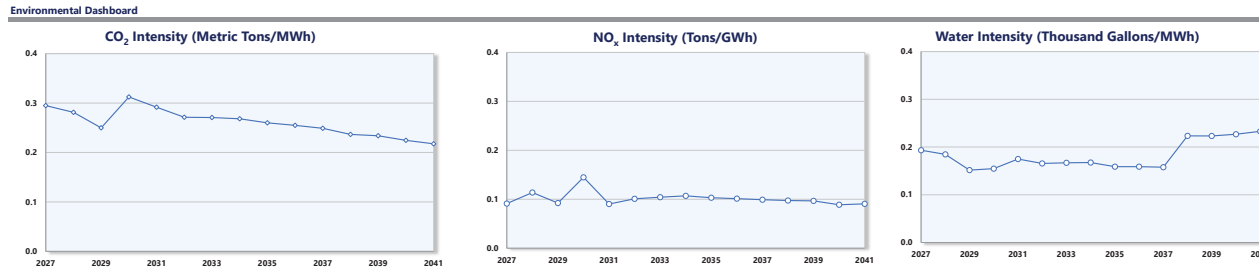


2026 Integrated Resource Plan

Portfolio ID - P07

Portfolio Description - Nuclear

Loads & Resources Dashboard



Appendix C

DETAILED BASE CASE DATA

Appendix C (cont.)

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS

Energy Consumption (MWh)													
Year: 2027	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Residential	82,340	67,432	65,543	63,614	81,683	113,265	145,863	135,641	104,948	75,798	63,474	82,079	1,081,680
Commercial	53,906	47,916	53,625	53,987	64,188	72,175	78,041	74,820	64,389	57,987	51,191	52,938	725,164
Industrial	5,054	4,732	5,283	5,324	5,705	5,561	5,607	5,764	5,435	5,383	4,972	4,509	63,328
Mining	9,886	10,014	10,532	10,260	9,176	24,255	24,130	26,282	27,339	27,694	26,895	27,675	234,140
Other	172	140	142	130	119	112	122	137	140	153	168	169	1,705
Total Net Energy Consumption	151,358	130,234	135,126	133,315	160,871	215,368	253,764	242,643	202,252	167,015	146,700	167,369	2,106,015
System Losses	13,092	10,210	11,405	11,278	15,540	21,235	25,554	23,342	19,538	15,165	12,044	14,360	192,764
Distributed Generation	15,295	16,355	22,448	23,639	23,895	23,167	22,788	23,604	23,523	21,470	19,841	17,629	253,655
Energy Efficiency	1,069	852	893	926	1,314	1,986	2,613	2,462	1,706	1,105	898	969	16,792
Total Gross Energy Consumption	180,814	157,652	169,872	169,158	201,619	261,755	304,718	292,052	247,019	204,755	179,484	200,327	2,569,226

Energy Consumption (MWh)													
Year: 2028	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Residential	84,417	69,471	67,540	65,715	84,078	116,138	149,069	138,579	107,419	77,716	65,156	83,885	1,109,183
Commercial	54,438	48,405	54,122	54,106	64,774	72,470	78,803	75,360	64,840	58,566	51,727	53,454	731,066
Industrial	5,053	4,901	5,283	5,323	5,705	5,560	5,607	5,764	5,435	5,383	4,967	4,510	63,492
Mining	35,751	34,622	36,121	35,230	34,959	33,949	33,959	35,906	36,701	37,277	36,167	37,209	427,850
Other	172	140	142	130	119	112	122	137	140	153	168	169	1,704
Total Net Energy Consumption	179,832	157,539	163,209	160,503	189,635	228,230	267,560	255,745	214,535	179,096	158,185	179,226	2,333,295
System Losses	15,555	12,351	13,775	13,579	18,319	22,503	26,943	24,603	20,724	16,262	12,987	15,378	212,979
Distributed Generation	15,893	18,458	23,146	24,387	25,074	23,969	23,255	24,526	24,124	22,321	20,525	17,936	263,617
Energy Efficiency	1,066	868	884	898	1,329	1,996	2,645	2,494	1,735	1,071	896	957	16,838
Total Gross Energy Consumption	212,347	189,216	201,014	199,367	234,357	276,698	320,403	307,368	261,118	218,750	192,593	213,497	2,826,729

Energy Consumption (MWh)													
Year: 2029	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Residential	86,116	71,151	69,185	67,467	86,138	118,684	151,970	141,233	109,625	79,415	66,675	85,574	1,133,232
Commercial	55,009	48,932	54,655	54,650	65,393	72,780	79,579	76,115	65,502	59,194	52,343	54,122	738,274
Industrial	5,053	4,732	5,283	5,323	5,705	5,559	5,606	5,764	5,435	5,383	4,969	4,509	63,322
Mining	60,513	55,788	61,198	59,293	59,839	57,925	59,231	61,001	60,885	62,464	60,568	62,465	721,170
Other	172	140	142	130	119	112	122	137	140	153	168	169	1,704
Total Net Energy Consumption	206,864	180,742	190,463	186,863	217,193	255,061	296,508	284,249	241,587	206,610	184,723	206,840	2,657,703
System Losses	17,894	14,170	16,075	15,809	20,981	25,149	29,858	27,345	23,337	18,760	15,166	17,747	242,291
Distributed Generation	16,922	16,187	24,139	24,977	26,170	24,942	24,159	25,289	24,914	23,280	21,027	18,572	270,581
Energy Efficiency	484	375	398	423	790	1,339	1,881	1,761	1,137	555	417	443	10,003
Total Gross Energy Consumption	242,164	211,475	231,075	228,072	265,135	306,491	352,407	338,644	290,975	249,206	221,332	243,602	3,180,577

Energy Consumption (MWh)													
Year: 2030	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Residential	87,640	72,725	70,782	69,240	88,246	121,299	154,933	143,919	111,895	81,153	68,201	87,205	1,157,239
Commercial	55,736	49,662	55,437	55,495	66,328	73,829	80,719	77,241	66,550	60,160	53,232	54,996	749,387
Industrial	5,053	4,732	5,283	5,323	5,705	5,559	5,606	5,764	5,435	5,383	4,968	4,510	63,322
Mining	60,497	55,795	61,203	59,297	59,839	57,990	59,303	60,994	60,883	62,459	60,563	62,454	721,275
Other	172	140	142	130	119	112	122	137	140	153	168	169	1,704
Total Net Energy Consumption	209,099	183,053	192,847	189,486	220,236	258,789	300,683	288,055	244,904	209,309	187,133	209,333	2,692,927
System Losses	18,087	14,351	16,276	16,030	21,275	25,517	30,279	27,711	23,658	19,005	15,364	17,961	245,514
Distributed Generation	16,992	17,259	24,967	25,872	26,532	25,469	25,328	25,468	25,867	24,116	21,404	19,695	278,969
Energy Efficiency	474	366	380	431	769	1,328	1,817	1,714	1,140	583	388	444	9,834
Total Gross Energy Consumption	244,652	215,030	234,470	231,819	268,812	311,102	358,107	342,948	295,569	253,013	224,289	247,433	3,227,243

Energy Consumption (MWh)													
Year: 2031	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Residential	89,254	74,339	72,352	70,924	90,250	123,808	157,786	146,557	114,112	82,842	69,674	88,800	1,180,699
Commercial	56,613	50,487	56,267	56,319	67,258	74,841	81,763	78,245	67,464	61,011	54,032	55,794	760,094
Industrial	5,053	4,732	5,283	5,323	5,705	5,559	5,606	5,764	5,435	5,383	4,969	4,510	63,322
Mining	60,505	55,791	61,200	59,295	59,839	57,956	59,266	60,998	60,884	62,461	60,565	62,460	721,219
Other	172	140	142	130	119	112	122	137	140	153	168	169	1,704
Total Net Energy Consumption	211,596	185,489	195,245	191,991	223,171	262,276	304,543	291,700	248,035	211,851	189,409	211,732	2,727,038
System Losses	18,303	14,542	16,479	16,242	21,558	25,860	30,667	28,062	23,960	19,236	15,550	18,167	248,628
Distributed Generation	17,013	18,179	25,058	26,610	27,164	26,021	25,629	26,012	26,433	24,830	21,851	19,717	284,517
Energy Efficiency	454	354	370	418	769	1,333	1,862	1,728	1,142	561	373	422	9,786
Total Gross Energy Consumption	247,366	218,564	237,152	235,262	272,662	315,491	362,702	347,502	299,570	256,478	227,183	250,037	3,269,969

Energy Consumption (MWh)													
Year: 2032	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Residential	90,732	75,858	73,876	72,602	92,251	126,316	160,621	149,130	116,282	84,516	71,182	90,431	1,203,797
Commercial	57,436	51,296	57,121	57,213	68,222	75,880	82,846	79,299	68,440	61,945	54,916	56,657	771,270
Industrial	5,053	4,901	5,283	5,323	5,705	5,559	5,606	5,764	5,435	5,383	4,969	4,510	63,490
Mining	60,501	57,785	61,201	59,296	59,839	57,972	59,283	60,996	60,883	62,460	60,564	62,457	723,237
Other	172	140	142	130	119	112	122	137	140	153	168	169	1,704
Total Net Energy Consumption	213,894	189,980	197,624	194,564	226,135	265,839	308,478	295,325	251,181	214,457	191,798	214,223	2,763,499
System Losses	18,502	14,894	16,679	16,460	21,845	26,212	31,064	28,410	24,264	19,473	15,747	18,380	251,930
Distributed Generation	18,023	19,538	25,741	27,121	27,626	26,544	26,091	26,778	26,663	24,329	22,483	19,968	290,905
Energy Efficiency	384	316	339	364	608	1,016	1,360	1,279	862	469	339	359	7,695
Total Gross Energy Consumption	250,803	224,729	240,383	238,509	276,213	319,611	366,993	351,792	302,970	258,728	230,367	252,930	3,314,029

Appendix C (cont.)

Energy Consumption (MWh)													
Year: 2033	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Residential	92,175	77,368	75,390	74,282	94,266	128,842	163,512	151,807	118,537	86,247	72,665	92,040	1,227,130
Commercial	58,323	52,173	58,040	58,181	69,249	76,990	83,978	80,412	69,458	62,892	55,835	57,600	783,130
Industrial	5,053	4,732	5,283	5,323	5,705	5,559	5,606	5,764	5,435	5,383	4,969	4,510	63,321
Mining	60,503	55,792	61,200	59,295	59,838	57,963	59,273	60,997	60,884	62,460	60,564	62,458	721,228
Other	172	140	142	130	119	112	122	137	140	153	168	169	1,704
Total Net Energy Consumption	216,226	190,204	200,056	197,211	229,177	269,466	312,491	299,116	254,454	217,135	194,201	216,777	2,796,514
System Losses	18,704	14,912	16,885	16,684	22,138	26,569	31,468	28,775	24,580	19,716	15,944	18,599	254,974
Distributed Generation	18,010	19,785	26,119	27,518	27,836	26,698	26,549	27,092	27,070	24,766	22,481	19,863	293,787
Energy Efficiency	389	305	342	364	616	1,027	1,378	1,288	876	467	344	362	7,758
Total Gross Energy Consumption	253,328	225,205	243,402	241,778	279,767	323,760	371,887	356,271	306,980	262,084	232,970	255,601	3,353,033

Energy Consumption (MWh)													
Year: 2034	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Residential	93,983	79,261	77,319	76,408	96,753	131,865	166,912	155,010	121,345	88,580	74,810	94,312	1,256,556
Commercial	59,312	53,169	59,099	59,305	70,493	78,352	85,415	81,851	70,847	64,256	57,146	58,952	798,199
Industrial	5,053	4,732	5,283	5,323	5,705	5,559	5,606	5,764	5,435	5,383	4,969	4,510	63,321
Mining	60,501	55,792	61,201	59,295	59,838	57,966	59,277	60,996	60,883	62,460	60,564	62,458	721,232
Other	172	140	142	130	119	112	122	137	140	153	168	169	1,704
Total Net Energy Consumption	219,022	193,093	203,044	200,462	232,908	273,855	317,332	303,757	258,651	220,833	197,656	220,400	2,841,013
System Losses	18,945	15,138	17,137	16,959	22,499	27,002	31,955	29,221	24,986	20,052	16,228	18,910	259,033
Distributed Generation	17,621	20,685	26,224	27,854	28,389	27,137	26,319	27,511	27,047	25,014	22,830	19,945	296,578
Energy Efficiency	394	305	345	362	627	1,031	1,385	1,305	888	466	347	363	7,820
Total Gross Energy Consumption	255,983	229,222	246,750	245,637	284,424	329,024	376,992	361,795	311,572	266,364	237,061	259,618	3,404,444

Energy Consumption (MWh)													
Year: 2035	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Residential	96,171	81,535	79,584	78,847	99,466	135,029	170,338	158,137	124,072	90,771	76,806	96,378	1,287,134
Commercial	62,379	55,966	62,254	62,479	73,997	82,099	89,580	86,014	74,666	67,768	60,121	61,873	839,197
Industrial	5,053	4,732	5,283	5,323	5,705	5,559	5,606	5,764	5,435	5,383	4,969	4,510	63,321
Mining	60,502	55,792	61,200	59,295	59,838	57,962	59,273	60,996	60,883	62,460	60,564	62,458	721,225
Other	172	140	142	130	119	112	122	137	140	153	168	169	1,704
Total Net Energy Consumption	224,277	198,164	208,464	206,074	239,126	280,761	324,920	311,048	265,197	226,535	202,628	225,388	2,912,581
System Losses	19,400	15,536	17,594	17,434	23,100	27,683	32,719	29,923	25,618	20,569	16,636	19,338	265,550
Distributed Generation	18,705	17,984	26,681	27,621	28,944	27,352	26,479	27,698	27,254	25,257	22,836	20,158	296,970
Energy Efficiency	391	313	345	361	637	1,018	1,386	1,309	884	461	351	361	7,817
Total Gross Energy Consumption	262,774	231,996	253,085	251,490	291,806	336,815	385,504	369,978	318,953	272,823	242,450	265,245	3,482,918

Energy Consumption (MWh)													
Year: 2036	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Residential	98,069	83,508	81,543	80,985	101,886	137,928	173,510	161,026	126,606	92,790	78,642	98,292	1,314,785
Commercial	63,557	57,171	63,427	63,723	75,299	83,586	91,226	87,631	76,232	69,162	61,457	63,054	855,525
Industrial	5,053	4,901	5,283	5,323	5,705	5,559	5,605	5,764	5,435	5,383	4,969	4,510	63,489
Mining	60,502	57,784	61,200	59,295	59,838	57,962	59,274	60,996	60,883	62,460	60,564	62,458	723,217
Other	172	140	142	130	119	112	122	137	140	153	168	169	1,704
Total Net Energy Consumption	227,353	203,504	211,596	209,456	242,848	285,146	329,737	315,554	269,297	229,949	205,799	228,482	2,958,720
System Losses	19,666	15,955	17,859	17,720	23,459	28,115	33,205	30,356	26,014	20,879	16,896	19,604	269,728
Distributed Generation	18,462	19,716	26,794	28,462	28,821	27,608	27,188	27,588	27,819	25,931	22,841	20,601	301,832
Energy Efficiency	367	303	323	355	604	984	1,323	1,237	858	460	317	343	7,474
Total Gross Energy Consumption	265,848	239,478	256,571	255,993	295,731	341,853	391,453	374,735	323,988	277,219	245,854	269,030	3,537,753

Energy Consumption (MWh)													
Year: 2037	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Residential	99,806	85,353	83,356	83,006	104,193	140,715	176,548	163,744	129,011	94,717	80,467	100,237	1,341,155
Commercial	64,841	58,349	64,692	64,987	76,747	85,210	92,917	89,366	77,762	70,642	62,708	64,368	872,589
Industrial	5,053	4,732	5,283	5,323	5,705	5,559	5,605	5,764	5,435	5,383	4,969	4,510	63,320
Mining	60,502	55,792	61,200	59,295	59,838	57,961	59,272	60,996	60,883	62,460	60,564	62,458	721,221
Other	172	140	142	130	119	112	122	137	140	153	168	169	1,704
Total Net Energy Consumption	230,374	204,365	214,673	212,741	246,602	289,556	334,466	320,006	273,232	233,356	208,876	231,741	2,999,989
System Losses	19,927	16,022	18,118	17,998	23,822	28,550	33,681	30,785	26,394	21,189	17,149	19,883	273,518
Distributed Generation	18,849	19,508	26,831	28,429	29,013	27,765	27,239	27,998	27,936	25,885	23,412	20,889	303,755
Energy Efficiency	368	296	327	355	607	991	1,340	1,255	852	459	323	343	7,517
Total Gross Energy Consumption	269,517	240,192	259,950	259,524	300,044	346,862	396,726	380,045	328,414	280,888	249,760	272,857	3,584,778

Energy Consumption (MWh)													
Year: 2038	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Residential	101,502	87,179	85,148	85,016	106,516	143,535	179,590	166,525	131,499	96,723	82,340	102,221	1,367,793
Commercial	66,102	59,618	65,979	66,402	78,339	86,879	94,718	91,048	79,357	72,008	64,061	65,633	890,144
Industrial	5,053	4,732	5,283	5,323	5,705	5,559	5,605	5,764	5,435	5,383	4,969	4,510	63,320
Mining	60,501	55,791	61,200	59,295	59,838	57,960	59,272	60,996	60,883	62,460	60,564	62,458	721,219
Other	172	140	142	130	119	112	122	137	140	153	168	169	1,704
Total Net Energy Consumption	233,331	207,460	217,752	216,165	250,517	294,044	339,308	324,469	277,314	236,727	212,101	234,990	3,044,180
System Losses	20,183	16,265	18,378	18,288	24,200	28,993	34,168	31,214	26,789	21,495	17,414	20,162	277,548
Distributed Generation	18,868	20,171	27,287	28,756	29,061	27,923	27,443	28,162	28,036	25,580	23,468	20,842	305,597
Energy Efficiency	370	293	330	356	601	1,008	1,345	1,262	849	458	327	344	7,544
Total Gross Energy Consumption	272,752	244,190	263,747	263,565	304,379	351,968	402,264	385,107	332,988	284,260	253,309	276,339	3,634,868

Appendix C (cont.)

Energy Consumption (MWh)													
Year: 2039	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Residential	103,289	89,104	87,072	87,135	108,985	146,523	182,932	169,672	134,198	98,753	83,936	103,768	1,395,369
Commercial	67,437	60,892	67,401	67,939	79,969	88,660	96,490	92,832	80,895	73,408	65,170	66,641	907,734
Industrial	5,053	4,732	5,283	5,323	5,705	5,558	5,605	5,764	5,435	5,383	4,969	4,510	63,320
Mining	60,501	55,791	61,200	59,295	59,838	57,959	59,271	60,996	60,883	62,460	60,564	62,458	721,216
Other	172	140	142	130	119	112	122	137	140	153	168	169	1,704
Total Net Energy Consumption	236,453	210,659	221,099	219,821	254,616	298,812	344,421	329,400	281,552	240,157	214,806	237,545	3,089,342
System Losses	20,453	16,516	18,661	18,597	24,596	29,463	34,683	31,688	27,198	21,806	17,636	20,381	281,678
Distributed Generation	18,934	20,799	27,463	28,937	29,271	28,074	27,703	28,270	28,247	25,843	23,458	20,727	307,726
Energy Efficiency	372	292	330	354	604	1,011	1,354	1,261	857	454	329	343	7,561
Total Gross Energy Consumption	276,212	248,266	267,553	267,709	309,086	357,359	408,161	390,619	337,853	288,261	256,229	278,997	3,686,307

Energy Consumption (MWh)													
Year: 2040	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Residential	104,615	90,414	88,290	88,371	110,578	148,629	185,429	171,968	136,050	99,979	84,839	105,233	1,414,394
Commercial	68,302	61,689	68,207	68,623	80,798	89,483	97,408	93,574	81,686	73,981	65,699	67,700	917,151
Industrial	5,053	4,901	5,283	5,323	5,705	5,558	5,605	5,764	5,435	5,383	4,969	4,510	63,488
Mining	60,501	57,784	61,200	59,295	59,838	57,959	59,271	60,996	60,883	62,460	60,564	62,458	723,207
Other	172	140	142	130	119	112	122	137	140	153	168	169	1,704
Total Net Energy Consumption	238,644	214,927	223,122	221,742	257,038	301,741	347,835	332,438	284,195	241,957	216,238	240,069	3,119,945
System Losses	20,643	16,850	18,831	18,759	24,830	29,752	35,027	31,981	27,453	21,970	17,753	20,598	284,447
Distributed Generation	18,388	22,568	27,424	28,386	29,745	28,111	27,218	28,477	28,031	25,982	23,482	20,733	308,545
Energy Efficiency	371	299	328	346	618	998	1,356	1,277	858	443	330	339	7,564
Total Gross Energy Consumption	278,045	254,644	269,705	269,233	312,231	360,602	411,436	394,173	340,538	290,351	257,804	281,739	3,720,500

Energy Consumption (MWh)													
Year: 2041	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Residential	106,130	91,723	89,563	89,663	112,215	150,887	188,312	174,643	138,126	101,460	86,065	106,758	1,435,485
Commercial	69,292	62,583	69,190	69,627	81,994	90,843	98,923	95,030	82,933	75,076	66,648	68,681	930,826
Industrial	5,126	4,971	5,359	5,401	5,789	5,643	5,692	5,853	5,518	5,463	5,040	4,575	64,435
Mining	61,378	58,621	62,082	60,161	60,723	58,839	60,192	61,945	61,812	63,385	61,439	63,363	733,991
Other	175	142	144	132	121	113	124	139	142	156	170	171	1,730
Total Net Energy Consumption	242,101	218,039	226,338	224,984	260,843	306,326	353,244	337,610	288,532	245,540	219,362	243,549	3,166,467
System Losses	20,942	17,094	19,103	19,034	25,197	30,204	35,572	32,478	27,872	22,295	18,010	20,897	288,697
Distributed Generation	18,981	19,120	27,677	28,685	29,416	28,237	27,851	28,002	28,435	26,508	23,532	21,486	307,930
Energy Efficiency	368	296	324	362	607	990	1,305	1,239	863	472	317	348	7,491
Total Gross Energy Consumption	282,392	254,549	273,443	273,065	316,063	365,756	417,972	399,329	345,702	294,815	261,220	286,279	3,770,585

Appendix C (cont.)

ATTACHMENT C.2: COINCIDENT PEAK DEMAND

Peak Demand (MW)													
Year: 2027	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	284	266	247	279	356	479	521	498	438	341	287	335	521
Energy Efficiency	4	3	2	5	7	8	8	8	7	7	3	3	8
Distributed Generation	7	11	4	17	23	35	22	23	29	24	2	0	22
System Losses	8	7	7	7	9	13	13	12	12	10	7	8	13
Gross System Demand with Losses	303	287	261	308	394	535	563	541	487	381	298	347	563

Peak Demand (MW)													
Year: 2028	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	350	334	312	343	412	504	540	524	463	365	309	371	540
Energy Efficiency	3	3	2	5	7	8	8	9	7	7	3	3	8
Distributed Generation	8	11	4	18	24	36	23	24	30	24	2	0	23
System Losses	10	9	9	8	10	13	14	13	13	11	8	9	14
Gross System Demand with Losses	372	357	328	374	453	562	584	569	513	407	321	383	584

Peak Demand (MW)													
Year: 2029	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	417	391	374	409	474	565	608	587	524	433	379	439	608
Energy Efficiency	2	1	1	2	4	5	5	6	5	4	1	2	5
Distributed Generation	8	12	4	19	24	38	23	25	31	25	2	0	23
System Losses	12	10	11	10	12	15	15	15	14	13	10	10	15
Gross System Demand with Losses	438	414	390	440	514	622	652	632	575	475	392	451	652

Peak Demand (MW)													
Year: 2030	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	424	391	375	408	475	565	608	584	534	436	385	440	608
Energy Efficiency	2	1	1	2	4	5	5	6	5	3	1	1	5
Distributed Generation	8	12	4	19	25	38	24	25	32	26	2	0	24
System Losses	12	10	11	10	12	15	15	14	15	13	10	10	15
Gross System Demand with Losses	447	415	392	439	515	624	653	630	585	478	398	453	653

Peak Demand (MW)													
Year: 2031	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	427	395	382	407	473	566	611	590	538	438	381	440	611
Energy Efficiency	1	1	1	2	4	5	5	6	5	3	1	1	5
Distributed Generation	9	12	4	20	26	39	24	26	33	26	2	1	24
System Losses	12	10	11	10	12	15	15	15	15	13	10	10	15
Gross System Demand with Losses	449	419	398	439	514	625	656	636	591	481	394	453	656

Peak Demand (MW)													
Year: 2032	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	426	398	383	413	481	572	617	593	533	434	388	444	617
Energy Efficiency	1	1	1	2	3	4	4	4	4	3	1	1	4
Distributed Generation	9	13	4	20	26	40	25	26	33	27	2	1	25
System Losses	12	11	11	10	12	15	16	15	15	13	10	10	16
Gross System Demand with Losses	448	422	400	445	522	631	661	638	585	477	401	457	661

Peak Demand (MW)													
Year: 2033	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	428	401	381	413	483	575	616	596	538	435	387	446	616
Energy Efficiency	1	1	1	2	3	4	4	4	4	3	1	1	4
Distributed Generation	9	13	4	20	26	41	25	26	34	27	2	1	25
System Losses	12	11	11	10	12	15	16	15	15	13	10	10	16
Gross System Demand with Losses	450	425	397	445	524	634	660	642	590	478	399	459	660

Peak Demand (MW)													
Year: 2034	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	431	401	383	416	484	579	616	600	540	439	388	449	616
Energy Efficiency	1	1	1	2	3	4	4	4	4	3	1	1	4
Distributed Generation	9	13	4	21	27	41	25	27	34	27	2	1	25
System Losses	12	11	11	10	12	15	16	15	15	13	10	11	16
Gross System Demand with Losses	453	426	400	448	526	639	661	646	593	482	401	461	661

Appendix C (cont.)

Peak Demand (MW)													
Year: 2035	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	436	401	387	422	490	583	628	607	545	447	390	450	628
Energy Efficiency	1	1	1	2	3	4	4	4	4	3	1	1	4
Distributed Generation	9	13	4	21	27	41	26	27	34	28	2	1	26
System Losses	13	11	11	10	12	15	16	15	15	13	10	11	16
Gross System Demand with Losses	459	425	404	455	532	644	673	654	598	491	402	463	673

Peak Demand (MW)													
Year: 2036	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	436	403	390	419	486	583	628	607	557	451	392	453	628
Energy Efficiency	1	1	1	2	3	4	4	4	4	3	1	1	4
Distributed Generation	9	13	4	21	27	42	26	27	35	28	2	1	26
System Losses	13	11	12	10	12	15	16	15	15	13	10	11	16
Gross System Demand with Losses	459	428	407	451	528	643	674	654	611	495	405	465	674

Peak Demand (MW)													
Year: 2037	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	436	407	393	426	489	587	634	609	553	454	398	453	634
Energy Efficiency	1	1	1	2	3	4	4	4	4	3	1	1	4
Distributed Generation	9	13	4	21	27	42	26	27	35	28	2	1	26
System Losses	13	11	12	10	12	16	16	15	15	14	10	11	16
Gross System Demand with Losses	459	432	410	459	531	649	680	656	607	498	411	466	680

Peak Demand (MW)													
Year: 2038	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	437	407	394	427	498	592	638	613	553	450	399	457	638
Energy Efficiency	1	1	1	2	3	4	4	4	4	3	1	1	4
Distributed Generation	9	13	4	21	27	42	26	27	35	28	2	1	26
System Losses	13	11	12	10	12	16	16	15	15	13	10	11	16
Gross System Demand with Losses	460	433	411	460	541	654	684	660	607	495	412	470	684

Peak Demand (MW)													
Year: 2039	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	444	413	394	428	501	595	638	617	559	451	402	460	638
Energy Efficiency	1	1	1	2	3	4	4	4	4	3	1	1	4
Distributed Generation	9	13	5	21	28	42	26	28	35	28	2	1	26
System Losses	13	11	12	10	12	16	16	15	15	13	10	11	16
Gross System Demand with Losses	467	438	411	462	543	657	684	664	613	496	415	472	684

Peak Demand (MW)													
Year: 2040	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	445	414	397	431	502	598	643	623	563	458	399	462	643
Energy Efficiency	1	1	1	2	3	4	4	4	4	3	1	1	4
Distributed Generation	9	13	5	21	28	42	26	28	35	28	2	1	26
System Losses	13	11	12	10	12	16	16	15	15	14	10	11	16
Gross System Demand with Losses	469	439	415	464	545	660	690	670	617	503	412	474	690

Peak Demand (MW)													
Year: 2041	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	448	416	400	433	505	602	647	626	566	461	401	464	647
Energy Efficiency	1	1	1	2	3	4	4	4	4	3	1	1	4
Distributed Generation	9	13	5	21	28	43	26	28	35	28	2	1	26
System Losses	13	11	12	10	12	16	16	16	16	14	10	11	16
Gross System Demand with Losses	471	442	417	467	548	664	694	674	621	506	414	477	694

Appendix C (cont.)

ATTACHMENT D.1(A)(1): POWER SUPPLY
Data in columns with red headers (C.3f) are confidential and competitively sensitive.
POWER SUPPLY - ESTIMATES FOR 2027-2041

Plant/Unit/Contract	In Service Year	Book Life	Type	Owned Capacity (MW)	Max Capacity (MW)	Average Heat Rate	Variable O&M Cost (\$/MWh)	Fuel	Min Capacity (MW)	Must Run	Baseload Intermediate Peaking Intermittent
Gas											
Gila River CC3	2003	2048	Combined Cycle	151.75	141			Gas	25.16	Yes	Intermediate
Black Mountain 1	2008	2053	Combustion Turbine	45	43.5			Gas	20.01	No	Peaking
Black Mountain 2	2008	2053	Combustion Turbine	45	43.5			Gas	20.01	No	Peaking
Valencia CT1	1986	2051	Combustion Turbine	14	14			Gas	9.94	No	Peaking
Valencia CT2	1986	2051	Combustion Turbine	14	14			Gas	9.94	No	Peaking
Valencia CT3	1986	2051	Combustion Turbine	14	14			Gas	9.94	No	Peaking
Valencia CT4	2006	2051	Combustion Turbine	21	19			Gas	10.07	No	Peaking
Renewables											
Jacobson	2017	2042	Solar	4.4	4.4			Solar	0	Yes	Intermittent
La Senita	2011	2036	Solar	1	1			Solar	0	Yes	Intermittent
Rio Rico	2014	2039	Solar	6	6			Solar	0	Yes	Intermittent
Grayhawk Solar	2018	2043	Solar	46	45			Solar	0	Yes	Intermittent
Black Mountain Solar	2012	2032	Solar	8.6	8.6			Solar	0	Yes	Intermittent
Kingsman Wind Farm	2011	2031	Wind	10	10			Wind	0	Yes	Intermittent
Red Horse Expansion	2016	2041	Solar	30	30			Solar	0	Yes	Intermittent
Future Gas											
Future NGCC 1	2031	2050	Combined Cycle	125	125			Gas	113	No	Intermediate
Black Mountain 3	2030	2050	Combustion Turbine	49	49			Gas	44	No	Peaking
Black Mountain 4	2030	2050	Combustion Turbine	49	49			Gas	44	No	Peaking
Black Mountain 5	2030	2050	Combustion Turbine	49	49			Gas	44	No	Peaking
Black Mountain 6	2030	2050	Combustion Turbine	49	49			Gas	44	No	Peaking
Future Renewables											
Dandelion Solar	2028	2050	Solar	140	140			Solar	0	No	Intermittent
Future Hybrid Solar 1	2035	2050	Solar	50	50			Solar	0	No	Intermittent
Future Energy Storage											
Dandelion Storage	2028	2050	Energy Storage	140	140			Energy Storage	0	No	Intermittent
Future Hybrid Storage 1	2035	2050	Energy Storage	50	50			Energy Storage	0	No	Intermittent

Appendix C (cont.)

ATTACHMENT D.1(A)1(): ANNUAL CAPACITY FACTOR

Data in this table is Confidential and Competitively Sensitive

Annual Capacity Factor - Existing Resources															
Plant/Unit/Contract	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gas															
Gila River 3 (UNSE)															
Black Mountain 1															
Black Mountain 2															
Valencia 1															
Valencia 2															
Valencia 3															
Valencia 4															
Renewables															
Jacobson															
La Senita															
Rio Rico															
GrayHawk Solar															
Black Mountain Solar															
Kingman Wind Farm															
Red Horse Expansion															

Annual Capacity Factor - Future Resources															
Plant/Unit/Contract	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gas															
Future NGCC 1															
Black Mountain 3															
Black Mountain 4															
Black Mountain 5															
Black Mountain 6															
Renewables															
Dandelion Solar															
Future Hybrid Solar 1															
Storage															
Dandelion Storage															
Future Hybrid Storage 1															

ATTACHMENT D.1(A)(4): AVERAGE FUEL COST
Data in this table is Confidential and Competitively Sensitive

Average Fuel Cost (\$/MMBtu)	
Year	Natural Gas
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	
2039	
2040	
2041	

Appendix C (cont.)

ATTACHMENT D.1(A)(5): PURCHASED POWER ENERGY COSTS FOR LONG-TERM CONTRACTS

Data in this table is Confidential and Competitively Sensitive

Plant/Unit/Contract	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Energy Cost for Long Term Contract (\$/MWh)															
Existing Renewable PPAs															
GrayHawk Solar															
Black Mountain Solar															
Kingman Wind Farm															
Red Horse Expansion															
Future Renewable PPAs															
Dandelion Solar															

Appendix C (cont.)

ATTACHMENT D.1(A)(6): FIXED O&M

Data in this table is Confidential and Competitively Sensitive

Plant/Unit/Contract	Fixed Operation and Maintenance Costs (\$/MW-wk)															
	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	
Gas																
Gila River CC3																
Black Mountain 1																
Black Mountain 2																
Valencia CT1																
Valencia CT2																
Valencia CT3																
Valencia CT4																
Future Gas																
Future NGCC 1																
Black Mountain 3																
Black Mountain 4																
Black Mountain 5																
Black Mountain 6																
Future Renewables																
Future Hybrid Solar and Storage 1																

Appendix C (cont.)

ATTACHMENT D.1(A)(8): ENVIRONMENTAL IMPACTS

Data in this table is Confidential and Competitively Sensitive

Plant/Unit/Contract	CO2 Emissions (Metric Tons)														
	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gas															
Gila River CC3															
Black Mountain 1															
Black Mountain 2															
Valencia CT1															
Valencia CT2															
Valencia CT3															
Valencia CT4															
Future Gas															
Future NGCC 1															
Black Mountain 3															
Black Mountain 4															
Black Mountain 5															
Black Mountain 6															

Plant/Unit/Contract	NOx Emissions (Metric Tons)														
	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gas															
Gila River CC3															
Black Mountain 1															
Black Mountain 2															
Valencia CT1															
Valencia CT2															
Valencia CT3															
Valencia CT4															
Future Gas															
Future NGCC 1															
Black Mountain 3															
Black Mountain 4															
Black Mountain 5															
Black Mountain 6															

Plant/Unit/Contract	Water Consumption (000 Gallons)														
	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gas															
Gila River CC3															
Black Mountain 1															
Black Mountain 2															
Valencia CT1															
Valencia CT2															
Valencia CT3															
Valencia CT4															
Future Gas															
Future NGCC 1															
Black Mountain 3															
Black Mountain 4															
Black Mountain 5															
Black Mountain 6															

Appendix C (cont.)

ATTACHMENT D.2, D.3: GENERATION TECHNOLOGY AND FINANCIAL ASSUMPTIONS

Resource								
Category for Cost Reductions	Resource Category		Solar	Wind	Battery Storage-Hybrid	Battery Storage	Battery Storage	Battery Storage
	Technology Type		Utility-Scale PV	Onshore	Lithium ion (4-Hour) - Utility-Scale PV	Lithium ion (4-Hour)	Lithium ion (8-Hour)	Flow (10-hour)
Performance Inputs		Units						
Plant Output	Capacity Factor	%	31.0%	40.0%	33.4%	16.7%	33.3%	41.7%
Plant Cost Inputs								
Capital Costs	Installed Cost (2030\$)	\$/kW-ac	\$1,564	\$2,009	\$2,674	\$2,051	\$3,491	\$3,724
Fixed O&M	Annual Fixed O&M (2030\$)	\$/kW-yr	\$23	\$51	\$45	\$44	\$44	\$26
	Annual Escalation	%/yr	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Transmission Wheeling	Transmission (2026\$)	\$/kW-yr		\$48.00				
Property Tax	Property Tax	%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%
Insurance	Insurance	%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
Financial Assumptions	Financing Lifetime	yrs	30	20	20	20	20	20
	Equity Share	%	53.7%	53.7%	53.7%	53.7%	53.7%	53.7%
	Debt Share	%	46.3%	46.3%	46.3%	46.3%	46.3%	46.3%
	Debt Cost	%	4.2%	4.2%	4.2%	4.2%	4.2%	4.2%
	Equity Return	%	9.8%	9.8%	9.8%	9.8%	9.8%	9.8%
ITC	Credit	%			15.0%	30.0%	30.0%	30.0%
	Capital Costs Eligible	%			95%	95%	95%	95%
MACRS	Term	yrs	5	5	5	5	5	5

Resource								
Category for Cost Reductions	Resource Category		Natural Gas	Natural Gas	Nuclear	Nuclear	Geothermal	Pumped Hydro Storage
	Technology Type		Combustion Turbine	Combined Cycle	SMRs	Large - PWR	Enhanced	10 Hour
Performance Inputs		Units						
Plant Output	Capacity Factor	%	20.0%	50.0%	90.0%	90.0%	85.0%	41.7%
Plant Cost Inputs								
Capital Costs	Installed Cost (2030\$)	\$/kW-ac	\$2,377	\$2,186	\$12,048	\$11,805	\$7,192	\$4,980
Fixed O&M	Annual Fixed O&M (2030\$)	\$/kW-yr	\$26	\$15	\$134	\$172	\$160	\$13
	Annual Escalation	%/yr	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Transmission Wheeling	Transmission (2026\$)	\$/kW-yr					\$48.00	\$48.00
Property Tax	Property Tax	%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%
Insurance	Insurance	%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
Financial Assumptions	Financing Lifetime	yrs	30	30	40	40	40	40
	Equity Share	%	53.7%	53.7%	53.7%	53.7%	53.7%	53.7%
	Debt Share	%	46.3%	46.3%	46.3%	46.3%	46.3%	46.3%
	Debt Cost	%	4.2%	4.2%	4.2%	4.2%	4.2%	4.2%
	Equity Return	%	9.8%	9.8%	9.8%	9.8%	9.8%	9.8%
ITC	Credit	%			50.0%	50.0%	30.0%	40.0%
	Capital Costs Eligible	%			95%	95%	95%	95%
MACRS	Term	yrs	20	20	15	15	5	20

Appendix D

STOCHASTICS ANALYSIS

Fuel, Market and Demand Risk Analysis

UNSE developed explicit market risk analytics for each portfolio using Monte Carlo computer simulations in Aurora. Specifically, a stochastic dispatch simulation was used to evaluate future uncertainty related to fuel prices, wholesale market prices, and peak retail demand. The results of this modeling were employed to quantify the risk of uncertainty and evaluate the cost performance of each portfolio. This type of analysis ensures that the selected portfolio not only has a low expected cost but is also robust enough to perform well against a wide range of future load and market conditions.

As part of the Company's 2026 resource plan, UNSE conducted risk simulations around the following key variables:

- Natural Gas Prices
- Wholesale Market Prices
- Retail Load and Demand

Correlations among these variables were preserved within the simulations to capture the combined effects of changing market and load conditions on portfolio performance.

Permian Basin Natural Gas Prices

UNSE ran fifty individual risk simulations to quantify the risk of uncertainty related to Permian Basin natural gas prices. Chart 1 details the natural gas price simulations against which the portfolios were evaluated.

Chart 1 – Permian Basin Natural Gas Price Simulations

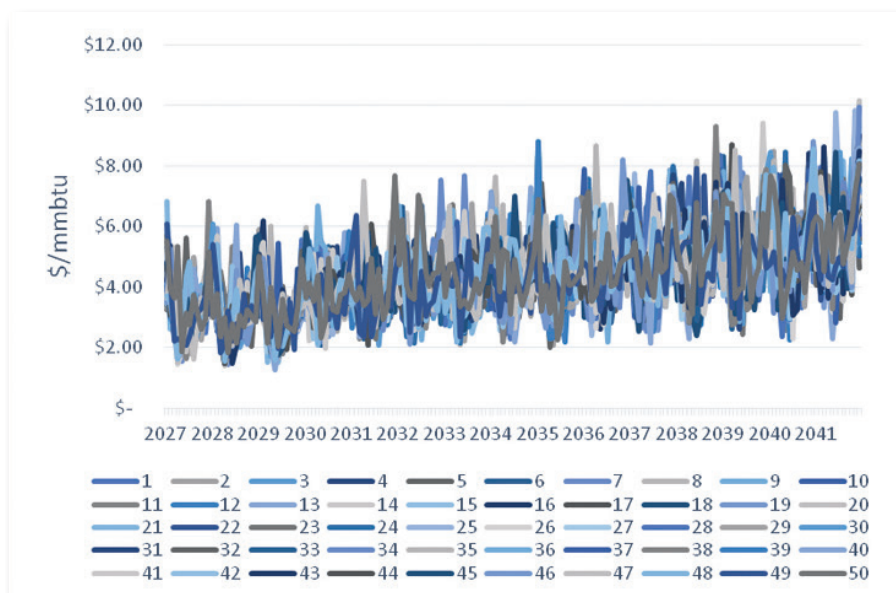


Chart 2 - Permian Basin Natural Gas Price Distributions



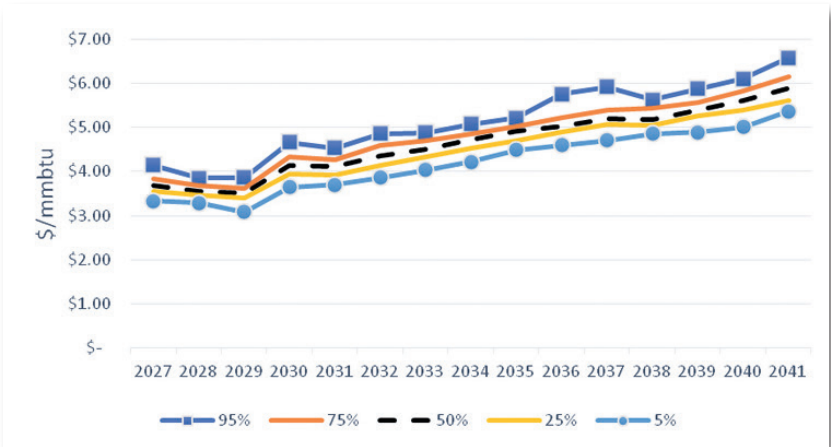
Chart 3 - San Juan Basin Natural Gas Price Simulations



San Juan Basin Natural Gas Price Distributions

Chart 4 shows the expected annual price distributions for natural gas sourced from the San Juan Basin. These distributions are based on the stochastic data simulations shown in Chart 3.

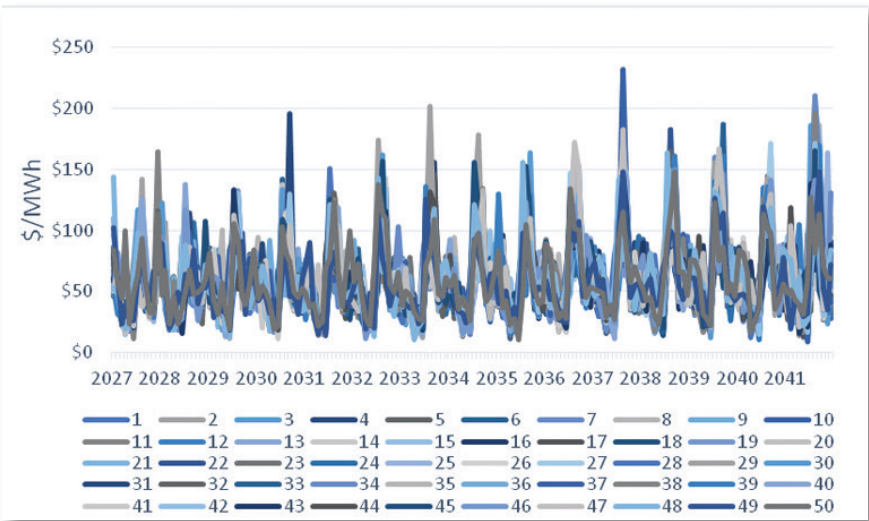
Chart 4 - San Juan Basin Natural Gas Price Distributions



Palo Verde (7x24) Wholesale Market Prices

UNSE ran fifty individual risk simulations to quantify the risk of uncertainty related to wholesale Palo Verde market power prices. Chart 5 details the wholesale power price simulations against which the portfolios were evaluated.

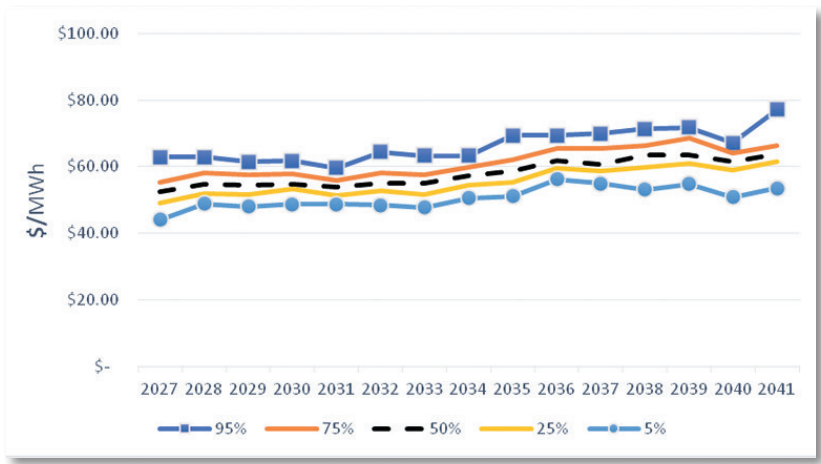
Chart 5 - Palo Verde Wholesale Power Price Simulations



Palo Verde (7x24) Wholesale Market Price Distributions

Chart 6 shows the expected annual price distributions for wholesale power purchased from the Palo Verde market. These distributions are based on the stochastic data simulations shown in Chart 5.

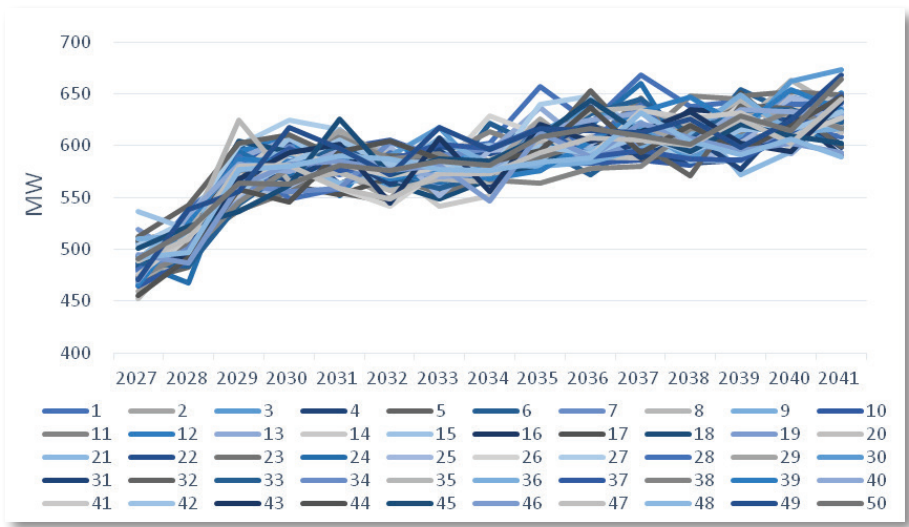
Chart 6 - Palo Verde (7x24) Market Price Distributions



Load Variability and Risk

As outlined in the previous sections, UNSE also conducted Monte Carlo simulations to quantify the uncertainty associated with retail load growth. Chart 7 below shows the results of the stochastic load simulations.

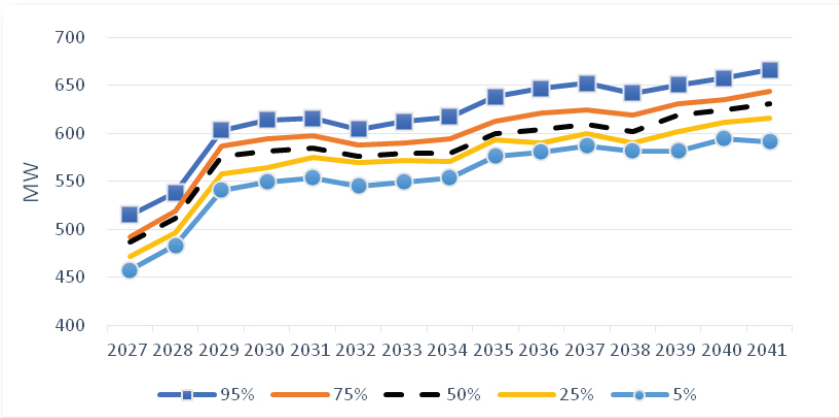
Chart 7 - UNSE Peak Retail Demand Simulations



Load Variability and Peak Demand Distributions

Chart 8 shows the expected demand distributions for UNSE’s peak demand forecast. These distributions are based on the stochastic data simulations shown in Chart 7.

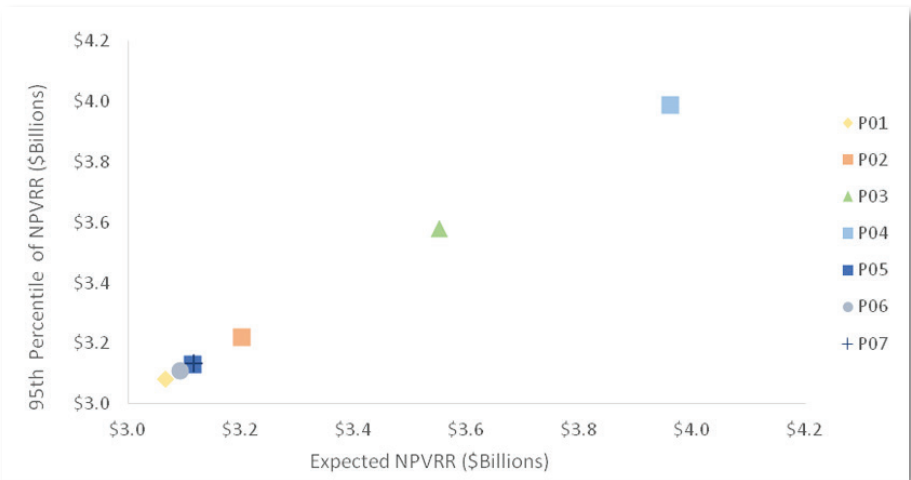
Chart 8 - UNSE Peak Retail Demand Distributions



NPVRR Mean and Worst-Case Risk

The degree to which each portfolio can adequately meet future load serving requirements at a reasonable cost is measured by examining the distribution of its net present value revenue requirement (NPVRR) outcomes for each portfolio across multiple stochastic iterations. The performance of each portfolio is summarized in the charts below under the Distribution of NPVRR Risk Results section. Chart 9 summarizes select portfolios with respect to both the expected average NPVRR and the “worst case” outcome risk as represented by the 95th percentile of its NPVRR outcomes. Values lower on the graph and farther to the left represent lower risk and lower cost portfolios.

Chart 9 - NPVRR Mean and 95th Percentile



Distribution of NPV Revenue Requirement Risk Results

Chart 10 shows the results of a Monte Carlo risk analysis performed on the NPV revenue requirements of the portfolios considered in this IRP. In this analysis, fifty iterations were performed on each portfolio, in which retail demand, natural gas prices, and Palo Verde market prices were randomly varied while preserving a high degree of correlation between gas and market prices. Chart 11 combines the results of each portfolio analysis. The peak of the curves indicates the most frequent revenue requirement outcomes, while the width of the curves reflects the potential range (i.e., risk) of outcomes. .

Chart 10 - NPVRR Risk Analysis Distributions by Portfolio

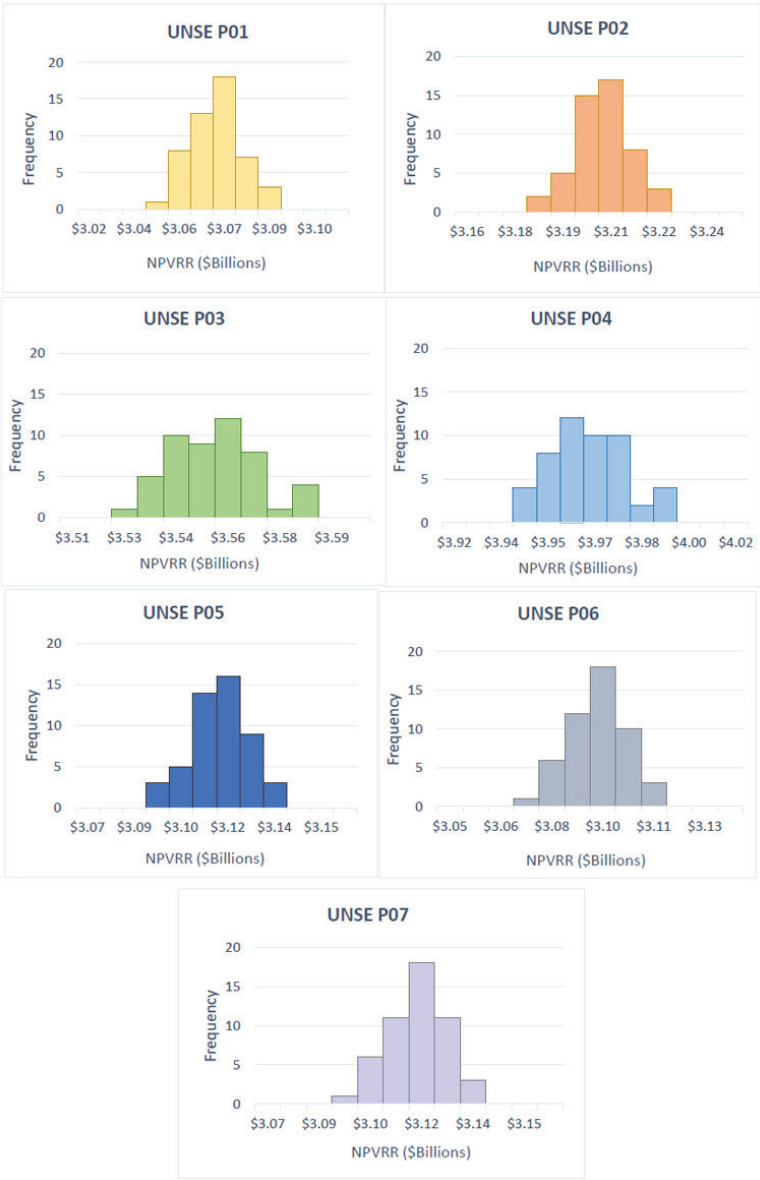
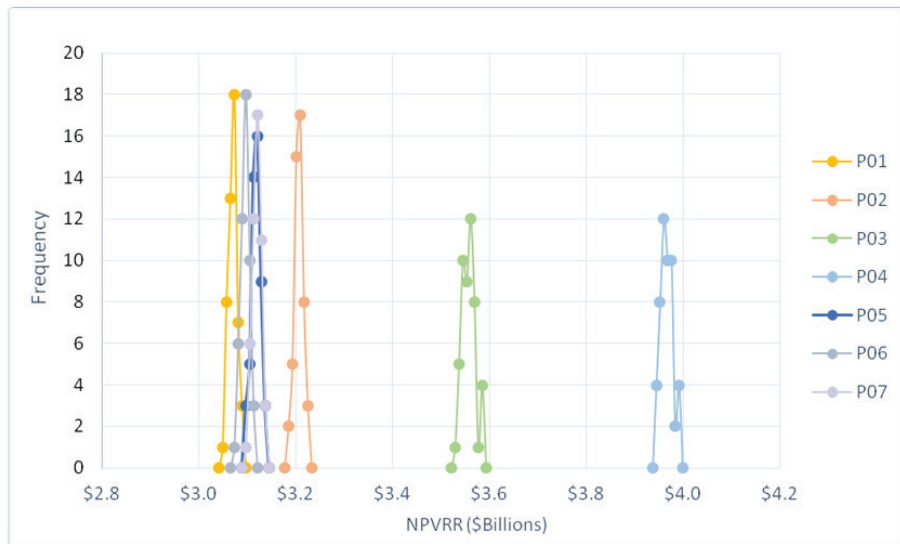


Chart 11 – NPVRR Risk Analysis Distributions



Appendix E

RESOURCE ADEQUACY STUDY

Tucson Electric Power PRM and ELCC Study

Prepared for UNSE Resource Planning Advisory Council Meeting

Feb 25th, 2026



Energy+Environmental Economics

Nick Schlag, Partner
Ruoshui Li, Managing Consultant
Melissa Rodas, Senior Consultant
Les Armstrong, Consultant

Agenda

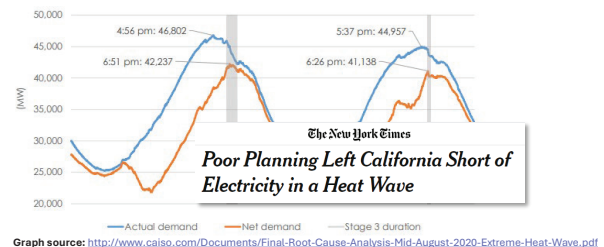
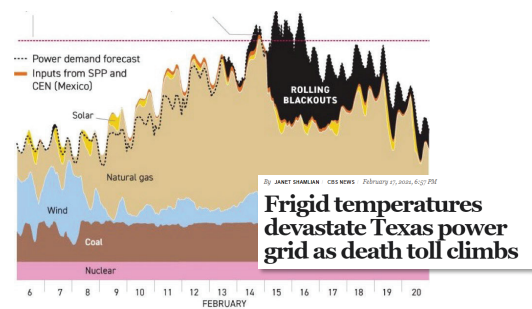
- + Introduction
- + Resource Adequacy Best Practices
- + Methods & Assumptions
- + PRM and ELCC Results

Background



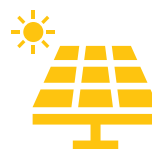
Resource adequacy is increasing in complexity – and importance

- + **Transition towards renewables and storage introduces new sources of complexity in resource adequacy planning**
 - The concept of planning exclusively for “peak” demand is quickly becoming obsolete
 - Frameworks for resource adequacy must be modernized to consider conditions across all hours of the year – as underscored by California’s rotating outages during August 2020 “net peak” period
- + **Reliable electricity supply is becoming increasingly important to society:**
 - Ability to supply cooling and heating electric demands in more frequent extreme weather events is increasingly a matter of life or death
 - Economy-wide decarbonization goals will drive electrification of transportation and buildings, making the electric industry the keystone of future energy economy



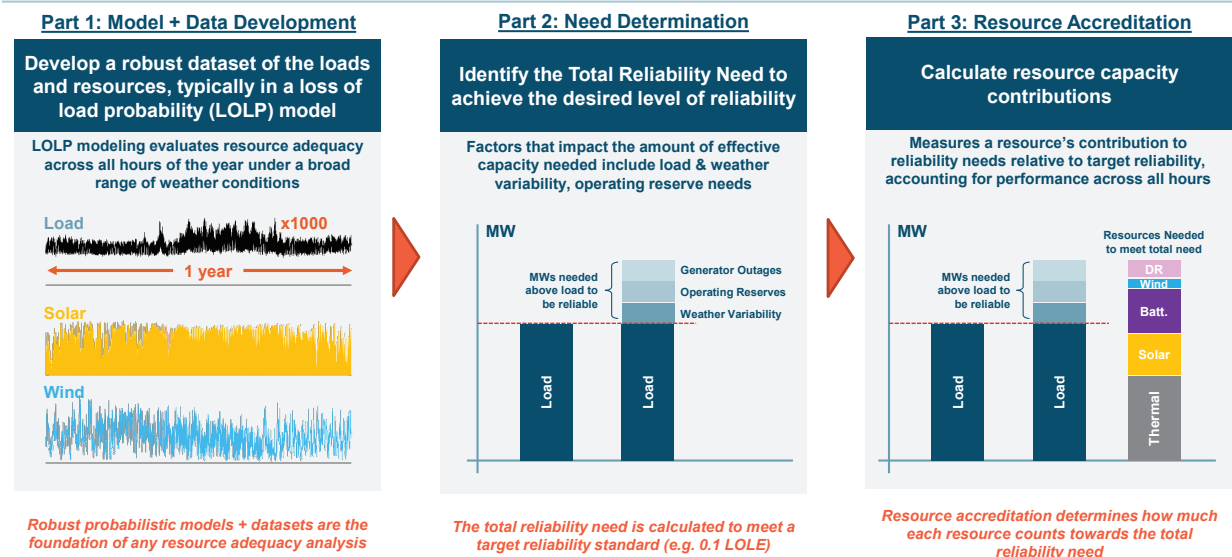
Study purpose

- + TEP retained E3 to conduct an RA study to establish PRM requirement and ELCC values for use in the development of TEP and UNSE's upcoming IRPs
- + This study was built on E3's previous study for TEP as well as data sets developed as part of an ongoing effort to update E3's study "Resource Adequacy in the Desert southwest"
- + Relatively to the last analysis in 2023, the major updates include:
 1. Updates to TEP and UNSE's load forecasts (including updated outlook for new large customers) and existing resource portfolio (based on recent RFP outcomes)
 2. Additional granularity in quantification of ELCC values to better capture dynamic of saturation effects
 3. Independent technology ELCCs for TEP and UNSE systems separately



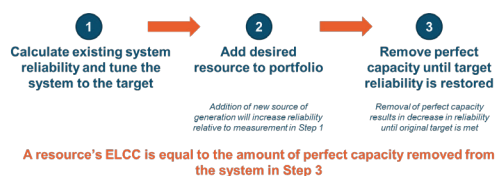
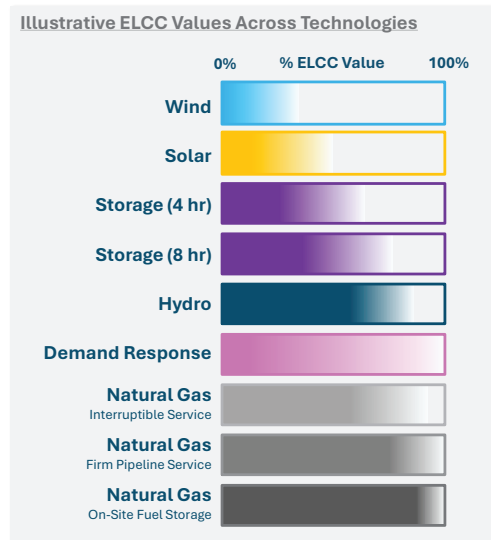
Resource Adequacy Best Practices

Planners are increasingly using LOLP models to support enhancements to resource adequacy



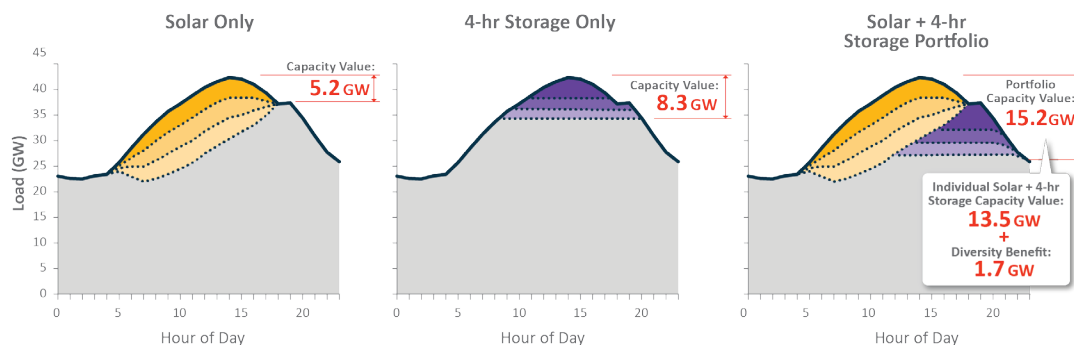
Using ELCC to accredit resource contribution to system needs

- + Effective Load Carrying Capability (ELCC) represents the equivalent “perfect” capacity that a resource provides in meeting the target reliability metric (e.g., 0.1 day/year LOLE)
- + ELCC is a technology-agnostic metric of capacity value and accounts for all factors that can limit availability:
 - Energy availability
 - Hourly variability in output
 - Duration and/or use limitations
 - Temperature-related de-rates and outage rates
 - Correlated outage risk...
- + Calculation of ELCC requires iterative use of LOLP modeling:



ELCC captures diversity benefits among technologies

- + Resources with complementary characteristics produce the opposite effect, synergistic interactions (also described as a “diversity benefit”)
- + As penetrations of intermittent and energy-limited resource grow, the magnitude of these interactive effects will increase and become non-negligible



Methodology and Input Assumptions

Setting up E3's RECAP model

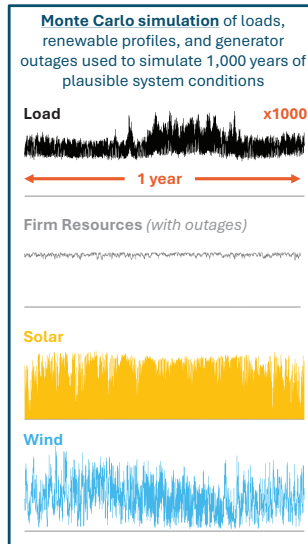
+ E3's Renewable Energy Capacity Planning (RECAP) model is a probabilistic method to consider system reliability across a wide range of load and weather conditions

+ Monte Carlo simulations consider system operations across a range of conditions

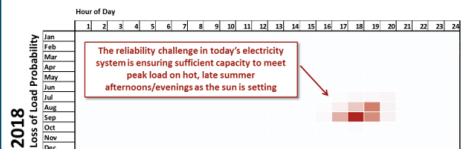
- Broad range of loads & renewables
- Randomly simulated plant outages
- Dispatch of use-limited resources

+ Model results include:

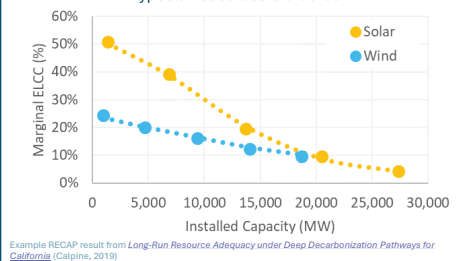
- Loss of load expectation (LOLE) and other reliability statistics
- PRM requirements
- ELCCs of different resources



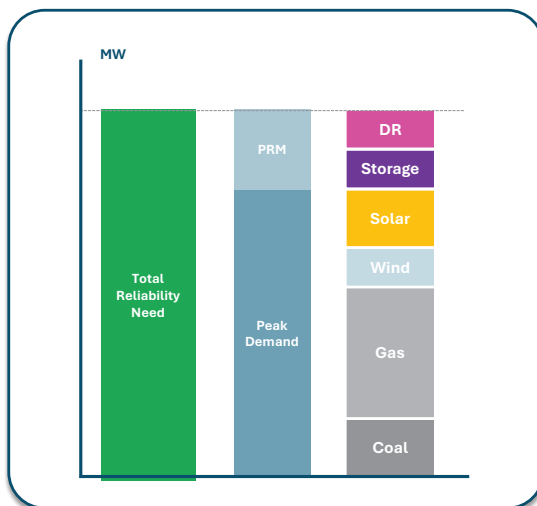
System reliability measured relative to "one day in ten year" standard; periods of high loss of load probability identified



Effective load carrying capability (ELCC) for a wide range of types of resources evaluated



Using RECAP for Need Determination and Resource Accreditation



Need Determination Deliverable:

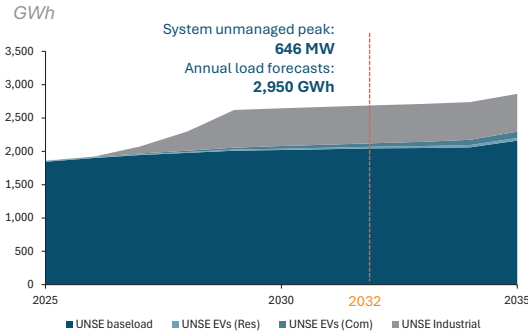
Total Reliability Need measured in ICAP, converted to an **PRM target** for UNSE +TEP system

Resource Accreditation Deliverable:

1. Static capacity value provided by **existing and committed resources** in the portfolio
 - Summer net dependable capacity for thermal resources
 - ELCC for existing renewable and storage resources
2. Dynamic capacity accreditation for **generic resources** evaluated in IRP analyses (changes with penetration)
 - Incremental wind curves
 - Incremental Solar – Storage surfaces

UNSE Loads and Existing Resources

UNSE Energy Forecast



- + Load among existing end uses projected to remain relatively flat (includes impacts of energy efficiency and behind-the-meter solar)
- + Significant increases in load projected in 2027 as a result of new Hermosa mine coming online

UNSE Total Capacity by Type, 2025 & 2032 (MW)

	2025	2032	Change
Coal (summer)	-	-	-
Natural Gas (summer)	267	431	+164
Wind	10	0	-10
Utility-scale Solar	97	96	-1
Battery Storage	-	-	-
Demand Response	-	-	-
Total	374	527	+153

Key portfolio changes

- + New natural gas resources
- + Existing wind retirement (-10 MW Kingman Wind)

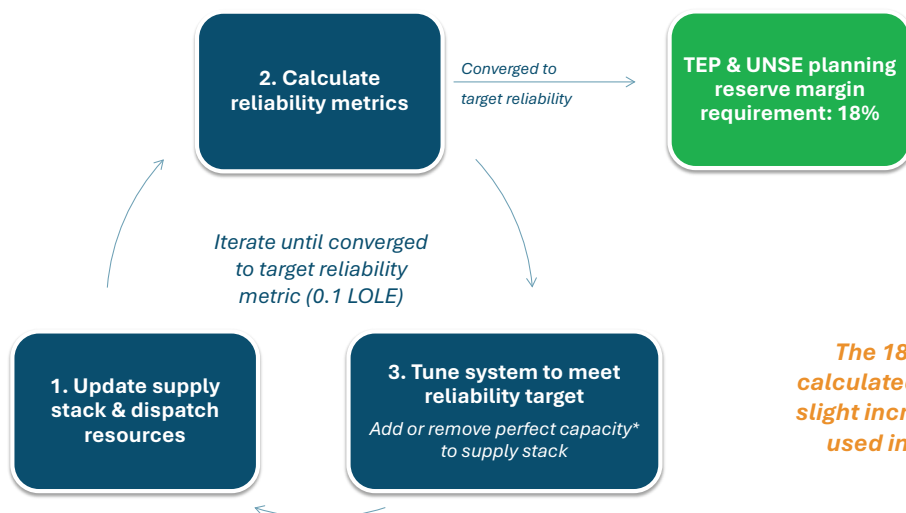
A Rich Temporal Library of Load & Renewable Profiles

Profile	Primary Source(s)	Weather Conditions Captured	Notes
Loads	UNSE Hourly Historical Load	2020 2024	<ul style="list-style-type: none"> Neural network regression used to back-cast hourly load patterns under broad range of weather conditions using recent historical load data (2017-2024 for TEP, 2020-2024 for UNSE) and long-term weather data (1970-2024) Historical shape scaled to match future forecasts of regional energy demand Shapes for load modifiers (e.g., transportation electrification) layered on top of neural network results
	ERA5 Land Historical Weather Data	1970 2024	
Wind	NREL WIND Toolkit	2007 2012	<ul style="list-style-type: none"> Profiles for existing wind resources simulated based on plant locations, known characteristics (e.g., hub height & power curve) Profiles for additional wind resources simulated based on generic locations chosen by E3 with input from TEP
Solar	NREL System Advisor Model	1998 2022	<ul style="list-style-type: none"> Profiles for existing utility-scale solar resources simulated based on plant locations, known characteristics (tracking vs. tilt, inverter loading ratio) Profiles for additional utility-scale solar resources simulated based on generic locations and technology characteristics chosen by E3 with input from TEP Profiles for behind-the-meter/distributed solar simulated for TEP/UNSE service area

Planning Reserve Margin Requirement



Calculating Target PRM using LOLP Modeling



The 18% PRM requirement calculated in this study reflects a slight increase to the assumption used in the 2023 IRP (16.5%)

Illustrative Example of Tuning to Calculate the PRM Requirement*

Without tuning adjustment (system “as specified”)

	Installed Capacity (MW)	Accredited Capacity (MW)**
Coal	0	0
Natural Gas	2,918	2,918
Wind	628	1,287
Solar	1,298	
Storage	1,030	
DR	10	
Tuning Adjustment	0	0
Total Capacity (MW)		4,205
Median Peak Demand (MW)**		3,779
Achieved PRM (%)		13%
Loss of Load Expectation (days/yr)		1 ❌

With tuning adjustment (calibrated to 0.1 days/yr)

	Installed Capacity (MW)	Accredited Capacity (MW)**
Coal	0	0
Natural Gas	2,918	2,918
Wind	628	1,287
Solar	1,298	
Storage	1,030	
DR	10	
Tuning Adjustment	+267	+267
Total Capacity (MW)		4,472
Median Peak Demand (MW)**		3,779
Achieved PRM (%)		18%
Loss of Load Expectation (days/yr)		0.1 ✅

* Results shown for joint system (TEP & UNSE), capturing benefits of existing load and resource diversity between the two systems; illustrative resource portfolio includes existing & committed resources and generic renewable & storage additions from previous IRP

** Thermal resources are accredited at summer net dependable capacity; renewables, storage, and DR are accredited using ELCC

*** The median peak demand outputs from RECAP differ slightly (<2% difference) from sum of UNSE and TEP forecasts as RECAP captures the coincident peak from all load components in two systems

UNSE Current Load Resource Balance in 2032

UNSE Load-Resource Balance in 2032

Existing & Committed Resources

	Installed Capacity (MW)	Accredited Capacity (MW)
Median Peak Demand (MW)		646
PRM Requirement (%)		18%
PRM Requirement (MW)		762
Coal	0	0
Natural Gas	431	431
Wind	0	0
Solar	96	39
Storage	0	0
DR	0	0
Tuning Adjustment	0	0
Total Capacity (MW)		470
Capacity Shortfall (MW)		292

+ In 2032, UNSE’s forecasted peak demand is 646 MW, resulting in a total requirement for accredited capacity of **762 MW** at 18% PRM

+ UNSE’s existing portfolio of resources provides **470 MW** of accredited capacity towards the PRM requirement

- Includes existing resources that will remain in UNSE’s portfolio and resources under development with executed contracts

+ Maintaining a reliability standard of 0.1 days per year would require procurement of an additional **292 MW** of accredited capacity

- This serves as the starting point for the ELCC analysis

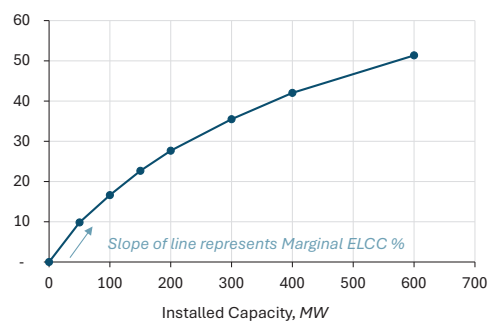
Effective Load Carrying Capability Results



Capacity Value for Generic UNSE Wind Additions

Cumulative Wind ELCC

Perfect MW



Cumulative and Marginal Wind ELCC

Wind Capacity MW	Cumulative ELCC (MW)	Average ELCC(%)	Marginal ELCC(%)
-	-	-	-
50	10	20%	20%
100	17	17%	14%
150	23	15%	12%
200	28	14%	10%
300	35	12%	8%
400	42	11%	7%
600	51	9%	5%

Cumulative ELCC (MW)
represents total capacity contribution of the incremental resources

Adding more resource capacity brings higher capacity value

Average ELCC (%)
represents percentage ELCC of the total capacity contribution of the incremental resource

Adding more resource capacity brings higher capacity value

Marginal ELCC (%) for wind measures how effective the additional wind can increase the portfolio ELCC

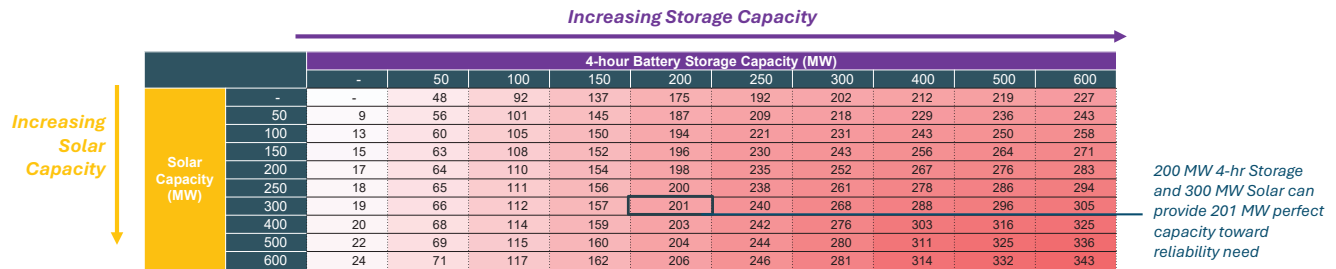
Adding the initial 50 MW adds 10 MW of incremental value, equivalent to a 20% marginal ELCC

Marginal ELCC decline to single digit after 200 MW penetration – at higher penetrations, loss-of-load risks shift to periods of low wind

Cumulative Portfolio Capacity Value provided by Generic Solar and Storage Addition in UNSE

Cumulative portfolio ELCC of Incremental Resource Additions

Perfect MW

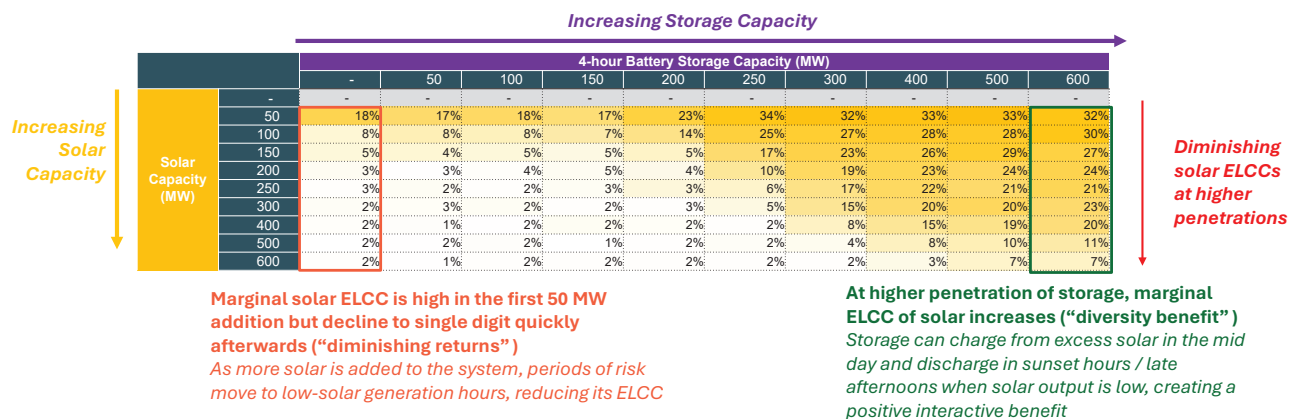


As the penetration of either resource increases, the total capacity contribution of the incremental resources also increases, reflecting their additional reliability contribution to the system

Marginal ELCC for UNSE Solar

Marginal ELCC of Incremental Solar Additions

% ELCC of marginal storage additions



Marginal ELCC for UNSE Storage

Marginal ELCC of Incremental Storage Additions

% ELCC of marginal storage additions

Increasing Storage Capacity →

		4-hour Battery Storage Capacity (MW)									
		-	50	100	150	200	250	300	400	500	600
<i>Increasing Solar Capacity</i> ↓	Solar Capacity (MW)	-	-	-	-	-	-	-	-	-	-
	50	-	95%	90%	89%	77%	33%	20%	10%	7%	7%
	100	-	95%	90%	88%	84%	43%	18%	11%	7%	7%
	150	-	95%	90%	89%	89%	54%	20%	12%	7%	8%
	200	-	95%	91%	88%	88%	67%	26%	13%	9%	7%
	250	-	95%	92%	89%	87%	73%	35%	15%	9%	7%
	300	-	95%	91%	90%	87%	77%	46%	17%	8%	7%
	400	-	95%	91%	90%	89%	79%	56%	20%	8%	9%
	500	-	95%	92%	90%	87%	79%	68%	27%	12%	9%
	600	-	95%	92%	89%	89%	80%	72%	31%	15%	10%
			95%	91%	90%	87%	82%	70%	32%	18%	11%

Similar diminishing return is observed in storage marginal ELCC (84% to 43% after 200 MW addition)

As more of the same duration (4-hr) storage is added to the system, system increasingly need resources that can sustain output for longer duration

Similarly, at higher penetration of solar, marginal ELCC of storage diminishes more slowly

Thank You

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Ruoshui Li, Ruoshui.li@ethree.com

DAY-AHEAD MARKET DEVELOPMENT IN THE WEST

Market Reform in the Western Interconnection

The Western Interconnection continues to undergo significant transformation driven by increasing renewable energy penetration, electrification trends, evolving policy objectives, and heightened reliability expectations. Regional electricity markets play an important role in facilitating efficient resource dispatch, improving reliability, and managing costs during this transition.

Two primary day-ahead market initiatives have emerged in the Western Interconnection: the California Independent System Operator (CAISO) Extended Day-Ahead Market (EDAM) and the Southwest Power Pool (SPP) Markets+ (Markets+). Both are designed to expand beyond traditional bilateral trading frameworks by providing centralized day-ahead and real-time market services across a broader geographic footprint.

Following a comprehensive evaluation of regional market alternatives, UNSE has selected participation in SPP Markets+, with market launch currently expected in October 2027. This decision reflects a determination that Markets+ aligns with operational priorities, governance preferences, and long-term resource planning objectives.

Markets+ is designed as a western-focused, stakeholder-driven market platform that builds on SPP's experience in reliability coordination and organized market operations. It is intended to provide coordinated day-ahead and real-time dispatch, expanded access to transmission, and enhanced operational visibility across participating balancing authorities.¹ Stakeholder engagement through working groups, task forces, and governance structures remains ongoing and supports continued alignment between market design and participant needs.

Markets+ Participation Framework

Participation in Markets+ represents a key component of long-term strategy to enhance reliability, flexibility, and cost-effectiveness relative to a purely bilateral framework.

Markets+ will provide centralized day-ahead and real-time market functions that enable coordinated dispatch across a diverse regional resource base. Participation is expected to improve system efficiency by enabling access to least-cost resources across a broader geographic footprint while maintaining full responsibility for serving native load.

¹ Southwest Power Pool, Markets+ Overview and Design Principles, <https://www.marketsplus.org/about>

Participation is guided by several core principles:

- **Reliability** – Maintaining sufficient resources and operational coordination to meet demand under a range of system conditions.
- **Customer Value** – Delivering long-term cost efficiency while prudently managing exposure to market risks.
- **Renewable Integration** – Supporting increased deployment and utilization of variable renewable resources.
- **Governance and Transparency** – Maintaining meaningful participation in market design, rulemaking, and oversight.

Markets+ incorporates a stakeholder-driven governance structure, including an Executive Committee, independent panels, and technical working groups. This structure is designed to provide participants with an active role in market evolution while maintaining transparent and balanced decision-making processes. Independent market monitoring is also expected to support fair and efficient market outcomes.²

Participation in Markets+ will require compliance with regional resource adequacy requirements. Markets+ participants are expected to utilize the Western Resource Adequacy Program (WRAP), which requires demonstration of sufficient capacity to meet load obligations and includes compliance and enforcement mechanisms.³ Accordingly, market participation complements, but does not replace, the obligation to maintain adequate resources to ensure reliability.

Impacts on Near-Term Procurement

Participation in Markets+ will influence near-term procurement of electricity and fuel through centralized day-ahead and real-time dispatch mechanisms. The following factors are expected to enhance operational efficiency while requiring continued attention to risk management, system operations, and alignment with market rules.

² Southwest Power Pool, Markets+ Governance and Market Monitoring Frameworks.
<https://southwestpowerpool.s3.amazonaws.com/newsstories/SPP009-Markets-Plus-Governance-1.pdf>

³ Western Power Pool, Western Resource Adequacy Program (WRAP) Overview. <https://www.spp.org/western-services/western-resource-adequacy-program/>

Key considerations include:	
Price Formation and Volatility	Centralized markets reflect system-wide supply and demand conditions, resulting in price variability driven by weather, load fluctuations, outages, fuel prices, and transmission constraints. Participation enables access to lower-cost energy when available, while requiring active management of price volatility.
Operational Coordination	Markets+ incorporates transmission constraints, reserve requirements, and system conditions into dispatch decisions, improving overall system efficiency and reliability while influencing dispatch patterns of individual resources.
Resource Optimization Across a Broader Footprint	Regional dispatch enables access to a diverse portfolio of generation resources across a wider geographic area, including renewable energy, storage, and dispatchable generation, improving overall system flexibility.
Market Liquidity and Competition	Broader participation increases market liquidity and competition, which may lead to more efficient pricing and improved procurement opportunities.

Impacts on Long-Term Resource Planning

Participation in Markets+ is expected to influence long-term resource planning decisions over a planning horizon of five to 25 years.

Key impacts:	
Resource Diversification and Reliability	Access to a broader regional resource mix enhances reliability and reduces exposure to localized supply disruptions or constraints.
Economic Efficiency and Cost Management	Centralized dispatch and access to regional resources may reduce production costs and improve utilization of existing assets, contributing to long-term customer value.
Infrastructure and Investment Signals	Market price signals and congestion patterns provide insight that supports planning decisions for generation and transmission infrastructure.
Alignment with Environmental Objectives	Regional markets facilitate increased utilization of renewable resources through broader geographic coordination, supporting emissions reduction and energy transition goals.

Participation in Markets+ supports the development of a flexible, resilient, and cost-effective resource portfolio while maintaining responsibility for long-term planning and resource adequacy.

Key Drivers and Implementation Considerations

As Markets+ advances toward implementation, several key considerations will continue to influence outcomes:

- **Transmission Constraints and Congestion Management:** Market benefits depend on available transmission capacity and effective congestion management practices.
- **Cost Allocation and Benefit Realization:** Appropriate allocation of costs and equitable realization of benefits remain important considerations.
- **Resource Adequacy Integration:** Coordination between Markets+ and WRAP will influence reliability planning and compliance requirements.
- **Market Seams:** Interfaces between Markets+, other organized markets (such as EDAM), and bilateral regions may introduce operational and pricing complexities.
- **Evolving Policy and Emissions Objectives:** Market frameworks must adapt to changing regulatory and environmental requirements.

Appendix F (cont.)

Markets+ is designed to economically dispatch resources across a large and diverse geographic footprint, increasing reliance on variable renewable generation and long-distance energy transfers. Effective coordination at market seams, robust transmission frameworks, and transparent operational processes will be essential to achieving intended reliability and cost benefits.⁴

Active participation in market development and implementation will continue to ensure that final market structures remain aligned with reliability needs, regulatory expectations, and customer interests.

Western Resource Adequacy Program

The Western Resource Adequacy Program (WRAP) is a regional reliability planning and compliance program administered by the Western Power Pool (WPP) with program operator services provided by the Southwest Power Pool (SPP). The program was initiated in 2019 in response to growing concerns regarding resource adequacy across the Western Interconnection, driven by thermal fleet retirements, increasing renewable penetration, and evolving load patterns. WRAP is the designated resource adequacy program of SPP's Markets+, which TEP has joined as a Phase 2 member (see above).

WRAP is the first region-wide resource adequacy framework in the Western Interconnection and is designed to provide a coordinated approach for ensuring sufficient generation and transmission capacity to meet demand during periods of system stress. The program establishes common reliability metrics and introduces compliance obligations to ensure that participating entities contribute to regional reliability while maintaining their independent planning and operational responsibilities.⁵

The WRAP includes two primary components:

- **Forward Showing Program (FS Program):** The planning component of WRAP, which requires participants to demonstrate, prior to each season, that they have secured sufficient capacity and transmission rights to meet their assigned share of regional reliability requirements.
- **Operational Program (Ops Program):** The real-time component, which facilitates the sharing of capacity among participants during periods of scarcity by requiring entities with surplus resources to assist those with deficiencies.⁶

WRAP implementation is proceeding through a phased transition. The program entered a non-binding transition period beginning in 2023 and implemented forward showing and operational requirements. The transition period is defined in the WRAP tariff as spanning from June 1, 2025 (Summer 2025) through March 15, 2028 (Winter 2027–2028). The program will become fully binding in the 2027–2028 timeframe.⁷

As of 2026, multiple utilities, including UNSE, through its affiliation with Tucson Electric Power, have indicated interest in or commitment to participating in WRAP's binding phase beginning in the winter 2027–2028 season. WRAP is intended to complement and not replace existing utility resource planning and emerging market structures but provides a near-term regional framework for addressing reliability challenges.⁸

⁴ Federal Energy Regulatory Commission (FERC), Wholesale Electricity Market Design and Regional Coordination Principles, as reflected in Commission orders and related literature.

⁵ <https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program>

⁶ https://gridlab.org/wp-content/uploads/2023/09/GridLab_WRAP-Report_Slides_reducedsize.pdf

⁷ WRAP Committee of State Representatives Revised Transition Plan presentation; 9/10/24

⁸ NW Council Presentation, 9/2024

Appendix F (cont.)

As WRAP practices mature and participants gain operating experience, UNSE will evaluate how regional diversity benefits and WRAP metrics can be incorporated into resource planning. Until additional experience is gained and participation levels stabilize, UNSE will rely primarily on its own reliability assessments and Planning Reserve Margin targets.

WRAP Reliability Metrics

WRAP establishes a common regional resource adequacy framework using a probabilistic reliability standard of approximately one loss-of-load event day in ten years (1-day-in-10-years LOLE). Based on this reliability target, the Program Operator develops seasonal Forward Showing Planning Reserve Margins (FSPRMs) and associated regional capacity requirements. These requirements incorporate the benefits of geographic load diversity, resource diversity, and the binding operational obligations that allow participants to aid one another during scarcity conditions. Resource contributions are measured using WRAP's standardized Qualifying Capacity Contribution (QCC) methodology, which assigns each resource an accredited capacity value representing its expected contribution to meeting system reliability needs during periods of greatest stress.

The accreditation process is based in part on Capacity Critical Hours (CCHs), which are historical hours identified as having the highest reliability risk based on load, resource availability, and system conditions. CCHs help establish when capacity is most valuable and are used in the evaluation of resource performance and accreditation. For variable generation and storage resources, QCCs are determined using Effective Load Carrying Capability (ELCC) methodologies. ELCC measures the amount of additional load that a resource can reliably support while maintaining the same system reliability standard, thereby quantifying the resource's capacity value during periods of highest reliability risk. Thermal resources are accredited using outage-adjusted methodologies that reflect expected availability during system stress conditions.⁹

Program Design and Compliance Framework

In addition to demonstrating adequate accredited capacity, WRAP participants must secure sufficient transmission rights to ensure that capacity can be delivered when needed. Compliance is evaluated separately for defined summer and winter seasons, reflecting differing regional reliability risks. WRAP is not an organized wholesale energy market and does not establish energy prices; rather, it is a capacity adequacy and reliability framework designed to complement emerging market structures such as Markets+.¹⁰

Participation in WRAP provides access to regional diversity benefits and coordinated capacity sharing, which can improve resource utilization and reduce overall capacity requirements across the region. However, those benefits depend on the availability of transmission, participant performance, and continued program participation. As a result, utilities remain exposed to potential regional scarcity events, transmission constraints, and uncertainty regarding future market participation levels, particularly during widespread extreme system conditions. These considerations support UNSE's continued use of utility-specific reliability assessments and planning reserve margin targets for long-term resource planning.¹¹

WRAP's governance structure is intended to provide independent, stakeholder-driven oversight through the Western Power Pool and the Resource Adequacy Participants Committee (RAPC), enabling participants to help shape program rules, tariff revisions, and business practices.

⁹ Western Resource Adequacy Program PDF, 5/2/2022, Roy, Ryan.

¹⁰ WRAP Presentation – Ryan Roy – 5/2/22

¹¹ Regional RA Footprint Study Results Summary (Brattle) – 11/2025

Appendix G

ENVIRONMENTAL REGULATIONS OVERVIEW

Overview

The U.S. Environmental Protection Agency (EPA) has the authority to regulate emissions and by-products produced by power generation facilities. These power plant emissions and by-products are regulated by statutory and regulatory programs. As these programs continue to evolve, they have had and will continue to have important implications for public health, the mix of U.S. generating resources, and economic growth by driving investment in new and cleaner technologies and contributing to the retirement of the more inefficient and higher emitting plants.

The discussion below provides a snapshot of the major environmental regulatory programs and recent proposals that may have an impact on UNSE and its resource planning efforts. Existing and future resources are modeled taking into account the potential impact of environmental regulations in effect at that time.

Greenhouse Gas Regulation

In May 2024, the EPA published final rules to regulate greenhouse gas (GHG) emissions from two categories of fossil-based electric generating units (EGUs) under Section 111 of the Clean Air Act: (i) existing steam units (including coal- and natural gas-fired); and (ii) new natural gas-fired turbines.¹

The final rules established:

- Emission guidelines for existing coal-fired steam EGUs, which are subcategorized based on federally enforceable retirement dates. These emission guidelines affect Springerville Units 1 and 2, as well as Four Corners Units 4 and 5;
- Emission guidelines for existing natural gas- and oil-fired steam EGUs aligned with routine methods of operation and maintenance, which are subcategorized based on the annual capacity factor of each unit beginning January 1, 2030. These emission guidelines affect Sundt Units 3 and 4;
- New source performance standards for new stationary natural gas-fired combustion turbines, which are subcategorized based on the annual capacity factor for each unit. For base load units (i.e., units with an annual capacity factor greater than 40%), the EPA established a two-phased performance standard. For phase 1, new base load units must initially meet performance standards based on the use of highly efficient combined cycle generation with the best operating and maintenance practices. For phase 2, the final rule requires that such base load units achieve emissions reductions equivalent to a 90% carbon capture and sequestration (CCS) rate beginning on January 1, 2032.

Various legal challenges to the final rules are pending before the U.S. Court of Appeals for the District of

¹ U.S. EPA, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emissions Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generation Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39798 (May 9, 2024). <https://www.govinfo.gov/content/pkg/FR-2024-05-09/pdf/2024-10162.pdf>

Appendix G (cont.)

Columbia Circuit. In April 2025, the Court granted the EPA's unopposed motion to hold the case in abeyance indefinitely (following a previous sixty-day stay), while the EPA conducts a rulemaking to reassess the rules. In June 2025, the EPA published a proposed rule containing two co-proposals to address the 2024 final rules². In the primary proposal, the EPA proposed to repeal the 2024 final rules in their entirety based on a determination that fossil-based electric generating units do not contribute significantly to GHG air pollution. In the alternative proposal, the EPA proposed to:

- Repeal the Best System of Emission Reductions determinations, presumptive standards of performance, and all related requirements in the emission guidelines for existing coal-fired steam EGUs;
- Repeal the requirements for existing natural gas- and oil-fired steam EGUs; and
- Repeal the phase 2 CCS-based requirements for new base load natural gas-fired combustion turbine EGUs, keeping the phase 1 performance standards in the 2024 final rules.

In September 2026, the EPA published a rule finalizing the alternative proposal and also issued a supplemental proposal seeking additional comment on the primary proposal. On the same day, legal challenges to the new final rule were filed in the U.S. Court of Appeals for the District of Columbia Circuit.

We cannot predict the outcome of the rulemaking or the legal challenges at this time.

National Ambient Air Quality Standards

Ozone and Particulate Matter are two of the six “criteria pollutants” for which EPA must set national ambient air quality standards (NAAQS) under the Clean Air Act. Under the NAAQS program, EPA considers data and information from air quality monitors and “designates” areas as attainment or nonattainment with the standard. If an area cannot meet the standard, the area is designated as nonattainment and classified according to the amount of time that the area has remained above the NAAQS (classifications include marginal, moderate, serious, severe and extreme). States, tribes or EPA must develop plans to bring nonattainment areas back into compliance with the standard. A nonattainment designation may result in more stringent regulation and may impact economic growth in the relevant area.

Ozone NAAQS

In October 2015, the EPA finalized the 8-hour ozone NAAQS at 70 parts per billion (ppb)³ (the 2015 ozone NAAQS), lowering the 75 ppb standard set in 2008⁴ (the 2008 ozone NAAQS). In 2020, the ozone standards were reviewed by EPA and retained, without revision.⁵

2 U.S. EPA, Proposed Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units, 90 Fed. Reg. 25752 (Jun. 17, 2025).

<https://www.govinfo.gov/content/pkg/FR-2025-06-17/pdf/2025-10991.pdf>

3 U.S. EPA, National Ambient Air Quality Standards for Ozone, 80 Fed. Reg. 65,291 (Oct. 2015).

4 U.S. EPA, National Ambient Air Quality Standards for Ozone, 73 Fed. Reg. 16,436 (Mar. 2008).

5 U.S. EPA, Review of the Ozone National Ambient Air Quality Standards, 85 Fed. Reg. 87,256 (Dec. 2020).

Appendix G (cont.)

The Phoenix-Mesa area, where Gila River Power Station is located, is currently designated nonattainment and classified as “moderate” for both the 2008 and 2015 8-hour ozone NAAQS. The Phoenix-Mesa area recently was on track to be reclassified to “Serious” nonattainment. EPA addressed this matter in March of 2026 by finalizing, under Section §179(b) of the Clean Air Act, a determination that the area would have attained the standard “but for” the presence of international emissions.⁶ A more stringent nonattainment classification could have resulted in additional regulatory requirements for existing sources in the Phoenix-Mesa area. UNSE will continue to monitor ozone NAAQS implementation and the EPA’s efforts to bring the regulated community into compliance with the ozone NAAQS.

Particulate Matter NAAQS

In March 2024 the EPA finalized a rule to lower the primary annual NAAQS for fine particulate matter (PM_{2.5}) from its current level of 12 micrograms per cubic meter (µg/m³) to 9 µg/m³.⁷

Lowering this standard set in motion requirements for Arizona to identify areas that may not meet the new standard and recommend that EPA designate these areas as nonattainment.

Arizona’s initial evaluation found that parts of Maricopa County, Santa Cruz County, and Pinal County may not meet the new standard. Arizona has not yet submitted nonattainment area boundary recommendations to the EPA and the EPA has not yet designated any areas within the State as nonattainment.

Following the D.C. Circuit Court of Appeals’ decision denying EPA’s motion to vacate the 2024 final rule, a coalition of industry groups filed a petition for certiorari with the Supreme Court on August 28, 2026.

UNSE will continue to monitor this matter.

Good Neighbor Federal Implementation Plan

In September 2018, the ADEQ submitted to the EPA the Arizona SIP Revision to address the interstate transport of ozone (Arizona Ozone Transport SIP Revision) under the 2015 ozone NAAQS. In June 2022, the EPA proposed to approve the Arizona Ozone Transport SIP Revision, finding that it contained adequate provisions to prohibit emissions that will significantly contribute to nonattainment or interference with maintenance of the 2015 ozone NAAQS in other states.

In March 2023, the EPA released its final FIP to address the interstate transport of ozone (Good Neighbor FIP) with an effective date of August 4, 2023. The Good Neighbor FIP establishes requirements for those states where the EPA disapproved Ozone Transport SIP Revisions in whole or part. The Good Neighbor FIP requires NO_x emission reductions from fossil-fueled generation facilities. The EPA provided an updated analysis in the Good Neighbor FIP that suggested Arizona may be significantly contributing to one or more nonattainment or maintenance receptors and that a separate action for Arizona was forthcoming.

In February 2024, the EPA published a proposed supplemental Good Neighbor rulemaking proposing to partially approve and partially disapprove the Arizona Ozone Transport SIP Revision and to expand the coverage of the Good Neighbor FIP to include Arizona. Arizona’s inclusion under the Good Neighbor FIP would subject certain of our fossil-fueled generation facilities to NO_x emission reduction requirements.

6 U.S. EPA, Review of the Ozone National Ambient Air Quality Standards, 85 Fed. Reg. 87,256 (Dec. 2020).

7 U.S. EPA, Reconsideration of the National Ambient Air Quality Standards for Particulate Matter, 89 Fed. Reg. 16,202 (Mar. 2024).

Appendix G (cont.)

In June 2024, the U.S. Supreme Court granted a stay of the Good Neighbor FIP pending the disposition of the petitions for review of the Good Neighbor FIP currently pending in the U.S. Court of Appeals for the District of Columbia Circuit. In October 2024, the EPA issued an interim final rule administratively staying the effectiveness of the Good Neighbor FIP for all emissions sources subject to the plan as promulgated.

In September 2024, the U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's request to remand the Good Neighbor FIP rulemaking record and further respond to comments related to the issues addressed in the U.S. Supreme Court's stay. The EPA published its updated response to comments for the Good Neighbor FIP in December 2024.

In March 2025, the EPA filed a motion in the U.S. Court of Appeals for the District of Columbia Circuit indicating it plans to reconsider the Good Neighbor Rule. In January 2026, the EPA published the first proposal of a two-phase plan to revise the interstate transport regulations for the 2015 ozone NAAQS. The EPA proposed to approve SIPs from eight states (including Arizona) based on a determination that emissions from these states do not significantly contribute to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in downwind states.

Water Consumption

Water availability is a major consideration for utilities operating power plants or planning new resources in the Desert Southwest. For facilities already in operation, utilities need to be cognizant of water use and supply trends in the area immediately surrounding those facilities. While existing facilities have secured the legal rights to the water needed for operation, there can be a disconnect between the legal right to water and its physical availability. For this reason, technologies and strategies to decrease power plant water use become an important planning goal within the integrated resource planning process. The most effective means of reducing power plant water use is through transitioning to a less water-intensive generating resource. Increasing power plant water use efficiency may also be effective. This section provides an overview of UNSE's water use at its existing generating facilities and discusses strategy to reduce overall water consumption intensity (i.e., gallons of water consumed per MWh generated).

Water consumption also has a localized environmental impact. The availability of water that is withdrawn from groundwater aquifers, as in the case of Gila River Power Station, Black Mountain Generating Station, and Valencia Power Plant, is dependent on the recharge to and other withdrawals from the aquifer. Future reductions in Arizona's Colorado River surface water allocations have the potential to increase groundwater withdrawals creating additional local aquifer demand. Groundwater availability is also dependent on the hydrogeological characteristics of the aquifer itself.

Facilities located in regions where local aquifers are stressed (e.g., within Active Management Areas) are subject to annual groundwater withdrawal limits and best management practices (BMPs) to minimize groundwater use. To the extent practicable, UNSE implements water conservation BMPs at its power plants to minimize groundwater use. These BMPs include operating cooling towers at high cycles of concentration and recycling / re-using water across each facility where feasible.

Appendix H

EXISTING RESOURCES

Introduction to Existing Resources

This section provides an overview of UNSE's existing generation and transmission portfolio, including thermal generation assets, renewable energy resources, renewable PPAs and transmission infrastructure that collectively support reliable electric service to customers.

For each major resource, information is provided regarding ownership arrangements, operating characteristics, fuel supply where applicable, environmental controls, historical performance, and outlook. For renewable resources, this section also summarizes technology characteristics, capacity ratings, and facility development information. The section concludes with an overview of UNSE's transmission system and its role in supporting resource adequacy, reliability, and access to regional energy markets.

UNSE's Existing Thermal Resource Portfolio

UNSE's existing resource portfolio consists of owned thermal generation, owned renewable resources, renewable energy PPAs, and transmission assets that together serve customer energy and capacity needs.

Table 1 provides a summary of UNSE's existing thermal generating resources. Subsequent sections describe the company's renewable energy, transmission, and other supply-side resources in greater detail.

Table 1 - UNSE Thermal Resources

Generating Station	Unit	Fuel Type	Net Nominal Capability (MW)	Commercial Operation Year	Operating Agent	UNSE Ownership Share (%)	UNSE Planning Capacity (MW)
Valencia	1	Gas	14	1989	UNSE	100	14
Valencia	2	Gas	14	1989	UNSE	100	14
Valencia	3	Gas	14	1989	UNSE	100	14
Valencia	4	Gas	19	2006	UNSE	100	19
Black Mountain	1	Gas	45	2008	UNSE	100	45
Black Mountain	2	Gas	45	2008	UNSE	100	45
Gila River	3	Gas	619	2003	SRP	25	154.8
Total Planning Capacity							305.8

Appendix H (cont.)

Valencia Power Plant

The Valencia Power Plant (Valencia) is located in Nogales, Arizona and provides UNSE with 61 MW of combustion turbine capacity. All four units are owned by UNSE. Units 1 through 3 entered service in 1989 and Unit 4 entered service in 2006. The facility provides peaking capacity, operational flexibility, and local reliability support for UNSE's Santa Cruz County service territory.



Table 2 - Valencia Unit Profiles

Units	Capacity (MW)	In-Service Date	Planned Retirement
Unit 1	14	1989	Not Planned
Unit 2	14	1989	Not Planned
Unit 3	14	1989	Not Planned
Unit 4	19	2006	Not Planned

Valencia Fuel Supply

UNSE procures natural gas through a combination of spot market purchases and hedging transactions consistent with the company's fuel procurement and risk management practices. Natural gas is primarily sourced from the Permian Basin and delivered to the Valencia Power Plant through Kinder Morgan's El Paso Natural Gas interstate pipeline system. Diesel fuel oil is kept on site and procured on an as-needed basis.

Valencia Pollution Controls

Valencia's combustion turbine Units 1 through 4 can operate on natural gas and are equipped with water injection technology to control emissions of nitrogen oxides (NO_x). The facility operates under a Title V air permit that includes plant-wide emissions limits of 250 tons per year for both NO_x and sulfur dioxide (SO₂), along with applicable monitoring, recordkeeping, and reporting requirements. The air permits also allow Units 1 through 3 to operate on diesel fuel oil.

Each unit is subject to applicable federal New Source Performance Standards (NSPS) requirements for NO_x and SO₂ emissions. In addition, because each combustion turbine unit has a generating capacity of less than 25 MW, the units are not subject to the federal Acid Rain Program.

Valencia Operational Outlook

The Valencia units provide peaking capacity, operational flexibility, and local reliability support for UNSE’s customers in Santa Cruz County. The facility serves as an important resource for maintaining reliable electric service in the Nogales area, particularly during periods of high demand and transmission system contingencies.

In addition, the Vail-to-Valencia 138-kV transmission line provides a critical connection between the Santa Cruz service territory and the broader regional transmission network, supporting resource deliverability and system resilience.



Black Mountain Generating Station

The Black Mountain Generating Station (Black Mountain) is located approximately five miles south of Kingman, Arizona and consists of two natural gas-fired combustion turbine units. These units provide 90 MW of capacity and support system reliability during periods of peak demand. Black Mountain is wholly owned by UNSE and serves an important role in supporting electric service to customers in northwestern Arizona.

Table 3 - Black Mountain Unit Profiles

Units	Capacity (MW)	In-Service Date	Planned Retirement
Unit 1	45	2008	Not Planned
Unit 2	45	2008	Not Planned

Black Mountain Fuel Supply

UNSE purchases natural gas on the spot market and through hedging contracts that are consistent with the company’s hedging policy. Natural gas is sourced from the San Juan basin and is delivered through Transwestern’s interstate natural gas pipeline to the facility.

Appendix H (cont.)

Black Mountain Pollution Controls

The Black Mountain units are natural gas-fired combustion turbines with dry Low NO_x Burners for NO_x control. As a greenfield site, a Prevention of Significant Deterioration (PSD) permit was obtained prior to construction. A PSD permit requires that Best Available Control Technology (BACT) be applied for control of SO₂ and NO_x, and the facility must comply with the Acid Rain program limits for SO₂ and NO_x.

Black Mountain Operational Outlook

The Black Mountain units continue to provide peaking capacity, operational flexibility, and reliability support for UNSE's customers in the Kingman and Lake Havasu areas. The existing Black Mountain units will continue to serve as a key component of UNSE's resource mix during the development and evaluation of the expansion project.

Gila River Generating Station

Gila River Generating Station (Gila River) is a 2,476 MW four block, 2 on 1 natural gas-fired combined cycle electric generating station located three miles north of the town of Gila Bend, in Maricopa County, Arizona. The plant is operated by SRP.

Gila River Ownership

Units 1 and 4 are owned by Salt River Project, Unit 2 is owned 100 percent by TEP, Unit 3 is owned 75 percent by TEP and 25 percent by UNSE.

Figure 1 – Gila River Ownership

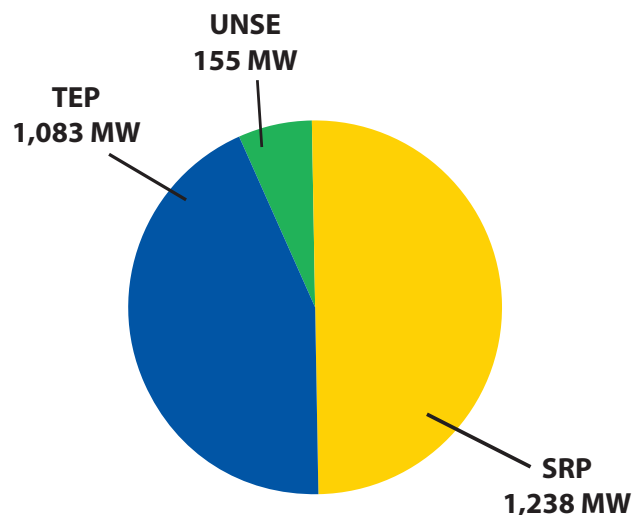


Table 4 – Gila River Unit Profiles

Units	Capacity (MW)	Entered Service	Planned Retirement
Power Block 1	619	2006	Not Planned
Power Block 2	619	2006	Not Planned
Power Block 3	619	2006	Not Planned
Power Block 4	619	2006	Not Planned

Gila River Fuel Supply

Each Gila River participant manages its own gas supply. UNSE purchases natural gas on the spot market and through hedging contracts that are consistent with the UNSE Energy Hedging policy. The plant has access to two separate pipelines operated by Kinder Morgan and Transwestern.

Table 5 - Gila River Pollution Controls

Block	SO ₂	NO _x	PM	Hg
1	NA	SCR	NA	NA
2	NA	SCR	NA	NA
3	NA	SCR	NA	NA
4	NA	SCR	NA	NA

Legend

SCRSelective Catalytic Reduction

Gila River Outlook

Gila River remains an important component of UNSE's resource portfolio, providing efficient dispatchable generation, capacity, and operational flexibility. The facility's combined-cycle technology and fast-ramping capabilities support reliable system operations and help balance variability associated with renewable energy resources. In addition, Gila River's integration within TEP's balancing authority area enhances operational coordination and contributes to system reliability across UNSE's service territory.

UNSE’s Existing Renewable Resource Portfolio

UNSE’s renewable resource portfolio includes both company-owned facilities and long-term contracted resources that provide carbon-free energy to customers. The portfolio has expanded over time through investments in utility-scale solar generation and renewable energy purchase agreements supporting resource diversification, reliability, and environmental objectives. The table below summarizes UNSE’s existing renewable energy resources, including solar and wind facilities.



Table 6 - UNSE’s Existing Solar and Wind Renewable Resources

Resource-Counterparty	Owned/ PPA	Technology	Location	Operator- Manufacturer	Capacity MWac
Western Wind	PPA	Wind	Kingman, AZ	Brookfield Renewable	10
La Senita School	Owned	SAT PV	Kingman, AZ	UNSE	1
Black Mountain	PPA	SAT PV	Kingman, AZ	Black Mountain, LLC	7
Rio Rico	Owned	Fixed PV	Rio Rico, AZ	UNSE	6
Red Horse Solar 3	PPA	SAT PV	Willcox, AZ	D. E. Shaw & Co., L.P. dba Red Horse III Solar	30
Jacobson Solar	Owned	Fixed PV	Kingman, AZ	UNSE	4
Grayhawk Solar	PPA	SAT PV	Kingman, AZ	D. E. Shaw & Co., L.P. dba Red Horse III Solar	46

Legend

- PPAPurchased Power Agreement - Energy is purchased from a third-party provider
- Fixed PVFixed Photovoltaic – Stationary Solar Panel Technology
- SAT PVSingle Axis Tracking Photovoltaic

UNSE's Existing Transmission Resources

UNSE's transmission system supports reliable electric service across the company's service territories in Mohave and Santa Cruz Counties. The system facilitates the delivery of energy and capacity from owned generation, purchased power resources, and wholesale market transactions while maintaining reliable service to customers. The transmission network is interconnected with neighboring utilities and regional transmission providers, providing access to a diverse set of generation resources and enhancing system reliability.

Mohave County Transmission Overview

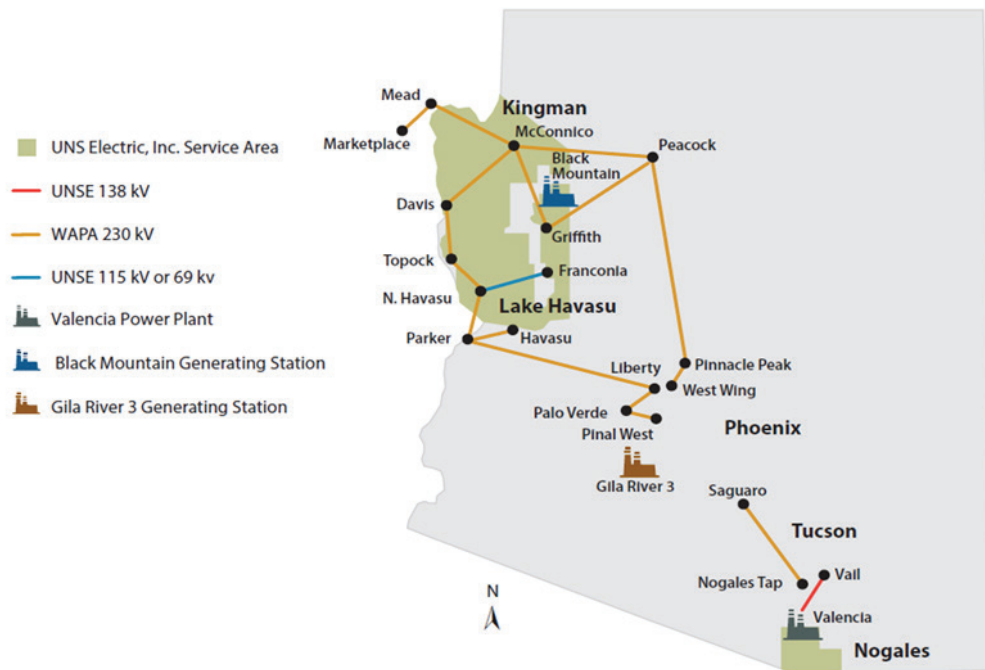
The UNSE-Mohave service territory is supplied through Western Area Power Administration's ("WAPA") 230-kV transmission network, which is interconnected with the regional extra-high-voltage transmission system through the Mead, Liberty, and Peacock substations. Firm power resources designated as network resources are delivered through key points of interconnection, including Liberty and Pinnacle Peak. UNSE-Mohave receives Network Integration Transmission Service ("NITS") from WAPA at several 230-kV delivery points, including Hilltop, McConnico, Black Mesa, North Havasu, and Griffith.

These facilities provide access to regional generation resources and support reliable service throughout northwestern Arizona. UNSE also utilizes point-to-point transmission service from WAPA and other transmission providers as needed to support system operations and resource deliverability.

Santa Cruz County Transmission Overview

UNSE serves its Santa Cruz County load through transmission facilities interconnected with TEP's system. The company owns approximately 60 miles of 138-kV transmission facilities extending between TEP's Vail Substation, located southeast of Tucson, and UNSE's Valencia Substation in Nogales, Arizona. This transmission line provides a critical link between the Santa Cruz service territory and the broader regional transmission network, supporting reliable service to customers, resource deliverability, and system resilience.

Figure 2 – Map of UNSE's Existing Resources and Transmission Network



Appendix I

OPERATIONS AND PLANNING

SECTION 1

SYSTEM OPERATIONS

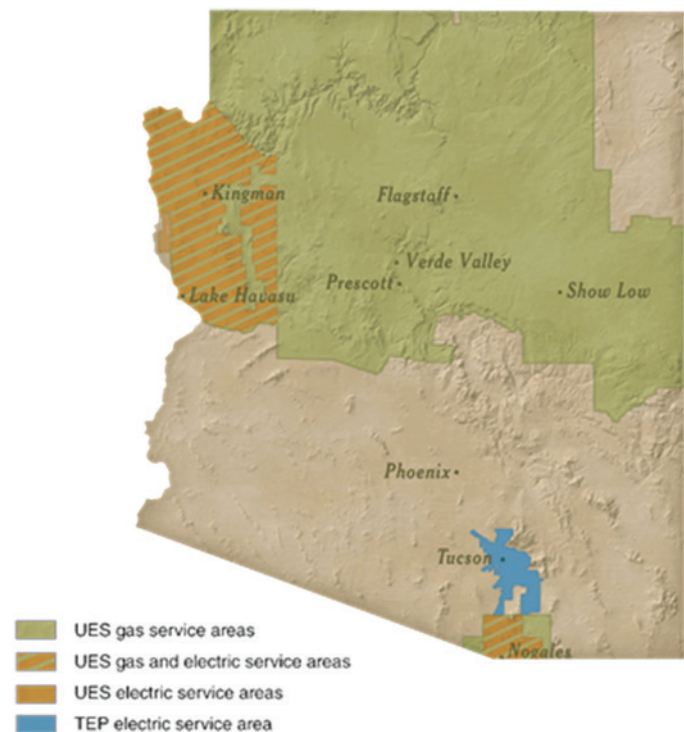
Balancing Authority Operations and Standards

UNSE has a Balancing Area Service Agreement (BASA) with TEP. Pursuant to the BASA, TEP provides services necessary for balancing UNSE's load and resources for safe and reliable operations. Additionally, the BASA enables UNSE to comply with the North American Electric Council's performance standards needed to support reliability across the Western interconnection. See the TEP 2026 IRP, Appendix I¹ for a detailed description of balancing authority operations and reliability performance standards.

Distribution Operations and ADMS

An Advanced Distribution Management System (ADMS) is the central software application that will provide distribution supervisory control and data acquisition, outage management and geographical information in a single interface providing improved visibility to UNSE operations personnel. By combining the information from these systems into a single view, an electrical distribution system model can be created for both real-time applications and planning needs. This single view improves situational awareness of the distribution system by providing additional information to operators that was not readily available in the past. Access to more information and system data will allow the opportunity for more in-depth analysis of evolving customer energy use patterns (i.e., solar and storage, charging electric vehicles, etc.), which can be used to evaluate how customers' load profiles impact supply-side resource decisions. UNSE began implementation of ADMS in 2020 and will continue to expand on the capabilities of the system as additional ADMS functionality is integrated and field devices are deployed.

Figure 1 - Map of UNSE and TEP Service Areas



¹ See <http://www.tep.com/2026-irp>

SECTION 2

DISTRIBUTION PLANNING

Overview

Distribution facilities are critical resources that enable UNSE to provide safe and reliable service to its customers. Sufficient distribution capacity must exist throughout the system to meet UNSE's existing and future load forecasts. UNSE's Distribution Engineering coordinates with TEP's Distribution and Transmission Planning groups to ensure the most cost-effective and beneficial system upgrades are planned and implemented to meet customer demand.

Distribution Planning Analysis

UNSE's distribution system is studied and planned to accommodate load growth from existing as well as new customers. A number of key metrics are analyzed throughout the year to ensure the distribution system is capable of providing safe and reliable service in all conditions.

Distribution substation transformers, switchgear, feeder circuit loading, and contingencies are analyzed on an annual basis to determine if system additions are needed. When loading or contingency issues are identified, multiple traditional and new technology system additions are evaluated to determine the most cost-effective solution.

Distribution system reliability is also analyzed on an annual basis to identify substations and feeder circuits that have poor reliability performance. System outage data is reviewed to determine the cause of outages in the area. Moreover, subsequent critical circuit patrols are conducted in the field to help further identify any system issues. Underground feeder cable replacements are also identified during the annual reliability analysis.

Power quality analysis is conducted on an as-needed basis. When voltage or frequency issues are identified by system operators, field personnel, or customers, monitoring equipment is installed in the field to collect data. This information is then analyzed by the distribution planning department to determine if the system is operating within industry standards. If necessary, additions are recommended to improve system performance.

Distributed generation (DG) is also closely monitored on a feeder level basis. Customer adoption of DG continues to grow and as it does, additional system studies will need to be conducted to identify operational issues.

Appendix I (cont.)

For the Santa Cruz County area, Distribution Planning also coordinates very closely with the Asset Management group. When the Asset Management group identifies substation equipment for replacement, the Distribution Planning department will evaluate and direct many of the replacements.

Table 1 outlines major future system additions that have been identified through distribution planning analysis.

Table 1 - Major Planned Distribution System Additions

Project	Description	Other Notes
Feeder Tie EA5022-5024 In Service Date [ISD] 2027	Create feeder tie between circuits 5022 and 5024 from Eastern Substation.	1) Supports new business 2) Improves System Reliability
Grier Substation (ISD 2028)	Creates feeder loop and provides alternate feed	1) Supports new business 2) Improve system reliability
Feeder Tie EA5022-5024 In Service Date [ISD] 2027	Replace 4/0 primary with 559 AAAC conductor and re-route portions of the line to improve accessibility	1) Increases capacity 2) Improves voltage 3) Improves protective coordination
Feeder Tie EA5022-5024 In Service Date [ISD] 2027	Three phase extension, London Bridge Road	1) Supports load growth

Distribution Modernization

UNSE is in the early stages of exploring smart grid technologies. The district engineer evaluates prospective smart grid equipment vendors and identifies areas of the grid that will reap the greatest reliability benefits from this emerging technology. Although UNSE expects to collaborate with TEP in some of these efforts, it is anticipated that some UNSE-specific vendors and projects will be identified due to the uniqueness of the Mohave County demographics and load structure.

SECTION 3

TRANSMISSION PLANNING

UNSE shares Transmission Planning functions with TEP. See the TEP 2026 IRP, Appendix I.

Appendix J

CUSTOMER PROGRAMS AND DISTRIBUTED GENERATION

SECTION 1

INTRODUCTION TO CUSTOMER PROGRAMS

UNS Electric's demand-side management portfolio encompasses a range of programs serving residential, commercial, and industrial customers. Energy efficiency (EE) programs deliver permanent reductions in energy consumption through measures such as appliance and equipment upgrades, building shell improvements, lighting retrofits, and high-efficiency HVAC systems. UNS Electric does not have any active demand response (DR) programs however, future programs will provide the utility with access to dispatchable load reductions during periods of peak system stress or tight reserve margins, and potentially during high wholesale market prices. Together, these resources can reduce system peak demand, lower customer bills, improve grid reliability and resilience, and support a cleaner energy future.

In the 2026 IRP, EE is reflected as adjustments to forecasted energy and peak demand levels used for resource planning. DR is modeled as a dispatchable demand-side resource. In future IRP planning cycles, UNS Electric endeavors to incorporate DR and EE capacity as resources in the capacity expansion model, with availability and performance characteristics derived from measured program experience and contractual obligations. These demand-side programs reduce the need for new generation capacity, defer transmission and distribution infrastructure investment, and deliver lasting value to customers and the grid alike.

As UNS Electric's service territory experiences growing electrification of transportation and building end uses, the role of demand-side resources is expanding beyond load reduction to active load shaping. Managed EV charging, smart thermostats, battery storage, pool pump and water heater dispatch, and other flexible load technologies are increasingly capable of shifting consumption in ways that facilitate the integration of variable renewable generation and reduce system costs. UNS Electric will design its future demand-side portfolio informed by its most recent energy efficiency and demand response potential study, which establishes the technical, economic, and achievable potential that defines the upper bound of demand-side resource acquisition, to capture this flexibility and to ensure that load growth from electrification is managed in a manner that benefits all customers.

UNS Electric is also committed to ensuring that the benefits of energy efficiency and demand response are accessible to all customers, including those in low-income households and vulnerable customers. Program design, marketing, and delivery strategies are tailored to reduce participation barriers and to direct a meaningful share of program investment toward customers who stand to benefit most from reduced energy burdens.

SECTION 2

DEMAND-SIDE MANAGEMENT PLAN AND TRANSPORTATION ELECTRIFICATION PROGRAMS

Energy Efficiency

Between 2024 and 2025, UNSE's energy efficiency portfolio continued delivering measurable customer and system benefits through a diverse mix of residential, commercial, and income-qualified programs. Key highlights include:

- UNS Electric exceeded Arizona's cumulative energy efficiency standard each year, achieving 24.33% cumulative annual savings as a percent of previous year retail sales in 2024, and 24.60% in 2025, compared to the ACC-required standard of 22%.
- In 2025, residential programs delivered 12,588 MWhs and commercial programs delivered 10,320 MWhs of energy savings.
- Multifamily Program Relaunch – UNS Electric relaunched the Multifamily Program in 2024 through expanded direct install offerings and increased property manager engagement. In 2025, the program achieved approximately 139 MWh in annual savings while serving more than 260 multifamily units and delivering over 1,400 energy-saving measures.
- Existing Homes Program – UNS Electric expanded Existing Homes offerings through enhanced HVAC measures, streamlined participation pathways, and expanded trade ally engagement. In 2025, the program achieved approximately 3,620 MWh in annual savings while supporting nearly 3,000 participating customers.

During this period, UNS Electric experienced a cut to its programs which impacted energy savings delivery. Simultaneously UNS Electric expanded delivery models and began shifting away from mature measures such as traditional LED lighting and appliances, toward higher-value opportunities such as attic insulation.

Energy efficiency program performance is evaluated through a measurement and verification (M&V) framework consistent with the protocols established by Energy Efficiency Rules and Arizona Corporation Commission direction¹. Reported savings and demand reductions are independently verified to ensure that the benefits credited to these programs in the IRP reflect actual, persistent, and replicable results. Compliance with energy efficiency standards can be seen in **Table 1** below.

¹ https://apps.azsos.gov/public_services/Title_14/14-02.pdf, Article 24.

Table 1 - Compliance with Energy Efficiency Standards

	Year	Incremental Annual Energy Savings (MWh)	Cumulative Annual Energy Savings (MWh)	Cumulative Annual Savings (% of previous year retail sales)	Cumulative EE Standard (ended 2020)
	2010-2023		412,411	22.32%	22.00%
Actual	2024	33,487	445,898	24.33%	22.00%
Actual	2025	22,907	468,805	24.60%	22.00%
Forecasted as of 4/1/26	2026*	10,764			

In July 2026, the ACC formally repealed Arizona's Electric Energy Efficiency Standard (EEES) rules. While UNS Electric's approved three-year DSM plan is still tied to the EEES requirements and will remain in effect until further order of the Commission, there are currently no enforceable EE savings mandates applicable to regulated electric utilities in Arizona. In the absence of new rules, future DSM program development will be at the discretion of individual utilities, subject to Commission review and approval.

Demand Response

At present, the Company does not operate formalized demand response (DR) programs. The Company's current load management capabilities are limited to legacy interruptible rate tariffs available to a subset of large commercial and industrial (C&I) customers, which have not been actively marketed or expanded in recent rate cycles. No automated, voluntary, or incentive-based DR mechanisms are currently deployed across the residential, small commercial, or general service customer classes. The Company is actively pursuing the foundational activities to establish a portfolio of dispatchable demand-side resources.

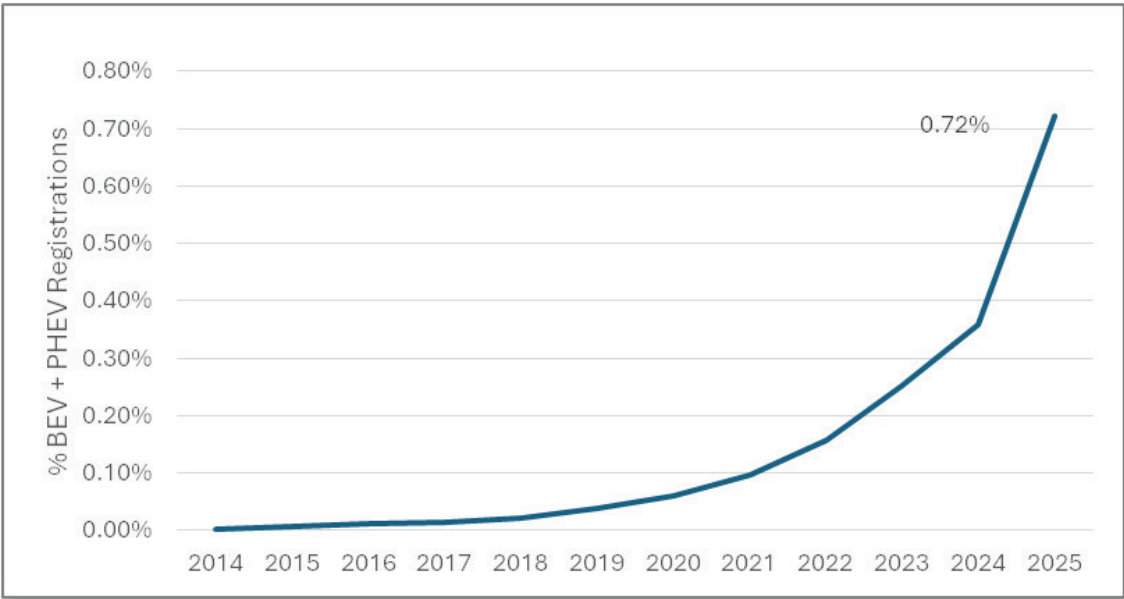
Transportation Electrification

UNS Electric’s three-year Transportation Electrification Implementation Plan (2023-2025) increased awareness and adoption of transportation electrification, recognizing the benefits to the Company and the community of beneficial electrification. Highlights include:

- 22 residential EV charging ports installed
- 24 commercial EV charging ports contracted

Figure 1 displays the approximate percentage of total vehicle registrations within UNSE’s service territory that are battery electric vehicles (BEVs) or plug-in hybrid electric vehicle (PHEVs) registrations, 2014-2025. While overall EV registrations remain below one percent of the total, the exponential growth rate highlights the continued adoption of this technology which will offer additional beneficial electrification and DR opportunities in the future.

Figure 1 - Share of Electric Vehicle Registrations (BEVs and PHEVs)²



2. Approximated based on Santa Cruz County, Kingman City, and Lake Havasu City data from EPRI.

Table 2 - Program Summaries

Program	Sector	Status	Description
Efficient Products	Residential Energy Efficiency	On-going	Promotes the purchase of high-efficiency retail products through upstream and point-of-purchase incentives offered at participating retailers. Eligible products include energy efficient products and select demand response-enabled technologies.
Existing Homes	Residential Energy Efficiency	On-going	Promotes energy efficiency improvements in existing residential homes through instant rebates for improvement to use less energy to cool and heat a customer's home. The program also provides rebates for connected devices that support flexible energy use.
Limited Income (LIEE)	Residential Energy Efficiency	On-going	Designed to serve income-qualified customers whose household income is at or below 200 percent of the federal poverty guidelines. The program provides eligible customers with weatherization and other energy efficiency measures intended to reduce electricity consumption and associated utility costs, while ensuring health and safety of the customer's dwelling.
Multi-Family	Residential Energy Efficiency	On-going	Designed to deliver energy efficiency improvements to apartment and multi unit residential properties with individually metered complexes of two or more units. The program helps property owners and managers reduce energy use, lower operating costs, and increase tenant comfort, improve health and safety by offering rebates for HVAC replacements, HVAC tune ups, duct sealing, and direct install efficiency measures.
Commercial & Industrial Comprehensive	Commercial Energy Efficiency	On-going	Assists eligible commercial and school district customers reduce energy consumption, improve operational efficiency, and implement technologies that support grid reliability. The program offers incentives and technical assistance for energy efficiency and demand management measures through both prescriptive and custom project pathways, enabling cost-effective energy savings tailored to customer needs.

continued ►

Appendix J (cont.)

Commercial Direct Load Control	Commercial Energy Efficiency	Re-launch in Progress	Supports peak demand reduction and assists in system emergencies through commercial and industrial (C&I) load curtailment.
Behavioral Comprehensive	Residential Energy Efficiency	On-going	Three coordinated subprograms: K-12 Education, Community Education, and Community Outreach, designed to educate current and future energy users on how awareness, behavior, and informed purchasing decisions can improve energy efficiency and reduce energy consumption.
Education and Outreach	Residential Energy Efficiency	On-going	Provide customers, community stakeholders, and the general public with accurate and accessible information related to the Company's energy efficiency and demand response programs. The program supports awareness of available programs, rate and payment options while facilitating enrollments and encouraging actions that contribute to optimized energy consumption.
Smart EV Home	Residential EV Rebates	On-going	Provide residential customers with rebates for installing Level 2 chargers at their home address. Chargers must have capability of connecting to wi-fi to enable future participation in DR programs. In order to receive a rebate, participating customers must take service on a time-of-use (TOU) rate.
Smart EV Charging Program	Commercial EV Rebates	On-going	Provide commercial customers with rebates for installing Level 2 or DC Fast Chargers at their business or establishment. Open to all commercial electric service customers. In order to receive a rebate, participating customers must take service on a time-of-use (TOU) rate.

SECTION 3

DEMAND-SIDE RESOURCES MARKET POTENTIAL STUDY

UNS Electric, with analytical support from Dunskey Energy + Climate Advisors, conducted a comprehensive Demand-Side Resources Market Potential Study in 2025 to quantify the technical, economic, and achievable potential for EE and DR programs over the 2026–2040 planning horizon. The results of this study inform the treatment of EE in the Integrated Resource Plan including assumptions related to future load growth, peak demand reduction, and resource adequacy.

Energy efficiency programs continue to play a meaningful role in shaping future load, particularly through the accumulation of savings from long-lived measures over time. While incremental annual EE savings are more modest in the near term, cumulative impacts increase as those savings persist and compound over the planning horizon. At the same time, the study finds that achieving annual incremental EE savings becomes increasingly challenging in later years due to the phase-out of residential lighting savings resulting from federal standards and broader market transformation, as well as the gradual exhaustion of other discretionary efficiency opportunities. As a result, the marginal contribution of EE declines over time even as cumulative savings continue to grow.

Demand response represents a potential source of peak demand reduction for UNS Electric over the study period; however, realizing this potential is expected to be more challenging given the absence of historically activated demand response programs in the territory. As a result, achievable DR impacts are very limited in the early years of the forecast as foundational program infrastructure, customer awareness, and operational capabilities must first be established. Peak demand reductions grow gradually over time as participation expands and program offerings mature, though the pace of this ramp up may differ from modeled results. Residential demand response is assumed to contribute earlier in the forecast, while commercial demand response becomes the primary driver of peak reductions in later years. Sustained program development, upfront investment, and ongoing implementation support are required to build a viable demand response portfolio and fully realize longer term peak reduction potential.

Study Scope and Resources Considered

The 2025 Market Potential Study evaluated energy efficiency and demand response opportunities for the UNS Electric service territory for the years 2026–2040, considering electricity-only impacts across residential, commercial, industrial process, and mining customer classifications. Results were developed for technical, economic, and achievable levels of potential under three market scenarios:

- BAU- (Below Business-as-Usual): Reflects reduced program activity relative to recent experience, including lower participation rates and more limited program offerings.
- BAU (Business-as-Usual): Reflects continuation of current program designs, delivery approaches, participation trends, and budget levels consistent with recent UNS Electric experience.
- BAU+ (Above Business-as-Usual): Reflects expanded program activity, including enhanced incentives, marketing, and/or new program offerings that support higher customer participation.

For purposes of the study scope and IRP integration, only the BAU scenario was used. All references to potential in this filing therefore reflect achievable potential under BAU assumptions, consistent with continuation of existing programs rather than program expansion or contraction. Specifically for DR, results reflect scenario specific demand response assumptions for UNS Electric, with demand response excluded from BAU–, limited to residential customers in BAU, and applied to both residential and non residential customers in BAU+.

During integration of the study results into the IRP, industrial process and mining impacts were excluded from the modeling framework to ensure consistency with UNS Electric’s load forecast and sector definitions. While the potential study classified customers based on the North American Industry Classification System (NAICS)-based industrial categories, these segments do not align directly with how UNS Electric defines and models large customers for IRP planning purposes. As a result, the IRP focuses on residential and commercial demand-side impacts, which are more directly actionable within existing program structures and forecasting assumptions.

These results reflect achievable BAU potential estimates used for planning context and are not intended to represent binding acquisition targets. Rather, they provide an indication of the scale and timing of demand-side impacts that could be available under sustained implementation of current programs.

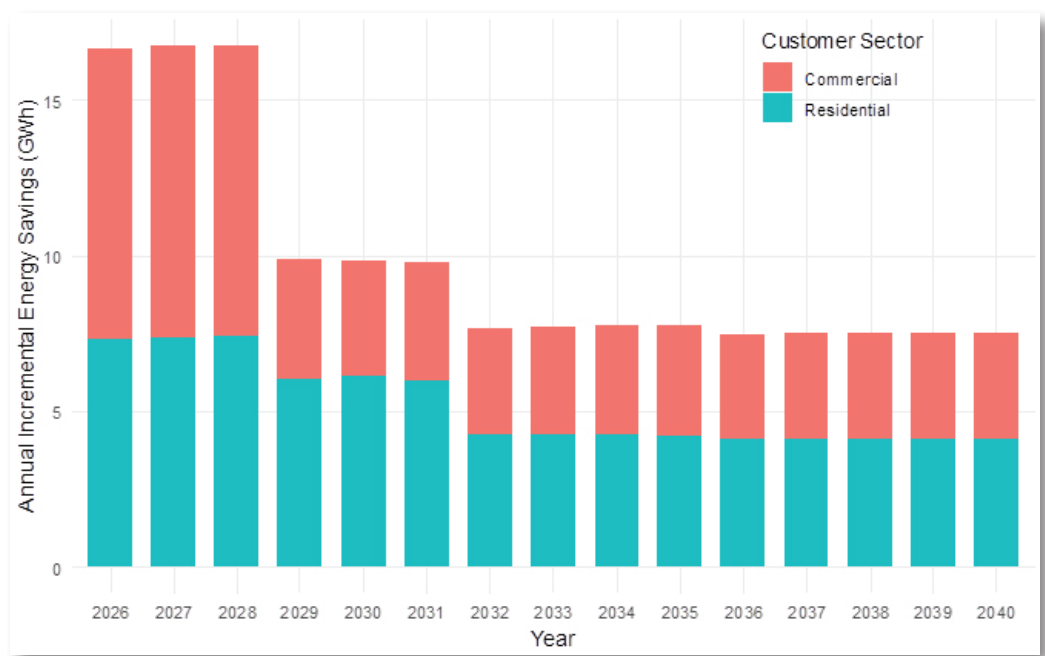
Energy Efficiency and Demand Response Potential

Energy Efficiency

Achievable energy efficiency and demand response potential reflects results developed under a Business-as-Usual (BAU) framework, which assumes the continuation of UNS Electric’s current program portfolio, incentive structures, delivery mechanisms, and customer participation trends.

Figure 2 represents annual first year incremental energy efficiency savings for the UNS Electric territory under the Business as Usual (BAU) scenario, disaggregated by Residential and Commercial customer sectors. Behavioral programs were excluded from the UNS Electric results to reflect current program availability, which materially affects both the magnitude and trajectory of achievable savings. The figure also shows a drastic decline in savings for both sectors beginning around 2029 reflecting the combined effect of the exclusion of behavioral interventions, the implementation of federal lighting standards, and broader market transformation.

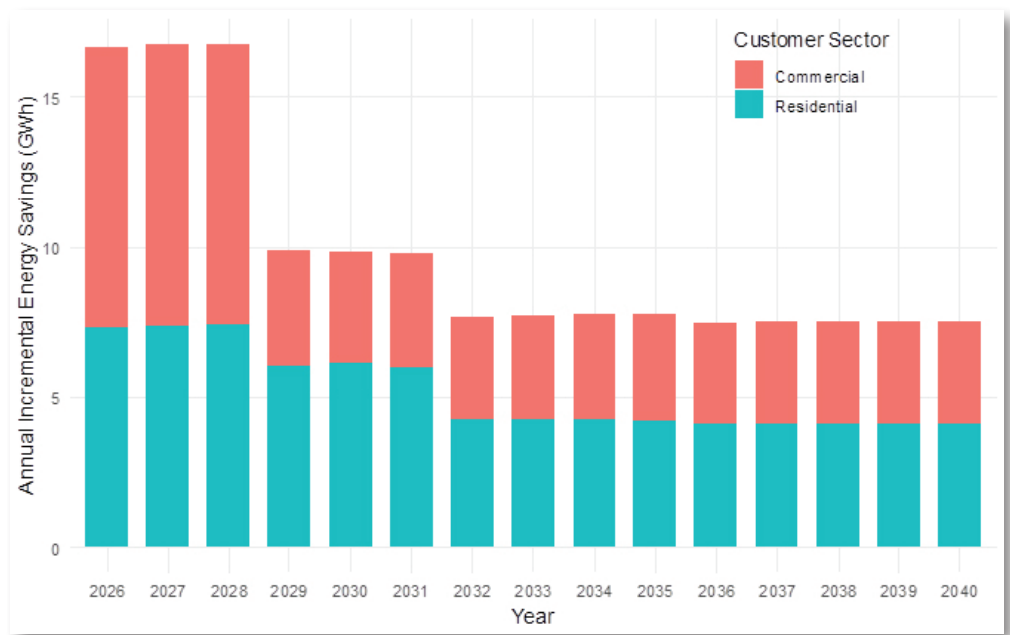
Figure 2 - Annual Incremental Energy Efficiency Savings by Customer Sector (BAU Scenario)



Note: Figure reflects first-year incremental energy savings by customer sector and does not represent cumulative impacts.

In **Figure 3**, demand savings from EE measures display right skewed distribution over the study period. The decline beginning around 2029 reflects increasing market saturation in commercial lighting, while residential lighting savings are already diminishing earlier in the horizon. Despite these trends, total MW savings stabilize in the later years, suggesting reduced but persistent contributions from remaining efficiency opportunities.

Figure 3 - Peak Demand Reductions from Energy Efficiency Measures Only

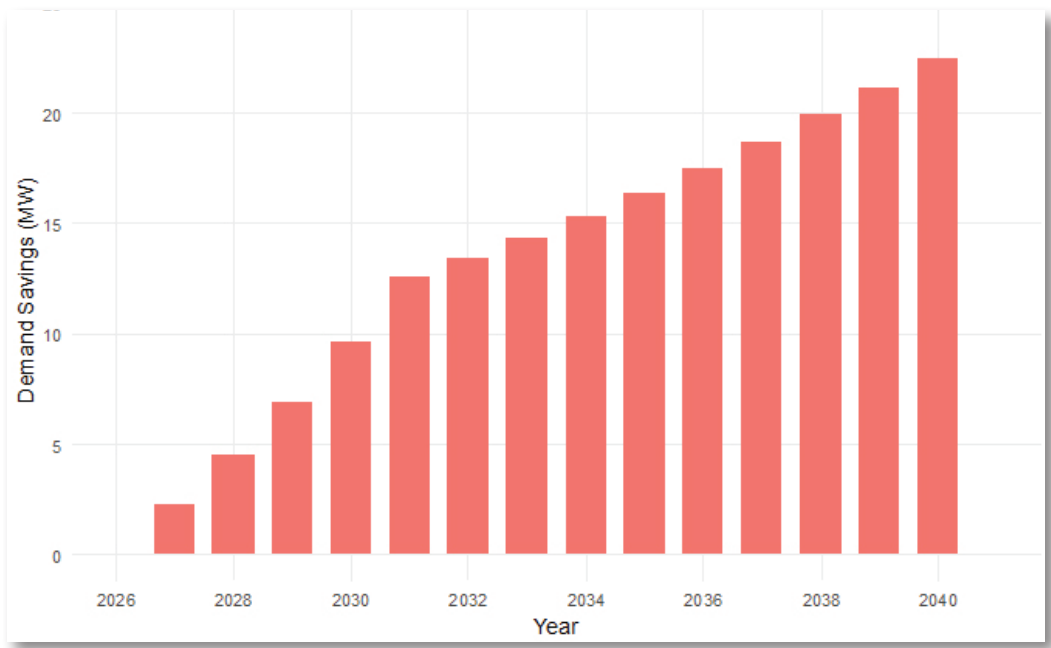


Demand Response

Figure 4 shows projected demand response potential for UNS Electric under the BAU scenario, expressed in megawatts (MW) over the planning horizon. The results reflect residential programs only, with impacts shifted to begin in 2027 to align with expected program implementation timing. Demand savings grow steadily from approximately 2–3 MW in the early years to over 20 MW by 2040, demonstrating consistent expansion in achievable residential demand response potential.

While commercial demand response is anticipated to begin in 2027, it is not explicitly represented in this dataset. Even so, the residential-only trajectory provides a reasonable and conservative proxy for total demand response growth over time. This profile was therefore used in resource planning modeling to represent expected demand response contributions under the BAU scenario, capturing the overall scale and timing of achievable capacity impacts.

Figure 4 - Demand Response Potential (MW) for BAU- Scenario



However, because the BAU scenario does not explicitly include commercial demand response, it does not fully capture the potential composition of savings across all sectors. To better illustrate how commercial programs could contribute, and to highlight the mix of leading measures, the BAU+ scenario is used for the top-measures analysis as illustrated in **Figure 6**.

Primary Drivers of EE and DR Impacts

Energy Efficiency

Energy efficiency impacts for UNS Electric are driven by a mix of end-use improvements across both the residential and commercial sectors, with results varying over time as measure adoption and market conditions evolve. illustrates that the largest contributors to EE savings differ by sector but are consistently concentrated in a few dominant end uses.

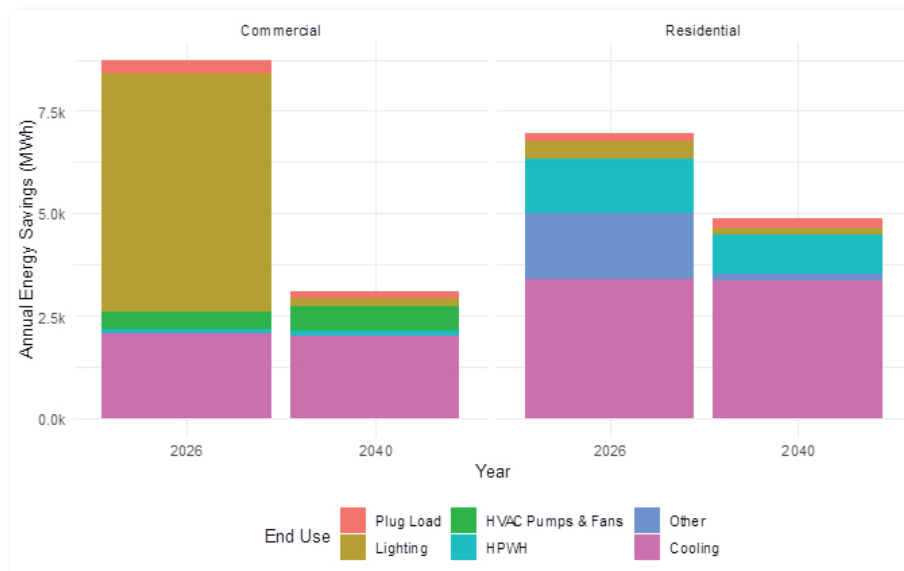
In the residential sector, cooling (HVAC) represents the largest share of energy savings in both 2026 and 2040. This strong contribution is largely driven by HVAC-related measures, particularly HVAC tune-ups and system optimization, which provide cost-effective and scalable efficiency gains across a broad portion of the housing stock. Additional residential savings come from lighting, water heating, and other end uses, though these are smaller in magnitude compared to cooling.

Appendix J (cont.)

In the commercial sector, energy savings are more distributed across end uses but show a notable shift over time. Early impacts (2026) are strongly influenced by lighting and other relatively mature technologies, while by 2040, savings become more balanced, with increased contributions from cooling and other equipment-based measures. Similar to the residential sector, HVAC improvements, including tune-ups and operational enhancements, play a key role in driving cooling-related savings, reflecting the importance of maintaining and optimizing existing systems in addition to equipment upgrades.

Overall, the results highlight that cooling efficiency is the primary driver of EE impacts across both sectors, with HVAC tune-ups serving as a foundational measure due to their broad applicability and relatively low implementation cost. As programs mature, EE portfolios become more diversified; however, HVAC-related measures continue to underpin a significant portion of total savings, particularly in a hot-climate service territory such as UNS Electric.

Figure 5 - Composition of Top Energy Efficiency End Use Measures by Energy Saving



Demand Response

The BAU+ scenario for UNS Electric illustrates the composition of demand response potential by demand response type across residential and commercial sectors in 2027 and 2040 (see Figure 6). While early-year impacts are modest, demand response potential grows substantially by 2040 in both sectors.

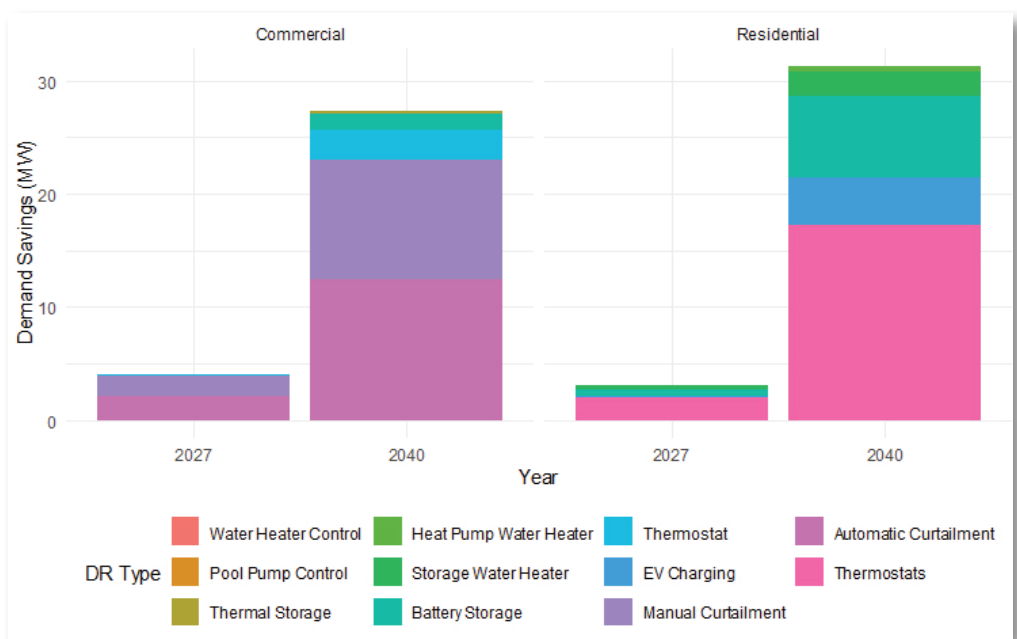
In the commercial sector, demand savings are driven primarily by manual curtailment, with additional contributions from automated controls such as thermostats and other enabling technologies. This reflects the importance of dispatchable load flexibility and operational response in commercial demand response programs.

Appendix J (cont.)

In the residential sector, demand response is led by thermostats and water heater control, supported by increasing contributions from electric vehicle charging and battery storage over time. These technologies represent scalable, customer-enabled approaches to load flexibility.

Overall, the BAU+ scenario demonstrates that as programs expand, demand response potential becomes more diversified across control strategies and enabling technologies, with both sectors contributing meaningfully to long-term growth in peak demand reduction.

Figure 6 - Top Demand Response Types by Demand Savings for BAU+ Scenario



SECTION 4

FUTURE CUSTOMER PROGRAM OPPORTUNITIES AND EVOLVING PORTFOLIO PRIORITIES

As customer technology adoption evolves and system needs become more dynamic, UNS Electric continues to evaluate demand-side resources that provide cost-effective energy savings, peak demand reduction, and greater operational flexibility.

Results from the Market Potential Study as well as other analyses inform future program design, customer targeting strategies, technology prioritization, and long-term resource planning by identifying where the greatest opportunities exist to expand cost-effective demand-side resources. Below are a summary of recommendations on the direction of customer programs that UNS Electric will consider in the near future.

Energy Efficiency Opportunities

- Expand adoption of high-efficiency HVAC systems, heat pumps, smart thermostats, and building envelope improvements such as air sealing, duct sealing, insulation, and weatherization measures that reduce cooling demand.
- Continue expanding participation in multifamily housing, manufactured housing, and low-to-moderate income customer segments.
- Evaluate additional delivery models that improve customer participation while reducing administrative complexity.

Demand Response Opportunities

- Launch demand response programs similar to Smart Rewards, Energy Storage Reward and Smart Charge.
- Evaluate additional flexible load opportunities to support a future Virtual Power Plant strategy.
- Explore opportunities for business participation in flexible load programs.

Beneficial Electrification

- Leverage capacity in EV batteries through managed charging, vehicle-to-grid (V2G), and vehicle-to-building (V2B) applications.
- Support EV infrastructure deployment to support public and home charging opportunities for low-to-moderate income customers, schools, and non-profits.
- Explore additional beneficial electrification opportunities, e.g., electric heat pumps that can participate in demand response opportunities.

The study results highlight a significant transition in portfolio composition, driven by the phase-out of lighting measures and the absence of residential behavioral programs that historically provided broad, scalable energy and peak demand savings. These changes remove a key source of relatively low-cost, high-volume impacts, fundamentally altering how savings must be achieved going forward.

As a result, the portfolio shifts toward equipment-based and demand response resources, which tend to be more capital-intensive and deliver savings more gradually over time. While this transition increases average program costs, it also reflects a necessary evolution toward resources that provide greater operational value to the grid, particularly in terms of peak demand reduction, flexibility, and system reliability.

The analysis indicates that demand response will play an increasingly important role in UNS Electric's future portfolio. As traditional savings opportunities decline, investments in demand response—especially those leveraging automated controls, flexible load technologies, and customer-enabled resources—will be critical to maintaining achievable savings trajectories while supporting long-term system needs.

Importantly, these findings underscore the need to move beyond a narrow focus on cost-effectiveness metrics centered solely on energy savings. Instead, UNS Electric's portfolio strategy must more fully incorporate peak capacity value, load flexibility, grid stability, and customer participation. Prioritizing these dimensions will better align program investments with long-term system planning objectives, ensuring that even higher-cost resources such as demand response deliver meaningful system-wide benefits.

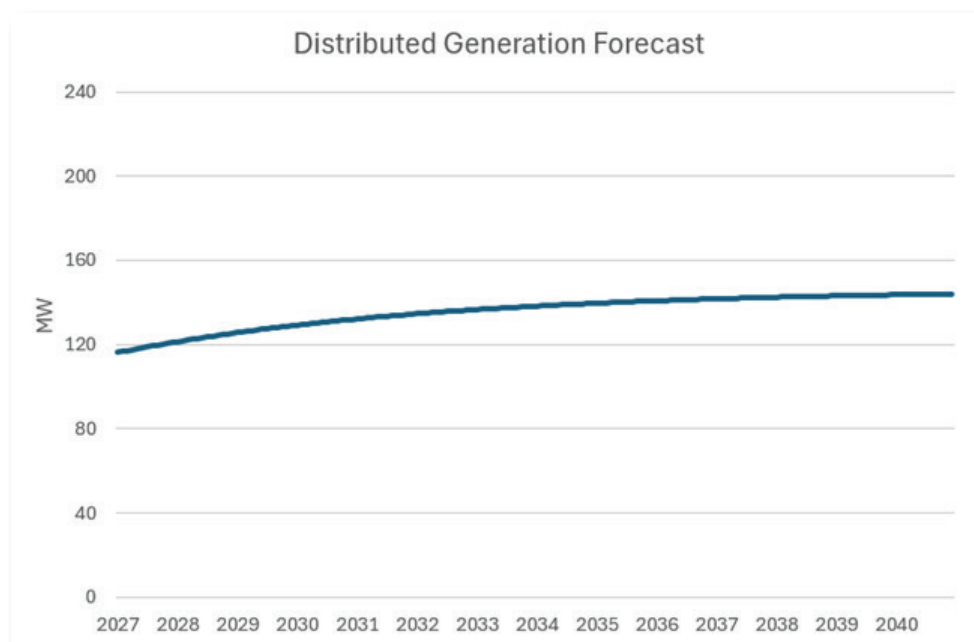
In this context, continued investment in demand response represents not only a necessary adaptation to evolving resource constraints but also a strategic opportunity to enhance grid performance and support a more flexible, resilient energy system.

SECTION 5

FORECASTING DISTRIBUTED GENERATION

UNSE supports a number of programs to promote the use of customer sited, solar distribution generation and battery storage. Forecast growth in DG adoption is shown in **Figure 7**. DG adoption is influenced by a combination of federal and state policy mechanisms, economic conditions, retail rate design, and customer technology incentives.

Figure 7 - UNSE DG Adoption Forecast



In the UNSE service territory, long-term drivers of DG adoption include broader technology cost declines for solar and storage, increasing availability of distributed energy technologies, and gradual development of customer awareness and market infrastructure. Building characteristics, baseline energy usage patterns, and the continued electrification of customer end uses also contribute to the underlying adoption potential.

However, DG adoption within the UNSE service territory demonstrates a higher degree of sensitivity to changes in policy, economic conditions, and retail rates than what is observed at TEP. The smaller scale and differing customer characteristics of the UNSE market, as opposed to the TEP market, contribute to greater responsiveness to external signals.

Appendix J (cont.)

Changes to retail compensation mechanisms, particularly the declining value and potential expiration of the Resource Comparison Proxy (RCP), are expected to have a more pronounced impact on customer adoption behavior in UNSE. These changes may result in short-term fluctuations, including potential increases in adoption ahead of policy transitions, followed by periods of reduced activity.

Rate case outcomes also play a significant role in shaping adoption trends within the UNSE territory. Increases in retail electricity rates have historically been associated with increased customer interest in solar adoption, as customers seek to mitigate bill impacts through self-generation.

Economic conditions further contribute to variability in adoption trends. Periods of economic uncertainty may disproportionately affect customer participation in DG programs within UNSE, given the higher relative sensitivity of customers to upfront investment costs.

The availability of storage incentives remains a key driver of adoption. Continued incentive support is expected to facilitate growth in battery deployment and enable the future expansion of flexible load and virtual power plant capabilities. Conversely, the removal of these incentives could slow the pace of adoption.

While the expiration of the REST rules is not anticipated to materially affect long-term adoption, installer-driven marketing strategies may temporarily influence customer behavior in advance of such changes.

Overall, DG adoption in the UNSE service territory is characterized by greater volatility and responsiveness to policy and economic signals, with customer decision-making more directly influenced by rate impacts, incentive availability, and market conditions.

Appendix K

FUTURE RESOURCE TECHNOLOGIES

Section 1

INTRODUCTION TO FUTURE RESOURCE TECHNOLOGIES

This chapter provides an overview of the future resources considered for development in the Company's resource portfolio. The information here is based on best-available current information, the Company's current resource mix, and its commitment to reducing carbon emissions. If a particular technology is bid into the Company's All-Source Request for Proposals (ASRFP), it is considered equally with all other technologies based on the specific criteria established in the ASRFP.

Future resources considered for development can be divided into four categories: flexible resources, energy storage resources, advanced baseload resources, and conventional resources. The four categories are shown in **Figure 1** and are described in more detail below. A combination of resources from these categories is needed to maintain a grid that is affordable, reliable, and sustainable. These three goals cannot be achieved by one technology alone. The combination that optimally supports the grid will depend on how individual technologies and the broader economy evolve over time.

Flexible Resources - Historically, grid operators serve variable demand from firm power resources using traditional supply-side techniques (e.g., generator droop control, peaker plant dispatch). As the portfolio share of intermittent renewable generation has grown, as bidirectional power flow has become more common, and as inverter-based resources have multiplied, grid operators face greater challenges managing a more dynamic grid. Flexible resources can support a more dynamic grid by controlling demand rather than supply. In addition to supporting a dynamic grid, flexible resources can be used to reduce the system peak demand, which is used to set capacity needs. Flexible resources can be deployed in place of other resources described below, thereby avoiding their cost.

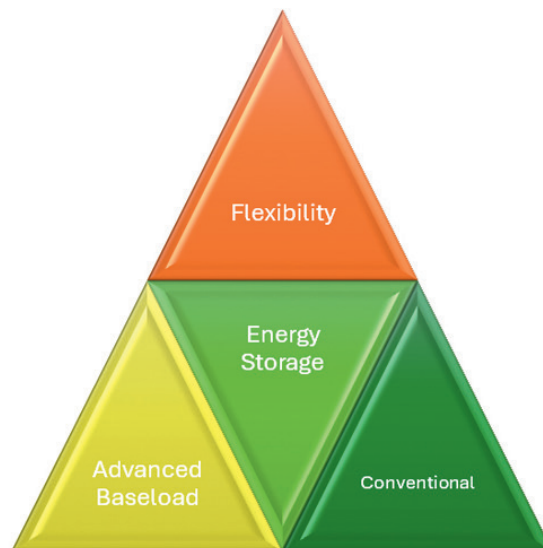
Energy Storage Resources – Unlike natural gas distribution systems, the electric grid was not originally designed to incorporate energy storage within the system. Storage serves as a buffer for any energy delivery system that can help improve stability and resilience. Storage is also one of the most versatile resource types with the ability to store or release energy depending on grid conditions and need. This is especially valuable with the rise of variable renewables, like wind and solar. Storage technologies can store energy when renewable energy exceeds demand on the grid and then discharge when demand exceeds renewable energy generation. The value of storage on the grid depends on its type, size, location, and operating modes. Energy storage resources include lithium-ion batteries, compressed air energy storage, pumped hydropower storage, liquid carbon dioxide storage, iron air batteries, and numerous other technologies.

Appendix K (cont.)

Advanced Baseload Resources – A new class of resources has emerged in recent years. These are near-zero carbon resources that can provide power whenever it is needed. This provides an advantage over variable renewables, like solar and wind, while avoiding the carbon emissions associated with other conventional resources like natural gas. These include advanced nuclear technologies, geothermal, and clean fuels, like biogas and hydrogen.

Conventional Resources – Conventional resources include solar, wind, reciprocating engines, and natural gas simple-cycle and combined-cycle turbines. These technologies support a stable grid today. Depending on how technologies evolve, these may be deployed into the future alongside a mix of other technologies mentioned here.¹

Figure 1. Resources that can contribute to a stable grid in the future.



¹ Additional conventional resources include natural gas and coal steam turbines. Existing steam turbines support our grid today and will continue to throughout their useful life, but, due to advancements in other technologies, it is unlikely that new steam turbines will be built.

Section 2

RESOURCE MATRIX

Technologies described in this section vary in how they support a grid that is affordable, reliable, and sustainable. Additionally, all technologies described here are expected to evolve over time in their ability to support these goals. **Figure 2** provides a qualitative overview of the benefits these technologies can provide to the system. Details are provided in Section 3, where we describe grid benefits of each technology, their technical readiness, commercial readiness, and environmental performance.

Grid Support – Technologies support the grid by providing energy when it is needed and providing ancillary services to keep the grid stable. Load carrying capability is a quantification of the degree to which energy is available when it is needed. In addition to the availability of energy, it is important that systems are able to ramp up and down quickly to dispatch energy exactly when it is needed. Additionally, the grid needs certain services, like frequency and voltage support, to stay stable. Conventional resources that deploy synchronous turbines, like natural gas plants, provide these services. Other conventional resources, like solar and wind, generate direct current and require an inverter to inject alternating current to the grid. These inverter-based resources cannot provide all of these services today.

Technical Readiness - As technologies are developed, they go through various technology readiness levels. NASA developed a nine-point scale for technology readiness that describes how technologies advance from lab-scale operations to pilot-scale operations to full-scale operations in a variety of real-world conditions. This scale focuses on whether or not a technology works as designed. It does not take into account other factors that contribute to whether a technology is ready to be procured by a utility. In general, utilities will only start to consider technologies at very high readiness levels.

Commercial Readiness – This category covers factors beyond technical readiness that contribute to a utility's ability to procure a new technology. This includes cost and other factors, such as supply chain maturity, permitting difficulty, constructability, risk, site requirements, fuel availability, and other considerations. It is more often commercial readiness that constrains deployment of new technologies rather than technology readiness.

Environmental Considerations – Water use is a critical consideration in arid areas such as ours. In addition to water use, technologies vary in their land use and safety risks they pose to workers and nearby communities. We take these into account when we consider future resources.

Figure 2 - Heat map showing desirability of various technologies to supporting an affordable, reliable, and sustainable grid.

Category	Type	Grid Support: Load Carrying Capability	Grid Support: Dispatch Speed	Grid Support: Ancillary Services	Technical Readiness	Commercial Readiness	Commercial: Cost	Environmental: Water Use	Environmental: Carbon Emissions
Conventional Resources	Wind	2	1	1	5	5	5	5	5
	Solar Photovoltaics	1	1	1	5	5	5	5	5
	Recirculating Engines	5	5	3	5	5	4	5	1
	Natural Gas Simple Cycle	5	5	5	5	5	4	5	1
	Natural Gas Combined Cycle	5	3	5	5	5	5	4	2
Flexibility Resources	Demand Response	1	2	1	5	4	5	5	5
	Virtual Power Plants	2	3	3	3	2	3	5	5
Energy Storage Resources	Lithium Ion Batteries	2	5	3	5	5	5	5	3
	Compressed Air Energy Storage	3	5	4	3	1	2	5	3
	Pumped Hydropower Storage	3	5	4	5	2	4	2	3
	Liquid Carbon Dioxide Storage	3	5	4	3	2	3	5	3
	Iron Air Batteries	3	5	3	3	2	5	5	3
	Flow Batteries	3	5	3	3	2	3	4	3
Advanced Baseload Resources	Geothermal	5	4	5	4	3	3	4	5
	Nuclear - Advanced Large Reactor	5	2	5	4	3	2	3	5
	Nuclear - Small Modular Reactors	5	3	5	2	1	1	3	5
	Biogas Cofiring	5	3	5	5	2	4	2	4
	Hydrogen Cofiring	5	3	5	2	2	1	1	3
	Carbon Capture and Storage	5	3	5	3	1	1	1	4

Characteristics are qualitatively rated on a scale of 1 - 5, with 1 (white) being least desirable and 5 (dark green) being most desirable.

Section 3

RESOURCE TECHNOLOGY OVERVIEW

3.1 Flexible Resources

Demand Response

Dating back to the 1970's, curtailable loads and interruptible tariffs have been used to help utilities meet their capacity requirements, often using low-tech methods. Most commonly, grid operators would "dispatch" curtailable loads simply by picking up the phone and calling their large industrial customers and asking them to shut down equipment. In return, these customers were compensated in the form of lower rates or other financial incentives (e.g., bill credits, seasonal payments). This is a so-called "Capacity DR" program model, and it remains the most common in the utility industry.

Today, there are several DR program models as well as many enabling technologies and market mechanisms, including:

- **Automated demand response.** Where either the dispatch signal, load response, or both are automated requiring no human intervention or manual curtailment.
- **Economic demand response.** The grid operators call economic demand response events in response to market price signals. Participating companies get paid to reduce their load in response to high prices, helping to reduce their exposure to the highest-priced hours while lowering system-wide electricity prices.
- **Reverse demand response.** Loads ramp up (not down) or storage is charged in response to excess renewables availability, low energy pricing, or other real-time signals.
- **Ancillary demand response.** Ancillary programs provide another level of services to the grid to support localized issues. Services include frequency regulation, voltage control, and operating reserves to balance fluctuations in real-time. These are on-demand, instantaneous resources and they can be called upon for a number of reasons: power outages, extreme weather, high prices, or insufficient generation.
- **Flexible load management (FLM) or continuous load management (CLM).** For smaller loads and those that do not negatively impact customer comfort, satisfaction, and/or revenues, it is possible to move away from event-based DR to offer programs that flex loads whenever needed. For example, short duration dispatch (e.g., 15-minute) has the benefit of limiting negative impacts to customers and can therefore be called upon more times each season without risk of fatigue. Automation techniques include frequency response and smart devices that respond automatically to event or price signals.
- **Dynamic operating envelopes.** As part of a flexible interconnection agreement or similar arrangement, a customer, building, or end-use device is sent an acceptable power band in which it must operate, usually day-ahead. In some cases, actual power demand may be electronically limited to match requirements.

Appendix K (cont.)

Grid Support

DR resources are typically dispatched during a small fraction of hours each year when grid capacity is near its system peak, e.g., ~ 90 hours or 1% of the year. However, as capacity constraints emerge on the transmission or distribution system and the value of marginal capacity availability on these systems goes up, those hours of the year during which DR can deliver value will tend to grow. As mentioned above, this may take the form of flexible interconnection agreements, dynamic operating envelope requirements, or similar mechanisms for enabling dynamic demand.

Technical Readiness

Since DR is a broad category of programs and techniques, there are dozens of enabling technology types that have evolved over the last several decades. For example, the technologies used to enable capacity DR in its traditional form are very well established, while those for enabling economic DR and price-based load response are still being demonstrated in pre-commercial phase.

Commercial Readiness and Economics

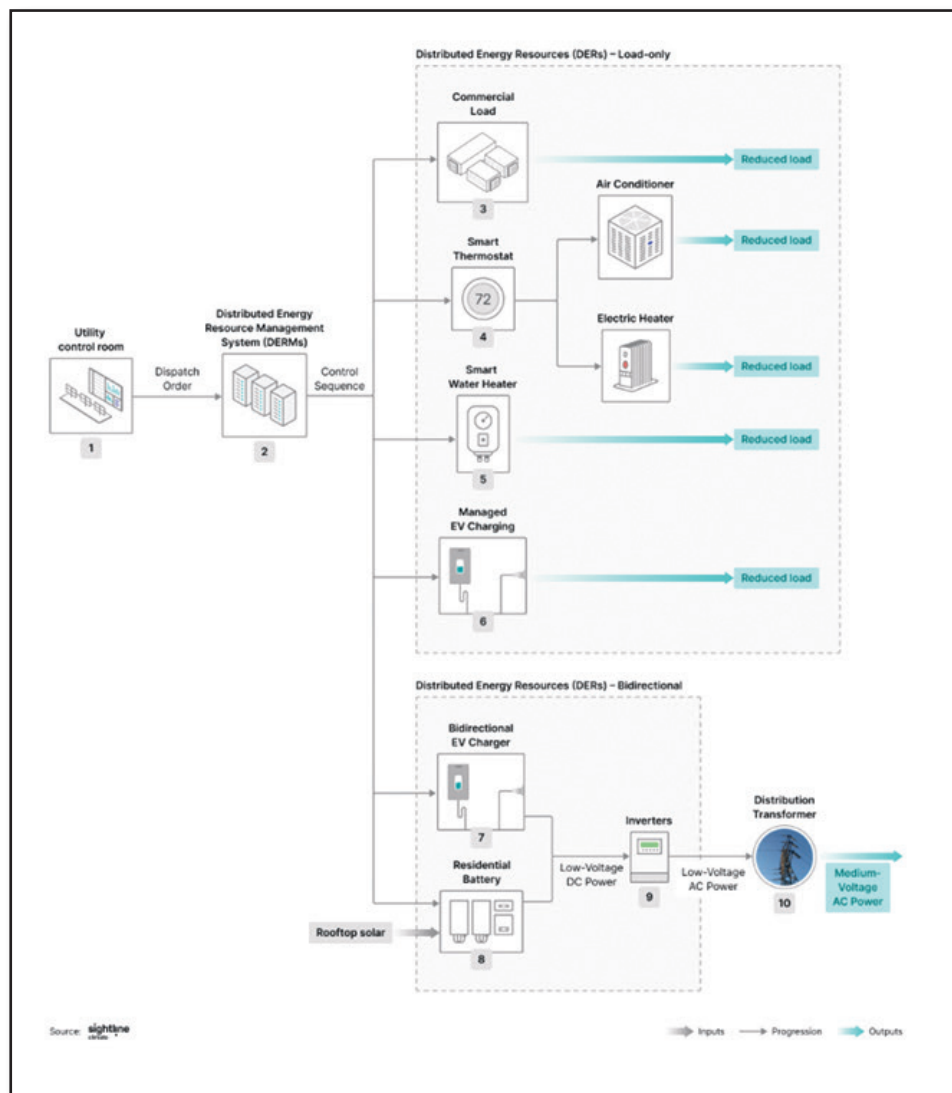
Similar to technical readiness, the relative degree of DR commercial readiness depends on the type of program being run and the given market or segment being served. Today, the most commercially mature programs manage residential thermostats, while battery and electric vehicle (EV) programs are growing in popularity. Any program that relies on customers to organically adopt new technology – be it a smart thermostat, battery, EV, or building controller – will be inherently limited in market reach by the diffusion rate of the technology.

Since DR resources are often dispatched during the most-expensive hours of the year, the economics tend to be favorable. How much a given DR resource is worth will depend upon many factors, including when it is called, how quickly it can respond, how much demand it drops, how often it can be called upon, and even where exactly the loads are located. Customer compensation for responding to DR event signals ranges from zero in the case of voluntary programs up hundreds of dollars per kW for locational and high-value resources.

Virtual Power Plants (VPPs)

Virtual Power Plants (VPPs) leverage the latest evolution of DR programs, incorporating many of the same technologies and techniques described in the previous section. What is unique about VPPs is the ability to expand capabilities beyond traditional DR to include multiple technology and load types, dispatching strategies, localized services, and distributed energy resource (DER) orchestration (**Figure 3**). By aggregating many small loads and managing them in concert, VPPs can deliver value in the aggregate for the bulk power system and with precision along the grid edge. This may take the form of congestion relief, voltage support, frequency response, infrastructure investment deferral, and other value streams.

Figure 3 - Generalized VPP configuration.



Like DR programs, VPPs are also dependent upon customer participation, customer-owned assets, and continuous communications and engagement. And unlike traditional grid assets, there are many variables that exist outside of the utility's sphere of control, including market influences, price sensitivities, and individual customer behaviors and choices. However, in spite of the challenges, utilities across North America have deployed more than 30 GW of VPP capacity in recent years and this growth trend seems likely to continue. Successful deployment of a VPP requires careful customer lifecycle management (CLM) in addition to technical solutions for managing edge devices and integrating them into grid operations (e.g., with the use of distributed energy resource management systems, or DERMS).

Grid Support

VPPs offer many of the same grid services as DR programs but also expand capabilities further in terms of delivering on benefits from frequency response, locational value, and device coordination (e.g., dispatching batteries to manage snapback effects from thermostat DR). Where DR programs alone tend to be very limited in the total capacity they can deliver, VPPs have the potential to deliver upwards of 10 - 20% of system peak capacity.²

Technical Readiness

Similar to DR, some enabling technologies for VPPs are more developed than others, with thermostat and battery programs driving the large majority of VPP dispatchable capacity so far. While many VPPs operate more-or-less autonomously in parallel with centralized grid controls (e.g., SCADA, EMS, ADMS), integration of these systems has been demonstrated in numerous pilots and is steadily moving toward scaled operations.

Commercial Readiness and Economics

A relatively small number of solution providers have delivered the vast majority of dispatchable capacity for VPPs in North America so far. In order for VPPs to continue to scale, customer market adoption of enabling technologies and devices must continue to grow, and utilities must have effective CLM strategies.

Many technology pilots over the years have demonstrated that it is rarely cost-effective for utilities to attempt to own or manage customer-owned devices directly. Successful VPP operation requires the balancing of shared benefits between the utility, customer, and third-party aggregator and/or technology partner. When utilities are “long on capacity” it is difficult to justify the complicated arrangements needed to enable VPPs. But when capacity is constrained, there’s a willingness to pay a premium for capacity upgrades, and/or grid expansions are slow and expensive, the economics of VPPs become more favorable. The U.S. Department of Energy estimates that widespread VPP deployment in the U.S. could save on the order of \$10B in annual grid costs through avoided generation investments, deferred infrastructure investments, and reduced operation of peaker plants.³

² <https://www.energy.gov/edf/virtual-power-plants-projects>

³ Ibid

3.2 Energy Storage Resources

Lithium-Ion Batteries

As their name implies, Li-ion batteries store energy electrochemically through the movement of lithium ions. A liquid electrolyte (most commonly) is used to transfer ions between a solid anode and cathode as the battery is charged or discharged. Compared to other commercial battery chemistries like lead-acid or nickel-metal hydride, Li-ion batteries have a high energy density, making them ideal for mobile applications (e.g., consumer electronics, electric vehicles).

Early Li-ion technologies – such as those having a nickel cobalt aluminum (NCA) chemistry – had poor safety, social, and environmental profiles. NCA were prone to spontaneous combustion due to “thermal runaway,” made from rare cobalt sourced largely from Congo, and were non-recyclable. Around 2020, a competing Li-ion chemistry – called lithium-iron phosphate (LFP) – began to dominate the global market for large-format battery cells. LFP batteries had a lower energy density than NCA but also had a better safety profile and could be manufactured without the need for cobalt. LFP battery energy density continues to improve as does its recycling, though recycling techniques for LFP remain immature relative to other battery chemistries (e.g., lead-acid).

Grid Support

Since Li-ion batteries have exceptional responsiveness and high power density, they can be used to quickly respond to voltage or frequency irregularities on the grid and provide stabilizing support. Their operating characteristics make Li-ion an ideal resource for displacing expensive peaker plants.

Utility-scale Li-ion batteries have typically been designed for 2-to-4-hour discharge times, though developers continue to push the technology performance (e.g., 8-hour discharge). A battery that charges and discharges over 8-hour periods can deliver significant storage value for cost-effective operation of solar photovoltaic (PV) systems in Arizona. In addition to renewables storage, Li-ion batteries are used to deliver frequency regulation, black-start support, peak shaving, congestion relief, and backup power. Li-ion batteries are currently the most economical option for 8-hour storage.

Technical Readiness

Li-ion batteries are fully technically ready and widely deployed.

Commercial Readiness and Economics

A number of high-profile battery fires had an overall cooling effect on the early commercialization of Li-ion batteries for grid applications. However, as costs continued to fall and gradual improvements were made in manufacturing, monitoring, and managing Li-ion technologies, applications and use cases have continued to expand, and so has the total capacity of interconnected systems on the grid.

Li-ion batteries have now been widely deployed across numerous industries. The technology has been a key enabler of utility “steel for fuel” replacement strategies. For example, in California, the capacity of utility-scale batteries recently reached 17 GW, representing nearly 40% of the state’s system peak and effectively displacing peaker plant operation.⁴

⁴ <https://www.energy.ca.gov/news/2026-05/california-energy-leaders-report-progress-grid-reliability-ahead-summer-2026>

Appendix K (cont.)

For decades, developers have been striving to make Li-ion cost-competitive with many traditional energy resources. For utility-scale applications we are now approaching this threshold, but for most smaller storage systems, the installed costs are still significantly higher. As technology performance continues to improve, we expect that these cost targets will be hit in the coming years.

Pumped Hydropower Storage

Pumped hydropower storage (PHS) is the most well-established utility-scale storage technology, representing more than 80% of all grid-connected energy storage in North America. Like CAES, PHS is typically treated as an LDES technology with daily charge-discharge cycles. PHS is most commonly co-located with large hydropower dams that are geographically constrained by geologic features (e.g., canyons, gorges). However, closed-loop PHS systems can also be deployed independently of traditional hydropower facilities.

Grid Support

Most PHS facilities are designed to pump water into an upper reservoir when electricity demand and/or prices are low, then run the water back through a turbine to generate electricity when demand and/or prices are high.

Technical Readiness

PHS is very well established and technically ready but closed-loop PHS systems remain rare.

Commercial Readiness and Economics

PHS has been widely adopted in markets worldwide, but there is currently only one closed-loop PHS system in operation in the U.S. Due to site variability, no two PHS systems have the same economics. A recent study indicated that total installed costs for PHS system was on the order of \$2,400/kW.⁵

Other Long Duration Energy Storage Technologies

Numerous technologies are being developed to provide long-duration energy storage (LDES), typically defined as 8-hours or more. Both technologies detailed above are capable of providing storage for long durations. Numerous other technologies are being developed to compete with lithium batteries and pumped storage. These technologies include flow batteries, compressed air energy storage, liquid carbon dioxide storage, sodium-ion batteries, supercapacitors, thermal storage, and hydrogen. As described in **Figure 2**, none have yet reached technical and commercial readiness needed for adoption beyond a pilot scale. We will continue to monitor these technologies as they advance.

⁵ https://www.energy.gov/sites/default/files/2023-09/7_Technology%20Strategy%20Assessment%20-%20%237%20Pumped%20Storage_508.pdf

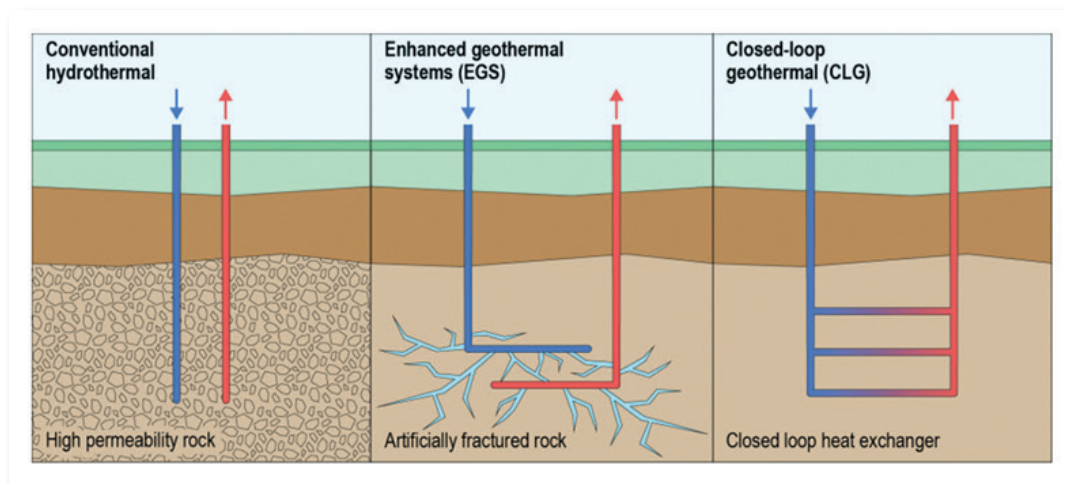
3.3 Advanced Baseload Resources

Geothermal

Geothermal energy systems generate electricity by extracting heat from deep in earth's subsurface and converting it to electricity. Pairs of wells are drilled thousands of feet into the earth. Water is circulated down one well, where it is heated by the heat of the earth. It is returned to the surface where it is processed in an Organic Rankine Cycle (ORC) to generate electricity.

Figure 4 shows different types of geothermal systems. In conventional geothermal systems (or "hydrothermal" systems), pairs of wells are drilled into rock formations with high permeability, allowing water to circulate and collect heat. Advanced geothermal systems enable extraction of heat from rock formations that are hot but not porous, which are ubiquitous. Enhanced geothermal systems (EGS) apply hydraulic fracturing to create porosity. In closed-loop geothermal systems, a series of horizontal wells are lined to create an underground radiator, allowing for circulation of water.

Figure 4 - Types of geothermal systems.⁶



⁶ <https://iea.blob.core.windows.net/assets/cbe6ad3a-eb3e-463f-8b2a-5d1fa4ce39bf/TheFutureofGeothermal.pdf>

Appendix K (cont.)

Grid Support

Since geothermal systems rely on the always-on heat of the earth, they can generate baseload electricity. However, ORCs rely on air cooling, so high ambient temperatures increase electricity used for cooling and reduce the overall power output significantly. This leads to a net efficiency of roughly 85%.

Geothermal systems can ramp up and down relatively quickly to balance supply and demand. ORCs use turbines like traditional power plants and can provide additional grid services like inertia.

Technical Readiness

Conventional geothermal systems have been in operation for more than 50 years and are fully technically ready for deployment.

EGS was successfully demonstrated for the first time in 2023. Since then, it has operated successfully. However, additional operational data and demonstrations in additional geologies are needed for full technical readiness.

Closed-loop systems are less technically ready – pilots have been completed but operational results have been mixed and further cost reductions are needed in order for closed-loop technologies to compete with other geothermal technologies.

Commercial Readiness and Economics

Geothermal's path to full commercial readiness is helped by its adoption of technologies developed in other sectors. ORC power plants are used in other technologies, so equipment is affordable and readily available. Drilling and fracturing techniques used in geothermal are very similar to those that have been perfected over decades in the oil and gas industry. This means there is a plentiful and skilled workforce available to transition into geothermal energy. For these reasons, geothermal plants have relatively short construction timelines.

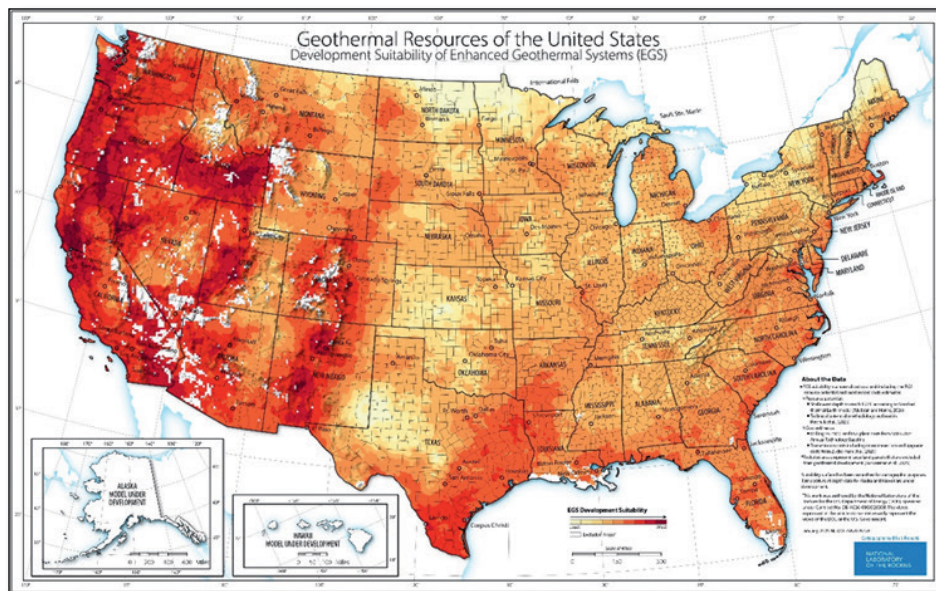
The path to full commercial readiness is hindered by drilling risk. Significant capital must be spent to drill a geothermal well, but heat, and thus energy production potential, cannot be fully confirmed without drilling. For this reason, energy project investors have been slow to enter this industry. Technological advances and development of new financing models are beginning to attract the first investors in EGS projects, but more traction is needed before this technology can reach its full potential.

Geothermal also faces unique siting challenges. Project sites must have access to transmission, land access, and other things all energy projects need. But these must occur in geographic locations where high temperatures can be accessed at relatively low depths. **Figure 5** shows the suitability of land to geothermal development. While additional geological data is needed, it is likely Arizona has good geothermal resources.

Geothermal technologies, while expensive, are among the cheapest options for clean baseload power. Costs for EGS and closed-loop geothermal are currently higher than conventional geothermal but are expected to decline as the technology reaches maturity.

Figure 5 - Geothermal resources across the United States.⁷

Darker red indicates better geothermal potential.



Water Use and Environmental Considerations

Water use varies across conventional and advanced geothermal systems. Conventional geothermal systems use some water for initial drilling, but very little in operations – water that is circulated through the formation is often naturally occurring and little water is needed to supplement it over time. Water use is largely unknown for EGS systems. Initial operational results show significant water is lost through artificial fractures and therefore needs to be supplemented to maintain operations. This is expected to decrease over time as the formation becomes saturated, but this has yet to be proven. Closed-loop systems are theoretically expected to use significantly less water. Across all system types, many water needs can be met with non-potable water, such as reclaimed water or brackish water.

Other environmental impacts are limited – geothermal energy emits no carbon dioxide and its surface footprint is very low.

Nuclear – Advanced Large Reactors

Nuclear power plants generate electricity by splitting uranium atoms inside a nuclear reactor. This process, called “fission”, heats up a fluid, which is used to generate electricity. Nuclear reactors vary in size, fuel type, and the fluid used to generate electricity (often called a coolant or working fluid). The vast majority of nuclear reactors deployed today use water as a working fluid and low enriched uranium (LEU) as fuel. The next generation of nuclear reactors use other working fluids, such as liquid metals or molten salts, and more advanced fuels such as high-assay low-enriched uranium (HALEU). These advancements offer increased efficiency, reduced waste, and improved safety features. However, these reactors are still under development and not yet ready for procurement by utilities.

⁷ https://www.nrl.gov/docs/libraries/gds-maps/geothermal-resources-united-states-development-suitability-of-enhanced-geothermal-systems.jpg?sfvrsn=673331c2_2

Appendix K (cont.)

Nuclear reactors vary in size. Most reactors in operation today are considered large reactors (over 300 MW). Smaller reactors, often “small modular reactors” (SMRs), tend to be between 20 MW and 300 MW. This section focuses on large reactors while the subsequent section below focuses on SMRs.

Grid Support

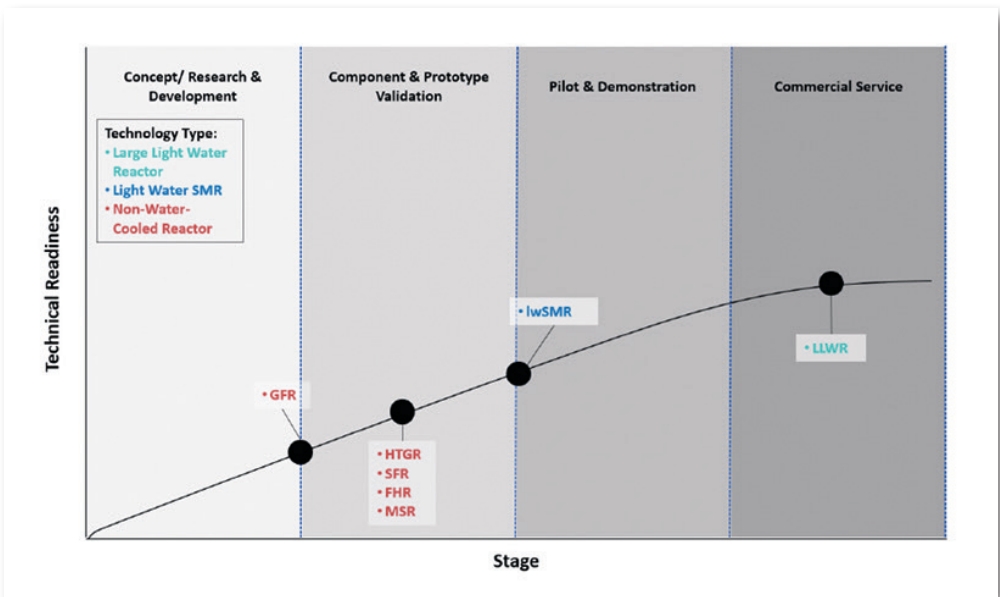
Nuclear reactors are able to provide baseload power. They operate continuously except during refueling outages, when spent nuclear fuel is replaced with fresh fuel. This leads to capacity factors generally exceeding 90%.

Nuclear systems can ramp up and down to balance supply and demand, but not as quickly as other technologies. Nuclear systems use turbines like traditional power plants, so they can provide additional grid services like inertia.

Technical Readiness

Nuclear energy has been operating for decades, so existing water-cooled designs are fully technically ready. However, newer designs that use different fuels or working fluids are less technically ready, as shown in Figure 6.

Figure 6 - Technical Readiness of various nuclear reactors as of 2025



Reactors include large light water reactors (LLWR), light water small modular reactors (lwSMR), high-temperature gas cooled reactors (HTGR), sodium-cooled fast reactors (SFR), fluoride-salt cooled high-temperature reactors (FHR), molten salt reactors (MSR), and gas-cooled fast reactors (GFR).⁸

⁸ <https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Energy-Analysis/Zero-x-40-Technoeconomic-Assessment.pdf>

Commercial Readiness and Economics

While some nuclear reactors are technically mature, constructing new reactors of any kind faces significant hurdles. These include high capital costs, permitting complexity, workforce shortages, and additional challenges associated with completing construction of highly complex megaprojects. These factors make nuclear energy among the highest cost energy sources available today.

Relatively few nuclear reactors have been built in the United States in the past quarter century. In 2020 and 2024, two large, water-cooled reactors came online after a difficult construction period that resulted in seven years of delay and cost overruns exceeding \$16 billion⁹. No one factor can be blamed for these overruns, but it is likely that complex nuclear regulations and shortages of specialized workforces may have been partially responsible. The challenges faced by this project demonstrated that, while nuclear energy is technologically mature, it faces many of the same challenges other emerging technologies face.

These challenges must be resolved before additional large reactors can be constructed. The U.S. government across multiple administrations have prioritized regulatory simplification. This has resulted in several additional projects gaining regulatory approval. Successful completion of the projects above developed a nuclear workforce, which should lead to smoother implementation going forward. However, these improvements have not unlocked the market for large water-cooled reactors; to date, no entities have made firm financial commitments to move forward with additional large water-cooled nuclear reactors. A handful of other advanced reactors, including water-cooled SMRs and other advanced reactors, have broken ground in the US and Canada in recent years.

Water Use and Environmental Considerations

Nuclear reactors use water in ways similar to other thermal power plants, like natural gas and coal. However, existing nuclear plants in Arizona have pioneered using reclaimed water to reduce burdens on drinking water sources. Similar methods could be pursued if new nuclear development is pursued in Arizona, as long as plants are developed near large supplies of reclaimed water. Nuclear plants can further limit their water use by using air cooling rather than water cooling.

Nuclear reactors have significant safety features to prevent pollution and impacts to workers and communities in the unlikely event of an uncontrolled nuclear reaction. Advanced reactors, including those constructed recently in the US, include “passive” safety features. These use unique designs to physically prevent runaway reactions without human intervention, allowing for quick response to safety issues.

Nuclear reactors generate radioactive waste that must be managed properly. This includes proper handling and isolation for long periods of time to allow for natural radioactive decay to safe levels. This typically involves on-site storage of waste.

⁹ <https://www.eia.gov/todayinenergy/detail.php?id=61963>

Nuclear – Small Modular Reactors

Small modular reactors (SMRs) are similar to the large reactors addressed above in many ways. They can use similar fuels and working fluids but tend to be between 20 MW – 300 MW.

SMRs were developed in response to challenges associated with constructing large reactors, which contribute to the high cost of nuclear energy. In order to reduce costs, SMRs use standardized designs and modular construction techniques to simplify construction. SMRs are less mature than large reactors, both technically and commercially.

Grid Support

SMRs support the grid in ways similar to large nuclear reactors. They have a similar capacity factor and provide the same ancillary services as other spinning resources. SMRs are able to ramp up and down to balance supply and demands. Their smaller size enable quicker ramp rates compared to large nuclear reactors.

Technical Readiness

SMRs are less technically ready than large reactors, as shown in **Figure 6** above. The most advanced SMRs are at the pilot stage, so additional projects are needed to demonstrate full technical readiness.

Commercial Readiness and Economics

SMRs are early in their path to commercial readiness. A small number have been successfully deployed internationally but have been used to generate industrial heat rather than electricity. The first SMRs for electricity generation in North America have broken ground recently. Numerous projects have been announced, but most are in the very early stages with limited development. Few have passed a final investment decision, indicating institutional capital is hesitant to invest in this space. However, SMRs are garnering significant interest from governments, utilities, and large electric customers, especially data centers, so this could change in the near future.

Today, SMRs are more expensive than their larger counterparts, since larger reactors can rely on economies of scale to reduce costs. SMRs should theoretically get cheaper over time. However, this relies on increasing modularization and construction simplification. SMRs currently under development have not fully realized these benefits. For example, GE Hitachi's BWRX-300, a 300 MW SMR, broke ground in 2025 in Ontario, Canada. This reactor provides less than one third of the power of GE Hitachi's 1000 MW large reactor, but takes up 80% of the footprint¹⁰. While some elements have been modularized, significant site work is still required, as shown in **Figure 7**. These elements limit the economic benefits of SMRs over large reactors.

¹⁰ Sightline Climate

Figure 7 - Construction of GE Hitachi's BWRX-300 SMR.¹¹



Water Use and Environmental Considerations

SMRs use water and impact the environment in ways similar to large nuclear reactors. Since SMRs are smaller, they contain a smaller volume of nuclear material compared to a large nuclear reactor. Therefore, the magnitude of environmental impacts at any one site would be reduced.

Other Advanced Baseload Resources

Depending on how technologies advance, the cheapest option for clean baseload power may be to construct new power plants, either nuclear or geothermal. In some cases, it may be more economical to decarbonize existing natural gas plants by cofiring a clean fuel like biogas or hydrogen, or capturing and storing the resulting carbon emissions. This class of technologies allows for reuse of existing assets to support a more sustainable grid. These technologies are approaching technical maturity in some respects, but they suffer from supply chain challenges and other considerations that limit their commercial maturity. We will continue to monitor these technologies as they advance.

¹¹ <https://www.gevernova.com/news/articles/ge-vernova-and-opg-are-writing-the-next-chapter-nuclear-power>

Appendix L

ACRONYMS AND ABBREVIATIONS

Appendix L (cont.)

ACC	Arizona Corporation Commission
ACE	Area Control Error
ADEQ	Arizona Department of Environmental Quality
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
APS	Arizona Public Service Company
ASRFP	All-Source Request for Proposals
BA	Balancing Authority
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
CAISO	California Independent System Operator
CEC	Certificate of Environmental Compatibility
CO₂	Carbon Dioxide
DAM	Day-Ahead Market
DER	Distributed Energy Resources
DG	Distributed Generation
DR	Demand Response
DSM	Demand Side Management
E3	Energy and Environmental Economics, Inc.
EDAM	Extended Day-Ahead Market
EE	Energy Efficiency
EEES	Electric Energy Efficiency Standard
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capability
EPA	U.S. Environmental Protection Agency
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
HLFCG	High Load Factor Customer Growth
ICT	Internal Combustion Turbine
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
LCOC	Levelized Cost of Capacity
LCOE	Levelized Cost of Energy
LCTN	Least-Cost, Technology Neutral
LOLE	Loss of Load Expectation
LTCE	Long-Term Capacity Expansion
NGCC	Natural Gas Combined Cycle
NO_x	Nitrogen Oxides
NPV	Net Present Value
NPVRR	Net Present Value Revenue Requirement
O&M	Operations and Maintenance
OASIS	Open Access Same-time Information System

Appendix L (cont.)

OBBBA	One Big Beautiful Bill Act
OMS	Outage Management System
PCM	Production Cost Model
PHEV	Plug-in Hybrid Electric Vehicle
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
RA	Resource Adequacy
RICE	Reciprocating Internal Combustion Engine
RPAC	Resource Planning Advisory Council
SGS	Springerville Generating Station
SMR	Small Modular Reactor (nuclear)
SPP	Southwest Power Pool
TEP	Tucson Electric Power
UNSE	UNS Electric, Inc.
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
XHLF	Extra-High Load Factor