UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-21

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit H: Salt River Project, *2023 Integrated Systems Plan*

Delivering water and power®

2023 INTEGRATED SYSTEM PLAN

2023 INTEGRATED SYSTEM PLANNING CONTENTS

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SECTION 1

Executive Summary



Salt River Project (SRP) is a community-based, not-for-profit organization with a mission to provide reliable, affordable and sustainable water and energy to more than 2 million people in central Arizona. To ensure we can continue to carry out this mission as we have for over a century, we regularly perform long-term power and water planning to anticipate and meet future needs. Recently, we completed an Integrated System Plan (ISP), an industry-leading, multidisciplinary effort to identify strategies to help guide our power system planning through 2035.[1]

The world is changing in dramatic ways that will directly and indirectly impact the power system. Key forces of change that are reshaping our industry include:

- Growing electricity demand driven by migration to the region, increasing levels of large customers such as manufacturers and data centers, and the rapid adoption of electric vehicles (EVs), which is also exacerbated by the increasing and prolonged severity of extreme heat due to climate change and urban heat effects;
- Rising costs and extended development timelines for new infrastructure projects as a result of the lingering effects of inflation and supply chain disruptions that began during the COVID-19 pandemic;
- The anticipation that the Inflation Reduction Act will encourage deployment of clean energy resources and accelerate research and development of innovative technologies;

[1]The ISP focuses exclusively on power system planning. SRP plans the water system through separate processes.

- Increasing momentum behind decarbonization efforts, including customer demand for sustainable energy, retirement of coal plants and expansion of renewable and storage resources throughout the West, and electrification of transportation and buildings; and
- Growing tightness in regional electricity markets as significant quantities of aging baseload generators receive additional regulatory scrutiny and approach the end of their operating lifetimes.

The past several years provide a powerful reminder of how suddenly — and unexpectedly — change can occur. In such a dynamic environment, we must plan for a range of potential outcomes in order to develop effective strategies that can stand up to the pressure of unanticipated changes while allowing for flexibility and adaptation.

Simply put, SRP's customers expect the same quality of service from us despite the changing and increasingly complex landscape. Meeting customers' needs over the next decade will require a complete transformation of our power system, including:

- How, when and where we generate and store electricity
- How we deliver electricity over our transmission and distribution systems
- How we engage with our customers through rate design and customer programs

Successfully transforming our power system and achieving our 2035 Sustainability Goals depends on our ability to plan in an integrated fashion, allowing for close coordination and collaboration among groups to identify the best systemwide solutions for customers. By planning together, we can best meet customers' needs and ultimately ensure a more reliable, affordable and sustainable future despite the challenges and uncertainties ahead.

The primary outcome of our first ISP is a set of seven interdependent **System Strategies**. These strategies will guide the actions of our planning teams and help establish a common vision for how we plan the system of the future. They will also help our teams ensure that their specific near-term actions — including siting, engineering, permitting, procurement, development, construction, operations, workforce development, etc. — are consistent with the common strategic vision.

Based on the System Strategies, SRP has already identified some of these near-term actions — the **ISP Actions** — which are summarized later in this section. While the System Strategies provide direction for planning the system, they are also developed with flexibility in mind. Because the future is difficult to predict, SRP cannot lock in all decisions through 2035 today. However, we can adapt and respond to these changing conditions while using the System Strategies to guide us.

Significant changes to SRP's power system are already underway. By the mid 2020s, we will add more than 2,000 megawatts (MW) of solar projects and more than 1,000 MW of battery storage. By 2032, we will retire more than 1,300 MW of capacity at four coal plants, replacing this capacity with new lower-carbon-emitting resources. We are also actively exploring regional market initiatives and have already committed to joining the Western Resource Adequacy Program (WRAP), a regional program designed to ensure there is enough resource capacity to maintain system reliability.

Need for Integrated System Planning

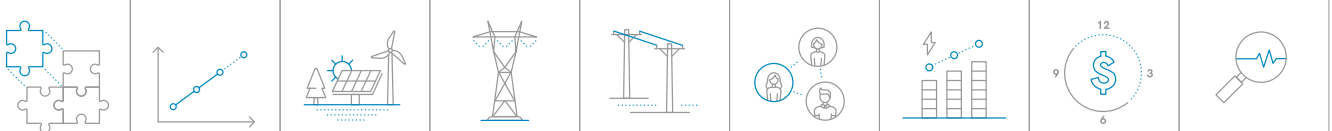
Historically, many of the planning functions that have existed within power utilities have operated independently from one another. While planning processes for generation, transmission, distribution and customer programs have relied on some common data sets and exchanged some information, planning cycles are often asynchronous, focus on different objectives and planning horizons, and lack direct visibility into how quickly other parts of the system are changing. The most prominent of these planning processes, the utility Integrated Resource Plan, has traditionally focused on future generation choices with limited insight into how those choices might impact all parts of the system.

Given the rapid pace of disruptive change in the power sector, planning decisions across the system must be coordinated from end to end to identify the best path forward for customers. For example:

- Adoption of EVs will increase electricity demand, requiring additional investments in new power generation and delivery infrastructure. But if SRP can provide pricing signals to customers that encourage them to charge their vehicles during periods that are more advantageous for the overall system, this can limit the amount of new infrastructure investment needed.
- Many of the new large-scale generation resources that SRP will consider — particularly renewables — will be located in areas where the existing transmission system may not be able to accommodate their delivery. Studying how the location of these new resources will impact the transmission system will provide a leading indicator of where new investment may be needed and may also allow for proactive siting of transmission and renewable resources.
- As the share of solar generation in SRP's portfolio increases over time, daytime energy will become increasingly abundant and lower the value of conservation during this period. This will have direct impacts on how we think about the value of future customer programs and the design of our future time-of-use price plans.

With this first ISP, we have transitioned to a holistic and collaborative framework that includes all of SRP's key planning areas. By planning for the entire power system within one process, we are positioning ourselves to answer the most difficult multidisciplinary and advanced engineering questions that will confront utilities in the coming decade. It will also help us ensure that the solutions we identify are robust given the many uncertainties for the future. A more in-depth overview of SRP's current system and the forces driving the need for an ISP is provided in Section 2.

KEY CONTRIBUTING DEPARTMENTS



Integrated System Planning & Support	Forecasting & Load Research	Resource Planning & Development	Transmission Planning, Strategy & Development	Distribution Planning & Strategy	Customer Programs	Financial Planning & Analysis	Pricing	Strategic Research & Insights

Our Planning Objectives

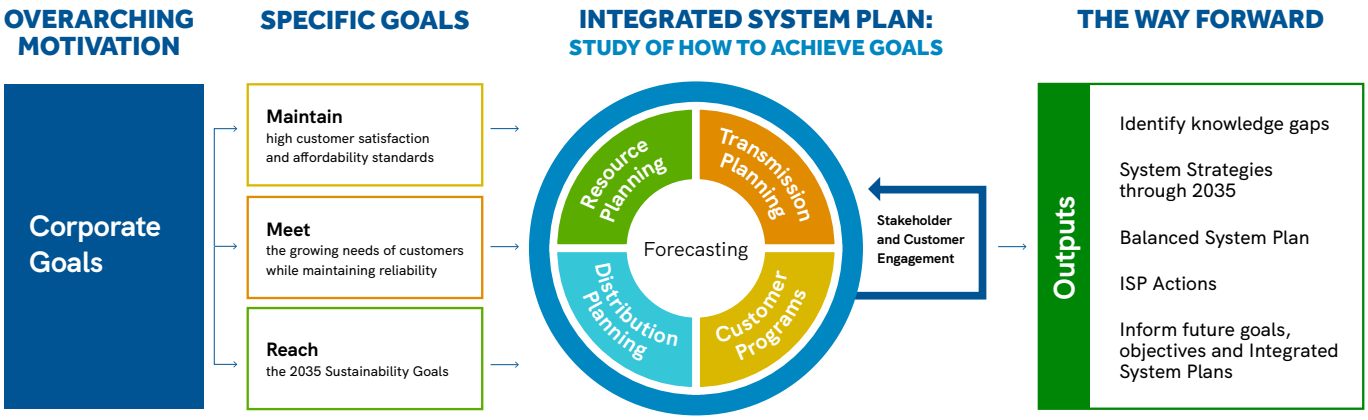
Reliability, affordability and sustainability are the cornerstones of SRP's 2035 goals, which in turn guide our planning efforts. Each of these is essential to upholding our mission and commitment to our customers.

Reliability: We are committed to maintaining electric reliability for our customers who depend on uninterrupted service, especially on the hottest days of the year.

Affordability: We recognize that electric bills represent a large cost to households and businesses. As many of our customers are facing mounting financial hardship and rising prices elsewhere in the economy, it is imperative that we strive to limit future increases to the cost of service.

Sustainability: We understand that our actions today will have far-reaching consequences for generations to come and recognize the importance of environmental stewardship to our community. These priorities are reflected in our comprehensive set of 2035 goals for minimizing our environmental footprint.

In the ISP, our teams performed rigorous systemwide modeling to identify viable pathways through 2035 to meet these goals. In addition to modeling, we engaged with customers and community stakeholders to inform and gather feedback on the ISP, while also building support for the ISP outcomes. The key deliverables of the ISP included the System Strategies approved by the Board, the Balanced System Plan and the ISP Actions. This first ISP also helped us identify opportunities to improve planning in future iterations. A more in-depth overview of the ISP process is provided in Section 3.



Stakeholder & Customer Engagement

A core component of the ISP effort included engaging our customers and stakeholders throughout the entire process, including study design, review of key findings, and development of strategies and actions. Since SRP delivers power to diverse communities, individuals and organizations, we took great care to ensure that we heard varying perspectives on how to design a first-of-its-kind ISP and how we should chart a path forward in planning the power system.

To engage our customers and stakeholders, we created an Advisory Group, which included 32 representatives from 23 different community organizations. This group met 18 times over the course of two years and provided feedback on all aspects of the ISP. We co-developed the ISP study design with the Advisory Group based on their feedback on how the future could unfold, how SRP could consider planning choices, and what aspects of planning the future power system were most important to capture. We also convened a Large Stakeholder Group, including over 140 organizations, eight times to inform a wider group of stakeholders and to receive feedback at key junctures throughout the process. In addition to engaging stakeholders, SRP convened groups of industry experts through four Technical Working Sessions to gather diverse industry perspectives on several key topics that are emerging in the industry. Through these three engagement tracks, customers, stakeholders and industry experts provided incredibly valuable feedback and played a key role in shaping the ISP study process and the final outcomes of the ISP. SRP greatly appreciates their participation and contributions throughout the entire process.

ISP PLANNING PROCESS **FAST FACTS**

NUMBER OF ADVISORY GROUP MEMBERS:

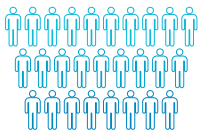


32
community representatives



from **23** organizations

NUMBER OF LARGE STAKEHOLDER GROUP MEMBERS:



250
community representatives from
143
organizations



1,349
SLIDES PRESENTED

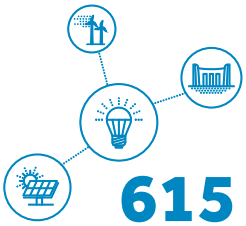
NUMBER OF MEETINGS:



31 stakeholder meetings



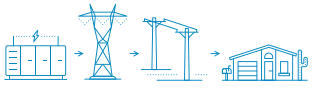
totaling over **62.5** hours of content



615
POINTS OF FEEDBACK COLLECTED AND INTEGRATED INTO THE ISP

1,411
RESIDENTIAL CUSTOMER SURVEYS CONDUCTED





42
SYSTEM PLANS CROSS-FUNCTIONALLY ANALYZED



4 **90-MINUTE RESIDENTIAL FOCUS GROUPS CONDUCTED**

STAKEHOLDER QUESTIONS ANSWERED:
588



In addition to convening stakeholders, SRP performed research in partnership with external research consultants to better understand the perspectives of residential customers. Residential customers have a diverse range of preferences, and it is challenging to capture these perspectives through a stakeholder meeting process given the time commitment required for those customers to meaningfully participate. To make sure that these diverse preferences were considered adequately within the ISP, we performed residential customer research. This customer research consisted of several focus groups and surveys of over 1,400 SRP customers, which SRP and its consultants ensured was a representative sample of residential customers based on demographics. Along with the stakeholder group meetings, this additional information provided us with a more complete picture of customers' desires and how the power system can help satisfy them.

Transparency was essential in the development of the ISP. To ensure visibility for interested SRP stakeholders and customers, we posted all ISP stakeholder engagement materials publicly, including pre-reads, agendas, presentations and meeting summary reports, throughout the process. These can be found on our ISP webpage at srp.net/isp.

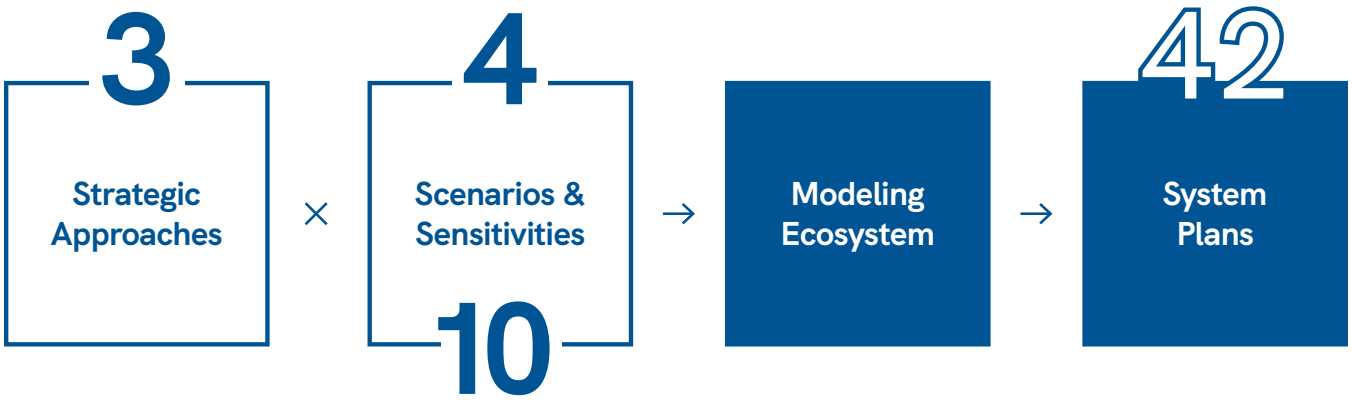
An Integrated Modeling Ecosystem

One of the principal challenges we encountered in implementing an ISP was designing an analytical framework with the appropriate level of detail to represent all parts of the system — from our biggest power plant to an individual customer's meter and every point in between. As the largest machine ever built by humans, the electric power system is incredibly complex. There is no single planning model with the capability to analyze the entirety of the electric power system as it undergoes transformative change over a long period of time. Instead, we sought to harmonize the models and tools currently used by each of our planning functions by utilizing common scenario definitions and consistent input assumptions. Additionally, we worked to improve the linkages between the models in such a way that information flowed fluidly between different analysis platforms. The result of these efforts is SRP's ISP modeling ecosystem that relies on common planning assumptions and connects tools used by each planning function with an unprecedented level of cohesion. This allows us to develop and analyze plans for the entire system.

Scenario-Based Analysis Framework

To identify solutions that benefit our customers across a wide range of uncertainties, we employed a scenario-based planning framework in the ISP. The planning framework included three key elements: scenarios, sensitivities and strategic approaches. A **scenario** represents a plausible future state of the world around us, reflecting societal, technological, economic, environmental and political trends and conditions — generally, factors that are outside of SRP's control. A **sensitivity** modifies one assumption in a scenario to isolate the impact of that assumption. A **strategic approach** represents a decision or set of decisions that are within SRP's control as we develop the power system of the future. A detailed description of the scenarios, sensitivities and strategic approaches is provided in Section 4.

Studying each strategic approach under a range of scenarios and sensitivities provided a framework for understanding how different decisions stand up against the uncertainty of the future. The ISP analyzed three strategic approaches across four scenarios and 10 sensitivities, producing a total of 42 unique system plans. The methodology employed to develop these system plans is discussed in Section 5.



Each of the 42 system plans comprised specific plans for customer programs, distribution investments, transmission investments, and generation additions and retirements from 2025 to 2035. Additionally, for each system plan, SRP evaluated a variety of metrics that measured impacts to reliability, affordability, sustainability and customer value. Assessing strategic approaches across a variety of futures allowed us to identify strategies that work well across various scenarios and helps mitigate future risks. This also allows us to take advantage of potential opportunities, thereby creating a plan that is adaptive yet resilient to the forces of change.

Key Findings from Analysis

SRP gained new insights from performing systemwide analyses of the 42 system plans. This ISP showed how customer needs, infrastructure buildout and operations could evolve under a wide range of future scenarios and uncertainties. We also learned how our actions can influence reliability, affordability and sustainability while also helping to manage future risks and uncertainties. SRP distilled these insights into a list of key findings below. A detailed description of the analysis results is provided in Section 6 of the report.

Customer Programs and Pricing Plans

- SRP will need to evolve programs and price plans to encourage shifts in consumer behavior and further educate customers on when to consume and when to conserve energy.
- Electrification of end uses, including transportation and heating demand, creates new opportunities to shift energy usage to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.
- Changes in how our customers use energy will require continued innovation and flexibility in planning.

Infrastructure

- Customers' energy demand is expected to increase rapidly through 2035 in most scenarios, even with significant expansion of customer programs and customer-sited generation.
- Significant investments in new transmission infrastructure are needed over the next decade to connect new resources and customers, while also achieving reliability and sustainability goals. These investments will need to be strategically located and timed.

- Load growth will drive new distribution infrastructure needs while changes in how our customers use energy will require innovation and flexibility.
- SRP will likely need to double or triple resource capacity at an unprecedented pace in the next decade to serve customers while achieving reliability and sustainability goals.
- New renewables and firm capacity are part of a least-cost portfolio, even under a wide range of gas price and technology cost sensitivities.
- When paired with firm capacity, solar and wind contribute to a least-cost portfolio while helping SRP reduce carbon emissions and water usage. If the U.S. government enacted a mandate for 85% CO_2 reductions by 2035 (Strong Climate Policy), further acceleration of renewable and storage deployment would be required.
- Hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230-kilovolt (kV) transformers could be needed relative to today.
- Location of generation matters and plays a significant role in the buildout of the 500 kV and 230 kV transmission system.

Operations

- Without new firm generation capacity, the system cannot satisfy reliability requirements under a high load growth scenario. In other load growth scenarios, the system can satisfy reliability requirements without new firm generation capacity but requires significant additions of renewable and energy storage resources.
- The reduction in coal generation and expansion of carbon-free resources over time allow SRP to meet, and in many cases exceed, SRP's 2035 goals for carbon emission reductions and water resiliency.
- A future system that relies more on variable renewable resources presents new challenges and will require new operating practices to ensure sufficient flexibility, reduce wear and tear on existing assets and maximize benefits to customers.

Partnerships to Meet the Pace of Transformation

- With the amount of future infrastructure and resources needed, internal and external partnerships are going to be essential to build the future system and maintain high customer value.
- To meet infrastructure needs, supply chain and development solutions are essential to managing costs and to meeting the needed pace of transformation.

These key findings from the analysis underscore the tremendous transformation of SRP's power system over the next 10-plus years. Making this transformation a reality will be a significant undertaking requiring additional planning beyond the ISP to ensure there are detailed, sound engineering and operational plans in place for any additional infrastructure or changes to the system. It will also require making decisions on specific investments, procurements, workforce development, information technology systems, etc.

While the analysis provides insights into how to plan the future power system and tradeoffs for different approaches, SRP ultimately needs a plan that is specific enough for our planning groups,

communities and stakeholders to plan the power system. The plan also needs to be flexible, given uncertainties about the future and the potential for innovation. The plan should include strategies that are no-regrets across all futures, while also making tradeoffs between different objectives and identifying strategies that achieve an appropriate balance between reliability, affordability and sustainability. The next sections describe SRP's vision for how to plan the future power system, including System Strategies, an illustrative Balanced System Plan and ISP Actions.

System Strategies

SRP developed seven interdependent **System Strategies**, representing long-term strategies for planning and operating all parts of the power system, including customer programs, distribution, transmission, generating resources, pricing and system operations. The strategies were approved by SRP's Board on Oct. 2, 2023, and will guide planning through 2035 and beyond. Each strategy is anchored to key findings from the ISP and relies on the other strategies also being in place to ensure success and achievability. To develop these strategies, we synthesized a range of metrics and outputs across scenarios, sensitivities and strategic approaches. We also incorporated feedback from the ISP Advisory Group before finalizing and receiving Board approval.

Each strategy will require that we take action today. Some will take longer than others to implement, but the execution of all strategies together will enable us to meet evolving customer needs, achieve our 2035 goals and beyond, manage costs for customers, achieve an adequate and reliable power system, and adapt toward a more sustainable future regardless of what that may be in 2035. The System Strategies are summarized below, and a full description is provided in Section 7.

Energy Investments
Invest in renewable resources and storage to manage fuel consumption and drive carbon and water reductions.

Capacity Investments
Invest in firm generation, including natural gas, to support reliability and manage affordability, while also supporting advancement of emerging firm technologies.

Proactive Transmission
Proactively plan to expand transmission infrastructure to enable generator interconnections and load growth.

Distribution Innovation
Ensure distribution grid readiness to maintain reliability and enable customer innovations to drive carbon reductions.

Partnerships & Suppliers
Explore partnerships and supply chain and development solutions that manage cost and availability to meet the pace of transformation.

Evolution of Customer Programs & Pricing
Evolve pricing and customer programs to improve economy-wide carbon reductions and pace infrastructure development, while recognizing customers' diverse needs.

Strategic Investment & Reinforcement of Existing Assets
Reinforce and maximize value of existing infrastructure with strategic investments to manage affordability and ensure future performance, grid security and resilience.



Balanced System Plan

The System Strategies set the direction for SRP's planning efforts through 2035. To provide an illustration of how the system could look in 2035, following implementation of the System Strategies, SRP developed a **Balanced System Plan**. The Balanced System Plan provides an illustration of power generation, transmission, distribution and customer program plans, as well as reliability, affordability, sustainability and customer focus metrics, through 2035. To develop this plan, we drew upon the key findings from the analysis and residential customer research and built out a system plan consistent with the System Strategies.

The Balanced System Plan adds a significant quantity of resources, more than doubling SRP's total installed capacity by 2035 relative to today. This includes adding:[2]

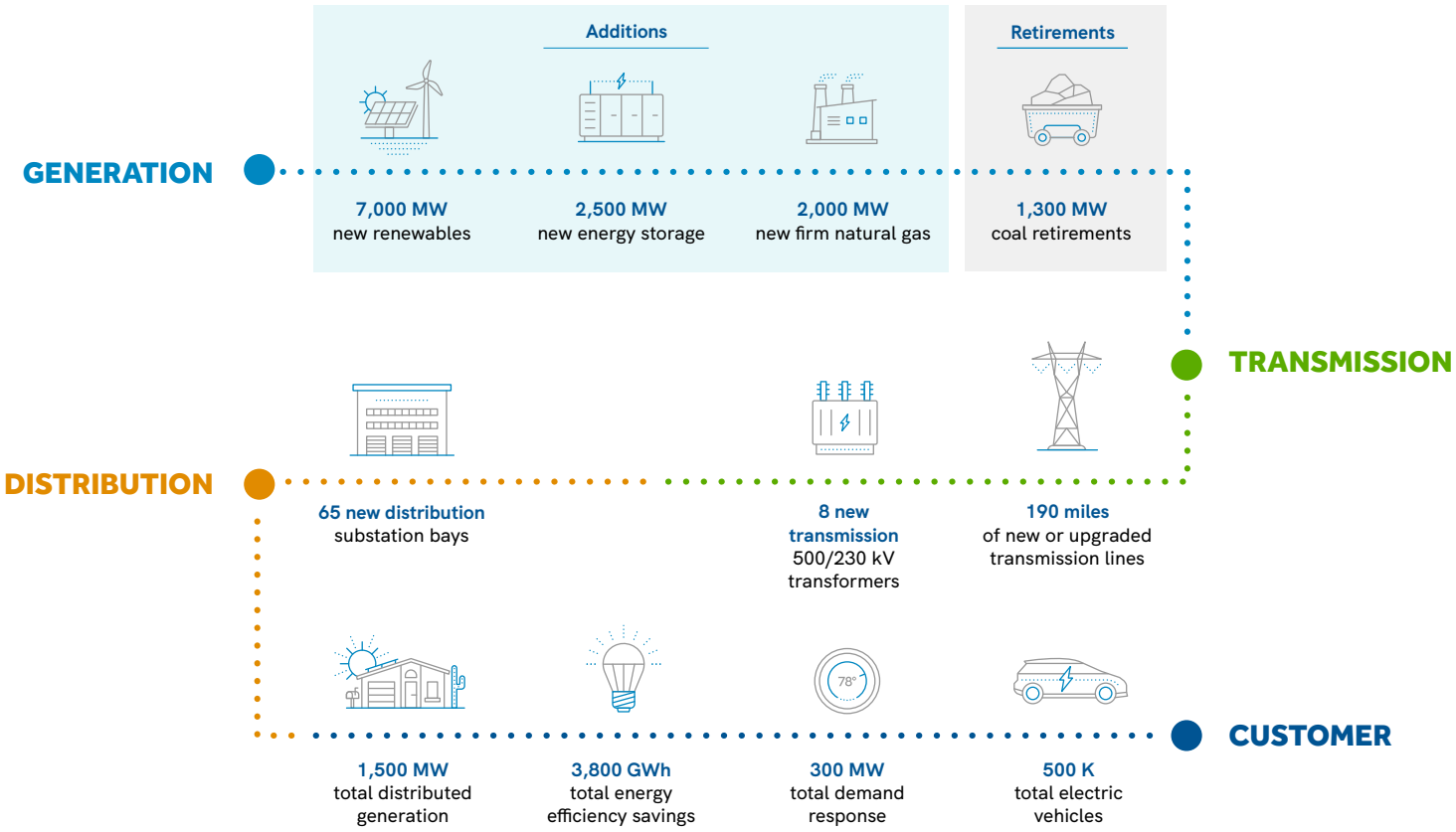
- 7,000 MW of new renewables
- 1,000 MW of new long-duration pumped hydro energy storage
- 1,500 MW of new battery storage
- 2,000 MW of new firm natural gas

This additional capacity, along with resources that are already contracted and planned to come online in the next few years, makes up for the loss of 1,300 MW of retired coal capacity and a retiring agreement with a natural gas plant. It also helps SRP keep pace with a greater than 40% growth in energy demand by 2035 and marks a significant increase of clean energy resources in the future power supply.

To deliver generation from these new resources and to accommodate the increase in energy demand, the plan includes more than 190 miles of new or upgraded high-voltage transmission lines, as well as eight 500/230 kV transformers. This infrastructure can take several years to site, engineer, permit, construct and energize, so it is crucial that SRP takes a proactive approach to ensure transmission is in place to enable future growth. The plan also includes more than 65 new distribution substation bays across existing and new distribution substations which is necessary to accommodate increasing energy demand.

Customers play a significant role in the transformation of the system in the Balanced System Plan. Customers' total energy demand is expected to increase significantly due to new large industrial customers, migration to the Valley and the growing popularity of EVs. However, this growth is mitigated to an extent due to customer adoption of distributed generation, like solar and batteries, and customer participation in SRP's energy efficiency and demand response programs. Moreover, as the power system evolves, we believe that customers can play a central role in achieving that transition through participation in future time-of-use price plans, electric vehicle managed charging programs and other offerings that have yet to be rolled out. The graphic on the next page shows the key elements of the Balanced System Plan, including power generation, transmission, distribution and customer program components.

[2] MW additions reflect the mix of resources determined to best balance reliability, affordability and sustainability needs. However, actual additions may change over time as external conditions change, such as load growth and technology costs.



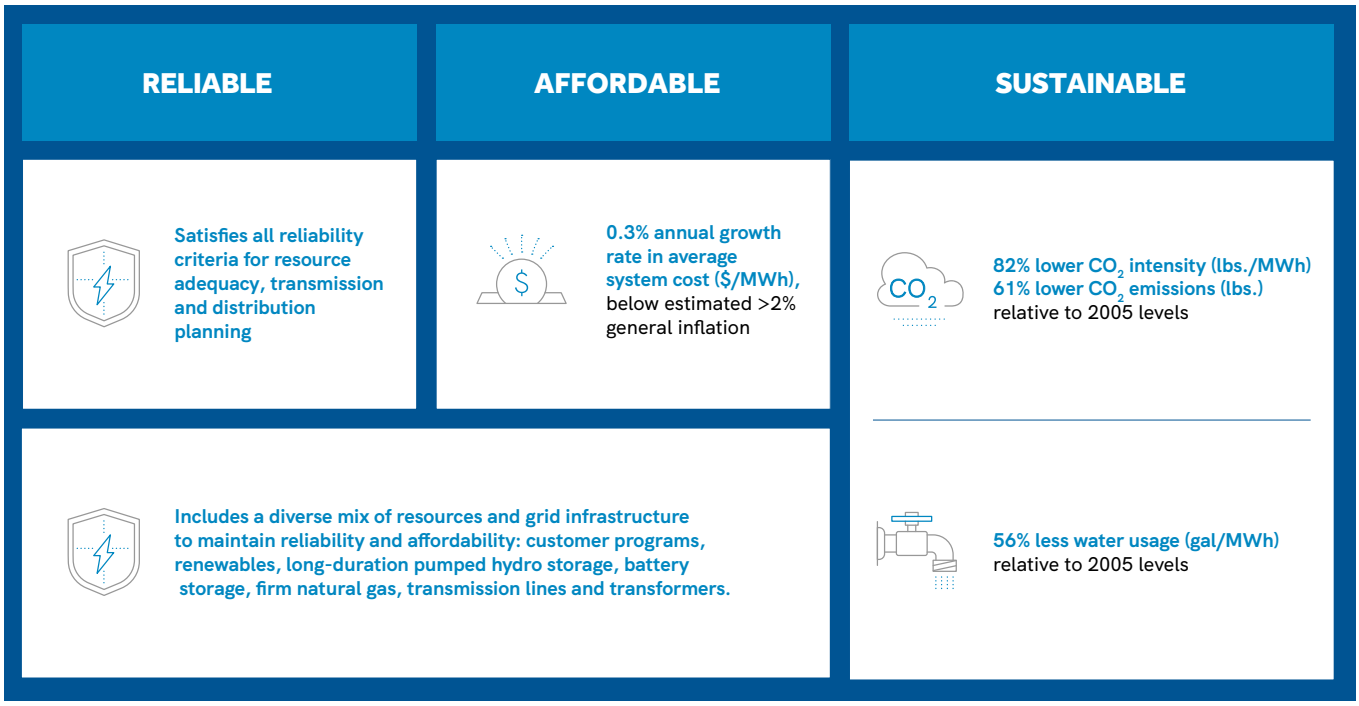
As mentioned earlier, the Balanced System Plan allows SRP to achieve important goals related to reliability, affordability and sustainability.

Reliability: By investing across the system — including new firm generation, long-duration and short-duration storage, renewables, transmission, distribution and customer programs — SRP will ensure strong reliability performance across the system.

Affordability: Due to the diverse mix of investments and programs, average system costs for this plan are projected to increase by less than 0.3% per year, well below projected general inflation. Ultimately, the driving force behind our plan is to meet customers' future energy needs at the best overall value. We believe this plan delivers on that goal.

Sustainability: As SRP retires coal capacity and adds significant amounts of clean energy resources, CO_2 emissions intensity is projected to decline by 82% (relative to 2005) and water usage intensity is projected to decline by 56% (relative to 2005), in both cases surpassing SRP's 2035 Sustainability Goals.

We are excited by the performance of this plan. However, as mentioned earlier, this illustration supports a common vision of what the future may look like based on what is known today. As expectations change — such as economic development forecasts, technology cost projections, or the implementation of new laws and regulations — the system plan will need to adapt and evolve accordingly. The Balanced System Plan is described in more detail in Section 8.



ISP Actions

Our planning processes do not stop with the ISP. In many ways, the conclusion of the ISP represents new beginnings as our teams start to execute the System Strategies. As a first step, SRP has defined 10 **ISP Actions**, which we have already started to implement. The ISP Actions will also help enhance our planning capabilities, establish a roadmap to implement the System Strategies and further our progress toward meeting our 2035 goals. The ISP Actions are summarized below, and a full description is provided in Section 9.

ISP Action #1: Residential Time-of-Use Pilot: Execute a residential time-of-use price plan pilot and perform customer research to evaluate customer response to new time-of-use peak periods and a super off-peak period in the middle of the day, which will inform SRP's load forecast for long-term system planning and SRP's price process.

ISP Action #2: Time-of-Use Evolution: Engage commercial, small business, large industrial and residential customers and stakeholders to inform them of how the evolving grid will impact time-of-use periods. Develop a roadmap for implementing new time-of-use periods, including the following elements: undertake a pricing process informed by the ISP as to how time-of-use plans need to evolve and develop a communication plan for all customer types and segments to educate them about any new time-of-use price plans.

ISP Action #3: Customer Programs: Continuously refresh program plans and drive participation in customer programs at levels consistent with those planned for in the ISP, representing a meaningful increase from SRP's initial 2035 Sustainability Goal for energy efficiency.

ISP Action #4: EV Management: Develop a roadmap by evaluating customer needs and system impacts and assessing viable pathways for managing EV charging through price plans, customer programs and educational efforts to align with time periods that are lower-cost and minimize additional infrastructure needs.

ISP Action #5: Electrification: Analyze the benefits and costs of non-EV electrification within SRP's service area, including effects on SRP operations and economywide emissions. Assess options for expanding E-Tech program offerings related to residential and commercial electrification.

ISP Action #6: Distribution Enablement Roadmap: Continue implementing SRP's Distribution Enablement (DE) Roadmap, including the following elements: deploy the Advanced Distribution Management System (ADMS) and Distributed Energy Resources Management System (DERMS) in 2024; continue implementing advanced locational planning tools; advance the interconnection process; execute the Distribution Enablement Research & Development plan; and share the Distribution Enablement Strategy with external stakeholders.

ISP Action #7: Resource Selection: Issue all-source requests for proposals (RFPs) or requests for information (RFIs) at least once every two years to compare with self-build options and ensure that SRP can agnostically select resource technologies that minimize total system costs while meeting SRP's reliability and 2035 Sustainability Goals.

ISP Action #8: Coal Transition Action Plan: Develop a coal repurposing action plan, including the following elements: coordinate with co-owners to develop a path forward for the Springerville Generating Station; prepare a plan or plans for repurposing the Coronado Generating Station site; develop solutions that preserve transmission following the retirement of coal plants; and test strategies for minimizing emissions from coal power plants.

ISP Action #9: Proactive Siting: Develop and initiate collaborative community engagement, land, resources and transmission siting research to proactively identify, prepare and preserve options for feasible future system infrastructure sites.

ISP Action #10: Regional Transmission: Pursue transmission projects that would enable SRP to access diverse renewable resource options beyond solar, such as wind and geothermal, and engage with project developers as appropriate.

The completion of the ISP Actions will significantly advance SRP's planning and development of the future power system. The ISP Actions related to time-of-use price plans, customer programs, EV management, electrification and the Distribution Enablement Roadmap will ensure that SRP continues to provide customers with the best options for managing their energy costs, adopting clean energy technologies and helping SRP achieve the future transformation of the power system. The ISP Actions related to resource selection, the coal transition action plan, proactive siting and regional transmission will ensure that SRP takes a proactive approach to managing the transition of existing coal assets, maintaining a reliable power grid, accessing the best available resource options and driving improved sustainability. Like the System Strategies, these ISP Actions work together to help SRP achieve its reliability, affordability and sustainability goals. To keep SRP's Board, customers and stakeholders informed on progress made toward the ISP Actions, SRP will provide annual updates.

Beyond the First ISP

SRP is excited to have completed this first ISP. It was a first-of-its-kind effort that required creative thinking in how to plan the entire system in a coordinated manner and led to a comprehensive set of System Strategies and ISP Actions that will allow us to take concrete steps to transform our power system. Given that this effort was trailblazing in many regards, there were challenges in doing end-to-end modeling of the entire system across so many different futures. However, upon reflecting on this effort, we are more confident than ever that an integrated system planning framework is the best way to plan the future power system. By planning for the entire power system within one process, we can identify solutions across the entire system and how those solutions must work together to allow us to achieve reliability, affordability and sustainability goals at the best value to our customers.

The first ISP is just a starting point. SRP has learned a lot about how to perform systemwide planning through this effort and plans to continue to improve upon it in future iterations of the ISP. This will provide us with opportunities to update scenarios as new information becomes available and consider any adjustments to strategies, a balanced plan and actions based on updated systemwide analysis. In the meantime, we will use findings from the ISP to support other ongoing efforts at SRP, including annual planning activities, procurement of new resources through all-source requests for proposals (RFPs), and our 2035 Sustainability Goals update process.

SECTION 2

SRP Overview and Background

About SRP

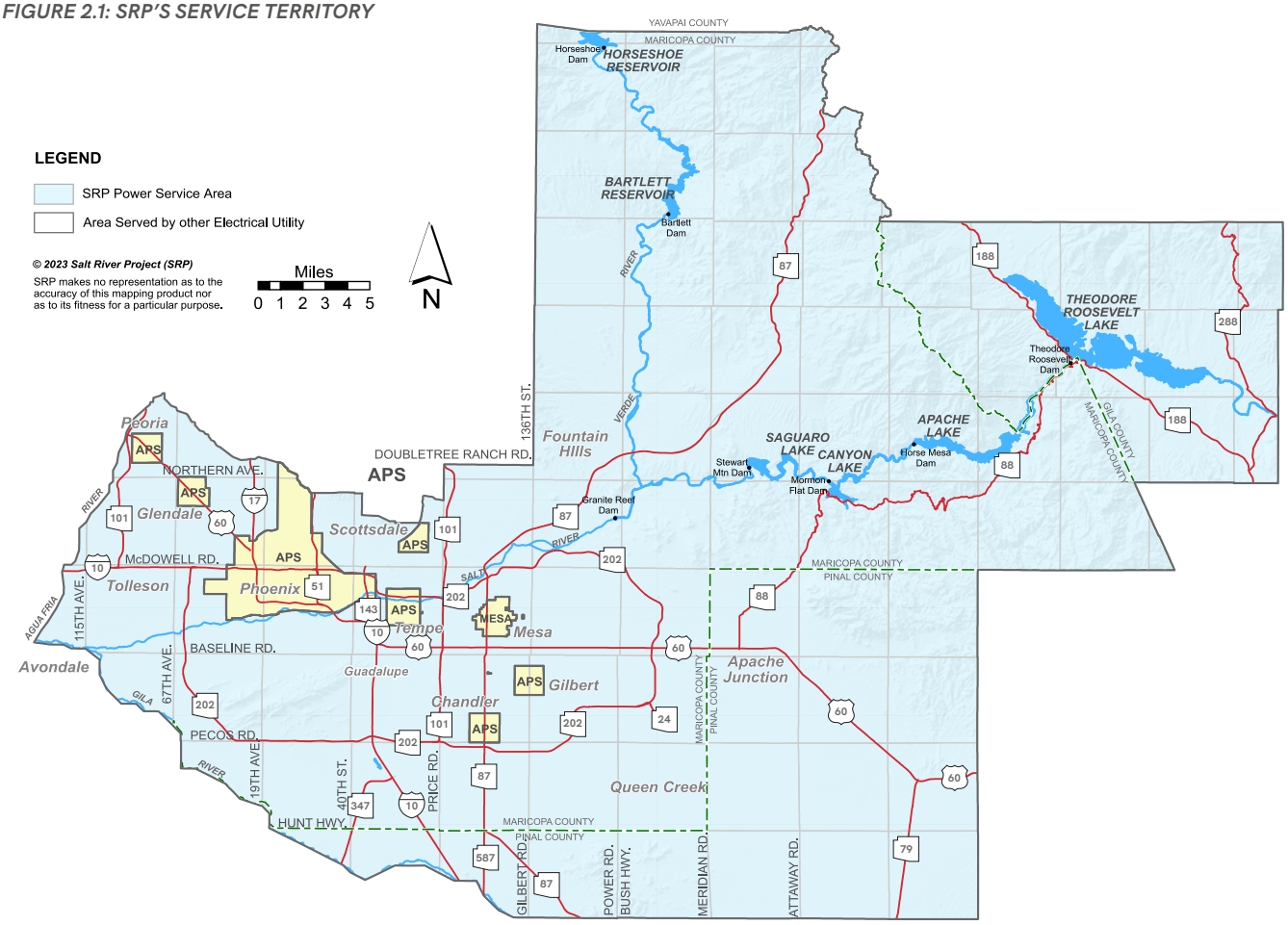
Salt River Project (SRP) is the oldest multipurpose federal reclamation project in the United States and one of the nation's largest public power utilities. As a community-based not-for-profit organization, SRP's mission is to serve our customers and communities by providing reliable, affordable and sustainable water and energy. Our long history, beginning in 1903, predates Arizona's statehood.

SRP comprises two separate organizations: the "Association," a private water corporation founded in 1903, and the "District," an electricity provider formed as an agricultural improvement district and a political subdivision of the State of Arizona in 1937.

SRP has helped and will continue to help the Phoenix metropolitan area develop and thrive by providing these essential water and power resources. Our guiding principles have remained the same since our founding: to act in the best interest of the people we serve and strive to help build a better future for Arizona.

For over a century, SRP has focused on building strategic partnerships and innovative solutions to meet the Phoenix metropolitan area's ever-changing needs. In the years ahead, we will continue to lead the way by applying a forward-thinking approach and new technologies to address energy supply challenges.

FIGURE 2.1: SRP'S SERVICE TERRITORY



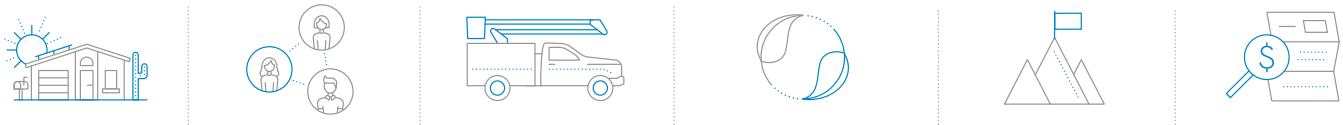
Electric Customers

SRP takes great pride in serving over 1 million electric residential, municipal, large commercial, industrial and small business customers. Residential customers are households that use electricity for their daily needs, such as lighting, heating and cooling. Municipal customers are local governments that use electricity to power public facilities, such as streetlights, traffic signals and water treatment plants. Small business customers are businesses that consume a relatively small amount of electricity, such as small shops and restaurants. Large commercial customers, such as shopping malls, hospitals and universities, consume a significant amount of electricity. Industrial customers are businesses that use electricity to power heavy machinery and equipment, such as factories and manufacturing plants.

J.D. Power recently ranked SRP highest in customer satisfaction in the western United States among large electric utilities for the 22nd time in the 23 years that J.D. Power has been surveying residential electric customers — and the 20th year in a row. Among large electric utilities (500,000-plus households), customers ranked SRP as the top-performing large electric provider in the West in all six customer satisfaction factors: power quality and reliability, price, billing and payment, corporate citizenship, communications, and customer service.

SRP's 2035 Goals

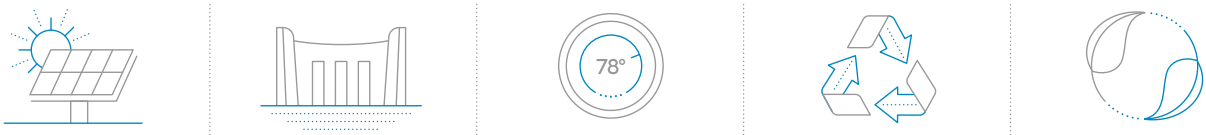
For over 120 years, SRP has fulfilled its mission to deliver reliable, affordable and sustainable water and energy. Our 2035 Corporate Goals define what we want to achieve over the long term in order to continue delivering on our mission. The categories for our corporate goals are shown below. These goals provide us with a purposeful structure for planning strategically as a company. They also allow us to anticipate and respond to the many ways in which our customers' expectations are changing, new technologies are emerging and advancing, and the energy sector is transforming.



CUSTOMERS | **COMMUNITY** | **WORKFORCE** | **SUSTAINABILITY** | **LEADERSHIP** | **FINANCES**

A subset of goals within the 2035 Corporate Goals are sustainability targets that impact SRP's future resource and customer program planning. They include Carbon Footprint and Water Resiliency Goals related to generating resources and Customer and Grid Enablement Goals related to customer programs.

SRP SUSTAINABILITY GOALS



Carbon Footprint | **Water Resiliency** | **Customer & Grid Enablement** | **Supply Chain & Waste Reduction** | **Customer, Community & Employee Engagement**

Carbon Footprint & Water Resiliency Goals:

- Reduce carbon emissions from generation intensity reaching 65% reduction by 2035 and 90% by 2050.
- Achieve a 20% reduction in generation-related water use intensity across all water types.
- Eliminate or offset power generation groundwater use in Active Management Areas (AMAs).

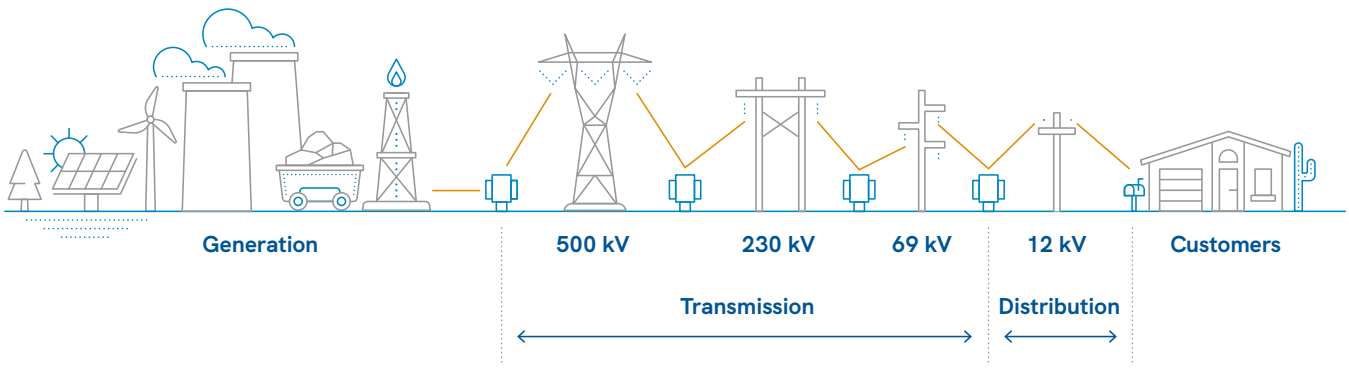
Customer & Grid Enablement Goals:

- **Energy Efficiency:** Deliver over 3 million megawatt-hours (MWh) of annual aggregate energy savings.
- **Demand Response:** Deliver at least 300 megawatts (MW) of dispatchable demand response and load management programs.
- **Electric Transportation:** Support the enablement of 500,000 electric vehicles (EVs) in SRP's service territory and manage 90% of EV charging through price plans, dispatchable load management, original equipment manufacturer integration, connected smart homes, behavioral and other emerging programs.
- **Electric Technologies:** Expand the electric technology (non-EVs) program portfolio to deliver 300,000 MWh of annual aggregate energy impact.
- **Grid Enablement:** Enable the interconnection of all customer-sided resources, including solar photovoltaic (PV) and battery storage, without technical constraints while ensuring current grid integrity and customer satisfaction.

The 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders. To learn more about SRP's 2035 Sustainability Goals, visit srp.net/2035.

Existing Power System

SRP is a vertically integrated utility that owns and plans for all-electric energy supply chain levels, including generation, transmission, distribution and customer programs. As a vertically integrated utility, SRP owns and controls the electricity supply chain's generation, transmission and distribution components. We are responsible for producing, transmitting and distributing electricity to our customers. We also design customer programs and pricing to ensure we meet customers' evolving needs and signal customers when to use electricity.



Being a vertically integrated utility, SRP has some advantages when planning, including greater flexibility in designing and implementing customer programs and pricing plans that meet the specific needs of our customers and our system. We can use our oversight of the entire electricity supply chain to ensure that our customer programs are integrated with our operations. This can help improve the reliability and efficiency of SRP's operations, ultimately benefiting customers by reducing costs and improving service quality.

Historically, many of the planning functions that have existed within vertically integrated utilities like SRP have operated independently from one another. While planning processes for generation, transmission, distribution and customer programs have relied on some common data sets and exchanged some information, planning cycles are often asynchronous, focus on different objectives and planning horizons, and lack direct visibility into how quickly other parts of the system are changing.

Generation Overview

Resource planning at SRP determines what generation resources we need to add to our system to maintain reliability and achieve SRP's 2035 Sustainability Goals. SRP's generation resources can be viewed as capacity or energy sources. Capacity is the maximum output a generating resource can physically produce or export at a single point in time, measured in megawatts (MW). This output helps serve high peak demand hours and when the system has critical needs. Not all resources have the same capability to produce power at full capacity for all hours of the day and year. Demand resources, such as Demand Response and Energy Efficiency, are measured by their capacity to reduce demand, also in MW.

Energy is the amount of electricity a generator produces over a specific period of time, measured in MWh. Many generators do not operate at their full capacity all the time. A generator's output may vary according to conditions at the power plant, the availability of fuel, variability of wind and sun, or dispatch instructions from the utility due to changes in fuel costs or market prices. To maintain a balanced grid, SRP must constantly match demand with supply at any given instant.



Think of capacity like the lanes on a freeway and the maximum number of vehicles it can allow. Commuters need enough lanes to accommodate the number of vehicles during rush hour traffic. This means several of the lanes may be empty during lighter traffic times of the day, but the additional lanes are necessary for vehicles during a peak traffic time. Think of the energy as the flow and number of vehicles traveling on the freeway over a given period of time.

ANALOGY

Capacity: Maximum number of cars that can fit on an interstate during rush hour.

Energy: Number of cars per year traveling on that same interstate.





Previously, SRP used an Integrated Resource Plan (IRP) to determine the generation resources needed to meet our forecasted demand. Using this IRP process, SRP could understand how different resource choices and energy portfolios performed in various scenarios and future business environments. Our past IRPs aimed to analyze possible critical uncertainties and the generation of resources available to navigate them. This process involved evaluating current and future energy needs and developing a resource plan to meet those needs in a cost-effective, sustainable and reliable manner. The IRP process included a variety of analyses, such as load forecasting, resource planning and economic analysis. The IRP process aimed to ensure that the utility can provide reliable and affordable electricity to its customers while minimizing environmental impacts.

Once the IRP was completed, SRP would then develop specific plans linearly based on annual load forecasts, starting with a resource plan, then transmission, distribution, and customer programs and pricing. The resource plan was based on the resulting strategic directions from the IRP process, inclusive of annual load growth projections. Then, each subsequent plan was developed and designed to meet SRP sustainability and corporate goals. On an annual basis, between IRP cycles, we monitored and evaluated our operations and adjusted individual planning area plans to ensure that we met our goals and continued providing reliable, affordable and sustainable electricity to our customers.

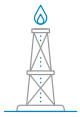
The overall objective of the IRP was to incorporate a flexible resource plan that could embrace the challenges, uncertainties and growing energy requirements of tomorrow's world. The following are the concluding strategic directions from the 2017-2018 IRP.



Coal Generation: Reduce the amount of energy in SRP's portfolio produced by coal generation.



Nuclear Generation: Preserve option for new nuclear generation in the mid-to-late 2030s with a focus on small modular technology.



Natural Gas Generation: Develop flexible natural gas generation options to meet peak demand and integrate renewables.



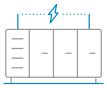
Customer Programs: Continue the promotion of energy efficiency programs and technologies that help customers save energy and money.



Renewable Energy: Grow SRP's renewables portfolio to reduce CO_2 intensity and manage costs; expand opportunities for customer-dedicated projects.



Market Resources: Implement Energy Imbalance Market participation as planned and seek opportunities to expand participation in other regional markets.



Energy Storage: Add cost-effective energy storage to support additional renewable energy integration.



New Technologies: Pursue pilot projects and research and development efforts for innovative applications of new power generation, load management, energy storage and electrification.

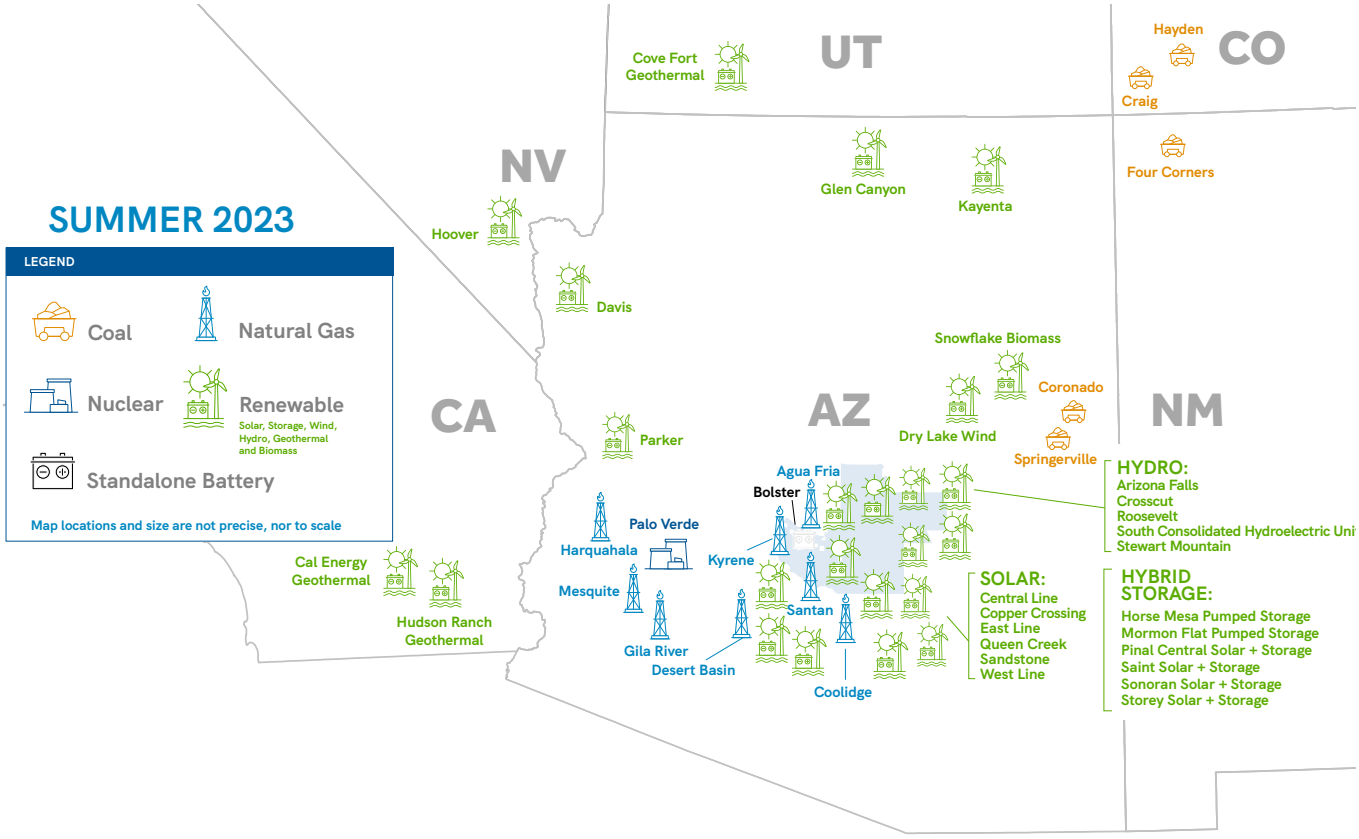
Featured in the next section are brief overviews of each planning area, where they are today and what we must consider when planning for the future.

SRP's Generation Sources Today

Over the past few years, SRP's service area has been experiencing significant and unprecedented growth in demand. In 2023, SRP served a multiday record peak for electricity demand. On several days, power demand reached over 8,000 MW, and SRP served its highest peak demand of 8,163 MW on July 18, 2023. The 2023 peak was 7% higher than last summer.

Where Does SRP Power Come From?

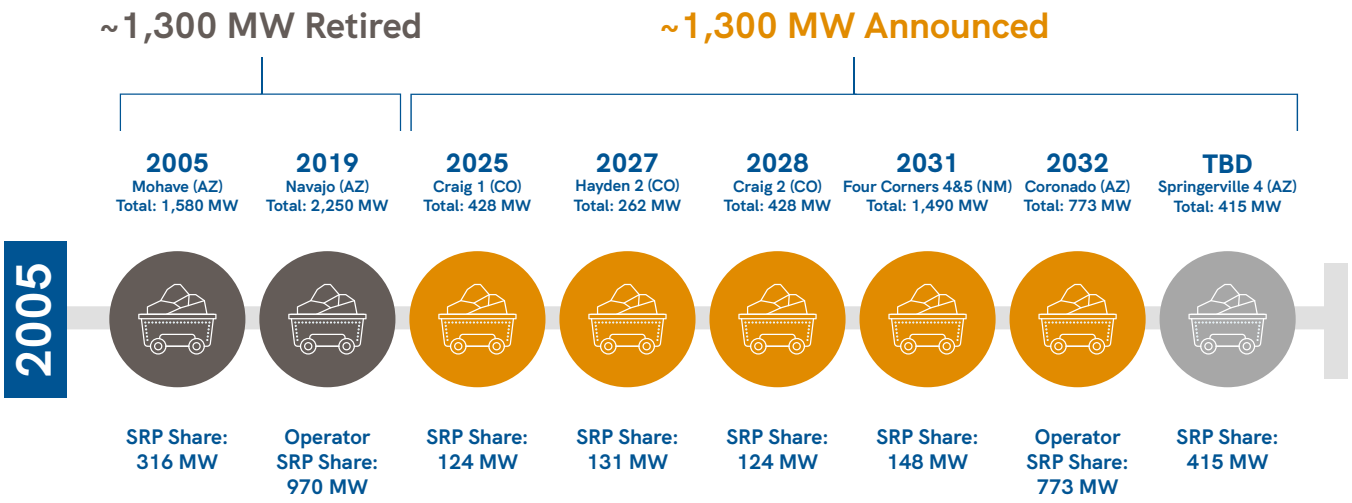
SRP generates electricity from renewable, traditional fossil fuel and carbon-free sources. The renewable sources include solar, geothermal, biomass, wind and hydropower. Traditional fossil fuel sources include coal and natural gas, and carbon-free sources include nuclear generation. Below is a graphic that displays what and where SRP generation sources are today.



To address growing demand and enable the achievement of our 2035 carbon reduction goals, SRP has been positioning its resource portfolio in alignment with the IRP strategic directions that would allow for a lower-carbon future by retiring coal plants, adding new renewable resources, integrating storage, adding flexible natural gas and acquiring existing zero-carbon nuclear resources.

Progress in Reducing Coal

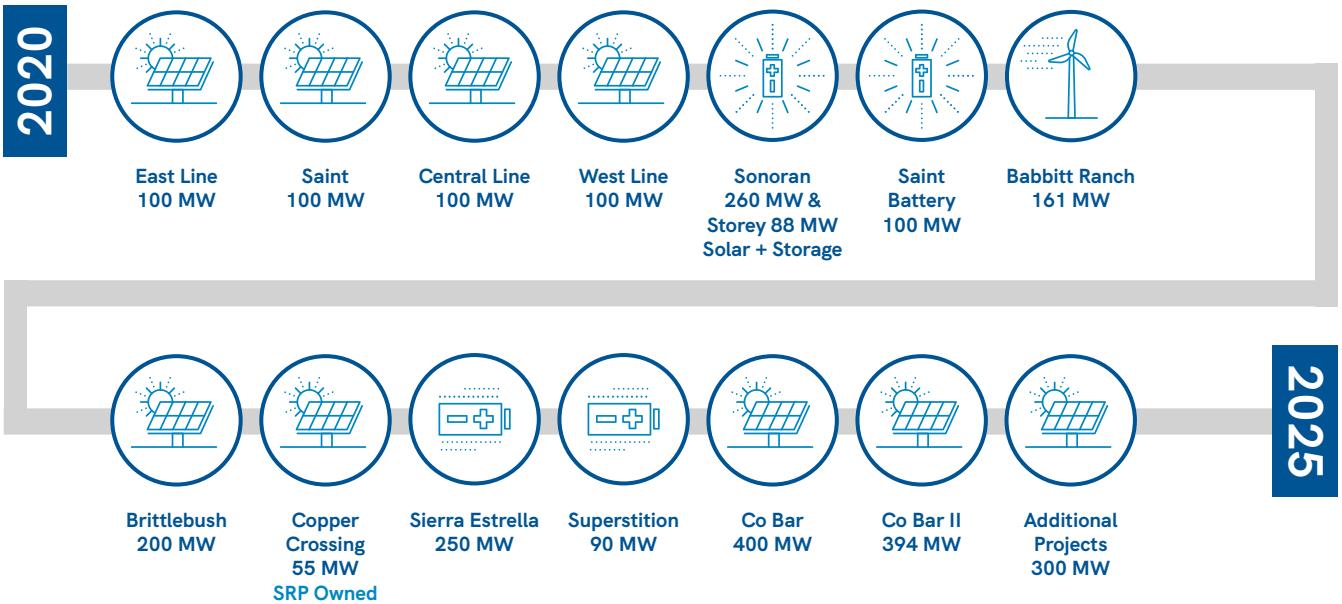
Since 2005, SRP has taken action to retire approximately 1,300 MW of coal generation. By 2032, SRP will retire an additional 1,300 MW from four coal plants already announced for retirement that will be replaced with new lower-carbon resources.



Increase carbon-free resources

In fiscal year 2023 (FY23), SRP added 104 MW of carbon-free generation from Palo Verde and has contracted an additional 10 MW in 2024 for a total of 114 MW. With this purchase, SRP increases the carbon-free energy delivered to our customers by up to 1,000,000 MWh annually, over 2.5% of our annual retail electricity.

SRP also prioritized additional renewable resources by adding 400 MW of new solar and has contracts in place for an additional 1,697 MW and continues to work with developers to implement 1,088 MW of storage and 161 MW of wind under contract.



Develop long-lead carbon-free resources

We have made great efforts to develop the capability to effectively integrate utility-scale storage technologies into our system to provide the optimal value to SRP and our customers, improve our ability to decarbonize with greater amounts of low-cost intermittent renewable resources, and potentially avoid or defer adding conventional generation or power delivery infrastructure while mitigating life-cycle environmental impacts. In addition to new lithium-ion storage technology, we have initiated early development of a Pumped Hydro Storage Project for up to 2,000 MW with a 10-hour duration. Pumped storage can provide utility-scale storage resource diversity and is a proven technology that SRP has had decades of experience owning and operating.

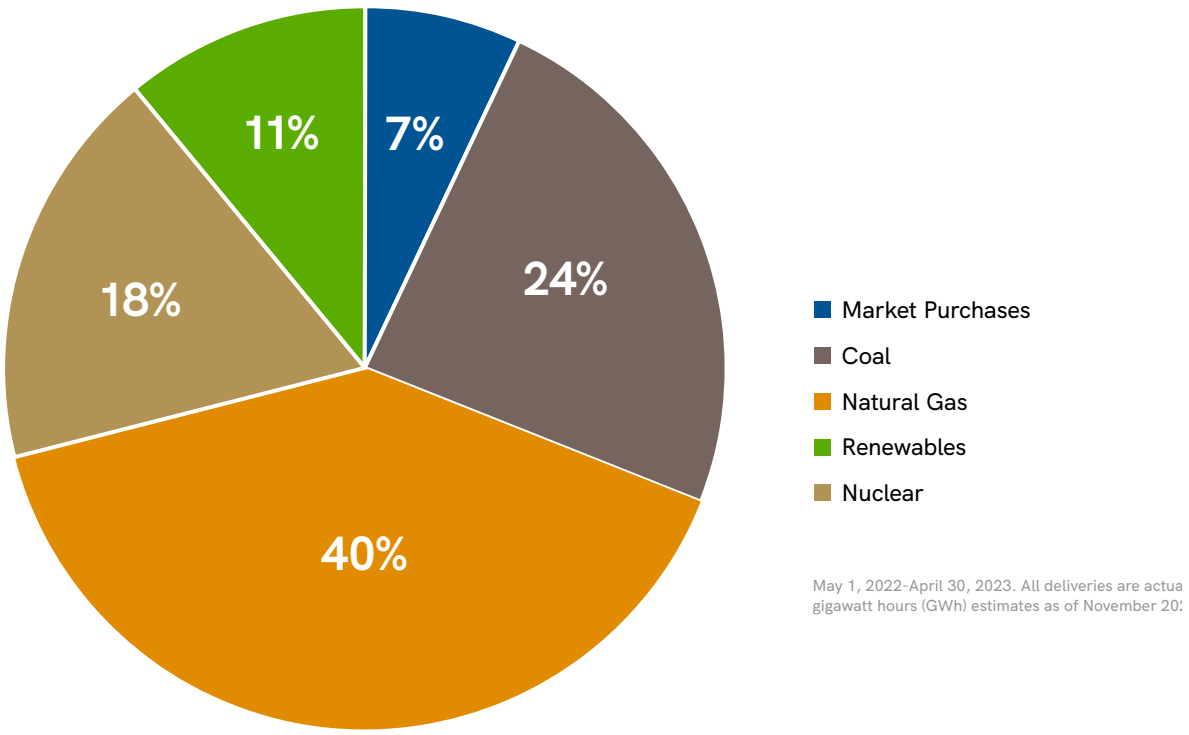
Adding flexible firm resources for future renewable integration and reliability

Without sufficient generation resources and power system stability, SRP customers may experience power shortages. Firm resources are sources of electricity (generation resources) that the utility can dispatch to meet system needs. Characteristics of a firm resource include reliable capacity in all seasons and over long durations. Natural gas is a firm resource that provides flexibility to balance ramps caused by intermittent resources (such as solar and wind) and fast response during emergencies. In 2023, we obtained an Amended Certificate of Environmental Compliance (CEC) authorizing SRP to build the natural gas peaking Coolidge Expansion Project to help integrate intermittent renewable resources.

SRP's Energy Mix

SRP's resource mix is constantly evolving to meet growing customer demands. The chart in Figure 2.2 summarizes SRP's latest energy mix delivered to customers from FY23.

FIGURE 2.2: ENERGY DELIVERED TO CUSTOMERS



May 1, 2022-April 30, 2023. All deliveries are actua
gigawatt hours (GWh) estimates as of November 20

Transmission System Overview

Transmission and distribution refer to the various stages of delivering electricity, from generating resources to a "load" such as a home or a business. The primary distinction between transmission and distribution is the voltage level at which electricity moves. At SRP, transmission refers to energized facilities at 69 kilovolts (kV) (69,000 volts) or higher.



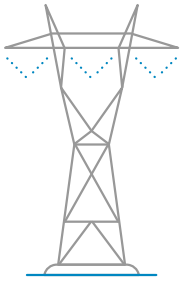
The transmission system is like the "interstate highway" of electricity delivery. It comprises three primary components: substations, switchyards and transmission lines. Both substations and switchyards are connection points where two or more transmission lines connect to form an "intersection."

The transmission lines are responsible for getting large quantities of electricity from the generation resources over long distances to the distribution system to deliver to customers. In some instances, larger energy customers connect directly to the transmission system.

SRP's transmission system is also part of a more extensive transmission network called the Western Interconnection, which ties SRP to other regional utilities and allows SRP to participate in wholesale power markets. The SRP transmission system is just a portion of this more extensive system with solely owned and co-owned lines with neighboring utilities. Being part of the Western Interconnection enables utilities to share generating resources to help balance the region's needs. Transmission Planning at SRP determines what new transmission infrastructure is needed to deliver energy reliably to SRP's service territory.

Transmission System Today

As of April 2023, SRP owns and/or operates and maintains about 3,333 circuit miles of three-phase power lines at 69 kV–525 kV voltages. Of these power lines, SRP owns approximately 955 miles of 69 kV, 263 miles of 115 kV, 493 miles of 230 kV and 361 miles of 525 kV. SRP jointly owns about 36 miles of 230 kV and 1,103 miles of 525 kV. These power lines and additional equipment, including over 1,200 circuit breakers and 72 transformers, make up the SRP transmission system today.



3,333 CIRCUIT MILES

Transmission Planning for the Future

As the demand for electricity in the Phoenix metropolitan area continues to grow, the need for new and upgraded transmission infrastructure also increases. Transmission infrastructure is planned to construct facilities and place them in service before they are needed. One of the significant challenges with planning the transmission system is the uncertainty around the location of the new electric demand and future generation resources. SRP proactively identifies and develops effective transmission solutions for current and future electric customers.

SRP is integrating low-carbon resources, such as solar, to meet our customers' growing electricity demand and replace retiring generation assets. This shift in our resource mix also impacts the transmission system. Some of the transmission-related challenges facing utilities are system voltage control, greater fluctuations in frequency, and increased risk of interruption due to forest fires. To best prepare for these transmission-related issues, we are shifting our planning practices to integrate consideration for all key planning areas. These new efforts will aid in developing plans to address grid needs across all of our planning areas holistically. This move also bolsters our efforts to achieve our 2035 Corporate Goals.

Distribution System Overview

The distribution electrical system includes the distribution substations and the infrastructure required to bring power safely and reliably to SRP customers. Distribution Planning is responsible for ensuring that we can serve the energy needs of current and future customers safely and reliably. This is accomplished by developing short- and long-term load growth plans and designing a highly configurable, robust looped system, allowing us to serve customers by multiple paths. If service from one path gets interrupted, we can still serve the customer from a secondary path. This configuration also allows us to reconfigure the system for optimal use of existing capacity.

This commitment to providing reliable power is why SRP has been ranked highest in customer satisfaction in the western United States among large electric utilities 22 times in the past 23 years that J.D. Power has been surveying residential electric customers.



Distribution System Today

As of 2023, SRP provides power to more than 1.1 million customers in a 2,900-square-mile service area. More than 1,198,000 advanced meters are serving SRP customers. Some of our customers are becoming increasingly involved with their energy future now more than ever by taking more of a prosumer role of consuming as well as producing electricity. In total, 51,287 customer-owned distributed energy resources (DERs) are interconnected with the SRP grid, including standalone solar generation, solar paired with battery storage, and standalone battery storage. Of those DERs, 50,468 are residential and 819 are commercial. These DERs provide a total generation capacity of 472 MW and a battery storage capacity of almost 16 MW.

Most of SRP's distribution system is looped, meaning there is more than one path that electricity can travel to serve a customer, but only one path at a time. SRP operates and maintains 21,736 circuit miles of lines that comprise the SRP distribution system, which entails 1,428 distribution circuits.

SRP operates and maintains 286 substations, including 191 distribution substations that transform power to the 12 kV voltage level to serve neighborhoods and other customers. A substation can accommodate one to four transformers, each serving 2,000–3,000 customers, depending on load requirements.

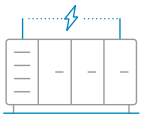
SRP is committed to providing reliable power, which is why we have ranked in the top 10 in the nation for our low System Average Interruption Duration Index (SAIDI) among all electric utilities with more than 500,000 customers every year for at least the past 10 years. This metric tracks the number of minutes customers are without power for more than five minutes averaged over all SRP retail customers. This includes any loss of customer load, planned or unplanned. SAIDI is an industry metric commonly used to assess overall power reliability.

1.1 MILLION+ CUSTOMERS

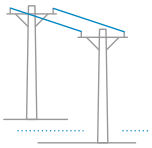


2,900-SQUARE-MILE SERVICE AREA

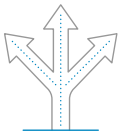
16 MW
DER BATTERY STORAGE CAPACITY



21,736
CIRCUIT MILES



286
SUBSTATIONS



Distribution Planning for the Future

The SRP distribution system is experiencing unprecedented growth due to a wide variety of new and expanding customers, including tech firms and advanced manufacturing. As more DERs, including solar generation and battery storage, are added to the distribution system, the possibility of voltage issues increases. The system is also experiencing an increase in electrification (EV adoption, smart appliances, etc.) that draws more of the load.

When we consider these factors, it becomes clear that we need to enhance our projection models of the distribution system and increase our ability to collect and analyze data. These efforts to plan for the changing grid will enable distribution planning to work collaboratively with other planning areas at SRP through an improved planning process.

Customer Programs Overview

Providing customers with reliable, affordable and sustainable service includes helping them understand and manage their energy usage through energy efficiency, demand response, electrification, EV and grid enablement programs. Customer programs enable us to effectively limit power plant emissions, lower costs, manage current demand and plan for future growth.



SRP has developed and fielded innovative customer programs and price plans to meet changing patterns in electricity use and customer needs. Demand Response (DR) programs such as smart thermostat and EV-focused programs and price plans encourage customers to shift energy usage to times energy is abundant and affordable. Looking to the future, we must evolve our programs to match the changing grid. Distributed energy programs enable the interconnection of thousands of customer-owned solar and battery systems each year. For customers unable to invest in their own renewable energy projects, SRP has invested heavily in system-scale solar and battery storage projects to offer unique solar energy programs that take advantage of economies of scale to help customers large and small achieve their individual sustainability goals. Customer programs will continue to meet evolving customer needs while spurring the transition to low-carbon energy for all customers.

Forecasting SRP customers' future energy demand (load) is one of the most important considerations for any long-term planning. We need to understand our customers' unique needs in order to plan for and maintain the reliability of SRP's transmission and distribution systems and have enough generating resources online to meet that load.

Customer Programs Today

For fiscal year 2023, SRP maintains a robust and comprehensive portfolio of customer programs; SRP's energy efficiency (EE) portfolio remains one of the largest and most cost-effective in the Southwest and across the country. For the 10th consecutive year, SRP was awarded the EPA's 2023 ENERGY STAR® Partner of the Year award with Sustained Excellence in recognition of outstanding delivery of Energy Efficiency programs.

Aside from EE and DR, SRP's growing Transportation Electrification programs are working to support the adoption of EVs and tackle the challenge of managing EV charging demands to avoid future on-peak hours. Electric Technology programs further support the electrification of fossil fuel-served loads today. In contrast, Distributed Energy programs support customer access to

utility-scale renewable energy projects and the interconnection of customer-owned solar and battery systems. SRP has also committed to developing programs like the Sustainable Energy Offering and others to partner with large customers with sustainability goals to reduce carbon emissions on a grand scale.

In fiscal year 2023, SRP's programs helped customers:

- Save 616,847 MWh — enough to power 37,000 homes annually — by:
    - Completing 70,000-plus residential efficiency upgrades and 1,200-plus commercial efficiency projects
    - Moving into 15,000-plus new, efficient homes and commercial spaces
    - Learning more about efficient, cost-saving behaviors (94,000 SRP Energy Scorecard™ and 148,000 SRP M-Power® participants)
    - Planting 5,300-plus drought-tolerant shade trees
- Develop 128 MW of dispatchable demand response capacity by:
    - Subscribing 87 MW of capacity through 76,143 smart thermostats in the residential SRP Bring Your Own Thermostat Program™
    - Enrolling more than 500 business customer facilities to deliver 41 MW of DR capacity
- Adopt 40,585 EVs within SRP's service territory and:
    - Install Level 2 or better charging for 3,300-plus EVs (581 business ports, 2,020 residential ports and 763 EV-ready homes)
- Electrify 15,897 MWh of business equipment load
- Achieve renewable energy goals by:
    - Commissioning 11,925 solar PV or PV+battery storage systems
    - Matching 100% of the electricity needs for 33 large commercial customers with 300 MW of dedicated solar energy through SRP's Sustainable Energy Offering (trimming carbon pollution in Arizona by 1.6 million tons)
    - Connecting 6,544 residential and small business customers to system-scale solar through the SRP Solar Choice™ program
- Avoid the consumption of 250 million-plus gallons of water through avoided generation and water efficiency embedded in the programs

Cutting carbon emissions by 1.6 million tons is equivalent to taking 300,000 cars off the road for a year!

SRP is committed to delivering programs and price plans that continually evolve to align with customer needs while maintaining a reliable, affordable and increasingly sustainable system. Despite recent achievements, there is a future need for even more energy efficiency to help maintain affordability by reducing customer energy consumption and pacing infrastructure investments. SRP has committed to accelerating its energy efficiency plans and goals while expanding demand response initiatives to help achieve established 2035 DR targets.

Customer Programs of the Future

As the population of SRP's service territory expands, we remain committed to meeting the growing needs of the communities we serve while staying focused on our 2035 Sustainability Goals. During our transition to a more sustainable future, the types and availability of low-cost resources will change with the increased adoption of renewables. As these changes occur, we will remain focused on striking the right balance of reliable, affordable and sustainable power for our customers. SRP continues to adapt its customer programs to meet changing patterns in electricity

use and needs by maintaining the acceleration of Energy Efficiency and Demand Response program plans to help address the significant load growth and capacity constraints SRP faces over the next several years.

As we plan further into the future, we must maintain affordability for our customers by continuing to leverage the existing infrastructure upgrades and expansion of customer program strategies to help reduce the need for costly new capital investments to meet near-term capacity needs. We must monitor how customers' energy usage and needs evolve and change as the digital economy drives how and when customers use power. Lastly, we must ensure customer programs will continue to help SRP cost-effectively meet growing customer needs while helping to address load growth and reliability challenges.

Uncertainties Facing SRP Today

While SRP's power system is transforming, other external factors also impact our planning efforts, including explosive load growth in SRP's service territory, evolving customer needs, supply chain volatility, regulatory policy uncertainties and resource adequacy uncertainty in the West. This section covers the significant drivers and trends we observed during our ISP planning efforts.

Explosive Load Growth & Evolving Customer Needs

The Phoenix metropolitan area continues to rank high in population growth nationally. For SRP, this growth means more customers, higher energy demand and increased peak demand. This demand is coming rapidly, putting pressure on us to develop solutions quickly. Demand has increased by 1.7% per year during the last decade, and these trends are expected to continue. While the SRP service area experienced extraordinary residential growth in the early mid-2000s, SRP is now experiencing unprecedented growth in the commercial and industrial sectors, including high-energy users such as semiconductor manufacturing, data centers and other high-tech industries.

Additionally, customers' energy usage and needs continue to evolve and change as the digital economy drives an evolution in how and when customers use power. These new customers not only need 24/7 power but also have specific power quality needs and an increased need for reliable power delivery. Large and small business customers are also driving renewable energy development needs for SRP, with an increased desire for partnership opportunities to help them achieve their sustainability goals.

Supply Chain Volatility

Volatility within the global supply chain impacts each group involved in SRP's integrated system planning process. COVID-19 exposed how quickly the interconnectedness of the global supply chain can lead to fewer suppliers, longer lead times, higher prices, material shortages and logistics challenges. Russia's war with Ukraine further exacerbated the disruptions to an already taxed supply chain and added to the uncertainty. Additionally, as inflation continues to rise, we can expect it to play a significant role in pricing in the future. Supply chain uncertainties are an essential factor in future planning and budgeting, as collectively or individually they can change the direction of our planning. Continuing to work jointly with our Supply Chain organization will enable us to find the flexible solutions needed to support our customers.

Regulatory Policy Uncertainty

Shifts in regulatory policies make it more difficult for SRP to make decisions because it is difficult to assign probabilities to possible future states confidently. Two policy developments that have a high potential impact on SRP's long-term planning efforts are the Inflation Reduction Act and the proposed EPA 111(b) and 111(d) rules.

Inflation Reduction Act

The Inflation Reduction Act of 2022 (IRA) was passed by Congress and signed into law by President Biden. SRP has traditionally contracted for renewable and energy storage projects through power purchase agreements (PPAs) with developers who could take advantage of previous tax credits. The IRA now provides SRP and other public power entities with access to direct pay credits for the first time, which may create the opportunity for SRP to receive federal incentives for self-built renewable and energy storage resources. The IRA could provide several potential benefits to power utilities; however, there are uncertainties about how the domestic supply chain will ramp up to meet increasing demand and what specific requirements must be met to qualify for IRA credits, given implementation guidance has not yet been issued.

Proposed EPA 111(b) and 111(d) rules

In May 2023, the EPA released its proposed carbon pollution standards for new, modified, reconstructed and existing power plants under sections 111(b) and 111(d) of the Clean Air Act. The regulatory package proposed standards for new gas-fired combustion turbines, existing coal and gas-fired steam plants, and certain large and frequently used existing gas-fired combustion turbines. The proposed standards are based on control methods and technologies (e.g., limited capacity factor, combusting hydrogen and installing carbon capture) that can be applied directly at electric generating units. If finalized, the 111(b) and 111(d) rules could help decarbonize the energy sector. Still, uncertainty remains regarding the availability and timing of the control technologies that the EPA relies on to reduce emissions.

Resource Adequacy in the West and the Impacts of Climate Change

SRP must maintain the ability to meet customers' energy demands at all times of the day and across a variety of system conditions. This resource adequacy requirement is becoming more complex as the utility industry transitions from conventional generating technology to renewables and storage. Reliable electricity supply is also becoming increasingly important to society as recent extreme weather events triggered regional outages that impacted customers and communities across the electric system. SRP routinely monitors the current trends affecting the desert Southwest region to understand better how to plan our investments and resources amidst uncertainty.

Because SRP is connected to an extensive grid system that includes neighboring utilities, the entire regional grid is at risk when one area or utility is not resource-adequate. Extreme temperatures also put pressure on utilities to maintain reliability by driving up customers' demand for more energy and fueling natural disasters such as wildfires that can damage the transmission system and limit utilities' ability to move power where their customers need it. The climate change impacts experienced over the last few years are expected to continue.

In light of the dramatic transition in the utility industry and the importance of regional resource adequacy, the SRP Board in January 2023 approved SRP's participation in the Western Resource Adequacy Program (WRAP), which is the first regional program of its kind in the history of the West. WRAP will deliver a regionwide approach to assessing and addressing resource adequacy. It will help ensure that entities use consistent planning approaches as utilities become increasingly reliant on variable resources like solar, wind and battery storage.

Technology Advancements

To achieve continued decarbonization while maintaining a highly reliable grid, SRP is monitoring, developing and deploying advanced low- and zero-carbon firm technologies such as clean hydrogen, long-duration storage and small modular nuclear. Accelerating the deployment of firm low-carbon energy solutions is required to continue to provide reliable and sustainable energy for SRP customers. Significant progress is being made around new nuclear technologies and long-duration storage that could provide reliable, safe and carbon-free generation in the future. Unfortunately, the current development timeline for some of these resources is over a decade. While today's market is experiencing some obstacles, a combination of new technologies, efficiencies in permitting and lower financial risk during construction may provide a compelling option for these resources in the future. Therefore, it is important for SRP to continue to pursue activities that preserve varying resource options, such as potential site locating and early permitting.

Planning for the Future

The electric power industry has undergone a dramatic transformation in recent years, and that transformation is expected to accelerate, driven by a variety of factors mentioned above, including:

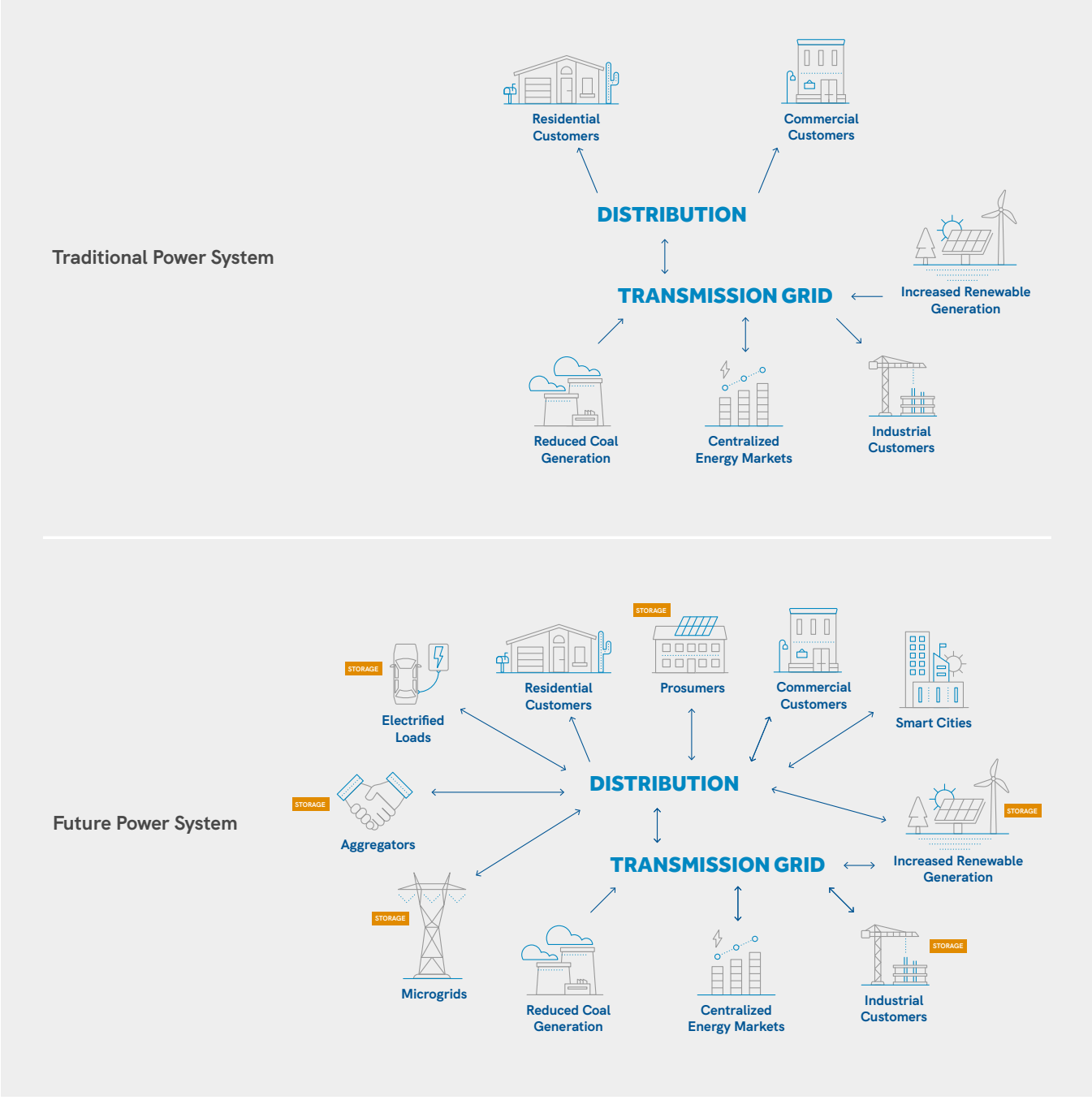
- Rapid deployment of large-scale variable energy resources (VERs) such as solar and wind
- The growth of distributed energy resources (DERs) like rooftop solar and residential battery storage
- Dramatic advances in digital energy and communications technologies
- Persistent low natural gas prices
- Increased reliance on just-in-time delivery of natural gas to support gas-fired generation
- Growing awareness of the electric sector's potential role in achieving environmental goals

While all of these external factors are changing, SRP is also evolving by integrating a significant number of low-carbon resources, such as solar, to meet our customers' growing electricity demand and replace retiring generation assets. This shift in our resource mix also impacts operations and the grid. Some of the transmission-related challenges facing utilities are system voltage control, more significant fluctuations in frequency, and increased risk of interruption due to forest fires. With these changes, traditional planning methods are increasingly insufficient to optimally develop a safe, reliable, affordable and environmentally responsible power system. Meeting our customers' needs over the next decade will require a complete transformation of the power system that touches all aspects of our business: how, when and where we generate and store electricity; how we deliver electricity over our transmission and distribution systems; and how we engage with our customers through rate design and customer programs. Our success

in this transformation depends on our ability to plan the system in an integrated fashion, allowing for close coordination and collaboration to identify the best solutions for our customers.

Integrated Resource Planning to Integrated System Planning

In the past, Integrated Resource Plans guided SRP's ability to plan long-term generation resource decisions by conducting structured analyses assessing risk and uncertainty. Given the many ongoing changes in the power sector, we must adapt these traditional planning methods to optimally develop a safe, reliable, affordable and environmentally responsible power system.



To best prepare for these impacts, SRP has transitioned from a conventional Integrated Resource Plan (IRP) solely focused on resource planning to a more holistic and comprehensive Integrated System Plan (ISP), including forecasting, resources, transmission, distribution and customer programs, to achieve our 2035 Corporate Goals.

An integrated system planning approach is necessary to meet changing customer needs, such as enabling two-way power flow for rooftop solar additions, managing charging of EVs, and anticipating the power system transition to a lower-carbon, increasingly complex grid. Given the effort needed to implement a holistic ISP, we focused on the period from 2025–2035 for our first-ever ISP, which will be covered in more detail in the next section.

SECTION 3

ISP Overview and Process

Why Integrated System Planning?

Historically, many of the planning functions that have existed within utilities have operated independently from one another. While planning processes for generation, transmission, distribution and customer programs have relied on some common data sets and exchanged some information, planning cycles are often asynchronous, focus on different objectives and planning horizons, and lack direct visibility into how quickly other parts of the system are changing. The most prominent of these planning processes, the utility Integrated Resource Plan (IRP), has traditionally focused exclusively or primarily on future generation choices with limited insight into the implications of those choices for other aspects of the utility's systems.

Given the rapid pace of change in the power sector, we identified a need to integrate planning within a single process — the Integrated System Plan (ISP) — to optimally develop a safe, reliable, affordable and sustainable power system. Planning decisions across the system must be coordinated to identify the best path forward for customers. For example:

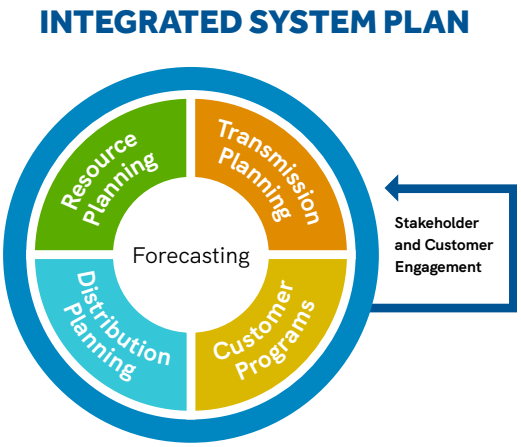
- Adoption of electric vehicles (EVs) will increase electricity demand, requiring additional investments in new power generation and delivery infrastructure. But if we can provide pricing signals to customers that encourage them to charge their vehicles during periods that are more advantageous for the overall system, we can limit the amount of new infrastructure investment needed. The most advantageous periods for charging will depend on future resource, transmission and distribution needs.
- Many of the new large-scale generation resources that we will consider — particularly renewables — will be located in areas where the existing transmission system may not be able to accommodate their delivery. Studying how the location of these new resources will impact the transmission system will provide a leading indicator of where new investment may be needed and may also allow for proactive siting of renewable resources to take advantage of transmission opportunities.
- As the share of solar generation in our portfolio increases over time, daytime energy will become increasingly abundant and lower the value of conservation during this period. This will have direct impacts on how we think about the value of future customer programs and the design of our future time-of-use price plans.

With this first ISP, we have transitioned to a holistic and collaborative planning framework that includes all key planning areas at SRP. By planning for the entire power system within one process, we are positioning ourselves to answer the most difficult multidisciplinary questions that will confront utilities in the coming years.

What is the Integrated System Plan?

SRP's ISP is a holistic power system roadmap that considers evolving customer needs for reliability, affordability and sustainability while achieving our 2035 Corporate Goals. The ISP includes all elements of meeting future customer demand: forecasting, power generation, transmission, distribution and customer programs. The ISP will help SRP plan for a future power system while maintaining a high standard of customer service from 2025 to 2035.

Before initiating the objective setting phase of the ISP, SRP retained Energy and Environmental Economics (E3), an energy consulting firm that works with utilities, regulators, policymakers, developers and investors to tackle the most pressing, difficult questions facing the electric industry. In our ISP — one of the first comprehensive efforts in the industry to initiate a systemwide planning process — E3's combination of broad experience, technical expertise and creative problem-solving made their support invaluable to our success. Further, having worked with each of Arizona's three largest utilities in support of integrated resource planning processes, E3 brought an understanding of our state's unique utility planning landscape that made their advice throughout the process germane and direct. At every step of the process, E3 was a vital partner for SRP, providing full-service support in the following areas: scoping the planning process; designing the analytical and stakeholder engagement frameworks; overseeing analysis and validation; and providing modeling support for the ISP process.



Objectives for the ISP

In April 2021, the SRP ISP project team and E3 concluded the objectives phase of the ISP after conducting many interviews and holding alignment workshops with SRP leadership. Through this process, the ISP project team received direction from senior leaders on the vision and objectives of the first ISP and received approval to develop a more detailed study plan.

ISP Vision Statement and Objectives

This vision, the goals and SRP's 2035 Corporate Goals guided the development of the ISP vision statement and objectives below.

"An ISP is a data-driven, collaboratively developed plan for generation, transmission, distribution and customer-sided resources to meet SRP's 2035 Corporate Goals and prepare for SRP's 2050 ambitions and system needs."

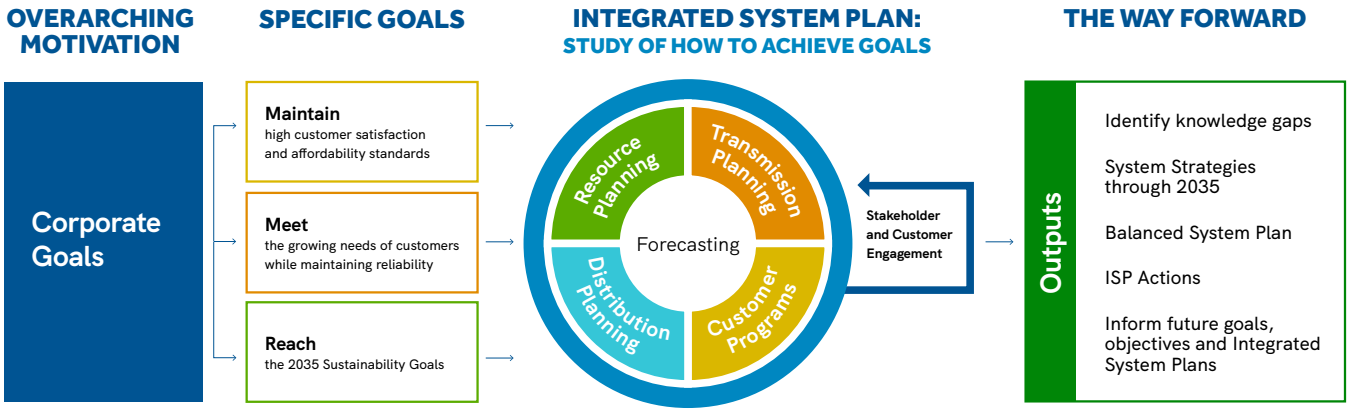
ISP objectives are to identify:

- Viable pathways for achieving SRP's 2035 Corporate Goals
- Costs, risks and trade-offs of these different pathways
- System solutions that are valuable across different pathways
- New capabilities or tools required to plan and operate as the system evolves effectively
- Activities SRP should undertake in the next six years to plan for these system solutions

SRP's 2035 Corporate Goals have been updated. The ISP leveraged goals established in 2019 and was completed prior to the 2024 updates.

Process for the ISP Development

The ISP process begins with SRP's Corporate Goals which establish the specific performance objectives of SRP and the motivation for the ISP. The ISP objectives relate to reliability, affordability and sustainability ("the what"), and the ISP determines how best to meet those objectives ("the how"). The ISP analytical process then combines the power system planning functions into an integrated planning framework to ensure that investments across the functional areas contribute together to support the corporate goals and objectives. In addition to the analysis, the ISP process included a comprehensive engagement process with customers and stakeholders to inform and gather input on the ISP and build support for the ISP outcomes. Key outputs of the ISP include a set of ISP Actions and longer-term System Strategies that help guide the development of SRP's power system through 2035.



The ISP analytical process, or "framework," was developed as part of the ISP objective setting process and involves conducting scenario analysis across the system functions to evaluate the cost and performance trade-offs and risks in achieving SRP's Corporate Goals. The process steps included:

1. Establishing an appropriate set of scenarios that evaluate key drivers of uncertainty outside of SRP's control.
2. Evaluating system needs for each scenario, subject to minimum reliability planning criteria.
3. Developing alternative solutions to meet the system needs for each scenario that consider key SRP decisions.
4. Synthesizing the scenario analysis to develop an illustrative Balanced System Plan that depicts the execution of ISP outputs, including System Strategies and ISP Actions, considering costs, performance and risk trade-offs metrics.

The objective development phase also included a stakeholder and customer engagement approach. SRP obtained the services of Kearns & West, a collaboration and strategic communications firm with experience in similar projects for other power utilities and an impartial approach to outcomes. Kearns & West offered input on establishing stakeholder groups and engagement methods, facilitated and documented meetings with stakeholders, and provided feedback on other aspects of stakeholder engagement. SRP, E3 and Kearns & West established a communications team, closely collaborating to create this approach. The communications team designed and executed all ISP stakeholder engagements, including scheduling, material

preparation and coordinating discussions with stakeholders internally and externally. The process included a review of best practices and lessons learned at SRP and other utilities. The effort also reviewed how other utilities capture residential and small commercial viewpoints in planning activities and consulted with SRP's Community, Communications and Marketing (CCM) organization to identify existing research resources and explore future approaches for gaining residential and small commercial customer input. Finally, the team consulted the CCM organization on best practices and options for stakeholder information sharing and regularly consulted SRP's 2017 IRP and Sustainability 2035 leads.

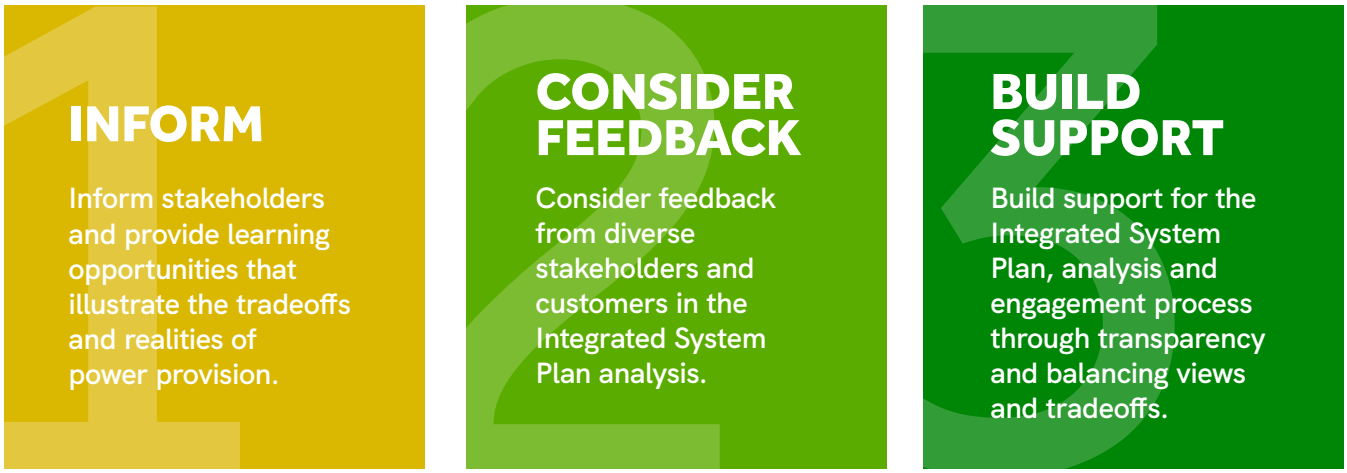
The stakeholder groups and customer engagement approaches are depicted below. SRP, E3 and Kearns & West also worked together to develop the details of the engagement approaches, including stakeholder group membership, roles, meeting topics and information sharing.

Stakeholder Group	Engagement Method
Advisory Group	• Focused engagement from a smaller diverse group • Regular meetings • ~20 representatives from diverse organizations • Role(s): Inform, Consult and Involve
Large Stakeholder Group	• Large-scale public platform • Eight meetings • Over 140 organizations • Role(s): Inform and Consult
Technical Working Sessions	• Small groups convened on specific topics with topical experts • Single sessions scheduled as needed around topics of interest • Role(s): Consult
Customer Research	• Multipronged approach to include the customer's voice • Surveys, customer preference elicitation, focus groups • Role(s): Consult

Role of the ISP Stakeholder Groups

A vital aspect of the ISP is developing and implementing a robust plan to actively engage customers and external stakeholders. SRP delivers power to diverse communities, individuals and organizations, and these stakeholders may hold varying views of the future and preferences for SRP's path forward. Providing information to stakeholders about the challenges SRP faces and collecting feedback on these challenges helped us roadmap a viable path forward. Inclusive, transparent and proactive dialogue with SRP stakeholders helped build support for the ISP process underlying SRP's strategic decisions. Much of the stakeholder and customer engagement efforts were planned to interact with the development of the ISP at specific touchpoints. These engagement efforts had the following three Global Goals:

FIGURE 3.1: ISP ENGAGEMENT GLOBAL GOALS



Transparency was essential in the development of the ISP. We designed the process to engage customers and other stakeholders and be responsive to their questions and input. In our best effort to keep transparency with all interested SRP stakeholders and customers, we posted all ISP stakeholder engagement materials publicly, including pre-reads, agendas, presentations and meeting summary reports, throughout the entirety of the project. These can be found on our ISP webpage at srp.net/isp.

Where We Needed Stakeholder Input for the ISP Process

Through the engagement tools described in the section below, SRP obtained input from stakeholders, including residential customers, regarding the questions proposed below. Their input helped shape all elements in the ISP study plan and informed the design on the final ISP outputs.

- Looking to 2035, what are Arizona's major sources of uncertainty relative to electricity generation, delivery, consumption and affordability?
- What system options should SRP include in its planning analyses for the future power system through 2035?
- What does success look like from your perspective when evaluating reliability, affordability and sustainability?

- What is the scope of the first ISP and which topics of interest should be considered for further research and future ISPs?
- What are the methods for balancing the trade-offs between reliability, affordability and sustainability?
- How might SRP improve our approach to stakeholder engagement for future ISP processes?

Stakeholder and Customer Engagement Tools

The ISP included customer research, technical working groups, large stakeholder group meetings, one-on-one discussions with interested stakeholders and the formation of an Advisory Group. This portfolio of engagement tools helped to achieve all three Global Goals described in Figure 3.1 on the previous page. Some groups focused more on bilateral dialogue, considering feedback and building support, whereas others focused on providing information to stakeholders and the public. The objectives and a brief description of each tool are given below.

The **Advisory Group** is made up of over 20 diverse community organizations and over 30 customer interest representatives. The group contributed wide-ranging expertise and perspectives to the ISP, which helped SRP produce a plan that reflects the diverse interests and values of the customers and communities we serve. Below are the mission and objectives of the ISP Advisory Group. For more information, please reference SRP's ISP Advisory Group Charter.

Mission Statement

The charge of the Advisory Group is to contribute wide-ranging expertise and perspectives to the ISP, resulting in an end product that integrates the diverse interests and values of the customers and communities SRP serves.

Objectives

- Create a dialogue around the ISP.
- Include diverse perspectives as input, guidance and review for the ISP.
- Provide a forum for deep and technical discussion of the trade-offs in energy system planning and the various perspectives to build support around the strategic directions and resource, transmission, distribution and customer program action plans.
- Focus communication for the Large Stakeholder Group.

Choosing a balanced and diverse group of stakeholders for the Advisory Group was critical to ensure that all perspectives were represented and that a single viewpoint was not dominant. To maintain balance, SRP chose members that were representative of one or more of the following stakeholder categories:

Local or special interest groups

- Community Advocates
- Equity Representatives
- Native American Interests
- Environmental Advocates
- SRP Resource Communities
- Public Interest Groups

Customer groups

- Commercial Customers
- Residential Customers
- Small Business Customers

Industry groups

- Energy Efficiency Industry Representatives
- Electric Vehicle Industry Representatives
- Renewable Energy Industry Representatives

Advisory Group Modeling Subgroups – Modeling subgroups were arranged as needed during the ISP process. Advisory Group members who were intensely interested in diving deeper into the ISP analysis self-selected into these subgroups. Efforts were made to include Advisory Group members who span stakeholder interests. Subgroup meeting discussions were reported in subsequent Advisory Group meetings. The Advisory Group's input, questions, ideas and concerns guided and initiated modeling subgroup meetings. If more than 50% of Advisory Group members were interested in participating in a specific subgroup, SRP would consider integrating the subgroup discussion content into the regular Advisory Group meeting series.

Large Stakeholder Group – This group of over 140 organizations was invited to eight meetings throughout the process. The meetings addressed informing stakeholders and considering feedback.

Mission Statement

To provide transparent communication to stakeholders regarding SRP's planning initiatives and allow for stakeholders to ask questions and provide feedback.

Objectives

- Keep stakeholders informed of SRP's planning initiatives in a transparent and proactive way.
- Build understanding of the trade-offs SRP faces and emerging trends in energy markets, regulations and technology.
- Provide opportunities for stakeholders to ask questions and receive answers from SRP experts.
- Provide feedback opportunities for stakeholders and consider their perspectives when balancing trade-offs while developing the ISP.

The Large Stakeholder Group was made up of over 140 organizations and 200 individuals, including representatives from SRP's customers and communities; 120 organizations were initially invited based on their existing relationships with SRP, standing within the Arizona community and diversity of perspectives. Types of organizations also included local and special interest groups, customer groups and industry groups. Throughout the process, SRP received many requests from individuals and entities to join the ISP Large Stakeholder Group outside of the initial organizations invited. They were all accepted and integrated into the process, resulting in a total of over 140 organizations at the end of the process. SRP strove to maintain inclusivity and representativeness within the Large Stakeholder Group so that the group reflected the diverse interests and values of the customers and communities SRP serves.

Technical Working Sessions – These sessions addressed specific technical topics of interest that arose throughout the ISP process and were attended by both external and internal SRP experts. The sessions leveraged external technical expertise for advice on the analytical methods used in

the ISP. The objectives of the Technical Working Sessions addressed considering feedback and building support and were to:

- Create a structured forum for external experts to give deep technical input to the most complex challenges in future planning.
- Build support around the ISP methodologies by leveraging external best practices.

Customer Research – This was a multipronged research approach that focused on understanding the preferences and perspectives of residential customers with the overarching goal of reflecting diverse customer voices and perspectives in the ISP. Customer focus groups and surveys were conducted to collect the preferences of SRP customers on balancing reliability, affordability and sustainability in potential energy futures. This data allowed SRP to consider the customer's perspective when choosing the best path forward. Customer research addressed bilateral dialogue, considering feedback and building support from our residential customers through the achievement of the specific following objectives:

- Co-create learning opportunities about the ISP and SRP's strategies, decisions and initiatives with customer input.
- Understand the energy/utility programs customers participate in and why.
- Understand customers' concerns about the future of Arizona, the economy and the United States.
- Align how customers plan for their futures and how secure they feel in their lot with the process and messaging of the ISP.
- Understand customer perspectives on power, reliability and potential trade-offs with sustainability.
- Understand the diverse perspectives and opinions on SRP's route to sustainability and how these opinions evolve.
- Include customer input into the ISP analysis and the balancing of trade-offs.

Guiding ISP Principles

These principles were developed in collaboration with ISP team and ISP Advisory Group members. The purpose of the Guiding ISP Principles was to balance all important considerations in developing an ISP. SRP strove to understand the inherent trade-offs between reliability, affordability and sustainability for the principles and sought to establish an ISP in accordance with these Guiding ISP Principles.

Integrated Long-Term View

Develop a holistic view, including resources, transmission, distribution and customer program perspectives, for meeting evolving customer needs and achieving our Corporate Goals for 2035 and beyond. The long-term view ensures that SRP is making the right decisions today to support its customers and stakeholders in the future.

Transparency

Engage customers and other stakeholders in a system planning process that is responsive to questions and input.

Measure Success Through the Eyes of Our Customers

Maintain industry-leading customer satisfaction by responding to evolving customer needs by providing safe, reliable, affordable and sustainable power while equitably recognizing the different needs, challenges and perspectives of our customers.

Manage Costs

Deliver exceptional system and energy value by minimizing impacts from additional grid needs and future uncertainties to average retail prices while maximizing customer value through diligent long-term-oriented cost management.

Build an Adequate and Reliable Power System

Meet (and in some cases exceed) industry standards to provide a dependable supply of electricity to all SRP customers. Provide a reliable grid that is able to prepare for and recover from both anticipated and unanticipated disruptions to ensure energy availability.

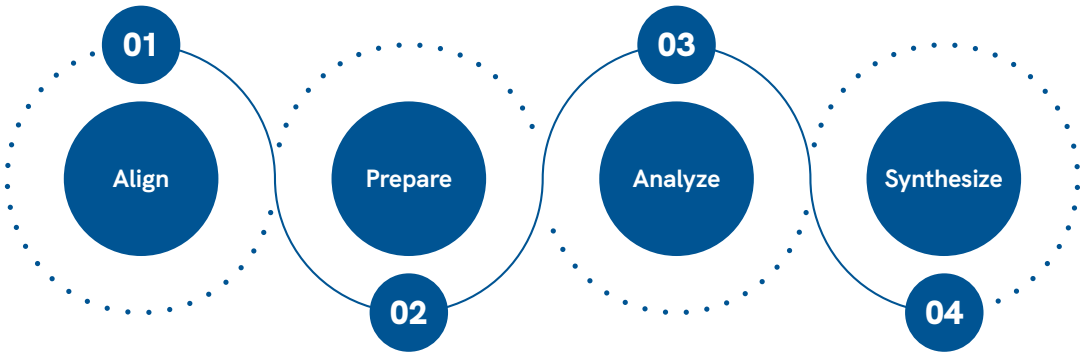
Adapt Toward a More Sustainable Future[1]

Meaningfully reduce carbon emissions and generation water usage to achieve SRP's 2035 Sustainability Goals to help address climate change and create less waste.

ISP Stakeholder Engagement Overview

Below is a summary of the stakeholder engagement process in the ISP and how we gathered and used internal and external stakeholder input to inform this first-of-its-kind planning effort in accordance with the above Guiding ISP Principles.

FIGURE 3.2: SRP ISP ROADMAP - STAKEHOLDER ENGAGEMENT



SRP ISP ROADMAP

Stakeholder Engagement

Align on Objectives of the first ISP

Collaboratively develop Study Plan:

Scenarios & Sensitivities Strategic Approaches Metrics

Gather input data

Perform system analysis

Validate and share results

Recommend new SRP system strategies

Recommend near-term actions

[1]The 2035 Sustainability Goals are being revised in 2024 in collaboration with community stakeholders. The next iteration of the ISP will focus on achieving and exceeding those revised goals.

Advisory and Large Stakeholder Group Engagements

For the initial Align Phase of the ISP depicted in Figure 3.2 on the previous page, SRP hosted four Large Stakeholder Group meetings over the summer of 2021. The SRP Summer Stakeholder Series was an opportunity to update, educate and engage with valued community stakeholders regarding SRP's efforts to transition from a traditional generation resource-focused Integrated Resource Plan (IRP) to a more holistic, comprehensive ISP inclusive of forecasting, customer programs, resource, transmission and distribution planning.

As shown in Figure 3.2, the Prepare Phase of the ISP stakeholder engagement strategy focused on creating a bilateral dialogue with stakeholders where they could comment, provide feedback and contribute their perspectives to the ISP analysis. This phase included customer research, one-on-one discussions with interested stakeholders, technical working groups, Large Stakeholder Group meetings and forming an Advisory Group. Together with community stakeholders, SRP set up a study plan that incorporated principles of scenario planning. This looked at how the future might unfold by analyzing key drivers, as well as the policy choices SRP could make and how those might perform in the future. We presented the co-created study plan for SRP's first-ever ISP to the Large Stakeholder Group on April 29, 2022.

Following along with the Figure 3.2 ISP Roadmap, at the end of April 2022, SRP kicked off the Analyze Phase of the ISP and conducted modeling through 2023. During this phase, SRP provided regular updates on ISP analysis to the Advisory Group as well as a final key findings presentation on April 21, 2023. Final key findings were presented to the Large Stakeholder Group on May 12, 2023.

As indicated in Figure 3.2, the final phase of the ISP was the Synthesize Phase, where SRP discussed with stakeholders and answered questions on viable pathways for meeting growing customer needs and achieving our 2035 Corporate Goals. SRP provided information to stakeholders about the trade-offs SRP faces, and collecting feedback helped SRP design a pathway moving forward. Inclusive, transparent and proactive dialogue with SRP stakeholders helped to build support for the first-ever ISP that will help guide major SRP strategy decisions.

Technical Working Sessions

In response to stakeholder feedback received throughout the objectives setting phase of the project, SRP developed Technical Working Sessions around topics of interest that stakeholders wanted to explore further. Starting in January 2021, SRP hosted four Technical Working Session webinars where experts from SRP and from around the country explored special topics. During 2022, SRP surveyed stakeholders to gauge their interest in different technical topics to help inform the topics for these sessions. The four sessions included the Inflation Reduction Act, inverter-based resources, regional market developments, and evolving time-of-day use programs.

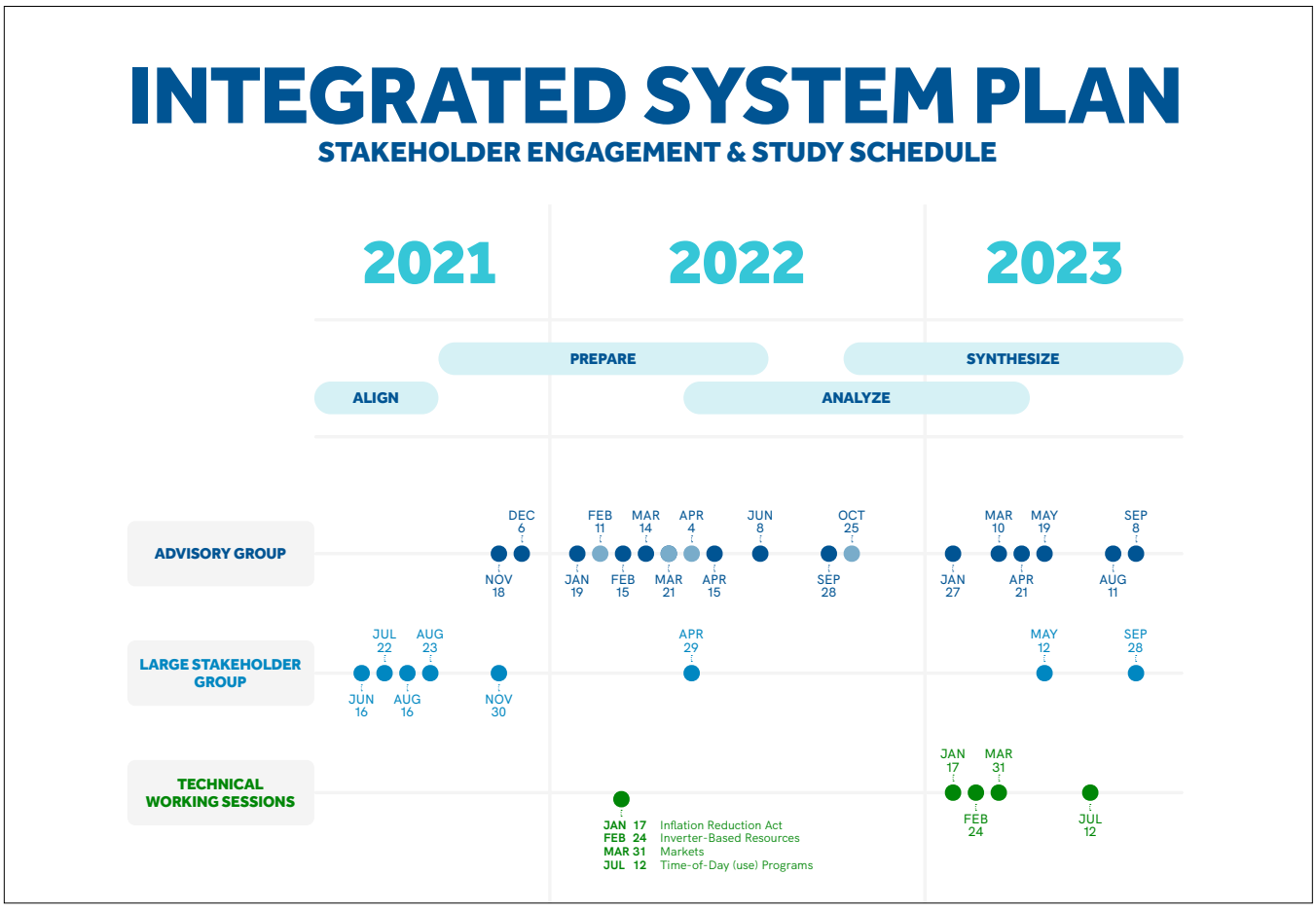
During these sessions, SRP shared work that has been done to date by our team in relevant areas. Each Technical Working Session featured a moderated panel discussion where external experts in relevant areas from around the country were invited to share leading industry experience and discuss potential enhancements SRP could undertake in future planning activities. Through these webinars, we had the opportunity to learn alongside stakeholders, gather input from these stakeholders, collect expert opinions in relevant topical areas and discuss potential enhancements applicable to SRP's system.

Customer Research

Throughout the process, SRP partnered with research consultant Bellomy Market Intelligence to execute the effort to bring the voice of SRP's residential customers into planning the future power system. Bellomy is a full-service market research firm that partners with healthcare, retail, financial, energy and consumer product companies to identify insights and strategic business implications derived from those insights. Having been immersed in the industry for over 25 years, Bellomy understands utility and energy clients' unique needs in regulated and deregulated landscapes. The customer research was a three-phased approach that started with phase 1, virtual focus groups (December 2021), followed by phase 2, quantitative confirmation survey (March 2022). The first two phases of research results were provided to Advisory Group members for consideration in designing the ISP study plan elements. Finally, for phase 3, a choice exercise was executed (May 2023). This research was designed to understand how customers think about reliability, affordability and sustainability related to power provision and gauge their reactions to a potential energy plan. All customers included in the research were SRP residential customers who were considered to be energy decision-makers and who did not work for a competing industry and were over 18 years old.

By using these engagement tools, SRP effectively collaborated with stakeholders and customers to build support for a shared vision for the future of the power system with 31 stakeholder meeting engagements executed and a multipronged residential customer research effort throughout the process, depicted in the timeline below.

FIGURE 3.3: ISP ENGAGEMENT TIMELINE



Transparent and Engaging ISP Process

SRP considered customers and community stakeholders essential partners in building a reliable, affordable and sustainable future power system. The holistic study plan was developed with input from SRP subject matter expert, customer and stakeholder feedback. The SRP project team, consisting of representatives from Forecasting, Resource Planning, Transmission Planning, Distribution Planning, and Customer Programs, performed a first-of-its-kind systemwide scenario analysis that allowed SRP to test strategies for building the future power system across a wide range of futures. Based on learnings from that analysis, the project team developed and shared with stakeholders the ISP key findings that identified costs, risks and trade-offs to consider when planning the future power system.

ISP PLANNING PROCESS FAST FACTS

NUMBER OF ADVISORY GROUP MEMBERS:

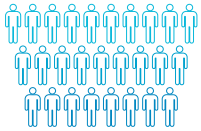


32
community representatives



from **23** organizations

NUMBER OF LARGE STAKEHOLDER GROUP MEMBERS:



250
community representatives from
143
organizations



SLIDES PRESENTED

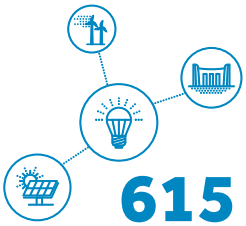
NUMBER OF MEETINGS:



31 stakeholder meetings



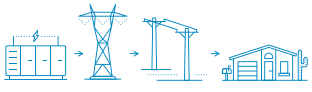
totaling over **62.5** hours of content



615
POINTS OF FEEDBACK COLLECTED AND INTEGRATED INTO THE ISP

1,411
RESIDENTIAL CUSTOMER SURVEYS CONDUCTED



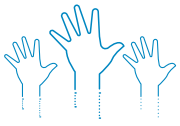


42
SYSTEM PLANS CROSS-FUNCTIONALLY ANALYZED



4
90-MINUTE RESIDENTIAL FOCUS GROUPS CONDUCTED

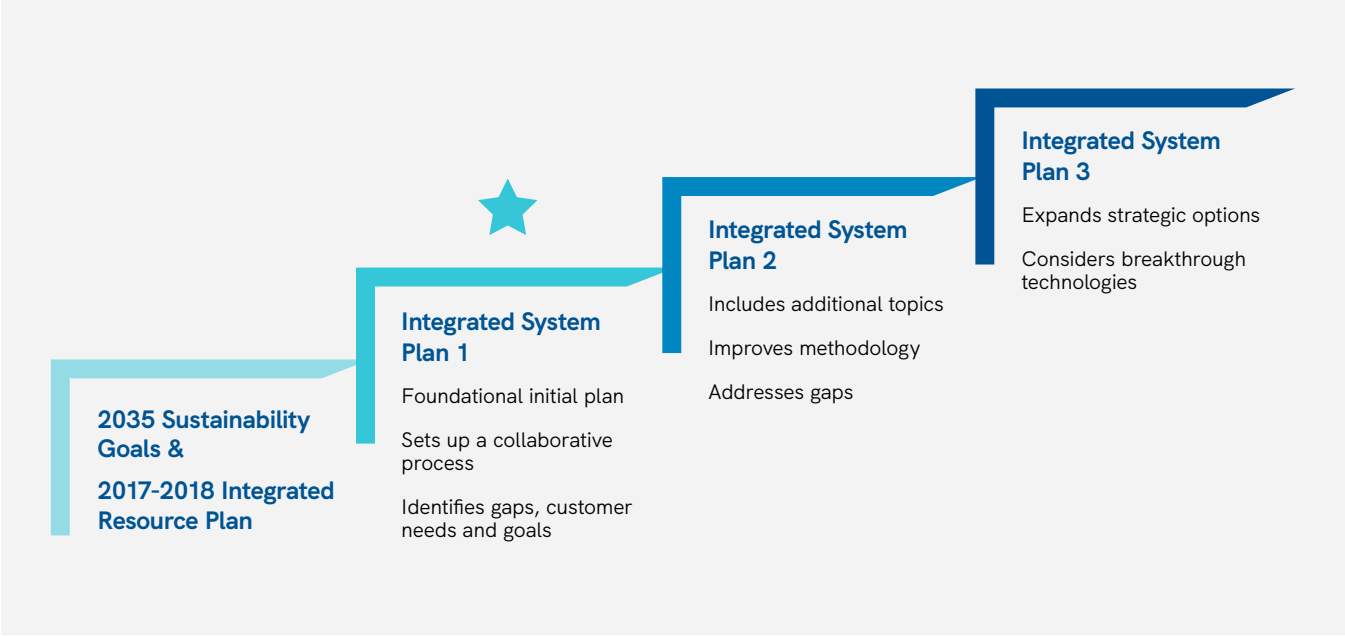
STAKEHOLDER QUESTIONS ANSWERED:
588



ISP Evolution

The scope of the ISP will evolve as SRP's planning groups gain experience and develop new capabilities. Participants in the objective development phase explored and discussed both the long-term vision and initial scope of ISP. Planning groups aligned on the importance of tackling a reasonable scope for the first ISP and building toward a long-term vision over time. One vision for what that evolution could look like is depicted below in Figure 3.4.

FIGURE 3.4: ISP LONG-TERM VISION



The initial ISP, or ISP 1, includes three key enhancements to current planning practices agreed to by the ISP team. The enhancements include consistent scenario and sensitivity analysis across the planning areas, incorporating transmission capacity headroom and expansion costs with supply-side resource planning, and expanding and enhancing the avoided cost framework to better evaluate customer programs. The process could evolve in future ISPs as new capabilities and tools are developed to be more cyclical. The pace and scale of ISP evolution will largely be determined by the experiences and lessons learned with ISP 1 and continued SRP exploration. The ISP enhancements for ISP 2 and ISP 3 in Figure 3.4 are illustrative and reflect stepwise progress of the potential elements identified in the long-term ISP vision.

Lastly, as part of the objective development engagement, the ISP team began a preliminary exploration of how the existing planning and sustainability processes might integrate with the ISP process in the future and the related issue of the cadence or frequency of the ISP. Consistent with the measured approach to the scope of ISP 1, the group generally agreed that gaining experience through ISP 1 would be helpful to inform future discussion on these topics.

The remainder of the report will describe the ISP 1 methodology, analytical framework, modeling results and critical findings that helped shape the concluding ISP deliverables, including System Strategies, ISP Actions and an illustrative Balanced System Plan.

SECTION 4

Scenarios, Sensitivities and Strategic Approaches

Scenario Framework

The decisions SRP makes today must withstand the risks and uncertainties of any future. Therefore, we utilized a scenario planning framework to test how different strategic decisions perform in an uncertain future.

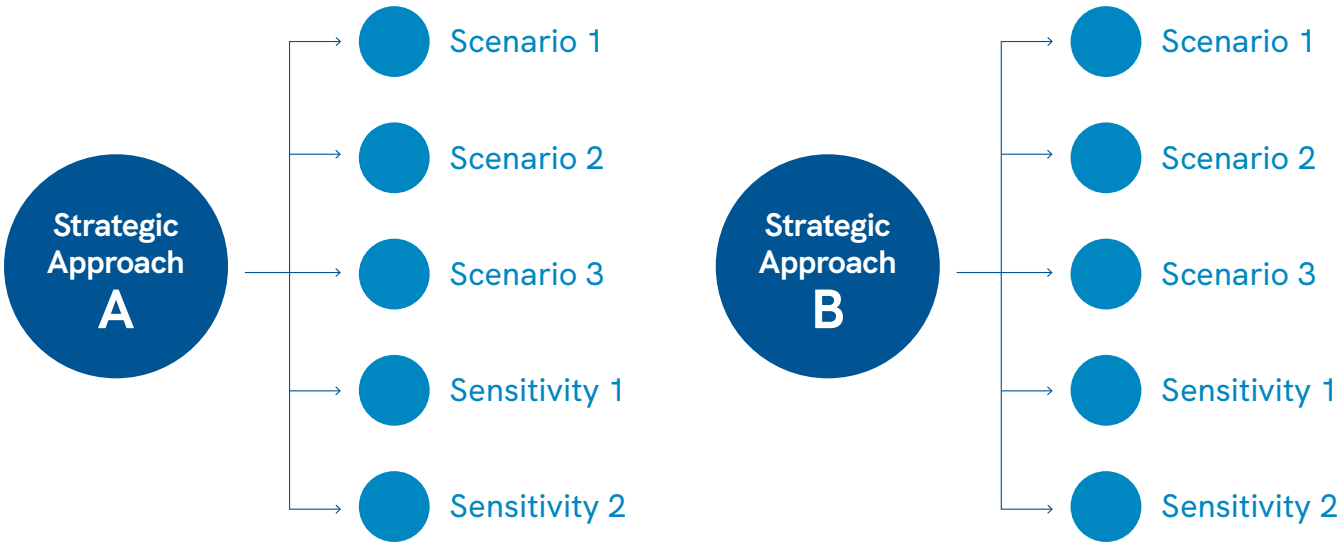
The scenario planning framework used for the Integrated System Plan included three key elements: scenarios, sensitivities and strategic approaches. Scenarios defined plausible future states of the world around us, reflecting societal, technological, economic, environmental and political trends and conditions. These factors are outside of our control and reflect the unpredictable nature of the future that needs to be accounted for in SRP's planning activities. Sensitivities, like scenarios, capture future states of the world around us but vary a single planning assumption. Finally, strategic approaches represented possible decisions that we could make in planning the future power system. These decisions are fully within our direct control.

FIGURE 4.1: SCENARIO DESIGN FRAMEWORK



In the Integrated System Plan, each strategic approach was tested against each of the future scenarios and sensitivities. This allowed us to examine the performance of each strategic approach under different futures and identify the components that best achieved SRP's goals, supporting the development of a robust system plan that positions SRP to take advantage of opportunities and react quickly as changes occur.

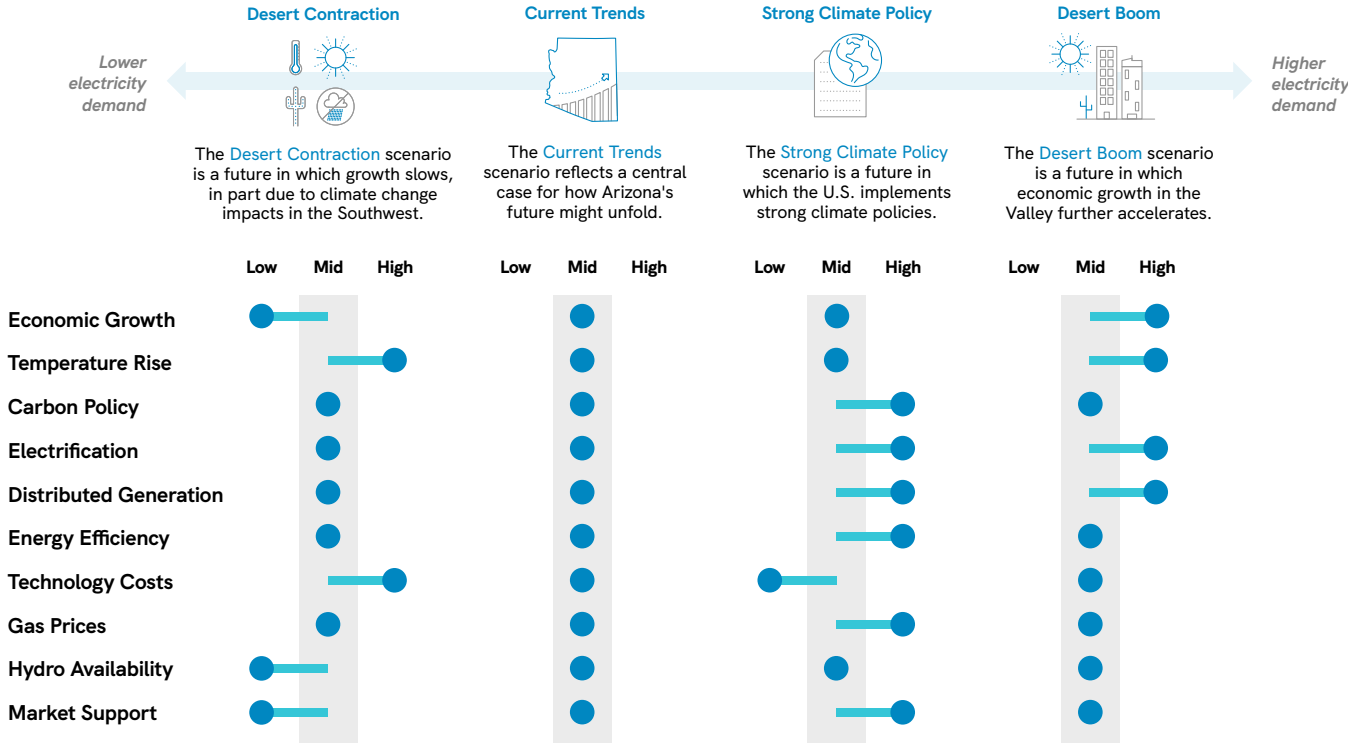
FIGURE 4.2: SCENARIO ANALYSIS



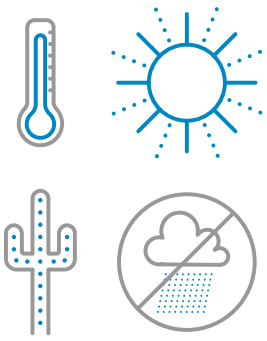
Scenarios

In collaboration with community stakeholders and based on results from customer research efforts, we developed four scenarios to analyze in the first Integrated System Plan: Desert Contraction, Current Trends, Strong Climate Policy and Desert Boom. The four scenarios considered many of the different external factors that can affect SRP's business environment and were designed to reflect a range of diverse yet plausible futures. Figure 4.3 below shows the four scenarios including how each external driver changed across the scenarios.

FIGURE 4.3: SCENARIOS



The following subsections describe each scenario in more detail and the key drivers associated with each scenario.

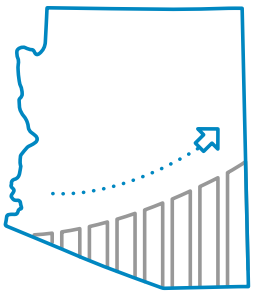


Scenario: Desert Contraction

The Desert Contraction scenario envisions a future where Arizona becomes a less desirable place for people and businesses due to a slowing economy and worsening climate conditions, which negatively impact residential and commercial growth. Additionally, global competition and consolidation initiates an exodus of large industry from the Valley, creating a cascading effect for the state's population. As a result, electricity demand in SRP's service area falls well short of current projections. Climate change also affects the region's watersheds, as declining rainfall throughout the West leads to lower reservoir levels along the Colorado River.[1] The corresponding reductions in generating capacity at large hydroelectric power plants significantly stress power markets, especially during peak demand periods.

[1]The Salt and Verde watersheds are more resilient to climate change and are unaffected in this scenario.

Key Drivers	Descriptions
Economic Growth	Higher summer temperatures and water supply issues stifle growth in the Southwest, limiting new migration and reversing expected growth trends. Large commercial and industrial customers emigrate out of Arizona and population growth levels off over time.
Climate Change	The Southwest experiences accelerated temperature rise consistent with the Intergovernmental Panel on Climate Change's (IPCC's) pessimistic Representative Concentration Pathway (RCP) 8.5 scenario, resulting in warming to the region that is more severe (0.91°F increase per decade). These conditions exacerbate current regional drought conditions, resulting in Lake Powell dropping below minimum power production levels for hydrogeneration from Glen Canyon Dam starting in 2025.
Policy	A worsening climate and intense global competition increase economic pressure on governments, resulting in a failure around the globe to adopt more consistent and aggressive carbon emission reduction regulations. While SRP remains committed to its 2035 Sustainability Goals, no federal or state sustainability policies are passed that supersede these goals.
Customer Participation (EE, DG, electrification)	Spurred by the worsening impacts of climate change and the lack of cohesive federal climate action, more and more Arizonans prioritize sustainability. Therefore, adoption rates for electric vehicles (EVs), heat pumps, and distributed solar and batteries increase. Growing adoption rates for these customer-sided technologies are tempered by lower overall population growth.
Technology	Increased global market competition, prolonged supply chain issues and stagnant economic growth in the Southwest raise material and labor costs, slowing the decline of renewable and storage costs. Tax credits provided through the Inflation Reduction Act help to reduce costs, although a stretched labor market makes qualifying for such credits expensive.
Market Dynamics	Extreme heat waves, wildfires and the loss of power capacity at Glen Canyon Dam as well as other hydrogeneration in the West lead to constrained regional markets that cannot be relied upon during peak periods.

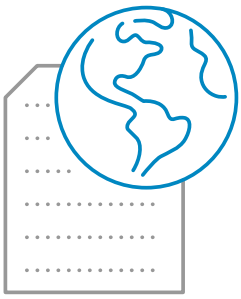


Scenario: Current Trends

The Current Trends scenario presumes that the large-scale changes currently underway in society, the region and the utility sector continue, resulting in substantial changes for SRP and Arizonans by 2035. Population in the Valley grows at a steady pace as the affordable cost of living and pleasant weather most of the year in the Phoenix area continue to attract new residents from California and surrounding states. With land availability, a competitive workforce, a geographical location in the middle of large markets (including California, Texas and Mexico), and with local and federal support of industries such as domestic semiconductor manufacturing, Phoenix becomes increasingly attractive to large commercial and industrial businesses. Data centers and manufacturing companies continue to move into the Valley, creating more jobs and bringing even more growth for Arizona. Some of these companies have significant load requirements measured in the hundreds of megawatts, much larger than those seen in the past. EVs gain popularity due to the broadening availability of vehicle models and improving charging infrastructure across the nation.

Key Drivers	Descriptions
Economic Growth	Continued growth is sustained in the greater Phoenix area, driven by continued migration and expansion in commercial and industrial business activities.
Climate Change	Climate change impacts are consistent with the projected RCP 4.5 scenario modeled by the IPCC, which envisions global emissions dropping below 2005 levels by 2100. Temperatures increase moderately (0.67°F per decade), while current drought conditions in the West persist but do not worsen throughout the study period.
Policy	While the Inflation Reduction Act provides a strong, sustained economic stimulus to support clean energy development, further federal action on climate policy is limited: Partisan politics continue to create a gridlock that prevents adoption of any comprehensive federal climate policy. In the absence of federal policy, state governments, utilities and corporations continue to drive advancements toward clean energy and sustainability goals. Like many other utilities in the region, SRP continues its independent efforts to meet voluntary sustainability goals.

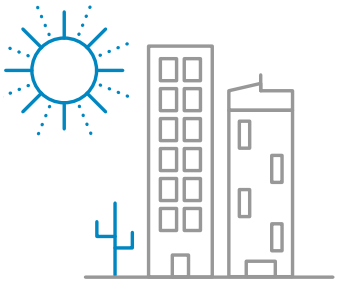
Customer Participation (EE, DG, electrification)	SRP continues to be a regional leader in offering energy efficiency and demand response programs to customers. The number of light-duty EVs increases significantly by 2035, benefiting from strong federal policy support provided in the Infrastructure Investment and Jobs Act, and consistent with SRP's current 2035 Sustainability Goals. Cost declines of distributed solar and batteries drive increased adoption by residential and commercial customers.
Technology	Renewable and storage technologies continue to advance over time, leading to sustained cost declines. Tax credits provided through the Inflation Reduction Act make carbon-free resources even more competitive, but the cost reductions are partially offset by continued supply chain constraints driven by a large spike in demand. Emerging technologies such as small modular reactors, natural gas power plants equipped with carbon capture and green hydrogen production become commercially available in the 2030s.
Market Dynamics	Diversity in load and generation resources across different Balancing Authority Areas in the Southwest allows SRP to rely on market purchases to meet part of its electricity demand when necessary and economical. Natural gas prices increase moderately over time, reflecting increased demand.



Scenario: Strong Climate Policy

The Strong Climate Policy scenario reflects a future where political consensus is reached on the need for swift and decisive action to combat climate change, resulting in several new policies and measures at the U.S. federal level. These policies are guided by an economywide net-zero emissions target by the year 2050, resulting in mass-based emissions reductions targets for electric utilities throughout the country by 2035. Decarbonization policies also impact demand: The pace of electrification in the building and transportation sectors accelerates, causing demand for electricity to increase, and government support for energy efficiency measures results in improvements in efficacy, reduction in cost and more widespread adoption. These two effects are offsetting but change the patterns and timing of electricity consumption. Extensive research and development support of clean energy resources advances power companies' operational learning curves and accelerates cost declines. Such cost declines also impact distributed generation on the customer side and create favorable conditions for the adoption of solar and storage systems. A Regional Transmission Organization (RTO) or a regional resource adequacy program would be established in the Southwest, allowing power companies to better take advantage of load and resource diversity in the region.

Key Drivers	Descriptions
Economic Growth	Growth is sustained as large commercial and industrial customers continue to migrate to the Valley. Furthermore, electricity demand is accelerated by rapid electrification of the building and transportation sectors.
Climate Change	Through 2035, temperatures in the Southwest remain consistent with the IPCC's RCP 4.5 scenario. Temperature increases moderately (0.67°F per decade), while current drought conditions in the West continue throughout the study period.
Policy	The U.S. federal government implements a suite of comprehensive policies to address climate change. These policies are designed around an economywide net-zero emissions target by 2050.
Customer Participation (EE, DG, electrification)	Stronger federal codes, standards and incentives lead to high energy efficiency growth. Technology improvements and rapid cost declines drive accelerated distributed solar and battery adoption among SRP's residential and commercial customers. The number of light-duty, medium-duty and heavy-duty EVs as well as heat pumps increases significantly, with federal support for these technologies.
Technology	Additional federal tax incentives, research and development investments, and increased deployment of clean energy resources advance learning curves, driving significant cost declines for renewables and storage and accelerating the commercialization of emerging technologies. Domestic manufacturing is able to keep up with demand, and no price increases from supply chain constraints are expected.
Market Dynamics	Federal policy support, incentives and subsidies drive increased transmission buildout across the nation. An RTO or a regional resource adequacy program would be established in the Southwest region, and system planning is conducted at a regional level. The regional planning paradigm and operational coordination allow the Balancing Authority Areas in the region to better take advantage of regional load and resource diversity, lowering the planning reserve margin SRP requires. More aggressive policies related to the natural gas supply chain increase natural gas prices.



Scenario: Desert Boom

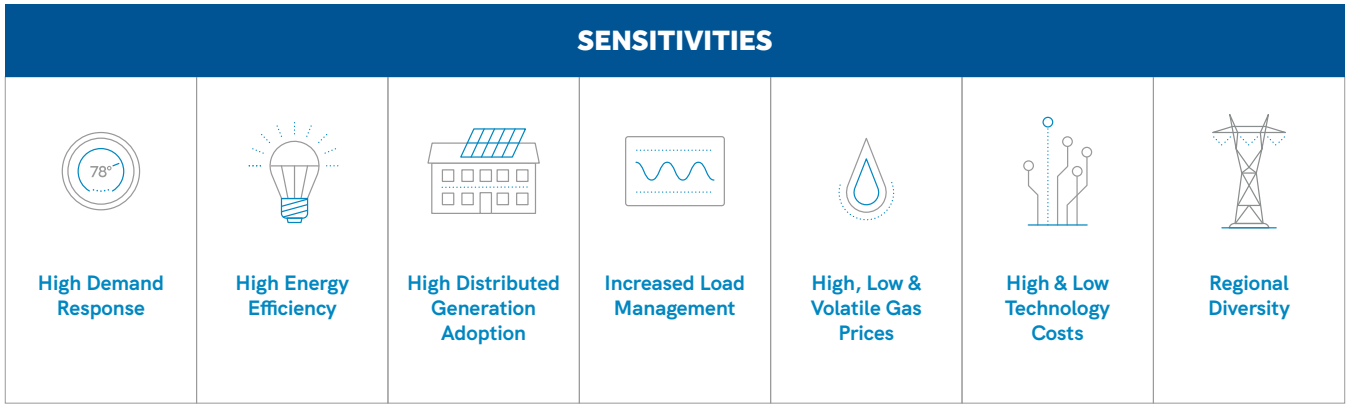
The Desert Boom scenario is characterized by explosive growth in SRP's service territory. Arizona becomes a regional energy, technology and manufacturing hub, creating a second "Silicon Valley" in the Phoenix metropolitan area. Economic growth in the Phoenix metropolitan area accelerates far beyond current projections and is led by a strong global technology industry and a supportive environment in Arizona. Electricity demand increases significantly with accelerated economic activity, growth in energy-intensive businesses and increased energy exports. Arizona's central location, affordable cost of living and skilled workforce attract an influx of people and businesses to the area. Strong economic growth supports accelerated EV and heat pump adoption, adding more electrification loads to the grid. Increased availability of distributed solar and battery technology helps mitigate system demand but not at the scale needed to provide full grid backup.

Key Drivers	Descriptions
Economic Growth	Growth accelerates significantly as Arizona becomes a regional energy, technology and manufacturing hub.
Climate Change	Climate change accelerates around the globe due to both climate policy inaction and strong global economic activity. Greater temperature rise occurs (0.91°F per decade) consistent with the Intergovernmental Panel on Climate Change (IPCC)'s pessimistic Representative Concentration Pathway (RCP) 8.5 scenario while current drought conditions in the West continue throughout the study period.
Policy	Governments around the globe prioritize economic growth over carbon emission reductions in the midst of an economic boom. SRP is committed to its 2035 Sustainability Goals, and no federal or state sustainability policies are passed that supersede these goals.
Customer Participation (EE, DG, electrification)	Population growth and higher incomes accelerate adoption of light-duty EVs, heat pumps, and distributed solar and batteries.

Technology	Renewable and storage technologies continue to advance over time, leading to sustained cost declines. Tax credits through the Inflation Reduction Act make carbon-free resources even more competitive, but the cost reductions are partially offset by continued supply chain constraints driven by a large spike in demand. Emerging technologies such as small modular reactors, natural gas power plants equipped with carbon capture, and green hydrogen production become commercially available in the 2030s.
Market Dynamics	Diversity in load and generation resources across different Balancing Authority Areas in the Southwest allows SRP to rely on market purchases to meet part of its electricity demand when necessary and economical. Natural gas prices increase moderately over time, reflecting continued demand growth and declining supply.

Sensitivities

In addition to the scenarios, SRP also analyzed 10 sensitivities under the Current Trends scenario. A **sensitivity** varied a single assumption in the Current Trends scenario, allowing SRP to understand the impact of the assumption on the overall system plan. Sensitivities were analyzed under the Current Trends scenario to assess the impact of varying individual assumptions on the system plan at a central case of potential future load growth. Details on the assumptions used for each sensitivity are included in Section 5: Methodology.



In the graphic above, the "High, Low & Volatile Gas Prices" icon encompasses three sensitivities, including High Gas Prices, Low Gas Prices and Volatile Gas Prices. The "High & Low Technology Costs" icon encompasses two sensitivities, including High Technology Costs and Low Technology Costs.

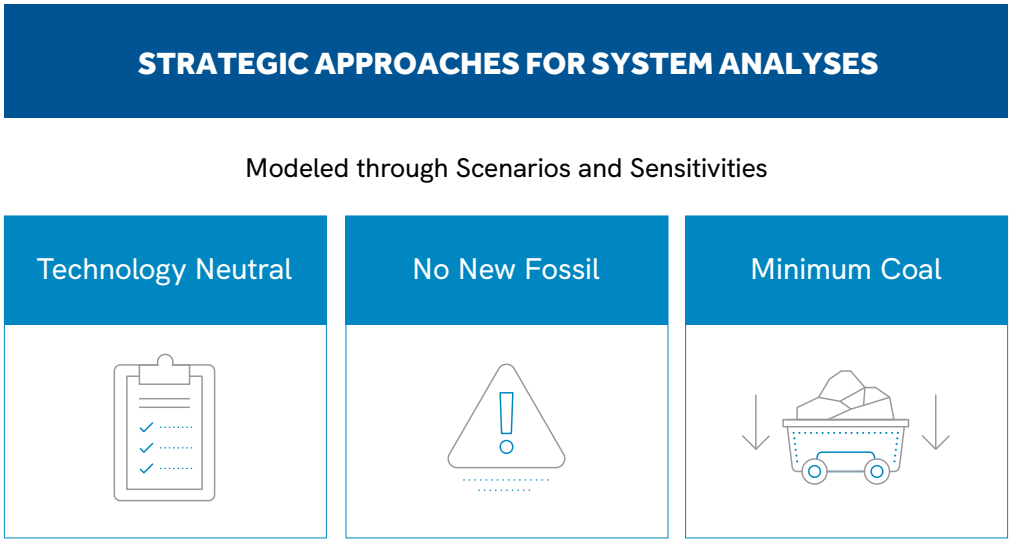
Strategic Approaches

SRP developed three strategic approaches to analyze in the Integrated System Plan. The three strategic approaches were analyzed across each of the scenarios and sensitivities described above.

The **Technology Neutral** strategic approach aims to develop future system plans on a least-cost basis to meet reliability and sustainability goals without any preferences for or restrictions upon the specific technologies included in the portfolio.

The **No New Fossil** strategic approach seeks to meet future system needs with exclusively carbon-free resources, excluding investment in new natural gas resources from consideration. Existing natural gas units remain in service and are still used to meet customer needs. Further, no changes to planned coal retirement dates are included in this strategic approach.

The **Minimum Coal** strategic approach aims to reduce power generation from coal in SRP's system by testing operational changes to SRP's coal resources, including seasonal operations and the full retirement of coal by 2035. This strategic approach builds upon the No New Fossil approach described above, meaning that all new generation resources must not rely on fossil fuel technologies.

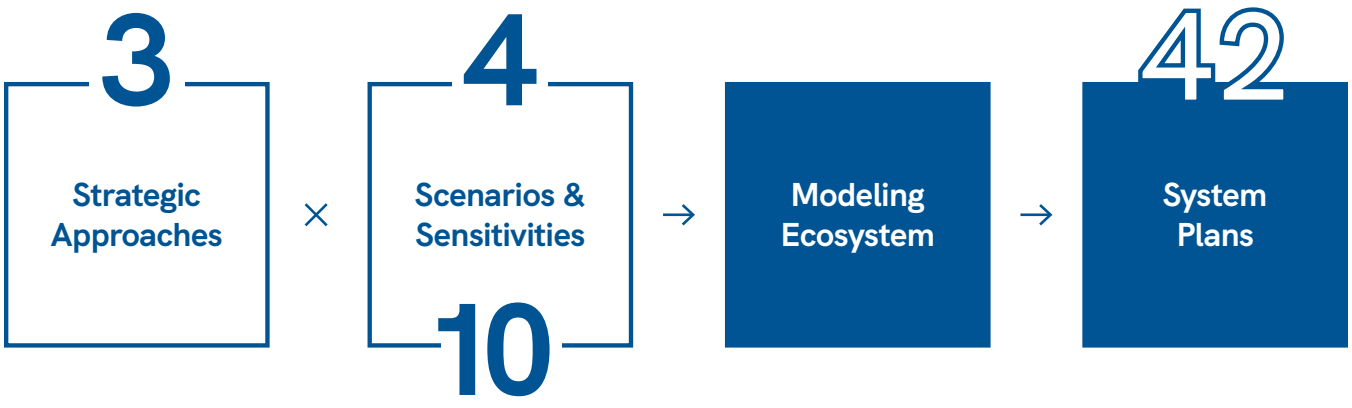


SECTION 5

Methodology

Methodology Overview

As discussed in Section 4, the ISP tested three strategic approaches across four scenarios and 10 sensitivities to evaluate 42 different planning cases. For each of these planning cases, SRP developed a system plan for the years 2025–2035 which included customer programs, distribution investments, transmission investments and resource additions.



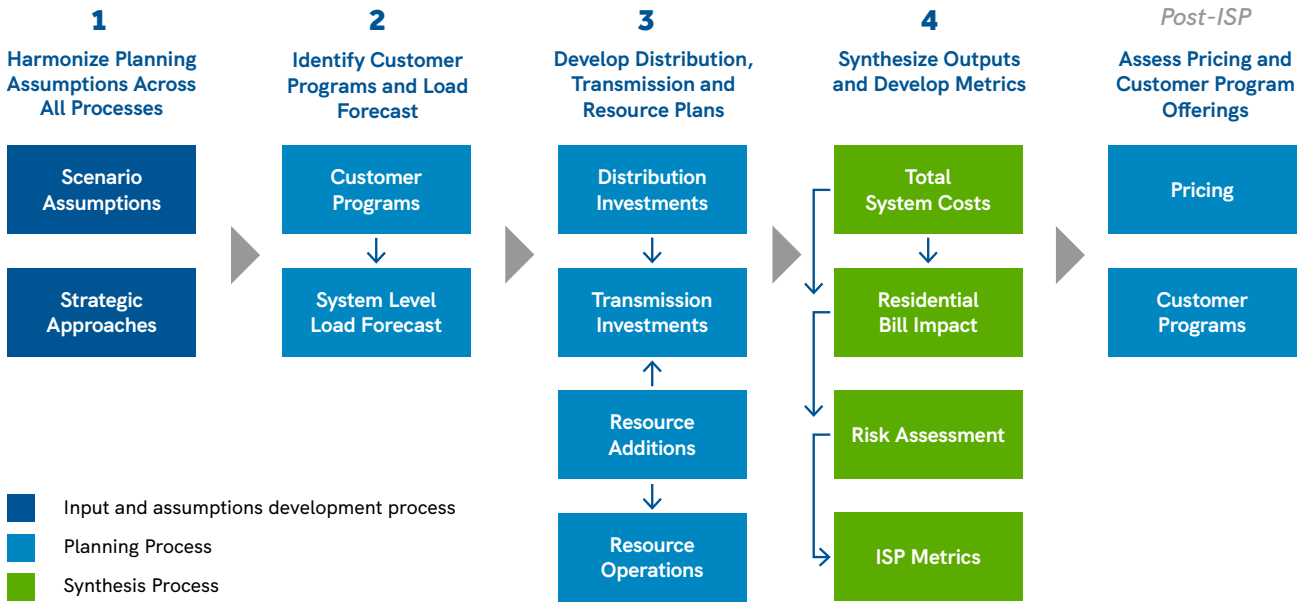
Our team evaluated and compared these plans by developing metrics to understand how each strategic approach performs across different futures and to identify the system components that could help SRP deliver a reliable, affordable and sustainable future power system. While we cannot know what the future will hold, assessing system plans across a variety of potential futures allowed us to identify strategies to mitigate future risks and take advantage of potential opportunities. This section describes the modeling ecosystem, key modeling inputs and metrics that we utilized to develop and evaluate each of the system plans.

Modeling Ecosystem

This first-of-its-kind ISP required a new approach to perform comprehensive system planning. Because there was no single planning model available that we could use to analyze all parts of the system simultaneously, we needed to develop an analytical ecosystem that included multiple planning processes, each with its own model(s). Each planning process utilizes the same planning assumptions, and then results from one planning process feed into other planning processes to help us create integrated system plans. An overview of this modeling ecosystem is shown in Figure 5.1.



FIGURE 5.1: MODELING ECOSYSTEM OVERVIEW



For a given planning case, we utilized the same scenario and strategic approaches across all planning processes (Step 1). We then forecasted energy demand during all times of the year, including the adoption of customer programs and customer-sited generation (Step 2). We next identified distribution investments, transmission investments and resource additions to meet future needs through 2035 (Step 3). The Distribution Investments planning process identified where the load would grow on the distribution system and the distribution infrastructure required, while the Resource Additions planning process identified which resources would be added. These results fed into the Transmission Investments planning process, which determined what transmission investments would be needed on SRP's system to connect large-scale resources to serve customers' energy demand. In addition, the Resource Operations process simulated how the future system could operate. We then leveraged all of these outputs to develop reliability, affordability, sustainability and customer-focused metrics (Step 4).

We will use this information to inform the design of customer programs and pricing plan offerings following the first ISP. These planning processes and metrics are described further in the following sections.

Due to time constraints, we could not perform every modeling process for all 42 planning cases. For the Transmission Investments, Residential Bill Impact and Risk Assessment processes, we performed modeling for a subset of the 42 planning cases, as detailed further below. We quantified all metrics for the 12 "core system plans" (three strategic approaches evaluated against four scenarios) and assessed all 42 system plans when developing key findings, as discussed in Section 6.

Customer Programs and End-Use Technologies

We developed customer program and end-use technology forecasts for energy efficiency, demand response, electrification (transportation and other technologies) and distributed

generation — including distributed solar and distributed batteries — for scenarios and sensitivities. These forecasts served as inputs into the load forecasts, which subsequently served as key inputs for each of the planning processes. The demand response forecast served as a direct input for the Resource Additions process.

Methodology Overview

To meet customers' diverse needs and the overall system needs, we developed a cost-effective portfolio of programs that achieve SRP's 2035 Sustainability Goals for energy efficiency, demand response, transportation electrification and electric technologies. In addition, we developed forecasts for customer adoption of other end-use technologies, including distributed generation in alignment with SRP's 2035 Sustainability Goal for grid enablement.

We developed customer program and end-use technology forecasts for the following scenarios and sensitivities:

- Current Trends
- Desert Boom
- Desert Contraction
- Strong Climate Policy
- High Energy Efficiency (sensitivity)
- High Demand Response (sensitivity)
- High Distributed Generation Adoption (sensitivity)

Across these scenarios and sensitivities, we assumed that external factors drive customer adoption differences relative to the Current Trends scenario. For example, in the Strong Climate Policy scenario, we assumed that increased federal support for decarbonization efforts drives an expansion in energy efficiency, electric vehicles, building electrification and distributed generation.

Key Inputs

Key inputs for the customer programs and end-use technologies planning process included SRP's 2035 Sustainability Goals, assumptions for specific measures and programs, and market drivers.

2035 Sustainability Goals

SRP has established 2035 Sustainability Goals for various customer program offerings. In all ISP cases, we included customer program projections that met or exceeded these levels by 2035. *Note: SRP's 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders.*

- Energy efficiency: 3 million MWh
- Demand response: 300 MW
- Transportation electrification: 500,000 EVs
- Electric technologies: 300,000 MWh
- Grid enablement: Enable all distributed energy resources that customers choose to install

SRP Customer Program Planning Assumptions

SRP offers customer programs for energy efficiency, demand response, transportation electrification and electric technologies. The assumptions for these programs reflect the suite of customer program opportunities available to SRP, as well as their performance and costs.

SRP has implemented a continuous improvement process over many years to refine planning assumptions for specific measures for energy efficiency, demand response and electric technology programs. SRP's Measurement & Evaluation team and third-party consultant Guidehouse formally evaluate a subset of programs each year to continually refine assumptions for the measures included in each program. Based on this process, we have defined planning assumptions for each of the following measures:

- Reduction in energy demand during peak hours (kW)
- Reduction in energy demand during the entire year (kWh)
- Timing of energy demand reduction on an hourly basis
- Useful life over which SRP can expect energy savings
- Incremental cost, which serves as the basis for rebate design

Market Research

SRP regularly performs market research to understand the market activity and customer willingness to participate in different programs and to adopt various end-use technologies. In addition to speaking with customers, SRP gathers information from implementation partners, trade allies and third-party research. To develop the distributed generation forecast, we relied on historic and recent trends for distributed generation installations within SRP's power system area as well as advanced metering infrastructure data for the historic and recent generation of the systems already installed. To develop the electric vehicle forecast, we relied on information from the Electric Power Research Institute (EPRI) related to feasible EV adoption rates and supplemented this with internal research on EV load impacts within SRP's service area. We then leveraged this market research information, along with historical trends, to inform the forecast of future customer participation in SRP programs and adoption of end-use technologies.

Key Outputs

Below are the key outputs from this planning process.

Output	Description	Output Units
Energy Efficiency and Electrification Impacts on Annual Load	Forecast of energy efficiency and electrification (transportation and other technologies)	MWh

Demand Response Capacity	Forecast of the amount of capacity on the system that is available to provide demand response services	MW
Distributed Generation Adoption	Forecast of customer-sited solar and batteries	MW
Customer Program Costs	Forecast of program costs for SRP customer programs	$

Load Forecast

In the load forecasting process, we forecasted customer energy demand on an hourly basis through 2035. The forecast reflects typical patterns in energy demand throughout the year and across the hours within a given day, including during peak energy demand periods. This information served as a key input for determining future system needs in the ISP.

Methodology Overview

First, our team created a baseline forecast for the Current Trends scenario. We then employed the Statistically Adjusted End-Use (SAE) model (developed by Itron) to forecast electricity demand from customer end uses. We updated this model to align with inputs related to economic growth, end-use saturation and efficiency trends, adoption of customer programs, adoption of distributed generation, adoption of electric vehicles, and temperature trends. Finally, we used the outputs of this model to determine the hourly energy demand through 2035.

To develop additional forecasts for each of the four planning scenarios and two of the sensitivity cases, we modified one or more key assumptions. We developed load forecasts for the following scenarios and sensitivities:

- Current Trends
- Desert Boom
- Desert Contraction
- Strong Climate Policy
- High Energy Efficiency (sensitivity)
- High Distributed Generation Adoption (sensitivity)

Key Inputs

The following sections describe the key inputs for the Load Forecast process, including economic growth and temperature increase. In addition to these inputs, we factored in changes in customer energy usage from energy efficiency, electrification and adoption of distributed generation. These inputs are the results of the Customer Programs and End-Use Technologies process and are discussed in Section 6.

Economic Growth

We developed economic growth projections for all four scenarios to determine key inputs, such as change in population and growth in energy demand from large customers. To do so, we developed an economic outlook for the Phoenix metro area by creating a composite forecast from a variety of external economic forecast providers, including University of Arizona, Arizona State University, Moody's, Woods & Poole Economics, and R.L. Brown Construction. We also developed an outlook for large customer growth by leveraging information from a variety of sources, including SRP's Strategic Energy Managers, SRP Economic Development, the Greater Phoenix Economic Council, state and local commerce authorities, and observed historical trends.

Figures 5.2 and 5.3 show the population and incremental large customer load growth forecasts for the four scenarios. In the Current Trends and Strong Climate Policy scenarios, the population and new industrial loads increase markedly, consistent with recent trends in migration and expansion of business activity. In the Desert Boom scenario, there is even greater growth as Arizona develops further as a regional energy, technology and manufacturing hub. In the Desert Contraction scenario, there is limited new migration and a significant slowing of large customer growth trends.

FIGURE 5.2: PHOENIX METRO POPULATION

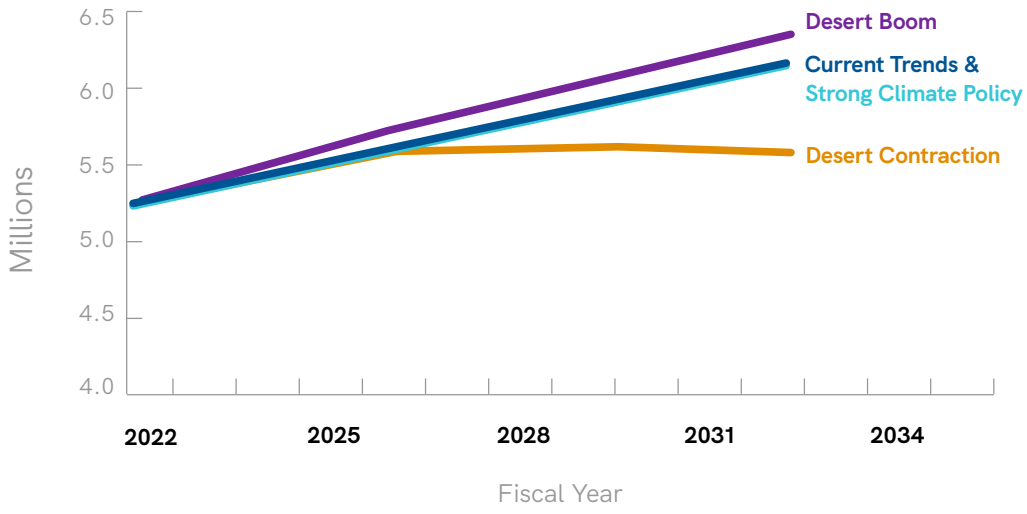
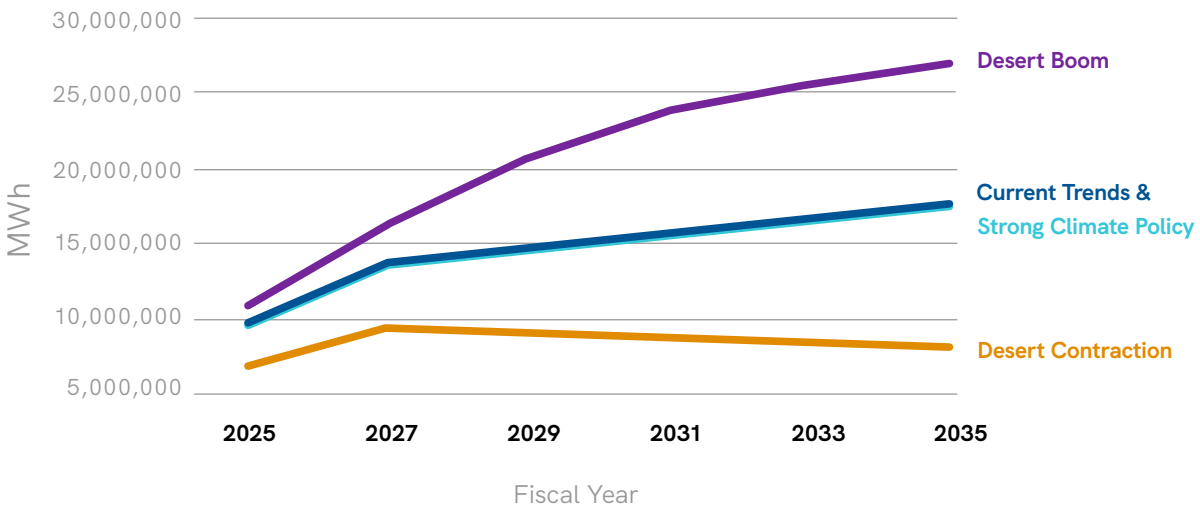


FIGURE 5.3 INCREMENTAL LARGE CUSTOMER LOAD GROWTH



Temperature Increases

In all scenarios, we considered the impacts of global warming. To characterize the future temperature increases, we relied on data from the Intergovernmental Panel on Climate Change (IPCC). For the Current Trends and Strong Climate Policy scenarios, we used the Representative Concentration Pathway (RCP) 4.5 trajectory, which corresponds to a temperature increase of 0.67°F per decade. For the Desert Boom and Desert Contraction scenarios, we used the RCP 8.5 trajectory, which corresponds to an even greater temperature increase of 0.91°F per decade. We then translated these changes in temperature into changes in cooling degree hours and heating degree hours (see figures 5.4 and 5.5), which are metrics that are correlated with energy demand from cooling and heating buildings.

FIGURE 5.4: COOLING AND HEATING DEGREE HOURS

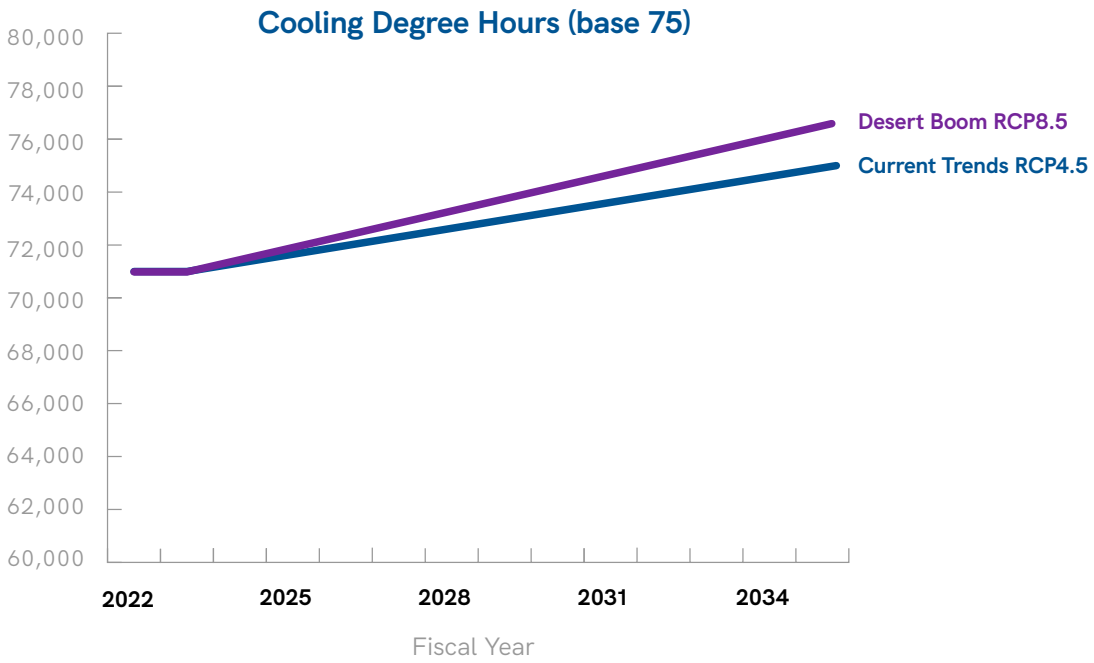
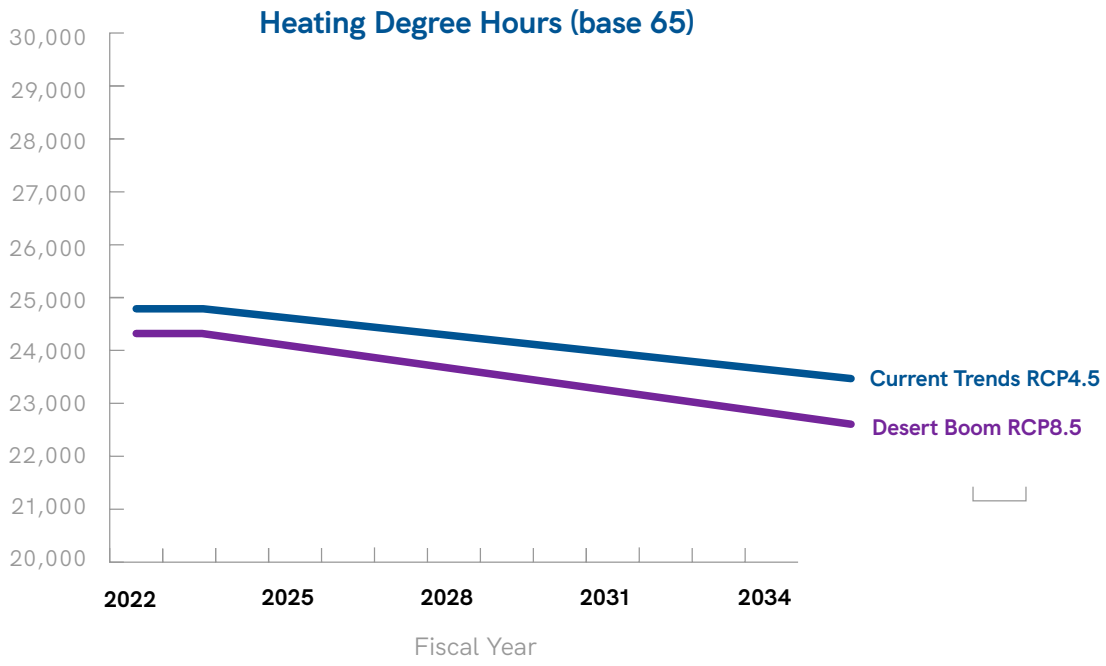


FIGURE 5.5: COOLING AND HEATING DEGREE HOURS



Key Outputs

SRP developed the following outputs, which served as inputs for other planning processes.

Output	Description	Output Units
System Load Forecast	System peak load and hourly energy demand forecast	MW
Transmission-Level Forecast	Peak load forecast for customers that connect directly to the high-voltage transmission system	MW
Distribution-Level Forecast	Peak load forecast for customers that connect to the lower-voltage distribution system	MW

Distribution Investments

In the Distribution Investments planning process, we determined which investments are needed on the distribution system to accommodate growth in customer energy demand, including the impacts from adoption of electric vehicles and customer-sited generation, while ensuring reliability.

Methodology Overview

First, we allocated the system-level load forecast (described in the Load Forecast section) to granular localized levels of the distribution system. We utilized LoadSEER (developed by Integral Analytics), which is a distribution forecasting and planning tool that allocates the system-level load to individual substations based on geographic, economic and historical customer usage data. This resulted in a peak load forecast for each substation, allowing us to understand where customer demand is changing and how the system may need to adapt.

After we allocated the system-level load forecast to the localized levels of the distribution system, SRP analyzed capacity-constrained locations and evaluated applicable infrastructure solutions to alleviate these constraints. Due to modeling limitations and time constraints, we focused on substation equipment and did not evaluate individual distribution lines that connect to the substations. We utilized the following reliability planning criteria, consistent with SRP's distribution planning practices:

- A distribution substation bay may not exceed 85% of its emergency rating.
- The total distribution system load should not exceed 70% of the total distribution system capacity.

One way we addressed an overloaded substation was by shifting loads to adjacent substations, which was possible if the neighboring substation had available capacity. This ensured the existing distribution infrastructure was used efficiently. In areas that were significantly capacity-constrained and existing distribution infrastructure could not be utilized, SRP strategically placed new substations, adding capacity to an area to address as many overloads as possible.

We performed this analysis for the following scenarios and sensitivities, which covered all planning futures in which load and customer programs change and could impact distribution investment needs:

- Current Trends
- Desert Boom
- Desert Contraction
- Strong Climate Policy
- High Energy Efficiency (sensitivity)
- High Distributed Generation Adoption (sensitivity)

For the two sensitivity analyses, the team estimated the required number of substation bay additions through interpolation by calculating the relationship between forecasted load and

resultant substations required in the four major scenarios. This relationship was then applied to the forecasted load for the two sensitivity cases. This process resulted in a high-level estimate of substation bay addition requirements for each sensitivity case, and it assumes that these technologies are adopted evenly throughout the service territory.

Key Outputs

The modeling process resulted in a plan detailing the location of each substation addition for each year as well as the load for each substation in each year.

Output	Description	Output Units
Substation Load Forecast	Projects addition of new substations and allocation of load between substations.	MW
Distribution Investments	Specification of substation additions or upgrades to meet system requirements, as well as associated costs.	$

Resource Additions

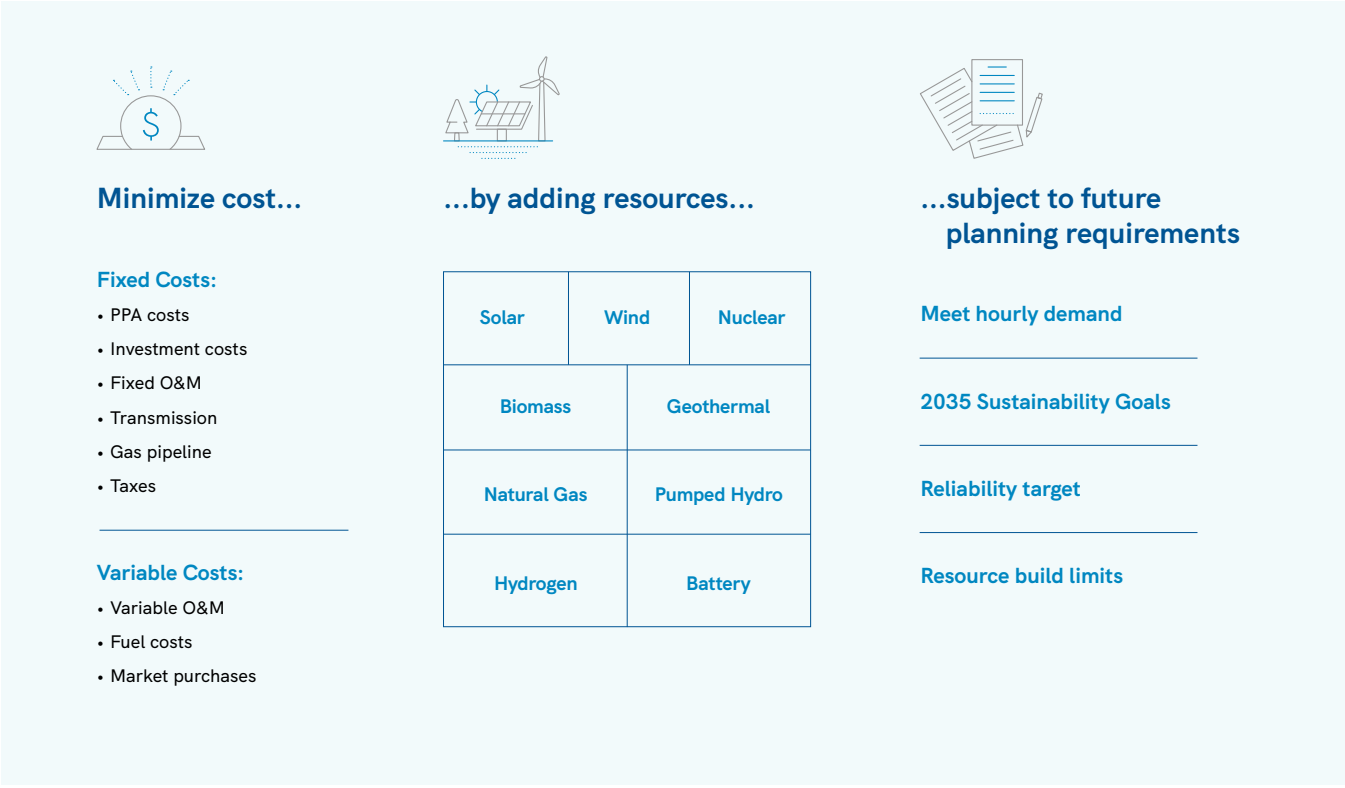
In the Resource Additions planning process, we determined the least-cost resource additions needed to meet future energy demand while ensuring reliability and meeting SRP's 2035 Sustainability Goals related to carbon dioxide emissions and water usage.

Methodology Overview

During this process, our team assessed future resource additions through a resource portfolio optimization analysis that identified the least-cost long-term combination of generation investments subject to reliability, policy and technical constraints.

To perform the analysis, we engaged Energy and Environmental Economics Inc. (E3) to deploy a long-term capacity expansion model, PLEXOS (developed by Energy Exemplar), which we had not leveraged in prior resource planning efforts. PLEXOS considers investment costs, fixed costs and production costs to simultaneously select new resources and simulate system operations over a long planning horizon (see Figure 5.6).

FIGURE 5.6: OVERVIEW OF THE RESOURCE ADDITIONS MODELING FRAMEWORK



E3 produced optimized resource portfolios for all cases presented in the ISP, except for the volatile gas price sensitivities[1], totaling 39 cases. Each portfolio identified resource additions through 2035.

Key Inputs

The key inputs for this analysis included the system load forecast (see Load Forecast section), resource options, resource and transmission costs, reserve margin requirements, fuel prices, reliability requirements and sustainability requirements.

Resource Options

The ISP considered a wide range of resource options to meet future needs, including renewable, storage and thermal resources.

Renewable Resource Options

The ISP considered several renewable resource options, including biomass, geothermal, solar and various wind options that vary by location and transmission path.

[1]The volatile gas price sensitivities are intended to evaluate the impact of gas prices unexpectedly changing over short time periods without SRP being able to change decisions around resource additions. Therefore, SRP evaluated the volatile gas price sensitivities in the Resource Operations analysis, using the same resource additions as in the Current Trends scenario.

FIGURE 5.7: RENEWABLE RESOURCE OPTIONS

Resource	State	First Available Year	Capacity Factor[2]
Biomass	Arizona	2025	Varies
Bioenergy with Carbon Capture and Storage	Arizona	2035	Varies
Geothermal	California	2031	90%
Solar	Arizona	2025	32.2%
Wind – Existing SRP Transmission	Arizona	2033	31.3%
Wind – Existing non-SRP Transmission	Arizona	2025	31.3%
Wind – New Transmission	Arizona	2031	31.3%
Wind – New Transmission	New Mexico	2026	45.5%
Wind – New Transmission	Wyoming	2029	55.4%
Wind – Existing Transmission	Wyoming	2029	55.4%

To ensure that the resource additions identified reflect realistic plans that SRP can execute, the ISP included build limits for the renewable resource options to reflect development limitations in being able to bring such new resources online. Below are the total build limits by 2035 for each resource:

- **Biomass –** SRP assumed up to 150 MW of new additions, based on the amount of fuel that SRP assumed could be made available from forest-thinning projects such as those in the SRP Healthy Forest Initiative™.
- **Bioenergy with Carbon Capture and Storage (BECCS) –** SRP assumed up to 100 MW of new additions, given that the CCS component of this resource is not widely commercialized today and has a certain degree of uncertainty in terms of availability and cost.

[2]Capacity factor is a measure of resource utilization and is expressed as a ratio of the actual output over a given period of time compared to the theoretical continuous maximum output over that period.

- **Geothermal –** SRP assumed up to 1,000 MW of new additions. Based on SRP's assessment of regional transmission, SRP expects that access to new geothermal resources in the Salton Sea area in California — which has high-quality geothermal energy — would require development of new long-distance transmission between the Salton Sea area and the Phoenix metropolitan area. SRP assumed that new transmission could be put in service as early as 2031 and that this would allow SRP to access up to 1,000 MW of geothermal resources. For details on the cost of this transmission, see the Transmission Costs section. In the Strong Climate Policy scenario, SRP assumed that increased federal support for regional transmission could accelerate the availability of this resource from 2029 to 2031.
- **Solar –** SRP effectively did not limit solar additions. In total, the model could add up to 20,000 MW of solar by 2035, but that threshold was never constraining.
- **Wind –** For wind, assumptions varied according to current and potential transmission availability. For more details on the cost of transmission, see the Transmission Costs section.
    - **Wind (AZ), Existing SRP Transmission —** SRP estimated that 800 MW of transmission would become available in 2033 following the retirement of the Coronado Generating Station and an additional 450 MW in 2034 in the Minimum Coal strategic approach following the retirement of the Springerville Generating Station.
    - **Wind (AZ), Existing Non-SRP Transmission —** SRP estimated that 50 MW of non-SRP transmission is currently available for new wind generation in Arizona.
    - **Wind (AZ), New Transmission —** SRP assumed a new transmission line could be added from eastern Arizona by 2035, which would provide access to approximately 500 MW of wind generation.
    - **Wind (NM), New Transmission —** SRP assumed new transmission could be added between a region in New Mexico with high-quality wind and the Valley by 2035. SRP assumed this transmission would enable SRP to access up to 1,500 MW of wind generation.
    - **Wind (WY), Existing Transmission —** SRP estimated that 100 MW of transmission could become available in 2029 following the retirement of the Craig and Hayden coal plants in Colorado.
    - **Wind (WY), New Transmission —** SRP assumed one or more new transmission lines could be added between Wyoming and southern Nevada by 2025, and that SRP could then utilize approximately 300 MW of existing transmission to deliver wind in Wyoming to the Phoenix metropolitan area.

For solar and wind resources, we developed hourly generation profiles by using the System Advisor Model (SAM) developed by the National Renewable Energy Laboratory (NREL). The solar profile reflects a project with single-axis tracking in Arizona, while the wind profiles reflect differences in generation profiles across the different states.

Storage Resource Options

The ISP also considered energy storage resources, including lithium-ion batteries and pumped hydro storage, which can help integrate renewable resources on the system. For battery storage, the ISP considered both stand-alone storage and hybrid storage that is co-located with solar.

FIGURE 5.8: STORAGE RESOURCE OPTIONS

Resource	First Available Year	Duration (hours)	Round-Trip Efficiency
Battery	2025	4	85%
Pumped Hydro	2033	10	80%

As was done for renewable resources, SRP included build limits for storage resources to reflect development limitations in being able to bring new resources online. Below are the total build limits by 2035 for each resource:

- **Battery –** SRP assumed up to 8,500 MW of new additions, above and beyond the battery storage resources that are already contracted.
- **Pumped Hydro –** SRP assumed up to 1,150 MW of new additions, which corresponds to one large new project.

Thermal Resource Options

In addition to renewable and storage resources, the ISP considered several thermal resource technologies. We modeled conventional natural gas technologies, including combined cycle, combustion turbine (both frame and aeroderivative) and reciprocating engine technologies. We also modeled a few emerging technologies, including combined cycle with carbon capture and storage (CCS), combustion turbine that burns 100% green hydrogen (Hydrogen 100),[3] combustion turbine that burns a blend of natural gas and an increasing share of hydrogen (Hydrogen Transition), and nuclear small modular reactors (SMR). The ISP also considered biomass and geothermal as thermal resource options. Those resources are discussed in the Renewable Resource Options section above.

FIGURE 5.9: THERMAL RESOURCE OPTIONS

Resource	First Available Year	Fuel
Combined Cycle (1x1)	2028	Natural Gas
Combined Cycle (2x1)	2028	Natural Gas
Combustion Turbine (Frame)	2027	Natural Gas
Combustion Turbine (Aero)	2025	Natural Gas

[3] Green hydrogen is produced from 100% renewable energy.

Reciprocating Engine	2025	Natural Gas
Hydrogen Transition	2030	Blend (Green Hydrogen and Natural Gas)
Combined Cycle with CCS	2030 or 2035 depending on scenario	Natural Gas
Hydrogen 100	2034 or post-2035 depending on scenario	Green Hydrogen
Nuclear SMR	2034 or post-2035 depending on scenario	Uranium

The resource availability assumptions reflect the time required to site, permit and construct resources. For emerging technologies, including combined cycle with CCS, hydrogen and nuclear SMR resources, we considered the uncertainty of when these resources would become available, given that they have not yet reached widespread commercialization. See Figure 5.10 for the availability assumptions for emerging technologies. We excluded these resources from consideration within the planning horizon under most scenarios. However, to test an alternative scenario in which these technologies progress more rapidly following government support, we accelerated SRP's availability in the Strong Climate Policy scenario.

FIGURE 5.10: FIRST YEAR AVAILABLE FOR EMERGING TECHNOLOGIES

Resource	Strong Climate Policy Scenario	Other Scenarios
Combined Cycle w/ CCS	2030	2035
Hydrogen 100	2034	Post-2035
Nuclear SMR	2034	Post-2035

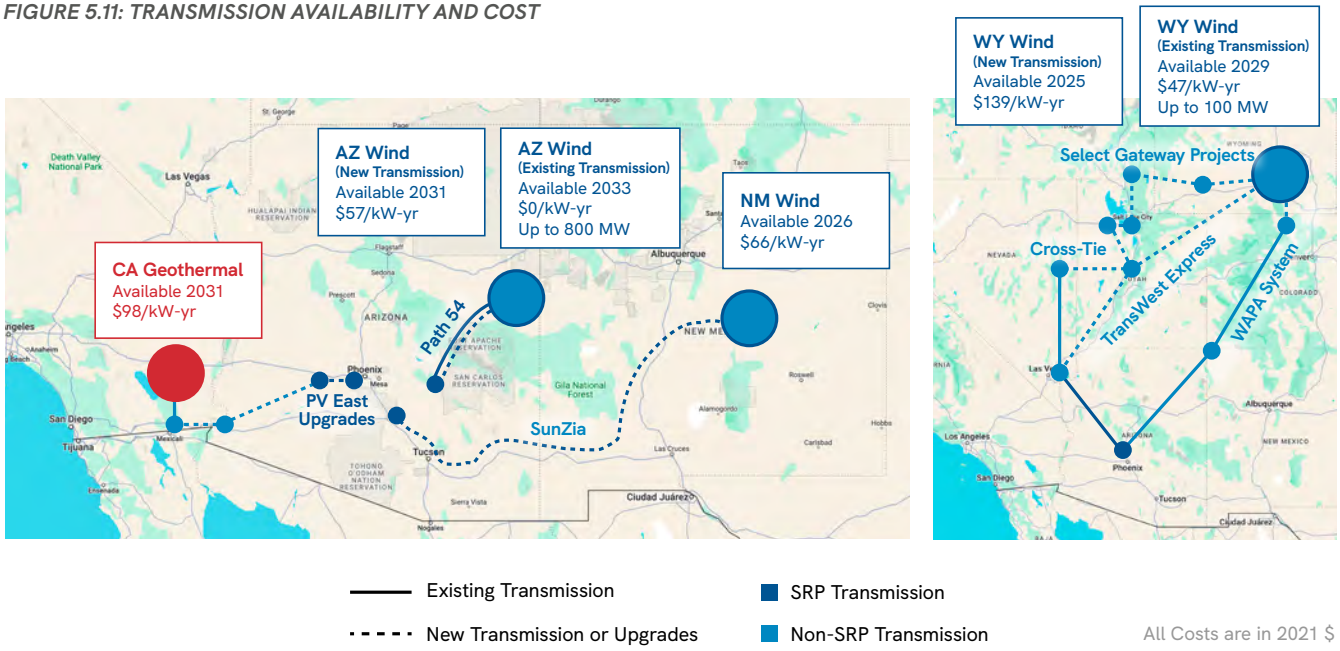
Transmission Costs

Several wind resource options, as well as the geothermal resource option, required consideration of transmission availability and costs of potential transmission expansion or upgrades. The Resource Additions planning process considered this availability and cost information when determining which resources to add.

See Figure 5.11 for the transmission availability and transmission cost adder for each resource option. For transmission paths that would require new or upgrades to transmission, we estimated the cost of this transmission and levelized the cost over the life of the transmission to determine

the transmission cost adder for those wind and geothermal resources. For existing transmission, we estimated how much transmission capacity would be available without further upgrades.

FIGURE 5.11: TRANSMISSION AVAILABILITY AND COST



Resource Costs

Our team forecasted future resource costs under different scenarios by relying on public data. We leveraged the 2022 NREL Annual Technology Baseline (ATB) for renewable and storage resource costs and the Energy Information Administration (EIA) 2022 Annual Energy Outlook (AEO) for thermal resource costs.

The fixed costs for resources included the following components: upfront capital, interconnection, property taxes, transmission (for remote resources, described in previous section), gas transportation (for gas resources), and fixed operations and maintenance costs. For upfront costs, we levelized these costs over the useful lifetime of each resource.[4] The variable costs for resources included fuel expense and variable operations and maintenance costs. This subsection focuses on the fixed costs, which don't vary with operations, while the Fuel Prices section below discusses fuel prices.

In August 2022, as our team was partway through the ISP analysis, Congress passed the Inflation Reduction Act (IRA), which provided an unprecedented federal investment in clean energy and created new federal tax credits for clean energy resources. Because of the significant nature of the IRA, we revised the cost of new resources to reflect these tax credits in all ISP scenarios and used these updated assumptions for the final ISP modeling. These revised costs were in part informed by the Technical Working Session SRP held with a group of industry experts on Jan. 17, 2023, to better understand the IRA.

[4]SRP utilized a lifetime of 15 years for battery storage resources, which was different from the NREL 2022 ATB but is consistent with the NREL 2023 ATB. SRP established this assumption based on experience with contracting for storage resources and after having conversations with members of the NREL ATB team to understand the underlying assumptions for battery lifetimes.

TECHNICAL WORKING SESSION ON THE INFLATION REDUCTION ACT

On 1/17/23, SRP held a Technical Working Session to better understand the impacts and uncertainties of the Inflation Reduction Act (IRA) and how to incorporate this into SRP's planning. Given the significant complexity of the IRA, SRP convened a group of experts with a wide range of viewpoints:

- Christine Turner, Solar Energy Manufacturers for America Coalition
- Mitch Rapaport, Nixon Peabody LLP
- Michael Mace, Public Financial Management (PFM)
- Hanson Wood, EDF Renewables North America

The experts highlighted a few ways in which the IRA could spur significant new clean energy investment:

- Provides significant incentives to grow domestic manufacturing, which could mitigate impacts from supply chain challenges experienced in recent years.
- Provides longer certainty for clean energy credits, through at least 2032 and likely longer.
- Expands eligibility of tax credits to a wider range of technologies, including standalone storage, nuclear, carbon capture and storage, and hydrogen.
- Creates an option for tax credit bonuses for domestic content and location within an Energy Community.
- Allows public power utilities like SRP to take advantage of tax credits via direct pay provisions, increasing feasibility of public power project ownership.

The experts also highlighted a few sources of risk and uncertainty:

- Greater guidance and certainty are needed from the Internal Revenue Service (IRS) for many of the IRA provisions to mitigate risks.
- Public power utilities like SRP must meet domestic content provisions to qualify for a direct pay credit.
- It is too early to tell whether projects will qualify for bonus tax credits, how much it will cost to monetize tax credits, and how tax credit savings will be split between developers and offtakers.
- Increased demand for clean energy demand could put increased pressure on supply chains in the near-term.
- Lack of support for new transmission in the IRA may lead to increased congestion, curtailment, and limitations in renewable resource growth.

Figure 5.12 shows the resource cost forecasts for the Current Trends and Desert Boom scenarios for renewable and nuclear resources in terms of levelized cost of energy (LCOE).[5] The LCOE metric expresses the levelized annual cost of a resource relative to its expected annual generation. One caveat in interpreting this metric is that it only reflects the cost of a resource and does not reflect the value that a resource provides to the system, nor does it reflect any renewable curtailment, which would increase the LCOE.

[5]Resource cost assumptions for the other scenarios and sensitivities are provided in Appendix A: [ASSUMPTIONS USED IN SCENARIOS, SENSITIVITIES AND STRATEGIC APPROACHES].

FIGURE 5.12: RENEWABLE RESOURCE COSTS (2023 $/MWH)

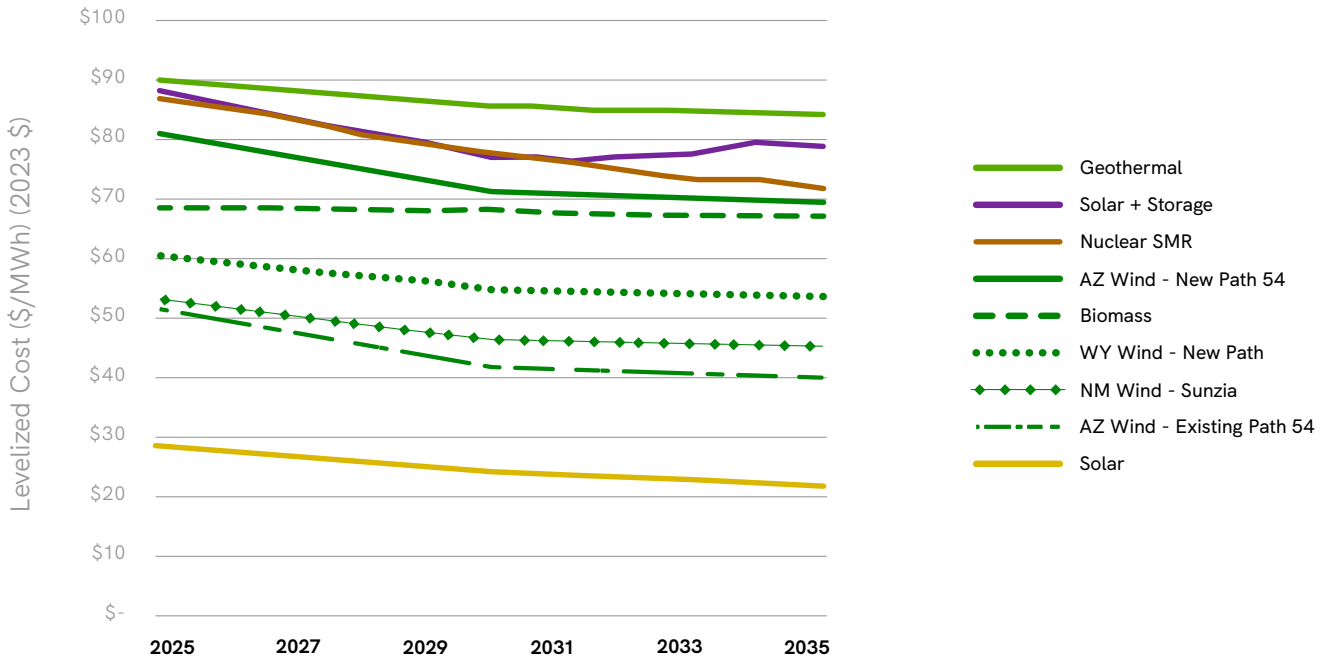
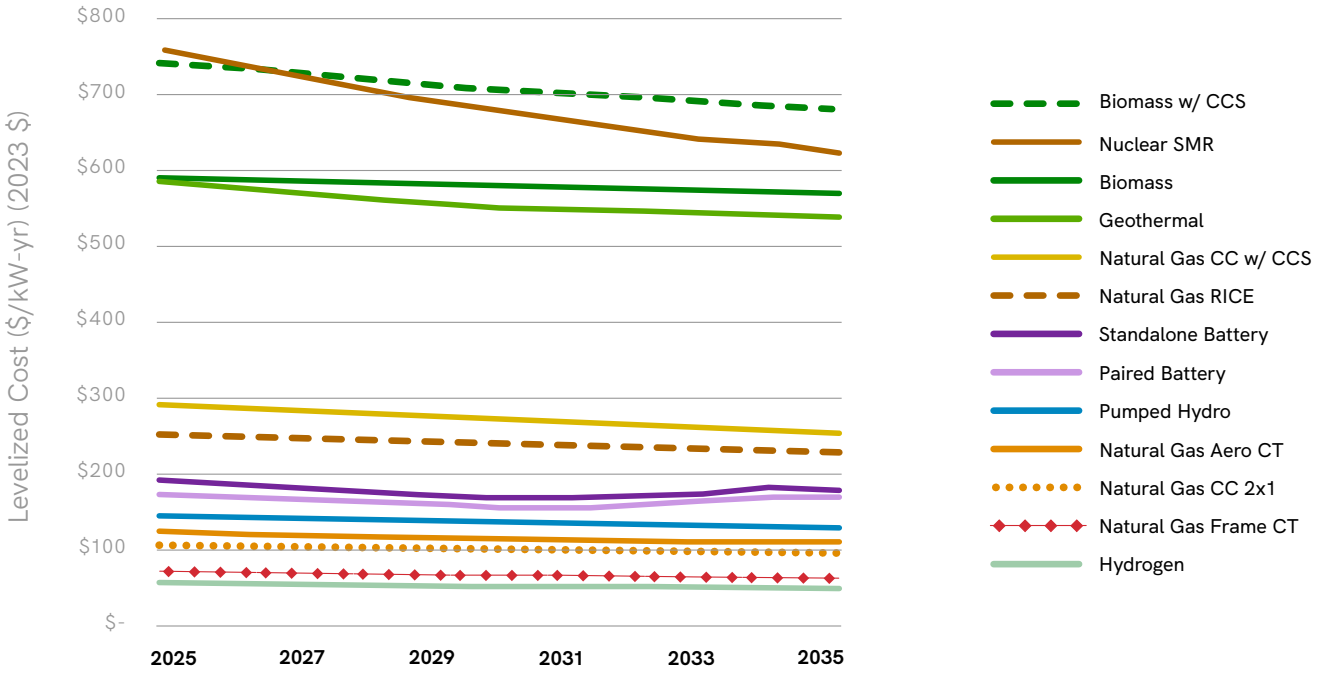


Figure 5.13 shows the resource cost forecasts for the Current Trends and Desert Boom scenarios for thermal and storage resources in terms of levelized fixed cost. Note that the LCOE metric used above is not commonly used for thermal and storage resources because the annual utilization of these resources can vary widely from one scenario to another or even year to year, while the LCOE metric assumes a fixed annual utilization.

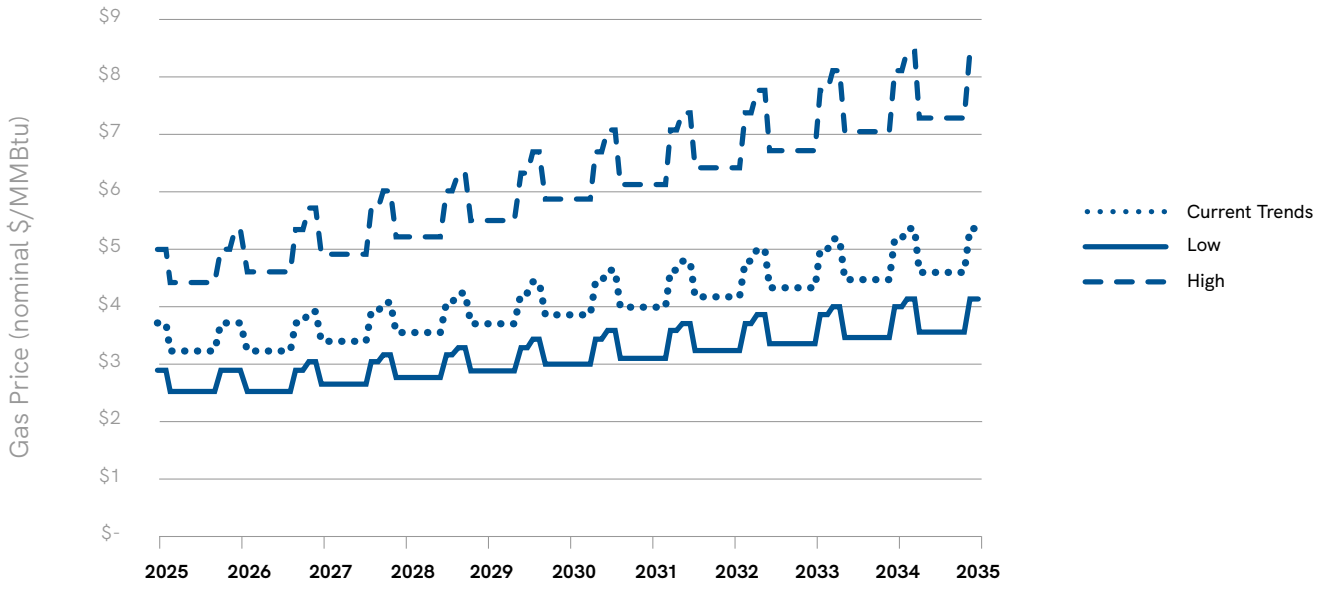
FIGURE 5.13: DISPATCHABLE RESOURCE COSTS



Fuel Prices

Fuel prices for the ISP were derived from several data sources. Natural gas forecasts were derived from the EIA 2022 AEO, with certain scenario trajectories regionalized based on SRP's gas supply. The gas price forecast varies by scenario and across the gas price sensitivities, reflecting low, mid, high and volatile trajectories. The low case reflects AEO's High Oil & Gas Supply Case; the mid case reflects AEO's Reference Case; the high case reflects AEO's Low Oil & Gas Supply Case; and the volatile gas case reflects observed volatility from 2000–2010 for the 2025–2035 analysis period. Figure 5.14 shows the Low, Current Trends (Mid) and High monthly forecasts through the 2025–2035 period.

FIGURE 5.14: GAS PRICE FORECASTS



Green hydrogen price forecasts were developed by E3, assuming electrolysis of hydrogen using an alkaline electrolyzer that is powered by solar energy (with solar resource costs as defined in this report). Hydrogen electrolyzer costs are derived from the California Energy Commission (CEC) publication on hydrogen production costs.[6] Hydrogen storage costs are derived from Department of Energy (DOE) project ST-001 costs.[7] Hydrogen transport costs are derived using Argonne National Laboratory's Hydrogen Delivery Scenario Analysis Model (HDSAM).[8] A $3/kg Production Tax Credit (PTC) is applied to all hydrogen produced through 2032. Market resource costs are derived and provided by internal SRP forecasts.

Reliability

To ensure system reliability, SRP must procure sufficient capacity to exceed annual peak demand over the entire planning horizon. In addition to serving the peak, a planning reserve margin (PRM) must be added to the amount of firm capacity on the system to ensure resource adequacy and avoid loss-of-load events while accounting for the potential for exceptional extreme loads, resource forced outages, uncertainties in load forecasting, and the operator's need to maintain a margin of operating reserves.

[6] https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf
[7] https://www.hydrogen.energy.gov/pdfs/review22/st001_ahluwalia_2022_p.pdf
[8] https://hdsam.es.anl.gov/index.php?content=hdsam

In most ISP cases, SRP applies a PRM of 16%, meaning that in each year of the planning horizon, SRP must have reliable capacity in an amount equal to or greater than 116% of forecast peak demand. In the Strong Climate Policy scenario and Regional Diversity sensitivity, the PRM is reduced to 13% as a proxy to represent the assumption that expanded transmission and regional coordination allows for increased resource and load diversity.

Due to high cooling loads, SRP has a summer-peaking system. Thermal generators are assumed to provide a PRM contribution (firm capacity value) equal to their summer monthly rating. Wind and pumped hydro storage resources contribute a fixed percentage of capacity (18% and 80%, respectively) to the PRM. Battery resource contributions to PRM decline with increasing battery penetration. New stand-alone solar resources are assumed to provide no firm capacity to SRP's system, but solar storage resources do contribute to the PRM due to the storage component.

CO_2 Emissions Target

SRP has established a goal of reducing carbon emissions intensity (lbs./MWh) by 65% by 2035 and by 90% by 2050, relative to 2005 levels. The carbon emissions intensity is the amount of carbon dioxide emissions (in pounds) from emitting power plants expressed relative to the amount of total generation (in megawatt-hours) across all power plants. In 2005, SRP's emissions rate was 1,576 lbs./MWh. In 2035, the CO_2 emissions target is 550 lbs./MWh. The ISP analysis capped CO_2 emissions to ensure that the future resource additions and operations are consistent with SRP satisfying its 2035 Sustainability Goals. *Note: SRP's 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders.*

Key Outputs

The following table reports the key outputs of the Resource Additions analysis:

Output	Description	Output Units
Resource Installed Capacity	Installed capacity of the generator, including new investments.	MW
Resource Contribution to Reliability	Firm capacity of the generator. For renewable resources options, this will equal the effective load carrying capability (ELCC) times the installed capacity.	MW
Resource Fixed Costs	Total fixed costs, including annualized build costs, fixed O&M and fixed charge (pipeline and/or fuel deliverability) costs.	$
Reliance on Emerging Technologies	Installed capacity and firm capacity for emerging technologies.	MW

Resource Operations

In the Resource Operations planning process, we simulated generating resource operations. For each future year, we simulated resource operations in each hour to understand how resources operate to meet total system demand and to understand the implications for cost, emissions, water usage and interactions with the regional power market. This information helped us evaluate the trade-offs between different system plans. This modeling process is sometimes referred to as production cost simulation in the industry.

Methodology Overview

Although the Resource Additions planning process considered resource operations when determining which resources to add in the future, that planning process did not have the same level of granularity as the Resource Operations planning process. In this planning process, SRP modeled every hour of the year (rather than a representative sample) and factored in more detailed operating characteristics for generators, which can influence operations. This refinement allowed SRP to say with more confidence how resource operations could evolve over time and what that would mean for affordability and sustainability metrics.

During this process, our team performed modeling for all 42 system plans. We used the Aurora model (developed by Energy Exemplar) to simulate future system operations, including existing resources and any new resources selected through the Resource Additions planning process. For the Volatile Gas Prices sensitivity cases, which did not vary the resource additions relative to the corresponding Current Trends cases, we only modified the gas prices and market prices over time to understand the impact of a volatile fuel price environment on system operations, affordability metrics and sustainability metrics.

Key Inputs

For this modeling process, we leveraged most of the same inputs utilized in the Resource Additions modeling process. Whereas the Resource Additions modeling process determined which resources to add to the system, the Resource Operations modeling process took the resource additions as fixed and then simulated future system operations. Therefore, this modeling process did not utilize the inputs related to resource additions or reliability given the system already had sufficient resources to meet future reliability needs. The Resource Operations process utilized the resource addition results as inputs and then leveraged the same data for these inputs:

- Load forecast
- Renewable generation profiles
- Variable operations and maintenance costs
- Fuel price forecast
- Market price forecast
- CO_2 emissions target

Because the Resource Operations modeling process simulated future system operations in a more granular manner, it also incorporated additional key inputs:

- Detailed operating characteristics for thermal generators
    - Minimum stable operating level
    - Startup time
    - Ramp rate
    - Minimum runtime
    - Minimum downtime
- Startup and shutdown costs for thermal generators
- Operating reserve requirements

Key Outputs

This planning process generated detailed system operations data for all 42 system plans. The table below summarizes the key outputs:

Output	Description	Output Units
Fuel, Operations and Maintenance Costs	Hourly fuel use, operations and maintenance costs	$
Market Purchase Costs	Costs of procuring external electricity generation outside of SRP	$
SRP Carbon Emissions (Mass)	Carbon emissions from generating resources during the planning period	Tons CO_2
SRP Carbon Emissions (Intensity)	Carbon emissions per MWh generation emitted during the planning period	Lbs. CO_2 per MWh
Carbon-Free Generation (%)	Percentage of total generation that was carbon-free	%
Water Use	Total water use during resource operation	Gallons
Criteria Pollutants (NO_x, SO_2, PM, VOC)	Criteria pollutant emissions from generation during the planning period	Tons
Thermal Plant Capacity Factor	Capacity factors for thermal plants during resource operation	%

Transmission Investments

In the Transmission Investments planning process, we studied the forecasted load and resource additions, determined future transmission needs and identified transmission investments to meet those needs. For the year 2035, we simulated transmission operations under different load and resource assumptions to understand which transmission investments were needed and at what cost.

Methodology Overview

For the ISP, we analyzed the portion of the transmission system rated 115 kV and above. We focused on this part of the transmission system for two reasons. First, transmission investments at these higher voltages require longer lead times for siting, engineering, permitting and construction, so there is more value in identifying investment needs for these assets through 2035. Second, analyzing the 69 kV system was not feasible due to limited resources over this study period. While we did not analyze the 69 kV system, we did estimate investment costs for the 69 kV system based on the number of new distribution substations.

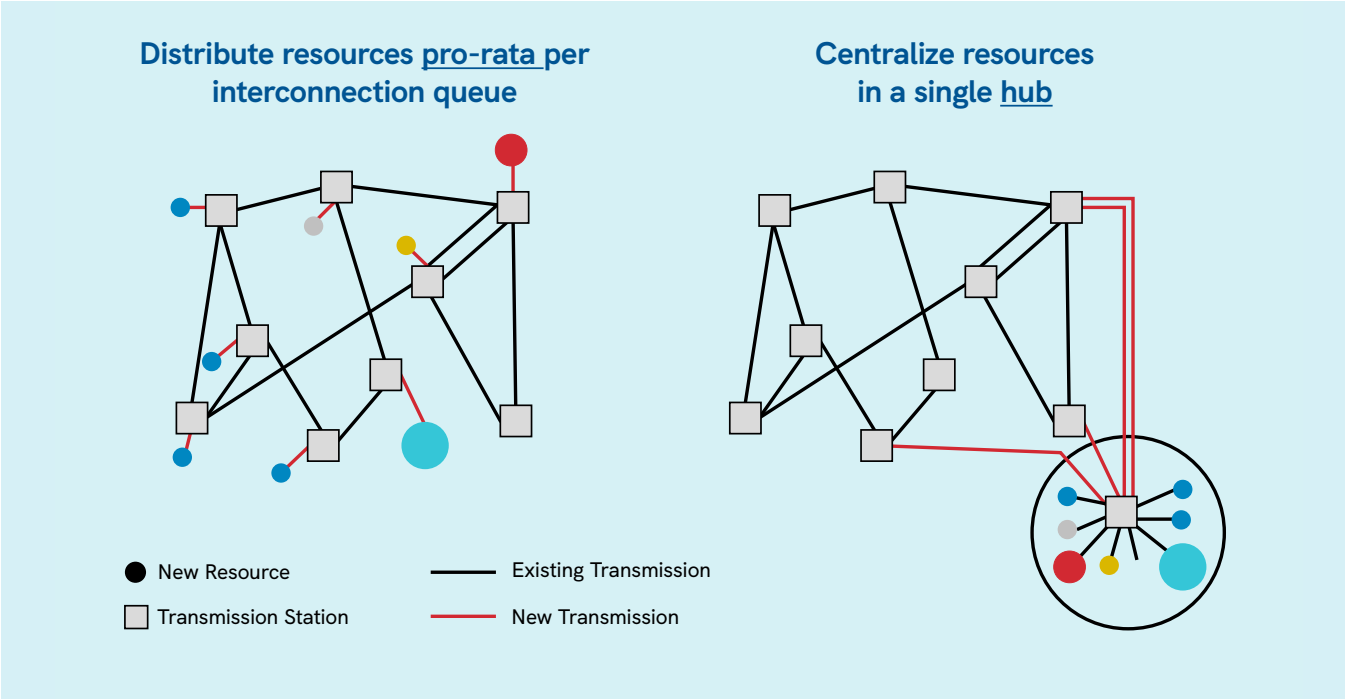
During this process, our team performed power flow analysis for the year 2035 to understand how power would flow across the transmission system and how the voltage would respond under certain conditions. We evaluated whether any element of the transmission system would be overloaded or be outside its acceptable voltage range. We also evaluated whether any element of the transmission system would be overloaded or fall outside its acceptable voltage range if other transmission elements were unavailable. We then identified transmission investments to mitigate the identified issues until none remained.

We studied two different operation hours for each case analyzed: the summer peak load hour, during which energy demand is greatest, and a summer peak renewables hour in which generation from solar, wind and other renewable resources are at maximum output. By studying these two conditions, we confirmed that the transmission system could meet the peak energy demand and accommodate renewable generation during peak production periods. For each case analyzed, we identified transmission investments that mitigated all issues across both operating conditions.

One of the key uncertainties in transmission planning is the location of future resources. Currently, developers decide where to site projects, submit interconnection requests and bid to provide energy to SRP or other utilities. As a result, we do not know where future resources will interconnect. The location of these resources can have a significant impact on the need for new transmission projects.

In the ISP, we chose to evaluate two resource location options: Pro-Rata and Hub (see Figure 5.15). The Pro-Rata option envisions new solar and battery resources being added across the system in proportion to the resources currently in SRP's interconnection queue. The interconnection queue served as a proxy for where developers would site future projects. With the Hub option, SRP would develop a new 500 kV switchyard southeast of the Valley and would encourage development of new gas, solar and battery storage resources at the hub. The Pro-Rata option represents a continuation of current practices in which developers locate throughout SRP's system, while the Hub option represents a potential alternative in which SRP concentrates development of resources in one location and connects that location to the rest of the system.

FIGURE 5.15: RESOURCE LOCATION OPTIONS



Our team identified transmission investments for the following cases under both the Pro-Rata and SRP Hub options. Due to time constraints through the ISP analysis, we could not perform detailed transmission analysis on all cases. Instead, we chose to analyze the following cases because they represent a wide range in both load growth and resource additions.

- Technology Neutral, Current Trends
- Technology Neutral, Desert Boom
- Minimum Coal, Current Trends

Key Inputs

For this modeling process, our team leveraged outputs from different planning processes, including Load Forecasting, Distribution Investments, Resource Additions and Resource Operations. As the transmission system acts as the link between utility-scale resources and customers, inputs related to loads and resources from these other planning processes were key inputs in determining transmission investment needs.

Because SRP's system is connected to other power systems in the Western Interconnection, we utilized models that represent the entire Western Interconnection. On an annual basis, SRP coordinates with neighboring utilities to develop "heavy summer" transmission models for up to 10 years into the future. For the ISP, we adapted the "2032 heavy summer" model to perform analysis for the different transmission cases through 2035.

Energy Demand

The projected energy demand at different locations on the transmission system came from two sources. First, the Load Forecasting modeling process identified the future energy demand for customers that connect directly to the transmission system. Second, the Distribution Investments modeling process identified the energy demand at each existing and new distribution substation to represent those customers connected to the distribution system. These inputs allowed SRP to identify the energy demand for each location on the transmission system.

Resource Locations

Figure 5.16 shows the location assumption for each new resource in the Pro-Rata and Hub options. For natural gas resources under the Pro-Rata option, we identified five potential locations based on preliminary gas siting screening efforts that were recently performed. For solar and battery storage resources under the Pro-Rata option, we allocated them to different substations in proportion to the interconnection queue. For the Hub option, we located new natural gas, solar and battery storage resources at the hub. The locations for other resources did not vary between the Pro-Rata and Hub options because the locations were already determined by the location of the underlying resource. The locations for wind and geothermal resources are discussed above in the Resource Additions section.

FIGURE 5:16: NEW RESOURCE LOCATIONS IN THE PRO-RATA AND HUB OPTIONS

New Resource	Pro-Rata	Hub
Natural Gas	Split across five locations	Placed at hub
Solar	Pro-rata allocation	Placed at hub
Battery Storage	Pro-rata allocation	Placed at hub
Pumped Hydro	Northeast of SRP service territory	
Wind	Varies by resource	
Geothermal	California, wheeled to Arizona, and injected at Hassayampa	
Biomass	Coronado	

Resource Operations

For the resource operations, our team identified the expected generation from all existing and planned resources for the peak load hour, so the transmission peak hour models reflected the planned resource outputs. This also included an economic dispatch order that was used to develop the peak renewable output hour scenarios.

Key Outputs

This planning process determined transmission investments. The table below summarizes the key outputs:

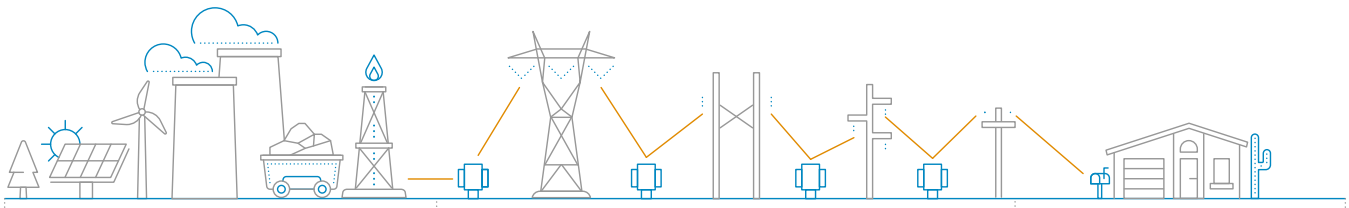
Output	Description	Output Units
Transmission Investments	Transmission projects to meet system requirements and associated upfront investment costs	$

Total System Cost

In this process, we performed simplified financial modeling to develop an annual total system cost metric for every case analyzed in the ISP. The purpose of this analysis was to provide indicative affordability metrics to compare system plans to one another and understand trade-offs between different system strategies. While the total system cost metric is helpful for these comparisons, it is not intended to provide a forecast of future rates for SRP customers or reflect SRP's financial outlook.

See Figure 5.17 below. We developed the total system cost by estimating system costs for generation, transmission, distribution, customer programs and other costs. These costs included costs of existing investments, new investments, operations and an estimate of system costs not modeled explicitly in the ISP. Many of these costs were outputs from the other modeling processes in the ISP.

FIGURE 5.17: COSTS INCLUDED IN TOTAL SYSTEM COST



Generation

Fuel

Market purchases and sales

Power purchase agreements

Existing and new investments

Operations and maintenance

Non-SRP transmission cost

Transmission & Distribution

Existing and new investments

Operations and maintenance

Customer Programs

Program and market enablement costs

Other

General & Administrative

Customer systems (metering, billing, customer service, etc.)

Telecom

Taxes

Assumed constant across all cases

Methodology Overview

For this methodology, our team first established a set of "base" costs that do not change across system plans. We forecasted the costs associated with existing generation, transmission and distribution assets, including the recovery of investment and maintenance costs. In addition, we forecasted other costs that do not relate to generation, transmission, distribution and customer programs, such as general and administrative costs. We held all of these "base" costs constant across cases.

We then determined the costs for investments that differed across the system plans and leveraged the outputs from the different planning processes to determine any incremental investments. To determine the annual costs for these investments, we applied straight-line depreciation and assumed a cost of capital consistent with SRP's weighted average cost of capital. SRP also estimated property taxes for these investments based on previously observed tax rates. Lastly, we leveraged the outputs from the planning processes to forecast operating expenses.

Generation

The Resource Additions process identified incremental generation investments, operation and maintenance fixed costs, and power purchase agreement costs. The Resource Operations process identified all variable operating costs associated with generation, including fuel expense, net market purchase costs, and variable operations and maintenance costs.

Transmission

The Transmission Investments process identified any incremental transmission system investments for the three cases analyzed. SRP further differentiated these costs by investments that are generation-driven versus load-driven to estimate costs in other cases. Using the three transmission cases analyzed, we calculated a linear relationship between (1) generation-driven costs and interconnected capacity additions, and (2) load-driven costs and peak load growth. We then applied those relationships to interconnected capacity additions and peak load growth observed in each of the remaining cases.

Distribution

The Distribution Investments process identified incremental distribution system investments, including transformers to serve new customers, new substations and substation upgrades. SRP identified these investments for each scenario as well as the high distributed generation and high energy efficiency sensitivities. The investment types and estimated costs remained consistent across the three strategic approaches.

Customer Programs

The Customer Programs process identified the incremental customer program operating costs. These costs reflected the cost of Energy Efficiency and Demand Response programs.

Key Outputs

The Total System Cost process generated annual cost estimates for all 42 system plans. The table below summarizes the key outputs. These outputs served as key inputs in calculating residential bill impacts across cases (see the Residential Bill Impact section below).

Output	Description	Output Units
Total System Cost	Total system costs across generation, transmission, distribution and other	$
Average System Cost	Total system cost divided by retail sales	$/MWh

Residential Bill Impact

In this process, we applied a simplified method to estimate the bill impacts over time for residential customers. While the Total System Cost process estimated how total costs could evolve over time, this process estimated how these changes could impact residential customers specifically and developed a residential bill impact metric.

This bill impact analysis does not necessarily reflect how future costs may be allocated and recovered from customers and therefore should not be considered as a projection of customer rates. SRP will carry out pricing processes in the future to determine future cost allocation and rates. Nevertheless, this metric provides a means for comparing cases to understand relative differences.

Methodology Overview

We leveraged information from our most recent Cost Allocation Study (CAS) to allocate costs in the ISP to residential customers. The CAS determined how the energy usage of residential customers differed from other customer classes (e.g., commercial and industrial) and developed cost allocators for different system cost components (e.g., generation and fuel). Because different system cost components are driven by different factors (e.g., total annual energy use, peak hour energy usage), the cost allocators differ by system cost component. This ensures that each customer class pays its fair share of system costs, based on the cost of serving those customers.

Below is the methodology we used in the ISP to allocate costs for different system components to residential customers:

- **Generation –** Generation-related costs, including operations and maintenance (O&M) costs, power purchase agreement (PPA) costs and recovery of investment costs, are allocated based on a blend of two factors: the share of annual delivered energy (in kWh) and the share of energy demand (in MW) during overall system peak periods.

- **Fuel –** Fuel costs, including natural gas, coal and (in some ISP cases) hydrogen fuel costs, are allocated based on the share of total annual energy demand (in kWh), calculated as the total annual delivered energy less any energy exported to the grid.
- **Transmission –** Transmission costs, including O&M costs and recovery of investment costs, are allocated based on the share of energy demand (in MW) during overall system peak periods.
- **Distribution –** Distribution costs, including O&M costs and recovery of investment costs, are allocated based on the peak hourly energy demand of the customer class (in MW) — not necessarily during the overall system peak period — relative to the peak hourly energy demands of other customer classes.
- **Customer Service, Billing and Metering –** Customer service, billing and metering costs are allocated based on the share of the total number of customers served by SRP.
- **Other Costs –** Other costs, including net market purchase expenses and any other costs not described above, are allocated according to the share of total generation, transmission and distribution costs.

To determine the average residential customer cost (in ¢/kWh), SRP divided the total costs allocated to residential customers by the total annual energy demand (in kWh). SRP then compared these average residential costs to the actual costs for residential customers in November 2022 to show the change through 2035.

Key Outputs

The key output of this process is the average residential bill impact:

Output	Description	Output Units
Average Residential Customer Cost	Average residential customer cost for each ISP case.	¢/kWh

Development and Operational Risk Assessments

Our team evaluated the development and operational risk factors for different system plans. While the various planning processes identified future infrastructure additions based on least-cost optimization analysis, as well as future operations based on simulations, there are many real-world risks to consider that could impact SRP's ability to develop and operate these system plans.

There are risks and challenges in developing new infrastructure, including risks related to permitting, siting, constructing and acquiring new infrastructure. As we have observed over the last few years, third-party projects can be delayed or even cancelled due to supply chain challenges. Supply chain issues have also led to increased timelines for acquiring new transmission and distribution infrastructure. There are also risks in developing large new infrastructure projects, which may depend on multiple regulatory approvals and therefore come with uncertainty. Because each of the ISP system plans requires significant development

of new resources, we performed a qualitative risk assessment to better understand the risks and challenges in building out these future power systems.

There are also risks and challenges in operating the power system in new ways. While the production cost model simulated future operations based on hourly optimization analysis, many real-world risks cannot be captured fully in that analysis and could potentially impact SRP's operations. There are risks related to more variable system operations, fuel availability, wear and tear on generating resources, etc. Because each of the ISP system plans requires a meaningful shift in the future operations of the system, we performed a qualitative risk assessment to better understand the risks and challenges in operating these future power systems.

Methodology Overview

Our team developed qualitative development and operational risk ratings for each system plan to understand the relative risks between different system plans. This approach is used to assess uncertainty in factors where it is not easily quantified and is known as the expert opinion method.

First, because the ISP assessed many planning cases, and some of the resulting system plans were relatively similar across cases, we clustered some plans together when performing the risk assessment.[9] The clustered system plans were representative of the 12 core system plans (three strategic approaches evaluated against four scenarios). We then convened an internal group of subject matter experts from various departments to assess the development and operational risks for each of the system plans. After the group assessed the different system plans independently, SRP held a joint workshop during which the group discussed findings, identified risks, discussed mitigation factors and developed risk ratings.

To develop a quantitative risk rating, each participant rated each cluster of system plans on a scale from 1 to 5, with 1 being lowest risk and 5 being highest risk. We identified a reference plan (Tech Neutral, Current Trends) to correspond to a risk rating of 3 to calibrate a point of reference. The participants rated each cluster of system plans based on how the risk factors for that plan compared to the risk factors identified for the reference plan, and SRP averaged these ratings to develop a final risk rating for each system plan.

Development Risk Assessment

To evaluate the development risks for different system plans, we convened an internal group of subject matter experts from the following groups within SRP:

- **Resource Planning, Acquisition and Development**, consisting of engineers and analysts responsible for acquiring and developing power generation resources (renewable and thermal) to meet system needs
- **Distribution Planning**, consisting of engineers who plan distribution infrastructure
- **Innovation & Development**, consisting of engineers who support research into emerging generation technologies (e.g., hydrogen, nuclear small modular reactors, and carbon capture and storage)

[9] For the development risk assessment, SRP clustered system plans based on resource additions across different technologies. For the operational risk assessment, SRP clustered system plans based on multi-hour ramping needs, natural gas fuel consumption, market purchases, solar additions, wind additions, battery storage additions, and curtailment.

- **Power Delivery**, consisting of engineers and planners who support generation interconnection and plan, site and build necessary transmission infrastructure
- **Land**, consisting of analysts responsible for acquiring necessary land for new projects
- **Supply Chain Management**, consisting of analysts managing procurement of long-lead-time equipment
- **Supply and Trading & Fuels**, consisting of power and natural gas traders and analysts focused on market operations
- **Customer Programs**, consisting of analysts who develop and manage customer programs (e.g., energy efficiency, electrification)
- **Environmental Services**, consisting of engineers and scientists who support site permitting and ensure compliance with environmental regulations
- **Community Partnerships**, consisting of community strategists who work with and support the communities that SRP operates within

We provided each of these groups with the outputs for different system plans and then tasked them with evaluating the system plans based on the following development risk factors:

- Permitting, siting and land acquisition
- Supply chain challenges
- Long lead times to develop infrastructure
- Interconnection of new resources
- Natural gas pipeline development
- Reliance on emerging technologies
- Reliance on customer adoption of end-use programs (such as energy efficiency and distributed generation)

Operational Risk Assessment

For the operational risk assessment, we followed a process similar to that used for the development risk assessment. To evaluate the operational risks for different system plans, we convened an internal group of subject matter experts from the following groups within SRP:

- **Supply and Trading & Fuels**, consisting of electricity and natural gas traders and analysts focused on markets and operations
- **Operations Planning**, consisting of analysts focused on modeling the market, optimal dispatch and maintenance planning
- **Transmission & Generation Operations**, consisting of real-time power dispatchers
- **Operational Readiness**, consisting of engineers leading the processes for enabling additional solar and batteries onto SRP's system
- **Generation Engineering**, consisting of engineers analyzing the maintenance needs of generation plants

We provided each of these groups with the outputs for different system plans and then tasked them with evaluating the system plans based on the following operational risk factors:

- System ramping needs and capabilities
- Renewable curtailment
- Thermal unit operations (capacity factor, starts and hours of operation)
- Reliance on market purchases for electricity
- Natural gas hourly and daily consumption

Key Outputs

Output	Description	Output Units
Development Risk Rating	Risk rating summarizing the degree of development risks associated with a given system plan	Likert Scale (1 = lowest risk, 5 = highest risk)
Operational Risk Rating	Risk rating summarizing the degree of operational risks associated with a given system plan	Likert Scale (1 = lowest risk, 5 = highest risk)

Metrics

We developed metrics for ISP cases to evaluate the performance of each strategic approach across scenarios and sensitivities, provide information to customers and other stakeholders, and to inform the ISP residential customer research. Figure 5.18 lists the metrics we developed to evaluate the performance of different system plans, which include reliability, affordability, sustainability and customer focus metrics.

FIGURE 5.18: ISP METRICS



Reliability

Resource Contribution to Reliability

Reliance on Emerging Technologies

Qualitative Risk Ratings (Development Risk and Operational Risk)

Planning Reserve Margin

Affordability

Total System Costs

Average System Costs

Average Residential Price Impact

Sustainability

CO_2 Reductions

Water Use

Carbon-Free Generation

Capacity Factor for Gas Fleet

Direct Air Emissions (NOx, SO_2, PM, VOC)

Customer Focus

Customer Preference Rating

CO_2 reductions from energy efficiency, distributed generation and electrification

We developed most of these metrics through the modeling processes described above. The Total System Cost and Residential Price Impact processes produced the affordability metrics. The Resource Operations process produced the sustainability metrics. And lastly, the Resource Additions, Development Risk Assessment and Operational Risk Assessment processes produced the reliability metrics.

For the Customer Focus metrics, we completed additional analysis separate from the modeling processes described above. To develop the Customer Preference Rating, SRP engaged Bellomy Market Intelligence to complete the ISP residential customer research. The goal of Bellomy's research was to bring the voice of SRP's residential customers into the planning of the future power system. More specifically, this research was designed to gain an understanding of how customers view and value sustainability, affordability and reliability related to their electricity service from SRP and gauge their reactions to potential energy systems being analyzed in the ISP. A choice-based methodology known as a conjoint exercise was utilized to understand customer preference for potential future energy systems being analyzed in the ISP and ultimately develop the Customer Preference Rating. More details on the specific methodology are included in appendices B and C, which contain reports from all phases of the ISP residential customer research effort.

To develop the CO_2 Reductions metric for various customer programs (including energy efficiency, distributed generation, demand response and electrification), we estimated the amount by which additional amounts of these programs could decrease economywide greenhouse gas emissions. For energy efficiency and distributed generation, we evaluated how much annual emissions would decrease in each planning case if customer adoption increased slightly. For electrification measures (including electric vehicles and heat pumps), we estimated how much annual emissions from electricity generation would increase from customers adopting these measures and increasing energy demand. In addition, we estimated how much emissions would decrease from displaced fossil fuel consumption (in vehicles or home heating systems) to arrive at an estimate for net decrease in economywide emissions for adoption of electrification measures.

Ultimately, planning a future energy system involves trade-offs between different planning goals for the system. No single system plan performed the best in every metric that we quantified. We utilized this suite of metrics to evaluate trade-offs between different strategic approaches and to understand how planning would need to adapt under future planning uncertainties.

SECTION 6

Results

This section presents the modeling results and key findings from the ISP analysis. The analytical results are presented for each planning process described in Section 5, including Customer Programs and End-Use Technologies, Load Forecast, Distribution Investments, Resource Additions, Resource Operations, Transmission Investments, Total System Cost, Residential Bill Impact, Development and Operational Risk Assessment, and Residential Customer Research. Several ISP key findings are highlighted in callout boxes throughout and then summarized at the end of this section.

Results

Customer Programs and End-Use Technologies

Customer programs play an important role in managing SRP's load and are a key input to the load forecast used in the ISP. Also, customer adoption of end-use technologies, such as electric vehicles and distributed generation, have an increasing impact on the load forecast over time. This section presents the forecasts through 2035 for annual energy efficiency savings, demand response capacity, additional electrification load, and customer adoption of distributed generation across each scenario.

Figure 6.1 shows the incremental new energy efficiency savings. Under Current Trends, Desert Boom and Desert Contraction, there is continued expansion in energy efficiency over time, reaching 3,236 GWh of new energy efficiency savings by 2035. Under Strong Climate Policy, expansions to federal codes, standards and incentives lead to even higher energy efficiency growth, reaching 3,896 GWh of total energy efficiency savings by 2035.

Figure 6.2 shows the cumulative demand response capacity through 2035. Under all scenarios, SRP doubles demand response capacity, reaching 300 MW of total demand response by 2035.

FIGURE 6.1: ANNUAL NEW ENERGY EFFICIENCY ASSUMPTIONS

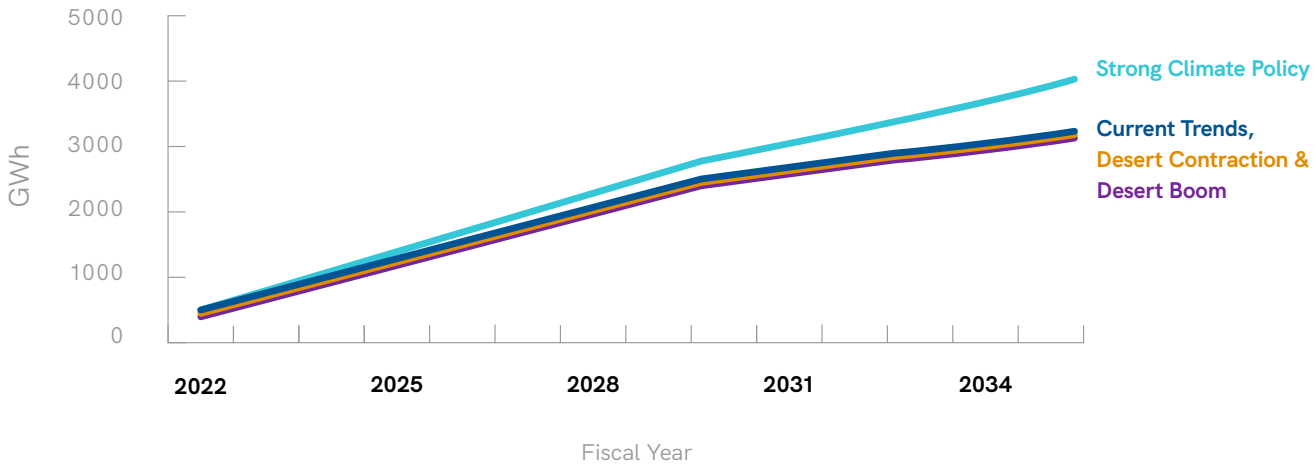
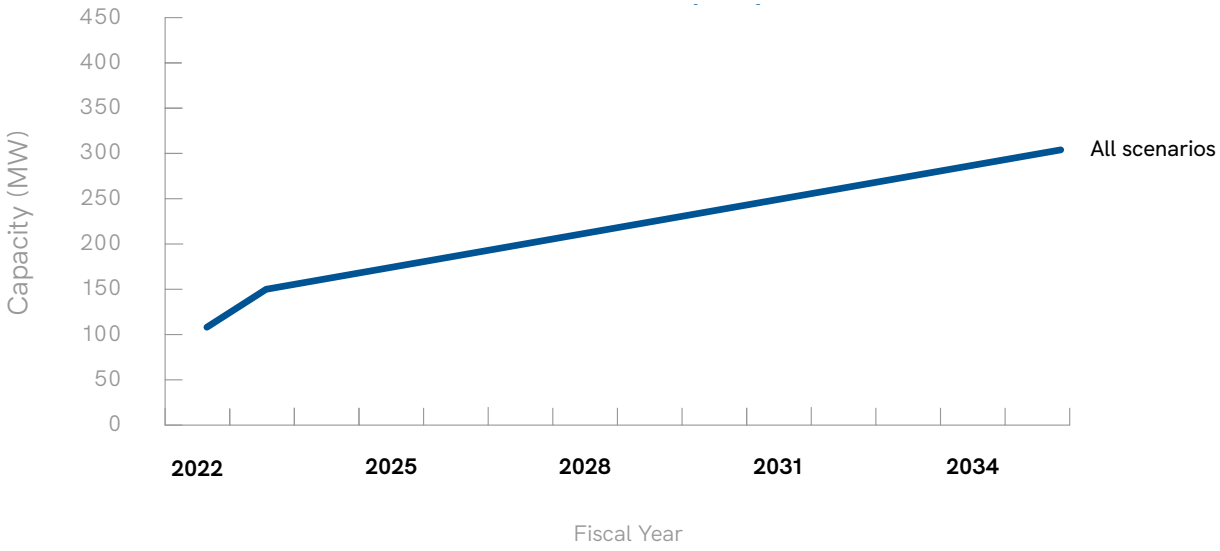


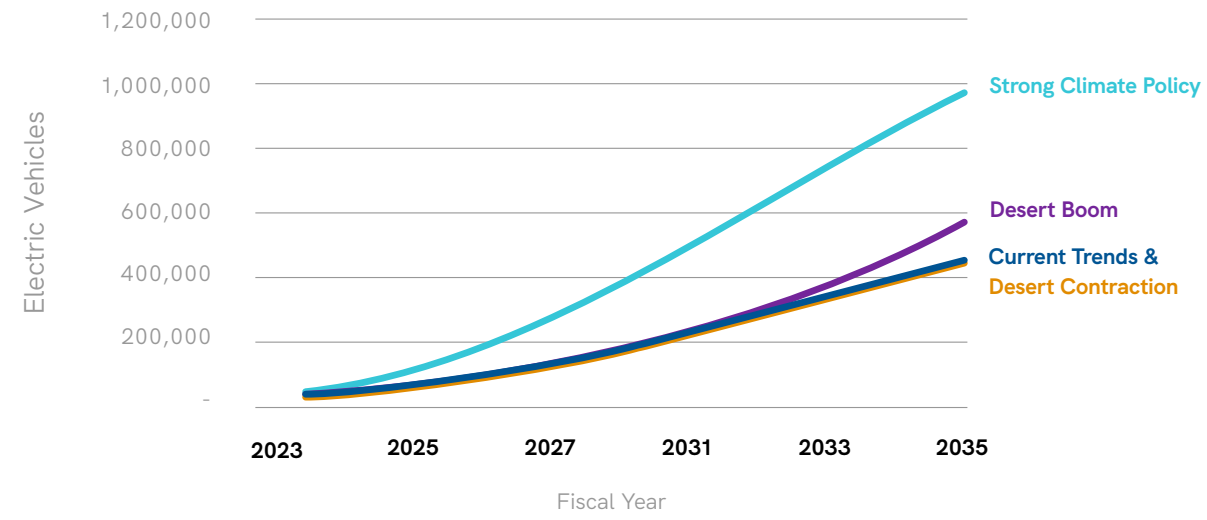
FIGURE 6.2: CUMULATIVE DEMAND RESPONSE CAPACITY ASSUMPTIONS



In addition to the energy efficiency and demand response programs, SRP's electric technologies programs, which serve commercial and industrial customers, grow meaningfully over time. The load impact from these programs grows from approximately 50,000 MWh today to levels consistent with SRP's goal of 300,000 MWh by 2035. The programs are varied and include electrification of material handling equipment (forklifts, scissor lifts, boom lifts, scrubbers, sweepers, etc.), truck stop and truck refrigeration equipment, industrial heating processes (melting, curing, steam, etc.), space and water heating processes, and commercial cooking equipment.

Figure 6.3 shows projected customer adoption of electric vehicles through 2035. Under the Current Trends and Desert Contraction scenarios, customers adopt 500,000 electric vehicles by 2035, consistent with SRP's 2035 goal for electric vehicle adoption. Under the Desert Boom scenario, customers adopt more electric vehicles due to increased economic and population growth. Under the Strong Climate Policy scenario, SRP assumed that increased federal support will result in greater customer adoption of electric vehicles at levels consistent with reaching net-zero economywide emissions by 2050.

FIGURE 6.3: ELECTRIC VEHICLE ADOPTION FORECAST



In addition to customer energy demand, customer adoption of generating resources also impacts the overall forecast for future energy demand. SRP forecasts customer adoption of rooftop solar and batteries to grow, reducing future energy demand (see figures 6.4 and 6.5).

In the Current Trends and Desert Contraction scenarios, rooftop solar and battery adoption increase steadily, reaching 1,296 MW and 75 MW, respectively, by 2035. In the Desert Boom scenario, an increased population and economic growth lead to stronger rooftop solar and battery adoption, reaching 1,804 MW and 157 MW, respectively, by 2035. In the Strong Climate Policy scenario, rooftop solar and battery adoption increase the most due to accelerated technology improvements and cost declines assumed in this scenario. By 2035, solar and battery adoption reach 2,257 MW and 250 MW, respectively, in the Strong Climate Policy scenario.

FIGURE 6.4: ROOFTOP SOLAR ADOPTION NAMEPLATE CAPACITY (MW) FORECAST

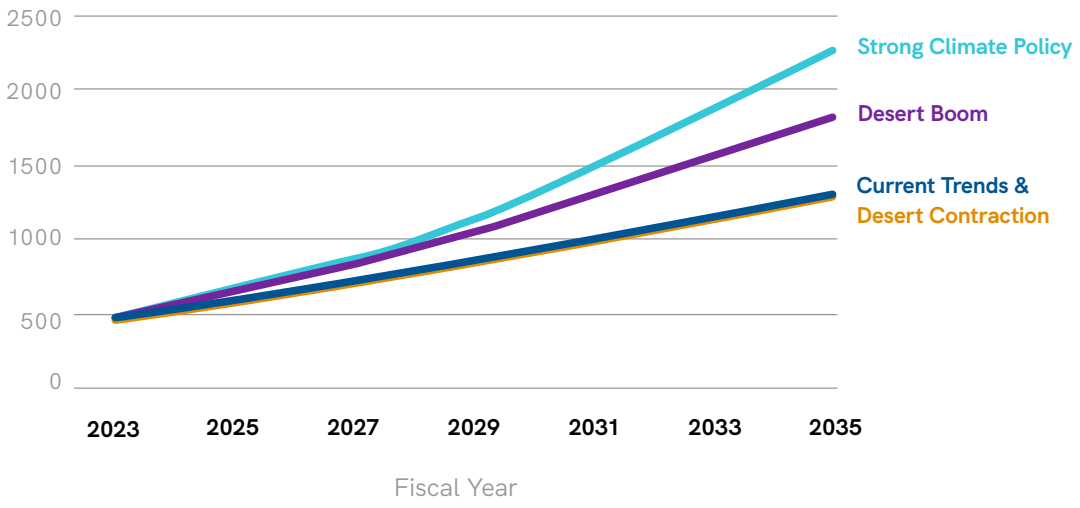
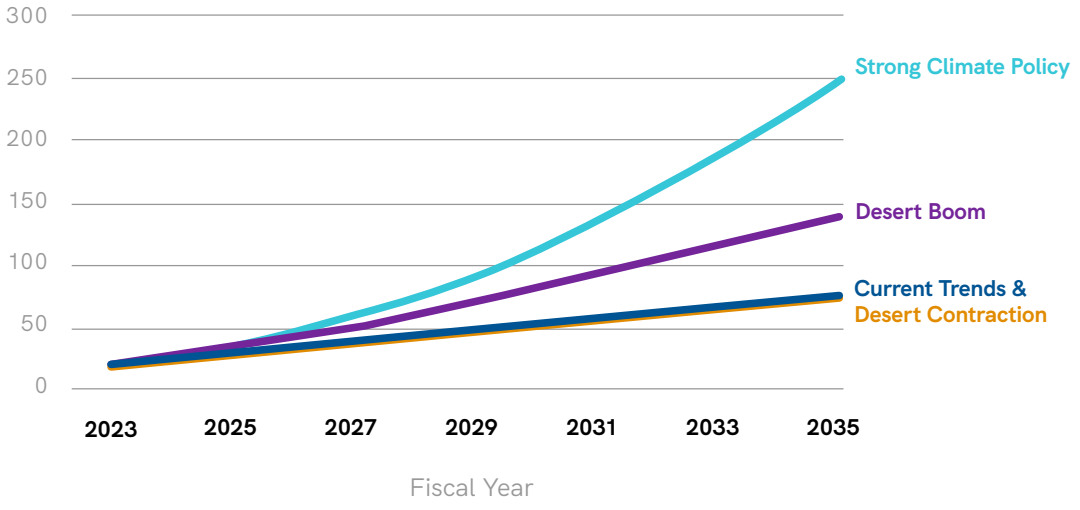


FIGURE 6.5: CUSTOMER-OWNED BATTERY ADOPTION NAMEPLATE CAPACITY (MW) FORECAST



Load Forecast

The load forecast is a key input to all the planning processes, as it is a main driver of future investment needs. This section presents the peak load and annual energy demand forecasts through 2035 for the four scenarios.

KEY FINDING

Customers' energy demand is expected to increase rapidly through 2035 in most scenarios, even with significant expansion of customer programs and customer-sited generation.

Figures 6.6 and 6.7 show peak load and energy demand forecasts for the four scenarios. SRP forecasts rapid load growth in the Current Trends, Desert Boom and Strong Climate Policy scenarios. In the Current Trends scenario, high economic and population growth lead to a substantial increase in both peak load and energy demand. In the Desert Boom scenario, accelerated migration into the Phoenix metropolitan area and increased economic development lead to even higher loads. In the Strong Climate Policy scenario, load growth from rapid electrification is offset by increased customer programs, resulting in a similar, but slightly lower, load forecast as for Current Trends. Across these three scenarios, between 2023 and 2035, peak load grows annually by 2.9%–4.0%, and annual energy demand grows annually by 3.1%–4.8%. The Desert Contraction scenario initially follows a rapid growth trajectory, but then peak load levels off and annual energy demand declines, reflecting a reversal of recent trends in migration and economic growth. Altogether, these load forecasts represent a wide range of future outcomes, from little to no growth in Desert Contraction to accelerated growth in Desert Boom.

FIGURE 6.6: PEAK LOAD (MW) FORECASTS BY SCENARIO

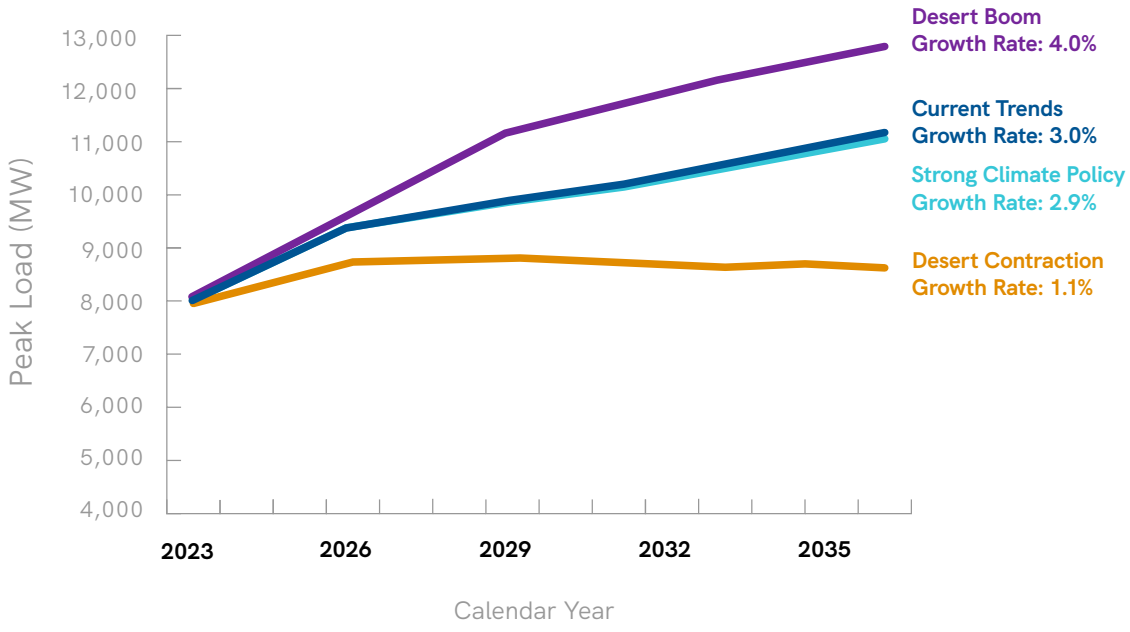
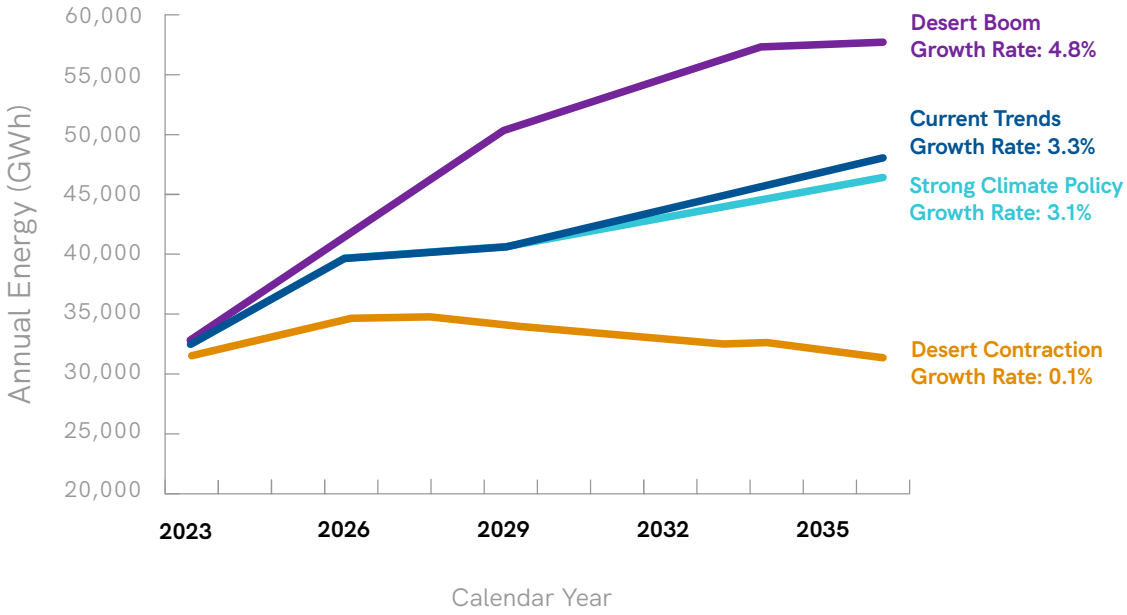


FIGURE 6.7: ENERGY DEMAND (GWH) FORECASTS BY SCENARIO



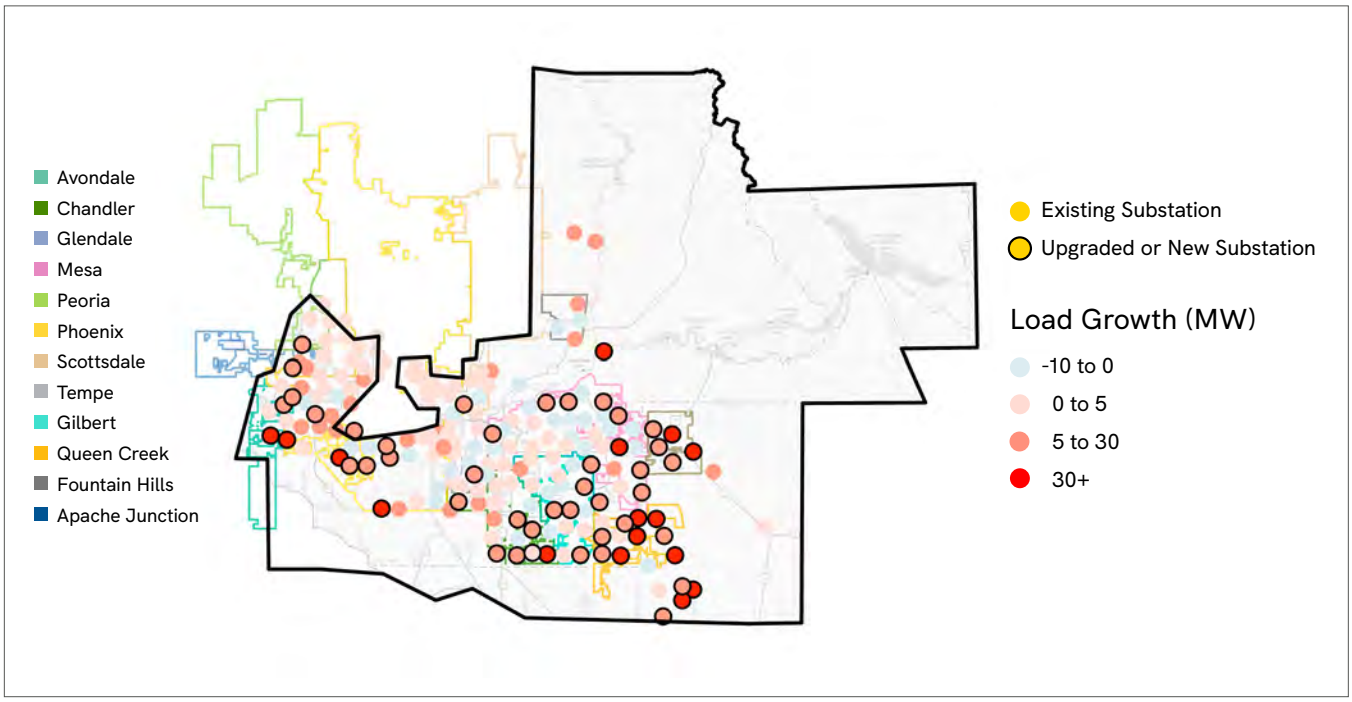
Distribution Investments

Future load growth and customer adoption of new technology increases the demand requirements on SRP's distribution system. SRP adapts to these changes through upgrades to existing infrastructure and investments in new infrastructure, such as distribution substations to serve new loads. This section describes the estimated distribution investments required to reliably serve customers across each scenario.

Figure 6.8 illustrates load growth changes in megawatts (MW) by distribution substation between 2022 and 2035 under the Current Trends scenario, highlighting new substation additions as well as upgrades required at existing substations (i.e., new substation bays added). Load growth and investment needs vary across SRP's service area. The Current Trends scenario results shown below are representative of the other scenarios' results and indicate the most significant load growth would occur in the Southeast Valley, requiring greater investments in that planning region. Additionally, the southwest portion of SRP's service territory sees relatively high load growth, requiring more investments. While these patterns are consistent across scenarios, the level of investments and upgrades needed by 2035 varies with load growth in each scenario, with more investments needed in the Desert Boom scenario and fewer investments needed in the Desert Contraction scenario.



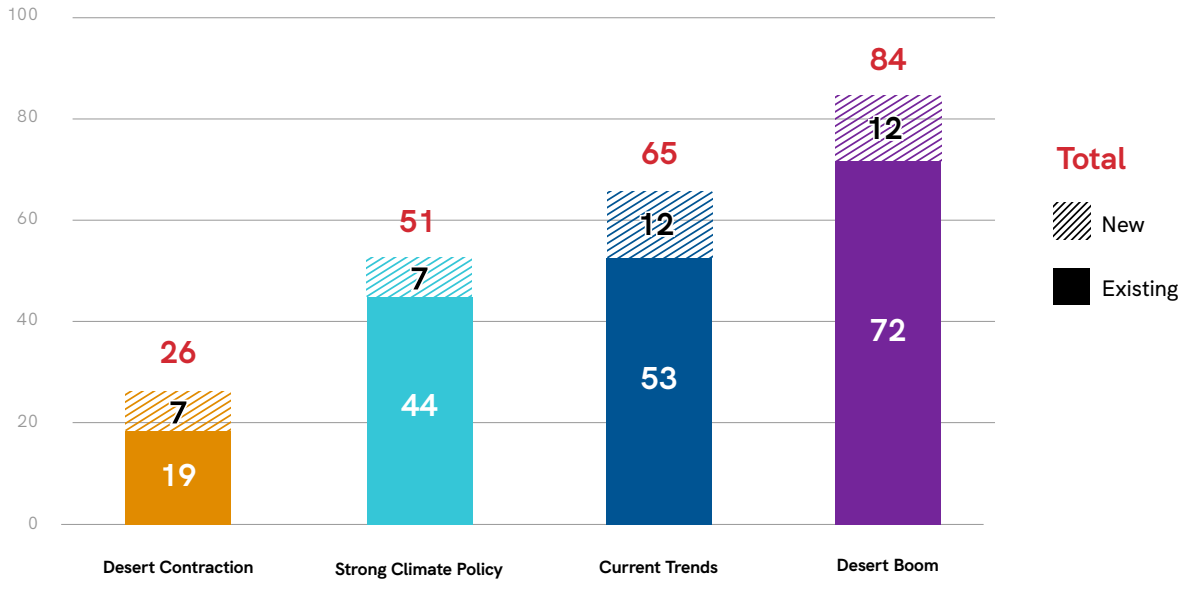
FIGURE 6.8: LOAD GROWTH BY DISTRIBUTION SUBSTATION THROUGH 2035 UNDER CURRENT TRENDS



See Figure 6.9 for the substation bay additions needed through 2035 across each of the scenarios and sensitivities. Across the scenarios, between 26 and 84 new substation bays are needed. A greater need for new distribution infrastructure is correlated with higher load growth across the scenarios. For example, substation bay additions more than triple in the Desert Boom scenario compared to what is required in the Desert Contraction scenario.

As electricity demand continues to grow in SRP's service territory, SRP will need to invest in the distribution system to enable this growth. The level of investments required will depend heavily on the rate of load growth.

FIGURE 6.9: SUBSTATION BAY ADDITIONS AT NEW AND EXISTING DISTRIBUTION SUBSTATIONS BY 2035

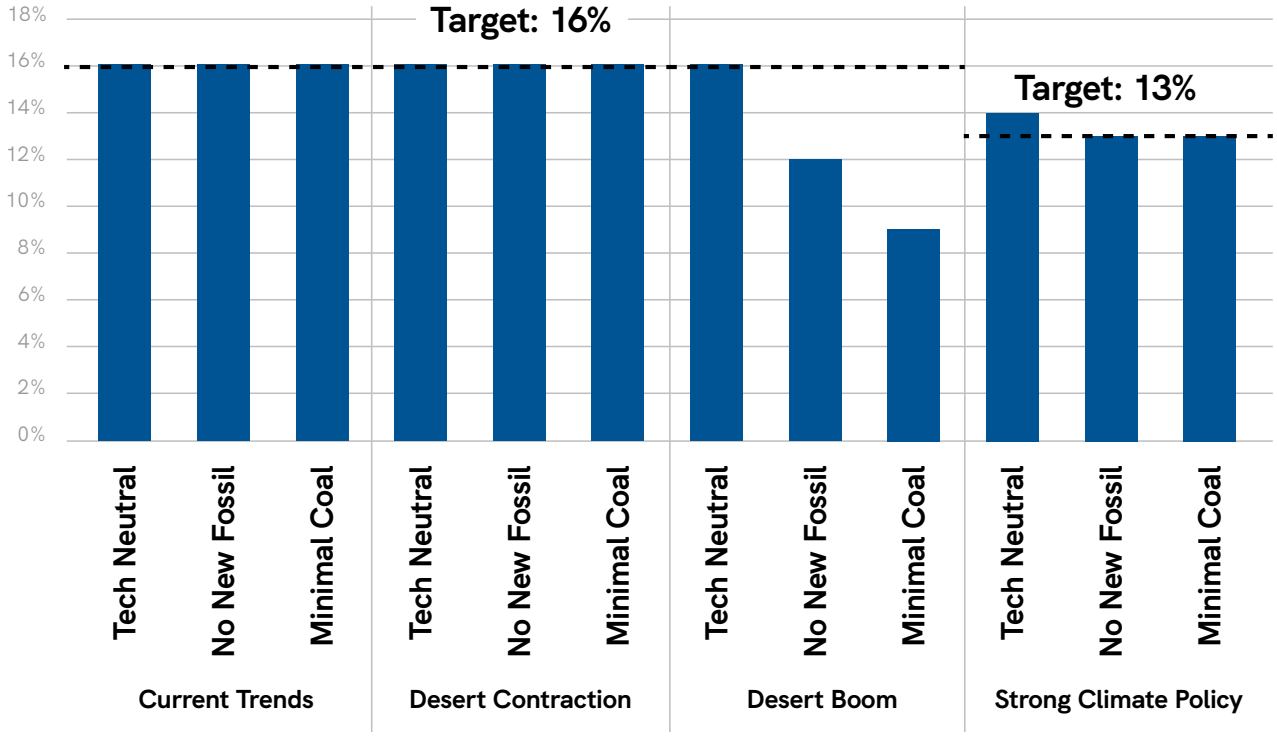


Resource Additions

SRP must add new resources to meet future energy demand, maintain system reliability, and meet the 2035 goals for carbon reduction and water resiliency. This section discusses the least-cost portfolios of generating resources selected by the long-term capacity expansion model across all scenarios and strategic approaches, as well as key reliability metrics.

For SRP to reliably serve customers across a wide range of system conditions, we must build sufficient resources to meet the planning reserve margin (PRM). The PRM is calculated using the load forecast and adding additional capacity to account for contingencies. This is a key metric because a plan that does not meet the PRM requirement is not reliable. Figure 6.10 shows the achieved PRM in 2035 across scenarios and strategic approaches compared with the requirement in each case. SRP's PRM requirement is 16% in all scenarios except for the Strong Climate Policy, where the PRM was reduced to 13% as a proxy to represent the potential benefits from expanded regional markets contributing to reliability.

FIGURE 6.10: ACHIEVED PLANNING RESERVE MARGIN IN 2035



All cases studied satisfy the PRM except for the No New Fossil and Minimum Coal strategic approaches in the Desert Boom scenario. Utilizing these two strategic approaches where firm resource options are limited[1], the accelerated load growth in Desert Boom compromises reliability as early as 2028. In these cases, there is insufficient capacity despite maximizing all available resource options. The third

KEY FINDING

Without new firm generation capacity, the system cannot satisfy reliability requirements under a high load growth scenario. In other load growth scenarios, the system can satisfy reliability requirements without new firm generation capacity but requires significant additions of renewable and energy storage resources.

[1] Firm resources include resources that can generate at sustained output for long periods of time. Firm resources studied in the ISP include natural gas, geothermal, biomass, natural gas with carbon capture and storage (CCS), biomass with CCS, nuclear small modular reactors (SMR), hydrogen and existing coal resources.

case, using a Technology Neutral strategic approach, is reliable in this scenario because it utilizes natural gas technology which was not an option in the No New Fossil and Minimum Coal strategic approaches. Because the No New Fossil and Minimum Coal cases do not meet SRP's reliability requirement, they are not viable in a Desert Boom scenario and were not evaluated further.

Figure 6.11 shows capacity additions through 2035 for all scenarios and strategic approaches. Customer programs, including energy efficiency, demand response and distributed generation, grow in all cases and offset the need for resource additions. Across all cases, renewable and energy storage resources make up a significant share of resource additions. In the Technology Neutral strategic approach, natural gas also accounts for a significant share of additions. In the No New Fossil and Minimum Coal strategic approaches, substantially more capacity is added as renewable and storage because these cases do not allow natural gas. This is because not all technology types contribute to reliability equally. Nearly all the capacity of a firm resource is counted toward the PRM while non-firm resources contribute a smaller portion. With fewer firm generation options, more total resources are needed to ensure reliability.

KEY FINDING

New renewables and firm capacity are part of a least-cost portfolio.

Due to differences in load growth, the Desert Contraction cases require fewer resources than Current Trends, while the Desert Boom cases require more resources. The Strong Climate Policy cases add significant amounts of renewable and storage resources to meet the stringent federal emissions target in this scenario.

KEY FINDING

If the U.S. government enacted a mandate for 85% CO_2 reductions by 2035 (Strong Climate Policy), SRP would need to significantly accelerate renewable and storage deployment.

FIGURE 6.11: CAPACITY ADDITIONS (MW) SELECTED BY MODEL BETWEEN 2025 AND 2035 UNDER ALL SCENARIOS

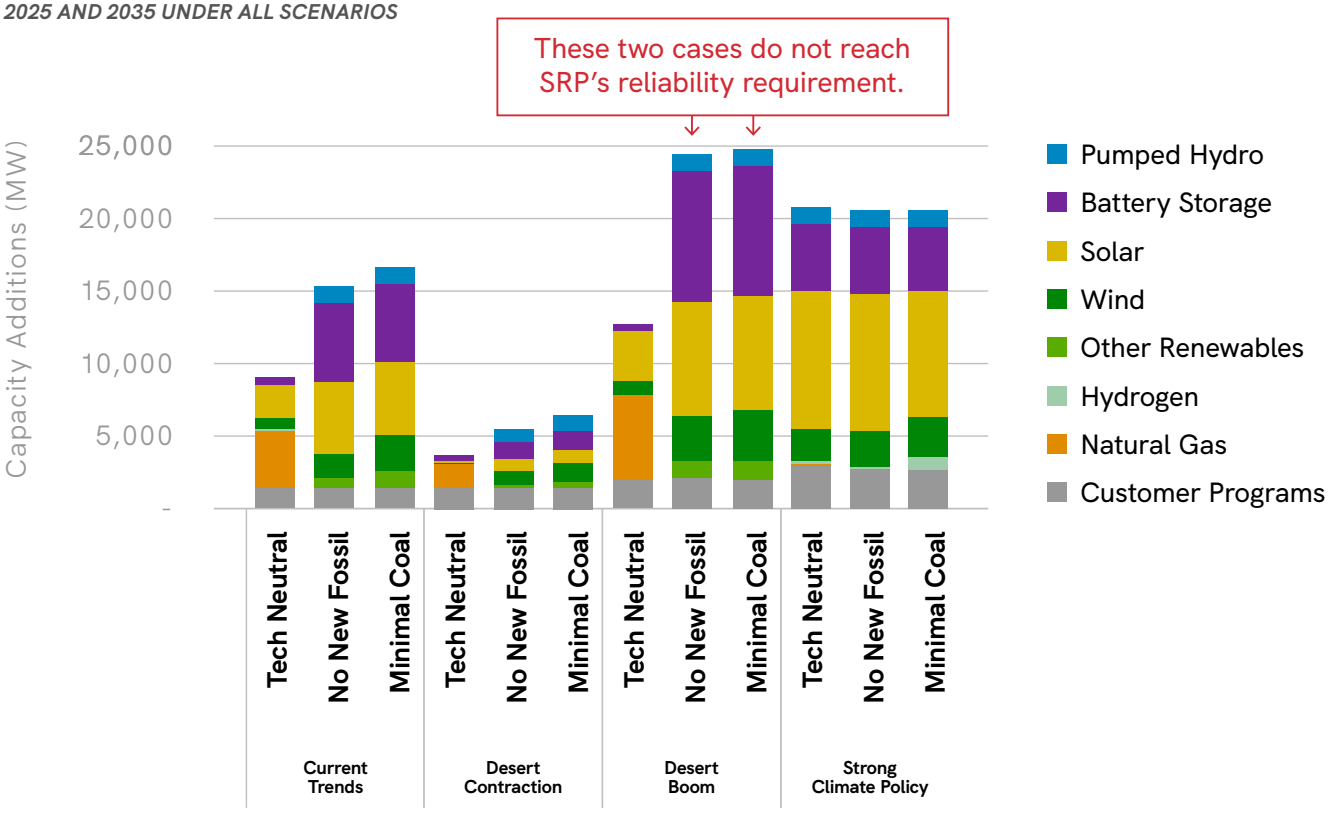


Figure 6.12 shows total installed capacity in 2035 for all scenarios and strategic approaches, as well as installed capacity in 2023 for reference. In the Technology Neutral and No New Fossil cases, more than 1,300 MW of coal capacity will be retired by 2035, with remaining coal capacity making up a small fraction of total capacity in 2035. In the Minimum Coal cases, all coal capacity retires by 2035. Looking across the system plans, there is a significant increase in total capacity between 2023 and 2035. Even the Desert Contraction scenario results in thousands of additional megawatts of capacity, while the other scenarios add more than 10,000 MW of capacity in many cases. Based on these results, SRP will likely need to double or triple its resource capacity in the next decade to serve customers to achieve reliability and sustainability goals, which marks an unprecedented rate of resource additions.

KEY FINDING

SRP will likely need to double or triple resource capacity in the next decade to serve customers while achieving reliability and sustainability goals. This will be at an unprecedented pace.

FIGURE 6.12: TOTAL INSTALLED CAPACITY (MW) IN 2023 AND IN 2035 UNDER ALL SCENARIOS

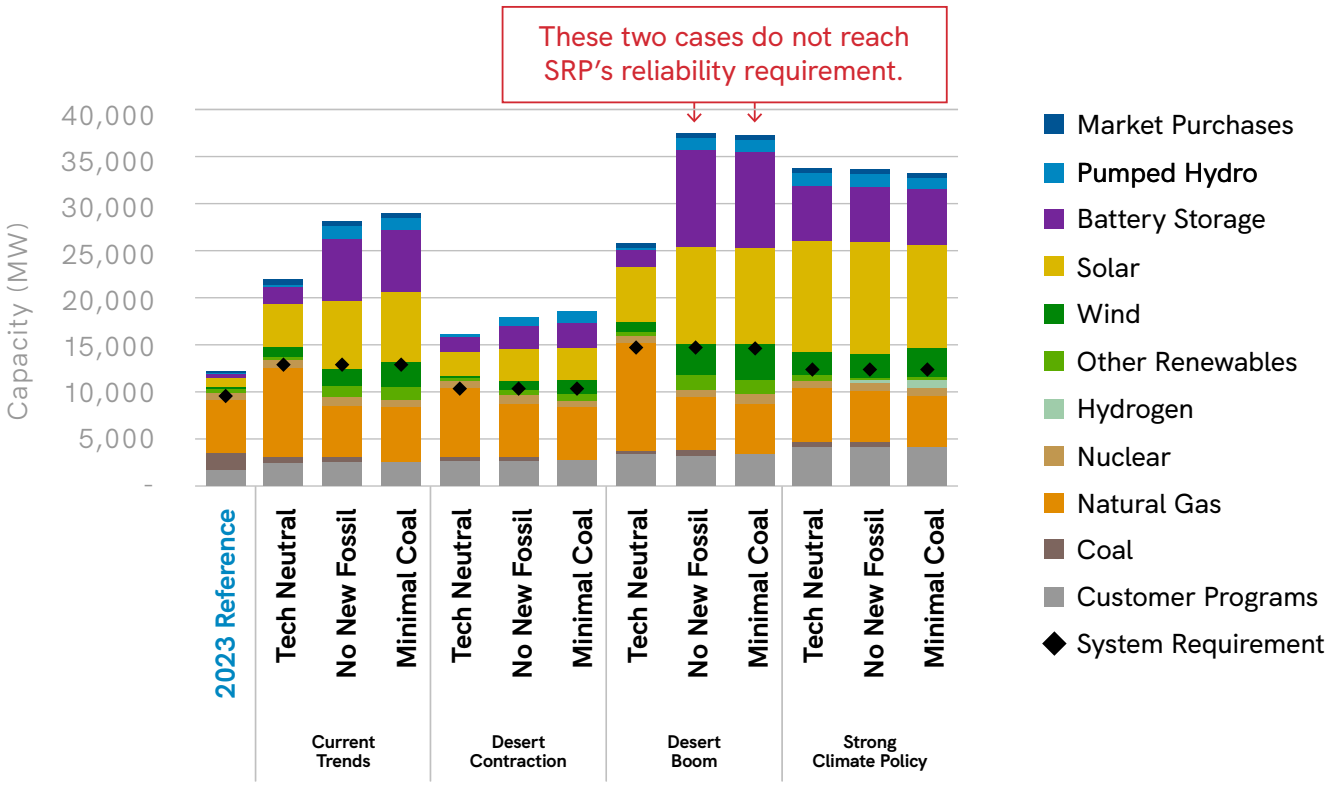
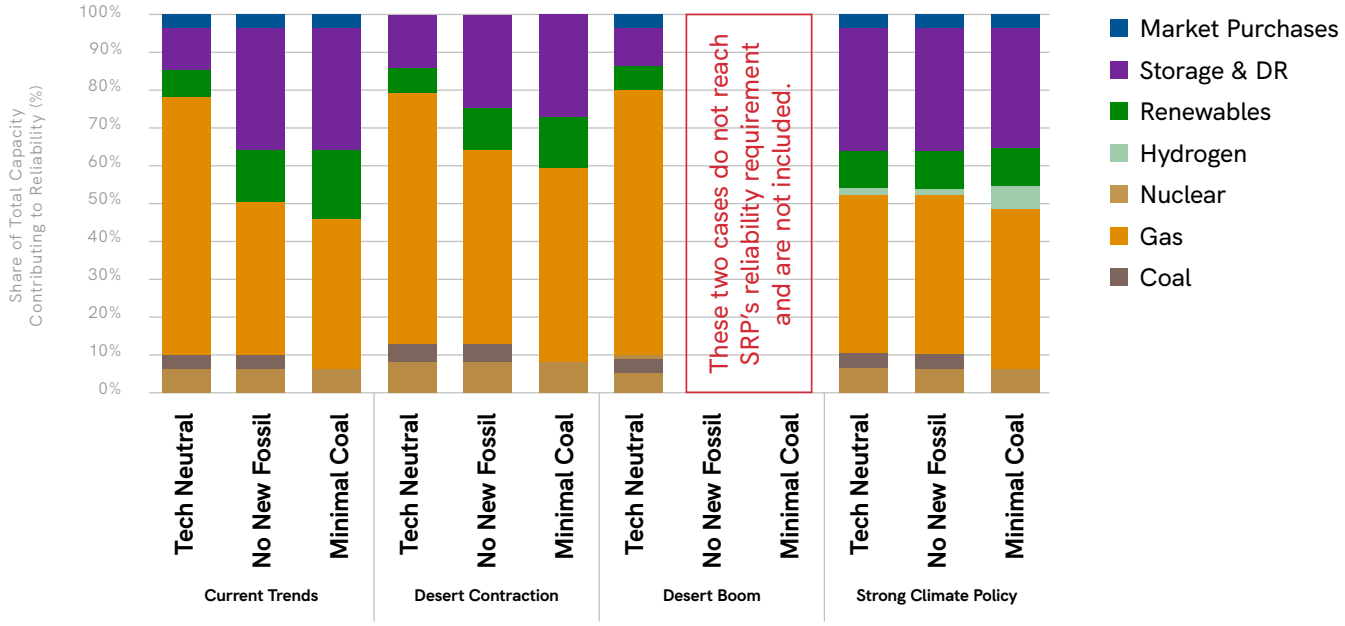


Figure 6.13 shows the contribution share of different resources toward satisfying the PRM requirement in each case. Firm resources are key to maintaining reliability; across all plans, firm resources (nuclear, coal, natural gas, geothermal, biomass and hydrogen) meet at least 55% of reliability needs in 2035, and more so in the Technology Neutral strategic approach. As noted previously, without new firm resources, reliability is compromised by 2028 in the Desert Boom scenario. New renewable and storage resources help contribute to reliability in all cases, and more so in the No New Fossil, Minimum Coal and Strong Climate Policy cases. Lastly, new firm capacity resources (natural gas or hydrogen), when included as an option per the scenario and strategic approach assumptions, are selected to help meet reliability needs at lower cost.

FIGURE 6.13: RESOURCE CONTRIBUTION TO RELIABILITY (RELIABILITY MIX) IN 2035



Note: Renewables includes solar, wind, geothermal, biomass and hydro. Storage & DR includes battery storage, pumped hydro and demand response (DR).

Relying on emerging technology can pose a risk in meeting future customer needs. Figure 6.14 shows the emerging technology selections across cases. The Strong Climate Policy scenario assumes accelerated availability of emerging technologies due to increased government support. Under this scenario, almost 200 MW of hydrogen are added in the Technology Neutral and No New Fossil cases and almost 800 MW in the Minimum Coal case, making up for lost capacity from the early retirement of Springerville Generating Station. This highlights again the value of a firm generation resource option and the potential for emerging technologies like hydrogen to provide firm generation. SRP acknowledges that to deploy 800 MW of hydrogen capacity, significant developments are needed in supply, storage and transportation infrastructure, which would require further advancements in the industry. While the ISP considers carbon capture and storage (CCS) and small modular reactor (SMR) options, these resources are not selected by the model in any of the cases by 2035.

FIGURE 6.14: RELIANCE ON EMERGING TECHNOLOGIES

	STRATEGIC APPROACH		
SCENARIO	Tech Neutral	No New Fossil	Minimum Coal
Current Trends	**No Emerging Technology Additions** Green hydrogen and nuclear SMR not available by 2035 CCS only available by 2035 in Tech Neutral		
Desert Contraction			
Desert Boom			
Strong Climate Policy	**178 MW** Green Hydrogen	**195 MW** Green Hydrogen	**790 MW** Green Hydrogen

Resource Operations

The changes in resource mix from coal retirements and new resource additions have significant implications for resource operations. This section describes the resource operations across cases as modeled in the production cost model, as well as key sustainability metrics.

Figure 6.15 shows the generation mix in 2035 across each scenario and strategic approach, including total generation in megawatt-hours (MWh) as well as the share of total generation for each resource type (%). Coal generation decreases significantly across all cases and only makes up a small share of generation in 2035. Customer programs and renewable generation increase across all cases. The total amounts of renewable and natural gas generation vary most significantly across cases and are explored further below.

FIGURE 6.15: TOTAL GENERATION (GWH) AND GENERATION MIX (%) IN 2035

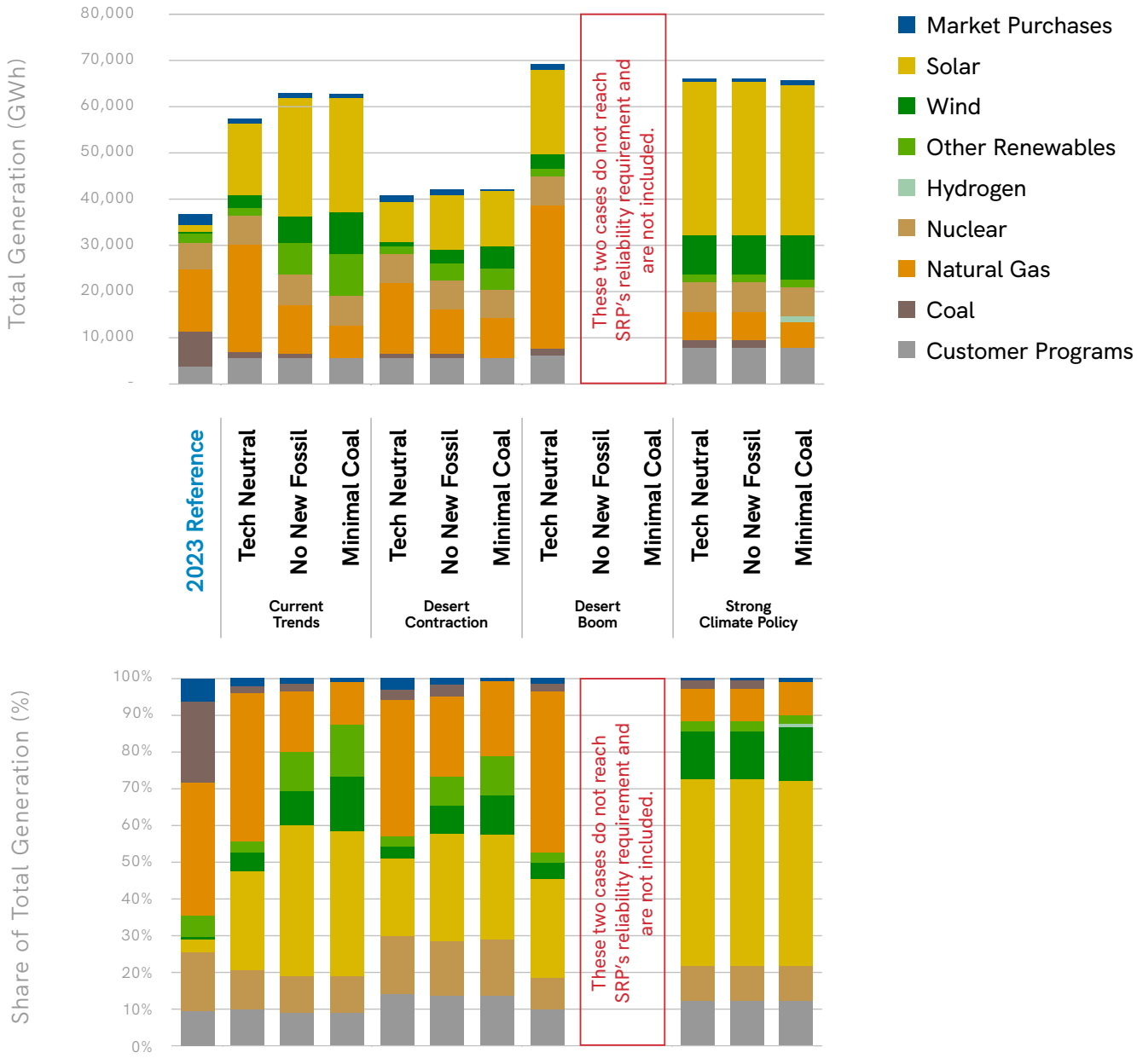
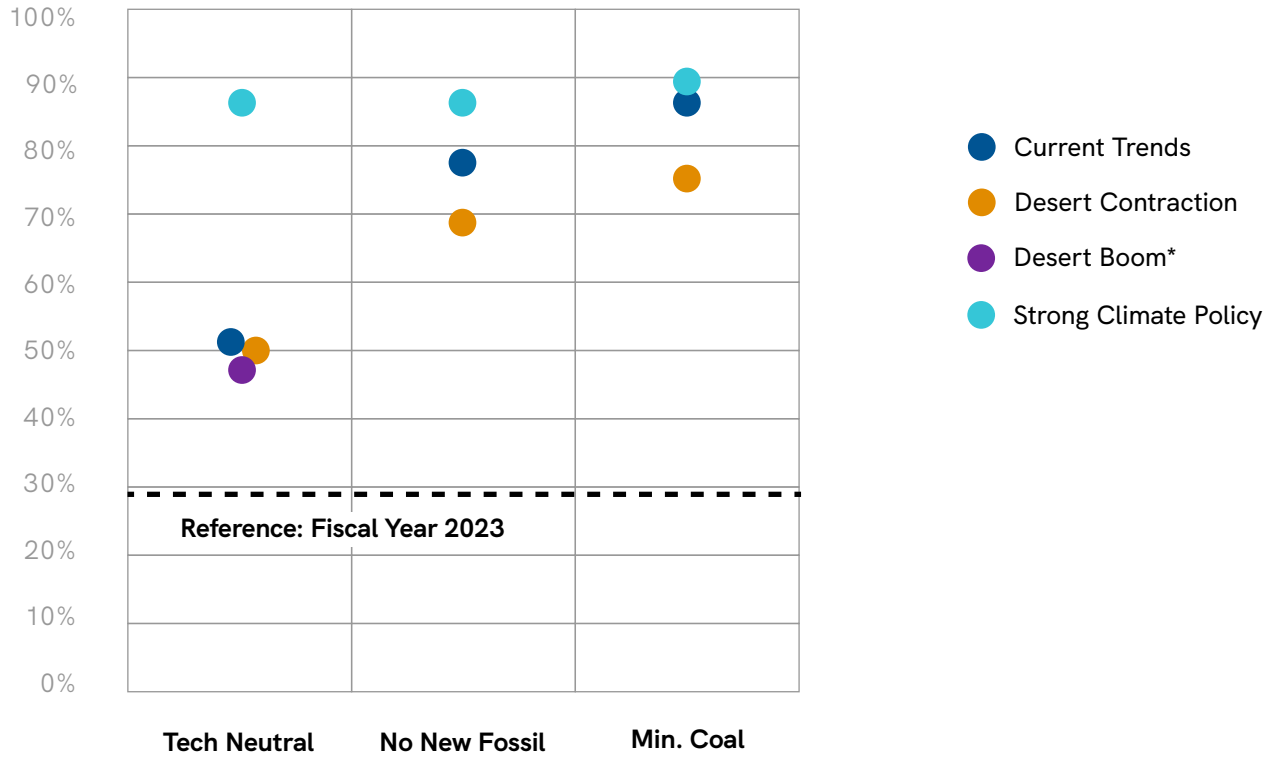


Figure 6.16 shows the percentage of generation coming from carbon-free resources, including nuclear, solar, wind, hydro, geothermal, biomass and hydrogen. Relative to 2023, the share of carbon-free generation increases across all system plans. System plans under the Strong Climate Policy scenario achieve the highest share of carbon-free generation across all strategic approaches, nearing 90%, driven by the more stringent federal emissions target. The No New Fossil and Minimum Coal strategic approaches result in more carbon-free generation compared with Technology Neutral because these cases add more renewable energy and storage to meet the PRM requirement.

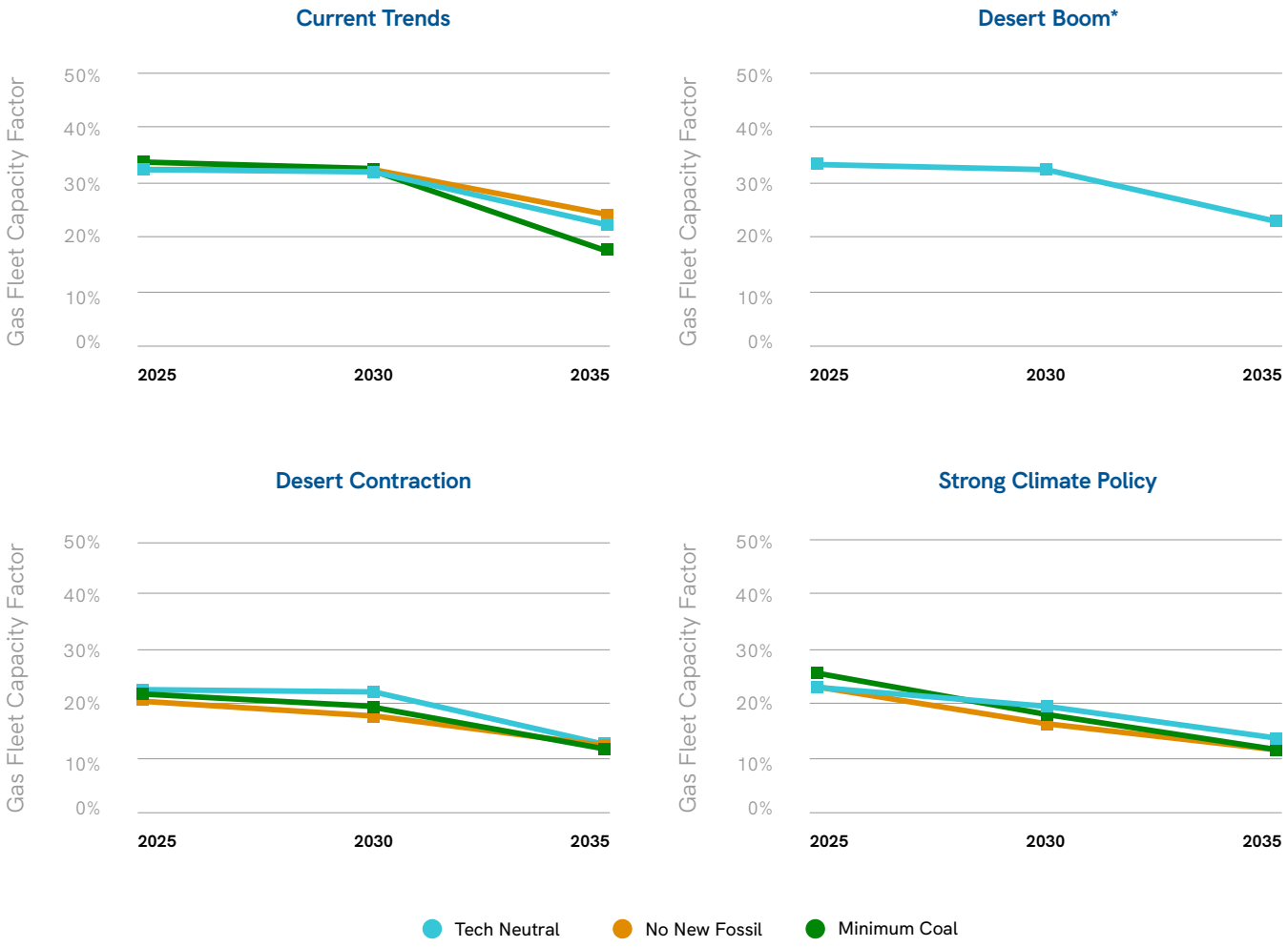
FIGURE 6.16: CARBON-FREE GENERATION BY 2035



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

The extent to which the natural gas-fired power plant fleet is utilized relates inversely to the share of carbon-free generation. Figure 6.17 shows the average capacity factor[2] for SRP's gas fleet[3]. The utilization varies slightly between strategic approaches and scenarios, but in all cases, the average utilization of SRP's gas fleet is projected to decline through 2035 as the system relies increasingly on renewable energy. These resources are available to help ensure system reliability but generate less during the year, in line with integrating more carbon-free resources and decreasing emissions.

FIGURE 6.17: CAPACITY FACTOR FOR GAS FLEET

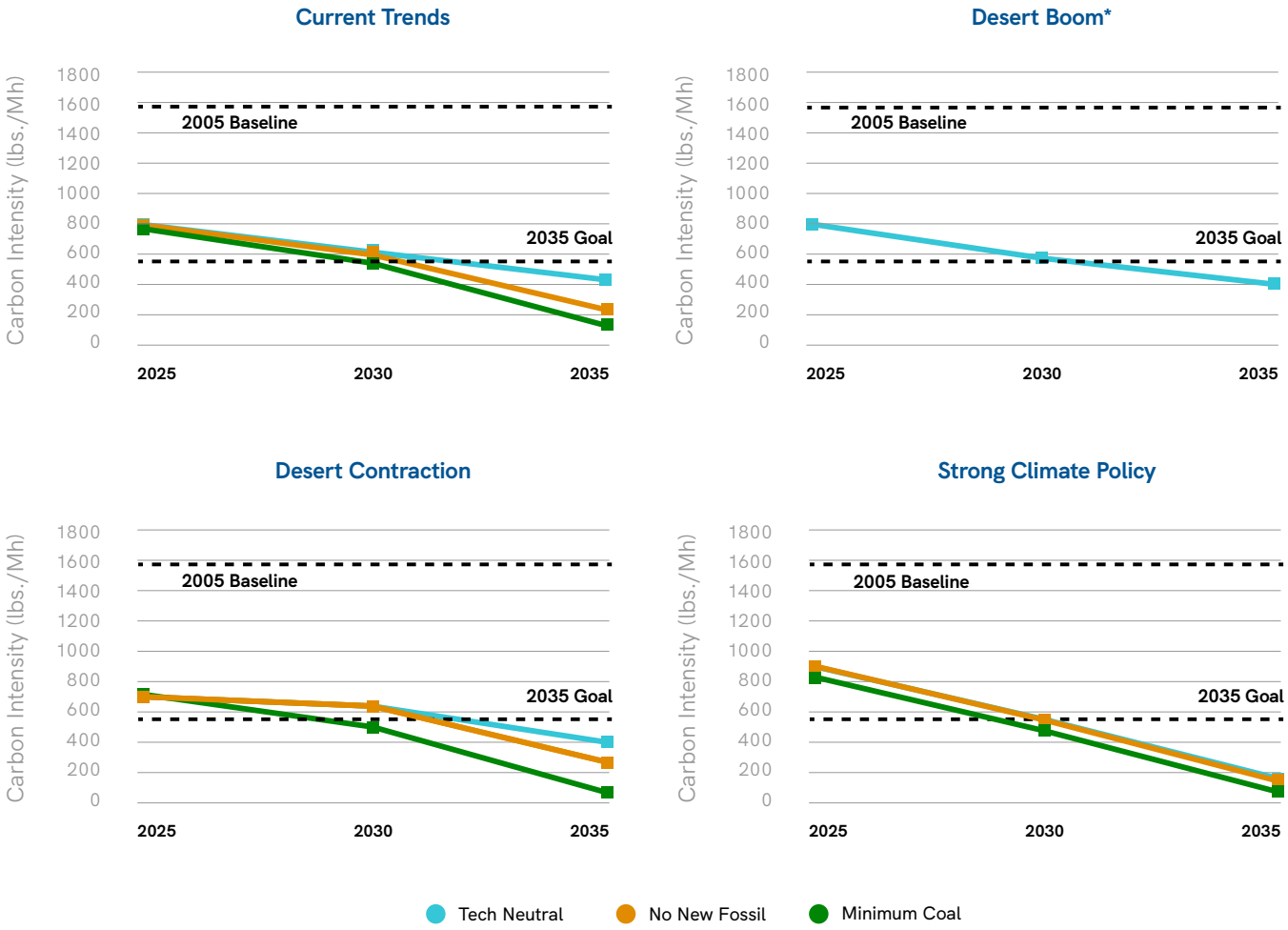


*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

[2] Capacity factor is a measure of resource utilization and is expressed as a ratio of the actual output over a given period of time compared to the theoretical continuous maximum output over that period.
[3] SRP's gas fleet includes combined cycle units, simple cycle combustion turbines (peakers) and boilers. Capacity factor for each type of gas unit will vary.

A growing share of carbon-free generation offsetting generation from gas and coal-fueled resources drives reductions in system CO_2 emissions. Figure 6.18 shows CO_2 emissions on an intensity basis.[4] All cases exceed SRP's 2035 goal of reducing carbon emissions intensity by 65% relative to 2005 levels. The No New Fossil and Minimum Coal strategic approaches result in greater CO_2 emission reductions, while the Strong Climate Policy scenario results in the most CO_2 emission reductions.

FIGURE 6.18: CO_2 EMISSIONS (INTENSITY BASIS IN LBS. PER MWH)

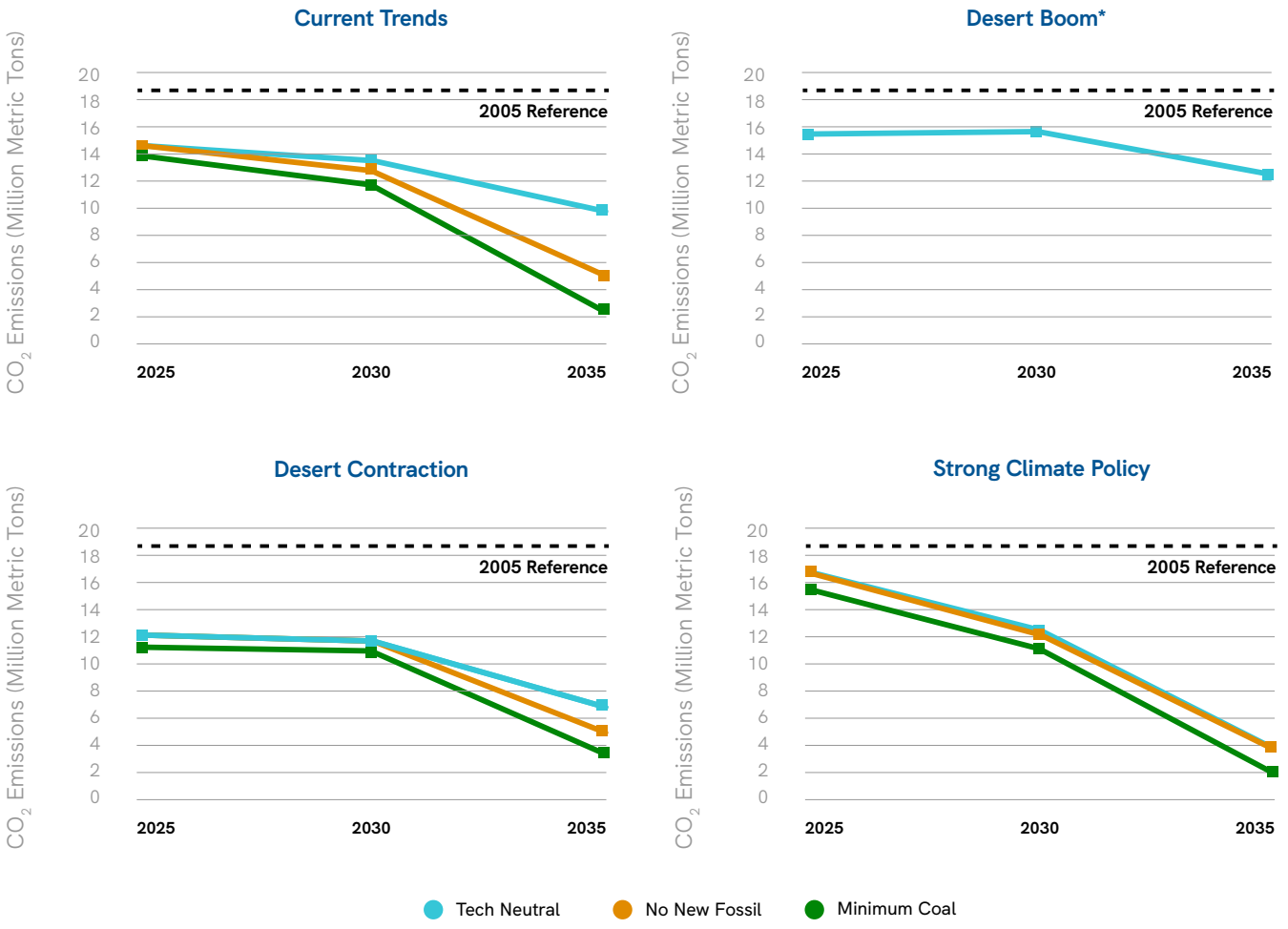


*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

[4] Carbon intensity is the amount of carbon dioxide emitted from generating electricity (in pounds), divided by the total generation required to serve SRP's customers (in megawatt-hours).

Figure 6.19 shows total annual CO_2 emissions on a mass basis. The trends within each scenario on a mass emissions basis align with the trends observed with CO_2 emissions intensity. However, the difference across scenarios is more pronounced for total CO_2 emissions because of differences in the load forecast: Higher load growth leads to an increase in total carbon emissions due to an increase in generation, some of which is carbon-emitting (when considering carbon intensity, higher emissions are offset when divided by a greater amount of energy generated). Total CO_2 emissions are higher in Desert Boom because load growth is higher, and emissions are lower in Desert Contraction because load growth is lower.

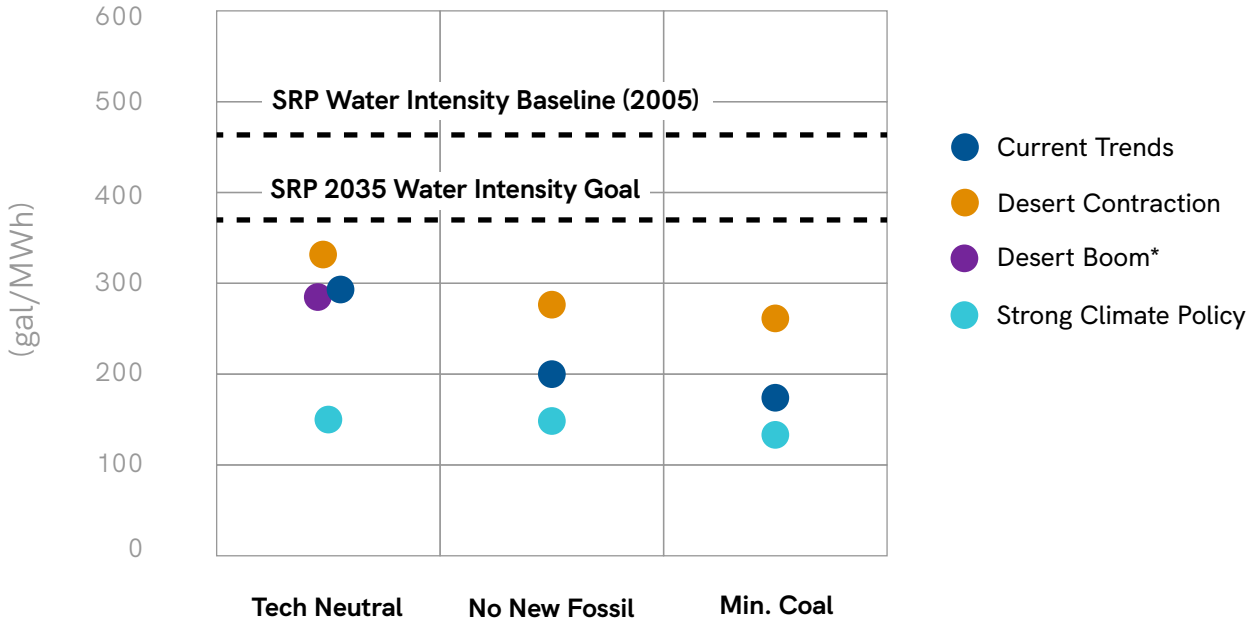
FIGURE 6.19: CO_2 EMISSIONS (MASS BASIS IN MILLION METRIC TONS)



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

SRP also projected water consumption from power generation on an intensity basis[5] to evaluate performance with the 2035 goal of reducing water usage intensity by 20% relative to 2005 levels. As shown in Figure 6.20, all cases exceed the 2035 goal. The greatest reductions in water usage intensity occur under the No New Fossil and Minimum Coal strategic approaches, again due to a higher share of carbon-free resources that use little or no water.

FIGURE 6.20: WATER USAGE INTENSITY IN 2035



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

[5] This is the amount of water consumed (in gallons) from generating electricity, divided by the total generation required to serve SRP's customers (in megawatt-hours).

Lastly, in addition to carbon emissions and water usage, SRP estimated direct air emissions from the generation fleet for several criteria air pollutants, and their precursor pollutants, including particulate matter (PM), nitrogen oxides (NO_X), sulfur dioxide (SO_2) and volatile organic compounds (VOC). Under all cases, emissions of all pollutants decline substantially by 2035 relative to 2025 levels. However, new biomass causes higher levels of NO_X and SO_2 emissions in the No New Fossil and Minimum Coal system plans.

FIGURE 6.21: DIRECT AIR EMISSIONS IN 2035



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

System operations change significantly over time in all cases. Coal generation decreases, while customer programs and renewable generation increase across all cases, pushing down natural gas generation across the fleet and improving sustainability metrics. Reductions in carbon intensity ranged from 74% to 96% (compared to SRP's goal of 65%) while reductions in water usage intensity ranged from 31% to 71% (compared to SRP's goal of 20%), both relative to 2005 baseline levels. Cases with less renewable and storage additions resulted in smaller reductions in carbon and water usage intensity, while cases with higher renewable and storage additions resulted in larger reductions. *Note: SRP's 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders.*

KEY FINDING

The reduction in coal generation and expansion of carbon-free resources over time allow SRP to meet, and in many cases exceed, SRP's 2035 goals for carbon emission reductions and water resiliency.

Transmission Investments

Both load growth and changes in the resource mix influence investment needs for the transmission system. This section describes the transmission investment needs through 2035, including 230 kV lines, 500 kV lines and 500/230 kV transformers.

Figure 6.22 shows the transmission investment needs through 2035 for the three system plans analyzed (Technology Neutral Current Trends, Technology Neutral Desert Boom and Minimum Coal Current Trends) and the two resource location options analyzed (Pro-Rata and Hub). These cases are described in detail in Section 5.

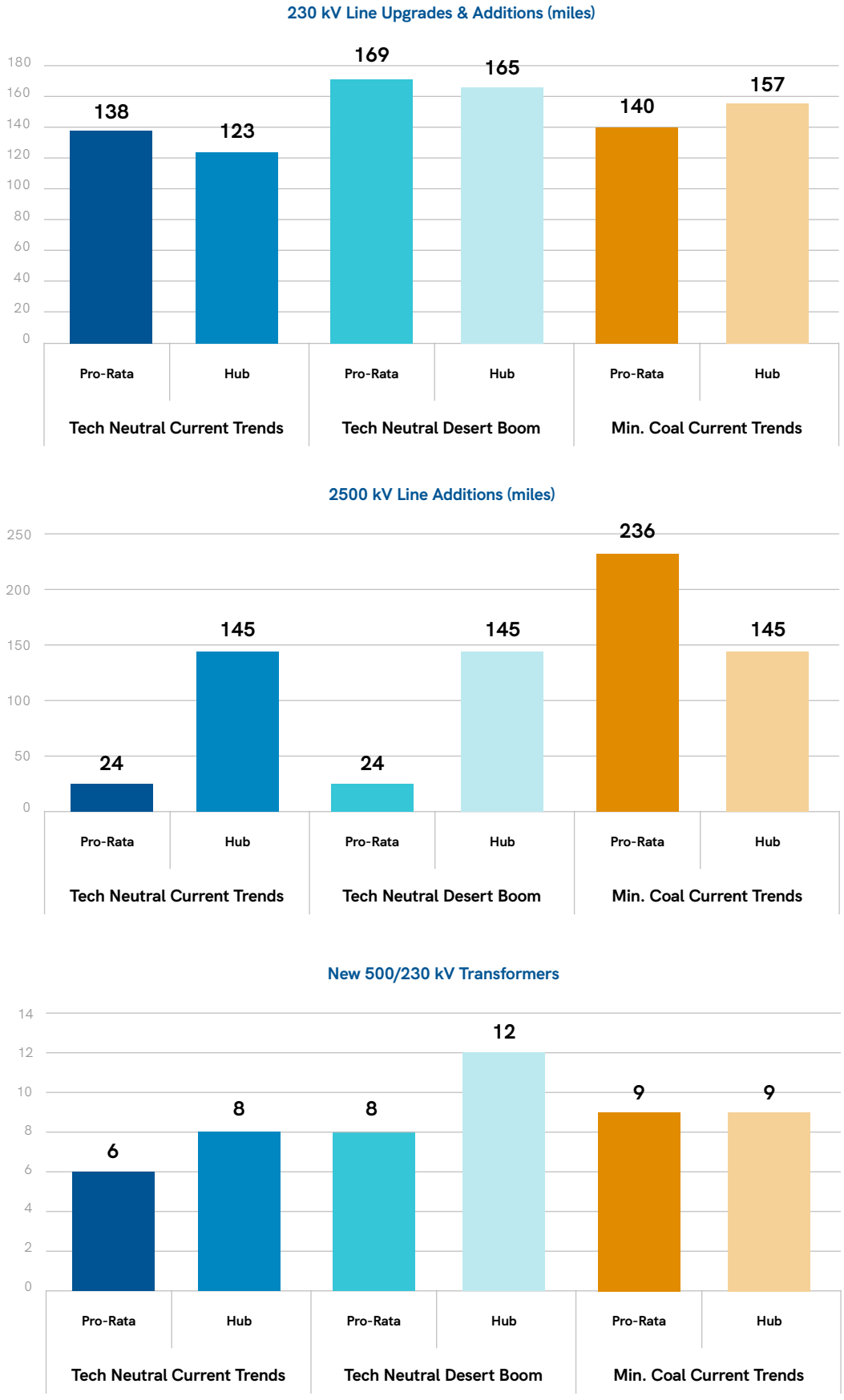
KEY FINDINGS

Location of generation matters and plays a significant role in the buildout of the 500 kV and 230 kV transmission system.

Significant investments in new transmission infrastructure are needed over the next decade to connect new resources and customers while also achieving reliability and sustainability goals. These investments will need to be strategically located and timed.

In all cases, a significant amount of transmission investment is needed by 2035. The investments in 230 kV lines are primarily driven by load growth in all cases; however, where 230 kV lines need to be added and which lines need to be upgraded depends on the resource location assumptions used. The investments in 500 kV lines, as well as the investments in 500/230 kV transformers, vary for each system plan based on the resource location assumptions. In the Technology Neutral Current Trends and Technology Neutral Desert Boom cases, the Hub resource location assumption requires far more 500 kV line-miles and more 500/230 kV transformers than the same cases using the Pro-Rata resource location assumption. In the Technology Neutral Current Trends and Technology Neutral Desert Boom cases, more investment is needed in the 500 kV system to connect resources at the hub to the rest of the system. By contrast, in the Minimum Coal Current Trends case, fewer 500 kV line-miles are needed under the Hub resource location assumption than under the Pro-Rata resource location assumption. This is driven by the higher levels of solar and battery resources in this case further exceeding existing transmission capabilities when located using the Pro-Rata location assumptions. The differences in results across the Pro-Rata and Hub resource location assumptions highlight how the location of resources has a significant impact on transmission investment needs.

FIGURE 6.22: TRANSMISSION SYSTEM INVESTMENTS BY 2035



KEY FINDING

Hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230 kV transformers could be needed relative to today.

The transmission analysis shows that up to 380 miles of new or upgraded transmission lines and 12 new 500/230 kV transformers could be needed over the next decade. The lead times for siting, permitting, building and energizing transmission infrastructure are 5–9-plus years for 500 kV lines, 3–7 years for 230 kV lines and 3–5 years for 500/230 kV transformers. To add the needed transmission infrastructure given these long lead times will require a proactive approach to transmission planning.

Total System Cost

Because maintaining affordability for customers is a fundamental component of SRP's mission, we developed affordability metrics for each system plan analyzed to assess and compare opportunities and risks. This section describes the total system cost and average system cost metrics, while the next section describes the residential bill impact metric.

The total system cost is the estimate of total costs in 2035 to serve customers, including costs related to customer programs, distribution, generation, transmission and normal utility operations. The average system cost is derived by dividing the total system cost by the total retail sales in 2035. Because energy demand growth varies across the scenarios, the average system cost provides a more direct comparison between cases for how costs are changing over time.

While these metrics allow comparison across system plans, they are developed using a simplified ISP analysis model and are not a comprehensive assessment of future financial indicators for SRP. Furthermore, the average system cost metric is not a customer rate metric and should not be interpreted as the rate that customers would pay under different cases. Lastly, differences in results across scenarios reflect scenario assumptions for external factors that are out of SRP's control (e.g., economic growth, fuel prices, resource costs and federal government policy).

Figure 6.23 shows the total system cost in 2035, broken out between generation, transmission, distribution, customer program and other costs. It also provides total system cost in 2025 for reference. Generation costs are the primary driver of differences in cost between cases. Transmission costs follow similar trends as generation costs, as both are influenced by load growth and new resource additions. Distribution costs vary across scenarios due to differences in load growth. Lastly, customer program costs grow through 2035 and continue to mitigate needs for new infrastructure across all cases.

Within the Current Trends and Desert Contraction scenarios, Technology Neutral is the lowest-cost strategic approach. While Technology Neutral allows new natural gas as a resource option, the other strategic approaches (No New Fossil and Minimum Coal) do not have a firm capacity option and thus lead to higher costs due to increased resource additions and transmission investments.

In general, the Desert Contraction cases have lower system costs than Current Trends, and the Desert Boom cases have higher costs, driven primarily by the differences in energy demand. In the Strong Climate Policy scenario, all three strategic approaches have similar costs due to a few factors. First, the aggressive federal emissions requirement in this scenario is a major driver, resulting in significant renewable and storage additions across all three strategic approaches. Second, in this scenario, a firm capacity resource is available in all three strategic approaches due to the accelerated availability of hydrogen. The unavailability of a firm capacity resource was the major driver of cost increases for these two strategic approaches under the other scenarios.

FIGURE 6.23: TOTAL SYSTEM COSTS FOR SRP'S POWER SYSTEM IN 2035 ($ BILLION)

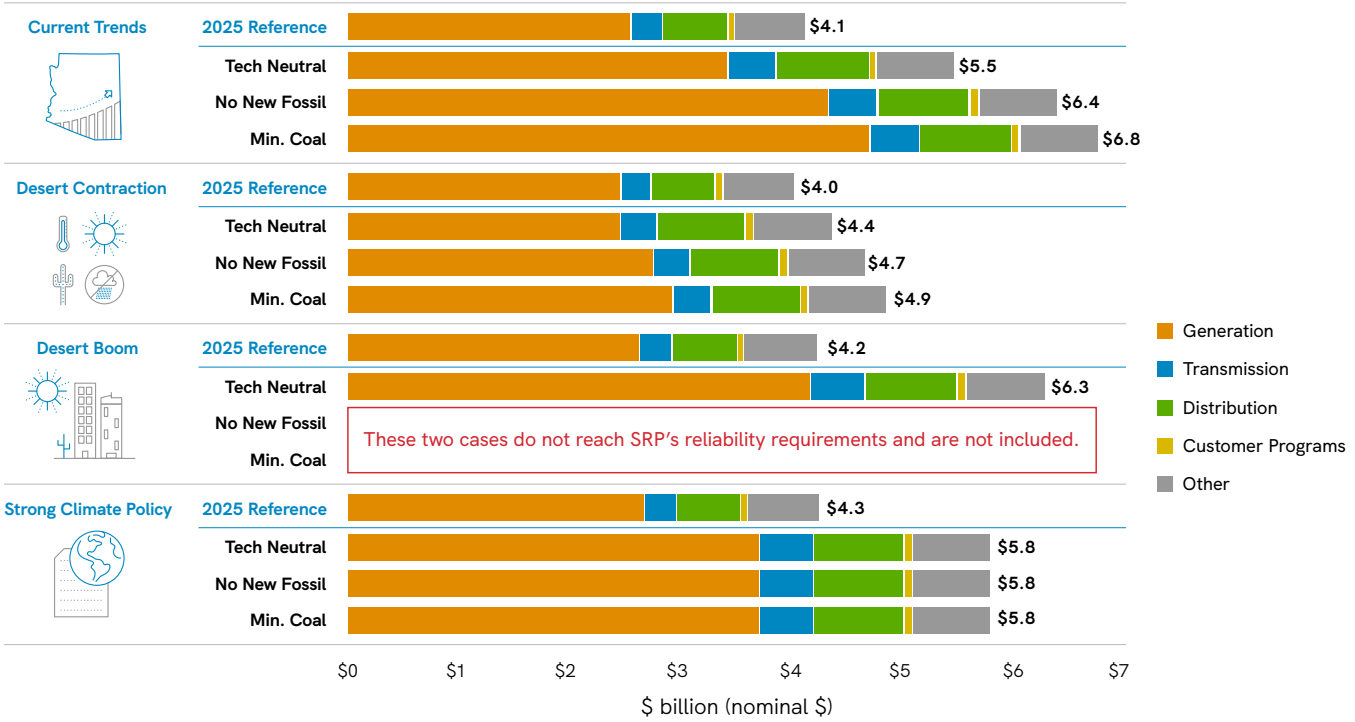
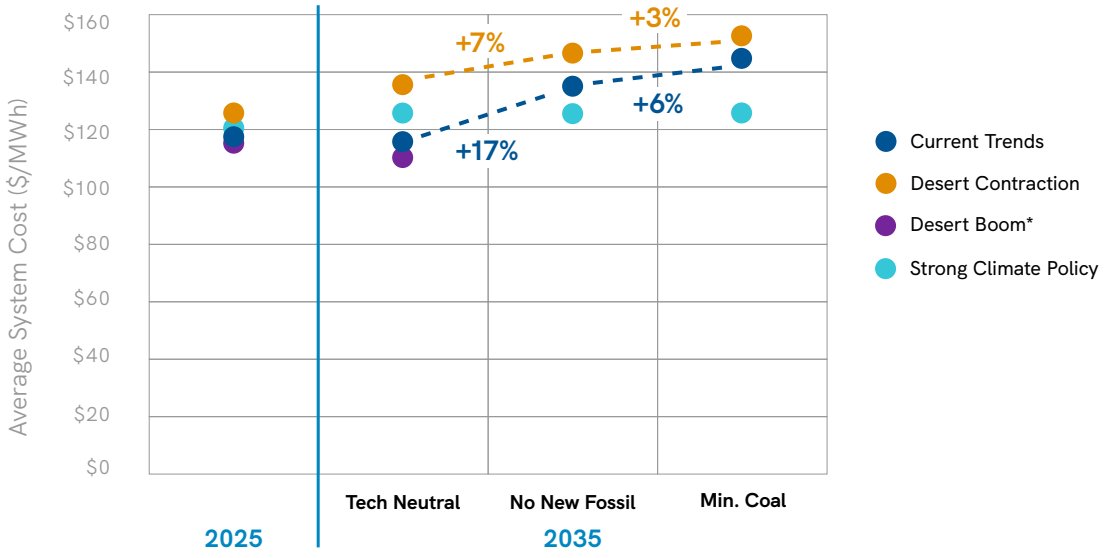


Figure 6.24 shows the average system cost in 2035, with 2025 provided for reference. The Technology Neutral strategic approach results in lower cost than the other strategic approaches with limited firm capacity options. In the Current Trends scenario, the No New Fossil and Minimum Coal approaches result in a 17% and 24% increase, respectively, in average system cost relative to Technology Neutral. In the Desert Contraction scenario, the No New Fossil and Minimum Coal approaches result in a 7% and 10% increase, respectively, in average system cost relative to Technology Neutral. The cost increase in Current Trends is greater than the cost increase in Desert Contraction because the higher load growth in Current Trends makes it more costly to reliably meet customer needs without new firm capacity resources.

FIGURE 6.24: AVERAGE SYSTEM COST ($/MWH)



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

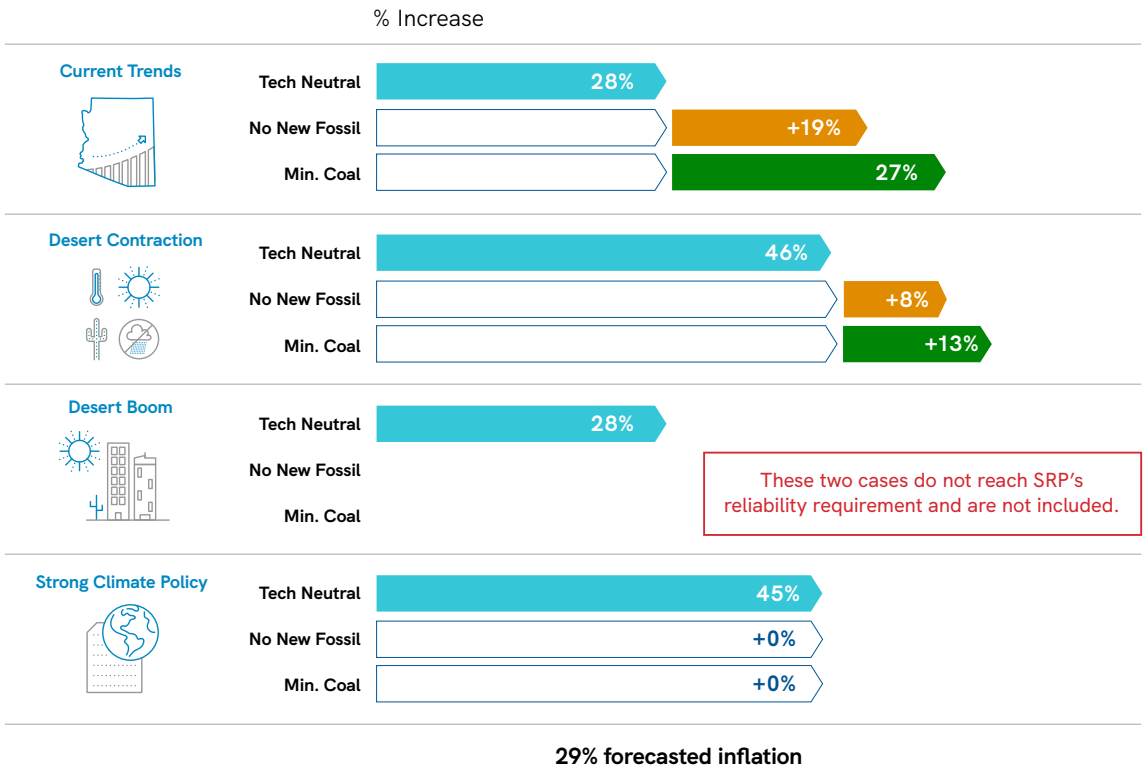
Residential Bill Impact

This section describes the residential bill impact metric across cases. This analysis does not necessarily reflect how future costs would be allocated and recovered from customers and therefore should not be considered a projection of customer rates. SRP will carry out pricing processes in the future that will determine future rates. Nevertheless, this metric is helpful for comparing across cases to understand relative differences.

Figure 6.25 shows the increase in average residential customer rates between 2023 and 2035 along with the forecasted inflation expected over this period for reference. The figure shows the increase in the Technology Neutral strategic approach and then shows the increase in the alternative strategic approaches relative to the Technology Neutral strategic approach. SRP projects the cumulative impact of inflation to be 29% between 2023 and 2035. The Technology Neutral Current Trends approach has an increase of 28% over this same period, meaning that rates increase by less than inflation in this case.

In all scenarios, the Technology Neutral strategic approach results in the lowest impact to average residential rates. The No New Fossil and Minimum Coal approaches are more costly, with the greatest increases relative to Technology Neutral under Current Trends. Under the Current Trends scenario, the No New Fossil strategic approach results in a 19% increase in customer rates relative to Technology Neutral, and the Minimum Coal strategic approach results in a 27% increase. Under the Desert Contraction scenario, increases are higher across the cases as the lower load growth leads to less revenue to offset costs. Comparing the cases in the Desert Contraction scenario, the No New Fossil strategic approach results in an 8% increase in customer rates relative to Technology Neutral, and the Minimum Coal strategic approach results in a 13% increase. Under the Strong Climate Policy scenario, the residential bill impact is similar across the three strategic approaches, for the same reasons discussed in the Total System Cost section.

FIGURE 6.25: INCREASE IN AVERAGE RESIDENTIAL CUSTOMER RATES BETWEEN 2023 AND 2035



Risk Assessments

The development and operational risk assessments identified risks and challenges that SRP could face for each of the system plans. It also identified potential mitigation options, which SRP is using to prepare its system and workforce for the future.

Development Risk

Because each of the ISP system plans requires significant development of new resources, we performed a qualitative risk assessment to better understand the risks and challenges in building out these future power systems, as well as mitigation options.

Development Risks and Mitigation Options

KEY FINDING

To meet the pace of infrastructure needs, supply chain and development solutions are essential to managing costs and to meet the pace of transformation needed.

Supply chain. SRP continues to observe inflation and supply chain disruptions that began during the COVID-19 pandemic. These disruptions led to rising costs and extended development timelines for new infrastructure projects, including solar projects, battery storage projects, transmission infrastructure, distribution infrastructure, etc. Future supply chain disruptions could also impact SRP's ability to develop new infrastructure, impacting ISP system plans with greater infrastructure additions the most. Mitigation steps that SRP is taking to address these risks include ordering key supplies as early as possible and seeking to develop a wider pool of potential suppliers to diversify supply chain risks.

Siting and permitting. Most infrastructure projects take several years for siting, permitting, construction and interconnection. Examples of projects with especially long and complex development processes include nuclear power plants, pumped hydro energy storage, gas pipelines and transmission. On the longer end of development timelines, some transmission projects can take well over a decade to site, permit, construct and energize. There are many variables that can impact the timing of developing projects, including stakeholder consultation, state and/or federal regulatory processes, development of enabling infrastructure (e.g., new transmission or gas pipelines), etc. If development timelines were to extend much longer than expected, this would limit the pace at which SRP can build out the system and put ISP system plans with greater infrastructure additions at more risk. To mitigate this risk, SRP strives to collaborate with government agencies, other utilities and key stakeholders as early as possible. We are also exploring multiple project options so that SRP is prepared to undertake any one of these options more readily should the need arise.

KEY FINDING

With the amount of future infrastructure and resources needed, internal and external partnerships are going to be essential to build the future system and maintain high customer value.

Multistate transmission. While any transmission can have long development timelines and face uncertainty in permitting, these challenges exist even more for transmission that spans multiple states. Such interstate transmission projects may span longer distances and require consultation with more landowners. They also require approvals from different state regulatory bodies and may require approval from multiple federal agencies. The complex nature of developing such projects results in risks to development timelines. These risks are greatest for ISP system plans that add geothermal or wind in states such as California and New Mexico. SRP is working to mitigate this risk by proactively pursuing regional transmission projects that facilitate integration of diverse renewable resources.

Technology maturity. Not all resource technologies have reached full maturity. Lithium-ion battery projects have proliferated in the last five years, but the total amount of capacity deployed is still limited relative to other technologies and they do not have a long track record of performance. Some battery projects, including a project contracted by SRP, have experienced fires that have rendered the resources unavailable. There are other technologies evaluated in the ISP that have not yet reached widespread commercialization, such as power plants powered by 100% hydrogen. There are still uncertainties in the cost, operations and enabling infrastructure for this technology. Given these risks and uncertainties, ISP system plans that rely more on less mature technologies have a greater amount of inherent risk. To mitigate these risks, SRP is actively gaining operational experience with newer technologies and monitoring advancements for emerging technologies. SRP is also balancing the development of newer technologies (e.g., battery storage) with the deployment of more mature technologies (e.g., pumped hydro storage).

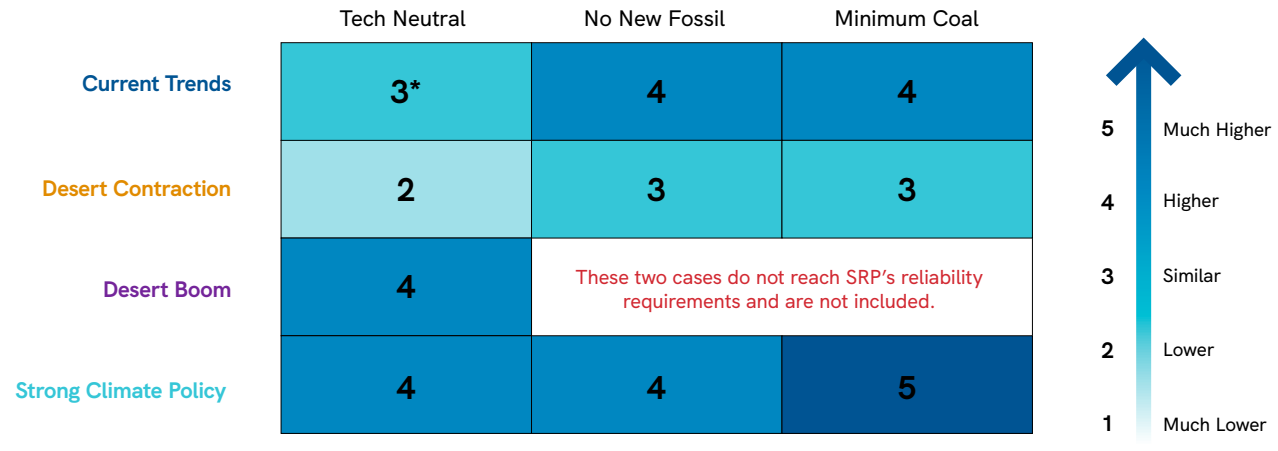
Diversification. The potential impact of any one of these development risks depends in part on the diversification of the system plan. If the system plan relies heavily on only a few technologies, then the entire system plan is at risk if one of those technologies encounters disruptions due to supply chain, permitting or other issues. To mitigate the risk associated with any one technology, SRP is pursuing a diverse system plan.

Development Risk Ratings

SRP identified a development risk rating for each of the core system plans in the ISP, as shown in Figure 6.26, using the considerations highlighted above. Technology Neutral Current Trends acted as a baseline, and SRP evaluated all other plans relative to the development risk associated with that plan.

Technology Neutral Desert Contraction has a lower risk level because the system plan adds far fewer generating resources, transmission and distribution than the other plans. For the Desert Contraction scenario, the two other strategic approaches (No New Fossil and Minimum Coal) have a similar amount of risk as the baseline due to the amount of resource additions. All other system plans have higher risk levels due to the very rapid pace of resource additions, with some cases reaching between 25,000 and 35,000 MW of installed capacity. The Minimum Coal Strong Climate Policy case has the highest risk level not only due to the rapid pace of resource additions, but also because of the reliance on almost 800 MW of hydrogen capacity, which would require significant development of hydrogen infrastructure that doesn't currently exist. As discussed above, SRP is employing a suite of strategies to help mitigate risks.

FIGURE 6.26: DEVELOPMENT RISK RATING



*Tech Neutral/Current Trends was the baseline case to which the development risk for all other cases were compared.

Operational Risk

Because each of the ISP system plans requires a meaningful shift in the future operations of the system, SRP also performed a qualitative risk assessment to better understand the risks and challenges in operating these future power systems, as well as mitigation options.

Operational Risks and Mitigation Options

KEY FINDING

A future system that relies more on variable renewable resources presents new challenges and will require new operating practices to ensure sufficient flexibility, reduce wear and tear on existing assets, and maximize benefits to customers.

Variability and uncertainty. The Inverter-Based Resources Integration Technical Working Session highlighted the profound changes that come with moving to a system that relies on more variable renewable generation to meet energy needs. Resources like solar and wind vary in output based on season and time of day. Also, this variability is not perfectly predictable, as the weather can impact solar generation due to cloud cover and wind generation due to changes in wind speed. Managing a system with higher penetrations of variable generation is more complex and comes with new risks in balancing energy demand, supply and market transactions. As a result, ISP system plans with higher penetrations of variable generation resources have greater operational risk. To mitigate these risks, SRP is taking several actions, including improving forecasts for variable renewable generation, increasing reserves to account for uncertainty and variability, pairing variable energy resources with flexible resources (e.g., energy storage) to reduce variability and increase dispatchability, managing resource curtailment to provide more flexibility to the system, and transacting with markets to provide more operational flexibility.

Ramping needs. With higher penetrations of variable generation, especially solar, the system experiences greater ramping needs for dispatchable generation. For example, on a system with a lot of solar generation, there is plentiful generation during the day. However, in the late afternoon and early evening, when electricity demand is high and solar generation rapidly declines, other resources need to ramp up output rapidly. This is a significant change in how the system must operate and creates new challenges. To mitigate these risks, SRP is working to add more flexible resources, such as battery storage, pumped storage hydro and natural gas, to maximize the flexibility from existing resources and from market transactions. SRP is exploring curtailing variable generation to help mitigate ramping needs and provide additional flexibility.

Natural gas plant operations. With increasing amounts of variable generation and increasing ramping needs, natural gas power plants operate differently than they have in the past. When variable renewable generation output is high and energy demand is low, natural gas plants ramp down output or even shut down. When variable renewable generation is low and/or energy demand is high, natural gas plants ramp up output. This may involve shutting down and starting up natural gas plants more frequently than in the past, potentially even daily, which puts increased wear and tear on the generating units. Some natural gas plants may shut down for extended periods of time before starting up again. Systems that cool completely can cause aging seals or fittings to shrink, which can increase risks for more frequent maintenance and repair.

Natural gas fuel transportation. SRP acquires transportation rights on regional natural gas pipelines to secure reliable delivery of natural gas fuel we purchase throughout the year. If natural gas fuel consumption were to increase significantly beyond today's level of consumption, such as in the Technology Neutral Desert Boom system plan, this could create risks in being able to deliver natural gas fuel during critical days for reliability.

Depending on the increase in fuel consumption and how the regional energy landscape evolves, this could require the need for new natural gas pipeline infrastructure. To mitigate this risk, SRP is deploying a diverse mix of additional generating resources such as solar and wind that help to offset natural gas fuel consumption. SRP may also explore fuel storage solutions that can allow natural gas plants to continue to have access to fuel without relying solely on pipelines during critical days.

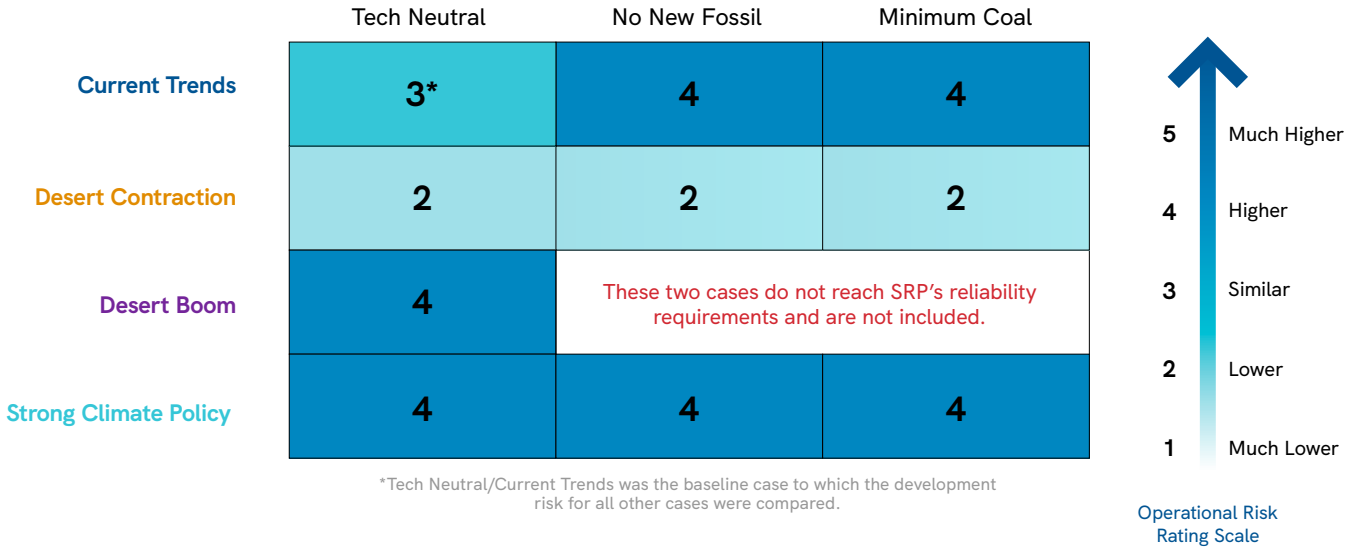
Curtailment. As variable renewable generation increases as a share of SRP's generation mix, there will increasingly be time periods when there is more renewable generation than can be delivered to customers, used to charge energy storage, or sold into markets. For example, during spring months, when energy demand is lower due to milder temperatures, solar generation is relatively high. The West already experiences higher levels of solar curtailment during these months, and this will become more pronounced as SRP and other utilities add more solar capacity. This will require changes in system operations to ensure the grid remains in balance. To accommodate these changes, SRP is making improvements to the dispatch of renewable resources to both curtail their energy production in a way that is most cost-effective and leverages their capabilities, when possible, and to provide ancillary services for controlling small mismatches between customer demand and generation. SRP is also exploring other uses for excess power generation, including storing in long-duration energy storage and generating hydrogen through electrolysis.

Operational Risk Ratings

SRP developed an operational risk rating for each of the core system plans in the ISP, as shown in Figure 6.27, using many of the considerations highlighted above. Technology Neutral Current Trends acted as a baseline, and SRP evaluated all other plans relative to the operational risk associated with that plan.

The three Desert Contraction system plans have a lower operational risk level because annual energy demand is lower, variable generation penetration is lower, and natural gas fuel demand is lower. These three factors mitigate many of the identified operational risks. The three Strong Climate Policy plans have a higher operational risk level because these plans would require a complete transformation of system operations, including a high generation share from variable resources, increased ramping needs, and increased stress for natural gas-fired generators that would need to start up, shut down and ramp up output more frequently. The No New Fossil Current Trends and Minimum Coal Current Trends system plans also have a higher operational risk level for similar reasons, although the operational risk is slightly lower due to a higher share of generation from dispatchable resources. The Technology Neutral Desert Boom system plan has a higher operational risk level because this plan would require increased natural gas fuel consumption to a point that may not be feasible without significant expansion to the regional natural gas delivery system. As discussed above, SRP is employing a suite of strategies to help mitigate risks.

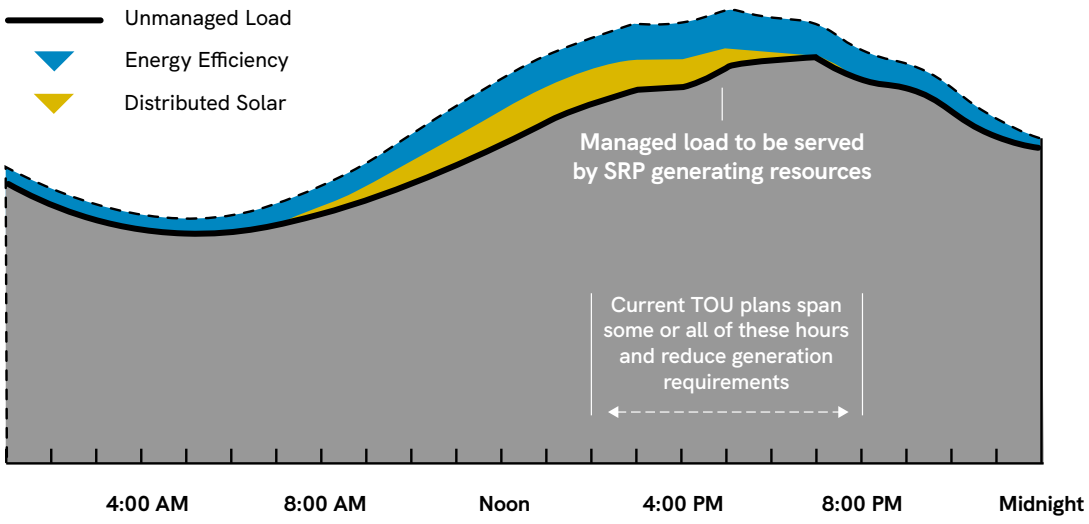
FIGURE 6.27: OPERATIONAL RISK RATING



Considerations for Future Customer Programs and Pricing Plans

Customer programs and pricing plans play an important role in managing SRP's load and peak energy demand. Figure 6.28 includes an illustrative projected peak day in 2035 and depicts how energy efficiency, distributed solar and time-of-use (TOU) programs can reduce SRP's load. Energy efficiency reduces total energy consumption throughout the day; distributed solar offsets generation from other resources during daytime hours; and TOU price plans can incentivize customers to reduce demand during peak hours. After accounting for these programs, the remaining load that SRP must serve is lower and shifted slightly later in the day.

FIGURE 6.28: ILLUSTRATIVE DEPICTION OF HOW CUSTOMER PROGRAMS AND PRICE PLANS HELP SRP MANAGE PEAK ENERGY DEMAND



SRP's existing customer programs work well for demand management in the current system. However, as increasing amounts of solar and wind are added to the system, the net load that is served by dispatchable resources begins to peak after the existing TOU window, as shown in Figure 6.29. This highlights the growing need for evening and overnight load reduction. However, the growth of mid-day renewable generation also presents the opportunity to shift load to these low-cost, low-emissions hours.

FIGURE 6.29: CUSTOMER PROGRAMS AND PRICING PLANS CAN HELP SRP MEET NEW SYSTEM NEEDS

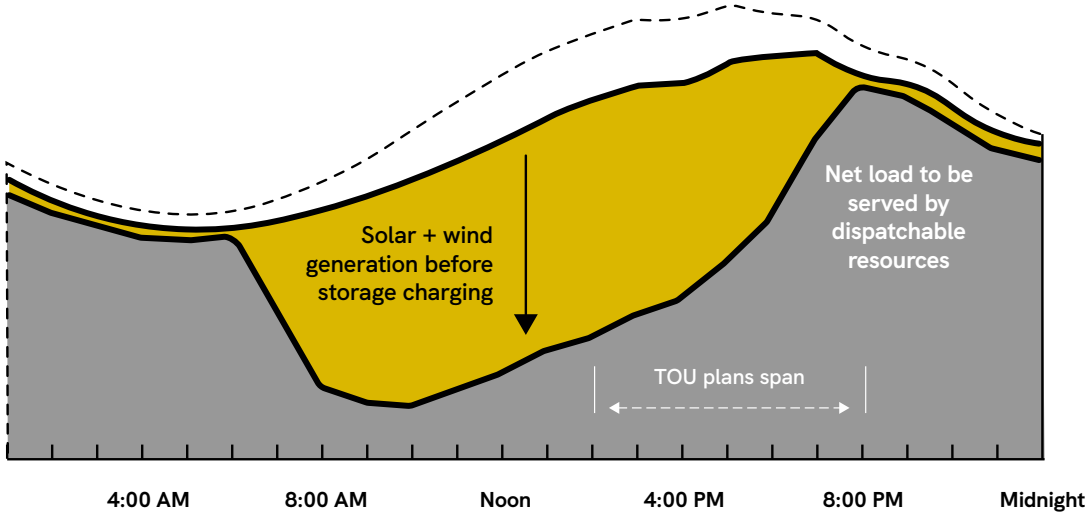


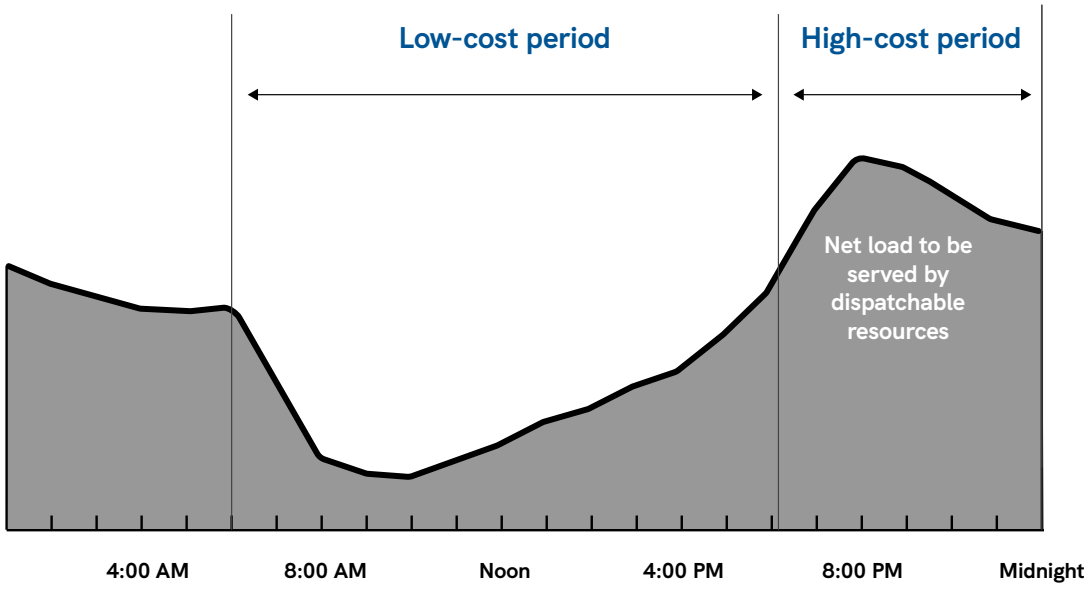
Figure 6.30 illustrates how system costs will change in the future system, with high-cost hours shifting to later in the evening, between 6 p.m. and midnight, and the low-cost period shifting to mid-day.

KEY FINDINGS

SRP will need to evolve programs and price plans to encourage shifts in consumer behavior, and further educate customers on when to consume and when to conserve energy.

Changes in how our customers use energy will require continued innovation and flexibility in planning.

FIGURE 6.30: AS THE SYSTEM TRANSFORMS, NET LOAD IS THE NEW TARGET FOR PRICING AND PROGRAMS.



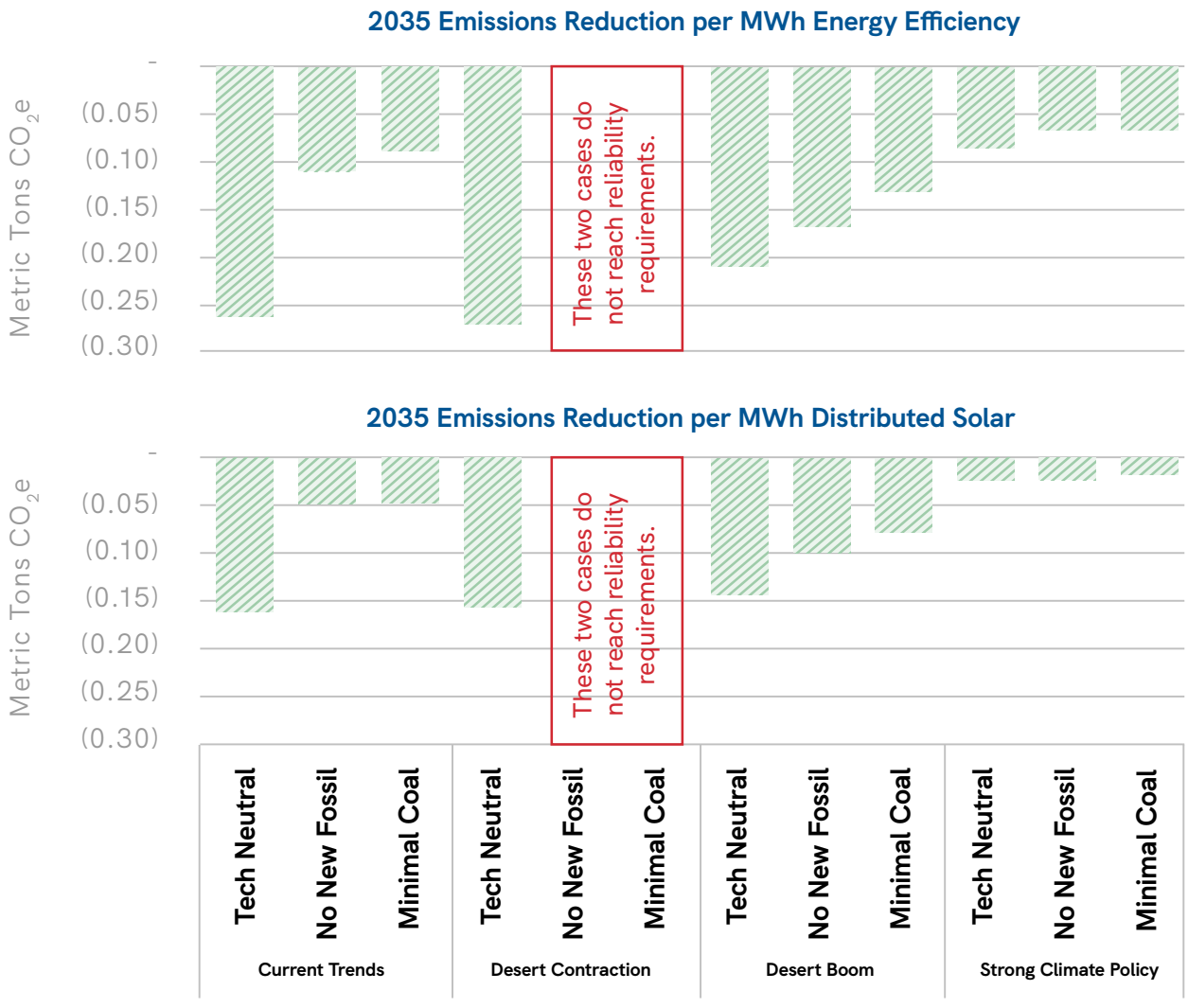
CO_2 Emissions Reductions from Energy Efficiency, Distributed Generation and Electrification

As customer programs reduce energy demand and peak load, they can also enable CO_2 emission reductions. Figure 6.31 first shows the avoided CO_2 per MWh of energy efficiency and distributed generation. Both programs result in avoided emissions without any increased grid emissions. The programs result in greater avoided CO_2 under Technology Neutral (except for under Strong Climate Policy) because the energy mix comprises a greater share of carbon-emitting sources in those cases. As the power sector decarbonizes, marginal carbon emission reductions from energy efficiency and distributed generation will diminish over time because the impacts of these programs tend to align with hours of lower marginal emissions. This finding is particularly prominent under Strong Climate Policy cases due to the more stringent carbon targets. However, continuing to offer programs that reduce load during high-demand hours will lead to greater emissions reductions.

KEY FINDING

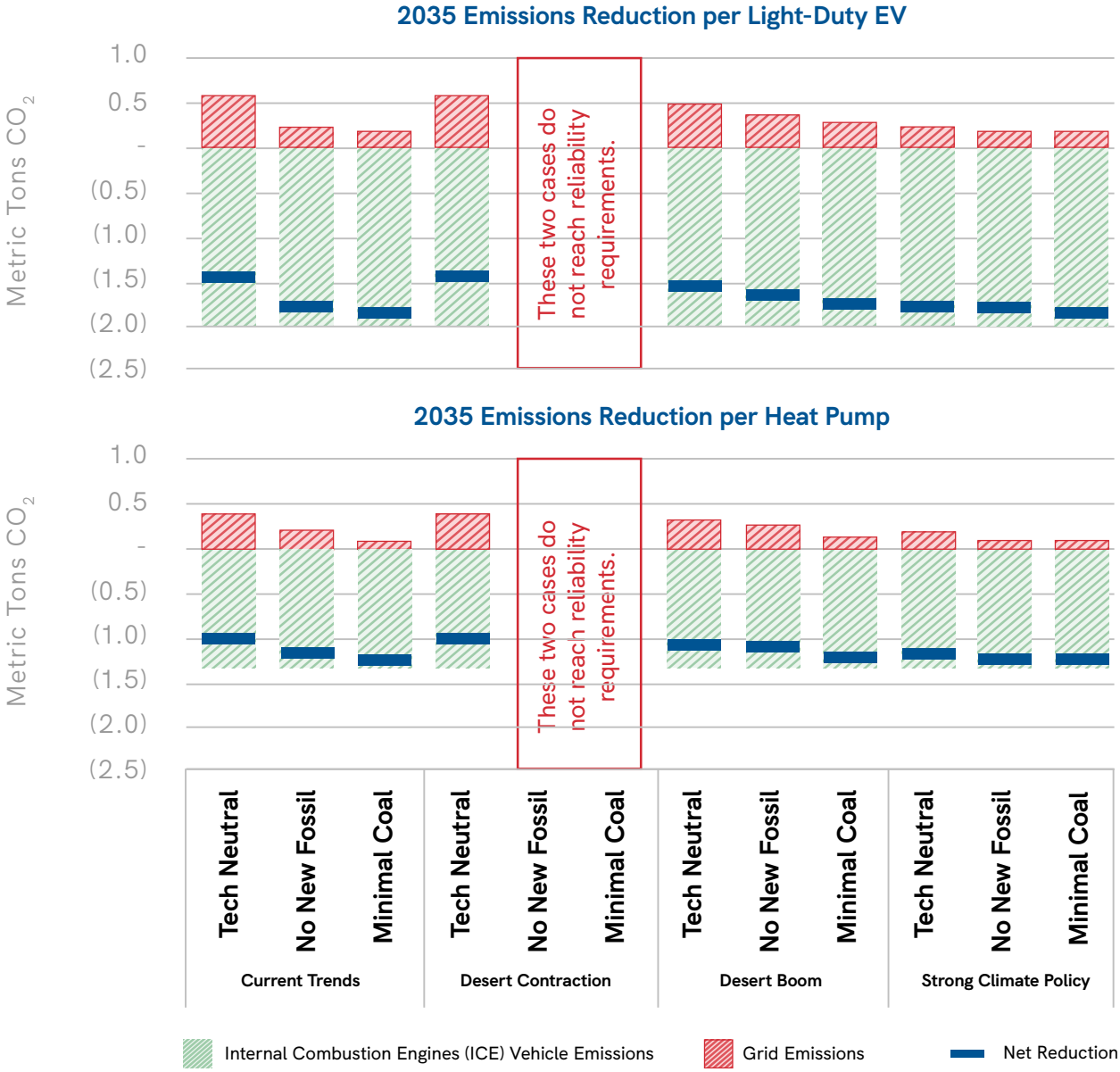
Electrification of end uses, including transportation and heating demand, creates new opportunities to shift energy usage to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.

FIGURE 6.31: AVOIDED CO_2 FROM ENERGY EFFICIENCY AND DISTRIBUTED GENERATION



Transportation and building electrification can also result in economywide carbon reduction, such as through greater adoption of electric vehicles and heat pumps. However, as these measures shift energy consumption to the electricity system, potential increases in grid emissions need to be accounted for. Figure 6.32 shows the marginal emission reductions, grid emissions and net reductions from light-duty electric vehicles and heat pumps in each scenario in 2035. The reduction in carbon emissions by replacing internal combustion engine vehicles outweighs the incremental emissions from EV charging loads. Under the current rate structure, light-duty and heavy-duty vehicles primarily charge overnight, when grid emissions are higher. However, shifting EV charging to daytime periods, when emissions are lower, through managed charging programs and/or pricing plans, could lead to further emissions reductions. Similarly, although incremental load from heat pumps increases carbon emissions on the grid, carbon emission reductions from offsetting gas usage is much more significant. In this case, heat pump usage concentrates in the morning when grid emissions are relatively high.

FIGURE 6.32: AVOIDED CO_2 FROM ELECTRIC VEHICLES AND HEAT PUMPS



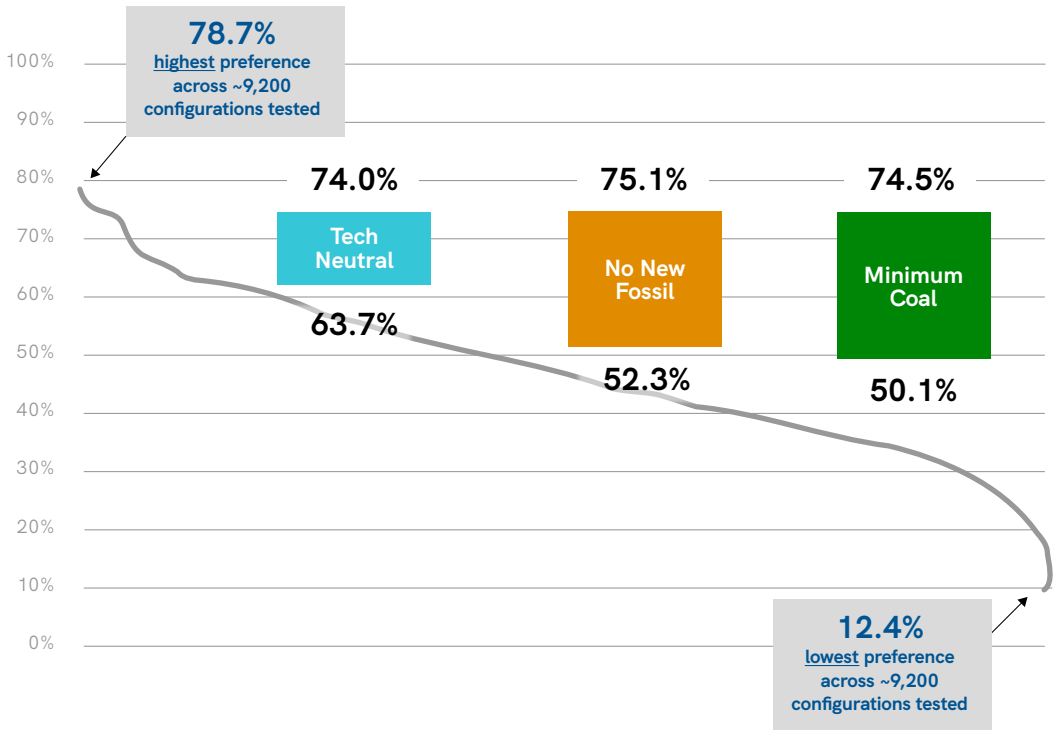
Residential Customer Research

Research consultant Bellomy assisted in the development of a Customer Preference Rating for each of the core system plans in the ISP, as shown in Figure 6.33. This metric was developed using over 1,000 residential customers' responses in a conjoint survey designed to understand how they value different aspects of the power system.

Residential Customer Preference Ratings represent the percentage by which customers expressed preferences of each strategic approach in various future scenarios relative to SRP's current system. Based on the results of the residential customer surveys, the preference ratings ranged between 12% and 79% versus the current system when all potential configurations were considered. System plans analyzed in this research that represented the ISP strategic approaches all achieved preferences over 50% versus SRP's energy system today.

Key findings from the research revealed that Technology Neutral was the most favorable strategic approach by SRP residential customers in futures with higher load growth such as Desert Boom and Current Trends. On the other hand, Minimum Coal and No New Fossil strategic approaches had a greater preference in futures where load growth was low, such as Desert Contraction, and additional federal incentives for carbon-free and hydrogen technologies were assumed, like in the Strong Climate Policy future scenario. Overall, there were more consistent preferences for Technology Neutral across the various futures when compared to the other strategic approaches.

FIGURE 6.33: CUSTOMER PREFERENCE RATINGS - SHARE OF PREFERENCE VERSUS CURRENT ENERGY SYSTEMS



Note: Within the Strong Climate Policy scenario, cases for Tech Neutral and No New Fossil are identical. Only one illustrative mix was shown to customers to represent both cases, thus data shown are identical for these two cases. No New Fossil and Minimum Coal cases were not tested in Desert Boom because they did not reach reliability targets.

Key findings from Residential Customer Research

Top factors – affordability and bill impacts: Affordability concerns were some of the most-selected future issues facing Arizona. In each phase of this research, affordability surpassed reliability slightly in importance when ranked by customers. Those with limited incomes, who make up approximately a third of SRP's residential customer base, put greater emphasis on affordability, while non-limited income customers reflected greater balance across factors. Additionally, when choosing a future energy system, customer selections revealed monthly bill impact as the top driver of preference.

Understanding and openness to change: Despite prioritizing affordability, customers recognized that the forthcoming challenges facing the region are interrelated and pose risks to sustainability, the economy and overall quality of life. Thus, they understood the need for a lower-carbon future energy system. Across scenarios, however, lower-cost strategic approaches were preferred by customers. While customers recognized the need for and expressed interest in SRP's investment in sustainable energy sources, they do not want to bear the cost of that investment.

Willingness to engage: Customers reported positive experiences with SRP's current programs and over half were interested in programs and rebates that will help them save money and energy. Additionally, about a third or more expressed interest in learning about SRP's energy efficiency programs, environmental efforts and infrastructure improvements.

Recommendations from residential customers for SRP's ISP

Findings revealed that from the residential customer's perspective, the ideal future energy system should:

- Manage cost, first and foremost.
- Keep monthly bill impacts below a 10% increase (from current electricity bills).
- Include a diverse energy mix to ensure reliability.
- Provide the cleanest, most sustainable energy without exceeding a 10% bill increase (from current electricity bills).

For additional details about the ISP customer research effort and key findings, please refer to the full reports for phases 1, 2 and 3 provided as appendices to this report.

Sensitivities

This section presents results for the 10 sensitivities that SRP analyzed for each strategic approach in the ISP.

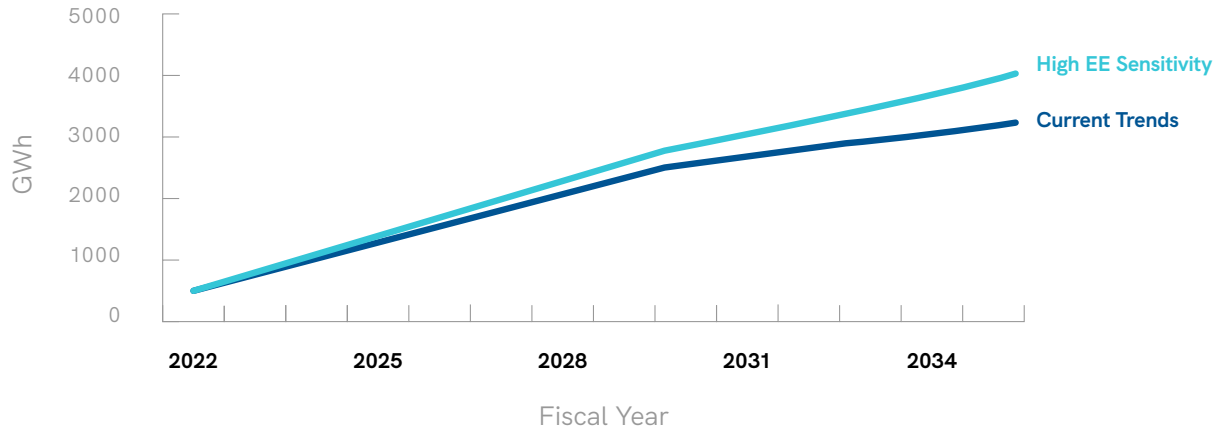
- High Energy Efficiency
- High Distributed Generation Adoption
- High Demand Response
- Increased Load Management
- High Gas Price
- Low Gas Price
- Volatile Gas Price
- High Technology Cost
- Low Technology Cost
- Regional Diversity

Each sensitivity is conducted relative to the Current Trends scenario as that scenario reflected the central planning assumptions. For presentation of the results, the three gas price sensitivities (High, Low and Volatile Gas Prices) are grouped together, as well as the two technology cost sensitivities (High and Low Technology Costs), yielding seven groups of sensitivities.

High Energy Efficiency

In the High Energy Efficiency (High EE) sensitivity, expansion of requirements pursuant to federal codes and standards lead to approximately 700 additional GWh of energy efficiency by 2035 relative to Current Trends. With this higher energy efficiency growth, total energy efficiency savings reach 4,471 GWh by 2035.

FIGURE 6.34: ANNUAL ENERGY EFFICIENCY ASSUMPTIONS



Figures 6.35 and 6.36 show peak load and energy demand forecasts for the High EE sensitivity, compared to Current Trends. In addition to reducing annual energy demand and overall load growth rates through 2035, these expanded energy efficiency customer programs reduce peak load by 395 MW in 2035 relative to Current Trends.

FIGURE 6.35: PEAK LOAD (MW) FORECASTS - HIGH ENERGY EFFICIENCY SENSITIVITY

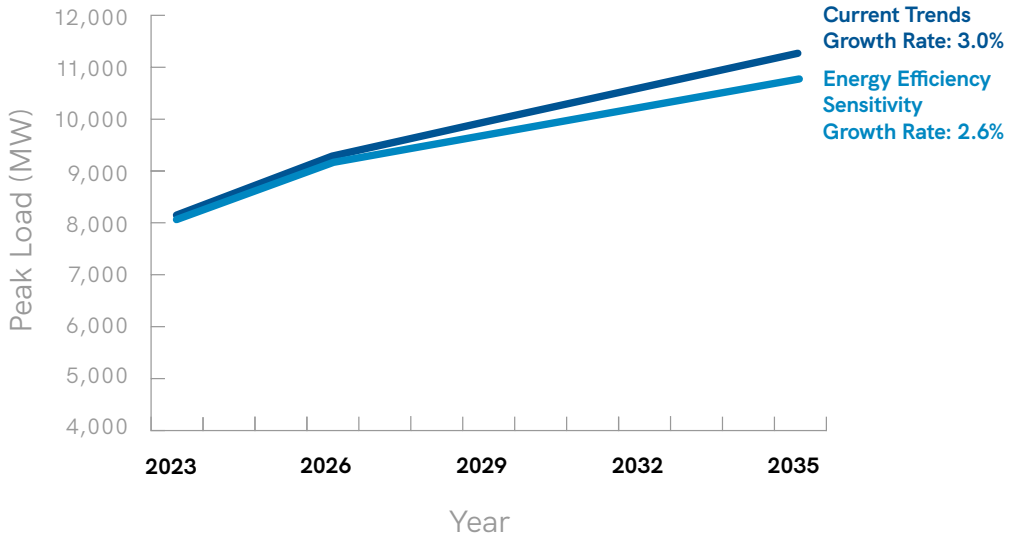


FIGURE 6.36: ENERGY DEMAND (GWH) FORECASTS - HIGH ENERGY EFFICIENCY SENSITIVITY

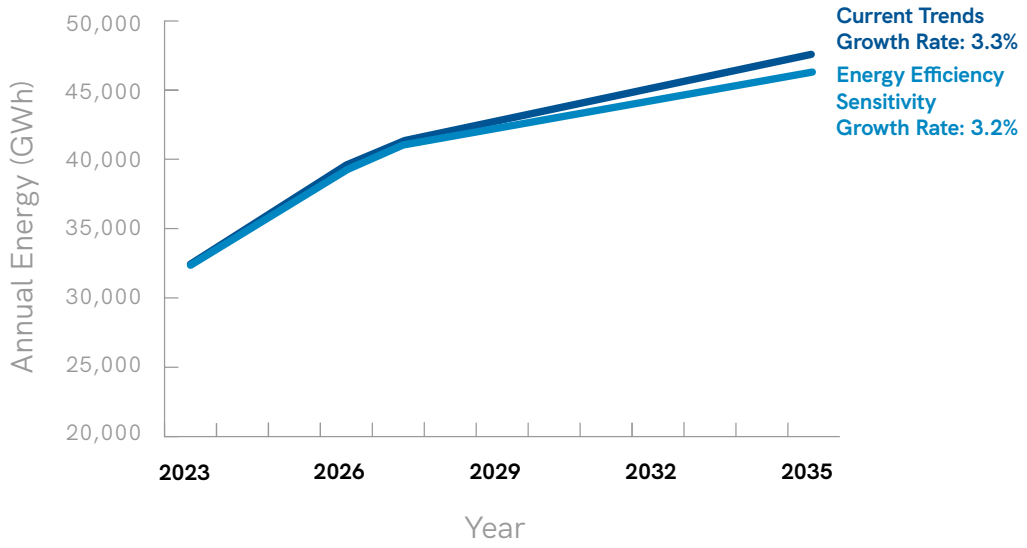
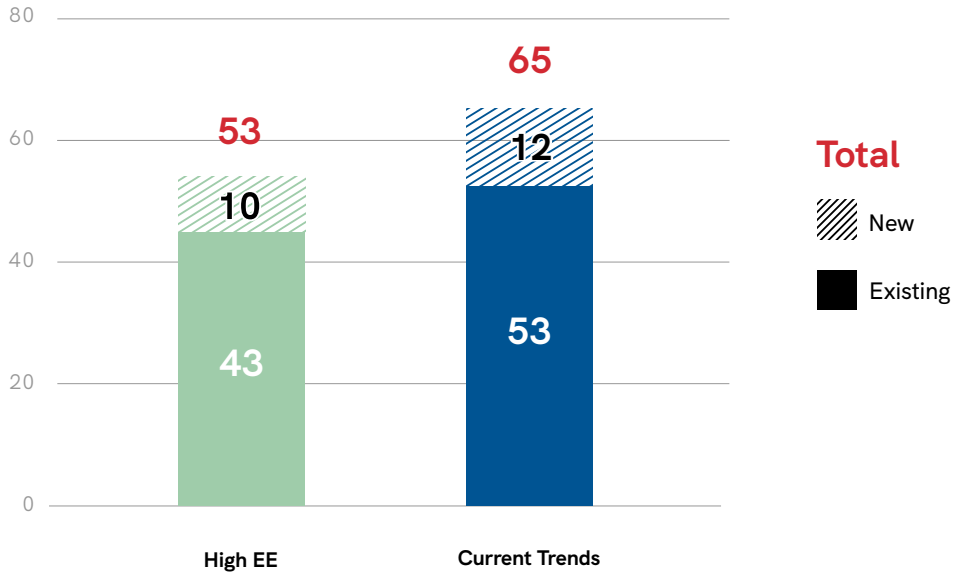


Figure 6.37 shows the distribution substation bay additions under the High EE sensitivity relative to the Current Trends scenario (see Figure 6.8 for the remaining scenarios). The High EE sensitivity results in slightly fewer substation bay additions than in Current Trends. The investment needs are similar to the Strong Climate Policy scenario, however, because the load forecasts are similar. The sensitivity results demonstrate a potential for energy efficiency to help defer distribution investment needs. However, this ability to help defer future investments will vary significantly across the system and must be assessed on a case-by-case basis when evaluating future distribution investments.

FIGURE 6.37: SUBSTATION BAY ADDITIONS AT EXISTING AND NEW SUBSTATIONS (FY23-35) - HIGH ENERGY EFFICIENCY SENSITIVITY



As shown in Figure 6.38, the additional energy efficiency in the High EE sensitivity case reduces the need for resources across all strategic approaches. In the Technology Neutral case, there are about 400 MW less new gas peaker builds in the High EE sensitivity than in Current Trends. In the No New Fossil and Minimum Coal cases, there are even fewer resource builds, particularly batteries (which had been the primary resource selected to meet capacity needs) and solar (which is less economic to add with fewer batteries to integrate the solar).

FIGURE 6.38: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH ENERGY EFFICIENCY SENSITIVITY

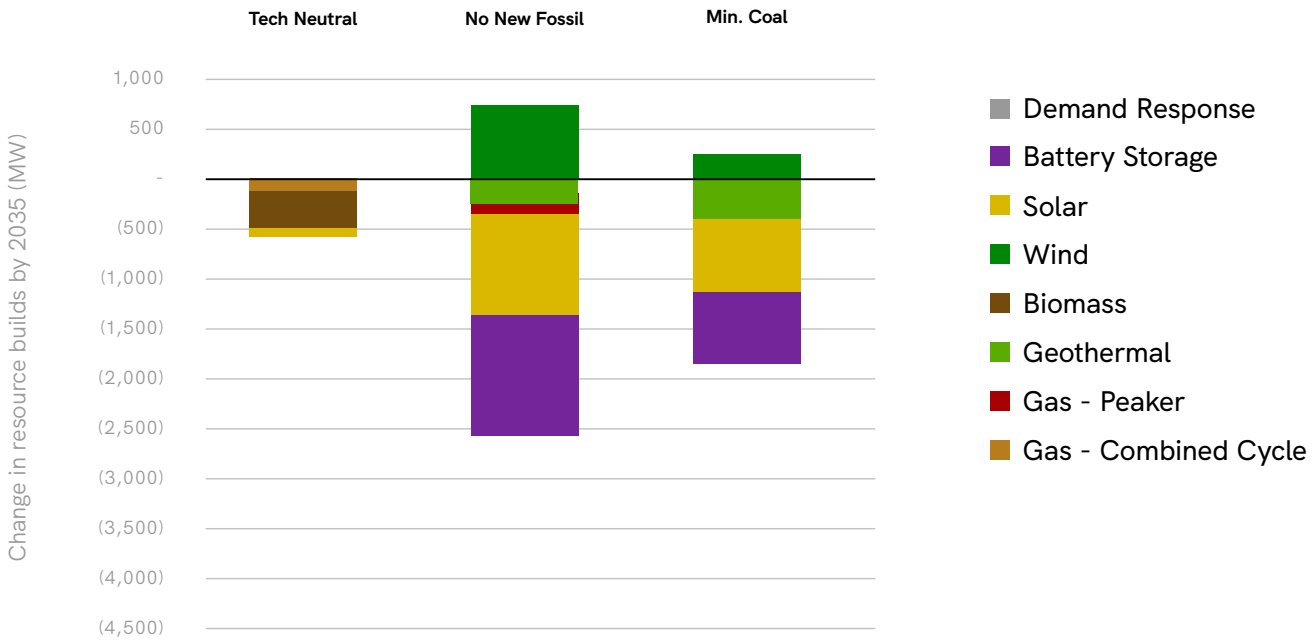
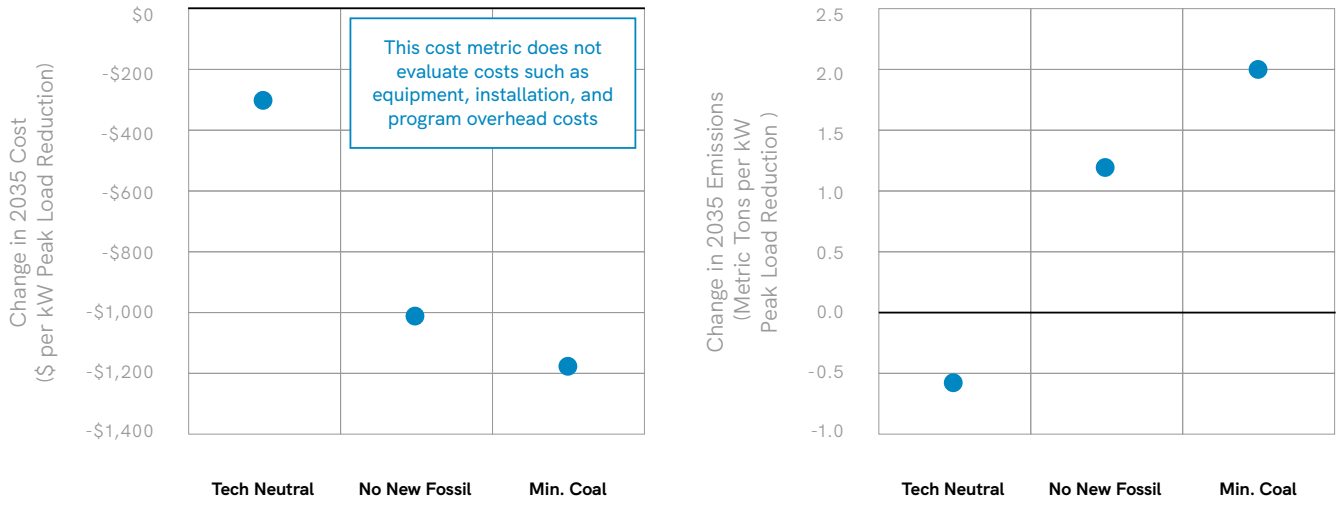




Figure 6.39 shows the resulting changes in total system cost and emissions under the High EE sensitivity, normalized by the kW reduction in PRM from the increased energy efficiency. It is important to note that the results do not include costs such as equipment, installation and program overhead, nor incentive payments or lost revenue that are relevant to ratepayer benefits and costs (such as those captured in the Ratepayer Impact Measure test). Because higher energy efficiency reduces the PRM requirement and the cost of meeting the PRM requirement under No New Fossil and Minimum Coal is higher without new firm resource options, additional energy efficiency results in greater cost savings in the Minimum Coal and No New Fossil cases. Conversely, additional energy efficiency results in relatively lower savings in the Technology Neutral case, where there are new firm capacity options. The Minimum Coal and No New Fossil cases also experienced emissions increases with more energy efficiency due to a net offset in renewable resource capacity and greater natural gas generation and market purchases, while the Technology Neutral case saw a decline in emissions due to a reduction in natural gas generation.

FIGURE 6.39: HIGH ENERGY EFFICIENCY: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, NORMALIZED BY KW PEAK LOAD REDUCTION



Overall, the High EE sensitivity case demonstrates the ability for energy efficiency to not only offset overall energy demand but also demand during peak periods, which in turn can help mitigate the need for incremental investments in the distribution system and firm capacity resources. Cost savings are highest in cases with limited firm capacity resource options (No New Fossil and Minimum Coal) due to the higher cost of meeting the PRM in those cases (relative to Technology Neutral), although emissions increase in those cases due to greater reliance on emitting generation resources to meet energy demand.

High Distributed Generation Adoption

The High Distributed Generation sensitivity included approximately 960 additional MW of distributed solar and approximately 175 MW of distributed storage by 2035. The expanded distributed generation reduces annual peak load and energy demand growth relative to Current Trends, as shown in Figure 6.41.

FIGURE 6.40: HIGH DISTRIBUTED GENERATION SENSITIVITY CAPACITY (MW)

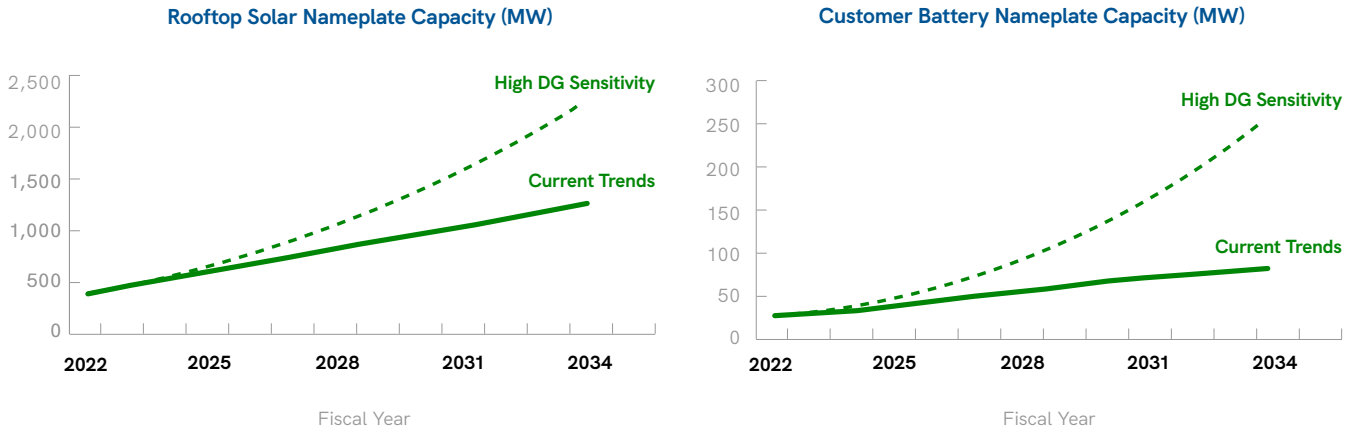


FIGURE 6.41: PEAK LOAD (MW) AND ENERGY DEMAND (GWH) FORECASTS - HIGH DISTRIBUTED GENERATION SENSITIVITY

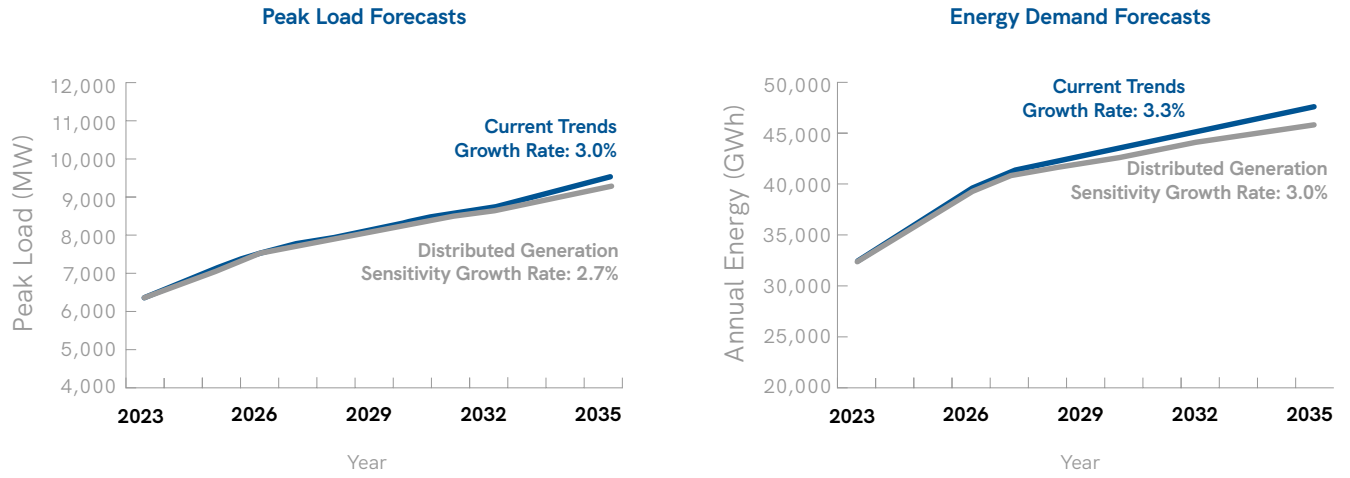
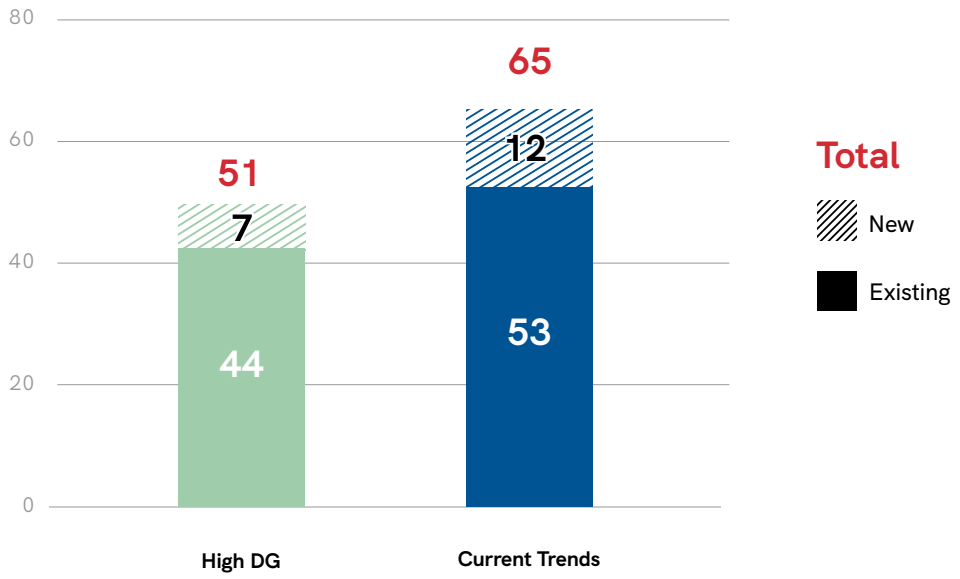


Figure 6.42 shows the distribution substation bay additions under the High Distributed Generation sensitivity relative to the Current Trends scenario (see Figure 6.8 for the remaining scenarios). The High Distributed Generation sensitivity results in slightly fewer substation bay additions than in the Current Trends scenario. The load forecast for this sensitivity is similar to that in the Strong Climate Policy scenario, which is why the investment needs are similar between these two cases. This result reflects the potential for distributed generation to help defer distribution investment needs generally. However, this ability to help defer future investments will vary significantly across the system and must be assessed on a case-by-case basis when evaluating future distribution investments.

FIGURE 6.42: SUBSTATION BAY ADDITIONS AT EXISTING AND NEW SUBSTATIONS (FY23-35) - HIGH DISTRIBUTED GENERATION SENSITIVITY



Additional distributed generation reduces the overall need for new resources, as shown in Figure 6.43. In the Technology Neutral case, increased distributed solar primarily displaces utility-scale solar, while distributed storage displaces some natural gas capacity. In the No New Fossil and Minimum Coal cases, increased distributed generation primarily displaces utility-scale solar and storage.

FIGURE 6.43: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH DISTRIBUTED GENERATION SENSITIVITY

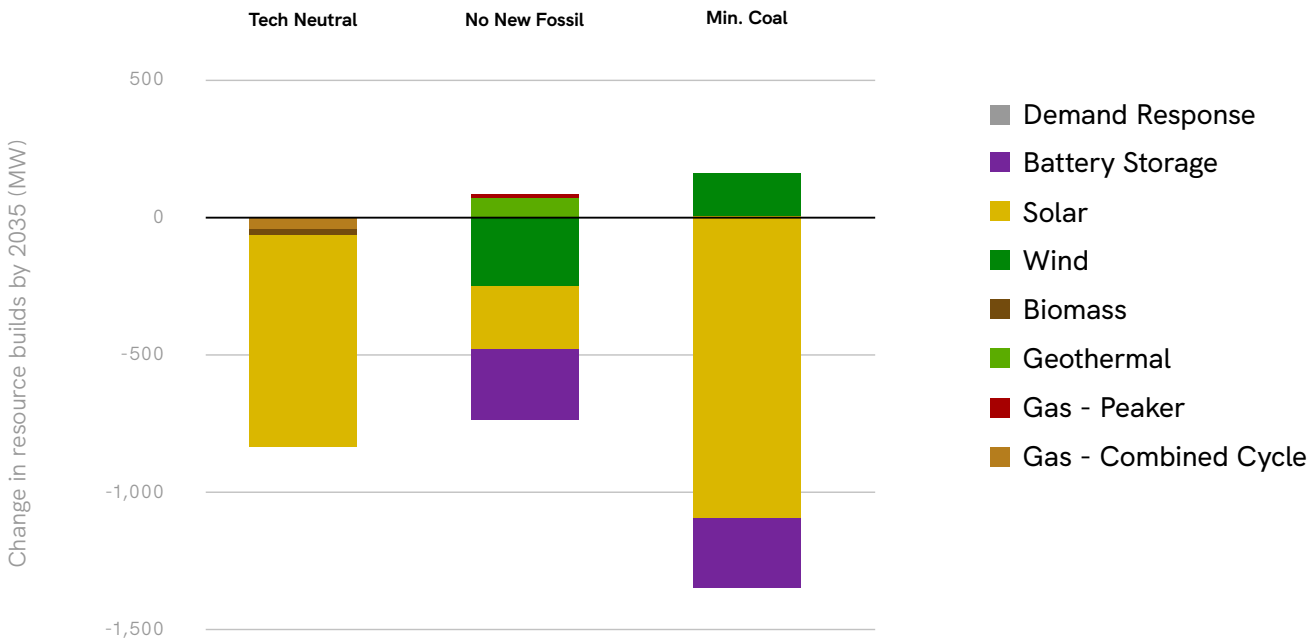
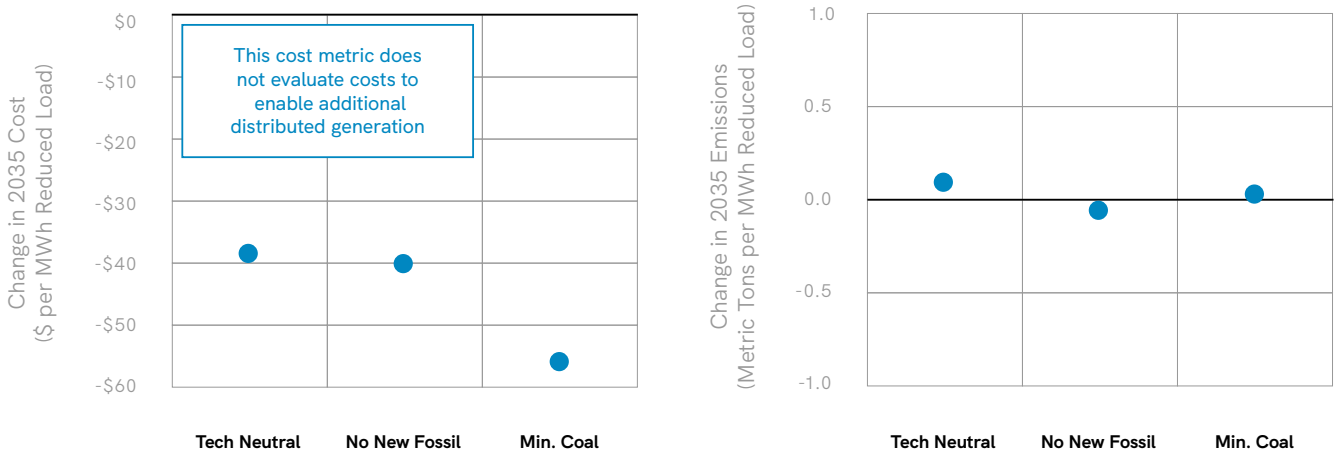


Figure 6.44 shows the resulting reductions in total system cost and changes in emissions under the sensitivity, normalized by the MWh of reduced load from additional distributed generation. It is important to note for these results that there is uncertainty as to how well distributed storage dispatch would align with grid needs and that these results do not include the costs to SRP or its customers of adding the distributed generation. Adding distributed generation generally leads to total system cost reductions, with the greatest reductions in the Minimum Coal case due to the greatest offset of capacity. However, there was very little impact of distributed generation on emissions across all cases, given it primarily substituted distributed solar generation for utility-scale solar generation.

FIGURE 6.44: HIGH DISTRIBUTED GENERATION: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, NORMALIZED BY MWH REDUCED LOAD

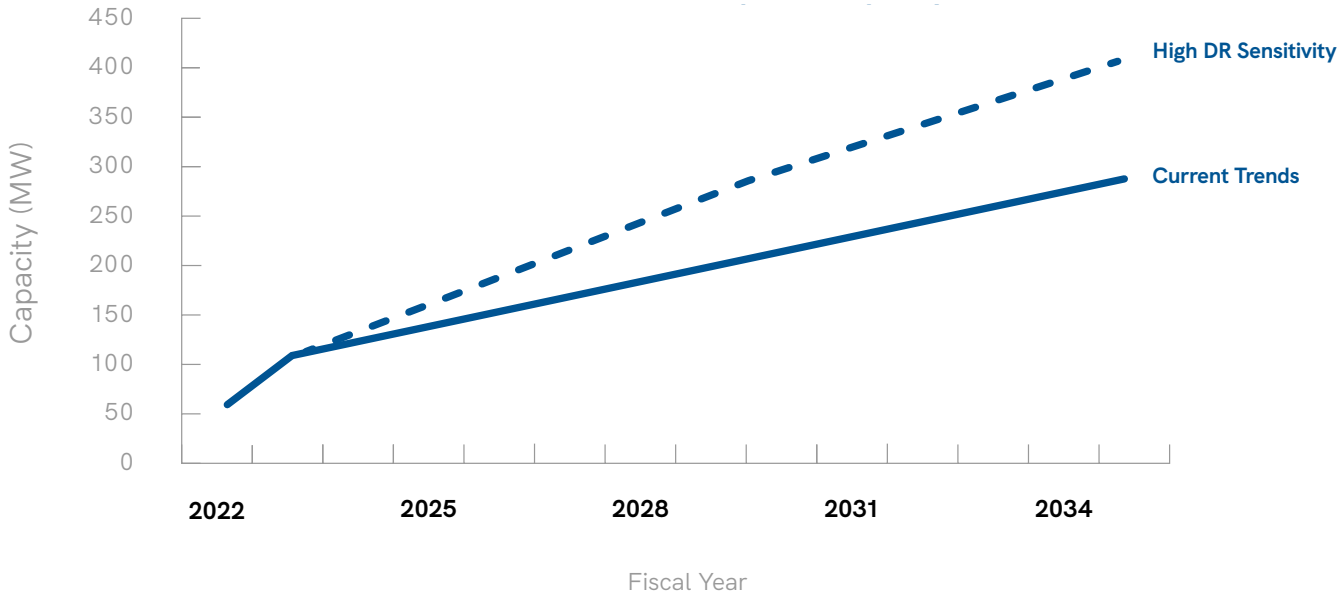


Overall, increased levels of distributed generation resources (solar PV and battery storage) reduce overall energy demand as well as energy demand during peak periods that need to be served by utility-scale resources. As a result, increased adoption of these resources helps mitigate the need for incremental distribution system investments and offsets the need for some utility-scale generation resources: Distributed solar primarily helps offset utility-scale solar, while increased distributed storage is able to offset a portion of capacity resources (gas and/or batteries). The analysis finds that increased adoption of distributed resources leads to the greatest reductions in total system costs in the Minimum Coal strategic approach due to the greatest offset of utility-scale resources and a relatively small impact on emissions across all cases.

High Demand Response

The High Demand Response sensitivity assumes an additional 100 MW of demand response by 2035, reaching a total of 400 MW (compared to 300 MW under the Current Trends scenario).

FIGURE 6.45: ANNUAL DEMAND RESPONSE CAPACITY ASSUMPTIONS



The additional demand response capacity results in a change in resource builds relative to the Current Trends scenario, as shown in Figure 6.46. Increased demand response displaces capacity resources in all strategic approaches. In the Technology Neutral case, adding an additional 100 MW of demand response reduces over 30 MW of natural gas peaker builds.
In the No New Fossil and Minimum Coal cases, the additional demand response substitutes for 50 MW of battery storage builds. The outcome that the reduction of battery capacity is equal to half of the demand response additions reflects the assumption that demand response provides less reliability capacity to the system than batteries; while demand response and battery resources provide similar services to the system, demand response is more limited in number and duration of dispatch events. Because some of the storage resources that are offset are battery storage paired with solar, there is a reduction in solar capacity and a corresponding increase in wind (and biomass in No New Fossil). Less capacity is offset in the Technology Neutral case because natural gas capacity has a greater contribution to reliability needs relative to demand response, battery storage and solar.

FIGURE 6.46: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH DEMAND RESPONSE SENSITIVITY

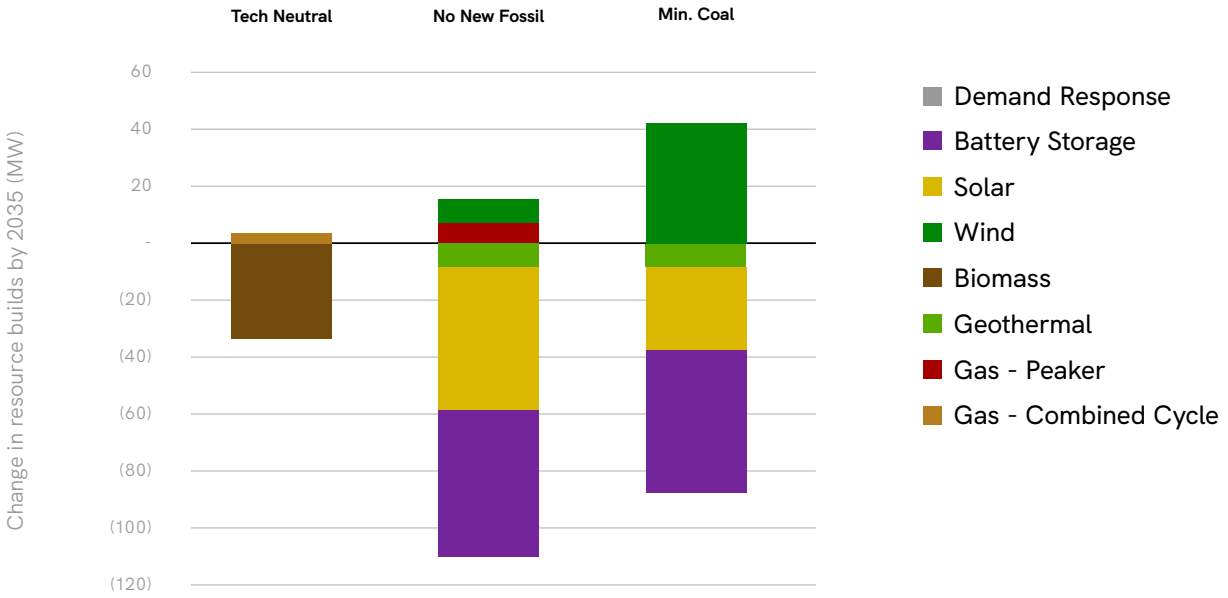
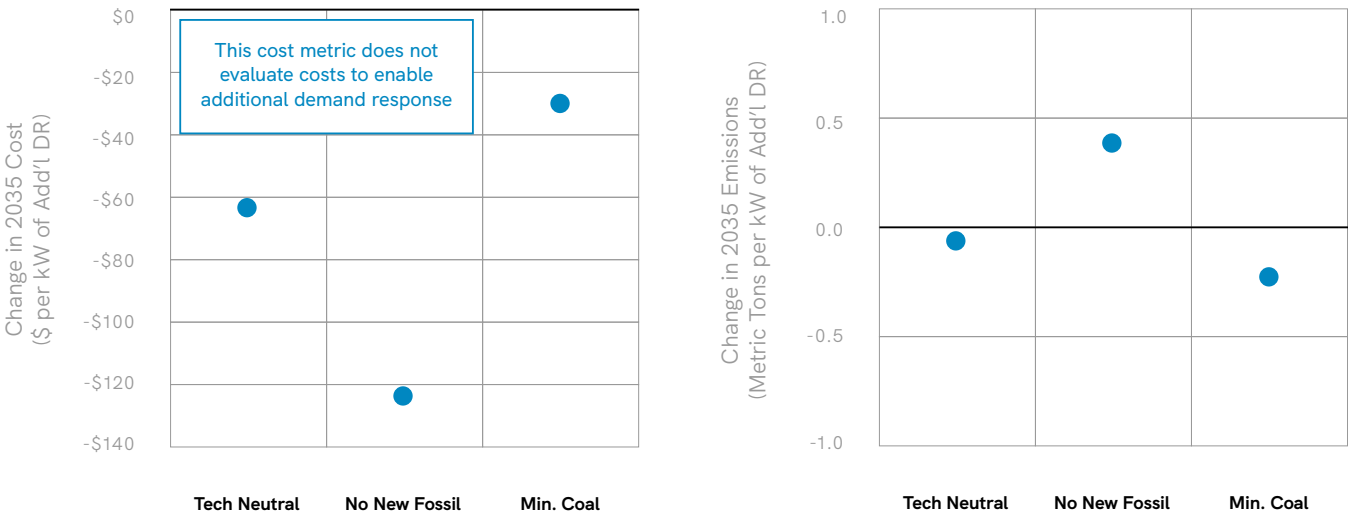


Figure 6.47 shows the resulting change in total system cost and emissions under the sensitivity, normalized by the additional demand response capacity. Note that the total system cost metric does not include the incremental costs needed to enable this additional demand response capacity, so the change in total system cost only reflects gross savings and not net savings. Additional demand response results in the greatest gross savings under the No New Fossil case due to larger offsets in capacity additions. The Technology Neutral case has a smaller reduction in costs because a relatively small amount of natural gas capacity is offset. Emissions increase in the No New Fossil case when demand response is added due to a slight increase in gas emissions to compensate for the net reduction in clean energy capacity. There are small emissions reductions in Technology Neutral due to the reduction in gas capacity and in the Minimum Coal case due to the greater additions of wind capacity offsetting the displaced capacity.

FIGURE 6.47: HIGH DEMAND RESPONSE: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, NORMALIZED BY KW OF ADDITIONAL DEMAND RESPONSE



Overall, increased levels of demand response largely help mitigate the need for capacity resources (gas and/or batteries). Mitigating the need for these resources leads to total system cost savings, with the greatest savings in the No New Fossil case, although this case also sees an uptick in emissions.

Increased Load Management

The Increased Load Management sensitivity assumed that there is an additional 200 MW of aggregate flexibility through managed EV charging or other flexible loads, allowing SRP to shift up to 800 MWh of energy demand each day.

SRP found that increased load management displaces a portion of resources needed for reliability. In the Technology Neutral strategic approach, additional load management reduces gas builds and helps integrate more solar capacity by shifting energy demand from evening hours to daytime hours. In the No New Fossil and Minimum Coal cases, load management substitutes one for one for battery storage capacity, offsetting the paired battery storage and solar that is otherwise built and leading to a small increase in wind.

FIGURE 6.48: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - INCREASED LOAD MANAGEMENT SENSITIVITY

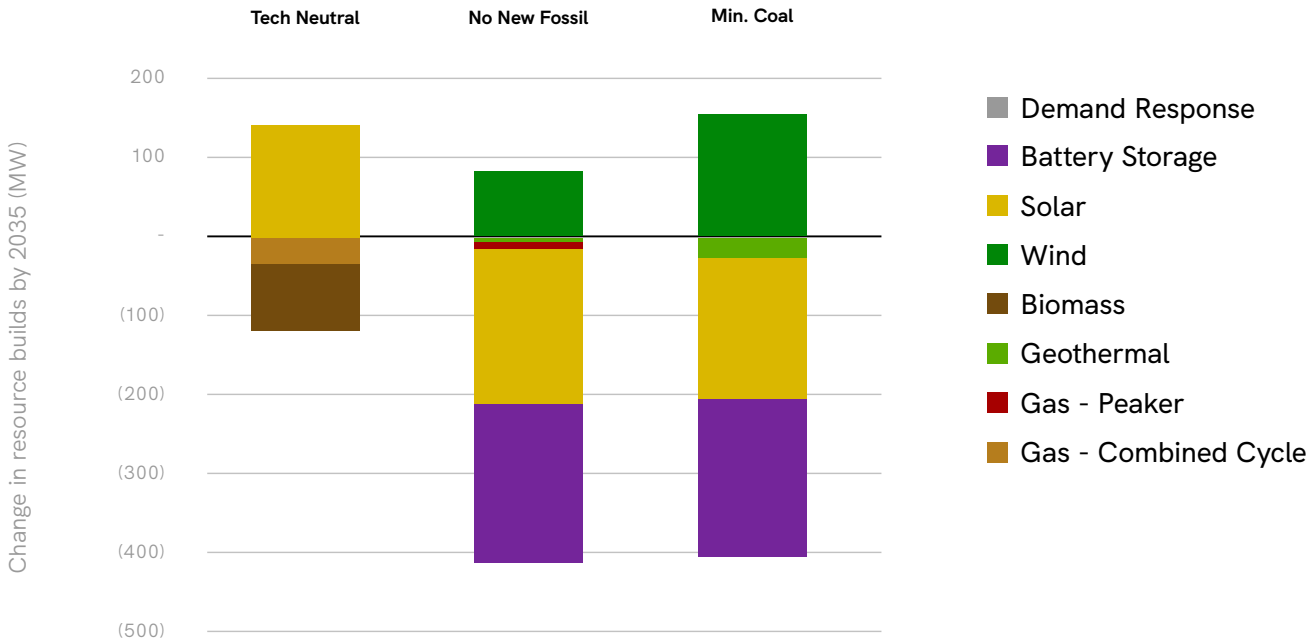
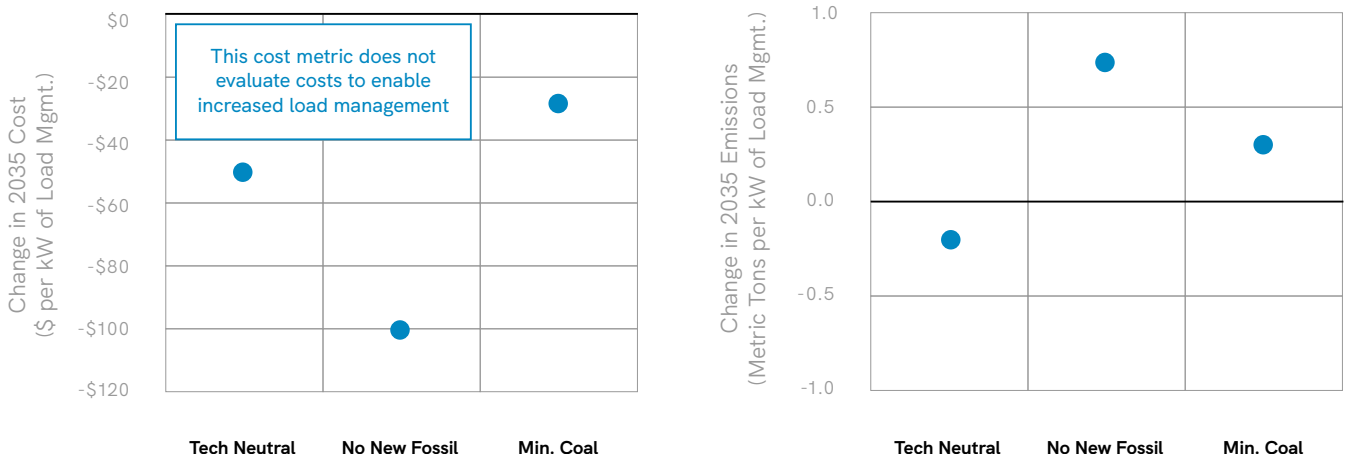


Figure 6.49 shows the resulting reductions in total system cost and changes in emissions under the sensitivity, normalized by kW of increased load management. This sensitivity assumes that SRP has sufficient control or can incentivize customers to get desired performance. Additionally, this sensitivity does not evaluate costs to enable increased load management. The dynamics of increased load management are similar to that of demand response, resulting in similar cost and emissions impacts. Relative to the Current Trends scenario, increased load management generally leads to reductions in total system costs, with the greatest impact on the No New Fossil case. The Minimum Coal case has the smallest reduction in costs because greater amounts of wind capacity are added to make up for the reduced solar and battery capacity. While emissions decrease in Technology Neutral due to the reduction in gas generation, emissions increase under No New Fossil and Minimum Coal due to the larger decline in clean energy capacity.

FIGURE 6.49: CHANGE IN 2035 TOTAL SYSTEM COST AND EMISSIONS, NORMALIZED BY KW OF INCREASED LOAD MANAGEMENT



Overall, increased levels of load management such as managed EV charging largely help mitigate the need for firm capacity resources (gas or batteries). Mitigating the need for these resources leads to total system cost savings, with the greatest savings in the No New Fossil case, although this case also sees the highest uptick in emissions.

High, Low and Volatile Gas Prices

The high and low gas price sensitivity cases were based on the 2022 EIA AEO Low and High Oil & Gas Supply Cases, respectively. SRP found that additions of natural gas and renewable/storage resources depend on gas prices, but in all cases, both new renewables and firm capacity are part of a least-cost portfolio. For example, higher natural gas prices (HGP) increase total capacity additions, driving increases for solar, wind and storage while offsetting some gas capacity. On the other hand, lower natural gas prices (LGP) reduce total capacity additions, driving higher additions of natural gas while offsetting solar and wind additions.

FIGURE 6.50: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO – HIGH AND LOW GAS PRICES SENSITIVITY

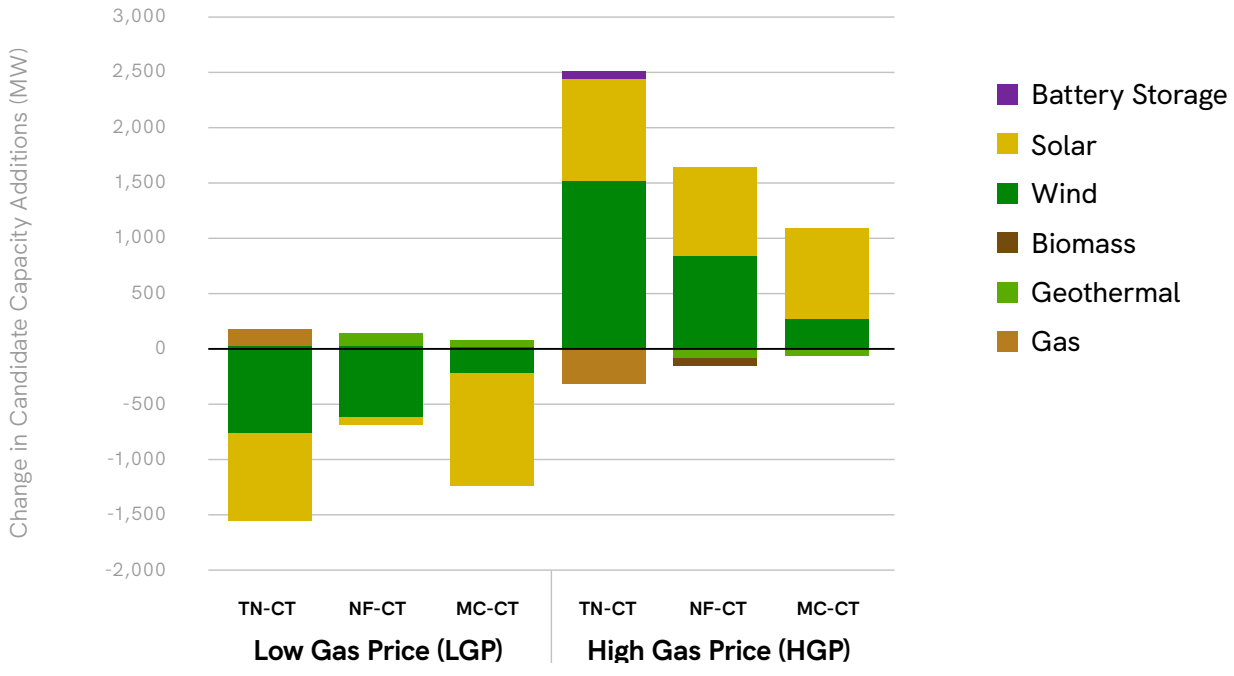


Figure 6.51 shows the change in 2035 total system cost and emissions, relative to the Current Trends scenario. High Gas Prices had the strongest impact on total system cost for the Technology Neutral approach, while the costs for the No New Fossil and Minimum Coal cases were relatively stable. For Technology Neutral, the High Gas Price sensitivity caused a larger change in cost than the Low Gas Price sensitivity because the high gas prices increased more than the low gas prices decreased. Cost impacts under No New Fossil and Minimum Coal were mild for both the High Gas and Low Gas price sensitivities. Emissions increased in the Low Gas Price sensitivity and decreased in the High Gas Price sensitivity for all strategic approaches, but to a lesser extent for No New Fossil.

KEY FINDING

New renewables and firm capacity are part of a least-cost portfolio, even under a wide range of gas prices.

FIGURE 6.51: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, RELATIVE TO THE CURRENT TRENDS SCENARIO

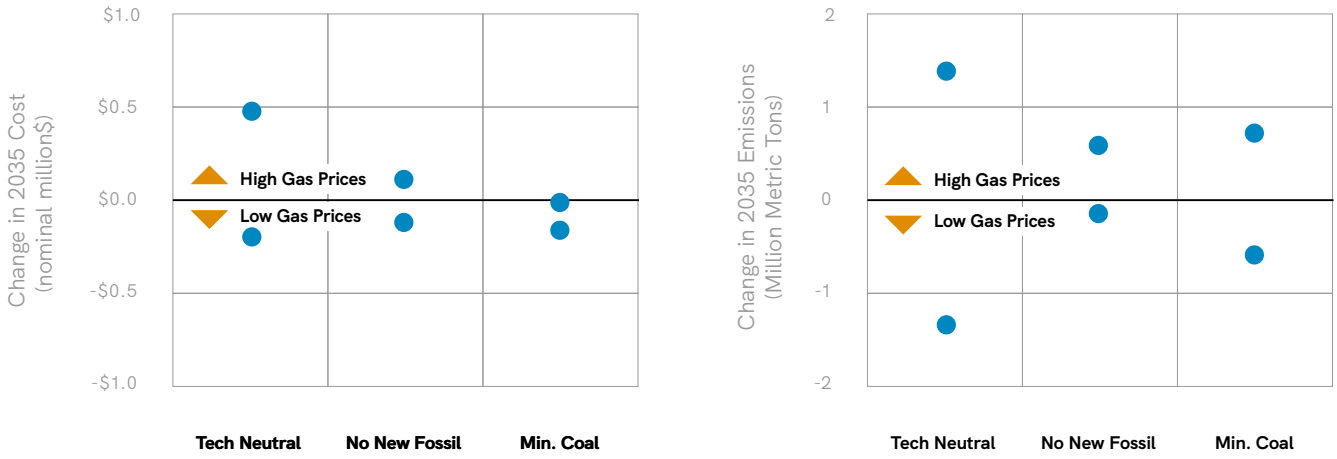
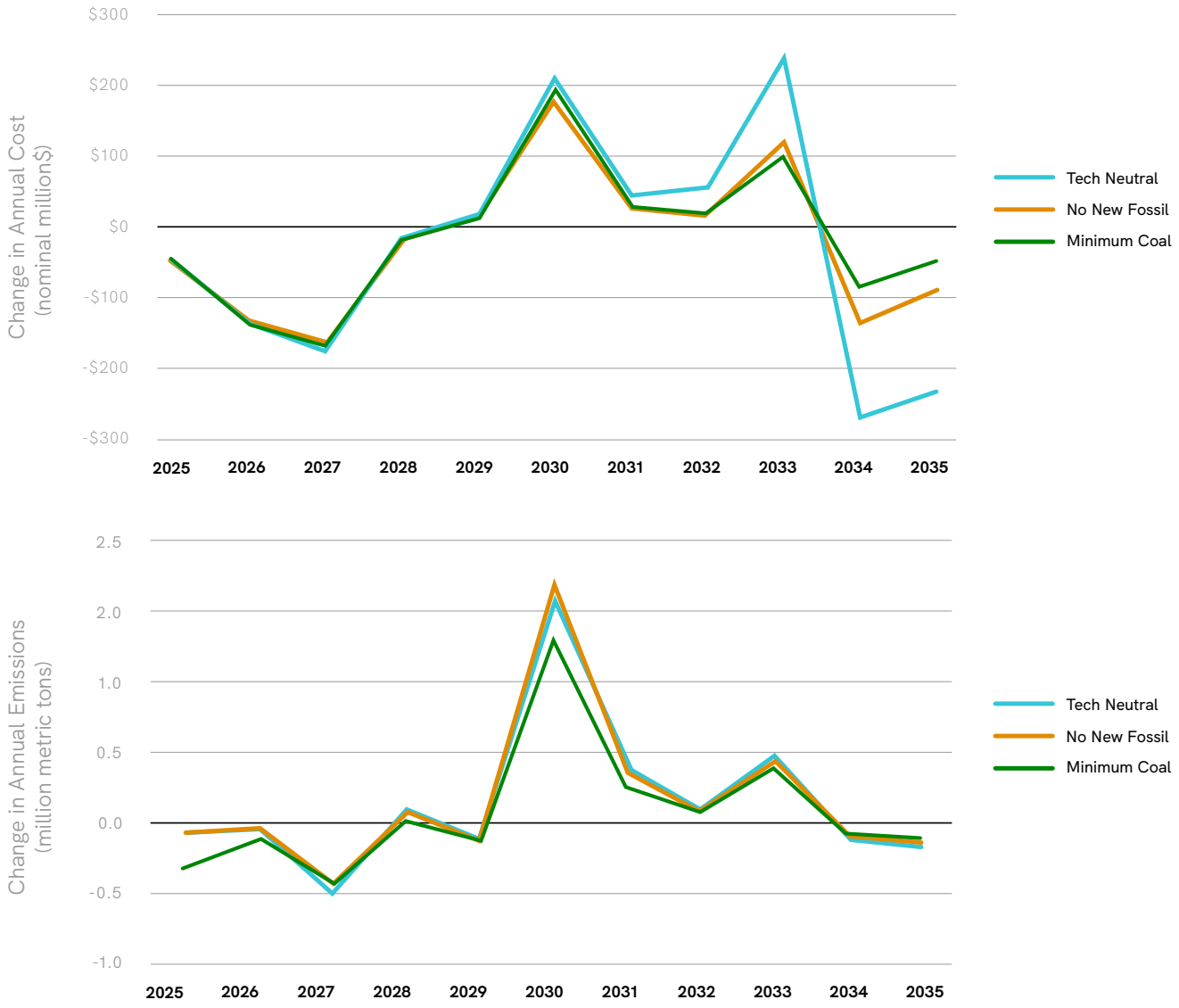


Figure 6.52 shows the impacts of the variable gas price sensitivity on total system cost and emissions between 2025 and 2035, relative to the Current Trends scenario. This sensitivity did not vary resource buildouts, so the changes over time are only a result of changes to gas prices (and associated impacts on market prices). The variability in natural gas prices leads to fluctuations in total system costs, particularly in the 2030s, with total system cost increasing or decreasing by over +/- $200 million in a given year and emissions increasing by over 2 million metric tons in a given year.



FIGURE 6.52: VARIABLE GAS PRICES: ANNUAL CHANGE IN TOTAL SYSTEM COST (TOP) AND EMISSIONS (BOTTOM), RELATIVE TO THE CURRENT TRENDS SCENARIO



Overall, the trajectory of future natural gas can have important implications for SRP's resource portfolio. Higher natural gas prices result in increased additions of renewables and storage (offsetting a smaller amount of natural gas builds in Technology Neutral), higher total system costs and lower emissions in 2035. Lower natural gas prices result in lower renewable additions (with a slight uptick in natural gas builds under Technology Neutral), lower total system costs and higher emissions. The potential for unexpected gas price volatility in the future could result in higher system costs or emissions.

High and Low Technology Costs

The High and Low Technology Cost sensitivities were based on the 2022 NREL ATB High and Low Cases, respectively. Lower Technology Costs (LTC) increase total capacity additions, driving increases in solar and battery storage while offsetting some natural gas capacity. On the other hand, Higher Technology Costs (HTC) reduce total capacity additions, primarily offsetting solar additions.

FIGURE 6.53: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH & LOW TECHNOLOGY COSTS

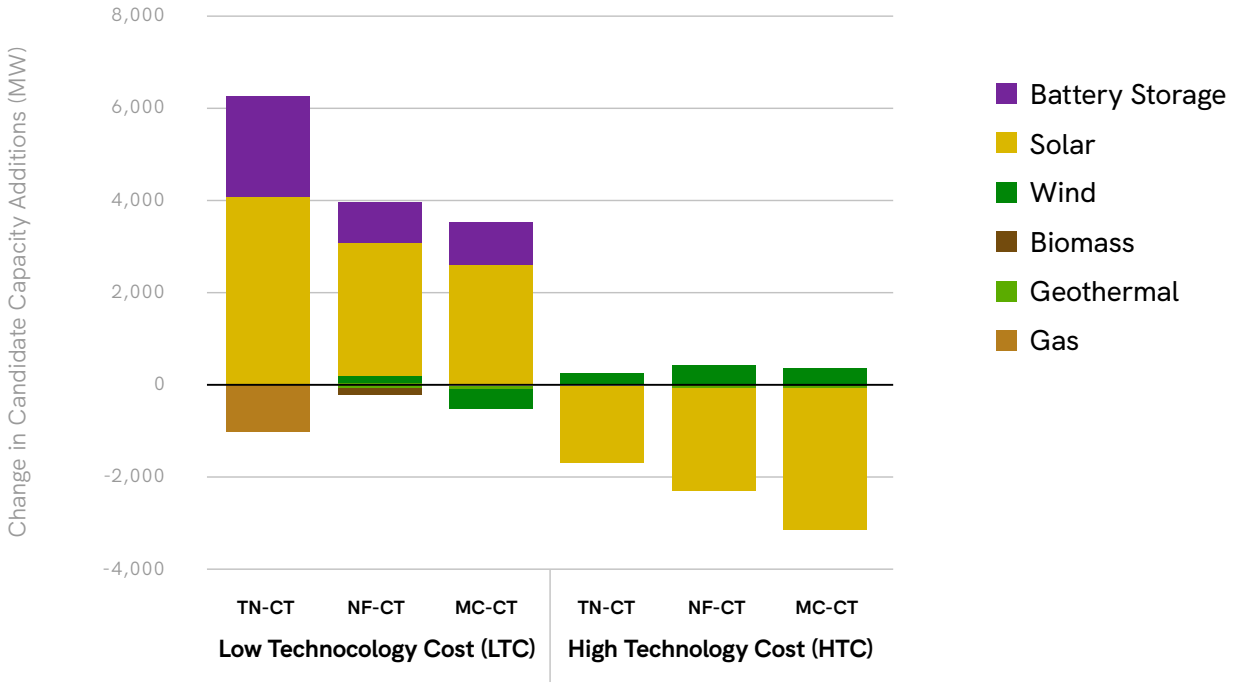
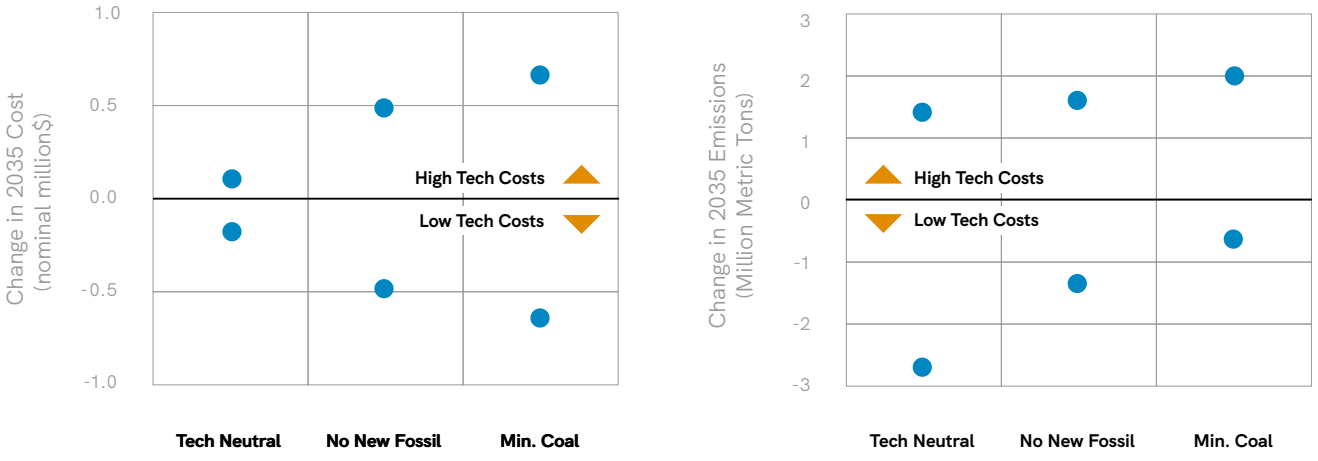


Figure 6.54 shows the change in 2035 total system cost and emissions, relative to the Current Trends scenario. The change in technology costs causes the greatest cost impact on the Minimum Coal case, while the Technology Neutral case experiences relatively low impacts to cost. Across all cases, higher technology costs lead to higher emissions and lower technology costs lead to lower emissions.

FIGURE 6.54: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, RELATIVE TO THE CURRENT TRENDS SCENARIO



Overall, the trajectory of future technology costs can have important implications for SRP's resource portfolio. Lower renewables and storage technology costs result in increased additions of solar and storage (and higher total capacity additions), lower total system costs and lower emissions in 2035. Higher technology costs result in lower renewable additions, higher total system costs and higher emissions. In all cases, new firm capacity is still needed.

Regional Diversity

In the Regional Diversity sensitivity, SRP reduced the target planning reserve margin (PRM) from 16% to 13% (338 MW reduction by 2035) to serve as a proxy to represent the assumption that expanded transmission and regional coordination allow for increased resource and load diversity. The lower PRM reduces the need for resources on SRP's system. In the Technology Neutral strategic approach, there are fewer gas peaker builds. In the No New Fossil and Minimum Coal cases, larger amounts of resources are offset. The most impacted resources are batteries (due to the lower total PRM requirement) and solar (which is less economic to add with fewer batteries to integrate the solar). These resources are partially replaced by wind in both cases.

FIGURE 6.55: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - REGIONAL DIVERSITY

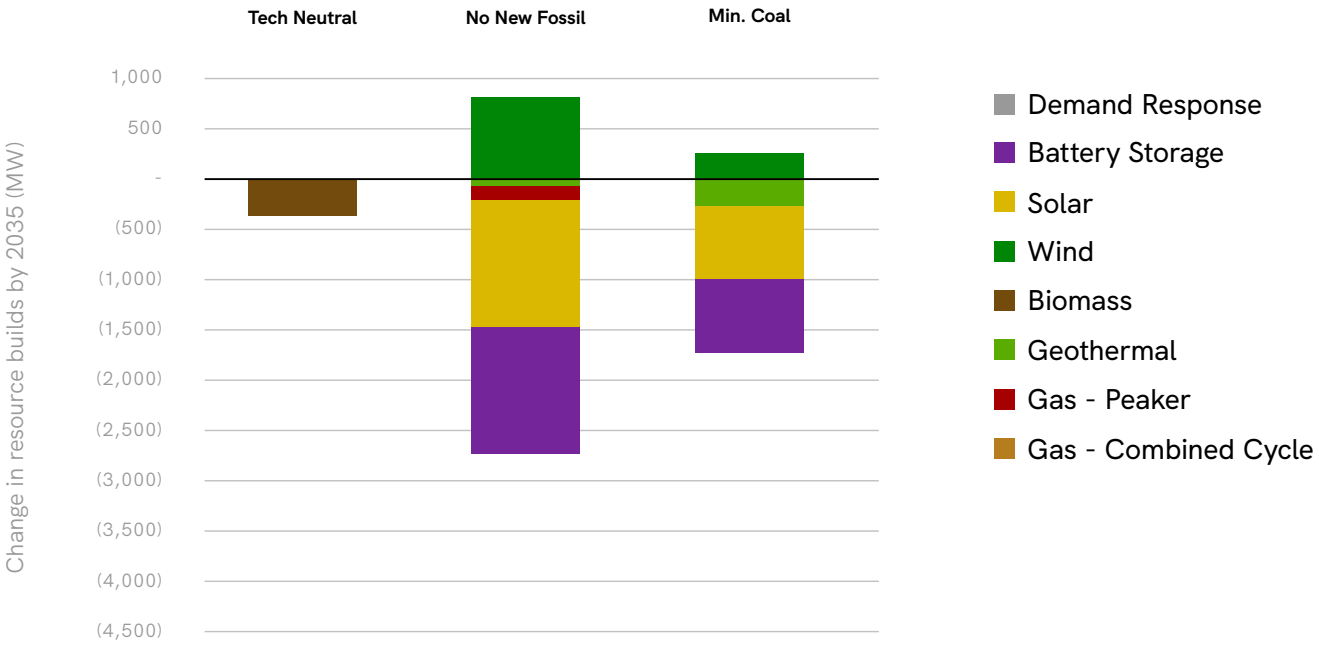


Figure 6.56 shows the resulting reductions in total system cost and changes in emissions under the sensitivity, normalized by the kW PRM reduction. For this sensitivity, the 3% PRM reduction is hypothetical, and the results do not consider any trade-offs or costs to realize greater regional diversity benefits for capacity planning. Because No New Fossil and Minimum Coal have higher costs of meeting the PRM due to the lack of new firm capacity resources, Regional Diversity results in the greatest cost reductions for these cases and the lowest cost reductions for Technology Neutral, in which there are new firm capacity resource options. While the Technology Neutral case experiences a very slight decrease in emissions, No New Fossil and Minimum Coal have increases in emissions due to natural gas generation and market purchases compensating for the reduction in renewable generation.

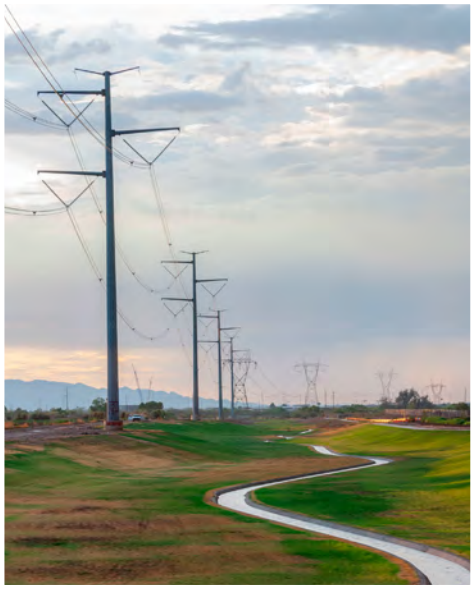
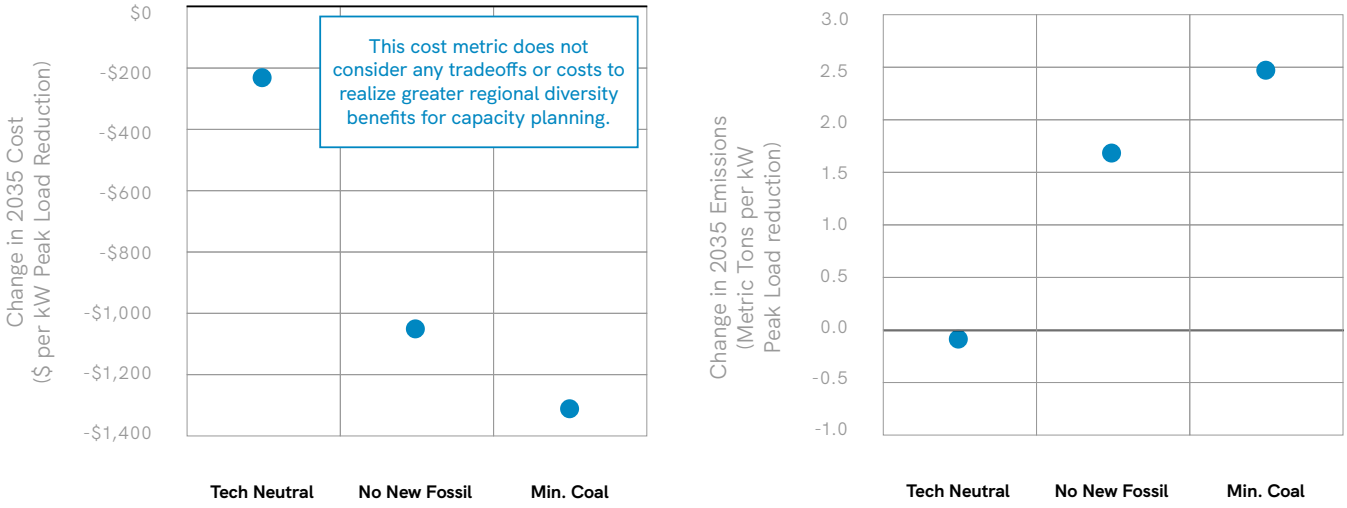


FIGURE 6.56: CHANGE IN 2035 TOTAL SYSTEM COST AND EMISSIONS, NORMALIZED BY KW PEAK LOAD REDUCTION



Overall, increased regional market participation largely helps mitigate the need for firm capacity resources (gas and/or batteries) due to increased resource and load diversity. Cost savings are highest in cases with limited firm capacity resource options (No New Fossil and Minimum Coal) due to the higher cost of meeting the PRM in those cases (relative to Technology Neutral), although emissions increase in those cases due to greater reliance on emitting generation resources to meet energy demand.

Summary of ISP Key Findings

The key findings from the analysis described above are summarized here for reference. These key findings served as the foundation to inform the ISP System Strategies described in Section 8.

Customer Programs and Pricing Plans

- SRP will need to evolve programs and price plans to encourage shifts in consumer behavior and further educate customers on when to consume and when to conserve energy.
- Electrification of end uses, including transportation and heating demand, creates new opportunities to shift energy usage to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.
- Changes in how customers use energy will require continued innovation and flexibility in planning.

Infrastructure

- Customers' energy demand is expected to increase rapidly through 2035 in most scenarios, even with significant expansion of customer programs and customer-sited generation.
- Significant investments in new transmission infrastructure are needed over the next decade to connect new resources and customers while also achieving reliability and sustainability goals. These investments will need to be strategically located and timed.

- Load growth will drive new distribution infrastructure needs while changes in how our customers use energy will require innovation and flexibility.
- SRP will likely need to double or triple resource capacity in the next decade to serve customers while achieving reliability and sustainability goals. This will be at an unprecedented pace.
- New renewables and firm capacity are part of a least-cost portfolio, even under a wide range of gas price and technology cost sensitivities.
- When paired with firm capacity, solar and wind contribute to a least-cost portfolio while helping SRP reduce carbon emissions and water usage. If the U.S. government enacted a mandate for 85% CO_2 reductions by 2035 (Strong Climate Policy), further acceleration of renewable and storage deployment would be required.
- Hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230 kV transformers could be needed relative to today.
- Location of generation matters and plays a significant role in the buildout of the 500 kV and 230 kV transmission system.

Operations

- Without new firm generation capacity, the system cannot satisfy reliability requirements under a high load growth scenario. In other load growth scenarios, the system can satisfy reliability requirements without new firm generation capacity but requires significant additions of renewable and energy storage resources.
- The reduction in coal generation and expansion of carbon-free resources over time allow SRP to meet, and in many cases exceed, SRP's 2035 goals for carbon emission reductions and water resiliency.
- A future system that relies more on variable renewable resources presents new challenges and will require new operating practices to ensure sufficient flexibility, reduce wear and tear on existing assets, and maximize benefits to customers.

Partnerships to Meet the Pace of Transformation

- With the amount of future infrastructure and resources needed, internal and external partnerships are going to be essential to build the future system and maintain high customer value.
- To meet the pace of infrastructure needs, supply chain and development solutions are essential to managing costs and to meet the pace of transformation needed.

SECTION 7

System Strategies

System Strategies

SRP faces an uncertain future that will continue to change at a rapid pace. In this dynamic and evolving environment, we must establish diverse strategies that can stand up to these changes while allowing for flexibility and adaptation. Utilizing our analysis and key findings, we have established seven System Strategies that will allow us to deliver the best value to our customers under future uncertainty and a wide range of potential outcomes.

The **System Strategies** are the Board-approved long-term strategies for planning and operating the power system in an integrated manner. These are strategies for all power system areas, including customer programs, distribution planning, resource planning, transmission planning, pricing and system operations. The strategies will guide us today through 2035, and they consider system developments needed beyond 2035 to meet SRP's 2050 goals. As a whole, these strategies will help to:

- Guide how we plan the system for the future and serve as the focal point for prioritizing our investments.
- Provide direction while maintaining flexibility to allow us to respond to future conditions.
- Guide our decisions on day-to-day planning activities.
- Signal to stakeholders and customers how we plan to evolve the system and meet the changing needs of our customers.

The System Strategies are also the starting point for developing the ISP Balanced System Plan and the ISP Actions, which are covered in detail in sections 8 and 9.

SRP used key insights from the ISP analysis, as discussed in Section 6, to develop the System Strategies that will help us maintain reliability and affordability while driving increased sustainability across a wide range of potential future scenarios. We also gathered and incorporated feedback from the Advisory Group members on these strategies before bringing them to SRP's Board. On Oct. 2, 2023, the Board approved the System Strategies.



Below are the seven interdependent System Strategies. Each strategy is reliant on the other strategies also being in place to ensure success and achievability. These are the strategies we can begin to implement now. Some strategies may take longer to implement than others, but the execution of all strategies together will enable us to meet evolving customer needs, achieve our 2035 Sustainability Goals, manage costs for customers, achieve an adequate and reliable power system, and adapt to a more sustainable future regardless of what the future may be in 2035.

Below is a detailed description of the seven System Strategies and discussion of the key findings from the ISP analysis that support them.

Energy Investments



Invest in renewable resources and storage to manage fuel consumption and drive carbon and water reductions.

The ISP analysis demonstrated that new renewables combined with firm generation are part of a least-cost power generation portfolio. Across the different future scenarios, we saw the least-cost system plans add an average of 4,800 MW of renewables and storage.

Renewables do more than just contribute to a least-cost portfolio. They help reduce fossil fuel consumption and contribute to improved sustainability, helping SRP meet its 2035 carbon reduction and water use goals. Our customers also want more renewables. We found from the residential customer research that customers want us to provide the most sustainable energy portfolio possible without significantly increasing their costs or compromising reliability. This strategy focuses on investing in renewables and storage to deliver exceptional value to our customers and help drive carbon and water reductions.

Capacity Investments



Invest in firm generation, including natural gas, to support reliability and manage affordability while also supporting the advancement of emerging firm technologies.

The ISP analysis shows that firm generation, such as natural gas, is key to maintaining reliability. Firm generation includes resources that can dispatch on demand and generate over long periods of time (e.g., multiple days). Without new firm generation, reliability is compromised by 2028 under a high load growth scenario.

Firm generation resources, when added along with renewable and storage resources, are also key to maintaining affordability. On average, the least-cost system plan adds more than 2,000 MW of natural gas capacity by 2035, helping to offset losses in firm generation from coal plant retirements and the expiration of a natural gas tolling agreement. When new natural gas is not allowed to be added, total system costs are 17%–24% higher under the Current Trends scenario and 7%–11% higher under the Desert Contraction scenario. The addition of firm generation allows SRP to mitigate these cost impacts and maintain affordability.

While adding new firm generation is key to maintaining reliability and affordability, it does not mean that these resources will have high utilization. The Energy Investments system strategy envisions adding renewable and storage resources to reduce fuel consumption from fossil fuel-fired resources, which is reflected in the ISP analysis. As a result, new and existing natural gas generation resources are projected to operate less over time, with the anticipated systemwide capacity factor declining to roughly 25% by 2035.

This strategy recognizes the need for the advancement of other emerging firm technologies (such as hydrogen, new nuclear and long-duration storage) and the role that emerging technologies can play in helping meet a portion of firm resource needs in the future. We expect the new investments in natural gas generation to be hydrogen-ready to allow SRP to transition those resources to hydrogen if and when hydrogen becomes a commercially viable fuel option.

Proactive Transmission

Proactively plan to expand transmission infrastructure to enable generator interconnections and load growth.



The ISP analysis showed that a significant investment in transmission is needed over the next decade, driven by the large amount of generation required to meet our growing loads. By 2035, SRP could need hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230 kV transformers relative to today. The location of this new generation capacity matters and has a significant impact on the buildout of the 500 kV transmission system. We must strategically locate and build out new grid infrastructure to connect new resources and customers. It is in our best interest to strategically find the best location for new-generation resources and transmission. Siting and permitting transmission can be a decade-long process, necessitating a proactive approach in transmission planning.

Distribution Innovation

Ensure distribution grid readiness to maintain reliability and enable customer innovations to drive carbon reductions.



The distribution innovation strategy is focused on ensuring we are prepared for anticipated growth while maintaining reliability and enabling customer innovation. Load growth will drive additional infrastructure needs, while changes in how our customers use energy will require innovation and flexibility. This strategy allows us to understand and adapt to the complexities of balancing energy load growth with innovation that may reduce customer demand, such as managed EV charging, expanded deployment of distributed solar, and next-generation demand response programs.

This strategy helps enable us to provide a dependable supply of electricity to all SRP customers and provide a reliable grid that can prepare for and recover from unanticipated disruptions to ensure energy availability, while at the same time helping us meet evolving customer needs.

Partnerships & Suppliers

Explore partnerships and supply chain and development solutions that manage cost and availability to meet the pace of transformation.



SRP anticipates the need to double or triple resource capacity in the next decade to be able to best serve our customers while achieving our 2035 Sustainability Goals. This is an unprecedented pace of resource development, with potential additional needs for hundreds of miles of new transmission lines and numerous transformers on the transmission and distribution system. It will also require making decisions on specific investments, procurements, workforce development, information technology systems, etc. With the amount of future infrastructure and resources needed and long lead times for certain assets, external partnerships will be essential to build the future system and maintain high customer value.

Customers and community partnerships will also be critical to achieving the transformation of the power system. To enable construction of the large amount of infrastructure SRP is planning, we must proactively build relationships and partnerships with communities, cities, counties, towns, government agencies and tribes, and engage with advocacy organizations to understand their perspectives. We can then better identify, prepare and preserve options for feasible sites for future system infrastructure. Through these partnerships, SRP can respond to evolving customer needs by providing safe, reliable, affordable and sustainable power while recognizing the different needs, challenges and perspectives of our customers.

In addition to partnering with customers and communities, supply chain disruptions and delays that are still being felt following the pandemic necessitate the need to find supply chain and development solutions. Future supply chain disruptions could further impact our ability to develop new infrastructure. This strategy helps enable supply chain solutions essential to managing costs for our customers and to meeting the pace of transformation needed which could include ordering key supplies as early as possible and developing a wider pool of potential suppliers to diversify supply chain risks.

Evolution of Customer Programs & Pricing

Evolve pricing and customer programs to improve economywide carbon reductions and pace infrastructure development, while recognizing customers' diverse needs.



SRP will need to evolve programs and price plans to deliver the best value to our customers. We saw in our Time-of-Use Exploratory Study, existing customer programs and price plans are effective at managing peak energy demand today, but as our energy mix changes, so must our customer programs and price plans. Adding significant amounts of solar energy will mean abundant, low-cost energy is often available during daytime hours. The more expensive peak period will then shift later into the evening once the sun sets.

This also creates new opportunities to shift energy from increased electrification programs to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.

During our transition to a more sustainable future, the timing and availability of low-cost resources will change with the increased adoption of renewable resources. We strive to strike the right balance of reliable, affordable and sustainable power for our customers. Currently, we have targets for Energy Efficiency and Demand Response adoption in our 2035 goals. We will continue studying options to accelerate and adapt to meet changing patterns in our customers' electricity use and help address significant load growth and capacity constraints over the next several years.

This strategy allows us to adapt to the needs of a changing grid and gives us an opportunity to recognize the different needs, challenges and perspectives of our customers and reflect that through new customer offerings that will help us maintain industry-leading customer satisfaction.

Strategic Investment & Reinforcement of Existing Assets



Reinforce and maximize value of existing infrastructure with strategic investments to manage affordability and ensure future performance, grid security and resilience.

SRP's existing assets and generation are the foundation for our future. Our existing and contracted generating assets will make up 50% of our capacity, 70% of our reliability needs and 45% of our carbon-free energy in 2035. Additionally, our existing transmission lines will make up an estimated 90% of the total number of 230-plus kV line miles in 2035, and our distribution substation bays will make up 85% of the substation bays we need in 2035. The existing system is important, and we must strategically reinvest in the system we have today by continuing to perform routine maintenance to extend the life of our assets. Existing resources are needed to meet future customer needs and maintain a reliable grid that can prepare for and recover from both anticipated and unanticipated disruptions to ensure energy availability. This will ensure continued grid security, safety and performance.

We must also explore repurposing existing or retired coal plants with other emerging technologies and making more strategic generation investments to connect and use existing transmission whenever possible.

This strategy allows us to deliver exceptional system and energy value by minimizing the need for additional grid resource investments, which helps keep costs lower for our customers.



The System Strategies discussed in this section will guide SRP's planning activities and investment decisions in a way that balances all important considerations in developing a reliable, affordable and sustainable power system. Through robust analysis in the ISP, SRP developed a detailed understanding of the inherent trade-offs between reliability, affordability and sustainability and sought to establish an Integrated System Plan that fully balances all considerations.

It is important to reiterate that none of the System Strategies above can stand on their own. These strategies are intertwined and need to be executed simultaneously to best serve our customers and ensure that we will continue to provide reliable, affordable and sustainable power regardless of what the future brings.

SECTION 8

Balanced System Plan

Balanced System Plan

The ISP Balanced System Plan is an illustration of what SRP's power system may look like in 2035 by implementing the seven System Strategies. We constructed the **Balanced System Plan** to help customers and stakeholders visualize the future power system based on what is known today. However, as discussed in previous sections, the entire utility industry faces a lot of change and uncertainty. As a result, we will inevitably need to adapt and evolve this plan as new information (e.g., updated economic development forecasts and technology cost projections) becomes available and as circumstances change, such as new laws or regulations being enacted.

Developing the Balanced System Plan

The ISP System Strategies detailed in Section 7 are the foundation for the Balanced System Plan. To identify how the system could evolve in a manner consistent with the System Strategies, SRP leveraged the results and key findings from the ISP analysis.

Of the strategic approaches analyzed, it was clear that no individual strategic approach performed best across all metrics. For example, the Technology Neutral strategic approach resulted in the lowest system cost and lowest residential customer bill impacts, whereas the Minimum Coal strategic approach performed best across multiple sustainability metrics. Separately, results from the ISP residential customer research found that customers want it all. They want SRP to advance sustainability performance while maintaining high levels of reliability and limiting cost increases.

In building out the Balanced System Plan, we considered the results of the various analyses, findings from the different strategic approaches and feedback from our customers to strike a balance between sustainability, affordability and various power system reliability risks.

Specific considerations used in developing the Balanced System Plan included the following goals:

- **Reliability:** Maintain firm generation capacity and expand grid needs while preparing for emerging grid technologies.
- **Affordability:** Utilize an all-of-the-above approach to diversify and moderate the pace of investments.
- **Sustainability:** Significantly expand investments in renewable energy and storage to drive carbon reductions and reduce water consumption.
- **Customer Focus:** Focus on managing costs and advancing sustainability and customer programs without sacrificing reliability.



FIGURE 8.1: GOALS OF THE BALANCED SYSTEM PLAN



Reliability

Maintain firm generation capacity and expand grid needs, while preparing for emerging grid technologies

Affordability

Utilize an all-of the-above approach to diversify and moderate pace of investments

Sustainability

Significantly expand renewable and storage development to drive emissions reductions and reduce water consumption from power generation

Customer Focus

Focus on managing costs, advancing sustainability and customer programs without sacrificing reliability

Resources and Customer Programs

The Balanced System Plan envisions significant resource additions between 2025 and 2035. By implementing the Energy Investment System Strategy, SRP could triple the total installed capacity of renewable and storage resources by 2035. Solar, being a low-cost renewable resource that helps displace fossil fuel generation, makes up the majority of the renewable energy additions in the Balanced System Plan, with 6,000 MW added. Other renewable additions include 800 MW of wind located in eastern Arizona to leverage existing transmission that becomes available when Coronado Generating Station retires in 2032, as well as 50 MW of geothermal and 50 MW of biomass to help provide resource diversity. The Balanced System Plan also includes 2,500 MW of additional energy storage, split between four-hour lithium-ion batteries and pumped hydro storage.

By implementing the Capacity Investment System Strategy, SRP would maintain similar levels of thermal generation as today to provide firm capacity. This includes investing in 2,000 MW of new natural gas generation to replace 1,300 MW of retiring coal generation and a 975 MW gas tolling agreement that expires in 2031. We did not include advanced nuclear or hydrogen in the Balanced System Plan due to development risks with those technologies becoming commercially available by 2035.

In addition to the utility-scale resource additions, the Balanced System Plan includes customer programs and customer-sited resources, which will help displace the need for utility-scale resources. Specifically, the Balanced System Plan envisions 700 MW of combined capacity from energy efficiency and demand response (labeled Customer Programs in figures 8.2 and 8.3) as well as 750 MW of customer-sited solar, demonstrating SRP's implementation of the Evolution of Customer Programs & Pricing System Strategy. While the Balanced System Plan does not reflect changes to customer pricing over time, SRP's evolution of price plans can help further mitigate resource additions by providing price signals to customers to moderate their demand during periods of lower supply.

FIGURE 8.2: BALANCED SYSTEM PLAN NAMEPLATE CAPACITY 2025-2035

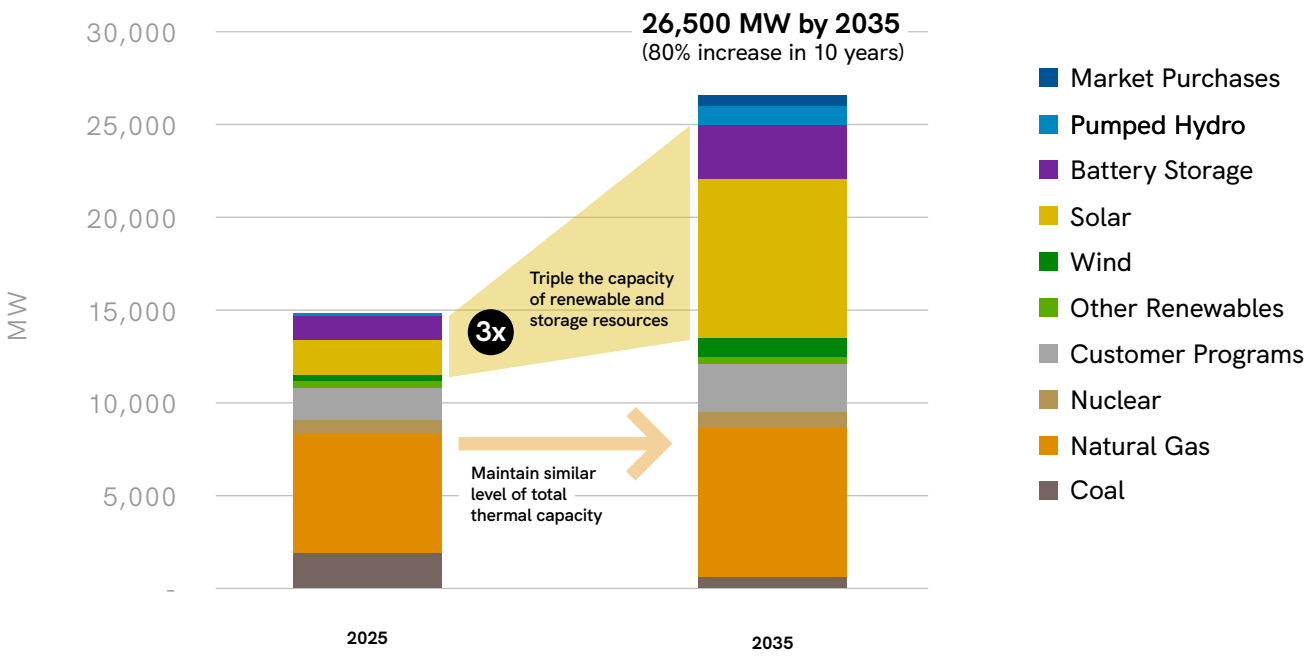


FIGURE 8.3: BALANCED SYSTEM PLAN NAMEPLATE CAPACITY ADDITIONS BY 2035 (MW)

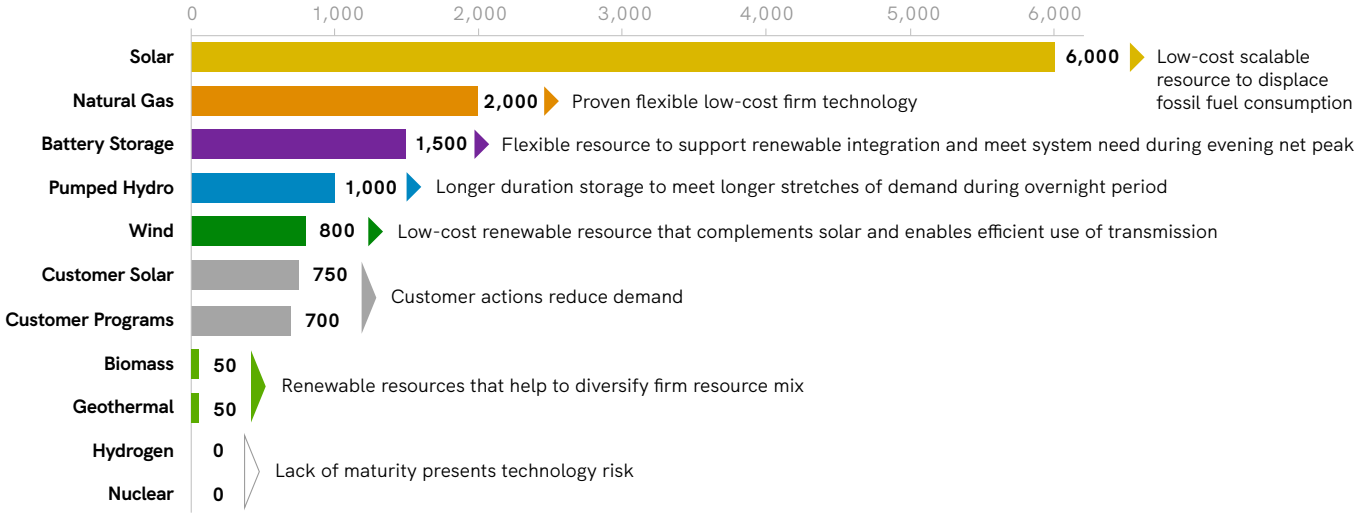
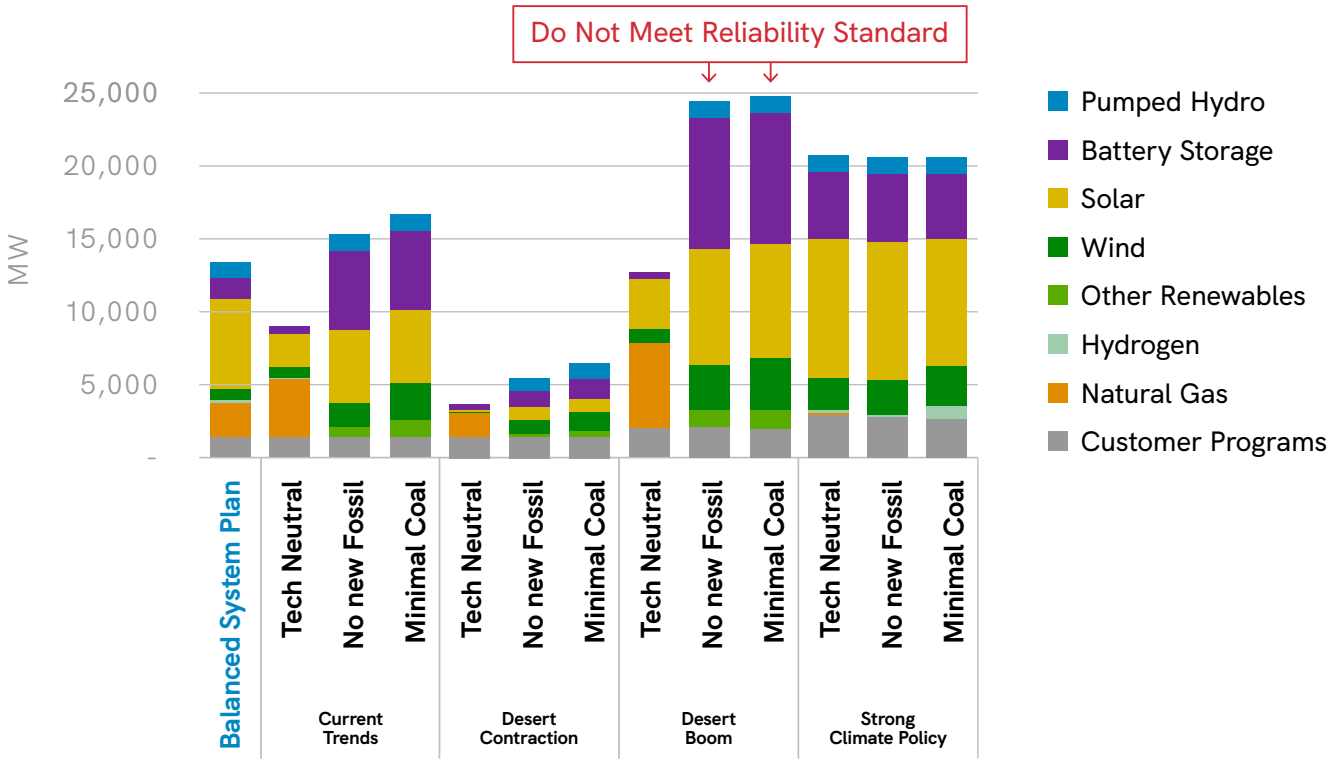


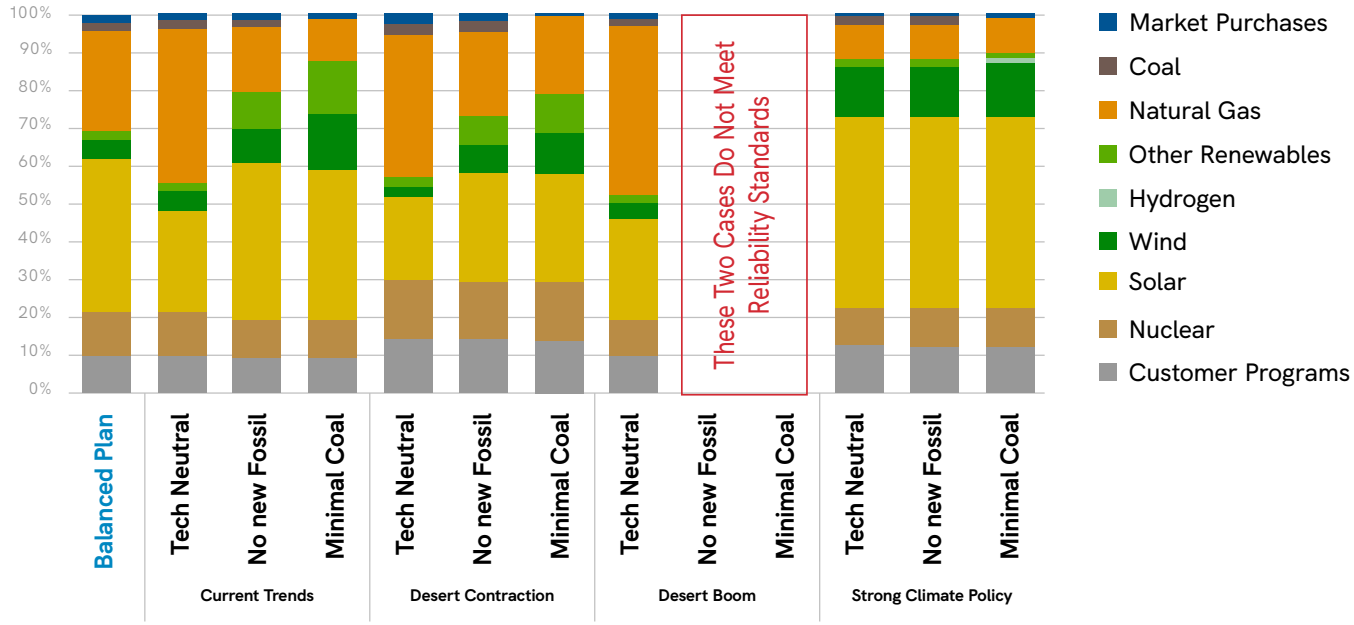
Figure 8.4 shows the nameplate capacity additions for the Balanced System Plan alongside those for the ISP cases for comparison. While we considered the full range of scenario analysis when constructing the Balanced System Plan, we used the Current Trends scenario assumptions to illustrate specific infrastructure requirements. In comparison to the other system plans under the Current Trends scenario, the Balanced System Plan includes approximately 6,000 MW of additional carbon-free resources and over 1,000 MW less gas than the Technology Neutral strategic approach (i.e., least-cost system). Natural gas is still included in the Balanced System Plan to help mitigate costs, unlike the No New Fossil and Minimum Coal strategic approaches, which were found to be considerably more expensive with natural gas not being included in the strategic approach assumptions. The Balanced System Plan thus results in less carbon-free resource additions compared to the No New Fossil and Minimum Coal cases in the Current Trends scenario.

FIGURE 8.4: NAMEPLATE CAPACITY ADDITIONS BY 2035



On an energy basis, for the Balanced System Plan, 70% of SRP's customer energy needs would come from carbon-free sources, which is in the middle of the range when compared to the other Current Trends scenario system plans, as shown in Figure 8.5.

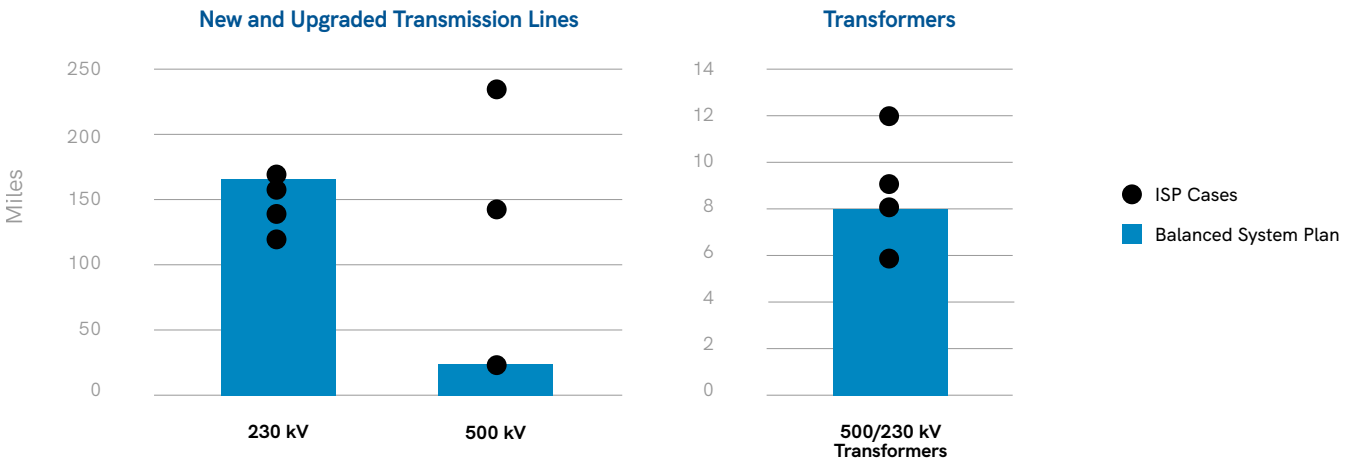
FIGURE 8.5: ENERGY MIX IN 2035



Transmission

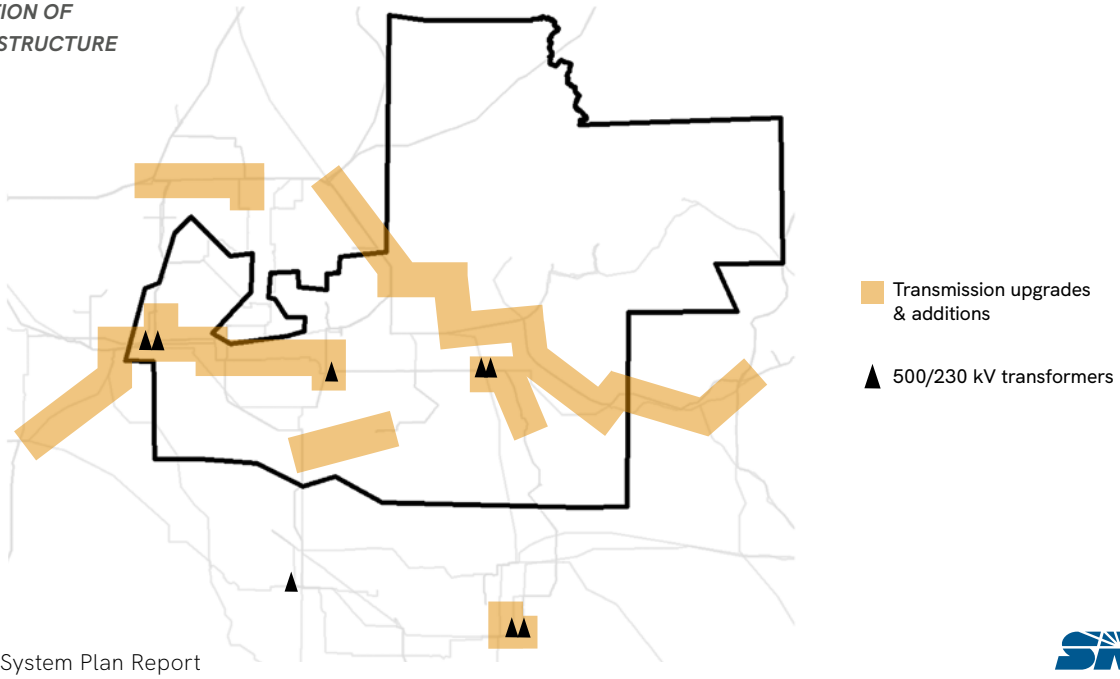
To connect the significant amount of new generation resources included in the Balanced System Plan to our customers, additional high-voltage transmission infrastructure would be needed at both the 500 kV and 230 kV levels. The additional transmission needs for the Balanced System Plan compared to the scenario-based system plans analyzed are shown in Figure 8.6. As detailed in Section 5, we evaluated two different location sensitivities for where the generation resources would be located (Pro-Rata and Hub). For the Balanced System Plan, we utilized a hybrid approach where resources were distributed across the transmission system, but certain areas that required significant upgrades were avoided. This resulted in 165 miles of new or upgraded 230 kV lines, 25 miles of new or upgraded 500 kV lines, and eight new 500/230 kV transformers by 2035. The long lead times for siting, permitting and procuring this transmission infrastructure emphasize the need to implement the Proactive Transmission System Strategy.

FIGURE 8.6: TRANSMISSION SYSTEM ADDITIONS BY 2035



An illustration of where this new transmission infrastructure could be located, overlaid with SRP's electric service area, is included in Figure 8.7.

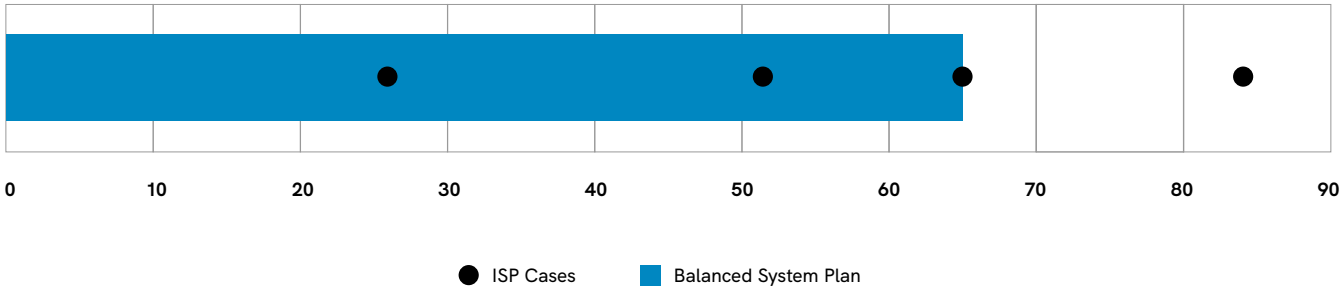
FIGURE 8.7: ILLUSTRATION OF TRANSMISSION INFRASTRUCTURE ADDITIONS



Distribution

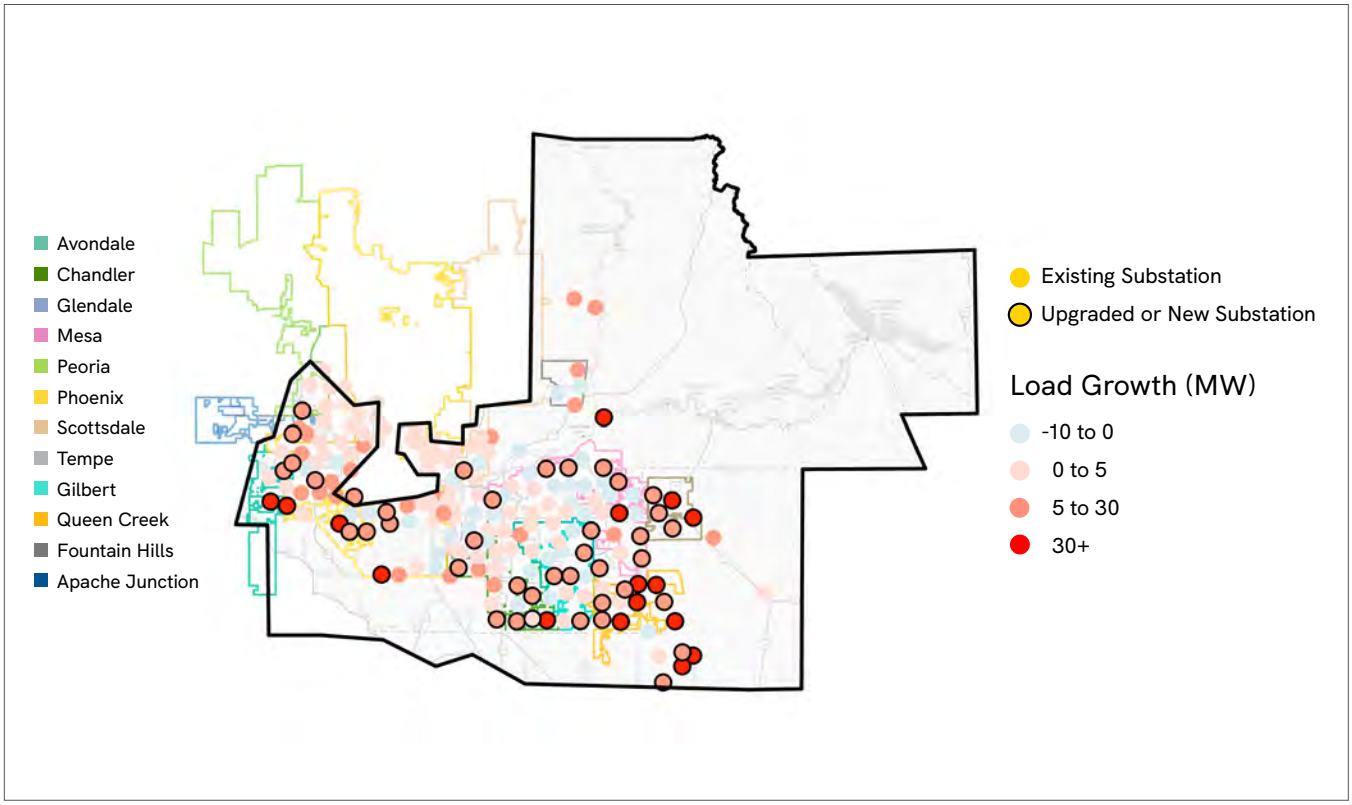
By implementing the Distribution Innovation System Strategy, SRP will need to add a number of additional distribution substation bays to ensure reliability. For the Balanced System Plan, this includes 65 additional substation bays to meet growing customer energy needs.

FIGURE 8.8: DISTRIBUTION SUBSTATION BAY ADDITIONS



We anticipated most of this substation bay addition will be located in the southeastern and western portion of the SRP electric service territory where there is the most potential for growth, as shown in Figure 8.9 below. However, additional substation bays will also be needed in central parts of SRP's electric service territory due to urbanization and growth in electric vehicles.

FIGURE 8.9: ILLUSTRATION OF DISTRIBUTION INFRASTRUCTURE ADDITIONS



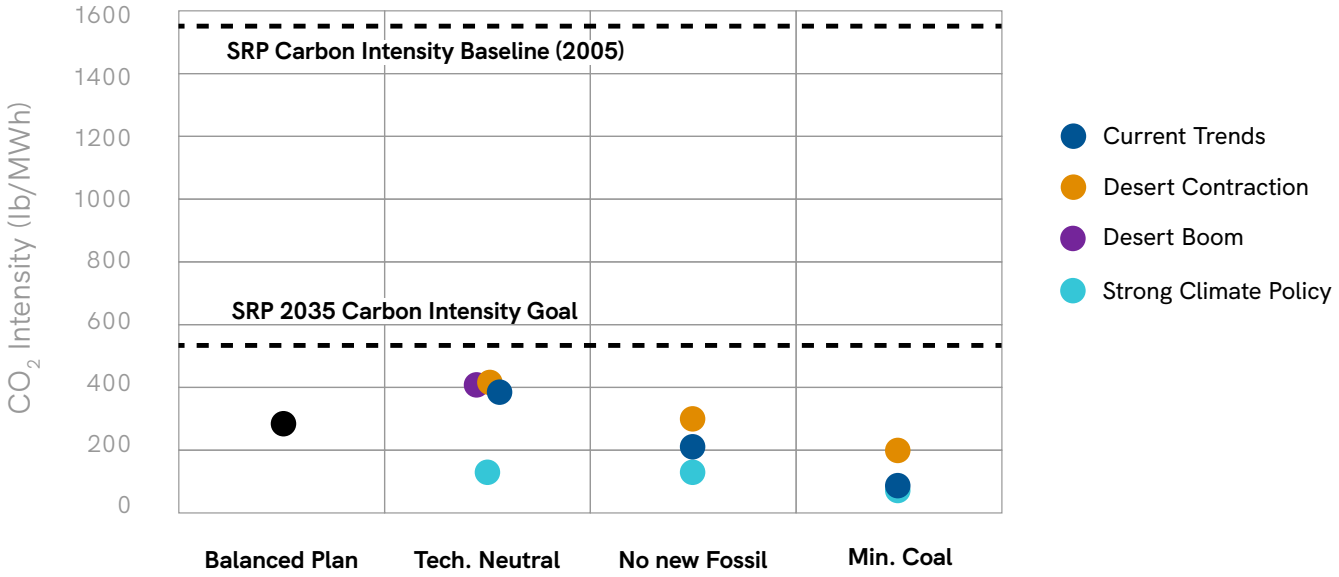
Balanced System Plan Performance

When developing the Balanced System Plan, we evaluated the plan's performance by quantifying the same metrics used to analyze each of the ISP cases. As noted earlier, we used findings from the ISP analysis and residential customer research to develop a system plan that advanced sustainability performance while avoiding significant cost increases to SRP and its customers. The following subsections discuss key metrics for the Balanced System Plan and show how it achieves this objective.

CO_2 Reductions

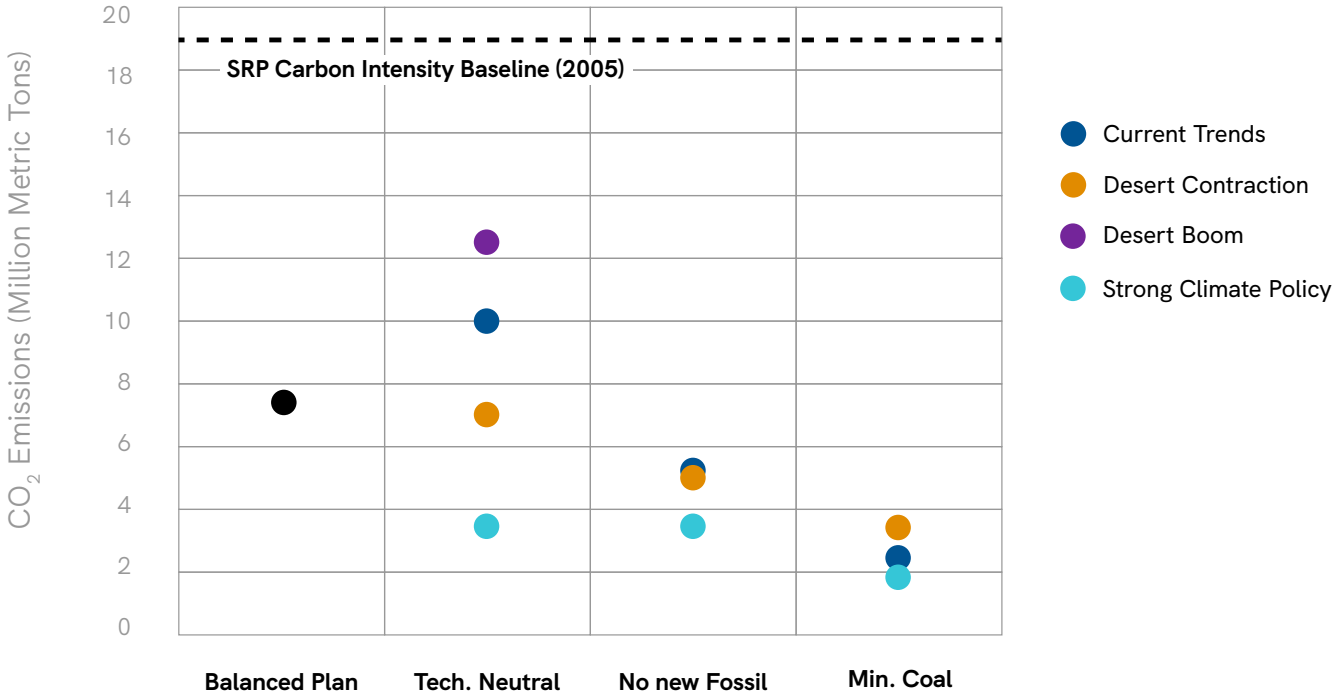
The CO_2 intensity and mass emissions for the Balanced System Plan in 2035 are included in figures 8.10 and 8.11, respectively, and are shown alongside the core system plans for comparison. The Balanced System Plan exceeds SRP's 2035 goal by achieving a CO_2 intensity rate of 284 lbs./MWh, an 82% reduction from SRP's 2005 baseline. Compared to the system plans developed for the Current Trends scenario (the scenario used for the Balanced System Plan), the Balanced System Plan carbon intensity is 28% lower than that of the Technology Neutral strategic approach at 396 lbs./MWh but is not as low as that of the No New Fossil and Minimum Coal strategic approaches at 202 lbs./MWh and 94 lbs./MWh, respectively.

FIGURE 8.10: BALANCED SYSTEM PLAN CO_2 INTENSITY IN 2035



Similarly, for CO_2 mass emissions, the Balanced System Plan performs in the middle of the range when compared to the core system plans, with a CO_2 emission rate of 7.39 million metric tons in 2035. This is a 61% reduction from SRP's 2005 baseline. Compared to the system plans developed for the Current Trends cases, the Balanced System Plan achieves 25% lower carbon emissions than the Technology Neutral strategic approach (9.83 million metric tons) but not as low as the No New Fossil and Minimum Coal strategic approaches (5.11 million metric tons and 2.40 million metric tons, respectively), as shown in Figure 8.11 on the next page.

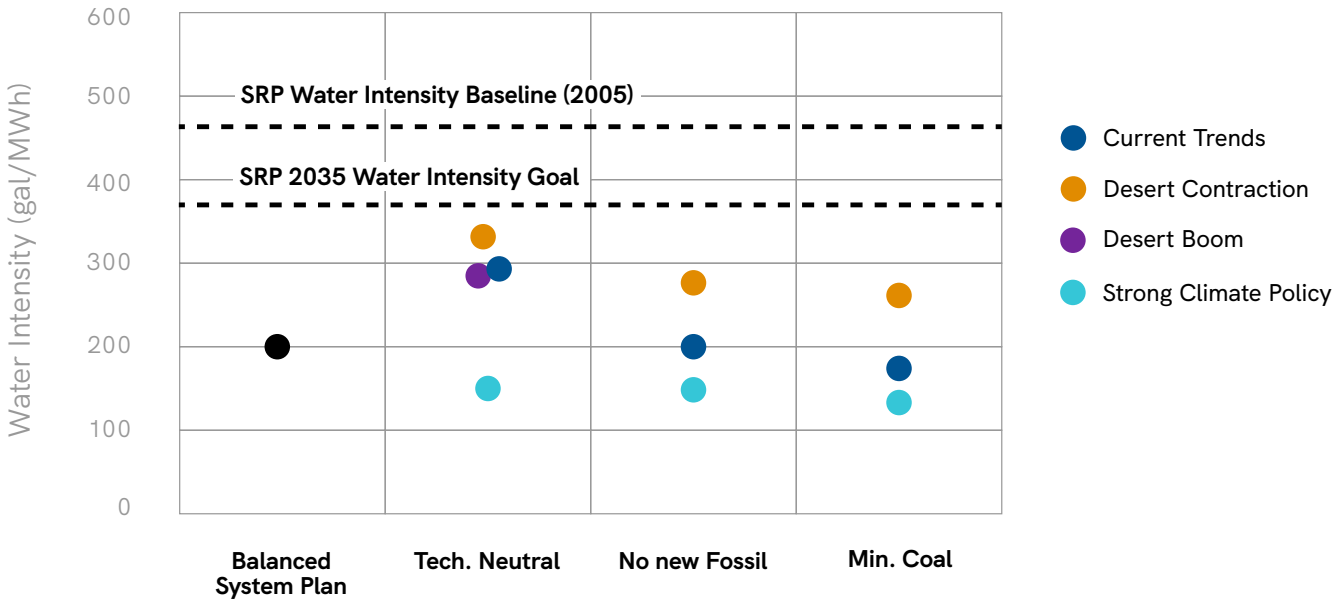
FIGURE 8.11: BALANCED SYSTEM PLAN CO_2 EMISSIONS IN 2035



Water Use

As shown in Figure 8.12, the Balanced System Plan also achieves a significant reduction in water consumption by 2035 with a water consumption rate of 204 gal/MWh (56% reduction from SRP's 2005 baseline levels), exceeding SRP's 2035 Sustainability Goal (20% reduction from 2005 baseline) and falling toward the lower end of the range of the core system plans analyzed in the ISP. Compared to the Current Trends cases, the Balanced System Plan achieves a 30% lower water consumption rate than the Technology Neutral strategic approach (293 gal/MWh), but not as low as the No New Fossil and Minimum Coal strategic approaches (199 gal/MWh and 171 gal/MWh, respectively).

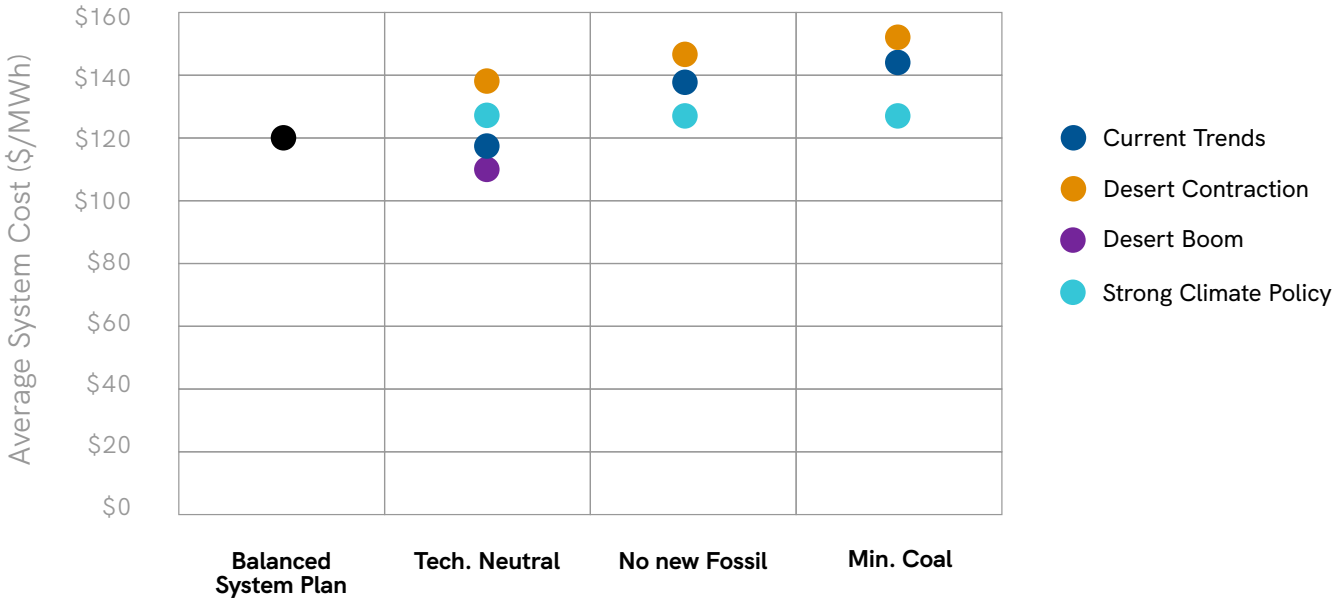
FIGURE 8.12: BALANCED SYSTEM PLAN WATER CONSUMPTION



Average System Cost

The average system cost for the Balanced System Plan, with comparisons to the core system plans from the ISP analysis, is shown in Figure 8.13. The Balanced System Plan results in an average system cost of $121/MWh, which is near the lower end of the range of costs observed from the ISP analysis. Compared to the Current Trends cases, the Balanced System Plan is only 4% higher than the Technology Neutral strategic approach ($116/MWh), despite adding more than double the amount of carbon-free resources and having a 28% lower carbon intensity. Meanwhile, the addition of 2,000 MW of firm natural gas in the Balanced System Plan allows the average system cost to be considerably lower than the No New Fossil and Minimum Coal strategic approaches ($136/MWh and $144/MWh, respectively).

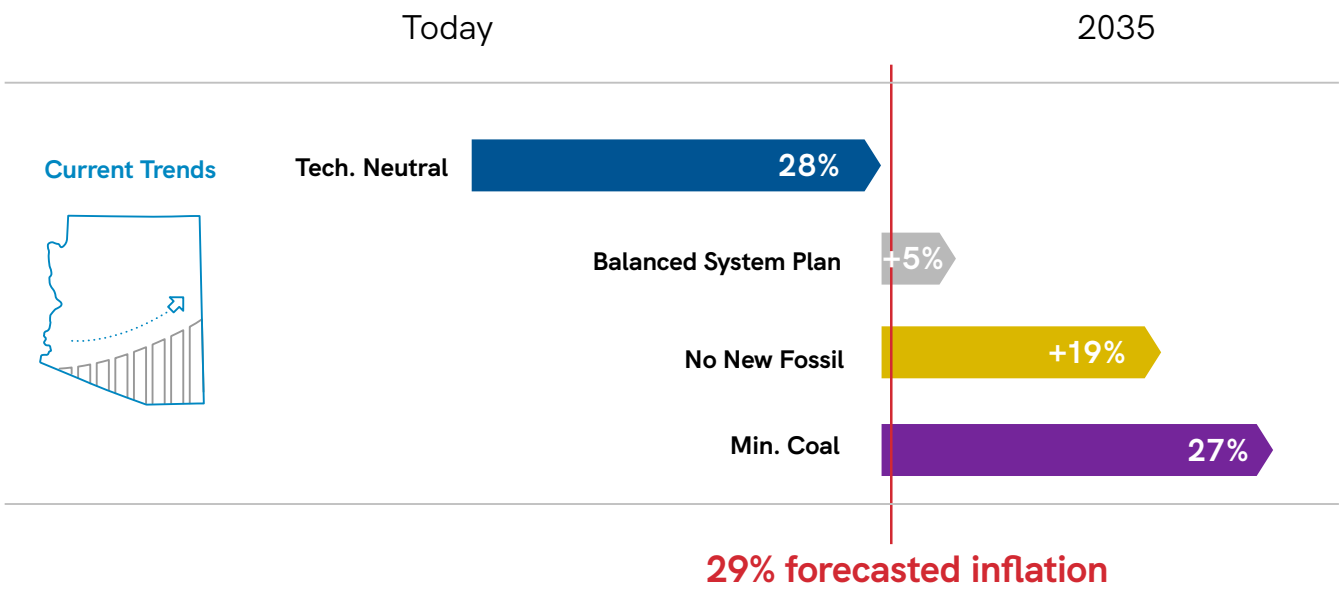
FIGURE 8.13: AVERAGE SYSTEM COSTS IN 2035 ($/MWH)



Residential Bill Impact

There are many factors that will impact costs in the future such as customer growth, inflation, the Inflation Reduction Act (IRA) funding and technology costs. Figure 8.14 shows the residential bill impacts for the Balanced System Plan compared to the other strategic approaches under the Current Trends scenario. This is a simplified look of what a base rate increase could look like in 2035, and we selected the Current Trends scenario because it reflects a central case for how the future might unfold. As shown in Section 6, the least-cost strategic approach, Technology Neutral, results in a price increase of 28% by 2035, just below inflation (estimated at 29% over the same time period). The Balanced System Plan results in a 5% increase in cost over the Technology Neutral strategic approach but is well below the residential price increases for the No New Fossil and Minimum Coal strategic approaches.

FIGURE 8.14: RESIDENTIAL PRICE INCREASE BY 2035



29% forecasted inflation

These are representative results based on ISP analysis modeling, not projections of SRP's future prices, and are not inclusive of factors beyond the scope of ISP analysis.

SECTION 9

ISP Actions

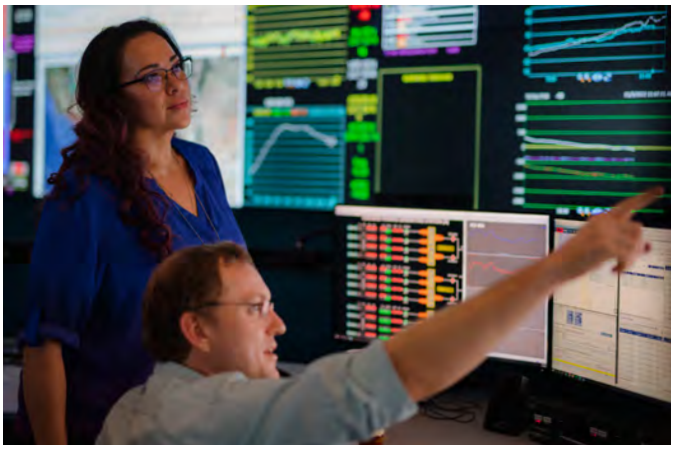
ISP Actions

SRP's planning processes do not stop with the ISP. In many ways, the conclusion of this ISP represents new beginnings as our planning groups begin to execute the System Strategies. To further progress toward implementing the System Strategies, we have defined 10 ISP Actions that we will take over the next few years.

We developed the ISP Actions based on the ISP key findings, the System Strategies and the Balanced System Plan. They include actions for all aspects of system planning, including pricing, customer programs, customer resources, utility-scale resources, distribution and transmission. Just as the seven System Strategies are integrated and interdependent, so are the ISP Actions. Each action furthers multiple System Strategies and requires collaboration across our planning groups. In this section, we will describe each of the 10 **ISP Actions** and show how each one furthers specific System Strategies.

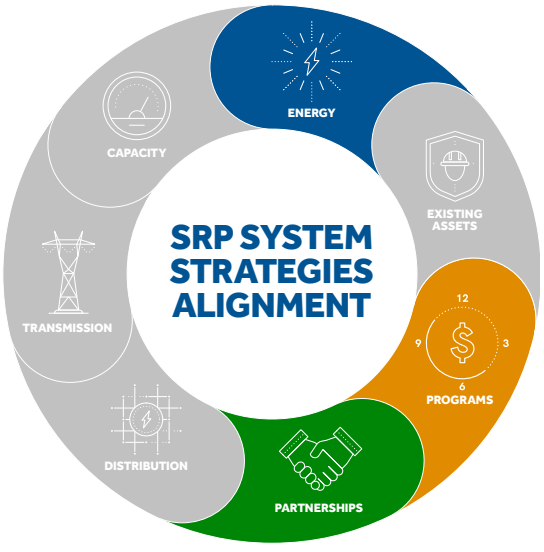
We are committed to pursuing diverse actions, establishing a roadmap for implementing the System Strategies and making progress toward our 2035 Sustainability Goals with the development of the ISP Actions.



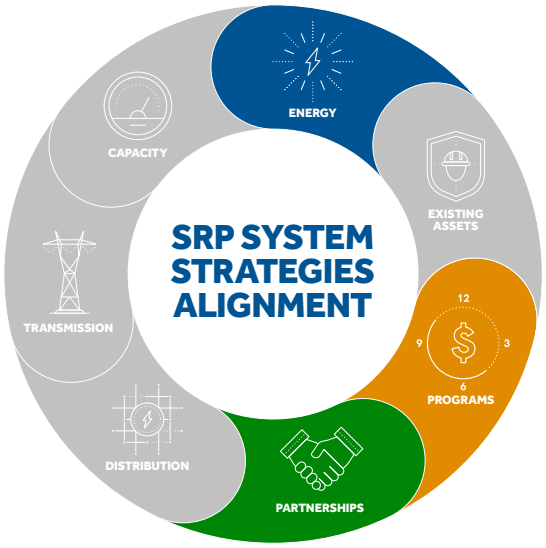


ISP Action #1: Residential Time-of-Use Pilot

We will execute a residential time-of-use price plan pilot and perform customer research to evaluate customers' responses to new time-of-use peak periods and a super off-peak period in the middle of the day, which will inform our load forecast for long-term system planning and our pricing process.



ISP Action #2: Time-of-Use Evolution



We will engage commercial, small business, large industrial, and residential customers and stakeholders to inform them of how the evolving grid will impact time-of-use periods and develop a roadmap for implementing new time-of-use periods.

To accomplish Action #2, we will:

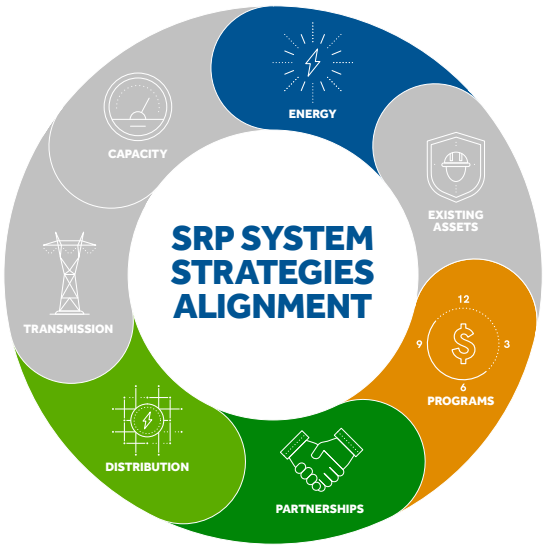
- Undertake a pricing process informed by the ISP to determine how time-of-use plans should evolve.
- Propose new time-of-use hours, including a super off-peak period when the cost to serve customers' needs is lowest and on-peak hours updated for the modern grid.
- Develop communication plans for all customer types and segments to educate about any new time-of-use price plans focusing on promoting affordability and potential sustainability benefits.

ISP Action #3: Customer Programs

We will continuously refresh program plans and take steps to drive participation in customer programs at levels consistent with those planned for in the ISP, representing a meaningful increase from our initial 2035 Sustainability Goal for Energy Efficiency.

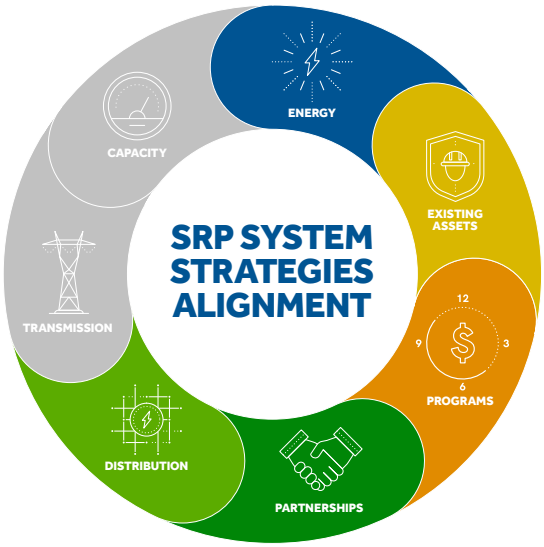
Steps will include:

- Evaluating the cost-effectiveness and emissions impacts of different customer program measures using the avoided costs and emissions impacts results from the ISP.
- Determining whether any changes to the customer programs portfolio are warranted based on this information, considering that these results must be weighed against other important factors such as customer access, equity, cost and satisfaction.



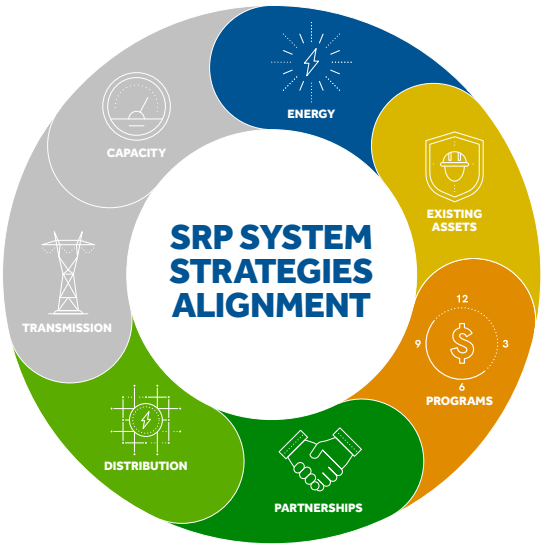
ISP Action #4: Electric Vehicle Management

We will develop an EV roadmap by evaluating customer needs and system impacts and assessing viable pathways for managing electric vehicle charging through price plans, customer programs and educational efforts to align with time periods that are lower-cost and minimize additional infrastructure needs.



ISP Action #5: Electrification

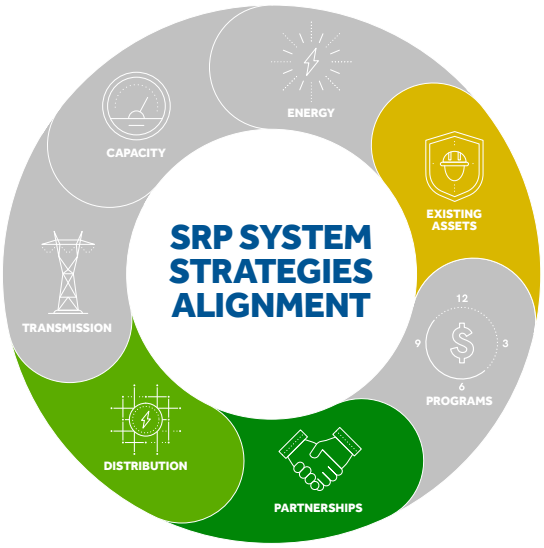
We will analyze the benefits and costs of non-EV electrification within SRP's service area, including effects on our operations and economywide emissions. Assess options for expanding E-Tech program offerings related to residential and commercial electrification.



ISP Action #6: Distribution Enablement Roadmap

We will continue implementing our Distribution Enablement (DE) Roadmap, which includes:

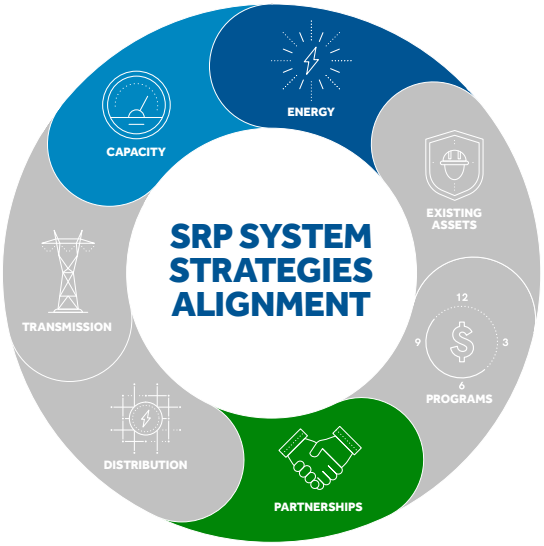
- Deploying the Advanced Distribution Management System (ADMS) and Distributed Energy Resources Management System (DERMS) in 2024. These systems are the foundational platforms needed to integrate distributed energy resources (DERs) with the existing distribution system. We will monitor signposts for the need to deploy more advanced capabilities to support the integration of customer-side resources.
- Implementing advanced planning tools, such as locational value maps and the ability to anticipate and plan solar, storage and electric vehicle adoption at specific customer locations.
- Advancing the interconnection process to enhance the customer experience and technical integration of customer-sited resource interconnections.



- Executing the DE Research and Development plan, which leverages R&D resources, including staff, lab facilities and standardized processes, to execute projects that will ensure readiness to onboard new distribution grid capabilities.
- Sharing the Distribution Enablement Roadmap with external stakeholders to build awareness and support for SRP's approach to transforming the distribution grid.

ISP Action #7: Resource Selection

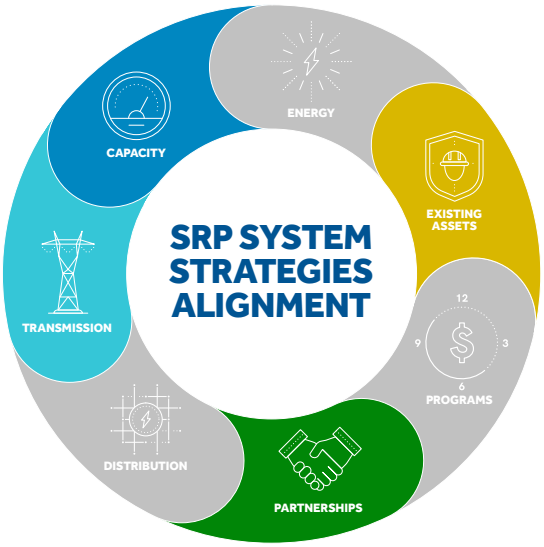
We will issue all-source requests for proposals (RFPs) or requests for information (RFIs) at least once every two years to compare with self-build options and ensure that we can agnostically select resource technologies that minimize total system costs while meeting our reliability and 2035 Sustainability Goals.



ISP Action #8: Coal Transition Action Plan

We will develop a coal repurposing action plan, which will include:

- Coordinating with co-owners to develop a path forward for the Springerville Generating Station, incorporating the need for replacement firm capacity to enable retirement and engagement with the community on a transition plan.
- Preparing plans for repurposing the Coronado Generating Station site, continuing development of system solutions that repurpose transmission following the retirement of coal plants.
- Developing solutions that preserve transmission access following the retirement of coal plants.
- Testing strategies for minimizing emissions from coal power plants, including dispatch strategies and seasonal operations, while leveraging their capacity to maintain reliability prior to retirement dates.

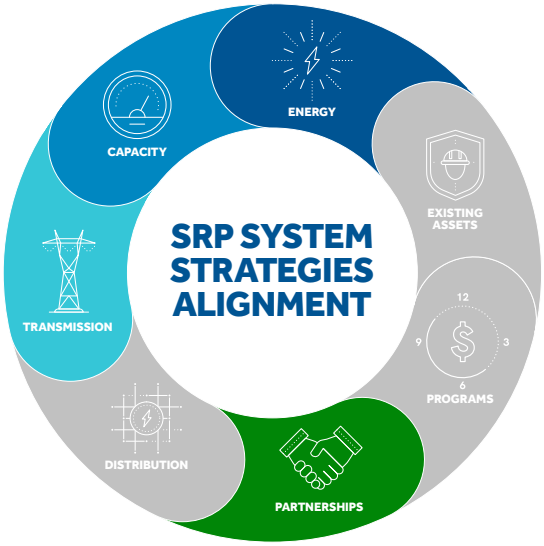


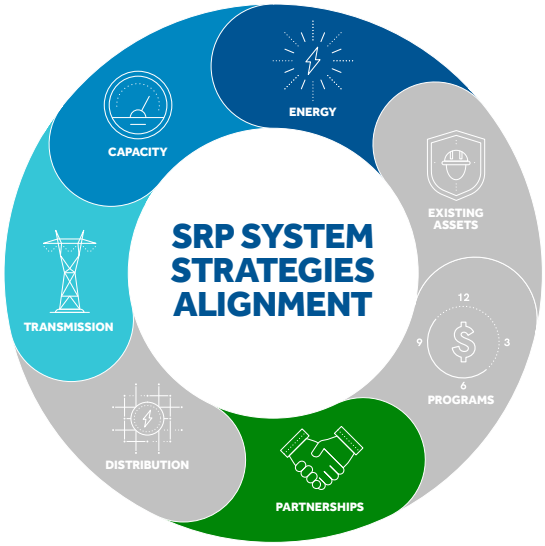
ISP Action #9: Proactive Siting

We will develop and initiate a collaborative community engagement, land, resources and transmission siting research process to proactively identify, prepare and preserve options for feasible sites for future system infrastructure.

ISP Action #10: Regional Transmission

We will pursue transmission projects to enable us to access diverse renewable resource options beyond solar, such as wind and geothermal, and engage with project developers as appropriate.





By implementing these 10 ISP Actions, we are confident that we can meet both the changing power needs of our growing customer base and evolving grid complexity. Many challenges lie ahead, but the actions related to customer programs, time-of-use price plans and EV management will help ensure our customers are provided with options to manage their energy costs while bolstering new clean energy technologies. Other ISP Actions related to phasing out coal resources, proactive siting and regional transmission flexibility will ensure SRP can provide sustained reliable power for the Valley while pursuing the best resource options for the future. These ISP Actions all work together to achieve a balance of reliability, affordability and sustainability for our future energy grid.

Future ISP Cycle and Next Steps

The first ISP was a significant advancement in our planning practices. For the first time, we performed integrated systemwide planning through 2035 and established a process for integrating planning activities across the organization. To continue to improve system planning practices and adapt plans to new information, we plan to complete an ISP on a regular cycle. We will continue to perform comprehensive systemwide modeling and engage SRP elected officials, customers and other stakeholders through a robust public process for future ISP cycles. While we have not yet established a schedule for the next ISP, we are targeting releasing an ISP every three to four years initially, recognizing that future ISP cycles may condense with technological and staff advancements.

SRP management and staff express appreciation for stakeholders and their participation in this first-ever Integrated System Plan process. Maintaining this open communication with customers and stakeholders will continue to produce a sound long-term strategic direction for future resources that balances system reliability, affordability and sustainability measures.

For more information and future updates on the progress of the ISP strategies and actions, refer to our website: srp.net/isp.

APPENDIX A

SRP's Integrated System Plan Assumptions Summary

SRP INTEGRATED SYSTEM PLAN STUDY PLAN APPENDIX – ASSUMPTIONS USED IN SCENARIOS, SENSITIVITIES AND STRATEGIC APPROACHES

This appendix details the assumptions underlying the key drivers outlined in the Integrated System Plan (ISP) Summary Study Plan document for the scenarios, sensitivities and strategic approaches that SRP will analyze. These assumptions were developed in collaboration with the ISP Advisory Group during the *Prepare* Phase of the ISP (November 2021–April 2022). SRP subsequently updated the assumptions in February 2023 to incorporate impacts from the Inflation Reduction Act of 2022. Additional details on these assumptions are included in the meeting materials from the *Advisory Modeling Subgroup Meeting 2: Inputs for the ISP Study Plan, Advisory Modeling Subgroup Meeting 3: Inputs for the ISP Study Plan – Part 2* and *Advisory Group Meeting 9: Continuing Forward*.[1]

Scenarios

Current Trends

Key Drivers	Assumptions
Economic Growth	Economic load grows 1,645 MW by 2035 and residential and commercial load grows by 1,776 MW by 2035, driven by an average population growth of 1.5% per year. The resulting total load growth is 2.9% per year.
Temperature Rise	"RCP[2] 4.5" climate scenario from the Intergovernmental Panel on Climate Change (IPCC)
Carbon Reduction Policy	No federal or state policy beyond SRP's 2035 Sustainability Goals (reduce the emissions intensity [CO2 per MWh] by 65% from 2005 levels by 2035)
Electrification	500,000 electric vehicles by 2035; 83% residential electric heating adoption by 2035
Distributed Generation	1,300 MW distributed solar by 2035
Energy Efficiency	3,800 GWh total energy efficiency by 2035
Renewable and Battery Storage Costs	Midpoint between low cost (Strong Climate Policy Scenario) and high costs (Desert Contraction Scenario) (see below)
Gas Resource Costs	Energy Information Administration 2022 Annual Energy Outlook (AEO)
Emerging Technology Availability	Carbon capture and sequestration (CCS) available in 2035. 100% hydrogen and nuclear (small modular reactors) are not available by 2035.
Emerging Technology Cost	Gas with CCS costs are midpoint between low costs (Strong Climate Policy Scenario) and high costs (Desert Contraction Scenario) (see below). 100% hydrogen and nuclear are not available by 2035.

[1] https://www.srpnet.com/grid-water-management/grid-management/integrated-system-plan
[2] Representative Concentration Pathway- RPC

Hydrogen Prices	Green hydrogen forecast developed by E3 using electricity production from solar (blend between Arizona and Utah using Renewable and Battery Storage Costs above), hydrogen production using alkaline electrolyzers (blend between optimistic and conservative cost declines from California Energy Commission publication CEC-500-2019-055), hydrogen storage (using costs from Department of Energy project ST-001), and hydrogen transport (blend between AZ and UT transport costs, using Argonne's Hydrogen Delivery Scenario Analysis Model (HDSAM) tool). $3/kg hydrogen production tax credit from Inflation Reduction Act applied at 85% monetization.
Gas Prices	Energy Information Administration (EIA) 2021 AEO "Reference" case regionalized based on SRP's gas supply
Hydro Availability	Hydro capacity and energy availability remain relatively constant at current drought conditions.
Market Support	Due to near-term capacity constraints, actions taken to contract maximum market capacity through 2032; afterwards 525 MW of market potential available.

Desert Boom

Key Drivers	Assumptions
Economic Growth	Economic development load grows by 2,900 MW by 2035 and population grows by an average rate of 1.8% per year.
Temperature Rise	"RCP 8.5" climate scenario from the IPCC
Carbon Reduction Policy	*Same as Current Trends*
Electrification	600,000 electric vehicles by 2035; 86% residential electric heating adoption by 2035
Distributed Generation	1,800 MW distributed solar by 2035
Energy Efficiency	*Same as Current Trends*
Renewable and Battery Storage Costs	*Same as Current Trends*
Gas Resource Costs	*Same as Current Trends*
Emerging Technology Availability	*Same as Current Trends*
Emerging Technology Cost	*Same as Current Trends*
Hydrogen Prices	*Same as Current Trends*
Gas Prices	*Same as Current Trends*
Hydro Availability	*Same as Current Trends*
Market Support	*Same as Current Trends*

Desert Contraction

Key Drivers	Assumptions
Economic Growth	Economic development load growth rate peaks in 2026 before declining, resulting in a total of 597 MW added by 2035 compared to 2022. Population growth rate follows a similar trend, peaking in 2027 before declining. This results in an average population growth rate of 0.4% per year between 2023 and 2035.
Temperature Rise	"RCP 8.5" climate scenario from the IPCC
Carbon Reduction Policy	*Same as Current Trends*
Electrification	*Same as Current Trends*
Distributed Generation	*Same as Current Trends*
Energy Efficiency	*Same as Current Trends*
Renewable and Battery Storage Costs	NREL 2022 ATB Market + Policy Conservative Scenario forecast. Inflation Reduction Act Investment Tax Credit (ITC) and Production Tax Credit (PTC) monetized at 80%.[3] Cost increases for solar (15%), wind (30%) and batteries (30%) added assuming existing supply chain challenges and trade friction worsen.[4]
Gas Resource Costs	*Same as Current Trends*
Emerging Technology Availability	*Same as Current Trends*
Emerging Technology Cost	Gas with CCS based on Energy Information Administration 2022 AEO +20%. 100% hydrogen and nuclear are not available by 2035.
Hydrogen Prices	Green hydrogen forecast developed by E3 using electricity production from UT solar (using Renewable and Battery Storage Costs above), hydrogen production using alkaline electrolyzers (conservative cost decline from California Energy Commission publication CEC-500-2019-055), hydrogen storage in UT (using costs from Department of Energy project ST-001) and hydrogen transport to AZ (using Argonne's Hydrogen Delivery Scenario Analysis Model (HDSAM) tool). $3/kg hydrogen production tax credit from Inflation Reduction Act applied at 80% monetization.
Gas Prices	*Same as Current Trends*
Hydro Availability	Glen Canyon Dam generation production is unavailable at the beginning of the study period (2025). Other hydrogeneration on the Colorado River and Salt River remain consistent with Current Trends assumptions.

[3] *Includes the base credit and 5x multiplier for satisfying prevailing wage and apprenticeship requirements. Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach). 80% reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

[4] *A smaller increase is made to solar as NREL's conservative scenario forecasts for solar already include adjustment to reflect trade frictions.*

Market Support	Loss of Glen Canyon Dam and other hydrogeneration facilities in the West results in 0 MW of market support available. Existing market purchases currently contracted by SRP are honored.

Strong Climate Policy

Key Drivers	Assumptions
Economic Growth	*Same as Current Trends*
Temperature Rise	*Same as Current Trends*
Carbon Reduction Policy	Federal policy that requires a CO2 mass emissions (tons) reduction by 85% from 2005 level by 2035.
Electrification	Electric vehicle adoption consistent with reaching economy-wide net-zero emissions by 2050 (975,000 by 2035); 86% residential electric heating adoption by 2035
Distributed Generation	2,300 MW of distributed solar by 2035
Energy Efficiency	Federal codes, standards and incentives lead to higher energy efficiency growth, reaching 4,500 GWh total energy efficiency by 2035.
Renewable and Battery Storage Costs	NREL 2022 ATB Market + Policy Moderate Scenario forecast. Inflation Reduction Act ITC and PTC monetized at 90%[5,6]. All near-term supply chain impacts are fully resolved by 2025.
Gas Resource Costs	Energy Information Administration 2022 AEO
Emerging Technology Availability	Gas with CCS available in 2030, 100% green hydrogen available in 2034, and nuclear (small modular reactors) available in 2034
Emerging Technology Cost	Energy Information Administration 2022 AEO. Inflation Reduction Act ITC applied to nuclear and 100% hydrogen, and CCS tax credit applied to gas with CCS all at 90% monetization.[4] 100% hydrogen unit based on frame combustion turbine.
Hydrogen Prices	Green hydrogen forecast developed by E3 using electricity production from AZ solar (using Renewable and Battery Storage Costs above), hydrogen production using alkaline electrolyzers (optimistic cost decline from California Energy Commission publication CEC-500-2019-055), hydrogen storage in AZ (using costs from Department of Energy project ST-001) and hydrogen transport (using Argonne's Hydrogen Delivery Scenario Analysis Model (HDSAM) tool). $3/kg hydrogen production tax credit from Inflation Reduction Act applied at 90% monetization.
Gas Prices	EIA 2021 AEO "Low Oil and Gas Supply" case regionalized based on SRP's gas supply
Hydro Availability	*Same as Current Trends*

[5] ITC and PTC include *the base credit and 5x multiplier for satisfying wage and apprenticeship requirements. 90% reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

[6] *Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach).*

Market Support	Favorable regional resource and load diversity allows for the potential for the wider region to carry slightly less total resource capacity while maintaining the same level of reliability. SRP assumes a regional coordination program and a regional diversity benefit and tests this assumption by reducing its Planning Reserve Margin requirement from 16% to 13%. Capacity (MW) market availability assumptions are consistent with Current Trends.

Sensitivities

Sensitivity	Assumptions
High Demand Response	Increased expansion in demand response over time, reaching 400 MW total Demand Response by 2035.
High Energy Efficiency	Federal codes, standards and incentives lead to higher energy efficiency growth, reaching 4,500 GWh total energy efficiency by 2035.
High Distributed Generation	Distributed solar and battery adoption reach 2,300 MW and 249 MW, respectively, by 2035.
Increased Load Management	Increased load flexibility through managed electric vehicle (EV) charging or other flexible loads. Modeled as a virtual battery addition with limitations on when it can charge or discharge.
Regional Diversity	Favorable regional resource and load diversity allows for the potential of a reduced loss of load probability on SRP's system. SRP tests this assumption by reducing the minimum Planning Reserve Margin requirement from 16% to 13%.
High Gas Price	EIA 2021 AEO "Low Oil and Gas Supply" case regionalized based on SRP's gas supply
Low Gas Price	EIA 2021 AEO "High Oil and Gas Supply" case regionalized based on SRP's gas supply
Volatile Gas Price	EIA 2021 AEO "Reference" gas regionalized based on SRP's gas supply, adjusted to reflect gas price volatility observed from 2000-2010
High Technology Cost	NREL 2022 ATB Market + Policy Conservative Scenario forecast. Inflation Reduction Act ITC and PTC monetized at 80%.[7] Cost increases for solar (15%), wind (30%), and batteries (30%) added assuming existing supply chain challenges and trade friction worsen.[8]
Low Technology Cost	NREL 2022 ATB Market + Policy Moderate Scenario forecast. Inflation Reduction Act ITC and PTC monetized at 90%[9]. All near-term supply chain impacts are fully resolved by 2025.

[7] *Includes the base credit and 5x multiplier for satisfying prevailing wage and apprenticeship requirements. Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach). 80% reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

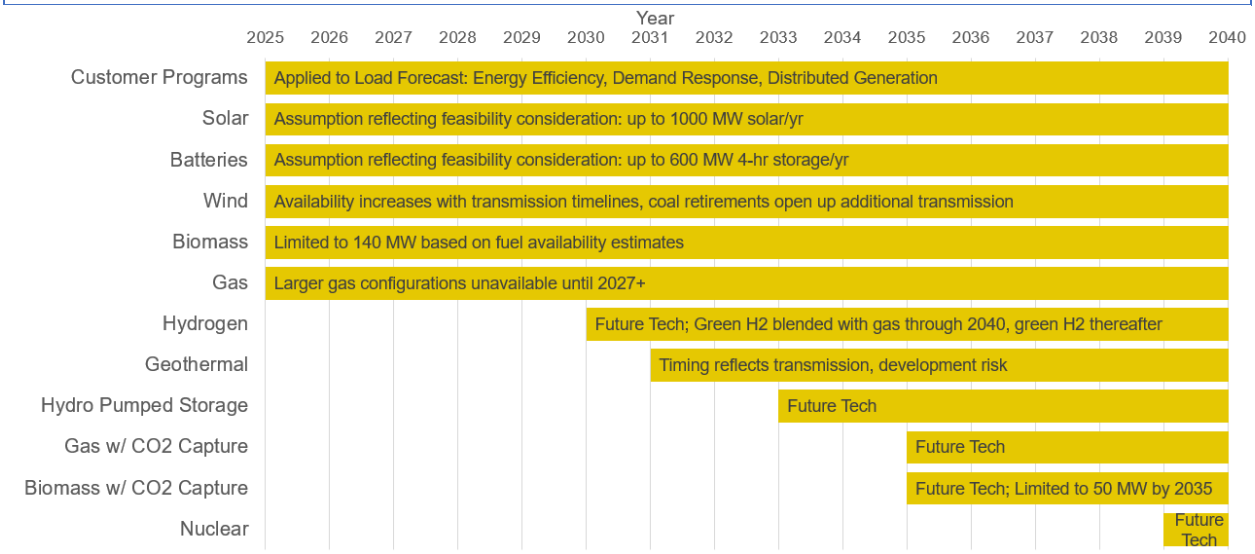
[8] *A smaller increase is made to solar as NREL's conservative scenario forecasts for solar already include adjustment to reflect trade frictions.*

[9] *Includes the base credit and 5x multiplier for satisfying wage and apprenticeship requirements for ITC and PTC. Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach). Monetization range reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

Strategic Approaches

Tech Neutral

Key Drivers	Assumptions
Technology Availability	All resource technologies available, limits based on technical feasibility availability of new resources (chart below). Strong Climate Policy Scenario includes accelerated availability dates for CO2 capture (2030), 100% green H2 (2034), and nuclear (2034).



No New Fossil

Key Drivers	Assumptions
Technology Availability	New gas and gas w/CO2 capture are removed as available resource technologies

Minimum Coal

Key Drivers	Assumptions
Technology Availability	New gas and gas w/CO2 capture are removed as available resource technologies
Coal Plant Operational Changes	Evaluates impacts from Coronado Generating Station Units 1 and 2 and Springerville Generating Station Unit 4 operating seasonally beginning in 2025 (off-line for three months of the year during non-peak periods) and SRP fully exiting coal by 4/30/2034.

Revision History

Revision	Date	Description
0	August 2022	Original
1	March 2023	Updated to incorporate impacts from the Inflation Reduction Act into technology costs.
2	April 2023	Corrected understated High DG sensitivity assumption and economic growth assumption in the Desert Boom scenario.

APPENDIX B

SRP Customer Research Future of Energy Phases 1 & 2 Report



Future of Energy

Phase I & II Report

June 30, 2022

bellomy

175 Sunnynoll Court
Winston-Salem, NC 27106

www.bellomy.com

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Background & Objectives

Background

Salt River Project (SRP) is preparing its first Integrated System Plan (ISP), which is focused on planning the power system through 2035. While multiple inputs are needed to prepare this plan, one crucial contribution is input from customers.

Looking into the future, SRP expects there to be many disruptions to the energy industry with a key aspect being the balance between reliability, sustainability, and affordability. Furthermore, the perspectives of different groups of customers, with different values and mindsets and each group's perspectives on this balance will need to be understood and considered.

Objectives

The goal of this research was to bring the voice of SRP's residential customers into the planning of the future power system.

More specifically, this research was designed to gain an understanding of how customers think about sustainability, affordability, and reliability related to power provision and gauge their reactions to a potential energy plan. SRP sought to understand areas of diverse viewpoints and agreement, as well as identify preferred methods of engagement with SRP on this topic.

The research aimed to address the following specific objectives:

1. Understand the concerns customers have about the future of Arizona, the economy and the U.S.
2. Understand diverse perspectives and opinions relating to SRP's sustainability plan and evolution.
3. Develop and test system-planning metrics that are understood and resonate with customers.
4. Generate a list of power system and future energy topics that interest customers.
5. Understand customer perspectives on power reliability and potential tradeoffs with sustainability and affordability.
6. Understand preferred methods of learning about and engaging with the power system planning process.

Methodology & Reporting

Approach

A three-phased research approach is being applied, starting with virtual focus groups (December 2021), followed by a quantitative confirmation (March 2022) and a choice exercise (planned for Fall 2022). This report addresses Phase I and Phase II.

All customers included in the research were SRP residential customers, energy decision makers, who did not work for a competing industry, and were over 18 years old.

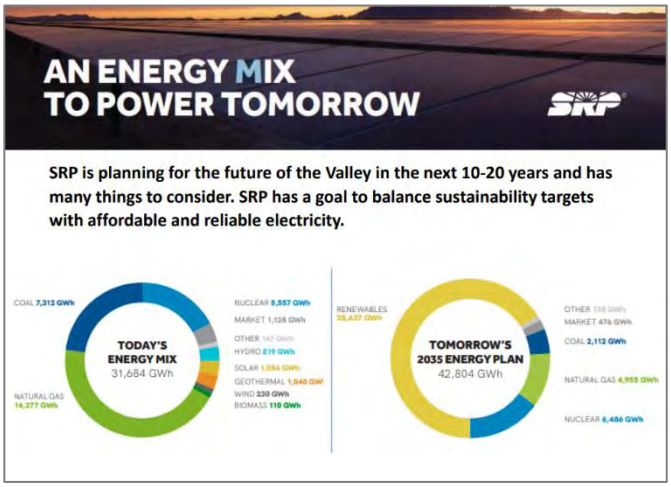
Phase I: Virtual Focus Groups

Four 90-minute virtual focus groups were held December 13 & 14, 2021. A total of 24 SRP customers participated virtually (via Zoom) and received a $125 bill credit for participating.

Customers were grouped to encourage engagement and maximize the ability to explore attitudes and extract observations.

Phase II: Online Survey

An online survey was fielded between March 7 – March 14, 2022. Respondents evaluated SRP's illustrative energy plan of how the system may develop in relation to attributes of customer interest identified in Phase I. Quotas were set for the survey to ensure the respondent pool best represented SRP's residential customer population.



Customers evaluated SRP's proposed energy mix, which describes the transition of the power system over the next 10-20 years. The visual depiction of the illustrative plan shown to respondents is displayed to the right. Customers were provided background on SRP's priorities.

Reporting

Quantitative results are reported in charts at the total level with qualitative results represented throughout. When evaluating survey data, sub-groups were compared to one another to investigate if there were statistically significant differences between two or more groups.

A 95% confidence level is used, which indicates we can conclude with 95% confidence that differences are not due to chance and that survey results should match results from the actual population (plus or minus the margin of error). Only significant differences relevant to the research objectives are reported.

The following subgroups are noted in this report:

- **Age** (18-44 years old/ 45-54 years old/ 55-64 years old/ 65+ years old)
- **Income** (Under $75k/year / $75k/year or more)
- **Gender** (Male/ Female)
- **Energy Mix Prioritization** (Affordability first/ Reliability first/ Sustainability first)
- **Hispanic** (Hispanic/ Non-Hispanic)
- **Credit Rating** (Preferred/ New Customer/ Satisfactory/Slow/Unsatisfactory)
- **Usage Category** (Low/ Moderate/ Medium/ High)
- **Overall Opinion of Energy Plan** (Positive/ Negative)
- **Overall Experience as SRP Customer** (Positive/ Neutral/ Negative)
- **Years at Address** (2 or less/ 3-5/ 6-20/ 21-39/ 40+)

Note: Rating scale questions are reported differently for 10-point and 5-point scales.
10-point scales are reported using Top-Box (TB – ratings of 10), Top-3-Box (T3B – ratings of 8,9, or 10), Middle-2-Box (M2B – ratings of 6 or 7), and Bottom-5-Box (B5B – ratings of 1-5).
5-point scales are reported using Top-Box (TB – ratings of 5), Top-2-Box (T2B – ratings of 4 or 5), Middle-Box (MB – ratings of 3), and Bottom-2-Box (B2B – ratings of 1 or 2).

Executive Summary



The illustrative plan was rated positively

Most customers reacted positively to the energy plan while a quarter felt it was excellent. Additionally, a majority expressed positive perceptions of SRP and cited outstanding customer service and reliability as reasons for this.

Affordability & reliability were top priorities for the future

Affordability was one of the most-selected future issues facing Arizona and customers felt that affordability should be prioritized.

Both affordability and reliability surpassed sustainability in importance. Customers noted that sustainable electricity was meaningless if not affordable and reliable, especially with rising inflation and increased usage during the Arizona summer heat.

- SRP might increase energy plan acceptance by anticipating and addressing questions on affordability and reliability.

A majority agreed SRP should prioritize the illustrative energy plan

Further, about half felt the plan fit with SRP's brand, was easy to understand, and seemed achievable. Customers reflected that the plan could be improved by providing more details on how it would be achieved and its impacts on affordability.

Respondents also hoped to ensure that SRP selected the best sources of electricity, though opinions on what sources were best varied. Customers were unclear on which sources of electricity SRP would use.

- Emphasizing transparency with customers as SRP solidifies energy sources, including cost impacts, may bolster trust.

Customers wanted to continue to hear about ways to save from SRP

Customers exhibited strong positive feedback on the benefits and effectiveness of SRP's cost saving offerings.

Customers most wanted to hear more about programs that can help them save money, including rebates and energy efficiency programs, which aligned with affordability priorities.

- Continuing to showcase and optimize offerings geared towards energy and cost savings may increase enrollment and contribute to positive overall perceptions of SRP.

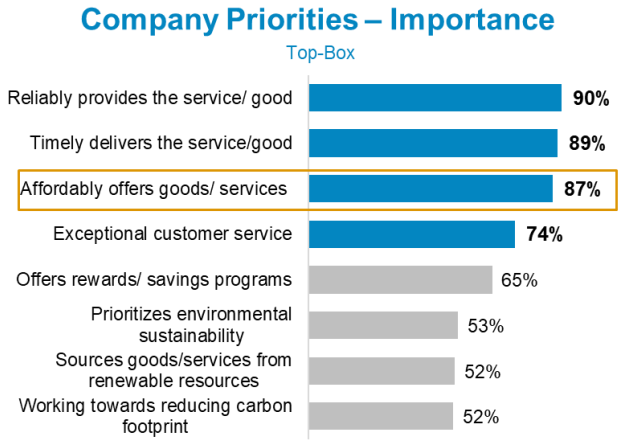
Detailed Findings

Future Issues and Priorities

Customers demonstrated affordability concerns

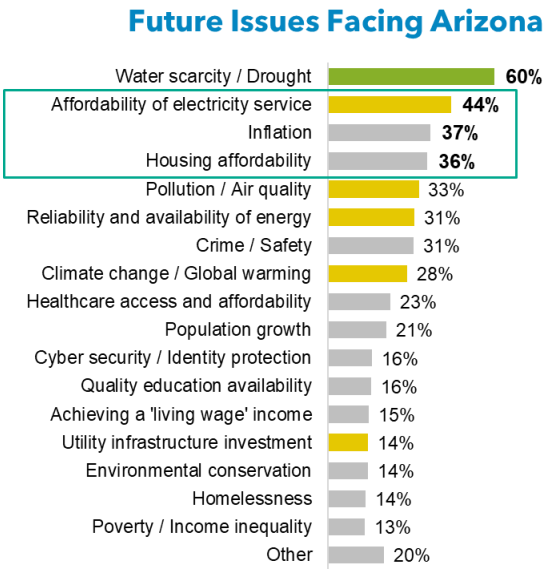
Affordability was rated as a top need for companies to prioritize in the future, with nearly 9 in 10 believing it was important for companies to prioritize the need.

This accompanied reliably providing goods and services, and providing them in a timely manner.



Respondents most selected that they were concerned about water scarcity. After water scarcity, affordability related to electricity, inflation, and housing were most concerning.

- The focus on affordability of electricity is of note, as it was the second-most selected future concern. These issues were followed by several items SRP is most able to impact related to pollution, energy reliability, and climate change (highlighted in yellow).
- Lower income customers (earning under $75k/year) reflected greater concern for affordability.



- *Year-round residents are more likely to prioritize housing affordability.*
- *Those with a household income of $75k or more were more likely to prioritize water scarcity but were less likely to prioritize housing affordability.*
- *Non-Hispanic customers were more likely to prioritize water scarcity.*

Further, 22% of customers were very concerned about other community members being able to pay their electricity bills.

*Groups **more likely** to be concerned about others' ability to pay their electric bill include:*

- *Customers with household incomes less than $75k*
- *Females*
- *Hispanic customers*

Similar concerns were seen across top issues

When asked to rank selected issues on importance, rankings mostly mirrored the most-selected future issues facing Arizona. Customers were most likely to rank the following first: Water scarcity (22%), Inflation (13%), Housing affordability (10%), Affordability of electricity (9%)

- *Younger customers (aged 18-44), those with a household income under $75k, females, and Hispanic customers were more likely to rank housing affordability first.*
- *Non-Hispanic customers were more likely to rank water scarcity first.*

Customers mentioned population growth/city sprawl and rising prices added to their concern about top-ranked Issues.

Ranked 1st: Water Scarcity/Drought

*"**Having enough water to sustain the millions of people within the state.** And the temperature increase due to global warming coupled with heat island effects from Phoenix and Tucson sprawl." – Survey Respondent*

Ranked 2nd: Inflation

*"Population growth and cost of living. Being senior citizen on set income inflation has hit hard, **gas prices and growing energy prices concern me**." – Survey Respondent*

Ranked 3rd: Housing Affordability/ Availability

*"**The housing prices are going up but the pay in work is not**, who makes 3x the rent anymore. Nobody and it's ridiculous." – Survey Respondent*

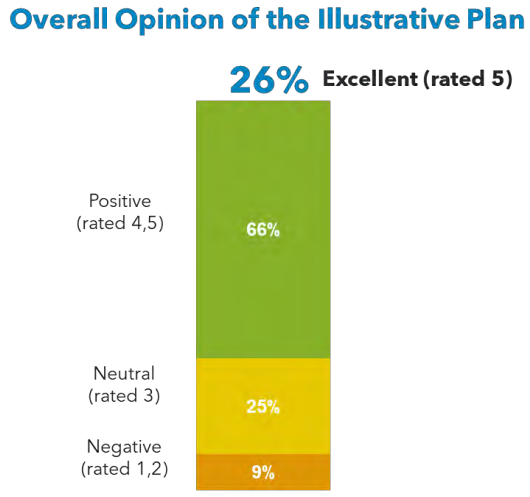
Ranked 4th: Affordability of Electricity Service

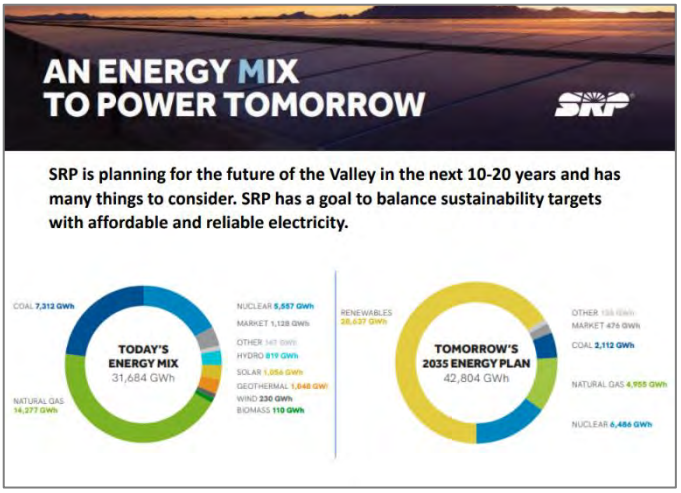
*"**Providing the uninterrupted service at an affordable price** for the growing population, taking inflation into consideration." – Survey Respondent*

SRP Energy Plan

Two thirds rated the energy plan positively

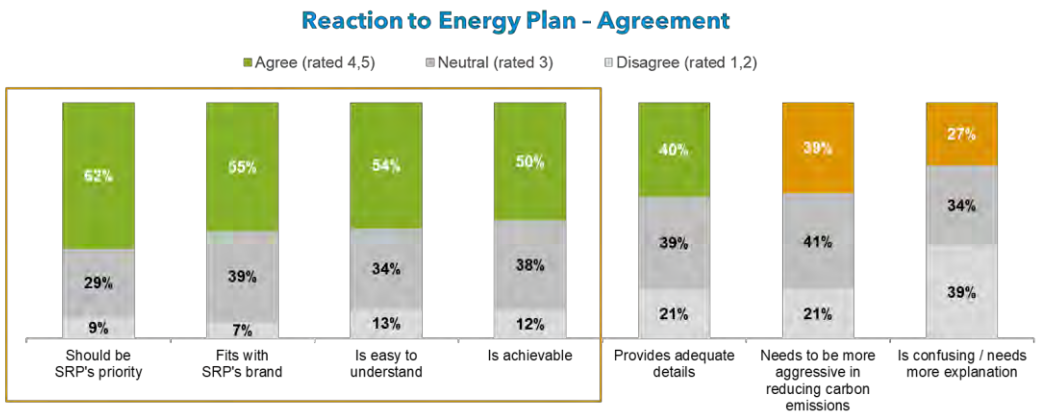
When evaluating SRP's energy plan, one-quarter (26%) rated it as excellent, but 66% rated it positively overall (rated 4 or 5 on a 5-point scale). This demonstrates opportunity for improvement.





- *Those ranking sustainability first had a more positive impression of the energy plan.*
- *Those with high electricity usage were less likely to rate the plan positively.*

Additionally, at least half agreed the plan should be SRP's priority (62%), fit with the brand (55%), is easy to understand (54%), and is achievable (50%).



- *Year-round residents were more likely to agree that the plan is achievable, fits with the SRP brand, is easy to understand, and provides adequate details.*
- *Customers with a household income under $75k and Hispanic customers were more likely to agree the plan fits with SRP's brand.*

Customers noted the plan could be improved with more specifics

Initial responses to viewing the plan revealed that customers were interested in more specifics. In addition to questions on plan affordability and achievability, respondents cited varying thoughts on which renewable sources SRP should prioritize.

- Twenty-seven percent (27%) of customers shared concerns around the type of energy sourced.
  *"**Renewable energy is fine, but solar and wind require lots of area to house enough energy to power cities.** Still have to maintain natural gas…and some coal. Nuclear power is the way to go, folks." – Survey Respondent*

- Nineteen percent (19%) shared affordability and cost concerns.
  *"I like the direction of the plan **but have my doubts that SRP will follow through on this plan in a way that is still affordable**." – Survey Respondent*

- Thirteen percent (13%) shared achievability concerns regarding the timing of the plan being too slow.
  *"How long will it take to achieve this? **Needs to be sooner rather than later**." – Survey Respondent*

  *"I don't view it as a plan. Rather strategic long-term objectives. **What is the road map to achieve, timing phases, costs, resources in the land?**" – Survey Respondent*

One-quarter (22%) felt that SRP should prioritize another goal (not already stated in the energy plan) and emphasized thoughts on specific energy sources.

*"**I did not see water conservation listed**, although I know it is on the SRP agenda." – Survey Respondent*

*"**Nuclear power is in my view, the only way forward**, renewable, wind, solar are efforts in futility. Sounds good to a few but a majority know better." – Survey Respondent*

*"**Making solar more affordable to the population**. This would increase the power grid, creating a partnership with the community. Making it more enticing for consumers to provide SRP with power." – Survey Respondent*

*"**Include hydrogen power** for vehicles in use." – Survey Respondent*

*"Since Arizona is a very hot state. **I believe solar panels would be excellent for SRP.** That should be the number one priority for SRP." – Survey Respondent*

Focus group participants were also generally positive about the plan's intent but suggested some opportunities for improvement. These opportunities included the amount of time needed to implement the plan, getting customer buy-in and being transparent, ensuring SRP's accountability for the changes, and clarifying how this would affect rates.

> *"Accelerate.* ***I want to see the short-term goals.*** *What, specifically, are we doing right now?" – Customer Focus Group Participant*

> *"****I feel like if we can reduce how much coal and other sources that we use at the moment****… So, if this is the company's goal and they want to focus on that, then I would be all for it." – Customer Focus Group Participant*

> *"****Why is it going to take us another 30 years*** *when I've gone to professional developments thrown by SRP about using renewable resources and whatnot?…I like that it's out there and that you have it projected. I also wish that you could be like the Lego corporation and be 100% renewable 20 years before your said date." – Customer Focus Group Participant*

> *"The thing that immediately stuck in my brain is the "Oh, solar isn't available 24 hours." And that's a really old talking point. And it's also not necessarily true anymore…So,* ***I feel like some of the messaging is based on talking points that are out of date and not necessarily forward-thinking****." – Customer Focus Group Participant*

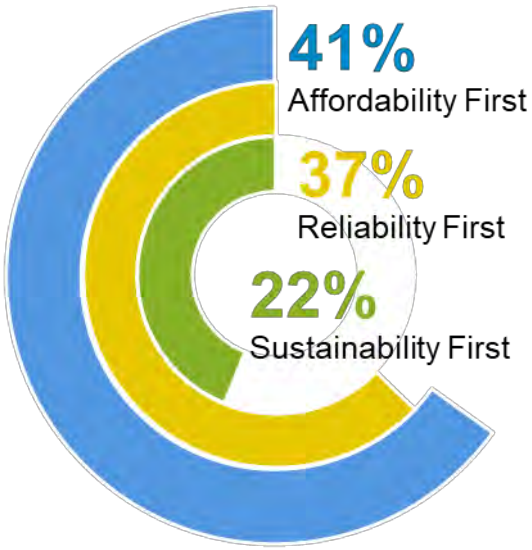
> *"****It's kind of curious why it would take so long to get more solar.*** *I mean, we're in the Valley of the Sun." – Customer Focus Group Participant*

> *"****I wonder how they could include in there something to do with conserving energy, wiser use****. I mean, I know there's been a lot of improvement like in the effectiveness of AC, with LEDs, and stuff like that. It would just be helpful…to consider the conserving side of it. And also, I wonder if the time has come to include in that chart an energy generated from the home, solar panels, whatever, like that. Because most of the people looking at the chart are homeowners like us." – Customer Focus Group Participant*

> *"What does all of this mean? And then, of course,* ***the financial piece of it, just like, okay, how would that even work, honestly, with thinking of all of it?*** *Like what could I do now to make a change? How is that going to develop over the years, just what that would all even look like?" – Customer Focus Group Participant*

Affordability and reliability were most ranked 1st

When asked how SRP should rank affordability, reliability and sustainability, two-fifths (41%) ranked affordability first, with 37% prioritizing reliability, and only 22% prioritizing sustainability.



In the focus groups, while a majority of customers ranked reliability first , they discussed a tough tradeoff between reliability and affordability

> *"If it's not on, it doesn't work, right? It doesn't matter what you spend. Again, we all have budgets, and we all try to stay within them." – Customer Focus Group Participant*

When asked reasons for ranking affordability, reliability, and sustainability as they did, customers responded as follows:

Affordability: Reasons Ranked First

23% Mentioned keeping energy costs down, the rising cost of living, and/or that if electricity isn't affordable, other priorities are meaningless.

*"I only have so much money, and already have seen enough scenarios where **people can't afford to run their air conditioning in summer due to costs**. I have been in valley 23 years and that's an issue every year." – Survey Respondent*

- *Both those with a satisfactory/low/unsatisfactory credit rating and those with a negative experience with SRP were significantly more likely to rank affordability first.*
- *Those with a household income less than $75k and Hispanic customers were more likely to rank affordability as first.*

Reliability: Reasons Ranked First

25% Mentioned that consistent energy is needed to maintain the status quo, and/or that if electricity isn't reliable, other priorities don't matter.

***"Residents and business are dependent upon a steady source of power.** Some uses are essential to life in the case of those who rely on devices to stay alive. Because of the summer heat, a break in power could be fatal to some." – Survey Respondent*

Sustainability: Reasons Ranked First

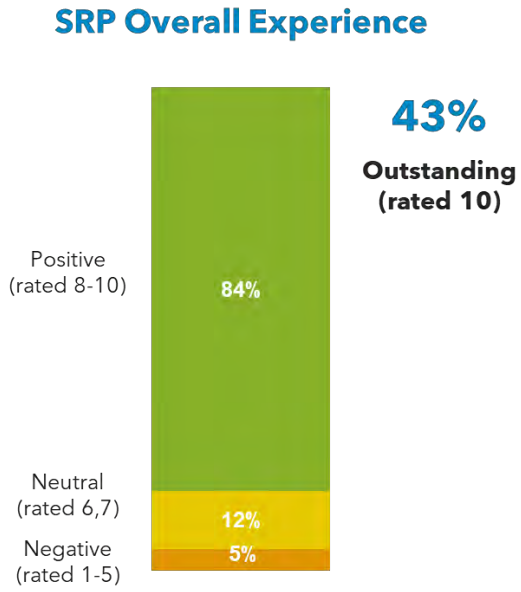
10% Mentioned the need to take care of the earth/ future energy needs.

***"Without sustainability there is no future."** – Survey Respondent*

Those who have lived at their address 2 years or less and those with a positive opinion of the energy plan were more likely to rank sustainability first.

Perceptions of SRP and Topics of Interest

Over four-fifths rated their experience with SRP positively



In qualitative findings, customers noted a highly positive perception of SRP, specifying that reliability of service and helpful customer service were key factors.

"Honestly, I'd give SRP a 10. I haven't had any major issues. Any time I've had anything that's come up, ***I'm able to get someone on the phone, speak with them****, … So, I've had a really good relationship with them." – Customer Focus Group Participant*

"I think the ***consistency of the service****. Being in Arizona, we do have the so hot weather all the time and having air conditioning is definitely a must…* ***And the consistency of them being able to provide that to us without any issues so far is something that I really appreciate****." – Customer Focus Group Participant*

- *Those with a household income under $75k were more likely to rate their experience as outstanding.*
- *Those who had a negative impression of the energy plan and those categorized with high usage were less likely to be satisfied with SRP.*

Over half had interest in ways to save

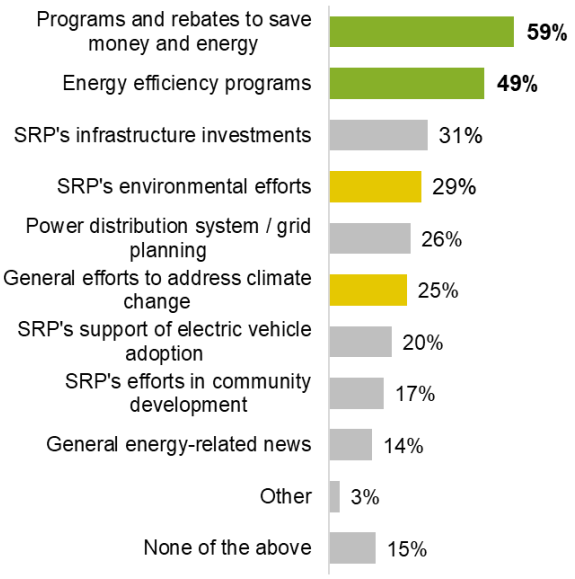
Customers would most like to continue to hear about ways to save via energy efficiency program and/or rebates. Meanwhile, over one-quarter were interested in topics related to SRP's environmental efforts and/or climate change.

Focus group participants agreed that SRP programs help customers manage and reduce their bills.

"I do have the M-Power so I do have prepaid electricity, so I am very acutely aware of my usage. ***I can see what I'm spending per day****." – Survey Respondent*

"I do like the idea that SRP does provide that time of use plan or ***keeps your bills consistent*** *throughout the month or throughout the year." – Survey Respondent*

Topics of Interest

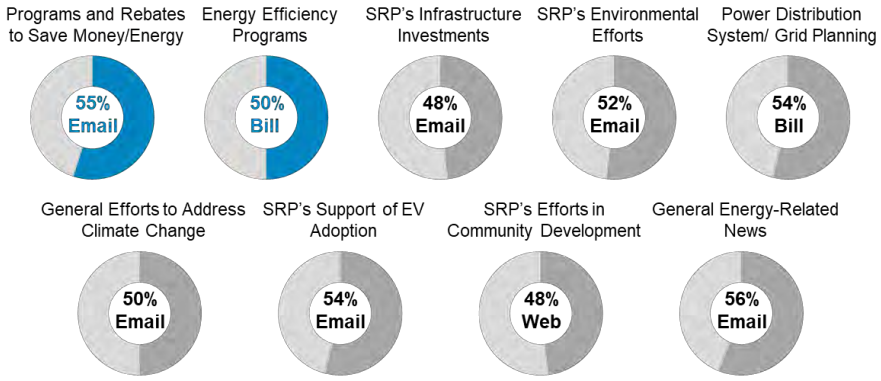


- *Those with a negative overall opinion of the energy plan were significantly more likely to want to hear about SRP's infrastructure investments and the power distribution system; they were less likely to want to hear about SRP's environmental efforts and general efforts to address climate change.*
- *Those with a household income less than $75k were more likely to want to hear about cost saving options.*

Across communication topics, customers most preferred to receive communication via bill insert and email.

Males were more likely to prefer email communications about programs and rebates to save money/energy.

Channel Preference



Appendix

Demographics

	Focus Group (n=24)	Online Survey (n=400)
GENDER		
Female	13	45%
Male	10	51%
Non-binary	1	0%
Prefer not to answer	-	4%
HOUSEHOLD INCOME		
Under $75k	15	41%
$75k or more	9	39%
Prefer not to answer	-	20%
CREDIT RATING		
Preferred	19	67%
Satisfactory/Slow/Unsatisfactory	3	12%
New Customer	2	21%
ETHNICITY (MULTIPLE SELECTIONS)		
White	20	69%
Black or African American	3	4%
Other	3	13%
Prefer not to answer	-	18%
HISPANIC ORIGIN		
Hispanic	2	15%
OWN/RENT HOME		
Own	18	73%
Rent	6	28%

	Focus Group (n=24)	Online Survey (n=400)
AGE		
18-44	13	30%
45-64	6	37%
65+	5	34%
EMPLOYMENT		
Ful-time/Part-time	-	51%
Self-employed	-	6%
Retired	-	33%
Unemployed/seeking employment/student	-	4%
Not working/not seeking	-	2%
N/A / Prefer not to answer	-	5%
YEARS AT ADDRESS		
2 or less	-	7%
3-5	-	10%
6-20	-	30%
21-39	-	30%
40+	-	15%
USAGE		
Low (6,000 kWh or less)	3	19%
Moderate (6,001-12,000 kWh)	8	33%
Medium (12,001-18,000 kWh)	8	29%
High (More than 18,000 kWh)	5	20%

Illustrative Plan Description and Background

In addition to the visual depiction of the illustrative plan, respondents were provided the following additional description and background:

> "SRP is working at all times to make sure your power stays on, including during Arizona's extreme summers. To ensure power quality continues to improve, SRP needs to plan long term for the future of the Valley. This means:
>
> - Balancing a transition to clean energy
> - Planning for population growth (and an increased demand for energy)
> - Considering the types of power to buy to make up their power mix (including solar, wind, geothermal, biomass, nuclear, natural gas, and coal)
> - Reducing SRP's carbon intensity (the amount of carbon released per unit of energy produced) by 90% by the year 2050"

APPENDIX C

SRP Customer Research Future of Energy Phase 3 Report



Future of Energy: ISP Residential Customer Research

Phase III Report

Revised: December 13, 2023

bellomy

175 Sunnynoll Court
Winston-Salem, NC 27106

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Appendix 18



Background & Objectives

Background

Salt River Project (SRP) is preparing its first Integrated System Plan (ISP), which is focused on a new way of planning the power system through 2035. While multiple inputs are needed to prepare this plan, one crucial contribution is input from residential customers.

Looking into the future, SRP expects there to be many changes and disruptions to the energy industry including evolving customer needs and expectations with a key aspect being the balance between reliability, sustainability, and affordability. Furthermore, the perspectives of different groups of customers, with different values and mindsets and each group's perception of this balance will need to be understood and considered.

Objectives

The goal of this research was to bring the voice of SRP's residential customers into the planning of the future power system.

More specifically, this research was designed to gain an understanding of how customers think about, and value sustainability, affordability, and reliability related to their electricity service from SRP and gauge their reactions to potential energy systems. SRP sought to understand areas of diverse viewpoints and agreement, as well as identify preferred methods of engagement on this topic.

The research aimed to address the following specific objectives:

1. Understand the concerns customers have about the future of Arizona, the economy and the U.S.
2. Understand diverse perspectives and opinions relating to SRP's sustainability plan and evolution.
3. Develop and test system-planning metrics that are understood and resonate with customers.
4. Generate a list of power system and future energy topics that interest customers.
5. Understand customer perspectives on power reliability and potential tradeoffs with sustainability and affordability.
6. Understand preferred methods of learning about and engaging with the power system planning process.

Methodology & Reporting

Approach

A three-phased research approach was applied, starting with virtual focus groups (December 2021), followed by a quantitative confirmation (March 2022) and culminating in a choice exercise (May 2023).

All customers included in the research were SRP residential customers, who were energy decision makers for their household (make decisions about their utility service and pay the bill), did not work for a related industry, and were over 18 years old.

Phase I: Virtual Focus Groups

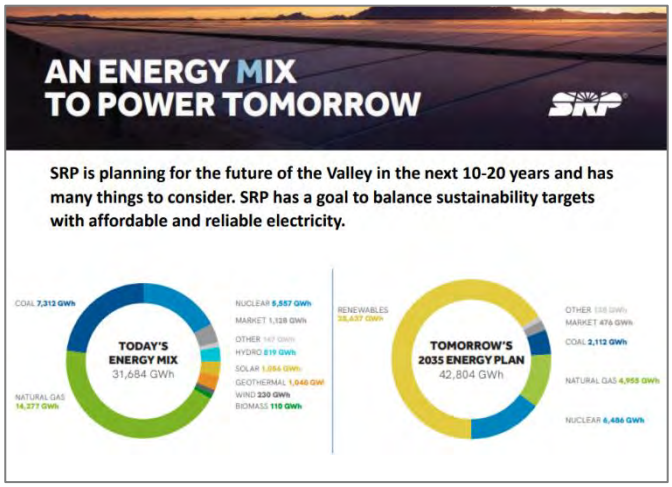
Four 90-minute virtual focus groups were held December 13 & 14, 2021. A total of 24 SRP customers participated virtually (via Zoom) and received a $125 bill credit for participating.

Customers were grouped to encourage engagement and maximize the ability to explore attitudes and have a meaningful conversation.

Phase II: Online Survey

An online survey was fielded between March 7 – March 14, 2022. Respondents evaluated SRP's illustrative energy plan of how the system may develop in relation to attributes of customer interest identified in Phase I. Quotas were set for the survey to ensure the respondent pool best represented SRP's residential customer population.

Customers evaluated a visual example of SRP's future potential energy mix, which describes the transition of the power system over the next 10-20 years. The visual depiction of the illustrative plan shown to respondents is displayed to the right. The illustrative energy plan shown in Phase II did not include details on bill impacts, water reduction, carbon emission reduction, or timing to meet the sustainability goals. Customers were provided background on SRP's priorities prior to evaluating energy mix; this wording is included in the Appendix on page 20.



Pre-Test Research: Optimizing Survey Materials

Prior to the Phase III survey, a multi-staged pre-test study was conducted to test education materials, survey instructions, and choice exercise design among non-SRP customers. The pre-test research included an initial pre-test survey, qualitative ride-along interviews, and a revised pre-test survey.

Throughout the three pre-test phases, respondents identified areas of the instructions and educational materials that were difficult to understand. Based on feedback from this pre-test, instructions for the choice exercise were crafted with clear tasks respondents could understand and accurately complete.

This confirmation helped secure the highest quality of actionable data. Changes made to the choice exercise included:

- Impactful phrase rewording which resulted in less confusion (~40% reduction in confusion)
- Redesign of the choice activity which created an easier survey experience.



This testing ensured SRP's diverse customer base would be able to understand and easily complete the choice exercise in Phase III.

Phase III: Choice Exercise Online Survey

In this 20-minute survey fielded between May 9 and May 29, 2023, offered in English and Spanish, respondents completed a choice exercise to assess their preferences for SRP's potential future energy system. Quotas were set to mirror the true population split for SRP's customer base. A choice-based methodology known as a conjoint exercise was utilized to understand customer preference for potential future energy systems being analyzed in the Integrated System Plan.

Conjoint methodology is used to optimize a product or service of interest by asking respondents to make a series of choices though an exercise simulating real-life situations, determining what tradeoffs they are willing to make.

The following best practices were used in development of the choice exercise for the Phase III survey:

- Exposing respondents to educational information regarding system inputs prior to asking them to make a choice (e.g., explaining energy mixes and defining carbon reduction)
- Ensuring complex inputs are positioned in customer-friendly terms (e.g., showing carbon reduction in terms of the number of gas-powered vehicles)
- Utilizing visuals where possible to "show" rather than "tell" (e.g., including a graphical representation of the energy mix)
- Creating precise levels for each system input (e.g., utilizing data outputs from other ISP research efforts to build levels)
- Ensuring system configurations are realistic to respondents to avoid asking them to make a non-sensical choice

- Including no more than seven inputs per system to ensure ease of comprehension
- Limiting the number of screens in the exercise to no more than twelve to minimize respondent fatigue

Customers were asked to evaluate 11 screens, each showing 2 energy plans and a “none of these” option representing the current energy system and choose the plan they would most prefer SRP to pursue. Through selections made, a customer preference rating was produced for each potential future energy system. An example of the choice exercise is shown on the following page.

The ISP's analytical framework and outputs from the system planning informed the following system inputs for the choice exercise:

- Illustrative energy mix (9 mixes tested)
- When SRP will meet its sustainability goals (2030 or 2035)
- Percent reduction in carbon emissions (4 levels for each energy mix)
- Percent reduction in water usage (4 levels for each energy mix)
- If SRP will build new gas power plants (yes or no)
- Monthly bill impact (4 levels calculated on customers' average bill)
- Number of 2-hour power outages (0, 1, 2, or 3)

Illustrative mixes and variations in options for the inputs shown were representative of the resource builds and implications for each strategic approach under the future scenarios from the ISP system plans. Various levels (or options) were shown for each component resulting in evaluation of over 9,200 possible system configurations. An example of the choice exercise screen respondents completed is located in the Appendix on page 21.

Reporting

Quantitative results are reported in charts at the total level with qualitative results represented throughout. When evaluating survey data, sub-groups were compared to one another to investigate if there were statistically significant differences between two or more groups.

A 95% confidence level is used, which indicates we can conclude with 95% confidence that differences are not due to chance and that survey results should match results from the actual population (plus or minus the margin of error). Only significant differences relevant to the research objectives are reported.

The following subgroups are noted in this report:

- **Age** (18-44 years old/ 45-54 years old/ 55-64 years old/ 65+ years old)
- **Income** (Under $75k/year / $75k/year or more) (Phase II Only)
- **Limited Income** (200% of HHS Poverty Guidelines/ Non-Limited at 200%)
- **Gender** (Male/ Female/Nonbinary)

- **Energy Mix Prioritization** (Affordability first/ Reliability first/ Sustainability first)
- **Hispanic** (Hispanic/ Non-Hispanic)
- **Credit Rating** (5 levels)
- **Usage Category** (Low/ Moderate/ Medium/ High)
- **Overall Opinion of Energy Plan** (Positive/ Negative)
- **Overall Experience as SRP Customer** (Positive/ Neutral/ Negative)
- **Years at Address** (2 or less/ 3-5/ 6-20/ 21-39/ 40+)

Analysis Note: Rating scale questions are reported differently for 10-point and 5-point scales.
10-point scales are reported using Top-Box (TB – ratings of 10), Top-3-Box (T3B – ratings of 8,9, or 10), Middle-2-Box (M2B – ratings of 6 or 7), and Bottom-5-Box (B5B – ratings of 1-5).
5-point scales are reported using Top-Box (TB – ratings of 5), Top-2-Box (T2B – ratings of 4 or 5), Middle-Box (MB – ratings of 3), and Bottom-2-Box (B2B – ratings of 1 or 2).

Executive Summary



In Phase I & II, most customers reacted positively to SRP's initial path forward, and a quarter felt it was excellent. A majority agreed the plan should be prioritized by SRP. Phase III revealed residential customers' preferences for the future energy system.

Top factors: affordability & bill impacts

Affordability concerns were some of the most-selected future issues facing Arizona. In each phase of this research, affordability surpassed reliability slightly in importance when ranked by customers. Those with limited incomes put greater emphasis on affordability, while non-limited income customers reflected greater balance across factors. Additionally, when choosing a future energy system, customer selections revealed monthly bill impact as the top driver of preference.

Understanding and openness to change

Despite prioritizing affordability, customers recognized that the forthcoming challenges facing the region are interrelated and pose risks to sustainability, the economy, and overall quality of life. Thus, they understood the need for a lower-carbon future energy system, however, across scenarios, lower cost strategic approaches were more preferred by customers. While customers recognized the need for and expressed interest in SRP's investment in sustainable energy sources, they do not want to bear the cost of that investment.

Willingness to engage

Customers reported positive experiences with SRP's programs and over half were interested in programs and rebates that will help them save money and energy. Additionally, about a third or more expressed interest in learning about SRP's energy efficiency programs, environmental efforts, and infrastructure improvements.

Recommendations

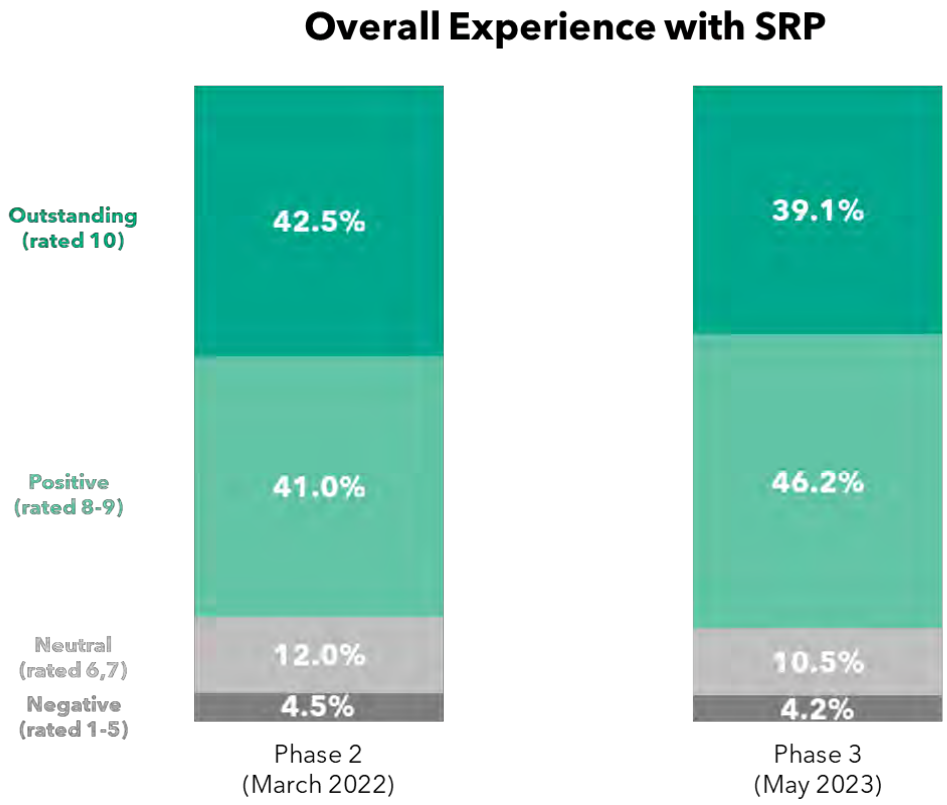
- **For SRP's ISP, focus investment on a least-cost portfolio:** With cost being the top driver of customer preference, it will be critical to ensure system costs are managed and explained to customers proactively and transparently.
- **For SRP's ISP, highlight and maintain grid readiness and resiliency:** Reliability was the second highest ranked priority.
- **In ISP implementation, utilize a targeted approach to customer programs:** Customers expressed a willingness to engage with SRP via customer programs. These programs should be designed to meet the varying needs of customers.

Detailed Findings

Experiences with SRP, Concerns, and Priorities

Most rated their experience with SRP positively

Similar to March 2022, in May 2023 surveying, over 4 in 5 customers rated their experience with SRP positively. While about 2 in 5 provided an "Outstanding" rating.



In qualitative focus groups, customers attributed their highly positive perception of SRP to the reliability of service and helpful customer service. Additionally, participants felt positively about SRP's customer programs, agreeing that programs help them manage
and reduce their electricity bills.

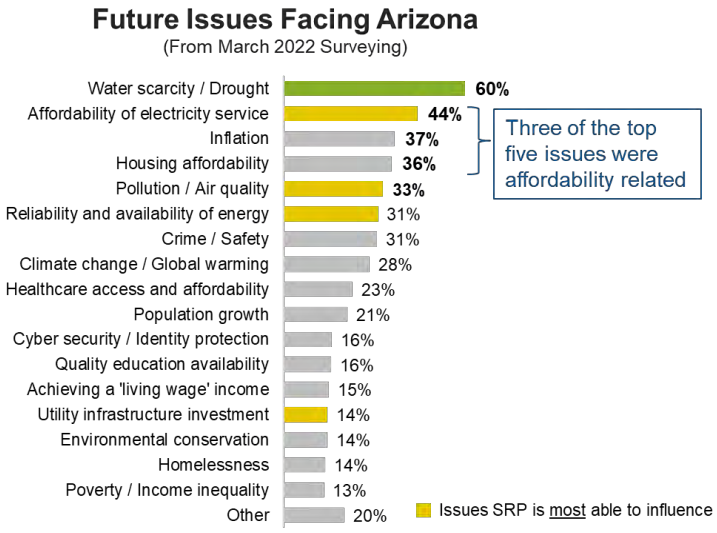
*Groups **more likely** to provide a positive rating of their experience with SRP included:*

- *Customers aged 55 or older*
- *Non-Hispanics*

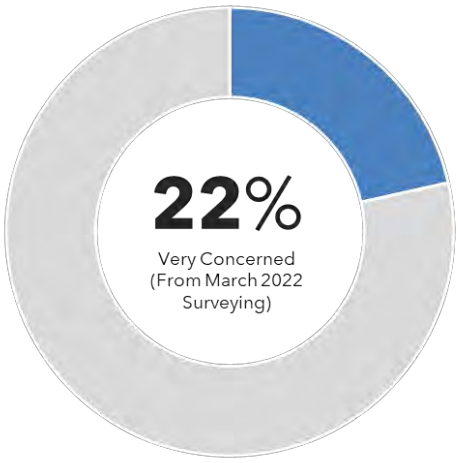
Customers demonstrated affordability concerns

Respondents most selected that they were concerned about water scarcity. After water scarcity, affordability related to electricity, inflation, and housing were most concerning.

The focus on affordability of electricity is of note, as it was the second-most selected future concern. These issues were followed by some items related to energy service, including pollution, energy reliability, and climate change.



- ***Lower income*** *customers (earning under $75k/year) reflected* ***greater concern for affordability****.*
- ***Year-round*** *residents are more likely to* ***prioritize housing affordability****.*
- *Those with a household* ***income of $75k or more*** *were more likely to* ***prioritize water scarcity*** *and were less likely to prioritize housing affordability.*
- ***Non-Hispanic*** *customers were more likely to* ***prioritize water scarcity****.*



Further, 22% of customers were very concerned about other community members being able to pay their electricity bills.

Groups ***more likely*** *to be concerned about others' ability to pay their electric bill include:*

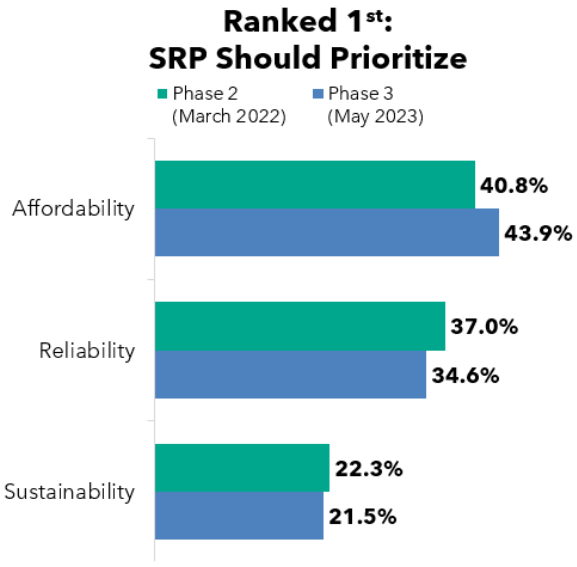
- *Customers with household incomes less than $75k*
- *Females*
- *Hispanic customers*

Affordability and Reliability were most often ranked 1st

When asked how SRP should rank affordability, reliability and sustainability, affordability was the top priority in both Phase II & III for over two-fifths of customers. Over one-third prioritized reliability, and less than one-quarter prioritized sustainability.

In the focus groups, while a majority of customers ranked reliability first, they discussed a tough tradeoff between reliability and affordability.

While the ranking of priorities was similar across Phases, reasons for these rankings in May 2023 highlighted greater emphasis on the rising cost of living and a need for consistent electricity.



Affordability: Reasons Ranked First

Almost half (46%) of those who ranked affordability first in Phase III mentioned keeping energy costs down and the rising cost of living. This was more than in Phase II where only one-third ranked affordability first for the same reason. The increase in concern over rising cost of living and keeping energy costs down may be due to the rise in inflation and increased conversation about rising prices across products and services in 2023.

*In Phase III surveying, groups **more likely** to rank **affordability first** included:*

- ***Limited income** customers (200% of HHS Poverty Guidelines)*
- *Females*
- *Hispanics*
- *Those enrolled in **M-Power for Pre-Pay***

Reliability: Reasons Ranked First

In Phase III, half (51%) of the customers who ranked reliability first noted a need for consistent electricity to maintain the status quo. This increased from about one-quarter (23%) ranking reliability first in Phase II for the same reason.

*In Phase III surveying, groups **more likely** to rank **reliability first** included**:***

- *Non-Limited income customers*
- *Males*
- *Those with Preferred Credit Ratings*

Sustainability: Reasons Ranked First

While the smallest proportion of customers ranked sustainability first, three-fifths (62%) of those who did in Phase III noted the importance of taking care of the Earth and future energy needs. This was higher than the almost half (45%) who ranked sustainability first for the same reason in Phase II.

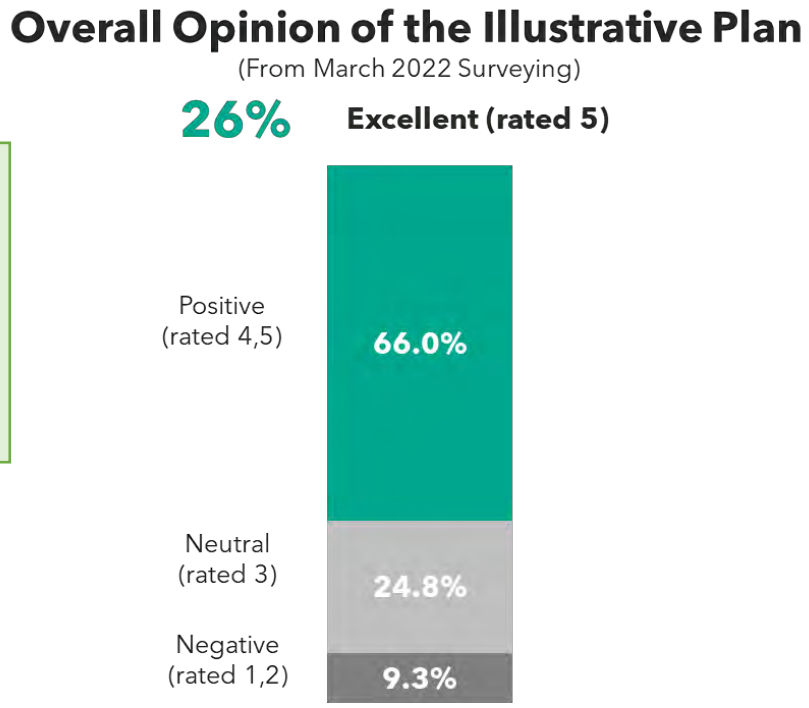
*Customers **aged 55 to 64 were less likely** than all other age groups to rank **sustainability first**. In Phase III surveying.*

SRP Energy Plan: Initial Reactions (Phase I & II)

Two thirds rated the initial energy plan positively

When evaluating an illustrative example of SRP's energy plan during initial phases of research (visual and background evaluated can be found in the Appendix on page 20), one-quarter (26%) rated it as excellent, but 66% rated it positively overall (rated 4 or 5 on a 5-point scale). This demonstrates opportunity for improvement.

- *Those ranking **sustainability first** had a **more positive** impression of the energy plan.*
- *Those with **high electricity usage** were **less likely** to rate the plan positively.*



Customers noted the plan could be improved with more specifics

Initial responses to viewing the plan revealed that customers were interested in more specifics. In addition to questions on plan affordability and achievability, respondents cited varying thoughts on which renewable sources SRP should prioritize.

- Twenty-seven percent (27%) of customers shared concerns around the type of energy sourced.
- Nineteen percent (19%) shared affordability and cost concerns.
- Thirteen percent (13%) shared achievability concerns regarding the timing of the plan being too slow.

Focus group participants were also generally positive about the plan's intent but suggested some opportunities for improvement. These opportunities included the amount of time needed to implement the plan, getting customer buy-in and being transparent, ensuring SRP's accountability for the changes, and clarifying how this would affect rates.

Phase III Customer Preference for Future Energy System

Monthly bill impact of most importance when selecting an energy system

After completing the exercise, over one-third of respondents (37%) reported the monthly bill impact was the most important input when choosing a preferred future energy system.

*Groups **more likely** to rank **monthly bill impact first** included:*

- *Year-round residents*
- *Those **employed part-time***

Among those ranking the **energy mix first (14%)**, top ranked priorities were evenly split:

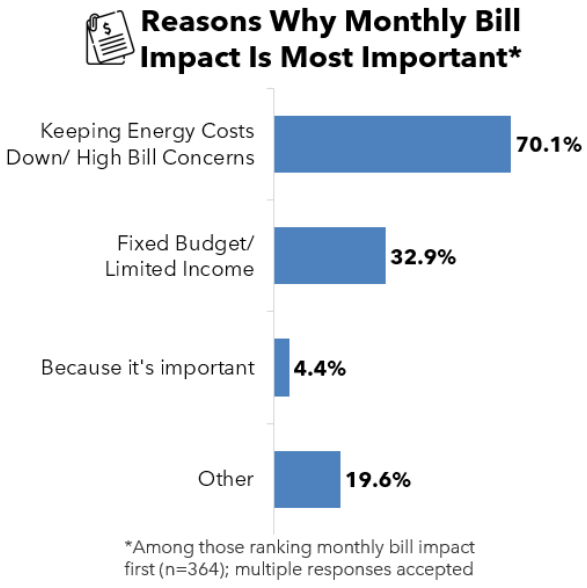
- Affordability – 31% ranked 1st
- Reliability – 36% ranked 1st
- Sustainability – 34% ranked 1st

This suggested the energy mix was seen as a component related to all three priorities.

Attribute	Ranked 1st Most Important
Monthly bill impact	36.8%
Reduction in carbon emissions	15.9%
Number of 2-hour power outages	14.5%
Energy mix	13.9%
Reduction in water usage	11.4%
If SRP will build new gas power plants	5.0%
When SRP will meet its sustainability goals	2.5%

Reasons for ranking inputs first varied

Customer open-ended comments highlighted concerns regarding financial constraints due to changing socio-economic conditions and future uncertainty stemming from inflation and escalating energy expenses. Looking to the future, customers attributed greater costs to the anticipated new infrastructure needed to meet growing demand for electricity and expressed concerns that cost increases could impact quality of life. Additionally, the viability and affordability of future green energy initiatives raised doubts for some given the present economic context.



*The following groups were **more likely** to mention **"fixed budget/ limited income"**:*

- *Customers **aged 55+***
- *Retirees*
- *Those with **limited incomes** (200% of HHS Poverty Guidelines)*

Among those ranking carbon reduction first, about a third mentioned reducing carbon via the use of cleaner energy sources (like solar or nuclear) while nearly half of those ranking energy mix first mentioned these topics as reasons for ranking energy mix as most important.

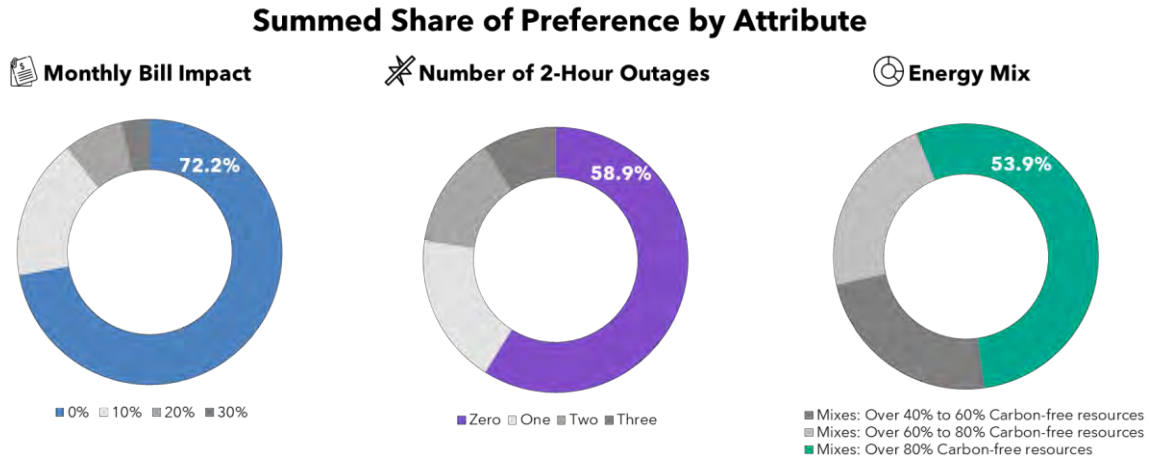
Reasons Why Most Important

Reduction in carbon emissions *(n=169)	Number of 2-hour power outages *(n=139)	Energy mix *(n=147)
37% Reducing carbon has direct impact on climate change	**58%** Dangers associated with outages (hot climate, health concerns, etc.)	**46%** Emphasis on reducing carbon and/or increasing solar or nuclear
32% Emphasis on reducing carbon and/or increasing solar or nuclear	**34%** General reliability concerns	**33%** Some energy sources are limited/ need a mix

Choices indicate a desire to "have it all"

The choice exercise also revealed the preference for each level of key factors in isolation.

- Bill Impact: a majority preferred 0% increase
- Outages: a majority preferred zero 2-hour outages
- Energy Mix: a majority preferred energy mixes with over 80% carbon-free sources



While monthly electricity bills have the largest impact on preference (72%), these preferences indicate that customers want the cleanest, greenest energy at the lowest cost with no implications to reliability.

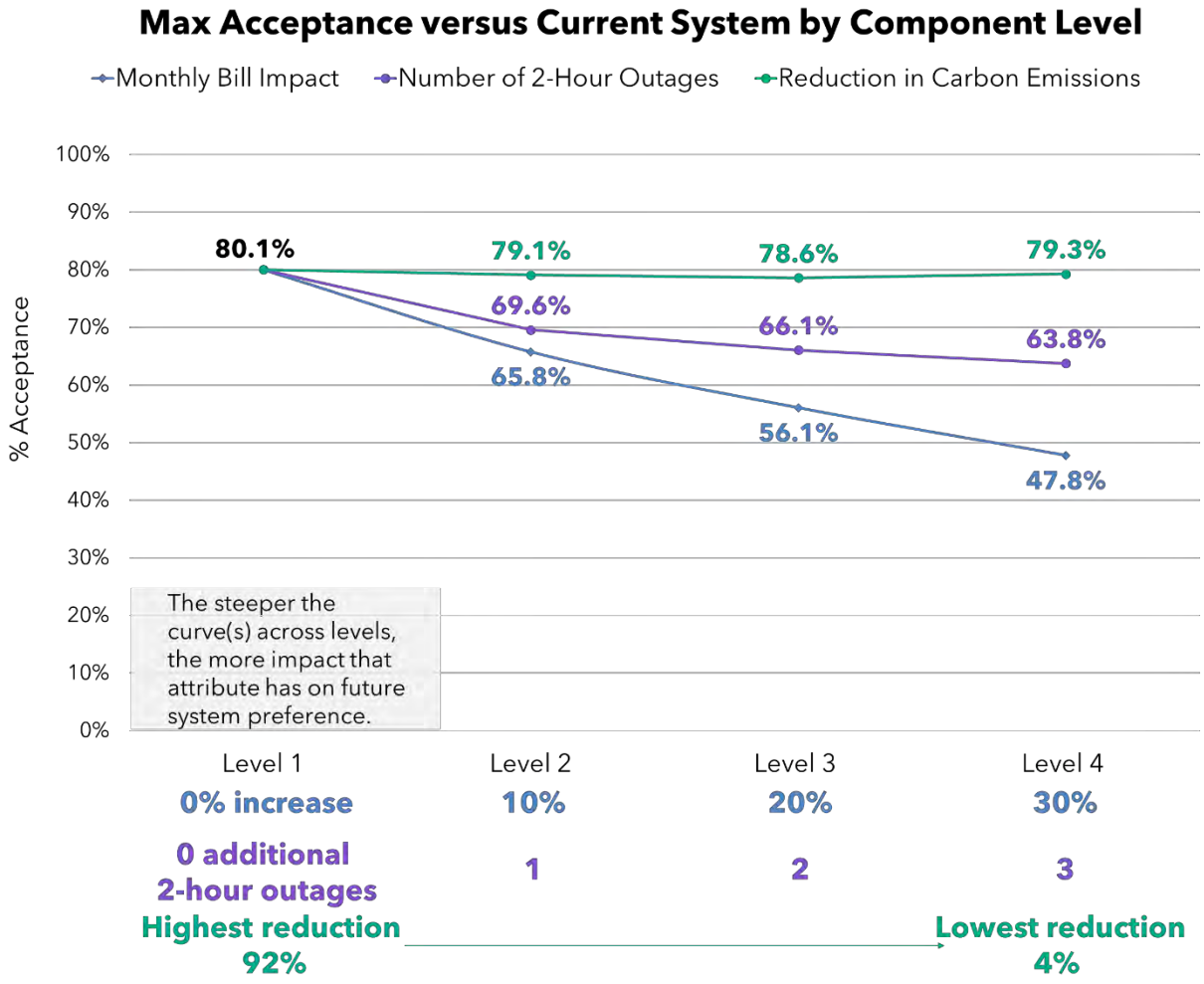
Real-world cost constraints force tradeoffs

While most customers agree that sustainability is important and should be considered by SRP and their customers, there are limitations on how much customers feel they can invest in the “greater good.” Customers expressed that fixed incomes and limited budgets often constrain the degree to which they can support and prioritize sustainability.

Acceptance of future energy systems declines above 0% bill impact

As bill impacts increase, the proportion of customers who accepted an energy system over the current system declined sharply. However, acceptance declines were less steep for the number of 2-hour outages suggesting that customers are less accepting of price increases and more tolerant of minimal additional 2-hour outages.

Furthermore, when tradeoffs are required, carbon reduction has minimal impact with acceptance of energy systems relatively unchanged as the level of reduction in carbon emissions increases.



Customer preferences for a balanced future energy system

While SRP does not know what the future will look like, it will be important to design the future energy system with customer preferences in mind. Findings revealed that from the residential customer's perspective the ideal future energy system should...

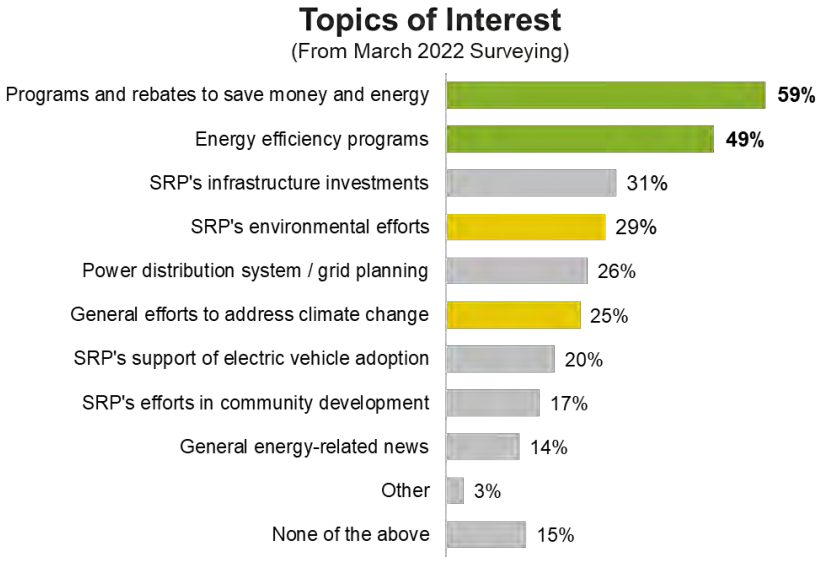
- Manage cost, first and foremost
- Strive to manage monthly bill impacts below a 10% increase
- Include a diverse energy mix to ensure reliability
- Provide the cleanest, most sustainable energy without exceeding a 10% bill increase

Topics of Interest

Over half had interest in ways to save

Customers would most like to continue to hear about ways to save via energy efficiency program and/or rebates. Meanwhile, over one-quarter were interested in topics related to SRP's environmental efforts and/or climate change.

Focus group participants agreed that SRP programs help customers manage and reduce their electricity bills.



*Those with a **household income less than $75k** were **more likely** to want to hear about the following:*

- *Programs and rebates to save money and energy*
- *SRP's support for community development*

*Groups more interested in hearing about **SRP's infrastructure investments** included:*

- *Customers **aged 65+***
- *Non-Hispanics*

***Part-time residents** were **more likely** than those living in Phoenix year-round to want to hear about the following**:** energy efficiency programs, SRP's environmental efforts, and general efforts to address climate change*

Appendix

Focus Group Participant Description*

Total	24
Gender	
Female	13
Male	10
Non-binary	1
Ethnicity	
Black	3
Hispanic	2
White	18
Other	1
Homeownership	
Own	18
Rent	6

Age	
25-34	6
35-44	7
45-54	2
55-64	4
65-74	2
75+	3
Income	
<25k	2
25-49k	5
50-74k	8
75-99k	3
100-149k	3
150+	3

** Focus Groups are exploratory in nature and cannot be projected to a larger population. Attendees are not representative of the full SRP customer base or stakeholders*

Survey Respondent Demographics

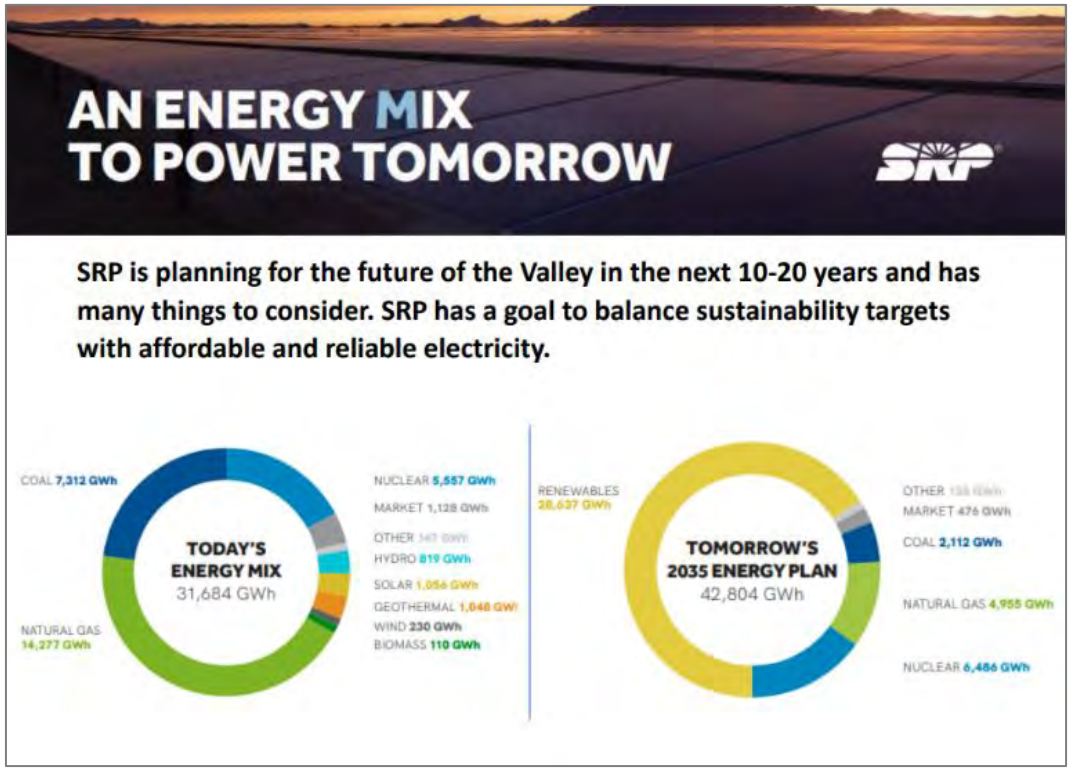
	Phase 2 Survey March 2022 (n=400)	Phase 3 Survey May 2023 (n=1,011)
GENDER		
Female	51%	49%
Male	45%	46%
Non-binary	0%	0%
Prefer not to answer	4%	5%
INCOME		
Limited Income 200%	31%	31%
Non-Limited Income 200%	69%	69%
CREDIT RATING		
Preferred	67%	64%
Satisfactory/Slow/ Unsatisfactory	12%	18%
New Customer	21%	18%
Cash Only	-	1%
ETHNICITY (MULTIPLE SELECTIONS)		
White	69%	69%
Black or African American	4%	5%
Other	13%	12%
Prefer not to answer	18%	17%
HISPANIC ORIGIN		
Hispanic	15%	12%
OWN/RENT HOME		
Own	73%	71%
Rent	28%	29%

	Phase 2 Survey March 2022 (n=400)	Phase 3 Survey May 2023 (n=1,011)
AGE		
18-44	30%	38%
45-64	37%	37%
65+	34%	25%
EMPLOYMENT		
Ful-time/Part-time	51%	53%
Self-employed	6%	8%
Retired	33%	27%
Unemployed/seeking employment/student	4%	3%
Not working/not seeking	2%	2%
N/A / Prefer not to answer	5%	7%
YEARS IN PHOENIX		
2 or less	7%	8%
3-5	10%	9%
6-20	30%	34%
21-39	30%	29%
40+	15%	20%
USAGE*		
Low (6,000 kWh or less)	19%	12%
Moderate (6,001-12,000 kWh)	33%	32%
Medium (12,001-18,000 kWh)	29%	31%
High (More than 18,000 kWh)	20%	23%

Illustrative Plan Description and Background (Phase I & II)

In addition to the visual depiction of the illustrative plan shown below, respondents were provided the following additional description and background during Phases I & II of this research:

> "SRP is working at all times to make sure your power stays on, including during Arizona's extreme summers. To ensure power quality continues to improve, SRP needs to plan long term for the future of the Valley. This means:
>
> - Balancing a transition to clean energy
> - Planning for population growth (and an increased demand for energy)
> - Considering the types of power to buy to make up their power mix (including solar, wind, geothermal, biomass, nuclear, natural gas, and coal)
> - Reducing SRP's carbon intensity (the amount of carbon released per unit of energy produced) by 90% by the year 2050"

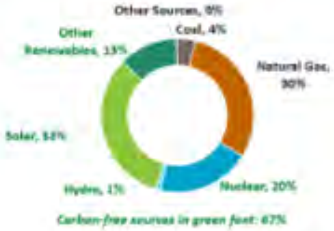


Choice Exercise Example Screen (Phase III)

Customers were asked to evaluate 11 screens, each showing 2 energy plans and a "none of these" option representing the current energy system. An example screen with question wording is shown below.

Which of these hypothetical future energy systems would you prefer SRP implement
Please read through each plan carefully and select the plan you most prefer.

Click here to view a glossary of terms. This will open in a new browser and you can come back to this page to complete the activity.

	2035	2030
Energy Mix:	 *Carbon-free sources in green font: 66%*	 *Carbon-free sources in green font: 67%*
SRP will meet its Sustainability Goals by:	**2035**	**2030**
% reduced carbon emissions (equal to number of gas-powered cars on the road each year):	**20% reduction** (about 675,000 gas-powered cars)	**61% reduction** (about 2.0 million gas-powered cars)
% reduced water usage (equal to the amount of water used by the number of 4-person households shown per year):	**16% reduction** (about 9,000 households)	**52% reduction** (about 30,000 households)
Will SRP build new gas power plants to source energy?	**Will** build	**Will not** build
Your monthly bill will:	Increase by **$30**	**Not increase**
Number of 2-hour power outages experienced in one year due to high energy demand (on a hot summer's day):	**Two** 2-hour outages	**Three** 2-hour outages
	Select	Select

None of these, I would stick with the current system at my current monthly bill amount.

Select



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982100 03/24

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-21

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit HH: SPP, *SPP Reliability Plan* (Jun 2, 2025)

SPP RELIABILITY PLAN

0820EXT00108

Business Owner: Derek Hawkins
Effective: 06/02/2025
Revised: 06/2/2025
Version: 8.0

Approved By:	Brian Strickland	Digitally signed by Brian Strickland Date: 2025.06.11 13:41:29 -05'00'
SME Signature (Brian Strickland)		Date

Approved By:	Derek Hawkins	Digitally signed by Derek Hawkins Date: 2025.06.11 13:42:26 -05'00'
Business Owner Signature		Date

Revision History

Author	Version	Revision Date	Effective Date	Description
ORWG	1.0	6/1/05		Complete re-write to align with revised NERC Policy 9 as approved by NERC 06/15/04.
		6/15/05		Per NERC ORS request, removed Appendix B – Reliability Assessment Process and Procedure.
		1/11/06		Added CLECO to the plan.
		1/26/06		Added Constellation Balancing Authorities BCA, CNWY, DENL, DERS, PUPP, and WMUC to the plan.
		1/27/06		Updated to reflect changes in SPP processes and procedures after the SPP EIS Market is implemented.
		2/9/06		Made necessary changes to conform with NERC functional model terminology present in existing reliability standards.
		9/8/06		Added LAGN to the plan with an effective date of November 1, 2006
		12/5/06		Added Constellation Balancing Authority BUBA
		1/1/09		Changes consistent with Criteria 12.3. Corrected Batesville Generating Station acronym from BCA to BBA. Added Missouri Public Service (MPS) to footprint.
		4/1/09		Added Nebraska entities – LES, NPPD and OPPD
		10/1/09		Added Constellation Balancing Authorities OMLP and PLUM
		4/1/10		DENL Balancing Authority moved from operation by Constellation to operation by NRG and changing DENL to NLR
		1/1/11		CNWY and WMUC Balancing Authority moved from operation by Constellation to operation by NRG and changed from CNWY to CWAY and from WMUC to WMU
		2-15-11		City Utilities of Springfield (SPRM) becoming a stand-alone Balancing Authority Areas instead of a TOP imbedded inside the SPA Balancing Authority Areas.
		4/11/12		Added Brazos Electric to list of Balancing Authorities. Updated map to reflect addition. Changed “OPS1” application in reference to outage scheduling to “CROW” application reference. Clarified the RTCA and monitored elements by voltage in sections C.4. and E1. Noted the primary and BUCC location changes in 2012 in section I.

Author	Version	Revision Date	Effective Date	Description
		6/1/13		Transferred the southern reliability members from SPP to MISO (with exception of the CECD entities) per Entergy move to MISO
		12/19/13		Removal of the CECD entities from the SPP Reliability footprint. Changed cover page date to Dec 19, 2013.
		3/1/14		Replaced "EIS" with "Integrated", removed OPS1 references, replaced PowerWorld with E-terravision, removed member map, and changed list of BA/TOPs to reflect new consolidated BA (SPP BA).
		6/1/15		Added the IS entities of WAPA, Corn Belt to the TOP list within the Introduction and the SPP Reliability Areas. Changed WECC references to PEAK Reliability.
	2.0	4/21/16		Changes made due to overall review, and to correct studies, update tools, Operating Criteria changes, DC tie additions, reduce redundancy of sections and Market constraint management.
Terry Oxandale	3.0	4/30/2019	4/30/2019	Modified for SPP RC for Western Interconnect effective 12/3/2019. Added changes in RE, additional TOPs in Appendix A, and included aspects of the Western Interconnect not included in the current Eastern Interconnect practices. Converted to current template and assigned new Operations document ID 0820PCS00108.
Brian Strickland, Derek Hawkins	3.1	11/20/2019	11/20/2019	Updated with additional information on loss of necessary applications, weather, Cyber Attack, and SPS/RAS. Updated AZPS (under CAISO RC) to AEPC (under SPP RC). Updated for clarifications per RCRT review. Deleted Gila River Power (GRMA) from Appendix A table being they are not a TOP per Bryan Wood.
Brian Strickland, Yasser Bahbaz	3.2	2/10/2021	4/1/2021	Added GRID effective 4/1/2021 to "BAs and TOPs in SPP RC Areas" section in Appendix A. Also updated file name of documents referenced in Appendix B.
Brian Strickland	4.0	1/07/2022		Added language to GMD to address monitor responsibilities and added a section on voltage. Changed business owner and SME per B. Wood.
Julie Gerush, Brian Strickland	5.0	04/12/2023	04/12/2023	Comments addressed from Operations review. Changes to accommodate changes to IDC. Updated cover pages.

Author	Version	Revision Date	Effective Date	Description
Heather Harris, Brian Strickland	6.0	04/01/2024	04/01/2024	Removed Appendix B (RC Related procedures), updated to identify no delegation of task or actions requested for adjacent RCs, minor language changes to mirror requirement language. Removed GRIF under entities due to merger with GRID. Added language for SOL/IROL communication and general cleanup Changed document ID.
Hayden Johnson	7.0	01/31/2025	02/01/2025	Added First Light Energy (BNBA) to the list of BAs/TOPs in the Appendix.
Hayden Johnson	8.0	06/02/2025	06/02/2025	Removed New Harquahala Generation Station (HGMA) from the list of BAs/TOPs in the Appendix.

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Introduction

The North American Electric Reliability Corporation (NERC) delegates its authority to monitor and enforce compliance with NERC Reliability Standards to the Regional Entities (RE). The RE carries out their reliability activities with the Registered Entities for their reliability region. Southwest Power Pool (SPP) is recognized as the Reliability Coordinator (RC) for all Transmission Operators (TOPs) and Balancing Authorities (BAs), listed in **Appendix A**, in both the Eastern and Western Interconnections.

SPP RC is responsible for the bulk transmission reliability and power supply reliability within its RC Areas. Bulk transmission reliability functions include assessment of real-time and next day operating conditions, congestion management, coordination of transmission and generation outages and instructing curtailment of transactions and/or load. SPP RCs use a risk-based approach to communicating actual and potential SOL exceedances with impacted TOPs, as described in SPP's Reliability Coordinator Area System Operating Limit Methodology and Reliability Coordinator Area System Operating Limit Methodology Western Interconnection. Power supply reliability entails monitoring BA Areas performance and coordinating BAs and TOPs actions, including instructions, for load curtailment, generation and transmission actions, and adjustments to voltage schedules in situations where the system is in jeopardy. SPP RC procedures and policies are consistent with those of NERC.

Operating agreements are in place to facilitate communication, notification, exchange of information, and coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability.

SPP RC communication mediums include phone, the SPP Reliability Communications Tool (R-Comm), the Reliability Coordinator Information System (RCIS), email, NERC Hotline, cellular phones, satellite phones, etc.

NOTE: Unless explicitly defined, any reference to "RC" is applicable to both East and West.

A. Responsibility and Authority

1. SPP has a wide-area view, operating tools, processes, procedures, authority and responsibility for the reliable operation of the Bulk Electric System (BES) within the SPP RC Areas in accordance with NERC Reliability Standards including applicable regional variances, the SPP Membership Agreement, SPP Required Data Specification (RDS), and SPP Reliability Customer agreements. These executed agreements are posted on the SPP website under SPP Documents & Filings/Governing.

    1.1. The SPP RC has a wide-area view, operating tools, processes and procedures to prevent or mitigate emergency operating situations in next day analysis and

real-time conditions. More details are provided in appropriate sections of this document.

1.2. The executed agreements give the SPP RC clear decision-making authority to act and instruct actions to be taken by the SPP RC Members and Reliability Customers to preserve the integrity and reliability of the BES. SPP's responsibilities and authorities, as well as its RC members' and customers' responsibilities are clearly defined in SPP's governing documentation.

2. SPP acts first and foremost in the best interest of the BES before that of any other entity. This expectation is clearly identified in the SPP Membership and Reliability Customer agreements, and in the job description of the SPP personnel acting in the role of the RC.

3. Per the SPP RC Member and Reliability Customer agreements, the BAs, TOPs, and other operating entities in the SPP RC Areas (i.e. West and East RC Areas) shall carry out required emergency actions as instructed by the SPP RC, including the shedding of firm load if required, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. In those cases, SPP RC Members or Reliability Customers must immediately inform the SPP RC of the inability to perform the operating instruction.

4. Weather-related event is to be determined in advance, based on weather evaluations, storm information, next day studies, etc., for action to be taken by SPP RC as necessary. The evaluation and coordination of analysis information may lead to issuing a Weather Advisory or Conservative Operations. In a coordinated effort, SPP has a process to exchange information related to weather events where SPP or a portion of SPP expects temperatures at a level that is of concern, or where tornado, ice storm, or high wind might be forecasted. Weather Advisories may be issued to prepare personnel and facilities for expected extreme weather conditions.

   4.1 For the Western Interconnection, SPP has a process to exchange information related to potential reliability impacted weather events, including utilizing R-Comm, emails, satellite phones, etc.

5. SPP Information Technology (IT) group maintains an awareness and level of protection from Cyber Attacks. SPP IT group has a process to determine if and when notifications should be made to Operations staff to increase awareness of potential cyber activities. In the event that Operations suspects or detects a Cyber Attack first, they will follow the process in accordance with the SPP Sabotage Procedure to notify the necessary parties.

6. In the event of the loss of a necessary application, SPP shall notify neighboring RCs, BAs, and TOPs to monitor the SPP RC Areas footprint when necessary.

B. Responsibilities – Delegation of Tasks

The SPP RC has not delegated any RC tasks. Communication and coordination are completed with adjacent RCs, yet no request for delegation of task or action is requested.

C. Common Tasks for Next Day Operations

1. SPP coordinates operations and ensures reliable operation of the BES by utilizing System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) during the real-time and next day operating horizons for the SPP RC Areas including additional thermal, voltage and stability-related analysis as necessary. SPP will communicate and coordinate the results of its reliability assessments with those performed by the SPP RC Members and Reliability Customers, to ensure that any potential or actual SOL exceedances are properly identified and reported. SPP models a sufficient wide-area view to ensure properly coordinated operations with neighboring RCs. SPP will share its Operational Planning Analysis (OPA) via its secure FTP site.

2. SPP is responsible for determination of IROLs within the SPP RC Areas, and does so via documented methodologies. As part of the daily OPA and/or RTA, SPP highlights additional potential SOLs. That list of potential SOLs and the existing list of SOLs are screened for potential IROL criteria. The potential IROL condition will be reviewed further by evaluating the system response to the loss of the SOL violated facility. The original potential IROL contingency will be assumed to be a confirmed IROL condition if the evaluation reveals that the ensuing SOL violated facility contingency results in cascading outages or widespread voltage problems, unless there are studies or system knowledge that the SOL is not an IROL. Additionally, when temporary constraints are defined for various operating circumstances identified through OPA and/or RTA, this process is performed to verify if an IROL exists. SPP disseminates IROL information within its RC Areas and with neighboring RCs.

3. SPP ensures that SPP RC Members and Reliability Customers operate to prevent the likelihood that a disturbance, action or non-action in the SPP RC Areas will result in an SOL or IROL exceedance in another entity of the Interconnection. SPP's RC Members and Reliability Customers are required to adhere to NERC Reliability Standards. SPP is required by its seams agreements with its neighbors to coordinate maintenance outages in such a way that impacts on the other systems' reliability are minimized. SPP performs OPA on a daily basis for the next day. If a potential SOL or IROL exceedance is observed on a neighboring party's system, SPP will coordinate with the impacted and impacting parties to develop an appropriate mitigation plan, if one does not already exist. In instances where there are differences in operating limits derived by SPP and its neighbors or between SPP entities, SPP will operate to the most conservative result until the reasons for these differences can be identified and an agreement is reached.

4. SPP ensures that its RC Members and Reliability Customers are always operating under known and studied conditions and ensures that they reassess and re-posture their systems following contingency events within 30 minutes. SPP performs next day OPA pursuant to the Reliability Assessment Process Overview. These analyses are performed for each day. These analysis model peak conditions for the day being studied including scheduled generation and transmission outages and anticipated generation dispatch to support the forecasted load plus net interchange. SPP performs an N-1 contingency analysis monitoring the post-contingency flow of both SPP and neighboring system facilities. If a potential SOL or IROL exceedance is observed, SPP will coordinate with the impacted and impacting parties to develop an appropriate mitigation plan if one does not already exist.

   SPP performs a next-day assessment of capacity and adequacy for each hour of the day, as well as a next-hour assessment of capacity and adequacy on an hourly basis. These analyses model peak conditions for the day/hour being studied including scheduled generation and transmission outages and anticipated generation dispatch to support the forecasted load plus net interchange. If a capacity issue is observed, SPP will coordinate with the impacted and impacting parties to develop an appropriate mitigation plan.

   SPP monitors, in real-time, all facilities considered critical. In the SPP EMS, real-time flows on all critical facilities are monitored and alarmed at the facility ratings, SOL and IROL levels. SPP tracks real-time and applicable post-contingency flows on all constraints and alarms when applicable SOLs and IROLs are approaching the limit or are exceeded. Additionally, when any identified IROL is exceeded in real-time, an email notification of the exceedance is sent to operations management and engineering staff to initiate post-event analysis.

   SPP also uses a State-Estimator solution to run its Real-Time Contingency Analysis (RTCA) application at least every 6 minutes. SPP has defined all branches and transformers with low side voltages of 115 kV and higher (with some 69kV) within the SPP RC Areas and all branches and transformers with low side voltages of 230 kV and higher within the first-tier BA Areas as contingencies in RTCA. SPP monitors the post-contingency flow on all SPP branches and transformers with low side voltages of 115kV and higher. Alarms are triggered if that flow exceeds the emergency rating of the branch or transformer. Additionally, SPP monitors post-contingency flow on all branches and transformers with low side voltages of 230 kV and higher within neighboring systems as well as selected lower voltage facilities within neighboring systems that are known to be impacted by an SPP contingency. The RC receives alarms for any RTCA exceedance.

5. The SPP RTO acts as the Transmission Service Provider (TSP) for all Transmission Owners in the Eastern Interconnection, subject to the SPP Tariff. For these entities,

SPP uses Flowgates as proxies for transmission limitations in the determination of ATC. The same Flowgates monitored in real-time by the SPP RC and their associated SOLs are also incorporated in the models used by SPP to calculate ATC and administer its OATT. SPP limits sales of transmission service to the SOLs of all identified Flowgates. When a need for a new Flowgate is determined by the SPP RC, the new Flowgate is included in the models used by the SPP TSP for calculation of ATC. These Flowgates are posted on the SPP OASIS.

5.1 SPP is not the TSP in the Western Interconnection, with the exception of WAUW.

6. SPP communicates reliability Operating Instructions in a clear, concise, and definitive manner. Per SPP RC procedures, the SPP RC requires the recipient to repeat back any reliability Operating Instructions communicated by the SPP RC. Proper communications protocols are included in Operator training provided by SPP.

D. Next Day Operations

1. SPP performs an OPA to identify potential SOL and IROL exceedances pursuant to the Daily Reliability Assessment Procedure. These analyses are performed daily with the exception of the weekend and holiday analyses being performed on the previous Friday, or day prior to the holiday. SPP's day-ahead reliability assessment consists of off-line PSS/E studies of the modeled system conducted by the Operations Engineering staff. Contingency-based analyses are conducted daily, which include Remedial Action Schemes (RAS). In these contingency analyses, at a minimum, SPP includes BES facilities in SPP and first-tier area above 100 kV as contingencies, and monitors facilities above 100 kV. SPP will include other facilities identified with impact to BES or with significant risk to the BES. SPP also runs a 7-day contingency analysis to review upcoming operating conditions over the next week for the Eastern Interconnection. Planned transmission and generation outages within the SPP RC Areas are coordinated with adjacent RCs. Outages external to the SPP RC Areas are obtained from neighboring RCs. Peak conditions are modeled using anticipated generation dispatch to support the forecasted load plus expected scheduled net interchange.

    1.1 If, in the next day OPA, parallel flows from the SPP RC Areas are observed as causing a potential problem on a neighboring system, SPP will contact the neighboring RC and coordinate to determine if the problem could result in an SOL or IROL exceedance. If it is agreed that an exceedance could occur, SPP will coordinate with the neighboring RC to develop an appropriate mitigation plan, if one does not already exist. The mitigation plan will identify appropriate actions to be taken to prevent the exceedance from materializing which may include creation of appropriate constraints to be monitored, commitment of appropriate generation capacity, reconfiguration of the transmission system, or re-dispatch of generation as well as actions to be taken in the event the

exceedance materializes in real-time, including identifying potential transmission system reconfigurations, generation that can be re-dispatched, schedules that can be curtailed, and, if necessary, load that can be shed.

2. SPP receives operating information, such as transmission and generation facility maintenance schedules, tap settings, and generation resource plans, required for performing an OPA from responsible SPP RC Members and Reliability Customers. The applicable SPP RDS requires SPP RC Members and Reliability Customers to submit the necessary data to SPP. SPP receives similar information from its neighbors. SPP uses load forecast, generation forecast, and/or tag data as its basis for incorporating Interchange Transactions into the OPA.

3. SPP shares the results of its OPA, when conditions warrant, or upon request, with other RCs. SPP also posts the results of its analyses via its secured FTP site for appropriate SPP RC Members, Reliability Customers, and neighboring RCs. If the results of the OPA indicate potential reliability problems and efforts outlined in (4.) below do not resolve the potential condition, the SPP RC issues the appropriate alerts via the RCIS.

4. The SPP RC initiates conference calls, or other appropriate communications, such as R-Comm, as necessary when conditions revealed by the OPA warrant. Conditions that warrant communications with other RCs include potential IROL exceedances determined as described in part 1.1 of this section and capacity deficiencies that could result in shedding of firm load.

E. Current Day Operations

1. SPP monitors facilities within the SPP RC Areas and adjacent RC Areas to ensure determination of potential SOL and IROL exceedances.

   1.1 SPP will make reasonable efforts to provide notice to a neighboring RC if SPP identifies a potential reliability problem in that RC's Areas. If both parties agree that a reliability problem exists, SPP will coordinate with its neighboring RCs any actions required to mitigate the situation. In the event that all parties cannot agree on the reliability issue, SPP will follow the most conservative approach. This coordination may include evaluation of the impact of maintenance and forced outages on the situation, implementation of existing emergency procedures or operating guides, reconfiguration of the transmission system, curtailment of point-to-point transactions, re-dispatch of generation, and load shedding.

2. In the SPP EMS, real-time flows on all critical facilities are monitored and alarmed at both SOL and applicable IROL levels. SPP uses constraint monitoring applications that track post-contingency flows on all constraints and alarms as applicable SOLs

and IROLs are approached and/or exceeded. Post-contingency flows on constraints are calculated using real-time flows and Line Outage Distribution Factors (LODFs) that are updated to reflect current system topography.

3. SPP monitors the necessary RC Area's parameters to ensure it is continuously aware of conditions within the SPP RC Areas.

   3.1. SPP monitors the status of BES elements using an EMS complete with State Estimator, Alarming, Real-Time Contingency Analysis, and Power Flow applications. SPP receives the data necessary to maintain the EMS from its RC Members and Reliability Customers in accordance with applicable SPP RDS.

   3.2. The SPP EMS model represents the SPP RC Areas, neighboring BA Areas and other portions of the Eastern and Western Interconnection. For the Eastern Interconnection, SPP's RC Area represents approximately one-third of the SPP EMS network model of Eastern Interconnection facilities. The EMS uses near real-time measurements received from these same entities via ICCP.

      3.2.1. For the Western Interconnection, SPP maintains a full model referenced from the Western Interconnection-wide Model (WIM) consistent with the Western Interconnection Modeling and Monitoring Methodology.

   3.3. SPP monitors, in real-time, pre-contingent and anticipated post-contingent element conditions. This is achieved through the EMS and constraint monitoring tools which utilize real-time Line Outage Distribution Factors based on the latest system topology.

   3.4. SPP monitors real-time flows and statuses of facilities 100 kV and above and select lower voltage facilities in the Eastern Interconnection. Contingencies of facilities with low side voltages of 115kV and higher within the SPP RC Areas as well as those with low side voltages of 230 kV and higher within neighboring systems are studied. The post-contingent flow on facilities with low side voltages of 115kV and higher within the SPP RC Areas as well as those with low side voltages of 230 kV and higher within neighboring systems are monitored.

      3.4.1. For the Western Interconnection, the monitoring of facilities is consistent with the Western Interconnection Modeling and Monitoring Methodology agreed upon according to applicable NERC standards.

   3.5. SPP monitors real and reactive reserves. SPP receives real-time operating reserves data from its RC Members and Reliability Customers, and compares this data to the operating reserves required. SPP monitors and displays the reactive output of generators within the SPP RC Areas as well as the remaining reactive capability by BA Area. SPP receives real-time voltages on critical buses

which alarm the RC when a voltage limit is exceeded. SPP will contact the appropriate TOP or BA as necessary to develop mitigation plans. SPP RC makes all reasonable efforts to provide notification and coordination of actions that may impact adjacent RC Areas for voltage control, including coordination of reactive resources.

3.6. SPP monitors voltage points based upon a ±5% tolerance around nominal voltage. This tolerance may vary per TOP and for nuclear power stations. When a high or low voltage alarm is received from the EMS system indicating limit violations, SPP will coordinate with the affected TOP to determine if the indicated voltage is correct and verify the TOP's voltage limits for that particular area. SPP will assist the affected TOP in developing a course of action to address undesirable voltage conditions including verifying and changing status of static reactive devices, reconfiguration, coordinating resource commitments, establish power transfer limits and re-dispatch as appropriate, etc.

3.7. The SPP RTO within the Eastern Interconnection monitors capacity and adequacy conditions through the SPP Reserve Sharing System (RSG) and market applications. SPP also receives resource plan information for all resources participating in the SPP Integrated Marketplace (Eastern Interconnection). This information contains data for each resource for each hour of a 7-day horizon beginning with the current day and is updated as necessary throughout the day. SPP will use this and other system information to perform hourly assessments of capacity and adequacy for the next hour.

3.7.1. For the Western Interconnection, SPP West RC will monitor capacity and adequacy conditions utilizing applicable RSG and BA submitted data as documented in the required data specifications.

3.8. SPP monitors current ACE and frequency in real-time for all BA Areas in the SPP RC Areas using the real-time data sent by the BAs through ICCP pursuant to applicable SPP RDS. This information is displayed to the SPP RC constantly.

3.9. SPP monitors current external impacts on its system from external network load, Market flows in the Eastern Interconnection, external generation to load (GTL) and transactions.

3.10. SPP receives and reviews resource plans and generation schedules from its Reliability Customers.

3.11. SPP monitors planned and unplanned transmission and generation outages. SPP's RC Members and Reliability Customers are required to submit all generator and transmission outages. Timing requirements and approval

procedures are documented in the applicable SPP Outage Coordination Methodology and applicable SPP RDS. The generator and transmission outages are sent to the Outage Scheduler database of the EMS system and used by the State Estimator and RTCA if the real-time measurements of the facility do not contradict with the submitted outage. The SPP RC Operators are constantly verifying the submitted outage data using State Estimator displays and its alarming application. They contact the appropriate SPP RC Member or Reliability Customer if a scheduled outage does not materialize in real-time as planned or if a line, transformer or unit trips without having a scheduled outage.

SPP utilizes graphical display systems designed to increase SPP RC situational awareness of the SPP RC Areas. The systems use near real-time and/or EMS data to provide a wide-area view.

4. SPP monitors BES parameters that may have significant impacts upon its RC Areas and neighboring RC Areas as follows:

4.1. SPP maintains awareness of all Interchange Transactions that wheel-through, Source, or Sink in the SPP RC Areas.

4.1.1. SPP acts as a Scheduling Entity on behalf of the Market Operating Entities or PSEs in its Eastern Interconnection RC Area by approving all transactions that wheel-through, Source and Sink in its Eastern Interconnection RC Area. SPP makes available its Eastern Interconnection RC tag information to all RCs in the Eastern Interconnection as necessary.

4.1.2. SPP is not a scheduling entity in the Western Interconnection. The RC maintains awareness of scheduling impacts on constraints through the Enhanced Curtailment Calculator (ECC).

4.2. SPP evaluates and assesses additional Interchange Transactions that could violate SOLs and/or IROLs. SPP utilizes Interchange information, real-time data in the SPP EMS, and SPP's constraint monitoring tools to make an assessment of the impacts of additional transactions on constraint loading. SPP is authorized to utilize all resources, including load shedding, to address a potential or actual IROL exceedances. This authorization is reiterated to each SPP RC Operator in their job description and by a personal memorandum from SPP's Chief Operating Officer (COO).

4.3. SPP monitors operational data submitted by BAs within the SPP RC Areas to ensure that the required amount of Operating Reserves are provided and available as required to meet NERC Control Performance Standards (CPS) and Disturbance Control Standards (DCS). If necessary, SPP will instruct the BAs in the SPP RC Areas to arrange for assistance from neighboring BAs. SPP has the

authority to instruct the acquisition of generation capacity and, if that instruction is not satisfied, instruct the shedding of load in the deficient BA Areas.

4.4. SPP will identify the cause of potential or actual SOL or IROL exceedances. SPP shall initiate control actions or emergency procedures to relieve the potential or actual IROL exceedance without delay, and no longer than 30 minutes. SPP will choose the most effective means of relieving the IROL exceedance within 30 minutes including instructing generation re-dispatch, facility switching, and load shedding. SPP is authorized to instruct utilization of all resources, including load shedding, to address a potential or actual IROL exceedance.

4.5. SPP will communicate start and end times for time error corrections to all BAs within its RC Area in both the Eastern and Western Interconnections.

4.6 SPP will review TOP submitted Geo-Magnetic Disturbance (GMD) plans and acknowledge, via email, of both receipt and review. SPP will ensure that all TOPs and BAs within its RC Areas are aware of GMD forecast information and will assist in the development of any required response plans. For GMD levels K8 or above, SPP RC will initiate a satellite phone call test to ensure satellite phone functionality has not been damaged during the event. SPP will communicate GMD forecast information to its BAs and TOPs via one or more of the following; R-Comm, email communication, ICCP, and/or phone communication.

While performing the role of the GMD monitor, for all K-7 or higher GMD warnings and alerts, SPP will participate in the Space Weather Prediction Center (SWPC) initiated phone communication with other Reliability Coordinators via the NERC Hotline and perform a roll call of RCs expected to participate. As the GMD monitor, SPP RC will contact RCs who did not participate in the SWPC call, provide details concerning the GMD notification and post a message to the Reliability Coordinator Information System and, for the Western Interconnection RCs, to R-COMM utilizing the blast message option outlining the GMD event information.

4.7. SPP will participate in NERC Hotline discussions, assist in the assessment of the reliability of the Regions and the overall interconnected system, and coordinate actions in anticipated or actual emergency situations. SPP will disseminate this information within its RC Areas as necessary.

4.8. SPP monitors system frequency and its BAs' performance, and if necessary, will instruct any rebalancing required for a BA to return to CPS and DCS compliance to ensure reliability. SPP receives at least one real-time frequency point via ICCP for each Balancing Authority Areas in the SPP RC Areas. At the instruction

of SPP, its BAs shall utilize all resources, including firm load shedding, to balance load and generation.

4.9. SPP coordinates with other RCs and neighboring BAs or TOPs, as needed, in the development and implementation of mitigation plans for potential or actual SOL, IROL, CPS or DCS exceedances. SPP coordinates pending generation and transmission maintenance outages with other RCs, as necessary, in both the real-time RTA and next day OPA timeframes. SPP participates in periodic conference calls with neighboring RCs as necessary.

4.10. SPP will assist the BAs in the SPP RC Areas in arranging for assistance from neighboring RCs or BAs by issuing reserve sharing contingency notifications (for the Eastern Interconnection SPP RSG Members) or EEAs as appropriate.

4.11. SPP identifies sources of large ACEs that may be contributing to frequency, time error, or inadvertent interchange and will implement corrective actions with the appropriate BA. SPP receives the real-time ACE for each BA Area in the RC Areas via ICCP. The SPP RC receives an alarm if any ACE values change significantly or exceed a predefined limit. Excessive ACEs would be addressed by a call to the BA to determine the cause of the deviation and the course of action that the BA has planned and/or implemented to address the situation. Assistance would be provided in the Eastern Interconnection RC Areas by accessing operating reserves with the SPP Reserve Sharing Group to address the deviation should that be required. Should the situation be causing overloads on system facilities, instruction would be issued to dispatch/re-dispatch generation to relieve the situation.

4.12. SPP maintains awareness that Special Protection System (SPS) or Remedial Action Scheme (RAS) within the SPP RC Areas are armed. The host BA/TOP is required pursuant to applicable SPP RDS to keep SPP informed of the operational status of the SPS. If there is concern with the state of an SPS/RAS, and if not previously informed, the RC shall contact the responsible TOP, or neighboring entity as applicable, to inquire about the SPS/RAS state change.

5. SPP will alert all affected BAs and TOPs in its RC Areas, and all affected RCs within the Interconnection when it foresees an IROL exceedance or a significant loss of real and/or reactive generation capacity within its RC Areas through OPA and/or RTA. SPP will disseminate this information to its BAs and TOPs, utilizing appropriate communication channels, such as R-Comm, verbal communications, etc.

6. SPP confirms RTA and/or OPA results and determines the effects within its RC Areas and adjacent RC Areas. SPP will derive and discuss options to mitigate potential or actual SOL or IROL exceedances and identify and implement only those actions as necessary as to always act in the best interest of the Interconnection at all times.

Communication and coordination are completed with adjacent RCs, yet no request for delegation of task or action is requested.

F. Emergency Operations

1. In the event the loading of transmission facilities progresses to, or is projected to progress to, an SOL exceedance, SPP will use congestion management processes to reduce the loading to prevent an exceedance as soon as practicable. In the event the loading of transmission facilities progresses or is projected to progress to an IROL exceedance, SPP will take immediate actions, but no longer than 30 minutes, to return loading to the facility rating up to and including load shed.

2. SPP maintains copies of all pertinent operating guides/instructions as supplied by SPP RC Members and Reliability Customers. SPP reviews and coordinates these instructions with the BAs and TOPs in the SPP RC Areas. The SPP RC Operator maintains communication with the Transmission Operator who may be implementing these guides for local area relief to ensure regional reliability is not jeopardized by the implementation of said procedures. SPP RC Operators will instruct the appropriate Transmission Operators to take specific actions on how to mitigate the situation.

3. For the Eastern Interconnection RC Area, SPP will comply with the provisions of the NERC TLR procedure as follows. If the SPP RC is the sink RC and receives notification via the IDC that another RC has issued a TLR that calls for curtailment and/or halts of transactions sinking in SPP, the SPP RC will use the IDC to acknowledge the transaction curtailments and/or halts for the next hour, or current hour, and monitor the transactions to ensure that the transaction curtailments/halts are properly implemented. SPP acts as the sink RC in the IDC for transactions sinking into ERCOT across the East and North DC ties and for transactions sinking into Western Interconnection across the Eddy County, Stegall, Blackwater, Rapid City, Miles City, Lamar and Sidney HVDC ties.

    3.1. If SPP determines, through Source-to-Sink impact evaluation, that curtailment of a transaction as identified by the IDC would actually increase flows on the constraint for which relief has been requested, it will not acknowledge curtailment of such transaction. SPP may also determine that, through Source-to-Sink impact evaluation, transactions having a significant impact on the constraint exist but are not identified for curtailment by the IDC. In those cases, SPP will instruct curtailment of those transactions as necessary.

    3.2. If SPP receives notification from the IDC that SPP has a Generation to Load (GTL) relief obligation in response to a TLR issuance, SPP will utilize its market systems to calculate and send dispatch instructions to its Market Participants (MPs) necessary to achieve the relief.

3.3. SPP will follow procedures included in Market Protocols and its operating procedures to implement relief procedures, up to and including the point that emergency action is necessary. When SPP observes constraint loading that approaches the applicable SOL, it will communicate with the constraint owner to verify actual real-time flows and coordinate necessary actions to be taken. SPP will make a coordinated decision based on current and/or anticipated conditions to pursue relief by using the congestion management process.

4. For the Western Interconnection, SPP will utilize the Western Interconnection Congestion Management Methodology, including Unscheduled Flow Mitigation Procedure (UFMP).

5. SPP will monitor system frequency and its BAs' performance. If SPP determines that one or more of its BA areas are contributing to a frequency excursion, SPP will instruct the BA(s) to use all resources available, including load shedding, to comply with CPS and DCS requirements.

6. SPP will take or instruct whatever action is needed, including load shedding, to mitigate an energy emergency within the SPP RC Areas. SPP will provide assistance to other RCs experiencing an energy emergency as necessary.

7. SPP requires that any BA Area within its RC Areas that is experiencing an energy emergency, first use Operating Reserves available within its applicable Reserve Sharing Group (RSG). If the energy emergency still persists, SPP will issue an EEA on behalf of the deficient BA Area.

G. System Restoration

1. SPP is knowledgeable of the restoration plans of each of the Transmission Operators in its RC Areas and has a written copy of each plan in its possession. SPP verifies that the most current plans are on file on an annual basis. During system restoration, SPP monitors the restoration progress and coordinates any needed assistance.

2. SPP has regional restoration plans for the SPP RC Areas that provides coordination between individual restoration plans of each SPP Transmission Operator and that ensures reliability is maintained during system restoration events. The SPP RC Areas Regional Restoration Plans and NERC Reliability Standards require that the role of the SPP RC during system restoration is to facilitate this coordination. Furthermore, the SPP RC approves, communicates, and coordinates re-synchronization of system islands or synchronizing points such that a burden is not caused on adjacent TOP, BA, or RC Areas. SPP Communications Protocols delineate the processes for Emergency Communications.

3. SPP will disseminate information regarding restoration to neighboring RCs and BAs/ TOPs not immediately involved in restoration by posting pertinent information on the RCIS and/or via phone call. SPP will also use the NERC Hotline for updates to other RCs as needed.

H. Facility

SPP performs the RC function at each of its two Coordination Centers. Each Coordination Center has the necessary facilities for the SPP RCs to perform their responsibilities. Full functionality is provided with full backup of the systems, communications, data, and tools required for SPP to perform as the RC for its RC Members and Reliability Customers. Both primary and alternate sites are staffed and functional 24x7.

1. SPP has redundant data communications between the two SPP sites, which are staffed 24x7 with working communications such as voice and data links between RC Member and Reliability Customer sites and SPP systems. SPP also employs a Voice-over-IP (VOIP) phone system that allows the phones to ring at both Coordination Center sites simultaneously. Cell phones are used as the alternate voice communication capability.

   SPP IT's 24x7 desk and additional on-call staff provide support of the voice and data communications, hardware, and software, working with communication service companies as appropriate.

2. A satellite phone system is installed at both of SPP's Coordination Centers as well as at all SPP RC Areas BA/TOP primary operations centers, for purposes of communicating during emergency conditions per SPP Communications Protocols. This system bypasses the Public Switched Telephone Network (PSTN) and can be used for point-to-point or broadcast (all-call) communications. The satellite service can also route a phone call to a land line, providing access to any operable wire or wireless phone.

3. SPP has detailed real-time monitoring capability of the SPP RC Areas and sufficient monitoring capability of surrounding RC Areas to ensure that potential or actual SOL or IROL exceedances are identified. SPP has monitoring systems that provide information that can be easily understood and interpreted, giving particular emphasis to alarm management and awareness systems, automated data transfers, synchronized information systems, over a redundant and highly reliable infrastructure. SPP monitors BES elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL exceedances within the SPP RC Areas. SPP monitors both real and reactive power system flows,

operating reserves, and the status of system elements that are or could be critical to SOLs and IROLs and system restoration requirements within the SPP RC Areas.

4. SPP utilizes two separate EMS clusters, an Authorized cluster and an Unauthorized cluster. If the Primary Location is lost, the primary EMS systems in the Alternate Location will automatically take over EMS functionality at the Alternate Location. As part of the EMS model upload and patching processes, all nodes of the primary and maintenance clusters are updated within the maintenance window.

5. SPP utilizes two separate ICCP clusters, a primary cluster and a back-up cluster (secondary ICCP). If the Primary Location is lost, the primary ICCP systems located in the Alternate Location will automatically take over primary ICCP functionality. As part of the ICCP model upload and patching processes, all nodes of the primary and maintenance clusters are updated within the maintenance window.

6. Per the applicable SPP RDS, SPP RC Members and Reliability Customers are required to send and receive near real-time data to both the primary and secondary systems concurrently as appropriate. Data from both systems are fed to the EMS providing an alternate data source for use when the primary source is failed for any reason.

I. Staffing

1. SPP 24x7 operations consists of four RC Operators and two Shift Engineers. The personnel is split between our primary and our alternate facilities with two RC Operators and one Shift Engineer at each location. These RC Operators and Shift Engineers are required to hold the NERC RC certification as well as being desk qualified at their position. SPP requires its RC Operators to complete yearly training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

2. SPP ensures that its RC Operators have a comprehensive understanding of the SPP RC Areas and required interaction with neighboring RCs. The SPP RC Operators have an extensive understanding of the RC Member and Reliability Customer systems within the SPP RC Areas such as staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities and restrictions. SPP makes year-round training opportunities available for the RC Operators, which includes the use of a Dispatcher Training Simulator (DTS) to provide realistic simulations of system emergencies described in the previous section.

   SPP creates training and performance support to ensure the SPP RC Operators understand the SPP region and the interface with neighboring regions. This includes opportunities for continuing education hours, including required

emergency operations and simulation hours. This training includes familiarization with Member BAs/TOPs by including RC training on the RC Members' and Reliability Customers' operating guides, system configuration, and transmission facilities. Control Center evacuation training and performance-based exercises are provided annually through instructor-led courses. Operations personnel who have a role in the evacuation plan are required to participate in the evacuation training and performance-based exercise annually. In addition, SPP conducts regional system restoration drills annually.

SPP's training department documents all training for recordkeeping and reporting purposes. All information required by the NERC Continuing Education program is available in a variety of report formats.

3. An Officer of SPP has signed the NERC Reliability Coordinator Standards of Conduct on behalf of the SPP RC. Each SPP RC Operator is required to sign and receive training on the SPP Standard of Conduct annually. The SPP Standard of Conduct requires the signatory to maintain proper confidentiality procedures and processes. SPP is an independent organization with an independent Board of Directors. SPP's independence enables its staff to fully comply with both the NERC and SPP Standards of Conduct.

Appendix A – BAs and TOPs in SPP RC Areas

Balancing Authorities and Transmission Operators in the SPP Reliability Coordination Areas:

Entity	BA	TOP	East	West
Arlington Valley Power Cooperative (AVBA)	X			X
American Electric Power – West (AEP)		X	X	
Arizona Electric Power Cooperative/SW Transmission Coop (AEPC)		X		X
Black Hills Corporation (BHE)		X		X
City Utilities of Springfield (CUS)		X	X	
Colorado Springs Utilities (CSU)		X		X
Corn Belt Power Cooperative (CBPB)		X	X	
El Paso Electric (EPE)	X	X		X
Empire District Electric Company/Liberty Utilities (EDE)		X	X	
Farmington Electric Utility System (FEUS)		X		X
First Light Energy (BNBA)	X			X
Grand River Dam Authority (GRDA)		X	X	
City of Independence Power & Light Department, Missouri (INDP)		X	X	
Gridforce Energy Management (GRID)	X			X
CORE Electric Cooperative (CORE)		X		X

Entity	BA	TOP	East	West
ITC Great Plains (ITC)		X	X	
The Board of Public Utilities, Kansas City, Kansas (BPU)		X	X	
Kansas City Power and Light Company (KCPL)		X	X	
KCP&L Greater Missouri Operations Company (UCU)		X	X	
Lincoln Electric System (LES)		X	X	
Midwest Energy, Inc. (MIDW)		X	X	
Nebraska Public Power District (NPPD)		X	X	
Oklahoma Gas and Electric (OKGE)		X	X	
Omaha Public Power District (OPPD)		X	X	
Platte River Power Authority (PRPA)		X		X
Public Service of Colorado (PSCO)	X	X		X
Sunflower Electric Power Corporation (SEPC)		X	X	
Southwest Power Pool (SPP)	X		X	
Southwestern Power Administration (SPA)	X	X	X	
Southwestern Public Service Company (SPS)		X	X	
Tri-State G & T (TSGT) *		X	X	X
Tucson Electric Power (TEPC)	X	X		X
Western Areas Power Administration (WACM)	X	X		X
Western Areas Power Administration (WALC)	X	X		X
*Western Areas Power Administration (WAUE)		X	X	
Western Areas Power Administration (WAUW)	X	X		X
Western Farmers Electric Cooperative (WFEC)		X	X	
Westar Energy, Inc. (WRGS)		X	X	

**Eastern and Western Interconnections*

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-21

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit I: Department, Order No. 202-25-7 (Aug. 20, 2025)

Order No. 202-25-7

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. §7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order No. 202-25-3

J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, MI. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[1] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order No. 202-25-3, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until August 21, 2025. That order was based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO). Specifically, I determined that MISO likely faced tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety. I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability. My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[2] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply

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[1] *See Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, Consumers Energy (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation. As a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline.

[2] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[3]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[4] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[5] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it was not projected to be available during the peak demand period this summer.[6]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."[7]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[8] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and these results "reinforce the need to increase capacity."[9]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-3 continue, both in the near and long term. The summer season has not yet ended, and the production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO this summer. That need is evidenced by the fact that the Campbell Plant was called on by MISO to generate large amounts of electricity during the heat wave that hit MISO this past June. According

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[3] *Id.*
[4] *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.
[5] *Id.*
[6] The start-up of Palisades is scheduled for the fourth quarter of 2025.
[7] NERC 2025 Summer Reliability Assessment at 16.
[8] *Planning Resource Auction—Results for Planning Year 2025–2026,* Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).
[9] *Id*. at 2,12.

to the U.S. Environmental Protection Agency's data, over the month of June, the Campbell Plant generated approximately 664,000 MWh, running at 61% capacity.[10] In fact, between June 11 and August 18, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits. MISO issued alerts for the Central Region on at least 40 of the 69 days between June 11 and August 18. In June, MISO issued alerts affecting the Central Region on 18 days, including an Energy Emergency Alert (EEA) level 1 ("Max Gen Step 1b") on June 23 to enable MISO to take emergency action to ensure grid stability, including bringing additional resources online.[11] The Central Region had alerts on 21 days in July, including one Max Generation Warning on July 29 and two Max Generation Alerts on July 28 and 29.[12] Two Capacity Advisory Initiate alerts have been issued in August to date.[13] Moreover, the May 2025 NERC Summer Reliability Assessment referenced a Seasonal Outlook issued by the National Oceanic and Atmospheric Administration (NOAA), which estimates that much of the Midwest has a 33%-40% chance to experience above-normal temperatures this summer.[14] The Seasonal Outlook released by NOAA on July 17, 2025, increased this estimate for much of the region to a 40%-50% chance.[15]

MISO's resource adequacy problems are not limited to the summer. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[16] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round

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[10] *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data),* https://campd.epa.gov/data/custom-data-download *(search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June." The data can then be filtered to only include the Campbell Plant.)*

[11] An Energy Emergency Alert is an alert declared by the Transmission Provider in accordance with the NERC Operating Manual associated with the Transmission Provider's inability to provide for the Energy and Operating Reserve requirements of the MISO Balancing Authority Area. For more information, see MISO, FERC Electric Tariff, Module A, § 1.E (Definitions) (92.0.0). For more information on Energy Emergency Alert levels, see North American Electric Reliability Corporation. (n.d.). *EOP-011-1 Emergency Operations*. https://www.nerc.com/pa/stand/reliability%20standards/eop-011-1.pdf.

[12] A Max Gen Alert occurs when MISO is forecasting a potential capacity shortage. A Max Gen Warning is a warning to prepare for a possible Max Gen Event. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[13] A Capacity Advisory alert is an advisory issued based on the potential for limited operating capacity margins (<5%) in the following 2-3 days. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[14] NERC 2025 Summer Assessment at 9.

[15] *Seasonal Outlook*, NOAA Climate Prediction Ctr., (July 17, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.

[16] M*idcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. Midcontinent Independent System Operator, Inc., 180 FERC ¶ 61,141 (2022).

concern."[17] MISO noted that over 60 percent of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[18]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[19] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[20]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[21] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[22]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[23]

On June 6, 2025, subsequent to the issuance of Order No. 202-25-3, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy

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[17] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).
[18] *Id.* at 3-4.
[19] *Attributes Roadmap*, MISO (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[20] *Id.* at 11.
[21] *MISO's Response to the Reliability Imperative*, MISO (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[22] *Id.* at 12.
[23] MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.

planning reserve margin requirements.[24] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[25] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[26] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[27]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[28] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[29]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[30] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three year grace period to commence commercial operations.[31] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[32] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

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[24] *2025 OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.
[25] *Id.* at 2.
[26] *Id.* at 7.
[27] *Id.* at 9.
[28] *Id.* at 7, 9.
[29] *Id.*
[30] M*idcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).
[31] 192 FERC ¶ 61,064 at P 84.
[32] *See generally, US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global. "With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."

Order 202-25-3 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[33] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[34] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[35]

The Department's July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[36] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[37] In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[38]

Grid operators—including MISO itself—have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the

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[33] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[34] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[35] *Id*.

[36] *See also Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[37] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

[38] *See Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center*, Data Center Dynamics (August 05, 2025), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/ (quoting Consumers Energy CEO Garrick Rochow).

changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[39] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[40] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[41]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[42] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-3 will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest under FPA section 202(c).

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until November 19, 2025.[43]

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[39] Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-media-document/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf.

[40] *Id.* at 6.

[41] *Id.* at 7.

[42] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b) (2018).

[43] 16 U.S.C. § 824a(c)(4).

Based on my determination of an emergency set forth above, I hereby order:

A. From August 21, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By September 4, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective from 00:00 Eastern Daylight Time (EDT) on August 21, 2025, and shall expire at 00:00 EDT on November 19, 2025, with the exception of applicable compliance obligations in paragraph D.

I. Issued in Norfolk, Virginia at 8:50pm Eastern Daylight Time on this 20th day of August 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners
Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-21

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit II: NERC, *Emergency Operations*

A. Introduction

1. Title: **Emergency Operations**

2. Number: **EOP-011-4**

3. Purpose: To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.

4. Applicability:

4.1. Functional Entities:

4.1.1 Balancing Authority

4.1.2 Reliability Coordinator

4.1.3 Transmission Operator

4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. Effective Date: See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. Cold weather conditions; and

1.2.6.2. Extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has

been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. Capability and availability;

2.2.3.2. Fuel supply and inventory concerns;

2.2.3.3. Fuel switching capabilities; and

2.2.3.4. Environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load, and demand response;

2.2.8. Provisions for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. Extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator;

evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator

communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

8.1. Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

8.1.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

8.1.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual

Load shed to situations where warranted by system conditions; and

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.
R4	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Alert.
R7	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR more of those entities 60 days or more late.
R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by the NERC Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by the NERC Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
3	October 26, 2022	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094	
4	October 23, 2023	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
4	February 15, 2024	FERC Order issued approving EOP-011-4. Docket No. RD24-1-000	

Attachment 1-EOP-011-4
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-21

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit J: CoPUC, 120 Day ERP Implementation Report, Public, filed on April 11, 2025, in Proceeding No. 23A-0585E

Colorado PUC E-Filings System



Tri-State Generation and Transmission Association, Inc.

2023 Electric Resource Plan

Phase II Implementation Report

PUBLIC VERSION

(Colorado Public Utilities Commission Proceeding No. 23A-0585E)

NOTICE OF CONFIDENTIALITY

A portion of this document has been filed under seal.

Confidential Information has been redacted in the following documents.

- Report Pages 26, 27, 37, 38, 48, 49, 59, 69, 70, 80, 81
- Attachment B

Highly Confidential Information has been redacted in the following documents:

- Attachments B, B-4, B-7, B-8, C, C-1, D-1, D-2, D-3, D-4, D-5, D-6, F-1, F-2, F-3, G

April 11, 2025

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Executive Summary

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a wholesale electric generation and transmission cooperative association with Utility Member Systems located across Colorado, Nebraska, New Mexico, and Wyoming.

This report is Tri-State's 2023 Electric Resource Plan (ERP) Phase II Implementation Report. The report complies with applicable Colorado Public Utilities Commission (CoPUC) Rules and Decisions as identified in Attachment A.

Tri-State's preferred portfolio is Portfolio 4 – New ERA Gas Flexibility Shafer Replacement (FLEXSR). The FLEXSR portfolio adds 700 MW of wind and solar, 650 MW of storage, and 307 MW of gas between 2026-2031, replaces the turbines at J.M. Shafer to improve its capacity contributions,[1] maintains the previously announced Craig 3 and SPV 3 retirement dates, and results in a generation portfolio that meets both Level 1 and Level 2 Reliability Metrics, the Colorado GHG emissions reduction targets,[2] the Colorado Renewable Energy Standard, and the New Mexico Renewable Portfolio Standard, all while avoiding costly transmission upgrades identified in other portfolios—making FLEXSR the least-cost portfolio.[3] This portfolio, which selects 1,657 MW of new resources from the 2024 Requests for Proposals (RFPs), reflects Tri-State Members' strategic directive to ensure reliable, affordable, and responsible service, and also addresses the CoPUC's recent concerns "…regarding the large, unexpected cost increases in transmission investments…" and a "need to improve [ ] transmission modelling and cost estimation processes in future ERP proceedings…"[4] The CoPUC Commissioners have also identified their concern in recent public meetings, recognizing that generation selected through ERPs has been "agnostic" in terms of evaluating associated transmission expenses and indicating a desire to "…analyze and optimize…options to ensure that our generation selection…to ensure that we're looking at optimizing costs across the system including the transmission system…"[5] Tri-State's approach to bid selections in the FLEXSR portfolio directly addresses these concerns, as described in detail in Attachment G.

Tri-State has selected the FLEXSR portfolio as a result of the portfolio's overall performance across the reliability, environmental, and financial categories analyzed and described in this report. Tri-State has taken steps to initiate a Resource Solicitation Cluster (RSC) for entering FLEXSR bids into Tri-State's Generator Interconnection through its Open Access Transmission Tariff (OATT) Large Generator

[1] The Shafer replacement is described in Attachment H.

[2] 2020 ERP Phase I Settlement Agreement, at Section 3.3.4 (Proceeding No. 20A-0528E): "Tri-State agrees that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its APCD-verified 2005 Baseline, the following reductions in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado (the "Interim-Year Emissions Reductions"): A twenty-six percent (26%) reduction in calendar-year 2025; a thirty-six percent (36%) reduction in calendar-year 2026; and a forty-six percent (46%) reduction in calendar-year 2027."

[3] Lowest PVRR, exclusive of SCoC and SCoM.

[4] These concerns arose in other recent Phase II proceedings. *See* Decision No. C24-0052, at ¶ 158 in Proceeding No. 21A-0141E (issued January 23, 2024).

[5] CWM March 5, 2025, Commissioner Gilman at 1:12:31 and 1:12:53. Publicly available at: https://www.youtube.com/watch?v=dol_38ci5dU.

Interconnection Process. Four of the ten bids already have a queue position and therefore do not need to be part of the RSC study. The benefits of FLEXSR over other portfolios are reflected in the analyses presented in this Phase II report.

Portfolio Analysis Summary

Tri-State modeled six portfolios for Phase II of the 2023 ERP and created three back-up bid pools, as identified in Attachment B-3. All of the Phase II modeling reflected input assumptions based on the best available information available at the start of modeling, reflective of any known Tri-State system constraints and compliance requirements, as described in Attachment B and Attachments B-1 through B-8.

Tri-State remains in a capacity-long position until 2030;[6] however, resource acquisitions are required through this Phase II for ensuring ongoing resource adequacy and reliability as two coal units are retired in 2028 and 2031 and to maintain progress toward emission reductions for Colorado statutory compliance as well as for New ERA funding eligibility. Waiting to procure resources needed for 2030 until the 2027 ERP would not be prudent given that the 2027 ERP Phase II process may not conclude until late 2028 or early 2029; however, Tri-State is cautious to not pursue new resources based on speculative loads. At the same time, retirement of dispatchable coal resources cannot be affordably or reliably replaced solely with semi-dispatchable resources. The new resources, including the dispatchable gas plant in Moffat County, will provide jobs and tax base that support community vitality across many areas of our system.

Tri-State considered the Social Cost of Carbon (SCoC) and Social Cost of Methane (SCoM) when determining which Phase II portfolio was preferred, including analysis of the environmental and financial comparisons shown in the Comparative Analysis section of this report. Tri-State has taken these comparisons into significant account in determining that our preferred portfolio in Phase II is the best course of action at this time. Tri-State's preferred portfolio achieves the lowest present value of revenue requirements (PVRR), meeting the affordability expectations of Tri-State Members in avoiding the risks associated with procuring bids selected in other portfolios at a higher cost that do not yield impactful environmental or reliability attributes.

All of the Phase II portfolios meet essential reliability targets, while achieving an 80 percent GHG emissions reduction in Colorado in 2030 (with respect to the 2005 baseline)[7] reflective of Colorado policy.[8] However, the other portfolios analyzed result in significant, unnecessary financial burdens by aggressively pursuing resources with high transmission interconnection upgrade costs that are not necessary to achieve the same operational, environmental, and reliability benefits resulting from procurement of FLEXSR bids. Tri-State is keenly aware of the economic challenges its Members face in rural America. Demographic data indicates 59 percent of our service area is considered economically disadvantaged or distressed.[9] Tri-State is not in a position to pursue generation procurements that

[6] *See* Table 2, Loads and Resources, submitted in the 2024 ERP Annual Progress Report filed December 2,2024 in Proceeding No. 23A-0585E.
[7] See Attachment D.
[8] §25-7-105(1)(e)(VIII)(I), C.R.S.
[9] U.S.D.A.: https://ruraldevelopment.maps.arcgis.com/apps/webappviewer/index.html.

would cause significant undue financial burdens for Members[10] or compromise its ability to meet the core reliability expectations of its Members.

Additional details on the comparative analysis Tri-State completed to support its preferred portfolio selection can be found in the Comparative Analysis section of this report.

Addressing Commission Rule 3605(h)(II)

The Commission must consider the following factors in issuing a Phase II decision:

> *In accordance with §§ 40-2-123 and 40-2-124, C.R.S., the Commission shall consider renewable energy resources, resources that produce minimal emissions or minimal environmental impact, energy-efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.*

Phase II of Tri-State's 2023 ERP included RFPs for a diverse mix of renewable, storage, and dispatchable resources located across the Tri-State system. Bidders were required to provide Best Value Employment Metrics (BVEM) information identifying Colorado employment benefits.[11] The Phase II portfolio analysis reflected GHG Targets (2025, 2026, 2027, and 2030),[12] Energy Efficiency Targets (2024, 2025, and 2030),[13] and Demand Response Targets (2025 and 2030)[14] as agreed upon in the Settlement Agreements in Phase I of the 2020 and 2023 ERPs.

Colorado's energy security, economic prosperity, and insulation from fuel price increases are best supported by a Tri-State portfolio that is diverse in the type, size, location, and operations of generation, including through bid procurements that avoid costly transmission network upgrades. Tri-State developed, in consultation with stakeholders, a set of robust reliability criteria in 2022, updated reflective of a third-party 2024 EWE Study, and tested portfolios' extreme weather event (EWE) sensitivities to ensure future resource additions can meet the necessary reliability and resource adequacy needs of its Members. The FLEXSR preferred portfolio meets these rigorous standards, both affordably and responsibly.

The preferred portfolio will continue to advance the environmental objectives of the State of Colorado because it is forecasted to achieve the Colorado GHG Targets. The GHG reductions were calculated using the Colorado Air Pollution Control District's (APCD) emissions workbook methodology.

[10] Tri-State is subject to Federal Energy Regulatory Commission rate jurisdiction, as of September 3, 2019.
[11] *See* HIGHLY CONFIDENTIAL Attachment F-1.
[12] 2020 ERP Settlement Agreement, at Section 3.3.4. (Proceeding No. 20A-0528E).
[13] 2020 ERP Settlement Agreement, at Section 3.11.9. (Proceeding No. 20A-0528E).
[14] 2020 ERP Settlement Agreement, at Section 3.11.8. (Proceeding No. 20A-0528E); 2023 ERP Settlement Agreement, at Section 4.9.1. (Proceeding No. 23A-0585E).

In accordance with § 40-2-129, C.R.S., the Commission shall determine: whether the utility has provided best value employment metrics; whether the utility has certified compliance with the objective standards for the review of such best value employment metrics as set forth in the RFP approved in the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility.

Tri-State has provided BVEM provided by bidders, for the bids advanced to modeling, in HIGHLY CONFIDENTIAL Attachment F-1.

Tri-State included evaluation of BVEM as a non-price factor in its bid evaluation, as described in the Bid Evaluation section of this report.

Tri-State intends to enter into power purchase agreements (PPAs) and Engineering, Procurement, and Construction contracts (EPCs) for the preferred portfolio generation and storage facilities; therefore, the developers and EPC contractors will be responsible for determining whether a project labor agreement will be used.

In accordance with § 40-2-134, C.R.S., the Commission shall determine whether the final cost-effective resource plan meets the energy policy goals of Colorado.

The FLEXSR preferred portfolio is the most cost-effective portfolio modeled, having the lowest PVRR. The preferred portfolio also complies with all applicable rules and regulations in the state of Colorado, including achieving at least an 80 percent reduction in GHG emissions by 2030 while continuing to ensure affordable and reliable service.

In accordance with § 40-3.2-106(3), C.R.S., the Commission shall consider the net present value of the cost of carbon dioxide emissions, the net present value of revenue requirements of the cost-effective resource plan, and other relevant factors as determined by the Commission in its Phase I decision.

The FLEXSR preferred portfolio has the lowest PVRR among the portfolios modeled, including analysis for optimization of interconnection cost as described in Attachment G. Tri-State considered the SCoC in its review of the portfolio modeling results as described in the Portfolio Analysis Summary section above and in the Comparative Analysis section below.

Stakeholder Engagement

Tri-State has engaged transparently and collaboratively in stakeholder engagement throughout the 2023 ERP. Numerous stakeholder groups representing a diverse set of interests participated in meetings in advance of Tri-State's filing of this Implementation Report. These discussions provided an opportunity to further educate stakeholders on the complexities of the Tri-State system, inform parties of key modeling inputs and assumptions, and facilitate dialogue on topics applicable to Phase II. These stakeholder meetings occurred between December 2023 and March 2025, covering the following topics:

1. November 29, 2023: Briefing on 2023 ERP Phase I Filing

2. January 24, 2024: EWE Focus Group[15] Meeting #1
3. March 1, 2024: EWE Focus Group Meeting #2
4. March 21, 2024: EWE Focus Group Meeting #3
5. April 23, 2024: 2024 DSM Roundtable Meeting (1 of 2)
6. June 11, 2024: FERC Filing Updates
7. September 24, 2024: Meeting on USDA Guidance and Phase II Portfolios[16]
8. October 30, 2024: Meeting on EWE[17]
9. December 10, 2024: 2024 DSM Roundtable Meeting (2 of 2)
10. December 23, 2024: Colorado PUC Staff Meeting on MIP[18]

Several e-mail communications and updates to stakeholders also occurred in advance of and during Phase II modeling with the aim of ensuring communications on key Phase II topics. Tri-State maintains ongoing collaboration with interested stakeholders across a variety of electric sector topics.

Bid Evaluation

Tri-State issued three Phase II RFPs on September 13, 2024. Tri-State's bid evaluation process was undertaken over a 45-day period following the close of the RFPs on October 28, 2024.[19] The bid evaluation process, completed prior to advancing projects to Phase II computer-based modeling, consisted of several steps – including a completeness screen, an economic screen, an interconnection/transmission screen, and a non-price factor screen.

The ***completeness review*** included an assessment of whether bids provided required information, such as fully completed bid forms or other narrative requirements. This screen also ensured submittal of the required bid fee(s). When bid information appeared incomplete or unclear, Tri-State contacted the bidders and provided them approximately two business days to supplement their bids with the necessary information to enable the bids to move forward in the bid evaluation process.

Following the completeness review, bids were sorted by technology type (wind, solar, etc.) and passed through an ***economic screen***. Either a levelized cost of energy (LCoE) or leveled cost of capacity (LCoC) was evaluated, depending on the technology type, as identified in the table below.

Table 1: Economic Screen by Technology Group Applied to Phase II Bids

LCoE	LCoC
Solar	Standalone Battery
Wind	Dispatchable Combustion Turbine
Solar + Battery	Dispatchable Natural Gas with CCS
Wind + Battery	
Geothermal	

[15] EWE Focus Group included Tri-State, Tri-State's Wyoming Members, Grid Lab, Sierra Club and their consultants, and Rocky Mountain Institute (RMI).
[16] 2023 ERP Settlement Agreement, at Section 4.4.3 (Proceeding No. 23A-0585E).
[17] 2023 ERP Settlement Agreement, at Section 4.8.3 (Proceeding No. 23A-0585E).
[18] 2023 ERP Settlement Agreement, at Section 4.4.8 (Proceeding No. 23A-0585E).
[19] The dispatchable RFP bid deadline was extended to November 27, 2024 due to the limited number of bids received.

Bids in each technology group, in various size ranges, were advanced to the transmission and interconnection screen if the costs were at or below the latest generic resource pricing and/or where other size, locational, or diversity considerations were applied.

The ***interconnection/transmission screen*** included a review of project/facility sizes (capacity), point of interconnection (POI), transmission provider, and queue status and transmission/interconnection provider verification. Bidders were expected to clearly identify projected interconnection and transmission costs in their proposals as well as reflect these costs in the prices associated with each bid. Tri-State's Transmission Planning team reviewed each bid's viability and the reasonableness of associated cost estimates. The viability screen focused on the ability of the transmission system to accommodate the new firm resource and the ability to construct the project, including network upgrades and interconnection facilities by the identified in-service date. Cost estimates were reviewed to ensure bids factored in a reasonable level of network upgrade and interconnection facility costs to integrate the project at the identified point of interconnection. Finally, Tri-State's Transmission Planning team verified whether the project was in an interconnection queue based on the information provided by the bidder. For projects achieving commercial operation in 2026 or 2027, bidders were required to be in an interconnection queue under a transmission provider's generator interconnection process. For those projects whose commercial operation dates (COD) were anticipated to be after 2027, bidders were encouraged to be in an interconnection queue, however, this will not be a requirement in the interconnection/transmission screen.

For projects under a PPA structure, interconnection with the Tri-State transmission system was viewed more favorably than those projects connecting to a third-party transmission system. For projects in which Tri-State was seeking ownership, interconnection with the Tri-State transmission system was required. The interconnection/transmission provider was noted as part of the interconnection/transmission screen.

Projects that did not receive favorable evaluation results during the interconnection/transmission screen were eliminated from further consideration in the bid evaluation process. In cases where the interconnection/transmission screen identified certain flawed aspects of an otherwise viable bid, related primarily to cost and/or in service date assumptions, Tri-State contacted bidders for clarification and cost updates.

Lastly, Tri-State conducted a ***non-price factor analysis*** of the bids that emerged from the interconnection and transmission screen. The non-price factor analysis considered project capabilities across four categories: community stewardship, counterparty profile, project feasibility, and project capability. The factors are identified in the table below.

Table 2: Non-Price Factors

Category	Factor
Community Stewardship	• Best Value Employment Metrics • Contribution to meeting GHG reductions in Colorado • Location in a Tri-State Member System • Location in Moffat County or West End of Montrose County • Community Benefits
Counterparty Profile	• Bidder's prior experience with project development

	• Bidder's record of litigation related to power supply agreements and failure to honor bids from prior solicitations, or failure to complete projects as proposed • Financial viability of the bidder • Markup of PPA or term sheet terms and conditions
Project Feasibility	• Certainty of financing and outside funding sources to include tax credits or government subsidies/incentives • Compliance with all applicable local, state and federal laws, rules and orders, and processes; permit(s) identification and status • Local opposition or community efforts to stop project development • Ability to source materials • Project retirement/decommissioning plan • Legal, engineering and other costs required to implement the proposed project
Project Capability	• Renewal and purchase options at end of PPA (if applicable) • Impact on scheduling project output to Tri-State load • Operational flexibility

Projects with overall favorable non-price factor analysis were advanced to modeling; however, poor evaluation results in certain non-price factor categories resulted in a project not being advanced to modeling.

Bids Received

Tri-State received 145 individual eligible bid proposals by the bid deadline, as identified in the 45-Day Report filed in Proceeding No. 23A-0585E on December 12, 2024. A total of 52 bids were advanced to modeling, as shown in HIGHLY CONFIDENTIAL Attachment C, following the bid evaluation described above. On December 5, 2024, Tri-State notified bidders whether their projects had advanced to modeling and offered a price refresh opportunity per Tri-State's Bid Policy,[20] due December 9, 2024. For bids not advanced to computer-based modeling, and for which bidders requested additional feedback on their bids, Tri-State identified at which stage of the bid evaluation process the bid failed to pass a screen and offered an opportunity for further discussion at or near the conclusion of Phase II. Tri-State also provided details in its 45-Day Report[21] identifying how many bids failed to pass each screen and factors that caused bids to fail at each screen.

Table 3: Summary of Bids Advanced to Modeling by Technology Type

Technology Type	Total (# of Bids)	MW	MW BESS
Solar	12	2,303	-
Wind	6	1,218	-
Solar+Battery	12	2,049	907
Wind+Battery	1	180	100
Short-Duration Storage	16	-	2,200

[20] Hearing Exhibit 102 Attachment SKH-7 (Proceeding No. 23A-0585E).

[21] https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1032592&p_session_id=

Long-Duration Storage	1	-	100
Gas Plant	2	495	-
Gas Tolling	1	314	-
Geothermal	1	20	-
TOTAL	**52**	**6,579**	**3,307**

Commission Rule 3605(h)(I)(A)(iii) requires that Tri-State "provide the Commission with the best value employment metrics information provided by bidders." The BVEM information provided by bidders whose bids were advanced to modeling is provided in Attachment F-1. As identified in Table 2 above, BVEM is a non-price factor analyzed by Tri-State as an element of bids' community stewardship.

Tri-State is also providing to the Commission and stakeholders a mapping of the bid project locations overlayed with a map of disproportionately impacted (DI) communities, in Highly Confidential Attachment C-1.[22] The file contains five maps: 1) all bids with DI overlay, 2) bids advanced to modeling with DI overlay, 3) bids selected in portfolio modeling with DI overlay, 4) bids selected in the preferred portfolio with DI overlay, and 5) bids selected in the preferred portfolio with Tri-State Member territories overlay.

Bids Selected in Portfolio Modeling

Table 4 identifies the bids selected in one or more of the portfolios modeled.

Table 4: Bids Selected in Portfolio Modeling

Bid	Technology Type	MW	Portfolios					
			1 – NEE	2 – NELG	3 – FLEX	4 – FLEXSR	5 – NNG	6 – NNGSR
PV-0004-4-nm	Solar	100	☒	☒	☒		☒	
PV-0004-5-wco	Solar	140	☒	☒			☒	
PV-0006-8-eco	Solar	200				☒		☒
WI-0013-2-wyo-wne	Wind	200	☒	☒	☒	☒	☒	☒
WI-0013-3-eco	Wind	200	☒	☒		☒	☒	☒
WI-0016-1-eco	Wind	297			☒			
PC-0009-2P-eco	Solar / Battery	150 / 75	☒	☒	☒		☒	
PC-0018-1P-nm	Solar / Battery	100 / 50	☒	☒	☒	☒	☒	☒
ST-0002-5-wco	4hr - Battery	50	☒	☒	☒	☒	☒	☒
ST-0002-6-wco	4hr - Battery	100		☒				
ST-0004-10-eco	4hr - Battery	100		☒		☒	☒	☒
ST-0004-6-eco	4hr - Battery	150				☒		☒
ST-0004-8-wco	4hr - Battery	200					☒	☒
ST-0004-9-eco	4hr - Battery	100					☒	☒
ST-0009-3-wco	4hr - Battery	200	☒	☒	☒	☒	☒	☒
ST-0009-4-nm	4hr - Battery	100	☒	☒	☒	☒	☒	☒
ST-0010-4-eco	4hr - Battery	150			☒		☒	☒
ST-0017-1-eco	4hr - Battery	100	☒	☒	☒		☒	☒
ST-0018-1-eco	4hr - Battery	50			☒		☒	
ST-0019-1-eco	Iron Air Battery	100	☒				☒	

[22] 2023 ERP Settlement Agreement, at Section 4.10.2. (Proceeding No. 23A-0585E).

GG-0006-1-wco	Combustion Turbine	307		☒				
GG-0006-2-wco	Combustion Turbine[23]	307	☒		☒	☒		

Independent Evaluator

Tri-State utilized the services of a third-party Independent Evaluator (IE) to support RFP administration, and to validate the bid evaluation process and results. The role of the IE was to ensure fairness, transparency, and consistency in Tri-State treatment of bids.

In order to provide the bidder a paperless (electronic only) experience and prior to the Phase II RFP release, the IE assisted Tri-State with web hosting, website development, and web-form development to provide a standardized bidder experience by hosting the following services: RFP website and bidder registration, notice of intent and non-disclosure agreements process support, and bidder document upload and storage management. Tri-State created an Outlook mailbox for each RFP that the IE could also access, enabling the IE to view communications with bidders, to monitor for consistency and transparency.

The IE reviewed the non-price factor evaluation criteria matrix prepared by Tri-State and confirmed its fairness and consistency and alignment to the Bid Policy. After Tri-State completed each bid evaluation screening phase, Tri-State prepared a summary of the results that included the purpose of the screen, the evaluation criteria, and the bid advancement results; then Tri-State and the IE discussed the results. The IE independently reviewed a subset of bids that passed and failed each screen to validate and ensure consistency across bid evaluation results. The IE communicated its completion of each screening review.

Due to only a very limited number of bids being received on October 28, 2024, in response to the Dispatchable RFP, Tri-State consulted with the IE for concurrence in issuing a 30-day extension for the Dispatchable RFP to November 27, 2024. Tri-State informed the 2023 ERP Settling Parties of the Dispatchable RFP extension via email. Beginning November 28, 2024, Tri-State and the IE completed an accelerated screening of dispatchable bids to remain on track with the 45-day bid evaluation period.

The IE uses and is familiar with EnCompass, the same modeling software used by Tri-State. Tri-State shared its model with the IE for review of Tri-State's modeling inputs and set-up, primarily for ensuring bid data was consistent with bidder-provided information. After Phase II portfolio modeling, the IE also reviewed modeling outputs for any anomalies.

The IE is expected to file a report providing its observations of Tri-State's Phase II process simultaneous to the filing of this report.

Phase II Portfolio Analysis

Tri-State modeled six portfolios:

1. New ERA Expanded (NEE)
2. New ERA Limited Gas (NELG)

[23] Eight 38.36 MW natural gas-fired turbines, hydrogen-capable with a demonstrated blend of 30%.

3. New ERA Gas Flexibility (FLEX)
4. FLEX Shafer Replacement (FLEXSR)
5. No New Gas (NNG)
6. NNG Shafer Replacement (NNGSR)

The modeling assumptions unique to each portfolio are identified in Attachment B-3.

Tri-State also conducted expansion plan modeling to identify three back-up bid pools:

7. Renewable Back-up Bid Pool (BkRE)
8. Standalone Storage Back-up Bid Pool (BkST)
9. Gas Plant Back-up Bid Pool (BkNG)

Tri-State will, to the extent necessary, utilize backup bid pools to replace preferred plan bids that fail. If a preferred plan bid cannot move forward, Tri-State aims to replace it with a similarly sized, similar technology type project, if possible, subject to limitations and economics. This designation of bids as back-ups is limited to creation of a potential pool of the next most economic bids, as Tri-State cannot anticipate which preferred plan bid or subset of bids could fail at a given point in time; therefore, modeling unknown and possible portfolio permutations would be inefficient. The bids identified in the back-up pools are not listed in an anticipated order of preference; this is because selection from the back-up pools depends upon which preferred plan bid would happen to fail and what location of the Tri-State system that bid was located and the transmission constraints projected at the bid locations at the time of CODs. Tri-State would, upon any bid failure(s), utilize bid(s)[24] from the relevant back-up bid pool along with the remaining preferred portfolio of bids still viable, and run a dispatch at that time to ensure continued adherence to the same affordability, reliability, and responsibility metrics and principles each Phase II portfolio was measured against. Tri-State will timely notify the Commission of any bid failures, identify steps taken to remediate the failed project, where feasible, and identify the back-up bid, or combination of backup bids, selected from the pools.

Additionally, a sensitivity analysis was performed to re-dispatch each portfolio under EWE conditions. The modeling assumptions and results of the sensitivity analyses are provided separately in Attachment E.[25]

Each section of this report that follows presents data and analytical results from base portfolio modeling, formatted in the following order:

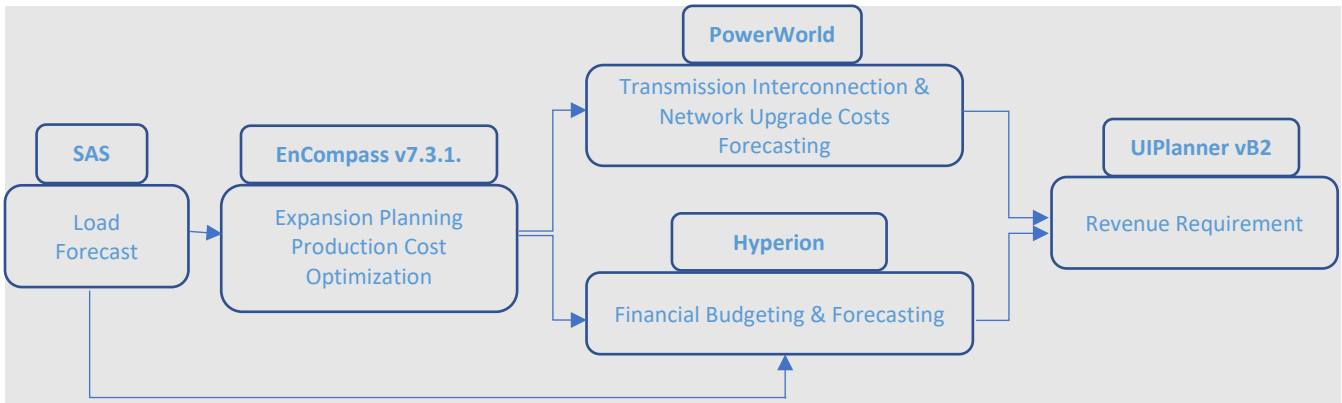
- Expansion Plan, Retirements, System Mix, and Capacity Factors
- Environmental Analysis
- Financial Analysis
- Transmission Analysis
- Reliability Analysis

An overview of Tri-State's approach to each element of the portfolio analyses is provided below.

[24] One bid, depending on the unit size, may need to be replaced by one or more bids.
[25] 2023 ERP Settlement Agreement at Section 4.8.1. (Proceeding No. 23A-0585E).

Figure 1 below identifies the software tools utilized by Tri-State for completing each component of the portfolio analyses and the succession of data flow through each modeling and analytical system. Use of the EnCompass modeling software for capacity expansion and portfolio optimization began in 2022.

Figure 1: Modeling Software Tools



Expansion Plan, Retirements, System Mix, and Capacity Factors

Tri-State used the EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses for Phase II modeling, inputting the applicable modeling assumptions described in Attachment B and Attachments B-1 through B-8, as applicable. Resource bids advanced to modeling as a result of the RFPs issued by Tri-State on September 13, 2024 and selected in the portfolio expansion plans are identified by a bid identifier, resource type, and project megawatts (MW).

The RAP for Phase II is 2026-2031, with the full Resource Planning Period (RPP) modeled for 2024-2043.[26]

Environmental Analyses

Based on the expansion plan and dispatch produced for each portfolio, Tri-State has provided an analysis of forecasted system-wide emissions and water use, as well as the annual social costs of carbon and methane.

For each portfolio, Tri-State separately produced a verification workbook, using the Colorado Air Pollution Control Division's (APCD) latest template,[27] calculating forecasted carbon emissions reductions, provided in Attachment D files. Target-year emissions reductions percentages for each portfolio, calculated within the verification workbooks, are provided in this report.

Financial Analyses

Pursuant to Rule 3605(h)(I)(A)(ii), Tri-State provided a financial analysis of each portfolio and each Tri-State owned resource, including:

- Annual revenue requirements;

[26] Tri-State's Hyperion financial forecasting for 2024 consists of six months of actuals and six months of forecast. Tri-State's financial forecasting for 2025 reflects Tri-State's Budget rather than EnCompass 2023 ERP Phase II dispatch output due to timing of the modeling, however, neither year is part of the Resource Acquisition Period (RAP).

[27] *See* Attachment B.

- Present value revenue requirement, with and without the social costs of carbon and methane; and
- A net present value of each owned resource, over the planning period, with and without the social costs of carbon and methane.

Additionally, one of the benefits of utilizing the EnCompass software is that it offers increased visibility into generation unit curtailments. EnCompass allows for a prioritization of curtailment order.[28] For each portfolio, curtailment MWhs by intermittent resource type seasonally and year are provided.

Transmission Analyses

Bidder-provided transmission cost estimates for proposed generation projects submitted in response to Tri-State's RFP were analyzed as part of the bid evaluation process to identify bids that should be advanced to portfolio modeling. Each portfolio was analyzed for its impact on transmission expenditures – both forecasted interconnection costs and additional network upgrades anticipated to be required, beyond already planned upgrades.

In addition to the traditional transmission interconnection and upgrades estimates prepared for each portfolio, Tri-State evaluated preferred portfolio bid selection in a manner that optimized interconnection costs, given growing transmission system constraints in recent years. As Tri-State was completing 2023 ERP Phase II portfolio modeling, it became increasingly clear that the EnCompass model was effectively selecting least-cost bids based on their operational profiles and the Tri-State system needs and transmission constraints, but the expansion plan model did not have full insight into the downstream transmission interconnection and network upgrade costs that were resulting from the bid selections. Additionally, the model could not identify opportunities where use of surplus interconnection could maximize the value of existing interconnections.[29] Tri-State was able to complete interconnection optimization for two of the portfolios—the preferred portfolio (FLEXSR) and the NNGSR portfolio. Optimizing the preferred portfolio enabled the avoidance of approximately $370M in transmission capital expenditures inclusive of allowance for funds used during construction (AFUDC) during the RAP. Optimizing the NNGSR portfolio enabled the avoidance of approximately $317M in transmission capital expenditures including AFUDC during the RAP.

Transmission planning cannot at this time be fully integrated into the generation planning process due to regulatory jurisdiction and organized market considerations, unique transmission and generation planning compliance requirements, bid timeline constraints, and variations in key modeling input cycles. However, Tri-State was able to address interconnection optimization in this Phase II by separately evaluating transmission cost and locational aspects of the bids following expansion plan selection. Going forward, Tri-State will integrate this optimization step across all portfolios beginning in Phase II of

[28] In the event that resources must be curtailed, Tri-State's model will first reduce dispatch of thermal resources to economic minimum levels, including taking thermal resources offline if possible. The model then curtails solar resources, wind resources, thermal resources below economic minimum and must take contracts (*i.e.,* hydropower and Basin contracts)–in that order.

[29] A recent report from GridLab suggests "PUCs should require evaluation of surplus interconnection options in integrated resource planning (IRP)," See *Existing Power Plants Sharing Grid Access with Renewables Can Lower Costs and Double U.S. Generation Capacity*, at page 4, released in February 2025: https://surplusinterconnection.s3.us-east-1.amazonaws.com/2025-02-21_GridLab_Surplus_Interconnection_Technical_Paper.pdf.

the 2027 ERP, to continue to enable the avoidance of interconnection and upgrade expenses and optimize use of the existing transmission system. Tri-State will work with its EnCompass software provider, and the IE, to identify potential approaches to informing the model of bid interconnection costs and transmission upgrade costs within the expansion plan selections, and will describe any proposed modeling changes in its Phase I filing for the 2027 ERP.

Reliability Analyses

Level 1 reliability metric checks were performed on each portfolio for all years of the RPP,[30] including:

- *Planning Reserve Margin (PRM):* Measure of required surplus of forecast generation capacity above forecast peak load inclusive of firm sales obligations. Reserve Margin requirement is inclusive of operating contingency/planning reserves (%).[31]
    - Target (min) is 22% transitioning to 30.5% in 2028 after the retirement of the Craig facility
- *Loss of Load Hours (LoLH)*[32]: Measure of the likelihood of failing to meet system load (hours per 10 years).
    - Target (max) is 1 day in 10 years (99.973% reliability)[33]
        - 2024-2031 – annually cannot exceed 2.4 hours[34]
        - 2032-2043 – cannot exceed 24 hours over entire period
- *Expected Unserved Energy (EUE)*[35]: Measure of annual summation of hourly energy not available to meet load and firm sales obligations; representative of potential load that would otherwise need to be shed to maintain system reliability.
    - Targets (max):
        - ≤ 0.4 GWh annually[36]

Evaluation of Level 2 Reliability Metrics, identified in Attachment B-5, was performed on each portfolio's EWE dispatch for all years of the RPP,[37] with results reflected in Attachment E.

Comparative Analysis

Tri-State compared and analyzed results across portfolios, which can be found in the Comparative Analysis section of this report.

[30] 2023 ERP Settlement Agreement, at Section 4.8.2. (Proceeding No. 23A-0585E).
[31] *Reserve Margin and Effective Load Carrying Capability (ELCC) Study,* Astrape Consulting, publicly available here: https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1011579&p_session_id=
[32] LoLH is equivalent to Loss of Load Probability (LoLP) terminology used in Tri-State's 2023 ERP Phase I.
[33] Splitting the LOLH target over the planning period reflects Tri-State's desire to have added assurance that intra-year reliability in the near-term is met by resources coming online during the RAP as the generation fleet makes significant transitions through this period. This approach also allows Tri-State to cautiously assess the impact of having an increasing percentage of intermittent resources in its fleet and the uncertain potential for more severe EWEs before applying similarly stringent LOLH metrics to the outer years of the planning period. There is more flexibility allowed in the out years as forecasting and technology uncertainty is greater during this period.
[34] The annual LOLH target of 2.4 hours is an equivalent representation of the 1 day in 10 years reliability standard.
[35] EUE is equivalent to Energy Not Served (ENS) terminology used in Tri-State's 2020 ERP Phase I.
[36] This metric is aimed at limiting EUE to a reasonable level below the historical annual average, consistent with the 2023 ERP Phase I.
[37] 2023 ERP Settlement Agreement, at Section 4.8.2. (Proceeding No. 23A-0585E).

State Renewable Policy Compliance Analysis

Tri-State reviewed the results of each portfolio and affirms that all portfolios meet or exceed the minimum applicable state renewable energy standard (RES) or renewable portfolio standard (RPS) requirements. RES/RPS standards are shown in the following table.

Table 5: Colorado RES and New Mexico RPS Requirements during RPP

	Colorado RES[38, 39]		New Mexico RPS[40]
	Co-ops	**Tri-State**	**Co-ops**
2024	10%	20%	10%
2025-2029	10%	20%	40%
2030-2050	10%	20%	50%

[38] § 40-2-124(1)(c)(I)(D) and (c)(V)(D), C.R.S.
[39] § 40-2-124(8)(b), C.R.S.
[40] N.M. Stat. Ann. § 62-15-34.

1. New ERA Expanded (NEE)

Assumptions unique to the New ERA Expanded (NEE) portfolio are identified in Attachment B-3.

Portfolio 1 (NEE) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 6: Expansion Plan (Portfolio 1 – NEE)

Year	Bid Project	Technology	Planning Region	Unit Size (MW)	Number of Units[41]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	PV-0004-5-wco	Solar	West Colorado	140	1	140
2028	ST-0019-1-eco	Iron Air Battery	East Colorado	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
2029	WI-0013-3-eco	Wind	East Colorado	200	1	200
	GG-0006-2-wco	Combustion Turbine	West Colorado	38.36	8	307
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
2030	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
2033	-	Wind / Battery	New Mexico	100	2	200
2035	-	Geothermal Storage	West Colorado	20	1	20
2036	-	Wind / Battery	New Mexico	100	1	100
	-	10hr - Battery	East Colorado	100	1	100
2037	-	Wind / Battery	Wyoming / W.Neb	100	1	100
2038	-	Wind / Battery	East Colorado	100	2	200
2041	-	Solar	New Mexico	100	1	100
2042	-	Solar	New Mexico	100	1	100
	-	Wind	East Colorado	100	3	300
2043	-	10hr - Battery	East Colorado	100	1	100
	-	Wind	East Colorado	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency was selected in the expansion plan of Portfolio 1 – NEE.
- 2030: Low Wyoming Energy Efficiency was selected in the expansion plan of Portfolio 1 – NEE.

[41] Each bid is modeled as a single project for purposes of expansion plan selection.

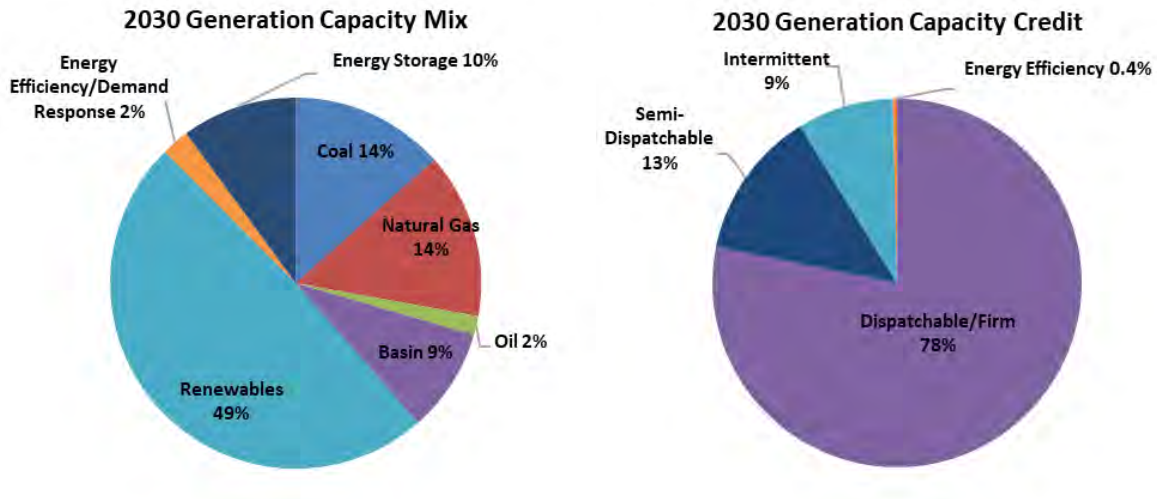
Unit retirements, scheduled or selected in the modeling, are shown in the following table.[42]

Table 7: Modeled Retirements (Portfolio 1 - NEE)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[43]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 2: Projected Tri-State System Capacity Mix 2030 (Portfolio 1 – NEE)[44, 45]



[42] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and its share of Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[43] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement by USDA to disperse all New ERA funds by September 30, 2031.

[44] "Renewables" category reflects wind and solar PPAs, Member Distributed Generation (DG), energy associated with renewable energy credits (RECs) received via the Basin contract, and hydropower purchases.

[45] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 3: Projected Tri-State System Energy Mix 2030 (Portfolio 1 – NEE)[46]

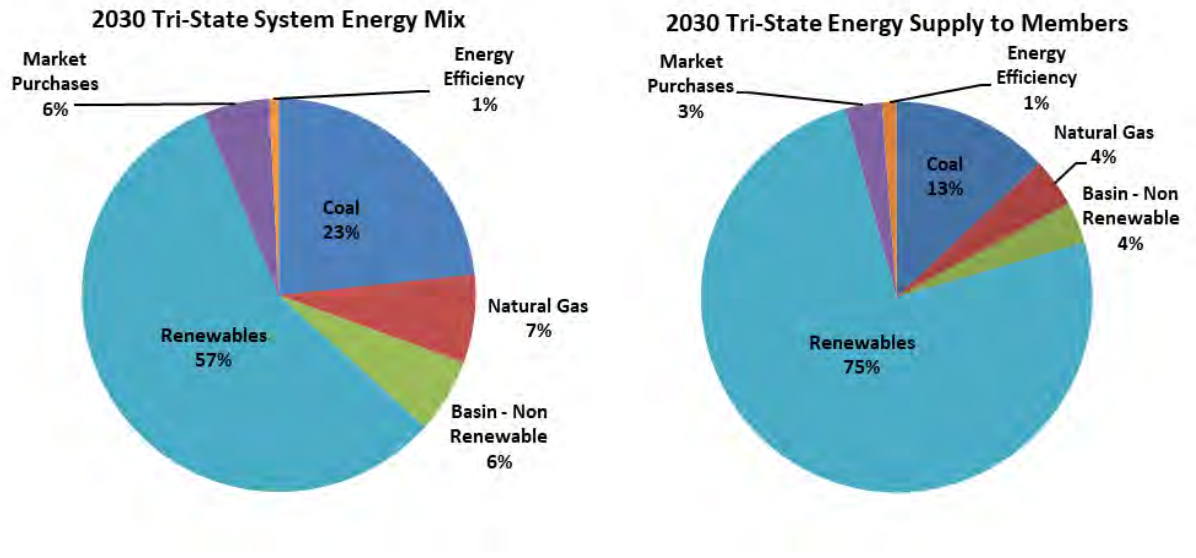


Table 8: Projected Annual Capacity Factors for Thermal Resources (Portfolio 1 – NEE)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	68%	84%	65%	73%	83%	82%	80%
SPV 3	87%	87%	89%	77%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	5%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	0%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	26%	19%	24%
GG-0006-2-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 1 (New ERA Expanded) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[46] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 9: Environmental Impact - System Wide (Portfolio 1 – NEE) [47]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,962,306	6,093	7,512	0.0335	975	4,183,354,305	24,235
2027	11,750,117	5,940	7,360	0.0327	961	4,161,589,886	23,953
2028	9,874,804	5,208	6,125	0.0290	841	3,480,893,766	20,201
2029	9,043,741	7,796	6,571	0.0268	729	3,080,720,212	17,940
2030	7,345,275	10,258	6,986	0.0238	607	2,691,211,959	16,047
2031	6,399,384	9,943	6,815	0.0207	370	2,139,654,056	13,265
2032	5,656,566	9,627	6,510	0.0177	259	1,784,885,467	11,492
2033	5,818,338	9,697	6,570	0.0187	278	1,863,239,379	11,783
2034	5,682,522	9,640	6,485	0.0181	274	1,803,058,523	11,491
2035	5,813,155	9,712	6,584	0.0187	273	1,845,867,435	11,847
2036	5,570,335	9,577	6,460	0.0173	252	1,750,921,710	11,305
2037	5,706,630	9,672	6,538	0.0181	266	1,785,001,792	11,627
2038	5,448,317	8,616	6,119	0.0176	252	1,666,538,080	11,330
2039	5,553,097	8,731	6,199	0.0181	254	1,712,426,151	11,584
2040	5,180,884	7,717	5,792	0.0167	221	1,547,476,901	10,991
2041	5,164,345	7,364	5,705	0.0167	222	1,513,398,513	11,008
2042	5,000,692	6,947	5,545	0.0159	210	1,426,738,301	10,699
2043	4,973,141	6,509	5,436	0.0159	202	1,395,662,722	10,776
Total	**134,188,571**	**154,604**	**122,581**	**0.406**	**8,306**	**43,732,557,038**	**273,981**
Pounds/Gallons per MWh[48]	**902**	**1.04**	**0.82**	**0.000003**	**0.06**	**147**	**2.030**

[47] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[48] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 10: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 1 – NEE)

Year	Annual Social Cost of Carbon
2025	$1,139,132,187
2026	$1,151,025,894
2027	$1,182,993,732
2028	$1,027,875,370
2029	$972,185,689
2030	$815,346,559
2031	$741,565,451
2032	$676,606,840
2033	$726,019,364
2034	$731,664,351
2035	$772,246,675
2036	$771,269,337
2037	$814,965,697
2038	$802,439,822
2039	$851,748,425
2040	$819,299,456
2041	$841,929,891
2042	$848,377,440
2043	$869,547,745

Table 11: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 1 – NEE)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,950,104
2027	$72,370,913
2028	$63,854,206
2029	$59,238,749
2030	$55,323,918
2031	$47,881,107
2032	$43,405,678
2033	$46,538,873
2034	$47,435,734
2035	$51,090,347
2036	$50,898,647
2037	$54,631,126
2038	$55,527,948
2039	$59,194,959
2040	$58,529,071
2041	$60,870,777
2042	$62,289,850
2043	$64,055,746

Table 12: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 1 – NEE)

Year	Target[49]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-1 for detailed GHG emissions calculations for the portfolio.

Portfolio 1 (New ERA Expanded) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 13: Total Financial (Portfolio 1 – NEE)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,836	$12,911	$837	$29,746	$30,584
Difference to preferred plan (Nominal $)	$393	($18)	($1)	$375	$374

Table 14: Total Financial Generation and Transmission (Portfolio 1 – NEE)

$, Millions	Expansion Plan CapEx + AFUDC:	Difference to preferred plan
Generation (Nominal $)	$1,508	$971
Transmission (Nominal $)	$1,506	$389

Table 15: Annual Financial (Nominal $) (Portfolio 1 – NEE)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,050
2027	$1,206
2028	$1,539
2029	$1,401
2030	$1,424
2031	$1,501

[49] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2032	$1,518
2033	$1,552
2034	$1,531
2035	$1,529
2036	$1,597
2037	$1,634
2038	$1,679
2039	$1,717
2040	$1,711
2041	$1,785
2042	$1,835
2043	$1,921

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Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 675 MW of battery storage (including hybrid batteries) built during the RAP in Portfolio 1 – NEE. The amount of curtailment is reduced to zero in 2030 as more batteries are built.

Table 17: Curtailed Intermittent Energy, Annual MWh (Portfolio 1 – NEE)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	185	0	0	185
2026	0	896	0	0	896
2027	0	1,429	0	0	1,429
2028	0	1,811	0	0	1,811
2029	0	52	0	124	176
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**4,373**	**0**	**124**	**4,497**

Table 18: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 1 – NEE)

	Winter	Spring	Summer	Fall
2025	0	118	0	67
2026	13	713	39	131
2027	18	1,189	1	221
2028	61	954	69	727
2029	0	0	12	164
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**92**	**2,974**	**121**	**1,310**

The following table reflects PPA pricing, penalties, and taxes.

Table 19: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 1 – NEE)

	Wind ($)	Solar ($)
2025	$0	$23,999
2026	$0	$145,247
2027	$0	$224,019

2028	$0	$214,350
2029	$0	$18,138
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$625,753**

Portfolio 1 (New ERA Expanded) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 20: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 1 – NEE)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2028	100	ST-0019-1-ECO	$1.50	$5.85	
2029	200	WI-0013-3-ECO		$14.62	$30.00
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2036	100	Battery	$1.50	$5.85	
2038	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	$81.56
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
2043	100	Battery	$1.50	$5.85	
2043	100	Wind		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2027	140	PV-0004-5-WCO		$3.25	$47.06
2029	307	GG-0006-2-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2035	20	Geothermal Storage	$1.30	$3.25	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24
2037	100	Wind + Battery		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62
2033	100	Wind + Battery		$5.85	$363.20

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2041	100	Solar		$5.85	$56.46
2042	100	Solar		$5.85	

Portfolio 1 (New ERA Expanded) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 1 New ERA Expanded.

Table 21: RAP Planning Reserve Margin, % Annual (Portfolio 1 – NEE)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	33%	52%	58%	35%

Table 22: Post-RAP Planning Reserve Margin, % Annual (Portfolio 1 – NEE)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	33%	32%	31%	31%	33%	36%	34%	31%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 1 New ERA Expanded.

Table 23: RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 24: Post-RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 1 – NEE.

Table 25: RAP Expected Unserved Energy, Annual MWh (Portfolio 1 – NEE)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 26: Post-RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

2. New ERA Limited Gas (NELG)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 2 (New ERA Limited Gas) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 27: Expansion Plan (Portfolio 2 – NELG)

Year	Bid Project	Technology	Planning Region	Unit Size (MW)	Number of Units[55]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	PV-0004-5-wco	Solar	West Colorado	140	1	140
	ST-0002-6-wco	4hr - Battery	West Colorado	100	1	100
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	WI-0013-3-eco	Wind	East Colorado	200	1	200
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	GG-0006-1-wco	Combustion Turbine	West Colorado	38.36	8	307
2030	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
2033	-	Geothermal Storage	West Colorado	20	1	20
	-	Wind / Battery	New Mexico	100	1	100
2036	-	10hr - Battery	East Colorado	100	1	100
	-	Wind / Battery	East Colorado	100	1	100
	-	Wind / Battery	New Mexico	100	1	100
2037	-	Wind / Battery	East Colorado	100	1	100
	-	Wind / Battery	New Mexico	100	1	100
2042	-	Wind	East Colorado	100	4	400
	-	Solar	New Mexico	100	2	200
2043	-	Wind	Wyoming / W.Neb	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 2 – NELG.

[55] Each bid is modeled as a single project for purposes of expansion plan selection.

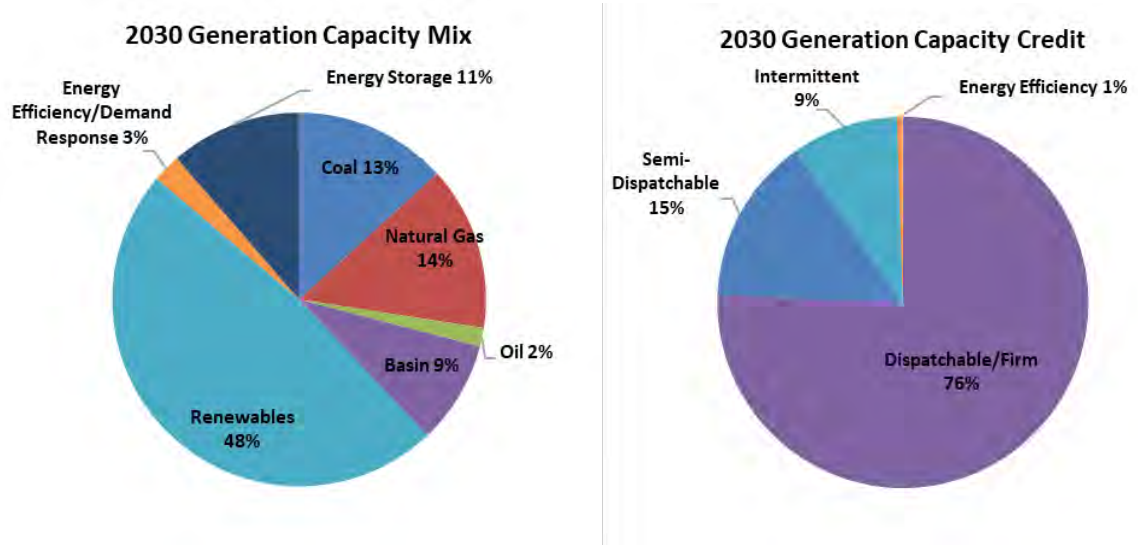
Unit retirements scheduled or selected in the modeling are shown in the following table.[56]

Table 28: Modeled Retirements (Portfolio 2 – NELG)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[57]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 4: Projected Tri-State System Capacity Mix 2030 (Portfolio 2 – NELG)[58, 59]



[56] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[57] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[58] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[59] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 5: Projected Tri-State System Energy Mix 2030 (Portfolio 2 – NELG)[60]

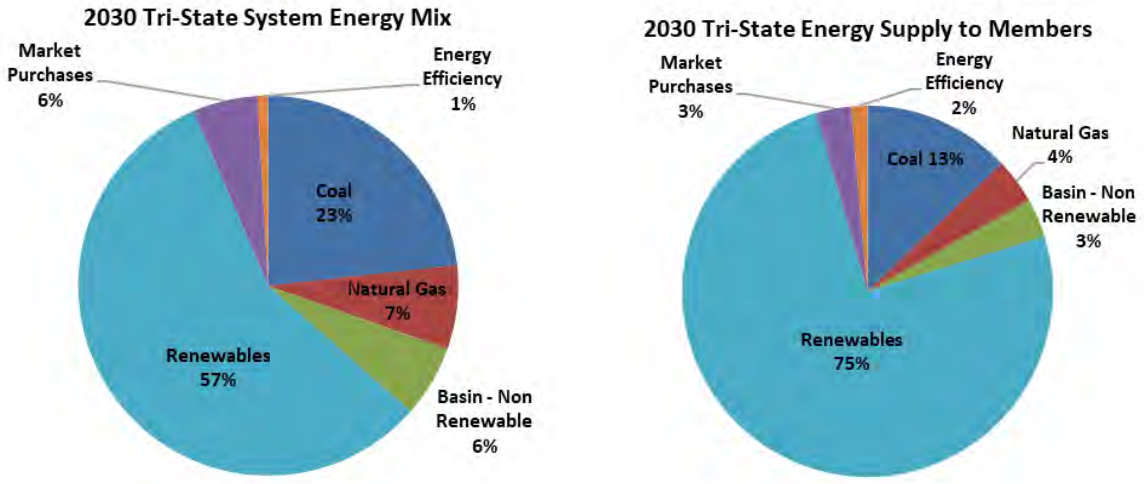


Table 29: Projected Annual Capacity Factors for Thermal Resources (Portfolio 2 – NELG)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	82%
LRS 3	67%	83%	64%	73%	83%	82%	80%
SPV 3	87%	87%	89%	77%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	1%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	25%	18%	24%
GG-0006-1-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 2 (New ERA Limited Gas) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[60] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 30: Environmental Impact - System Wide (Portfolio 2 – NELG) [61]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,942,684	6,082	7,499	0.0335	974	4,177,652,419	24,195
2027	11,727,659	5,926	7,347	0.0325	958	4,150,755,120	23,895
2028	9,879,304	5,209	6,129	0.0290	839	3,477,044,578	20,198
2029	9,036,223	7,796	6,566	0.0268	726	3,057,173,748	17,831
2030	7,334,742	10,249	6,979	0.0238	606	2,670,517,035	15,863
2031	6,390,985	9,941	6,811	0.0207	369	2,119,971,139	13,074
2032	5,643,142	9,626	6,504	0.0177	258	1,756,894,095	11,314
2033	5,846,331	9,721	6,629	0.0185	276	1,840,356,862	11,660
2034	5,721,745	9,570	6,526	0.0180	272	1,784,592,739	11,401
2035	5,816,518	9,313	6,528	0.0185	267	1,808,182,520	11,756
2036	5,617,103	9,352	6,437	0.0175	253	1,746,259,917	11,294
2037	5,668,595	8,918	6,321	0.0183	262	1,762,046,825	11,511
2038	5,370,590	7,698	5,885	0.0174	240	1,607,675,000	11,165
2039	5,444,002	7,486	5,871	0.0179	237	1,637,977,953	11,421
2040	5,033,242	6,320	5,407	0.0162	202	1,458,912,630	10,787
2041	5,081,355	6,125	5,424	0.0162	205	1,437,999,469	10,924
2042	4,923,968	5,904	5,263	0.0158	200	1,383,150,176	10,618
2043	4,899,783	5,453	5,150	0.0159	192	1,362,250,327	10,712
Total	**133,622,891**	**146,245**	**120,547**	**0.404**	**8,194**	**43,139,330,433**	**272,022**
Pounds/Gallons per MWh[62]	**946**	**1.04**	**0.85**	**0.000003**	**0.06**	**153**	**2.123**

[61] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[62] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 31: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 2 – NELG)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,653,707
2027	$1,174,732,910
2028	$1,026,795,307
2029	$973,309,290
2030	$818,577,657
2031	$739,322,590
2032	$676,519,826
2033	$726,175,264
2034	$736,202,715
2035	$775,083,935
2036	$775,046,549
2037	$809,721,903
2038	$794,053,163
2039	$832,968,427
2040	$796,824,782
2041	$828,400,211
2042	$835,361,013
2043	$856,721,090

Table 32: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 2 – NELG)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,834,755
2027	$72,194,298
2028	$63,843,496
2029	$58,876,581
2030	$54,688,462
2031	$47,192,177
2032	$42,731,594
2033	$46,052,949
2034	$47,065,889
2035	$50,698,390
2036	$50,851,295
2037	$54,083,272
2038	$54,721,101
2039	$58,358,076
2040	$57,442,190
2041	$60,401,484
2042	$61,819,253
2043	$63,671,990

Table 33: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 2 – NELG)

Year	Target[63]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-2 for detailed GHG emissions calculations for the portfolio.

Portfolio 2 (New ERA Limited Gas) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and allowance for funds used during construction (AFUDC), annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 34: Total Financial (Portfolio 2 – NELG)

$, Millions	**Portfolio PVRR** (2024 WACC 5.9%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$16,841	$12,852	$831	$29,693	$30,524
Difference to preferred plan (Nominal $)	$399	($77)	($7)	$322	$314

Table 35: Total Financial Generation and Transmission (Portfolio 2 – NELG)

$, Millions	**Expansion Plan CapEx + AFUDC:**	**Difference to preferred plan**
Generation (Nominal $)	$370	($167)
Transmission (Nominal $)	$1,494	$378

Table 36: Annual Financial (Nominal $) (Portfolio 2 – NELG)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,046
2027	$1,231
2028	$1,312
2029	$1,326

[63] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2030	$1,432
2031	$1,510
2032	$1,571
2033	$1,572
2034	$1,556
2035	$1,552
2036	$1,623
2037	$1,670
2038	$1,709
2039	$1,746
2040	$1,781
2041	$1,821
2042	$1,907
2043	$1,962

[redacted]

64 [redacted]

65 [redacted]

66 [redacted]

67 [redacted]

68 [redacted]

[redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 775 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 38: Curtailed Intermittent Energy, Annual MWh (Portfolio 2 – NELG)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	73	0	0	73
2026	0	962	0	0	962
2027	0	853	0	0	853
2028	0	1,132	0	11	1,143
2029	0	242	0	337	579
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**3,262**	**0**	**348**	**3,610**

Table 39: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 2 – NELG)

	Winter	Spring	Summer	Fall
2025	0	50	0	23
2026	35	669	80	178
2027	33	703	32	85
2028	132	288	26	697
2029	0	0	288	291
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**200**	**1,710**	**426**	**1,274**

The following table reflects PPA pricing, penalties, and taxes.

Table 40: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 2 – NELG)

	Wind ($)	Solar ($)
2025	$0	$9,370
2026	$0	$156,979
2027	$0	$114,621
2028	$0	$143,388
2029	$0	$56,325
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$480,683**

Portfolio 2 (New ERA Limited Gas) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 41: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 2 – NELG)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2028	100	ST-0004-10-ECO			
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	200	WI-0013-3-ECO		$14.62	$30.00
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2036	100	Battery	$1.50	$5.85	
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	
2042	100	Wind		$5.85	$81.56
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2027	140	PV-0004-5-WCO		$3.25	$47.06
2027	100	ST-0002-6-WCO	$1.30	$3.25	
2029	307	GG-0006-1-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2033	20	Geothermal Storage	$1.30	$3.25	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2043	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62
2033	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	$56.46
2042	100	Solar		$5.85	

Portfolio 2 (New ERA Limited Gas) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 2 – NELG.

Table 42: RAP Planning Reserve Margin, % Annual (Portfolio 2 – NELG)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	36%	54%	59%	36%

Table 43: Post-RAP Planning Reserve Margin, % Annual (Portfolio 2 – NELG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
32%	31%	31%	32%	32%	33%	31%	34%	36%	34%	32%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 2 – NELG.

Table 44: RAP Loss of Load Probability, Hours (Portfolio 2 – NELG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 45: Post-RAP Loss of Load Probability, Hours (Portfolio 2 - NELG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 2 – NELG.

Table 46: RAP Expected Unserved Energy, Annual MWh (Portfolio 2 - NELG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 47: Post-RAP Loss of Load Probability, Hours (Portfolio 2 - NELG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

3. New ERA Gas Flexibility (FLEX)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 3 (New ERA Gas Flexibility) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 48: Expansion Plan (Portfolio 3 – FLEX)

Year	Bid Project	Technology	Planning Region	Unit Size (MW)	Number of Units[69]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	ST-0018-1-eco	4hr - Battery	East Colorado	50	1	50
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	WI-0016-1-eco	Wind	East Colorado	297	1	297
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	GG-0006-2-wco	Combustion Turbine	West Colorado	38.36	8	307
2030	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
2033	-	Wind / Battery	New Mexico	100	1	100
	-	Geothermal Storage	West Colorado	20	1	20
2036	-	Wind / Battery	New Mexico	100	2	200
	-	10hr - Battery	West Colorado	100	1	100
	-	Solar	West Colorado	100	1	100
2038	-	Wind / Battery	East Colorado	100	2	200
2041	-	Solar	West Colorado	100	1	100
2042	-	Wind	East Colorado	100	3	300
	-	Solar	New Mexico	100	1	100
	-	Solar	West Colorado	100	2	200
2043	-	Wind	Wyoming / W.Neb	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 3 – FLEX.

[69] Each bid is modeled as a single project for purposes of expansion plan selection.

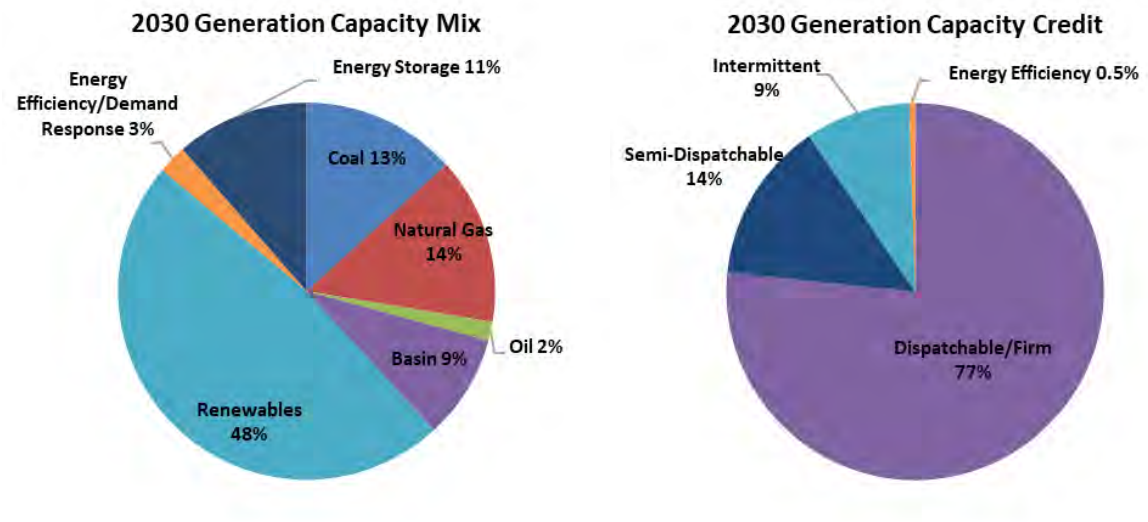
Unit retirements scheduled or selected in the modeling are shown in the following table.[70]

Table 49: Modeled Retirements (Portfolio 3 – FLEX)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[71]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 6: Projected Tri-State System Capacity Mix 2030 (Portfolio 3 – FLEX)[72, 73]



[70] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[71] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[72] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[73] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 7: Projected Tri-State System Energy Mix 2030 (Portfolio 3 – FLEX)[74]

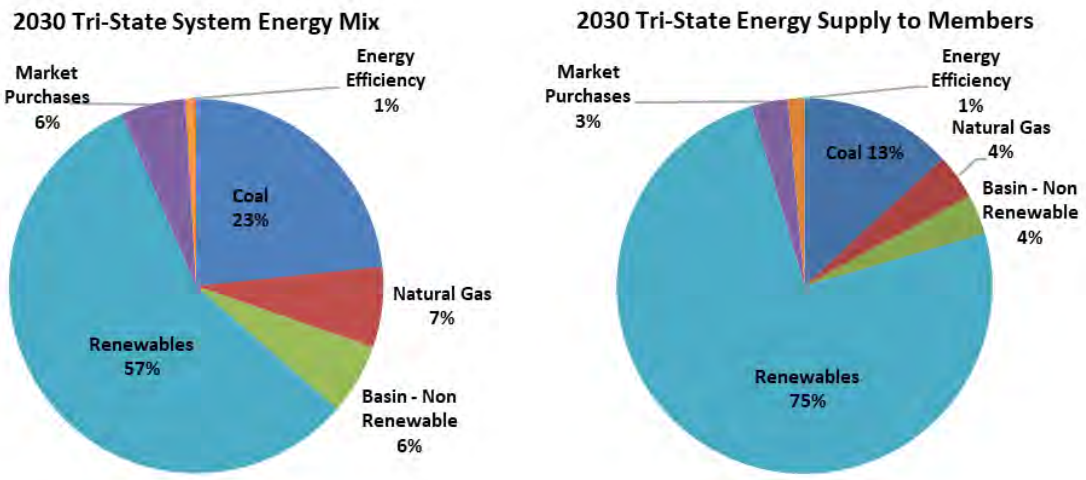


Table 50: Projected Annual Capacity Factors for Thermal Resources (Portfolio 3 – FLEX)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	82%
LRS 3	67%	83%	52%	70%	83%	82%	80%
SPV 3	87%	87%	89%	75%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	3%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	22%	16%	21%
GG-0006-2-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 3 (New ERA Gas Flexibility) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[74] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 51: Environmental Impact - System Wide (Portfolio 3 – FLEX) [75]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,943,290	6,082	7,500	0.0335	974	4,177,494,353	24,196
2027	11,568,153	5,770	7,226	0.0311	936	4,045,072,240	23,327
2028	9,779,075	5,148	6,077	0.0284	818	3,407,958,468	19,883
2029	8,967,361	7,781	6,521	0.0267	724	3,038,458,535	17,867
2030	7,315,232	10,260	6,967	0.0237	605	2,657,827,563	16,039
2031	6,350,647	9,935	6,786	0.0206	367	2,096,814,877	13,210
2032	5,635,838	9,629	6,501	0.0176	257	1,753,123,139	11,482
2033	5,820,676	9,711	6,616	0.0184	274	1,827,280,223	11,797
2034	5,720,467	9,667	6,551	0.0179	272	1,784,031,850	11,563
2035	5,832,550	9,741	6,639	0.0185	270	1,814,000,679	11,908
2036	5,602,277	9,601	6,471	0.0175	255	1,753,655,478	11,394
2037	5,653,752	9,638	6,515	0.0177	261	1,752,980,829	11,500
2038	5,458,897	8,694	6,154	0.0176	252	1,654,130,594	11,329
2039	5,548,435	8,783	6,219	0.0180	252	1,690,762,833	11,575
2040	5,178,596	7,783	5,816	0.0165	220	1,530,568,107	10,959
2041	5,191,519	7,349	5,728	0.0167	223	1,503,734,603	11,078
2042	5,095,815	6,784	5,539	0.0165	218	1,460,467,941	10,943
2043	5,039,030	6,269	5,391	0.0164	208	1,427,643,128	10,961
Total	**133,946,532**	**154,182**	**122,485**	**0.404**	**8,246**	**43,275,923,319**	**273,416**
Pounds/Gallons per MWh[76]	**949**	**1.09**	**0.87**	**0.000003**	**0.06**	**153**	**2.134**

[75] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[76] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 52: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 3 – FLEX)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,712,185
2027	$1,158,755,608
2028	$1,016,378,097
2029	$965,892,008
2030	$816,400,243
2031	$734,656,192
2032	$675,644,270
2033	$722,988,638
2034	$736,038,329
2035	$777,220,279
2036	$773,000,815
2037	$807,601,751
2038	$807,109,612
2039	$848,947,387
2040	$819,836,199
2041	$846,359,980
2042	$864,515,211
2043	$881,068,315

Table 53: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 3 – FLEX)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,836,579
2027	$70,477,977
2028	$62,847,444
2029	$58,997,890
2030	$55,296,246
2031	$47,683,283
2032	$43,367,675
2033	$46,595,924
2034	$47,733,888
2035	$51,349,932
2036	$51,298,669
2037	$54,036,042
2038	$55,522,239
2039	$59,145,438
2040	$58,361,648
2041	$61,255,841
2042	$63,710,822
2043	$65,154,538

Table 54: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 3 – FLEX)

Year	Target[77]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-3 for detailed GHG emissions calculations for the portfolio.

Portfolio 3 (New ERA Gas Flexibility) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 55: Total Financial (Portfolio 3 – FLEX)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,761	$12,891	$836	$29,652	$30,488
Difference to preferred plan (Nominal $)	$318	($38)	($2)	$281	$278

Table 56: Total Financial Generation and Transmission (Portfolio 3 – FLEX)

$, Millions	Expansion Plan CapEx + AFUDC:	Difference to preferred plan
Generation (Nominal $)	$1,129	$592
Transmission (Nominal $)	$1,457	$340

Table 57: Annual Financial (Nominal $) (Portfolio 3 – FLEX)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,050
2027	$1,220
2028	$1,371
2029	$1,399
2030	$1,427
2031	$1,503

[77] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2032	$1,525
2033	$1,557
2034	$1,537
2035	$ 1,531
2036	$1,607
2037	$1,639
2038	$1,697
2039	$1,726
2040	$1,751
2041	$1,785
2042	$1,833
2043	$1,906

[redacted]

78 [redacted]

79 [redacted]

80 [redacted]

81 [redacted]

82 [redacted]

[redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 497 MW of wind, 350 MW of solar, and 775 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 59: Curtailed Intermittent Energy, Annual MWh (Portfolio 3 – FLEX)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	101	0	0	101
2026	0	770	0	0	770
2027	0	1,019	0	0	1,019
2028	0	847	0	7	854
2029	0	9	0	207	216
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**2,746**	**0**	**214**	**2,960**

Table 60: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 3 – FLEX)

	Winter	Spring	Summer	Fall
2025	0	60	0	41
2026	13	601	79	77
2027	18	725	52	224
2028	49	412	1	392
2029	0	0	70	146
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**80**	**1,798**	**202**	**880**

The following table reflects PPA pricing, penalties, and taxes.

Table 61: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 3 – FLEX)

	Wind ($)	Solar ($)
2025	$0	$13,166
2026	$0	$125,261
2027	$0	$151,371
2028	$0	$107,958

2029	$0	$18,876
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$416,632**

Portfolio 3 (New ERA Gas Flexibility) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 62: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 3 – FLEX)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	150	ST-0010-4-ECO	$1.50	$5.85	
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	50	ST-0018-1-ECO	$1.50	$5.85	
2029	297	WI-0016-1-ECO		$14.62	$30.00
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2038	100	Wind + Battery		$5.85	$81.56
2038	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2029	307	GG-0006-2-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2033	20	Geothermal Storage	$1.30	$3.25	
2036	100	Solar		$5.85	
2036	100	Battery	$1.50	$5.85	
2041	100	Solar		$3.25	
2042	100	Solar		$6.56	
2042	100	Solar		$6.56	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24
2043	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	$56.46

Portfolio 3 (New ERA Gas Flexibility) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 3 – FLEX.

Table 63: RAP Planning Reserve Margin, % Annual (Portfolio 3 – FLEX)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	33%	54%	58%	36%

Table 64: Post-RAP Planning Reserve Margin, % Annual (Portfolio 3 – FLEX)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	32%	32%	31%	31%	33%	36%	34%	31%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 3 – FLEX.

Table 65: RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 66: Post-RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 3 – FLEX.

Table 67: RAP Expected Unserved Energy, Annual MWh (Portfolio 3 – FLEX)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 68: Post-RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

4. FLEX Shafer Replacement (FLEXSR)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 4 (FLEX Shafer Replacement) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 69: Expansion Plan (Portfolio 4 – FLEXSR)

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[83]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	ST-0004-6-eco	4hr - Battery	East Colorado	150	1	150
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	PV-0006-8-eco	Solar	East Colorado	200	1	200
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	WI-0013-3-eco	Wind	East Colorado	200	1	200
	GG-0006-2-wco	Combustion Turbine	West Colorado	38.36	8	307
2030	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming/ W. Neb.	200	1	200
2033	-	Wind / Battery	East Colorado	100	2	200
2036	-	Wind / Battery	New Mexico	100	2	200
	-	Wind / Battery	East Colorado	100	1	100
	-	Geothermal Storage	West Colorado	20	1	20
	-	Solar	New Mexico	100	1	100
2037	-	Wind / Battery	East Colorado	100	1	100
2038	-	Wind / Battery	East Colorado	100	1	100
	-	Wind / Battery	New Mexico	100	1	100
2042	-	Solar	New Mexico	100	2	200
	-	Wind	Wyoming/ W. Neb.	100	1	100
	-	Wind	East Colorado	100	2	200
2043	-	Wind / Battery	East Colorado	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 4 – FLEXSR.

[83] Each bid is modeled as a single project for purposes of expansion plan selection.

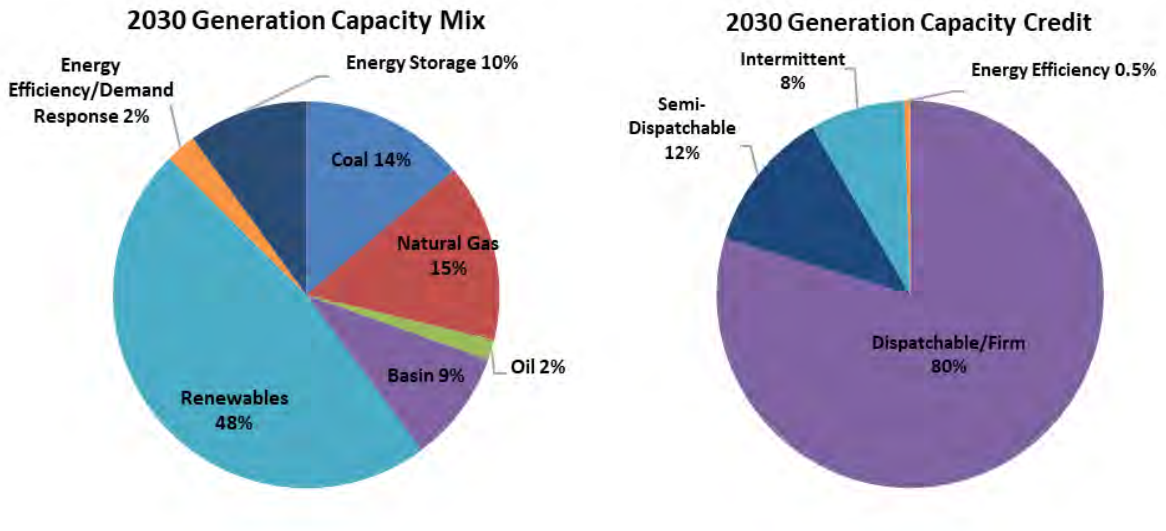
Unit retirements scheduled or selected in the modeling are shown in the following table.[84]

Table 70: Modeled Retirements (Portfolio 4 – FLEXSR)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[85]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 8: Projected Tri-State System Capacity Mix 2030 (Portfolio 4 – FLEXSR)[86, 87]



[84] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[85] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[86] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[87] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 9: Projected Tri-State System Energy Mix 2030 (Portfolio 4 – FLEXSR)[88]

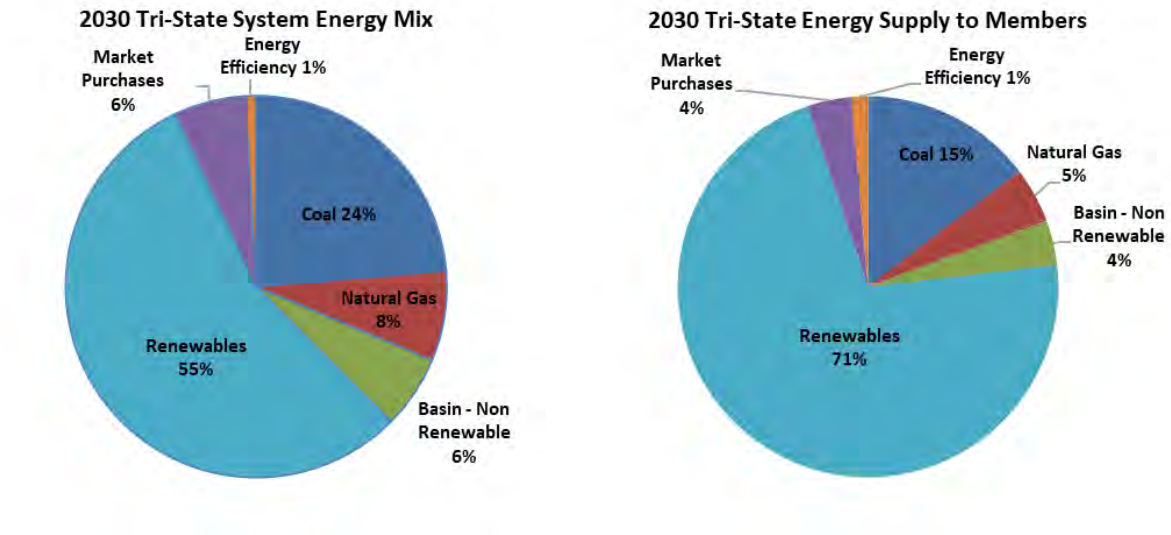


Table 71: Projected Annual Capacity Factors for Thermal Resources (Portfolio 4 – FLEXSR)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	67%	83%	53%	70%	82%	82%	80%
SPV 3	87%	87%	89%	75%	65%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	3%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	25%	22%	23%
GG-0006-2-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 4 (FLEX Shafer Replacement) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[88] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 72: Environmental Impact - System Wide (Portfolio 4 – FLEXSR) [89]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,942,421	6,082	7,499	0.0335	974	4,177,610,423	24,195
2027	11,568,735	5,770	7,227	0.0311	937	4,046,667,348	23,331
2028	9,819,361	5,161	6,103	0.0283	814	3,399,083,138	19,893
2029	9,204,229	7,855	6,616	0.0273	767	3,162,829,891	18,345
2030	7,412,404	10,284	7,047	0.0238	610	2,702,448,101	16,151
2031	6,458,059	9,980	6,884	0.0207	371	2,133,619,472	13,382
2032	5,712,026	9,667	6,578	0.0177	259	1,771,382,260	11,617
2033	5,853,864	9,745	6,652	0.0185	275	1,823,859,347	11,905
2034	5,797,935	9,690	6,616	0.0180	276	1,814,833,359	11,665
2035	5,898,663	9,785	6,694	0.0187	274	1,828,879,124	12,058
2036	5,625,841	9,611	6,460	0.0178	260	1,775,162,952	11,446
2037	5,698,331	9,682	6,499	0.0184	270	1,777,568,735	11,664
2038	5,351,664	8,533	6,016	0.0175	249	1,631,722,206	11,143
2039	5,433,584	8,599	6,069	0.0180	250	1,664,645,441	11,377
2040	5,111,931	7,566	5,683	0.0167	220	1,515,089,860	10,911
2041	5,218,379	7,217	5,684	0.0171	227	1,526,405,089	11,155
2042	5,033,011	6,829	5,500	0.0163	216	1,447,560,576	10,793
2043	4,988,533	6,377	5,382	0.0162	206	1,414,798,721	10,834
Total	**134,373,893**	**153,989**	**122,479**	**0.406**	**8,315**	**43,514,083,924**	**274,271**
Pounds/Gallons per MWh[90]	**952**	**1.09**	**0.87**	**0.000003**	**0.06**	**154**	**2.141**

[89] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[90] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 73: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 4 – FLEXSR)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,628,339
2027	$1,158,813,840
2028	$1,020,565,222
2029	$991,405,565
2030	$827,244,896
2031	$747,081,881
2032	$684,777,928
2033	$727,110,962
2034	$746,005,989
2035	$786,030,277
2036	$776,252,143
2037	$813,969,586
2038	$791,254,956
2039	$831,374,435
2040	$809,282,328
2041	$850,738,875
2042	$853,860,285
2043	$872,238,852

Table 74: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 4 – FLEXSR)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,833,899
2027	$70,489,792
2028	$62,881,612
2029	$60,575,560
2030	$55,682,337
2031	$48,304,507
2032	$43,879,284
2033	$47,023,762
2034	$48,155,833
2035	$51,996,947
2036	$51,534,377
2037	$54,805,537
2038	$54,614,207
2039	$58,132,606
2040	$58,102,968
2041	$61,679,010
2042	$62,837,645
2043	$64,400,027

Table 75: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 4 – FLEXSR)

Year	Target[91]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-4 for detailed GHG emissions calculations for the portfolio.

Portfolio 4 (FLEX Shafer Replacement) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 76: Total Financial (Portfolio 4 – FLEXSR)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,443	$12,928	$838	$29,371	$30,210

Table 77: Total Financial Generation and Transmission (Portfolio 4 – FLEXSR)

$, Millions	Expansion Plan CapEx + AFUDC:
Generation (Nominal $)	$537
Transmission (Nominal $)	$1,116

Table 78: Annual Financial (Nominal $) (Portfolio 4 – FLEXSR)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,050
2027	$1,227
2028	$1,306
2029	$1,362
2030	$1,383
2031	$1,435
2032	$1,489
2033	$1,509
2034	$1,511
2035	$1,509

[91] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2036	$1,599
2037	$1,606
2038	$1,669
2039	$1,695
2040	$1,702
2041	$1,745
2042	$1,779
2043	$1,855

[redacted]

92 [redacted]

93 [redacted]

94 [redacted]

95

96 [redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 300 MW of solar, and 650 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 80: Curtailed Intermittent Energy, Annual MWh (Portfolio 4 – FLEXSR)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	73	0	0	73
2026	0	945	0	0	945
2027	0	1,432	0	0	1,432
2028	0	707	0	10	717
2029	0	453	0	20	473
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**3,610**	**0**	**30**	**3,640**

Table 81: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 4 – FLEXSR)

	Winter	Spring	Summer	Fall
2025	0	50	0	23
2026	13	672	77	183
2027	19	1,127	58	228
2028	44	527	0	146
2029	0	0	1	472
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**76**	**2,376**	**136**	**1,052**

The following table reflects PPA pricing, penalties, and taxes.

Table 82: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 4 – FLEXSR)

	Wind ($)	Solar ($)
2025	$0	$9,370
2026	$0	$152,487
2027	$0	$193,537
2028	$0	$90,037
2029	$0	$51,807
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$497,237**

Portfolio 4 (FLEX Shafer Replacement) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

As described in the Executive Summary Portfolio Analysis section above and in Attachment G, Tri-State analyzed Portfolio 4 – FLEXSR bid selections for transmission interconnection and upgrade cost considerations and the potential to utilize surplus interconnection, and implemented transmission modeling optimizations. As a result of this analysis, the FLEXSR preferred portfolio avoids significant transmission upgrade costs during the RAP.

Table 83: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 4 – FLEXSR)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2027	150	ST-0004-6-ECO	$0.00		
2028	200	PV-0006-8-ECO		$5.85	
2028	100	ST-0004-10-ECO			
2029	200	WI-0013-3-ECO		$14.62	$30.00
2033	100	Wind + Battery		$5.85	$81.56
2033	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	$148.74
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
2043	100	Wind + Battery		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2029	307	GG-0006-2-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2036	20	Geothermal Storage	$1.30	$3.25	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	
2042	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2036	100	Solar		$5.85	$56.46
2036	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2042	100	Solar		$3.25	
2042	100	Solar		$3.25	

Portfolio 4 (FLEX Shafer Replacement) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 4 – FLEXSR.

Table 84: RAP Planning Reserve Margin, % Annual (Portfolio 4 – FLEXSR)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	38%	52%	54%	34%

Table 85: Post-RAP Planning Reserve Margin, % Annual (Portfolio 4 – FLEXSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
32%	32%	32%	33%	32%	32%	32%	35%	37%	35%	32%	32%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 4 – FLEXSR.

Table 86: RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 87: Post-RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 4 – FLEXSR.

Table 88: RAP Expected Unserved Energy, Annual MWh (Portfolio 4 – FLEXSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 89: Post-RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

5. No New Gas (NNG)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 5 (No New Gas) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 90: Expansion Plan (Portfolio 5 – NNG)

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[97]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	PV-0004-5-wco	Solar	West Colorado	140	1	140
2028	ST-0019-1-eco	Iron Air Battery	East Colorado	100	1	100
	ST-0004-9-eco	4hr - Battery	East Colorado	100	1	100
	ST-0004-8-wco	4hr - Battery	West Colorado	200	1	200
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	WI-0013-3-eco	Wind	East Colorado	200	1	200
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	ST-0018-1-eco	4hr - Battery	East Colorado	50	1	50
2030	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
2033	-	Wind / Battery	New Mexico	100	2	200
2035	-	Geothermal Storage	West Colorado	20	1	20
2036	-	Wind / Battery	East Colorado	100	2	200
	-	Wind / Battery	New Mexico	100	1	100
2037	-	Wind / Battery	East Colorado	100	1	100
	-	Geothermal[98]	West Colorado	12	1	12
2038	-	Wind / Battery	East Colorado	100	2	200
2042	-	Wind / Battery	East Colorado	100	1	100
	-	Solar	New Mexico	100	1	100
	-	Solar	West Colorado	100	2	200
2043	-	Wind / Battery	East Colorado	100	2	200
	-	Wind / Battery	Wyoming / W.Neb	100	1	100

[97] Each bid is modeled as a single project for purposes of expansion plan selection.
[98] Enhanced Geothermal Baseload (*see* Attachment B-8). Unit size is 25 MW, dispatchable maximum of 12 MW.

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 5 – NNG.

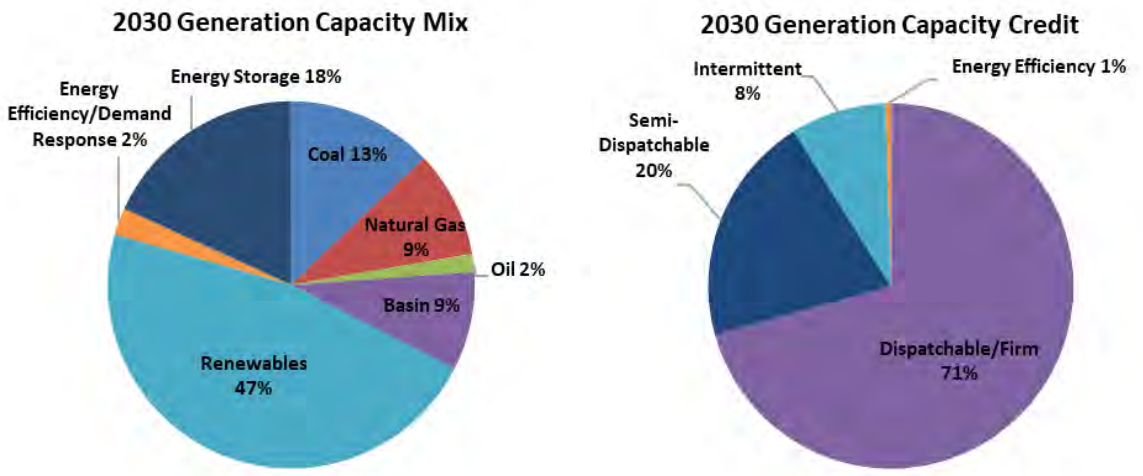
Unit retirements scheduled or selected in the modeling are shown in the following table.[99]

Table 91: Modeled Retirements (Portfolio 5 – NNG)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[100]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 10: Projected Tri-State System Capacity Mix 2030 (Portfolio 5 – NNG) [101]



[99] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[100] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[101] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

Figure 11: Projected Tri-State System Energy Mix 2030 (Portfolio 5 – NNG) [102]

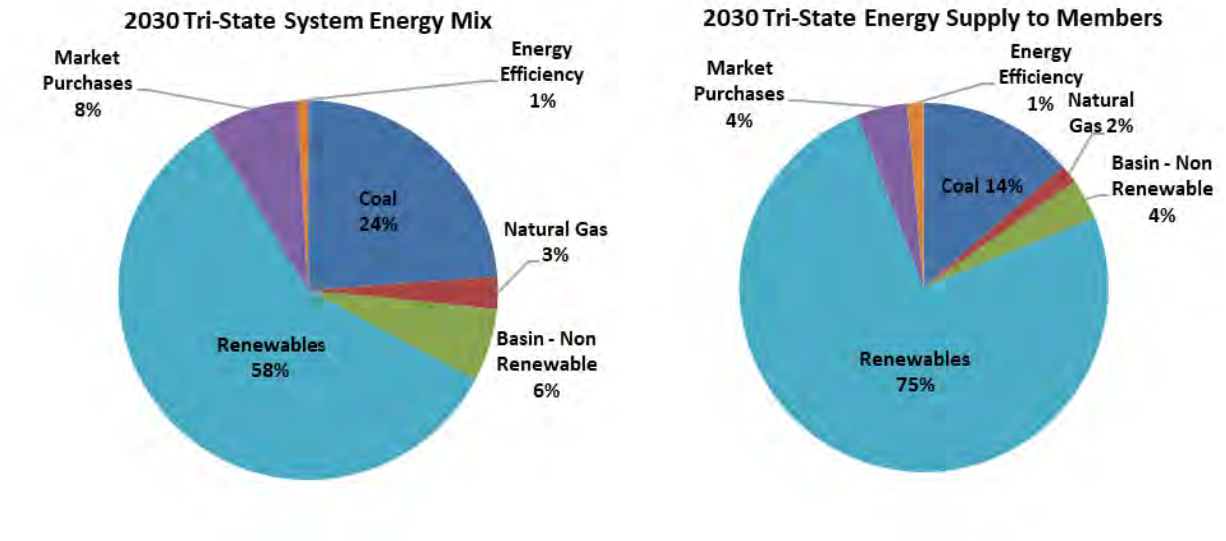


Table 92: Projected Annual Capacity Factors for Thermal Resources (Portfolio 5 – NNG)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	67%	83%	64%	73%	82%	81%	79%
SPV 3	87%	87%	89%	77%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	1%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	30%	27%	27%

Portfolio 5 (No New Gas) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[102] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 93: Environmental Impact - System Wide (Portfolio 5 – NNG)[103]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,942,265	6,082	7,499	0.0335	974	4,177,589,447	24,195
2027	11,726,163	5,927	7,347	0.0326	958	4,152,095,618	23,899
2028	9,883,456	5,211	6,132	0.0290	839	3,476,173,634	20,198
2029	8,959,962	4,974	5,831	0.0267	701	2,986,775,243	17,946
2030	7,013,425	4,657	5,500	0.0237	557	2,526,716,133	16,088
2031	5,999,591	4,341	5,298	0.0205	314	1,924,297,995	13,251
2032	5,264,320	4,036	5,000	0.0176	203	1,558,763,516	11,552
2033	5,390,667	4,091	5,043	0.0184	219	1,627,608,477	11,744
2034	5,289,574	4,044	4,975	0.0179	218	1,586,884,489	11,497
2035	5,408,588	4,109	5,066	0.0184	216	1,627,443,211	11,822
2036	5,196,722	3,983	4,903	0.0177	203	1,565,648,310	11,396
2037	5,297,401	4,068	4,958	0.0183	216	1,599,262,492	11,628
2038	5,013,729	3,964	4,754	0.0175	205	1,473,591,656	11,134
2039	5,111,419	4,012	4,817	0.0179	206	1,513,672,212	11,383
2040	4,871,635	3,892	4,696	0.0167	185	1,405,407,473	10,925
2041	4,990,642	3,996	4,805	0.0171	195	1,416,107,699	11,183
2042	4,890,992	3,945	4,778	0.0163	188	1,362,105,080	10,925
2043	4,853,274	3,938	4,726	0.0165	186	1,351,564,503	10,934
Total	**129,348,747**	**84,826**	**103,400**	**0.407**	**7,640**	**41,231,625,068**	**274,106**
Pounds/Gallons per MWh[104]	**916**	**0.60**	**0.73**	**0.000003**	**0.05**	**146**	**2.139**

[103] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[104] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 94: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 5 – NNG)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,613,302
2027	$1,174,583,082
2028	$1,027,226,838
2029	$965,095,102
2030	$782,717,739
2031	$694,045,278
2032	$631,105,309
2033	$669,577,102
2034	$680,596,397
2035	$720,724,943
2036	$717,042,375
2037	$756,699,323
2038	$741,290,549
2039	$782,081,140
2040	$771,240,407
2041	$813,611,550
2042	$829,766,536
2043	$848,588,980

Table 95: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 5 – NNG)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,833,909
2027	$72,206,255
2028	$63,846,020
2029	$59,255,701
2030	$55,464,509
2031	$47,830,289
2032	$43,632,908
2033	$46,386,308
2034	$47,461,289
2035	$50,983,048
2036	$51,311,539
2037	$54,636,281
2038	$54,569,169
2039	$58,162,802
2040	$58,177,007
2041	$61,837,927
2042	$63,603,366
2043	$64,997,048

Table 96: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 5 – NNG)

Year	Target[105]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-5 for detailed GHG emissions calculations for the portfolio.

Portfolio 5 (No New Gas) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 97: Total Financial (Portfolio 5 – NNG)

$, Millions	**Portfolio PVRR** (2024 WACC 5.9%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$17,067	$12,429	$838	$29,496	$30,334
Difference to preferred plan (Nominal $)	$624	($499)	($1)	$125	$124

Table 98: Total Financial Generation and Transmission (Portfolio 5 – NNG)

$, Millions	**Expansion Plan CapEx + AFUDC:**	**Difference to preferred plan**
Generation (Nominal $)	$652	$115
Transmission (Nominal $)	$3,008	$1,891

Table 99: Annual Financial (Nominal $) (Portfolio 5 – NNG)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,049
2027	$1,212
2028	$1,415
2029	$1,423
2030	$1,441

[105] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2031	$1,523
2032	$1,544
2033	$1,580
2034	$1,555
2035	$1,610
2036	$1,706
2037	$1,739
2038	$1,722
2039	$1,766
2040	$1,789
2041	$1,818
2042	$1,868
2043	$1,954



106 [redacted]

107 [redacted]

108 [redacted]

109 [redacted]

110 [redacted]

[redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 1,275 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 101: Curtailed Intermittent Energy, Annual MWh (Portfolio 5 – NNG)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	73	0	0	73
2026	0	860	0	0	860
2027	0	759	0	0	759
2028	0	1,707	0	0	1,707
2029	0	62	0	255	317
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**3,461**	**0**	**255**	**3,716**

Table 102: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 5 – NNG)

	Winter	Spring	Summer	Fall
2025	0	50	0	23
2026	47	579	57	177
2027	33	672	16	38
2028	117	709	0	881
2029	0	0	176	141
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**197**	**2,010**	**249**	**1,260**

The following table reflects PPA pricing, penalties, and taxes.

Table 103: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 5 – NNG)

	Wind ($)	Solar ($)
2025	$0	$9,370
2026	$0	$138,416
2027	$0	$105,188
2028	$0	$198,901

2029	$0	$31,189
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$483,064**

Portfolio 5 (No New Gas) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 104: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 5 – NNG)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2028	100	ST-0004-9-ECO	$1.50	$5.85	$30.00
2028	100	ST-0004-10-ECO			
2028	100	ST-0019-1-ECO	$1.50	$5.85	
2029	150	ST-0010-4-ECO	$1.50	$5.85	
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	50	ST-0018-1-ECO	$1.50	$5.85	
2029	200	WI-0013-3-ECO		$14.62	$81.56
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2036	100	Wind + Battery		$14.62	
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$6.56	$1,098.06
2038	100	Wind + Battery		$6.56	
2038	100	Wind + Battery		$6.56	
2042	100	Wind + Battery		$6.56	
2043	100	Wind + Battery		$6.56	
2043	100	Wind + Battery		$6.56	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2027	140	PV-0004-5-WCO		$3.25	$47.06
2028	200	ST-0004-8-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2035	20	Geothermal Storage	$1.30	$3.25	
2037	12	Geothermal	$1.30	$3.25	
2042	100	Solar		$5.85	
2042	100	Solar		$5.85	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2043	100	Wind + Battery		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62
2033	100	Wind + Battery		$5.85	$363.20
2033	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	$56.46

Portfolio 5 (No New Gas) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 5 – NNG.

Table 105: RAP Planning Reserve Margin, % Annual (Portfolio 5 – NNG)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	39%	53%	58%	35%

Table 106: Post-RAP Planning Reserve Margin, % Annual (Portfolio 5 – NNG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	33%	31%	31%	31%	33%	36%	33%	32%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 5 – NNG.

Table 107: RAP Loss of Load Probability, Hours (Portfolio 5 - NNG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 108: Post-RAP Loss of Load Probability, Hours (Portfolio 5 - NNG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 5 – NNG.

Table 109: RAP Expected Unserved Energy, Annual MWh (Portfolio 5 – NNG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 110: Post-RAP Loss of Load Probability, Hours (Portfolio 5 – NNG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

6. No New Gas Shafer Replacement (NNGSR)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 6 (No New Gas Shafer Replacement) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 111: Expansion Plan (Portfolio 6 – NNGSR)

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[111]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	ST-0004-6-eco	4hr - Battery	East Colorado	150	1	150
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	ST-0004-8-wco	4hr - Battery	West Colorado	200	1	200
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	ST-0004-9-eco	4hr - Battery	East Colorado	100	1	100
	PV-0006-8-eco	Solar	East Colorado	200	1	200
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	WI-0013-3-eco	Wind	East Colorado	200	1	200
2030	WI-0013-2-wyo-wne	Wind	Wyoming/ W. Neb.	200	1	200
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
2033	-	Wind / Battery	East Colorado	100	2	200
2036	-	Geothermal Storage	West Colorado	20	1	20
	-	Wind / Battery	New Mexico	100	3	300
2037	-	Wind / Battery	East Colorado	100	1	100
2038	-	Wind / Battery	East Colorado	100	2	200
2041	-	Solar	West Colorado	100	1	100
2042	-	Solar	West Colorado	100	1	100
	-	Wind	East Colorado	100	2	200
	-	Solar	New Mexico	100	2	200
2043	-	Solar	West Colorado	100	1	100
	-	Wind	Wyoming/ W. Neb.	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 6 – NNGSR.

[111] Each bid is modeled as a single project for purposes of expansion plan selection.

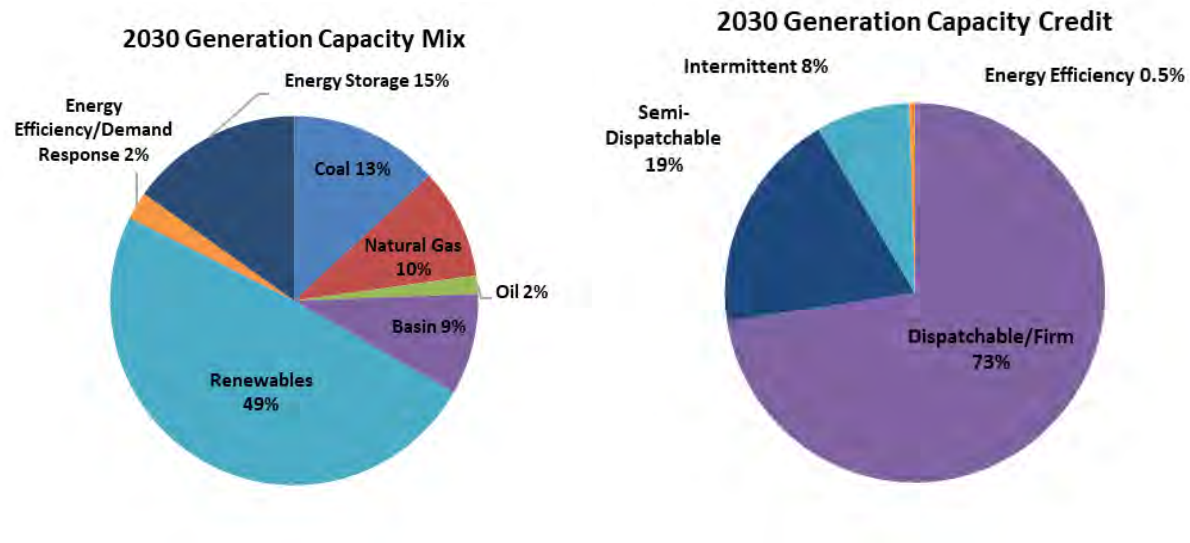
Unit retirements scheduled or selected in the modeling are shown in the following table.[112]

Table 112: Modeled Retirements (Portfolio 6 – NNGSR)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[113]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 12: Projected Tri-State System Capacity Mix 2030 (Portfolio 6 – NNGSR) [114, 115]



[112] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[113] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[114] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[115] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 13: Projected Tri-State System Energy Mix 2030 (Portfolio 6 – NNGSR)[116]

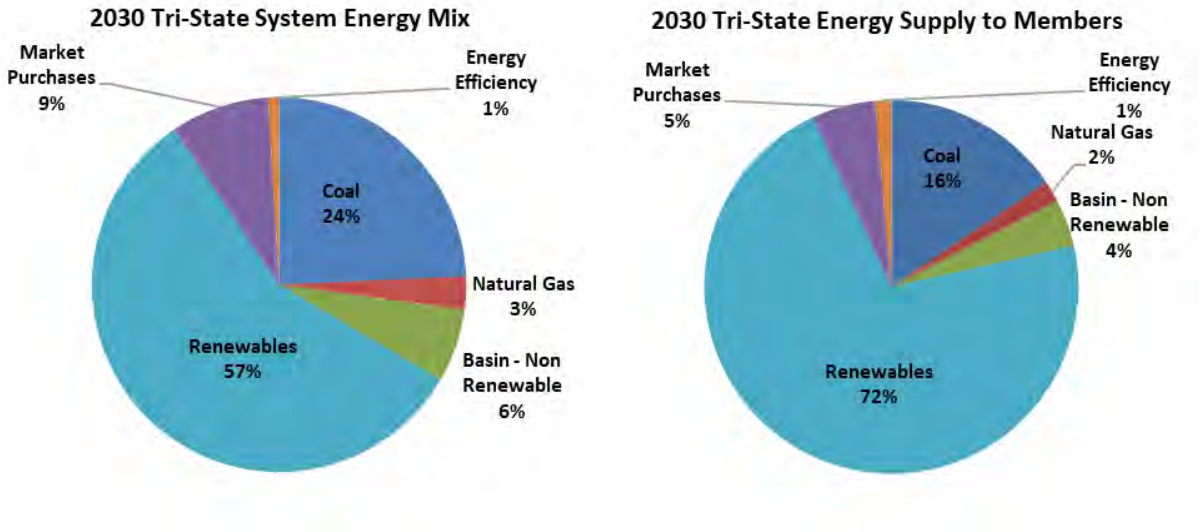


Table 113: Projected Annual Capacity Factors for Thermal Resources (Portfolio 6 – NNGSR)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	67%	83%	53%	70%	81%	81%	78%
SPV 3	87%	87%	89%	75%	65%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	3%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	29%	27%	23%

Portfolio 6 (No New Gas Shafer Replacement) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[116] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 114: Environmental Impact - System Wide (Portfolio 6 – NNGSR)[117]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,946,206	6,083	7,503	0.0335	974	4,178,260,972	24,199
2027	11,570,025	5,771	7,228	0.0311	936	4,046,421,059	23,332
2028	9,814,861	5,160	6,100	0.0283	815	3,401,715,998	19,898
2029	9,111,475	5,027	5,871	0.0272	737	3,073,163,383	18,316
2030	7,050,577	4,679	5,541	0.0238	558	2,532,813,977	16,162
2031	6,019,427	4,364	5,342	0.0204	312	1,913,037,441	13,312
2032	5,363,900	4,052	5,095	0.0176	206	1,604,501,764	11,641
2033	5,520,168	4,151	5,180	0.0184	223	1,661,803,495	11,946
2034	5,414,719	4,107	5,110	0.0180	221	1,615,591,795	11,712
2035	5,560,472	4,185	5,220	0.0186	221	1,665,887,399	12,084
2036	5,239,029	3,999	4,961	0.0176	203	1,573,524,559	11,453
2037	5,344,620	4,099	5,025	0.0182	215	1,590,771,662	11,726
2038	5,084,182	4,014	4,837	0.0175	205	1,470,546,688	11,293
2039	5,164,519	4,055	4,885	0.0180	205	1,504,603,982	11,518
2040	4,894,020	3,929	4,744	0.0167	183	1,379,333,329	11,025
2041	5,034,909	4,021	4,859	0.0171	196	1,413,662,279	11,266
2042	4,876,519	3,942	4,765	0.0163	188	1,347,184,439	10,913
2043	4,887,594	3,957	4,771	0.0165	186	1,347,404,577	10,997
Total	**130,142,142**	**85,151**	**104,306**	**0.405**	**7,642**	**41,220,146,679**	**275,198**
Pounds/Gallons per MWh[118]	**922**	**0.60**	**0.74**	**0.000003**	**0.05**	**146**	**2.148**

[117] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.
[118] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 115: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 6 – NNGSR)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,993,624
2027	$1,158,943,111
2028	$1,020,097,553
2029	$981,414,787
2030	$786,863,978
2031	$696,339,955
2032	$643,043,287
2033	$685,662,450
2034	$696,698,482
2035	$740,964,313
2036	$722,879,934
2037	$763,444,178
2038	$751,707,224
2039	$790,205,684
2040	$774,784,316
2041	$820,828,229
2042	$827,311,151
2043	$854,589,790

Table 116: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 6 – NNGSR)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,847,236
2027	$70,492,985
2028	$62,895,824
2029	$60,478,517
2030	$55,718,807
2031	$48,051,268
2032	$43,969,826
2033	$47,182,943
2034	$48,348,612
2035	$52,112,380
2036	$51,565,121
2037	$55,096,401
2038	$55,345,788
2039	$58,855,626
2040	$58,711,741
2041	$62,293,992
2042	$63,533,142
2043	$65,368,924

Table 117: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 6 – NNGSR)

Year	Target[119]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-6 for detailed GHG emissions calculations for the portfolio.

Portfolio 6 (No New Gas Shafer Replacement) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 118: Total Financial (Portfolio 6 – NNGSR)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,531	$12,509	$842	$29,039	$29,881
Difference to preferred plan (Nominal $)	$88	($420)	$3	($332)	($329)

Table 119: Total Financial Generation and Transmission (Portfolio 6 – NNGSR)

$, Millions	Expansion Plan CapEx + AFUDC:	Difference to preferred plan
Generation (Nominal $)	$265	($272)
Transmission (Nominal $)	$1,100	($16)

Table 120: Annual Financial (Nominal $) (Portfolio 6 – NNGSR)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,051
2027	$1,236
2028	$1,317
2029	$1,335
2030	$1,358

[119] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2031	$1,447
2032	$1,480
2033	$1,507
2034	$ 1,526
2035	$1,523
2036	$1,610
2037	$1,618
2038	$1,685
2039	$1,711
2040	$1,741
2041	$1,786
2042	$1,839
2043	$1,899



120 [redacted]

121 [redacted]

122 [redacted]

123 [redacted]

124 [redacted]



Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 300 MW of solar, and 1,200 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 122: Curtailed Intermittent Energy, Annual MWh (Portfolio 6 – NNGSR)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	101	0	0	101
2026	0	1,205	0	0	1,205
2027	0	1,233	0	0	1,233
2028	0	285	0	13	298
2029	0	5	0	0	5
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**2,829**	**0**	**13**	**2,842**

Table 123: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 6 – NNGSR)

	Winter	Spring	Summer	Fall
2025	0	60	0	41
2026	72	825	98	210
2027	36	938	54	205
2028	182	57	0	59
2029	0	0	0	5
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**290**	**1,880**	**152**	**520**

The following table reflects PPA pricing, penalties, and taxes.

Table 124: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 6 – NNGSR)

	Wind ($)	Solar ($)
2025	$0	$13,166
2026	$0	$166,014
2027	$0	$171,286
2028	$0	$42,920
2029	$0	$798
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$394,184**

Portfolio 6 (No New Gas Shafer Replacement) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

As described in the Executive Summary Portfolio Analysis section above and in Attachment G, Tri-State analyzed Portfolio 6 – NNGSR bid selections for transmission interconnection and upgrade cost considerations and the potential to utilize surplus interconnection, and implemented transmission modeling optimizations, to ensure that the benefits of this approach were evaluated under both a new gas and no new gas portfolio. As a result of this analysis, this portfolio avoids significant transmission upgrade costs during the RAP similar to the preferred portfolio, but has a higher PVRR.

Table 125: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 6 – NNGSR)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2026	150	ST-0004-6-ECO			
2028	200	PV-0006-8-ECO		$5.85	
2028	100	ST-0004-10-ECO			
2028	100	ST-0004-9-ECO			$30.00
2029	150	ST-0010-4-ECO	$1.50	$5.85	
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	200	WI-0013-3-ECO		$14.62	
2033	100	Wind		$5.85	$81.56
2033	100	Wind		$5.85	
2037	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	$148.74
2038	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	
2042	100	Wind		$5.85	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2028	200	ST-0004-8-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2036	20	Geothermal Storage	$1.30	$3.25	
2041	100	Solar		$5.85	
2042	100	Solar		$6.56	
2043	100	Solar		$6.56	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	
2043	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2036	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	
2042	100	Solar		$5.85	

Portfolio 6 (No New Gas Shafer Replacement) – Reliability Analysis

PRM, LOLH, and EUE results are ("Level 1 Reliability Metrics") as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 6 – NNGSR.

Table 126: RAP Planning Reserve Margin, % Annual (Portfolio 6 – NNGSR)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	42%	51%	53%	33%

Table 127: Post-RAP Planning Reserve Margin, % Annual (Portfolio 6 – NNGSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	32%	31%	31%	31%	33%	36%	34%	31%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 6 – NNGSR.

Table 128: RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 129: Post-RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 6 – NNGSR.

Table 130: RAP Expected Unserved Energy, Annual MWh (Portfolio 6 – NNGSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 131: Post-RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

7. Renewable Back-up Bid Pool (BkRE)

The approach to modeling back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. The expansion plan selected the following renewable bids as the most economic for the back-up pool.

Table 132: Renewable Back-up Bid Pool

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[125]	Total MW
2027	PC-0004-1P-nm	Solar / Battery	New Mexico	90	1	90
	PV-0004-5-wco	Solar	West Colorado	140	1	140
2029	WI-0016-1-eco	Wind	East Colorado	297	1	297
	PC-0021-1P-wco	Solar / Battery	West Colorado	125	1	125
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	WI-0005-3-eco	Wind	East Colorado	150	1	150

[125] Each bid is modeled as a single project for purposes of expansion plan selection.

8. Standalone Storage Back-up Bid Pool (BkST)

The approach to modeling back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. The expansion plan selected the following standalone storage bids as the most economic for the back-up pool.

Table 133: Standalone Storage Back-up Bid Pool

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[126]	Total MW
2027	ST-0002-6-wco	4hr - Battery	West Colorado	100	1	100
2028	ST-0006-3-nm	4hr - Battery	New Mexico	100	1	100
2029	ST-0018-1-eco	4hr - Battery	East Colorado	50	1	50
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100

[126] Each bid is modeled as a single project for purposes of expansion plan selection.

9. Gas Plant Back-up Bids (BkNG)

The approach to back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. Only one alternative gas plant bid is available during the RAP, therefore Tri-State did not conduct further modeling to determine a gas plant back-up bid pool.

Table 134: Gas Plant Back-up Bid Pool

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[127]	Total MW
2030	GG-0005-1-wco	Combustion Turbine	West Colorado	45.325	4	181.3

[127] Each bid is modeled as a single project for purposes of expansion plan selection.

Comparative Analysis

A comparative analysis of environmental, financial, and reliability results across each of the Phase II portfolios is provided below.

Environmental Analysis

The following tables identify each portfolio's system-wide forecasted CO_2 and CH_4 emissions in 2026 and 2031.

Figure 14: Comparison of Forecasted System CO_2 Emissions in 2026 and 2031, by Portfolio

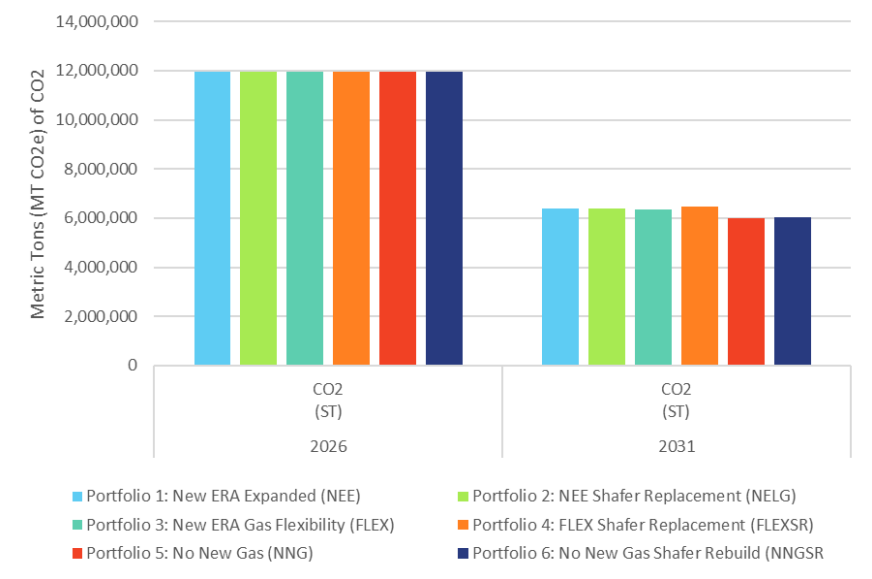
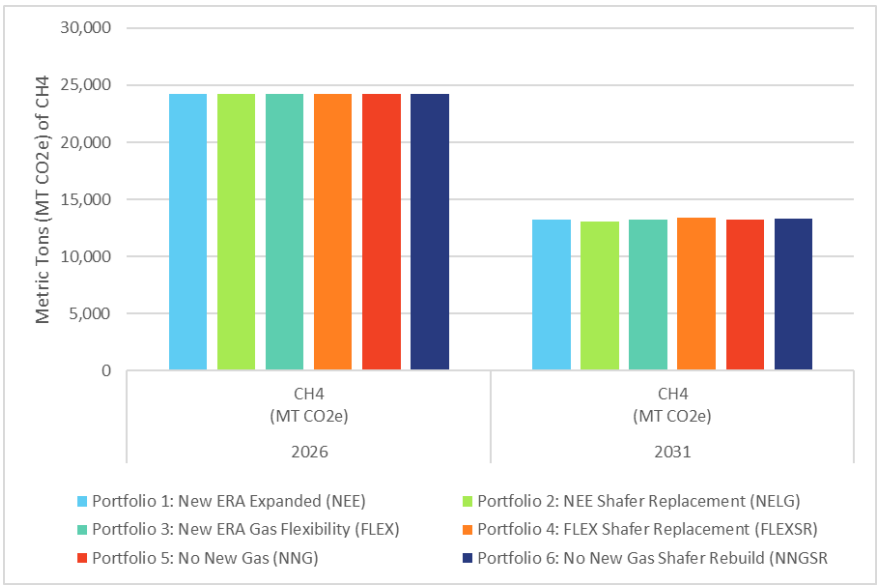


Figure 15: Comparison of Forecasted System CH_4 Emissions in 2026 and 2031, by Portfolio



The following table identifies each portfolio's forecasted achievements toward Colorado GHG reduction targets. Modeling indicates all Phase II portfolios are able to achieve the Colorado GHG reduction

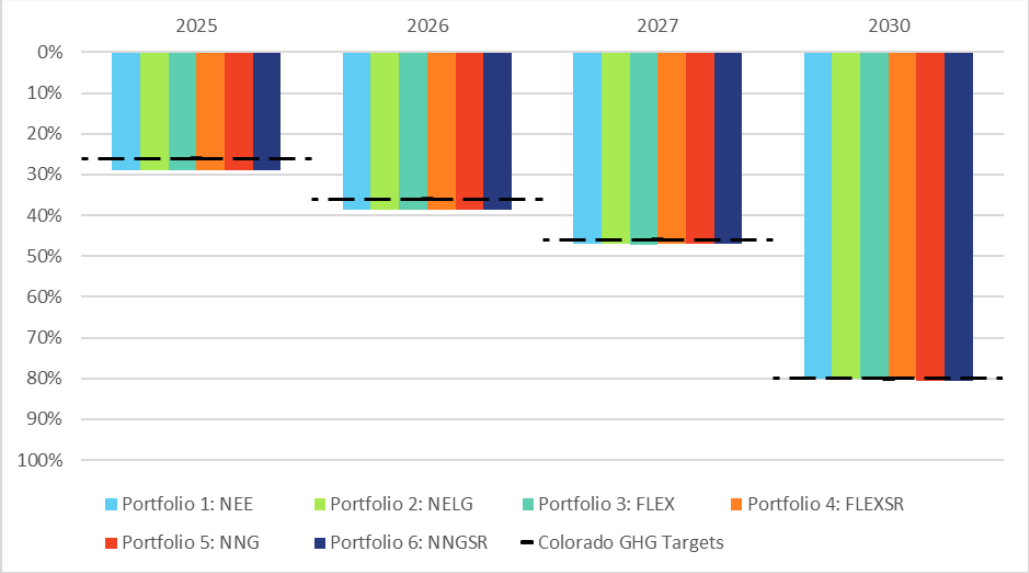
targets in 2025,[128] 2026, 2027, and 2030. Forecasted emissions reductions in 2030 in Phase II meet the minimum statutory requirement, and do not vary substantially across portfolios. This is driven in part by the model seeking a least-cost expansion plan, based on actual bid pricing (versus generic resources in Phase I), as well as new APCD guidance issued in December 2024 on the approach to forecasting market emission rates. In Phase II, emission rates for market purchases and sales are reflective of expectations that the residual mix of supply from the market is anticipated to be primarily thermal energy.

Additional discussion of Tri-State's consideration of the environmental results of the portfolio analyses can be found in the Portfolio Analysis section of the Executive Summary; and discussion of SCoC and SCoM in the Financial Analysis section below.

Table 135: Comparison of Forecasted Colorado GHG Reduction by Portfolio in GHG Target Years

	2025	2026	2027	2030
Portfolio 1: New ERA Expanded	29%	39%	47%	80%
Portfolio 2: New ERA Limited Gas	29%	39%	47%	80%
Portfolio 3: New ERA Gas Flexibility (FLEX)	29%	39%	47%	80%
Portfolio 4: FLEX Shafer Replacement	29%	39%	47%	80%
Portfolio 5: No New Gas (NNG)	29%	39%	47%	80%
Portfolio 6: NNG Shafer Replacement	29%	39%	47%	80%

Figure 16: Comparison of Portfolio Achievements Toward Colorado GHG Reduction Targets



[128] Trending at the end of Q1-2025 is positive toward achievement of Tri-State's first GHG reduction target.

Figure 17: Comparison of Colorado CO2e

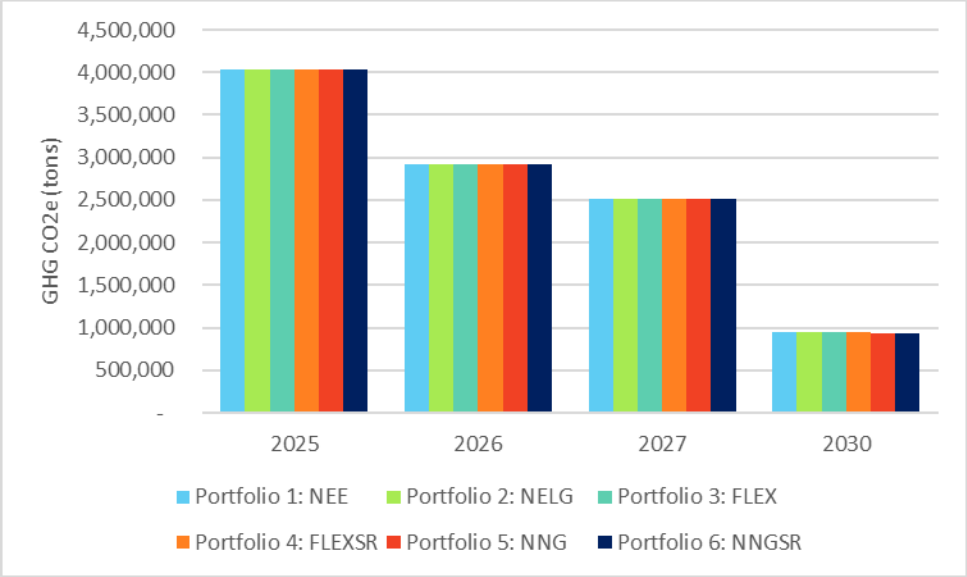


Figure 18: Comparison of SCoC During the RAP

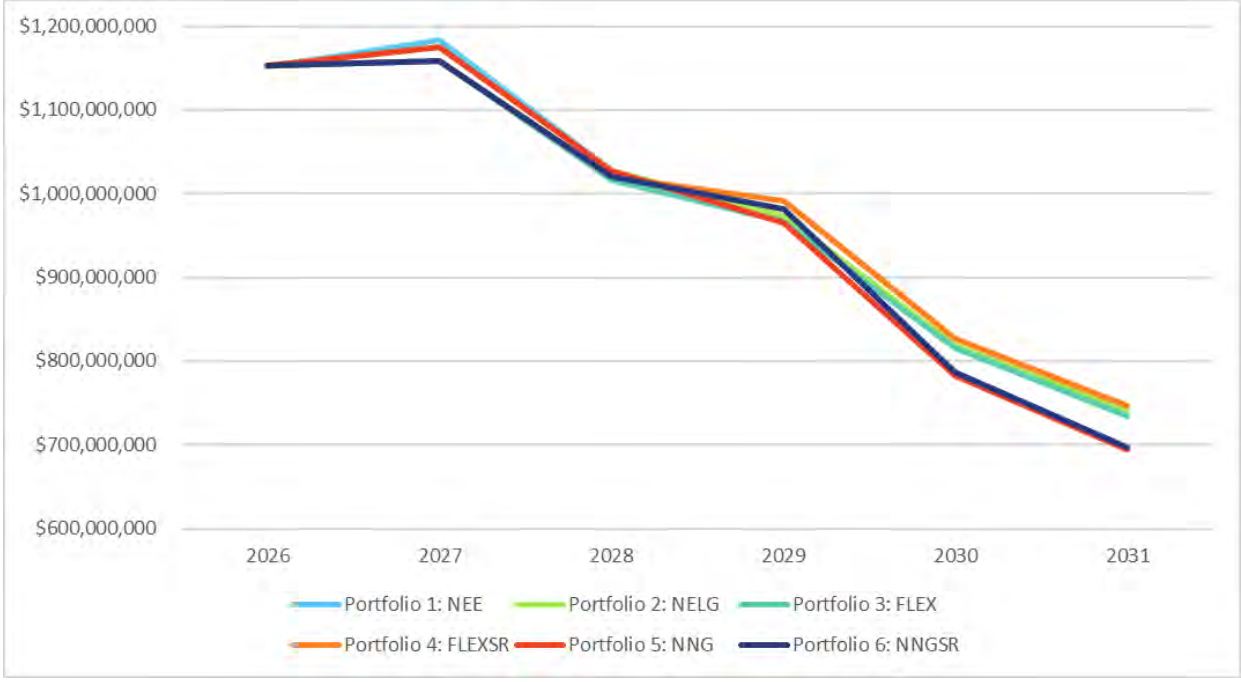
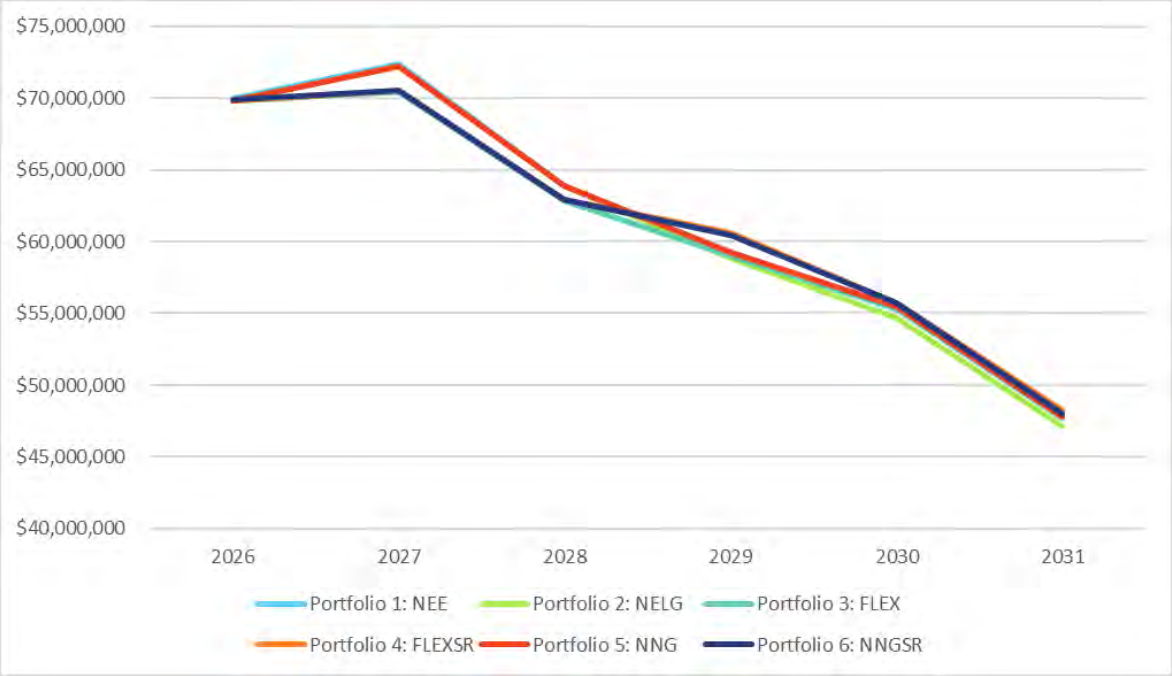


Figure 19: Comparison of SCoM During the RAP



Financial Analysis

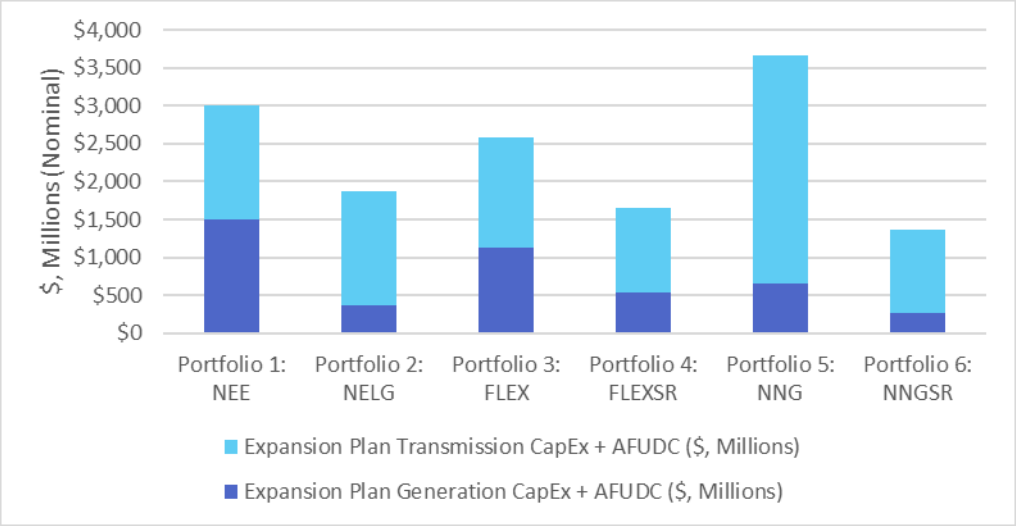
The following table compares total financial results for each portfolio, both with and without the SCoC and SCoM. Portfolio 4 – FLEXSR is the lowest cost plan on a PVRR basis, requiring fewer new resource acquisitions than other portfolios while achieving comparable emissions reductions and reliability results—an important value for Tri-State's Members. Further discussion of the financial benefits achieved with Portfolio 4 – FLEXSR bid selections is identified in Attachment G.

Table 136: Comparison of PVRR

	PVRR ($, Millions)	**PVRR w/SCoC and SCoM ($, Millions)**
Portfolio 1: New ERA Expanded	$16,836	$30,584
Portfolio 2: New ERA Limited Gas	$16,841	$30,524
Portfolio 3: New ERA Gas Flexibility	$16,761	$30,488
Portfolio 4: FLEX Shafer Replacement	$16,443	$30,210
Portfolio 5: No New Gas	$17,067	$30,334
Portfolio 6: No New Gas Shafer Replacement	$16,531	$29,881

The following figure compares capital expenditures and MW additions by portfolio.

Figure 20: Comparison of Generation and Transmission CapEx (Nominal $) During the RPP



As shown in below, the MW level and type of resource additions selected in Portfolios 2 and 3 are relatively similar. Renewable MWs were relatively consistent across all portfolios, except for Portfolio 3 which selected more wind and less solar. Portfolios 1-4 selected a gas plant bid and had a similar amount of storage MW selections, whereas Portfolios 5 and 6, which did not allow new gas, required a considerably larger amount of storage resource additions. Portfolio 4, the preferred portfolio, requires the least amount of resource additions with less transmission capital expenditures. Portfolio 5 requires more MW resource additions than other portfolios in order to maintain system reliability without the addition of a dispatchable gas resource, but at a higher PVRR than any other portfolio. Tri-State is concerned about the potential risk in overreliance on 4-hour batteries suggested by the resource additions in Portfolios 5 and 6; Tri-State has not yet deployed any batteries on its system and storage technologies, including longer duration storage options, are anticipated to make advancements in the coming years.

Table 137: Comparison of MW Additions by Portfolio, by Technology over the RAP

MW	Portfolio 1: NEE	Portfolio 2: NELG	Portfolio 3: FLEX	Portfolio 4: FLEXSR	Portfolio 5: NNG	Portfolio 6: NNGSR
Wind	400	400	497	400	400	400
Solar	240	240	100	200	240	200
Standalone Storage -Short Duration	450	650	650	600	1,050	1,150
Standalone Storage - Long Duration	100	0	0	0	100	0
Gas	307	307	307	307	0	0
Solar Hybrid	250	250	250	100	250	100
RAP Total	**1,747**	**1,847**	**1,804**	**1,607**	**2,040**	**1,850**
Solar Hybrid – Battery Storage Component	125	125	125	50	125	50
RAP Total w/Hybrid Storage	**1,872**	**1,972**	**1,929**	**1,657**	**2,165**	**1,900**

Table 138: Comparison of Number of Bids by Portfolio, by Technology over the RAP

	Portfolio 1: NEE	Portfolio 2: NELG	Portfolio 3: FLEX	Portfolio 4: FLEXSR	Portfolio 5: NNG	Portfolio 6: NNGSR
Wind	2	2	2	2	2	2
Solar	2	2	1	1	2	1
Standalone Storage -Short Duration	4	6	6	5	9	9
Standalone Storage - Long Duration	1	0	0	0	1	0
Gas	1	1	1	1	0	0
Solar Hybrid	2	2	2	1	2	1
RAP Total	**12**	**13**	**12**	**10**	**16**	**13**

Table 139 below identifies the percentage of Tri-State's system energy and energy supplied to Members that is forecasted to be renewable, for each portfolio in 2030. Table 140 identifies the percentage of generation capacity mix that is renewable for each portfolio in 2030. Table 141 identifies the percentage of generation capacity credit that is dispatchable/firm for each portfolio in 2030. While the preferred portfolio yields a slightly lower percentage of renewables on an energy supply basis, on a generation capacity supply basis the preferred portfolio has a similar percentage of renewables in its mix as the other portfolios. Importantly, all portfolios achieve Tri-State's aspirational target of having 70 percent clean supply to Members in 2030, but the preferred portfolio does so at the least cost.

Table 139: Comparison of Renewables' Contribution to System and Member Supply in 2030, by Portfolio

	2030 System Energy Mix	2030 Tri-State Energy Supply to Members
	% Renewables	
Portfolio 1: NEE	57%	75%
Portfolio 2: NELG	57%	75%
Portfolio 3: FLEX	57%	75%
Portfolio 4: FLEXSR	55%	71%
Portfolio 5: NNG	58%	75%
Portfolio 6: NNGSR	57%	72%

Table 140: Comparison of Renewables' Contribution to Generation Capacity in 2030, by Portfolio

	2030 Generation Capacity Mix
	% Renewables
Portfolio 1: NEE	49%
Portfolio 2: NELG	48%
Portfolio 3: FLEX	48%
Portfolio 4: FLEXSR	48%
Portfolio 5: NNG	47%
Portfolio 6: NNGSR	49%

Table 141: Comparison of Dispatchable/Firm Contribution to the System Mix in 2030, by Portfolio

	2030 Generation Capacity Credit
	% Dispatchable/Firm
Portfolio 1: NEE	78%
Portfolio 2: NELG	76%
Portfolio 3: FLEX	77%
Portfolio 4: FLEXSR	80%
Portfolio 5: NNG	71%
Portfolio 6: NNGSR	73%

Curtailments

The following table identifies the annual total curtailment costs (PPA pricing, penalties, and taxes) estimated to result from the modeled curtailments, by resource type. None of the portfolios result in wind PPA curtailment costs. Significant solar curtailment costs in all portfolios reflects the inherent challenges in integrating a large amount of intermittent resources into the system in a short timespan. More intermittent resources leads to more curtailment, but storage additions mitigate curtailments.

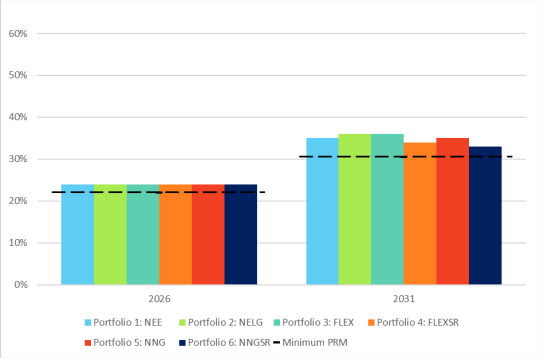
Table 142: Comparison of Solar Curtailment Costs by Portfolio, Real (2024) $

	Portfolio 1: NEE	Portfolio 2: NELG	Portfolio 3: FLEX	Portfolio 4: FLEXSR	Portfolio 5: NNG	Portfolio 6: NNGSR
2026	$145,247	$156,979	$125,261	$152,487	$138,416	$166,014
2027	$224,019	$114,621	$151,371	$193,537	$105,188	$171,286
2028	$214,350	$143,388	$107,958	$90,037	$198,901	$42,920
2029	$18,138	$56,325	$18,876	$51,807	$31,189	$798
2030	$0	$0	$0	$0	$0	$0
2031	$0	$0	$0	$0	$0	$0
RAP Total	**$601,754**	**$471,313**	**$403,466**	**$487,868**	**$473,694**	**$381,018**

Reliability Analysis

PRMs are relatively consistent across all portfolios. Increasing PRMs after 2026 occur as a result of the large amount of intermittent resource additions during the RAP.

Figure 21: Comparison of PRMs During the RAP



Each of the portfolios met Level 1 and 2 Reliability Metrics. The preferred portfolio (FLEXSR) achieves reliability in the most cost-effective manner.

NNG and NNGSR portfolios rely on an extensive amount of storage resources to maintain reliability, creating a heavy reliance on a semi-dispatchable technology during the energy transition—a technology that Tri-State has not yet deployed. Storage technology may evolve and improve in both cost and performance in the coming years, thus Tri-State and its Members seek to make investment during this RAP in a manner that result in a balanced and diversified technology mix, at the least cost.

Conclusion

This Implementation Report provides extensive detail on the multiple portfolios modeled. Tri-State believes this analysis builds a clear record that supports approval of Tri-State's preferred portfolio, FLEXSR, including as a result of the analyses provided in Attachments G and H. Tri-State requests the Commission approve Tri-State's preferred portfolio, Portfolio 4 – FLEXSR, as the final cost-effective resource plan for Phase II of the 2023 ERP, pursuant to Rule 3605(h)(II).

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-21

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit JJ: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Proceeding 20A-0528E

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

PROCEEDING NO. 20A-0528E

APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2020 ELECTRIC RESOURCE PLAN

DIRECT TESTIMONY AND ATTACHMENTS OF BRAD NEBERGALL ON BEHALF OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

December 1, 2020

Colorado PUC E-Filings System

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GLOSSARY

Term	Meaning
AQCC	Colorado Air Quality Control Commission
Basin	Basin Electric Power Cooperative
BoR	Bureau of Reclamation
CAISO	California Independent System Operator
CDPHE	Colorado Department of Public Health and Environment
CEP	Clean Energy Plan
CO_2	Carbon Dioxide
DSM	Demand-Side Management
EE	Energy Efficiency
ERP	Electric Resource Plan
EV	Electric Vehicle
GHG	Greenhouse Gas
GW	Gigawatt
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
MW	Megawatt
PSCo	Public Service Company of Colorado
RAP	Resource Acquisition Period
RE Act	Rural Electrification Act
REP	Responsible Energy Plan
RES	Renewable Energy Standard
RFP	Request for Proposals
RPS	Renewable Portfolio Standard
Tri-State	Tri-State Generation and Transmission Association, Inc.
WAPA	Western Area Power Administration
WESC	Wholesale Electric Service Contract

I. INTRODUCTION AND QUALIFICATIONS

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Brad Nebergall. My business address is 1100 West 116th Avenue, Westminster, CO 80234.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: I am employed by Tri-State Generation and Transmission Association, Inc. ("Tri-State") as Senior Vice President, Energy Management.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A: I am testifying on behalf of Tri-State.

Q: PLEASE SUMMARIZE YOUR BACKGROUND AND EXPERIENCE IN THE ELECTRICITY UTILITY INDUSTRY PRIOR TO BECOMING AN EMPLOYEE OF TRI-STATE.

I graduated from Iowa State University with a B.S. in Business Administration and a focus in finance. I also have an MBA from the University of Houston. After several years working in commercial banking, I joined an affiliate of InterNorth in 1986, which eventually merged with another company to become Enron Corp. I spent the next 20 years serving in various roles within Enron affiliates, including founding Enron's natural gas trading business in England, co-founding an initiative to capture opportunities within NOx and SO_2 emissions credits trading, and managing Enron's Midwest Region with responsibility for all power, natural gas and diesel sales to large regional energy consumers. After Enron declared bankruptcy in 2001, I was recruited post-bankruptcy to restructure the wind power

operations of Enron Renewable Energy Corporation. I was responsible for all commercial and operational activities for 28 producing wind farms. I held that position through 2006.

Q: WHEN DID YOU BEGIN YOUR EMPLOYMENT WITH TRI-STATE?

A: I became a Tri-State employee in 2007. In 2008, I was promoted to my current position of Senior Vice President, Energy Management.

Q: WHAT ARE YOUR RESPONSIBILITIES AS SENIOR VICE PRESIDENT, ENERGY MANAGEMENT FOR TRI-STATE?

A: I am responsible for Tri-State's activities related to marketing, energy trading, origination, risk management, resource dispatch, corporate development and resource planning. My responsibilities require that I have knowledge of Tri-State's operations, strategic initiatives, costs/expenses, and long-term commitments to Members, lenders and other third parties. In addition, my job requires that I study and track market and industry conditions, including market prices for Tri-State's purchased fuel, its capital expenses and the price at which wholesale electricity can be bought and sold on the spot market.

Q: DO YOUR RESPONSIBILITIES INVOLVE PLANNING TRI-STATE'S FUTURE GENERATION NEEDS AND THE RESOURCES TRI-STATE WILL BUILD OR PURCHASE TO MEET THOSE NEEDS?

A: Yes. Tri-State's resource planning function is a significant part of my responsibility.

II. PURPOSE OF TESTIMONY

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: Given that this is the first Electric Resource Plan ("ERP") that Tri-State is filing under new Commission Rule 3605, it may be helpful to provide some background on Tri-State and context for the Commission's and parties' consideration of Tri-State's 2020 ERP. In that regard, my testimony begins with an overview of Tri-State, including its organization, membership, and generation and transmission systems, and discusses how Tri-State is different from investor-owned utilities and how those differences are relevant to the Commission's evaluation of Tri-State's ERP.

The next section of my testimony discusses the evolution of the Commission's regulation of Tri-State's resource planning and some of the unique challenges associated with the current ERP cycle. Next, I discuss Tri-State's Responsible Energy Plan ("REP"), which describes Tri-State's vision for transitioning to a clean energy portfolio and grid, and the relationship between the REP and Tri-State's 2020 ERP. The next section of my testimony provides an overview of Tri-State's resource planning process and discusses some of the key considerations that factored into the development of Tri-State's 2020 ERP.

Finally, I will provide an overview of Tri-State's 2020 ERP, including the objectives of the ERP, the various scenarios and alternatives that were considered, and Tri-State's preferred plan for purposes of moving forward into Phase II of this ERP proceeding.

Q: PLEASE IDENTIFY THE OTHER WITNESSES WHO WILL BE TESTIFYING ON BEHALF OF TRI-STATE.

A: Tri-State's witnesses are:

Ms. Lisa Tiffin, Senior Manager, Analytics & Forecasting. Ms. Tiffin will address various topics associated with the Phase I of the ERP, including Tri-State's load forecast, the assessment of existing resources, planning reserve margins, and the forecasted assessment of need for additional resources.

Mr. Brian Thompson, Resource Planning Manager. Mr. Thompson's testimony will address technical aspects of Tri-State's Phase I filing, including costs and benefits of the integration of intermittent renewable energy resources; studies commissioned and prepared by Tri-State to support the development of this filing; modeling assumptions and analytical methodology proposed to assess the costs and benefits of energy storage systems; emissions and water usage and the social cost of carbon.

Mr. Andy Berger, Senior Manager, Environmental Policy. Mr. Berger will provide an overview of the environmental laws and policies influencing Tri-State's resource planning and will explain how compliance with state and federal environmental laws affects Tri-State's Electric Resource Plan ("ERP").

Mr. Christopher Pink, Vice President, Transmission Engineering. Mr. Pink will discuss transmission system capabilities, including injection capabilities, of Tri-State's transmission system, Tri-State's transmission planning process, and, finally, he will provide a discussion of Tri-State's transmission needs and planned projects. He will provide information as required by Commission Rule 3605(d) or identify where such information can be found in the ERP.

Ms. Susan Hunter, Senior Manager, Origination. Ms. Hunter's testimony will address Tri-State's plan for meeting the resource need, including the Phase II evaluation process and Tri-State's proposed RFP.

III. OVERVIEW OF TRI-STATE

Q: SINCE THIS IS THE FIRST TIME THE COMMISSION WILL EVALUATE AND ISSUE A DECISION IN CONNECTION WITH TRI-STATE'S ELECTRIC RESOURCE PLAN, IT MAY BE HELPFUL TO PROVIDE SOME BACKGROUND ON TRI-STATE, ITS MEMBERSHIP, AND ITS MISSION. WHEN WAS TRI-STATE ESTABLISHED?

A: Tri-State was established in 1952.

Q: WHY WAS TRI-STATE ESTABLISHED?

A: A full answer to that question requires a short history review. Congress passed the Rural Electrification Act ("RE Act") in 1936. At that time, 90 percent of rural America lacked electric power. Congress was concerned with the failure of then-existing electric utilities to extend service to rural communities and determined that the national interest would be served by subsidizing rural electrification. The RE Act allowed rural electric distribution cooperatives such as Tri-State's original Members to receive government-subsidized loans to facilitate the delivery of electricity to rural customers.

In late 1951, discussion began among rural electric cooperatives in Colorado, Nebraska, and Wyoming concerning the adequacy of power being supplied to them by the United States Bureau of Reclamation ("BoR"). These cooperatives

ultimately determined that the supply of federal power on which they had historically relied would not be sufficient to meet their growing needs. The cooperatives decided they should develop electric generating facilities that they would own to ensure adequate power supplies for the future. The cooperatives formed Tri-State in 1952 to fulfill that purpose – to ensure a sufficient and reliable power supply for its Utility Members – and Tri-State's Members continue to own and govern Tri-State to meet their collective needs. This is important because this original purpose and the underlying collective benefit for its Members has continued to guide Tri-State and its resource planning decisions for the last nearly 70 years.

Q: WHAT IS TRI-STATE'S MISSION ON BEHALF OF ITS MEMBERSHIP?

A: Tri-State's primary corporate mission is to provide its Utility Members a reliable, affordable, and responsible supply of electricity in accordance with cooperative principles.

Q: PLEASE DESCRIBE TRI-STATE'S MEMBERSHIP.

A: Tri-State has 42 Class A Utility Members and three Non-Utility Members. Tri-State's Utility Members consist of rural electric distribution cooperatives and public power districts which, like Tri-State, operate on a not-for-profit basis. Tri-State's Utility Members include 11 distribution cooperatives located in New Mexico, 17 distribution cooperatives located in Colorado, eight distribution cooperatives located in Wyoming, and two distribution cooperatives and four public power districts located in Nebraska. In addition to providing retail electric service in the

four states in which they are located, certain of Tri-State's Utility Members also provide retail electric service that extends into multiple other states. Tri-State's three Non-Utility Members are all located in Colorado. Figure 1 below generally depicts Tri-State's Utility Members and their service territories.

Figure 1. Tri-State's Utility Members and Their Service Territories



Tri-State operates in interstate commerce and facilitates the generation and transmission of wholesale electricity across a four state, 200,000 square mile area. Tri-State's Utility Members, in turn, serve customers in 56 Colorado counties, 20 Nebraska counties, 28 New Mexico counties, and 14 counties in Wyoming.

All of Tri-State's Colorado Utility Members have voted to exempt themselves from regulation by the Commission, as permitted by the Colorado Public Utilities Law.

Q: HOW IS TRI-STATE GOVERNED?

A: As I have described, Tri-State is a multistate, regional, generation and transmission cooperative corporation that operates on a not-for-profit basis in interstate commerce providing wholesale electric power and transmission services to its Utility Members. To best serve the varying and unique needs of its Members, Tri-State is directly owned and governed by its Members through a Board of Directors.

Tri-State's Board of Directors is comprised of representatives from each of its Utility Members who are elected by the local boards of their respective cooperative or public power district. Tri-State's Board meets on a monthly basis to make decisions regarding the strategic and business affairs of the cooperative. All matters requiring a decision by the Board are decided by a majority vote of the Board members present and voting. Each Utility Member is entitled to one vote. The Members, acting through their representatives on the Board, are responsible for approving rates, major capital investments, long-term contractual commitments and, as relevant here, Tri-State's resource planning decisions.

Recognizing that Board decisions have a significant impact on all Members, the Board acts for the collective benefit of all Members and seeks to treat all Members equitably. This means that Tri-State's assets and system are planned and operated on the basis of mutual benefits and the sharing of costs and risks among all Members. Through its democratic control, Tri-State's Board works to ensure that corporate decisions balance the interests of all Members in all states.

Q: HOW IS TRI-STATE DIFFERENT FROM COLORADO'S INVESTOR-OWNED ELECTRIC UTILITIES?

A: I believe the primary differences are that Tri-State is owned by its Members rather than shareholders, does not seek to generate a profit for outside investors, and is a multistate wholesale electricity supplier that does not provide retail electric service.

Q: WHY ARE THESE DIFFERENCES IMPORTANT TO THE COMMISSION'S CONSIDERATION OF TRI-STATE'S ELECTRIC RESOURCE PLAN?

A: In several ways. First, Tri-State is a wholesale electricity supplier – an aggregator of its Utility Members' loads. It is not a retail electric utility like Colorado's two investor-owned electric utilities. This is important because Tri-State does not have a direct relationship with end-use retail consumers; that relationship is the exclusive province of Tri-State's Utility Members. As a result, Tri-State is not in the same position as Colorado's retail electric IOUs when it comes to certain resource planning issues such as energy efficiency and demand side management.

Second, unlike Colorado's two retail electric IOUs, which are essentially single-state utilities serving only Colorado customers, Tri-State is a multistate utility serving Members in four states which, in turn, serve customers in multiple states. This difference is important for two reasons. Rather than having a system that is designed to serve the needs of only one state, Tri-State's system has for decades been designed, constructed and operated to serve its Members in multiple states and without regard to state boundaries. As a result, Tri-State's resource planning decisions in Colorado, as well as the Commission's decisions within the scope of its resource planning authority, will have an impact on system operations outside of Colorado and vice versa. Likewise, Tri-State's integrated system must take into consideration the legislative and regulatory requirements and public policy goals of all states in which it operates, not just in Colorado.[1] These state requirements and goals differ among the states yet, under the cooperative business model, the associated costs of compliance are shared by all Members in all states.

Finally, while Tri-State's Board and Members share the Commission's interest in ensuring a reliable and affordable power supply, Tri-State's not-for-profit business model means many of the issues related to utility profits and ownership of resources, which frequently arise in IOU ERP proceedings and lead into subsequent rate cases, are not present in Tri-State's ERP. And, like the wholesale power rates of Colorado's two electric IOUs, Tri-State's wholesale power rates are

[1] Tri-State also has resource planning obligations and submits an Integrated Resource Plan to the Western Area Power Administration.

regulated by the Federal Energy Regulatory Commission ("FERC").

These and other differences between Tri-State and the two Colorado electric IOUs require different considerations as the Commission evaluates Tri-State's 2020 ERP. These considerations are discussed throughout Tri-State's Electric Resource Plan and the testimony of Tri-State's witnesses.

Q: YOU HAVE MENTIONED TRI-STATE'S INTERSTATE GENERATION AND TRANSMISSION SYSTEM SEVERAL TIMES. PLEASE PROVIDE A BRIEF OVERVIEW OF TRI-STATE'S SYSTEM.

A: Tri-State's generating fleet includes: Craig Generating Station, Laramie River Station, Springerville Generating Station Unit 3, J.M. Shafer Generating Station, Rifle Generating Station, Limon Generating Station, Frank R. Knutson Generating Station, Pyramid Generating Station, and Burlington Generating Station.[2] Tri-State's resource mix also includes power provided by Basin Electric Power Cooperative ("Basin") and the Western Area Power Administration ("WAPA") under long-term power purchase agreements. Finally, Tri-State's resource mix includes power purchase agreements associated with the following existing renewable resources: Cimarron Solar, Kit Carson Windpower, Colorado Highlands Wind, Carousel Wind, San Isabel Solar, Alta Luna Solar, and Twin Buttes II Wind, as well as contracts with six small hydropower producers.

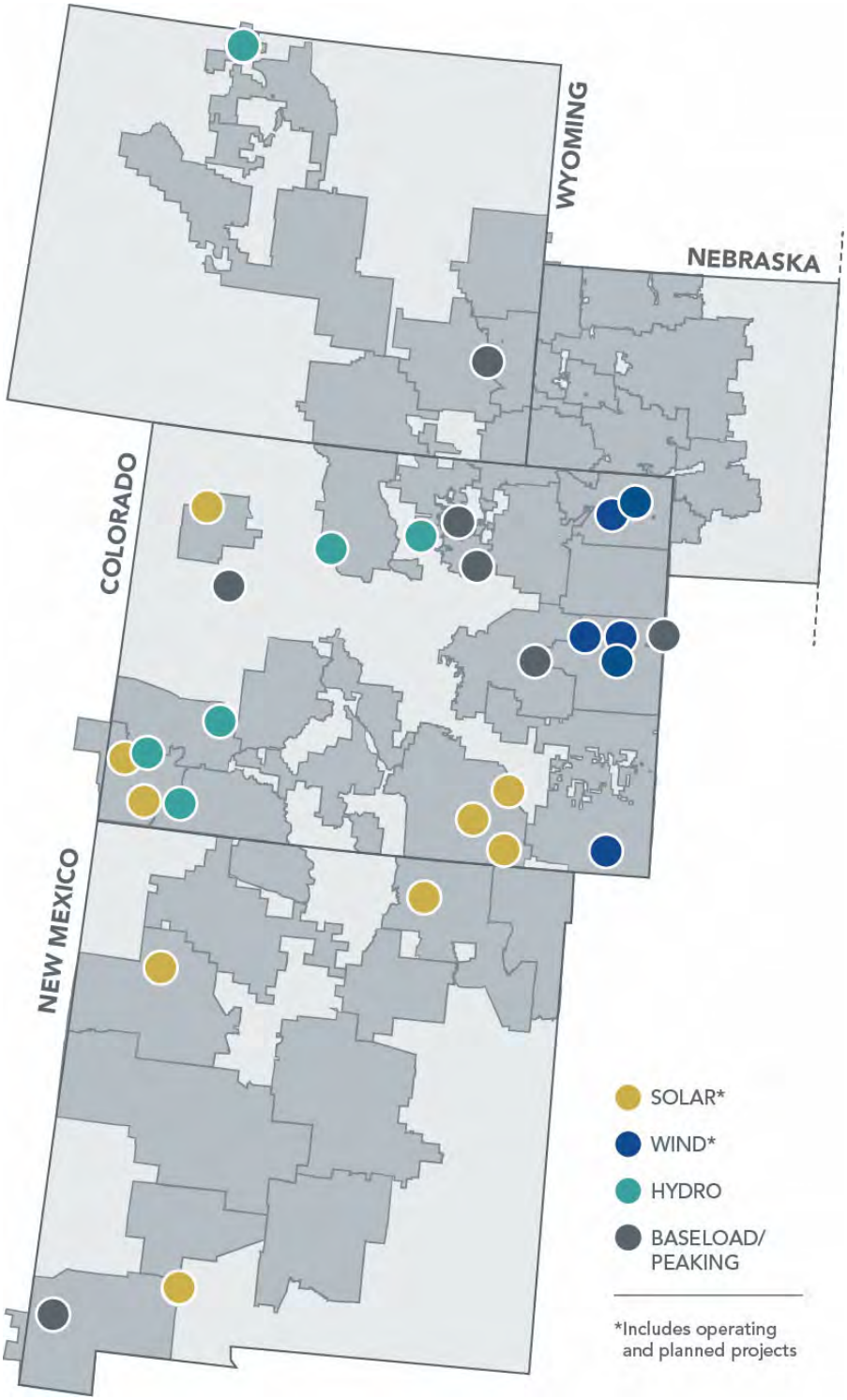
Tri-State's total system resource mix includes 2,432 MW of thermal generation

[2] Tri-State's Escalante Station, located in New Mexico, was retired on November 19, 2020, and is not included in this list.

resources, 452 MW of renewable wind and solar resources, 27 MW of small hydropower resources, and 580 MW of WAPA hydropower resources. Additionally, Tri-State Members own or contract for 131 MW of additional generation resources, consisting of renewable resources such as small solar, hydro, wind, landfill-gas and waste heat.

As a result of competitive bidding processes that Tri-State initiated in 2018 and 2019, Tri-State has executed contracts for additional wind and solar resources that are in various stages of development. Figure 2 below provides a general depiction of Tri-State's operating and planned generation resources. These resources are discussed in greater detail in Volume II of Tri-State's 2020 ERP.

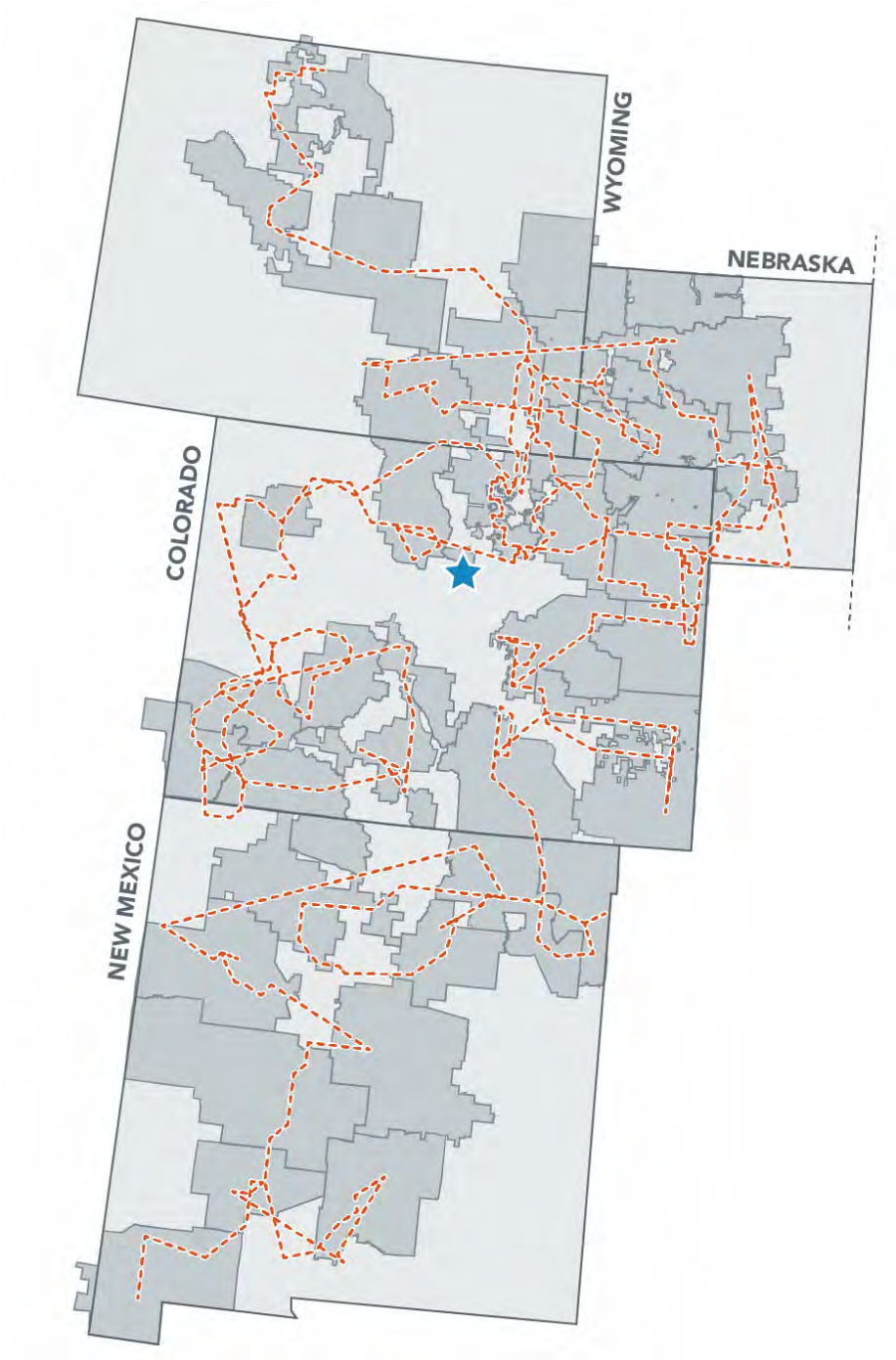
Figure 2. Tri-State's Operating and Planned Generation Resources



In 2019, Tri-State's Utility Member system peak demand was 3,009 MW and Utility Members purchased 16,413 GWh of energy from Tri-State. Tri-State's existing resources, resources under development, plans to retire certain of these resources, and Tri-State's projected resource mix in 2030 are discussed in greater detail in Ms. Tiffin's direct testimony.

Tri-State presently owns, operates, and maintains an extensive interstate transmission system with facilities located in four states: Colorado, New Mexico, Wyoming, and Nebraska. This transmission system includes over 5,665 miles of transmission lines with operating voltages up to 345 kV, 409 substations and switchyards, and over 475 communications sites used for system operations. In addition, Tri-State owns and operates the David A. Hamil DC Tie located in Stegall, Nebraska, which provides a means to transfer electric power between the Eastern and Western Interconnections. As of 2020, Tri-State's total transmission system investment is approximately $559,000,000. Tri-State also relies upon wheeling agreements with PSCo, WAPA, Public Service Company of New Mexico ("PNM"), PacifiCorp, and other transmission service providers for delivery of resources to its Utility Members. Figure 3 provides a general depiction of the location and extent of Tri-State's interstate transmission system.

Figure 3. Overview of Tri-State's Transmission System



Mr. Pink discusses Tri-State's transmission system and the information required by Commission Rule 3605(d) in greater detail in his testimony.

IV. REGULATION OF TRI-STATE'S RESOURCE PLANNING

Q: AT THE BEGINNING OF YOUR TESTIMONY, YOU NOTED THAT THIS IS THE FIRST TIME THE COMMISSION WILL BE EVALUATING AND ISSUING A DECISION IN CONNECTION WITH TRI-STATE'S ELECTRIC RESOURCE PLAN. HOW HAS THE COMMISSION'S REGULATION OF TRI-STATE'S ELECTRIC RESOURCE PLAN CHANGED OVER THE YEARS?

A: During the nearly 70 years since Tri-State was established, the Commission has regulated Tri-State's resource planning to varying degrees. For the last 10 years, Commission Rule 3605 has required Tri-State to file its ERP as an informational report; however, during that period, the Commission did not conduct related adjudicatory proceedings and the Commission did not issue decisions approving Tri-State's ERP. This approach was the result of a proposal advanced by Tri-State and Western Resource Advocates in Docket No. 09I-041E and approved by the Commission in Decision No. C10-0101. Pursuant to that Decision, Tri-State filed its first ERP report on November 30, 2010, a subsequent full ERP report on October 30, 2015, and Annual Progress Reports in the intervening and subsequent years.

Q: DID THAT INFORMATIONAL FILING REQUIREMENT SUBSEQUENTLY CHANGE?

A: Yes. Pursuant to previous Commission Rule 3603, Tri-State's next full ERP would have been due on October 31, 2019. However, in 2019, the Colorado General Assembly passed Senate Bill 19-236, which became Colorado Revised Statute §

40-2-134. That statute required the Commission to promulgate rules requiring wholesale electric cooperatives to submit electric resource plans to the Commission for approval, and rules for the Commission's evaluation and approval of such ERPs. Given these new requirements and the timing of the associated rulemaking proceedings, Tri-State requested in Proceeding No. 19V-0311E a variance of the October 31, 2019, ERP filing deadline. The Commission granted that variance in Decision No. C19-0629 and held that the timing of Tri-State's next ERP filing would be established in the rulemaking proceeding required by § 40-2-134, C.R.S.

On July 31, 2019, the Commission issued its Notice of Proposed Rulemaking in Proceeding No. 19R-0408E regarding electric resource planning rules for wholesale electric cooperatives. The resulting new Rule 3605 went into effect nearly one year later on July 15, 2020, and established a December 1, 2020, filing deadline for Tri-State's full ERP. Commission Rule 3605 requires that Tri-State submit an electric resource plan that, in many respects, is substantially similar to those required of PSCo and Black Hills Energy. Rule 3605 also provides for Phase I and Phase II ERP processes for Tri-State.

Unique to this first ERP filing, Rule 3605 also required Tri-State to file the Assessment of Existing Resources section of its ERP into an adjudicated proceeding on June 1, 2020, for review by the Commission and interested parties. Finally, I would note that certain of the Commission's ERP rules that are at issue in Proceeding No. 19R-0096E apply to Tri-State; however, those rules have not

been finalized and, therefore, are not incorporated into Tri-State's 2020 ERP.

Q: HOW IS THE CHANGE IN THE RESOURCE PLANNING RULES RELEVANT TO THE COMMISSION'S CONSIDERATION OF TRI-STATE'S 2020 ELECTRIC RESOURCE PLAN?

A: The change in resource planning rules applicable to Tri-State presents primarily practical challenges that Tri-State believes the Commission should consider as it evaluates this first ERP under the new rules.

First, the new rules presented timing challenges for Tri-State. While Tri-State was preparing to file its ERP in October 2019 under the prior resource planning rules applicable to Tri-State, those efforts were largely suspended when SB19-236 became law and Tri-State awaited the Commission's development of new resource planning rules for wholesale electric cooperatives. As noted previously, those new rules did not take effect until July 15, 2020 – only four-and-a-half months before Tri-State's first ERP under the rules was due to be filed. Tri-State had a general understanding of what those rules would be as a result of participation in the rulemaking proceeding; however, it could not proceed with certainty until the rules were finalized.

At the same time, Tri-State was required to prepare, file, and respond to numerous and extensive discovery requests related to its June 1, 2020, Assessment of Existing Resources (Proceeding No. 20M-0218E). The Rule 3605(c) information required in this advance filing ordinarily would not be filed separately and would be included in the full ERP itself, as is the case for similar information contained in the

ERPs filed by Public Service and Black Hills. However, in its Decision Adopting Rules, the Commission explained that such advance filing would "allow for Staff and other parties to Tri-State's initial 2020 ERP proceeding to conduct discovery and learn about Tri-State's generation fleet and the underlying financial requirements in the months leading to the later assessment of Tri-State's complete ERP filing." Given the limited nature of the Commission's historical involvement in Tri-State's resource planning, Tri-State recognizes the potential benefits of providing this information in advance of its initial ERP filing. Nevertheless, preparing that filing and responding to over 750 discovery requests presented a substantial challenge at the same time that the same Tri-State personnel were working on the scenario development, modeling, and analyses for the full ERP.

During the course of the Assessment of Existing Resources proceeding, several parties provided recommendations concerning the process for developing, or the contents of, Tri-State's ERP. As Tri-State explained in its response to initial comments filed in that proceeding, not all of those recommendations were appropriate, and it was impossible to accommodate certain of these recommendations in time for the 2020 ERP filing. Depending on the particular recommendation, further changes could be addressed in a subsequent rulemaking or incorporated into Tri-State's next ERP, which is scheduled to be filed on June 1, 2023.

When the Commission deliberated on whether to close the Assessment of Existing Resources proceeding, it discussed further expectations of what Tri-State should

include in its full ERP filing. The Commission's written decision, however, did not issue until the afternoon of November 25, 2020 – two business days before the ERP was due on December 1, 2020. Accordingly, Tri-State did not have the Commission's written decision so as to specifically inform it of these additional requirements or in time to address all of these requirements in the ERP filing. Tri-State will review these new requirements and will supplement its ERP filing, as appropriate, as soon as possible.

Tri-State encourages the Commission to use this first ERP under the new rules to determine what does and does not make sense for purposes of the Commission's review of Tri-State's 2020 ERP, and consider any potential additional or changed requirements in the context of the 2023 ERP.

V. TRI-STATE'S RESPONSIBLE ENERGY PLAN

Q: IN JANUARY 2020, TRI-STATE ANNOUNCED ITS RESPONSIBLE ENERGY PLAN. PLEASE PROVIDE AN OVERVIEW OF THAT PLAN.

A: Earlier this year, Tri-State's Board of Directors described its vision for the future of the cooperative in the Responsible Energy Plan ("REP"). The Responsible Energy Plan is included as **Attachment BN-1** to my testimony and outlines Tri-State's commitments and goals to help make that vision a reality. The REP focuses on reducing Tri-State's greenhouse gas ("GHG") and carbon dioxide ("CO_2") emissions, increasing Tri-State's use of renewable and clean energy resources, increasing Utility Member flexibility with respect to their power supply options, extending the benefits of a clean grid to our Utility Members and their customers

through various beneficial electrification initiatives, supporting our employees and communities as Tri-State implements these transitions, and striving to meet Colorado's clean energy goals while maintaining or reducing Tri-State's wholesale rates to its Utility Members.

Q: SINCE JANUARY, SOME QUESTIONS HAVE BEEN RAISED CONCERNING THE DECISIONS INCLUDED IN TRI-STATE'S REP AND THE COMMISSION'S RESOURCE PLANNING AUTHORITY OVER TRI-STATE. WHAT IS TRI-STATE'S POSITION RELATIVE TO THIS ISSUE?

A: Following SB19-236 being signed into law last year, Tri-State recognizes that its electric resource plans are subject to review and approval by the Commission. The announcement of the REP does not intrude upon or interfere with the Commission's resource planning jurisdiction. Some actions related to the REP - such as the retirement of existing generation resources, the assessment of need for additional resources, and Tri-State's plans for acquiring those resources - will require Commission approval in this or subsequent proceedings, and Tri-State will apply for those approvals. Other REP actions, however, do not necessarily require Commission approval; these include changes to the wholesale contract structure between Tri-State and its Utility Members, support for Utility Members' electric vehicle programs and other beneficial electrification initiatives, and Tri-State's support for employees and communities impacted by the transition from fossil fueled generation.

Q: LET'S DISCUSS THE REP COMPONENTS IN MORE DETAIL. PLEASE DESCRIBE HOW THE RESPONSIBLE ENERGY PLAN IS INTENDED TO REDUCE TRI-STATE'S GREENHOUSE GAS AND CARBON DIOXIDE EMISSIONS.

A: The REP, as originally announced, called for actions that would result by 2030 in a reduction of 90%, relative to 2005 levels, in the CO_2 emissions from generation resources owned or operated by Tri-State in Colorado. These actions were part of an overall effort that would also result in in a reduction of 70% by 2030, in the CO_2 emissions associated with Tri-State's Colorado wholesale power sales, compared to the base year of 2005. The REP contemplated a combination of plant retirements, the addition of new clean energy resources, and other actions needed to achieve these reductions including the retirement of the three Craig Station units by 2030. Additionally, the REP committed Tri-State to cancel its participation in the Holcomb Station project. These REP actions in Colorado are paired with Tri-State's decision to retire the Escalante Station in New Mexico by the end of 2020, and Tri-State separately announced the early retirement of the Nucla Station in 2019.

Q: DURING THE ASSESSMENT OF EXISTING RESOURCES PROCEEDING, SOME COMMENTERS CLAIMED THAT TRI-STATE'S RESPONSIBLE ENERGY PLAN WOULD NOT ACHIEVE THE 70% REDUCTION IN CO2 EMISSIONS IN COLORADO BY 2030 THAT YOU JUST MENTIONED. WERE THOSE CLAIMS ACCURATE?

A: No. I believe those commenters confused the base case projections in the Assessment of Existing Resources with the REP initiatives. The 34% CO_2 emissions reduction shown in the base case projections reflected a "business as usual" base case and did not include GHG and CO_2 emission restrictions. It was not intended to illustrate all of Tri-State's Responsible Energy Plan commitments or the emission reductions associated with it, nor did it include additional actions required to reach Colorado GHG emission targets. Tri-State has modeled many scenarios for its full ERP, including scenarios related to CO_2 emission reduction and costs as required by Rule 3605 and to meet the commitments of the Responsible Energy Plan. These scenarios and the associated emission reductions are discussed in the testimony of Ms. Tiffin.

Q: HAS TRI-STATE SUBSEQUENTLY REVISED ITS EMISSION REDUCTION PLANS AS COMPARED TO WHAT WAS ORIGINALLY DESCRIBED IN THE RESPONSIBLE ENERGY PLAN?

A: Yes. Tri-State's plans for emission reductions continue to evolve. The REP, as originally presented, called for a reduction of 70%, relative to 2005 levels, in the CO_2 emissions associated with Tri-State's Colorado wholesale power sales by 2030. The preferred plan included in Tri-State's 2020 ERP now calls for a reduction of 80%, relative to 2005 levels, in the CO_2 emissions associated with Tri-State's Colorado wholesale power sales by 2030. This is consistent with Colorado's overall GHG and CO_2 emission reduction goals and is consistent with what would be required if Tri-State had voluntarily submitted a Clean Energy Plan.

Tri-State's preferred plan is discussed in greater detail in Ms. Tiffin's direct testimony.

Q: PLEASE DESCRIBE THE RESPONSIBLE ENERGY PLAN'S PROVISIONS RELATED TO INCREASING TRI-STATE'S USE OF RENEWABLE AND CLEAN ENERGY RESOURCES.

A: The REP calls for Tri-State to add to its system one Gigawatt (1 GW) of new utility scale renewable energy projects by 2024. These new resources consist of six utility scale solar projects and two utility scale wind projects: Axial Basin Solar (145 MW; 2023), Coyote Gulch Solar (120 MW; 2023), Dolores Canyon Solar (110 MW; 2023), Escalante Solar (200 MW; 2023), Spanish Peaks Solar (100 MW; 2022), Spanish Peaks II Solar (40 MW; 2023), Crossing Trails Wind (104 MW; 2020), and Niyol Wind (200 MW; 2021).[3] (See Figure 2) These additions will bring Tri-State's total renewable resources to over 2 GW, and we forecast that by 2024 50% of the power consumed by Tri-State's Utility Members' customers will come from renewable resources.

Q: IN THE ASSESSMENT OF EXISTING RESOURCES PROCEEDING THAT PRECEDED THIS ERP, SOME PARTIES EXPRESSED CONCERNS REGARDING THE POWER PURCHASE AGREEMENTS ("PPAs") TRI-STATE ENTERED INTO IN CONNECTION WITH THESE NEW RESOURCES. PLEASE EXPLAIN TRI-STATE'S POSITION WITH REGARD TO THOSE PPAs.

[3] Figures and dates represent each project's nameplate capacity and anticipated commercial operation date.

A: First, I would note that Tri-State provided detailed data on these PPAs as part of its Assessment of Existing Resources and throughout the discovery process in Proceeding No. 20M-0218E. Information on these resources also is included in the revised Assessment of Existing Resources in the 2020 ERP.

These eight resources were contracted through a competitive request for proposals ("RFP") process in 2018 and 2019 prior to the Commission's new ERP rules for Tri-State. Tri-State's competitive acquisition process assured that these new resources provide the best value for its Utility Members. Furthermore, the timing of this competitive acquisition process was intended to ensure that the projects, and by extension Tri-State and its Utility Members, could secure the maximum benefits under the Investment Tax Credit and Production Tax Credit.

These resources will play a significant role in Tri-State's transition to a cleaner portfolio and its ability to timely achieve its emission reduction objectives. These resources also contribute to achieving Colorado's overall legislative and policy goals related to clean energy and emission reductions. Revisiting, let alone reopening, these past renewable RFPs would be counterproductive to Colorado's policy goals and to the interests of Tri-State's Utility Members and their customers in Colorado and in other States. Tri-State believes that the present ERP process should focus on future resource acquisitions and the retirement of existing resources.

Q: WHAT STEPS HAS TRI-STATE TAKEN UNDER THE RESPONSIBLE ENERGY PLAN TO INCREASE ITS UTILITY MEMBERS' FLEXIBILITY WITH REGARD TO POWER SUPPLY OPTIONS?

A: For nearly 20 years, Tri-State's Utility Members have had the option to self-generate up to 5% of the energy they need to serve their member-customers. This option has been very popular and successful, with approximately half of Tri-State's Utility Members taking advantage of it, resulting in 130 MW of renewable energy projects in service or under development. Over the years, Tri-State has provided substantial financial subsidies in connection with such projects. Furthermore, some of Tri-State's Utility Members also have developed local renewable energy projects that exceed the 5% self-generation option pursuant to a Tri-State Board policy addressing such projects.

Given the growing interest in local clean energy, many of Tri-State's Utility Members have expressed a desire for more flexibility in their power supply options. In response, the Tri-State Board, as part of the REP and otherwise, has taken a number of steps to provide that flexibility.

In December 2019, the Tri-State Board approved a new community solar program developed and recommended by the Members' Contract Committee. Under that program, Utility Members have the option to build or contract for community solar projects up to established energy thresholds. Solar generation under the program would not be included in the 5% self-supply option in the Utility Members' Wholesale Electric Service Contract ("WESC") with Tri-State. If all Tri-State Utility

Members took advantage of this new program, it would yield 63 MW of new local community solar projects. This program is being considered by the Federal Energy Regulatory Commission ("FERC") in a pending proceeding.

In 2019, the same Contract Committee began considering possible changes to the WESC that would provide Utility Members even greater power supply flexibility in the form of a partial requirements contract. In October 2020, the Tri-State Board approved a flexible partial requirements contract option and its associated board policies. Under that option, Utility Members may express their intent to transition from their current full requirements contract to a partial requirements contract by participating in an "open season" that will begin in early 2021. This initial "open season" will allocate up to 300 MW to the Utility Members. This self-supply option is in addition to the 5% self-supply option already included in the WESC and the community solar option. The partial requirements contract option also is being considered by FERC in a pending proceeding.

Q: HOW ARE THESE VARIOUS SELF-SUPPLY OPTIONS FACTORED INTO TRI-STATE'S 2020 ERP?

A: While we know which of Tri-State's Utility Members already are taking advantage of the 5% self-supply option under the WESC, we don't yet know how many Utility Members will implement community solar projects or transition to partial requirements contracts and, if so, in what capacity amounts. This challenge and how it was considered in the 2020 ERP is discussed in the testimony of Ms. Tiffin.

Q: YOU MENTIONED ONE OF THE RESPONSIBLE ENERGY PLAN'S OBJECTIVES IS TO EXTEND THE BENEFITS OF A CLEAN GRID TO TRI-STATE'S UTILITY MEMBERS AND THEIR CUSTOMERS. PLEASE EXPLAIN THAT AND THE STEPS TRI-STATE HAS TAKEN SO FAR.

A: Tri-State recognizes that the transition to a cleaner grid and power supply brings opportunities to power homes and businesses with reduced emissions electricity and to more efficiently use that electricity. Tri-State is committed to making sure that its Utility Members, and the retail end-use customers they serve, are able to take advantage of these opportunities.

So far, Tri-State has committed $2 million to extend the electric vehicle ("EV") charging network across our Utility Members' service territories by allocating each Utility Member $45,000 to install EV charging stations. Access to these charging facilities will make EV charging more available in rural communities and will give rural consumers the option to choose an EV the next time they buy a vehicle. It also will substantially expand the regional and state EV charging networks for everyone to use thereby advancing one of the Governor's Roadmap goals. Tri-State also is working with its Utility Members to explore additional opportunities for energy efficiency and demand-side management programs that can lower energy bills and energy use. Tri-State's beneficial electrification, EE and DSM initiatives, and the role they play in Tri-State's 2020 ERP are discussed further in the testimony of Ms. Tiffin.

Q: HOW IS TRI-STATE SUPPORTING ITS EMPLOYEES AND THE VARIOUS COLORADO COMMUNITIES THAT WILL BE AFFECTED BY THE REP AND THE SHIFT TOWARD CLEAN GENERATION RESOURCES?

A: Tri-State recognizes that its transition to a cleaner energy portfolio will affect the many employees who have worked hard for decades to "keep the lights on" by ensuring the safe and reliable operation of Tri-State's coal-fired power plants, and also will affect the Tri-State and subsidiary employees who have ensured the fuel supply for those plants. Similarly, this transition will affect the communities in which those plants are located.

Tri-State is providing support to the communities impacted by plant closures. For Craig Station and the Colowyo Mine, Tri-State is providing retraining and transition support for employees. Tri-State is working with its employees and community members to identify economic development opportunities, retraining programs, and other strategies to ease the transition over time. For example, one of the new solar projects I mentioned will be located on Colowyo Mine property. Tri-State also is working with local, state, federal, and industry leaders to develop, provide financial support for, and implement retraining, educational, and economic development solutions in addition to those that Tri-State is implementing on its own. While this issue is not addressed in the Commission's ERP rules for Tri-State, it is an important issue to Tri-State, its employees, and the impacted communities.]

VI. TRI-STATE'S 2020 ELECTRIC RESOURCE PLAN

Q: WHAT ARE THE OBJECTIVES OF TRI-STATE'S 2020 ERP?

A: Consistent with the Commission's ERP Rules, Tri-State's 2020 ERP is intended to describe Tri-State's need for additional electric resources, and ultimately identify a cost-effective resource portfolio to reliably meet such need. Tri-State's 2020 ERP also is intended to accomplish these regulatory objectives while complying with the legislative and public policy requirements and goals that I discussed previously, and advancing progress toward Tri-State's own goals set forth in the Responsible Energy Plan.

I also would note that the 2020 ERP, together with the complementary initiatives in the REP, is intended to respond to what Tri-State's Utility Members and their member-customers have been asking for – a transition to a cleaner power supply, reduced GHG emissions, and an opportunity to realize the potential benefits of lower cost electricity. Tri-State believes that the preferred plan submitted as a part of the 2020 ERP meets these objectives.

Q: PLEASE PROVIDE AN OVERVIEW OF THE ERP FILING.

A: Tri-State's 2020 ERP consists of two volumes containing the ERP itself and 18 appendices. Tri-State's 2020 ERP is included as **Attachment BN-2** to my testimony.

The ERP begins with an Executive Summary and an Introduction and Background section that discusses the development and organization of the 2020 ERP, and provides an update on progress made since Tri-State's 2015 ERP informational

filing.

The next section of the ERP addresses the current resource planning "landscape" in terms of Tri-State's system energy mix, market dynamics, and other external factors, and presents much of the information required by Rule 3605(a)(IV). As discussed in this section, Tri-State's 2020 ERP uses a 20-year resource planning period from 2021 through 2040 and, as required by Rule 3605(a)(IV)(A), a 10-year resource acquisition period ("RAP") beginning in 2021 and extending to the end of 2030. Tri-State believes that the next 12 to 24 months will provide greater clarity with respect to the variables, challenges, and opportunities that I discussed previously, and Tri-State recommends a measured approach to acquiring new resources during the RAP. Furthermore, Tri-State believes that additional time may allow for the development of new non-emitting dispatchable resources that could be cost-competitive for future acquisition, and Tri-State's 2023 ERP will provide an opportunity in the relatively near future to further consider these options.

The next section of the ERP provides Tri-State's assessment of resource needs, including current load and resource balance, RES/RPS requirements, GHG/CO2 reductions and demand-side management and energy efficiency.

The next section of the ERP presents Tri-State's Alternative Resource Analysis. This section discusses the Base Case as well as the multiple alternative plans that Tri-State considered, including the social cost of carbon and other plans required by Commission rules. This section compares the various plans and presents Tri-State's preferred plan. The next section outlines Tri-State's action plan for the

RAP, including the competitive bidding process and the ERP Implementation Report Plan.

The last section of Volume I of the ERP identifies the relevant confidential and highly confidential information, as required by Rule 3605(a)(IV)(K).

The first section of Volume II of the ERP provides load forecasting as required by Rule 3605(b) followed by details on commodity pricing.

The next section of the ERP presents Tri-State's Assessment of Existing Resources, including some of the information identified in the Commission's November 25, 2020 written decision closing Proceeding No. 20M-0218E.

The next section of the ERP addresses Tri-State's transmission system and transmission planning, and presents the information required by Rule 3605(d).

The next section of the ERP discusses in detail the Phase I modeling including constraints, assumptions, and methodology.

The last section of the report includes detailed environmental data for all scenarios.

Q: WHAT IS THE RESOURCE NEED IDENTIFIED IN THE ERP?

A: Tri-State's analysis shows a need for new capacity to provide replacement capacity support for the retirement of the Craig 3 unit in 2029. Tri-State also identifies the preferred addition of renewable and energy storage resources prior to that time, which will serve to achieve GHG reductions in the relatively near-term.

Q: PLEASE DESCRIBE THE ALTERNATIVES TRI-STATE CONSIDERED IN DEVELOPING THE 2020 ERP.

A: In addition to the Base Case, Tri-State considered seven alternative plans: four different base load scenarios yielding an 80% Colorado CO_2 emissions reduction, relative to a 2005 baseline, by 2030; two different low load scenarios yielding 80% Colorado CO_2 emissions reductions, relative to a 2005 baseline, by 2030; and a scenario that applies the social cost of carbon to all thermal generation units. Table 1 below provides a summary of the alternatives Tri-State considered.

Table 1. Summary of Electric Resource Plan Scenarios

Scenario	**Description**
Base Case	Business as usual case to be used as a reference to measure other scenarios against.
80% CR V1	An 80% carbon-reduction by 2030 from a 2005 baseline for Colorado wholesale electricity sales scenario that includes forced (i.e. not a cost-driven model selection) expansion plan low level demand-response and aggressive level energy efficiency resources in Colorado.
80% CR V2	An 80% carbon-reduction by 2030 from a 2005 baseline for Colorado wholesale electricity sales scenario that includes only existing demand-side management and energy efficiency.
80% CR V3	An 80% carbon-reduction by 2030 from a 2005 baseline for Colorado wholesale electricity sales scenario that is similar to 80% CR V2, but includes an additional wind

	resource to improve carbon dioxide reduction and enhance reliability.
80% CR V4	An 80% carbon-reduction by 2030 scenario that is similar to 80% CR V2, but includes an additional solar resource to improve carbon dioxide reduction and enhance reliability.
Low Load 80% CR V1	An 80% carbon-reduction by 2030 scenario that allows for low-level demand-response and/or low- or aggressive-level energy efficiency resources and uses the low load forecast.
Low Load 80% CR V2	An 80% carbon-reduction by 2030 scenario that includes only existing demand-side management and energy efficiency resources and uses the low load forecast.
Social Cost of Carbon	A Social Cost of Carbon scenario that uses the technical support document under Executive Order 12866—Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis, to determine the social cost of carbon and it applies the appropriate cost to carbon-emitting resources.

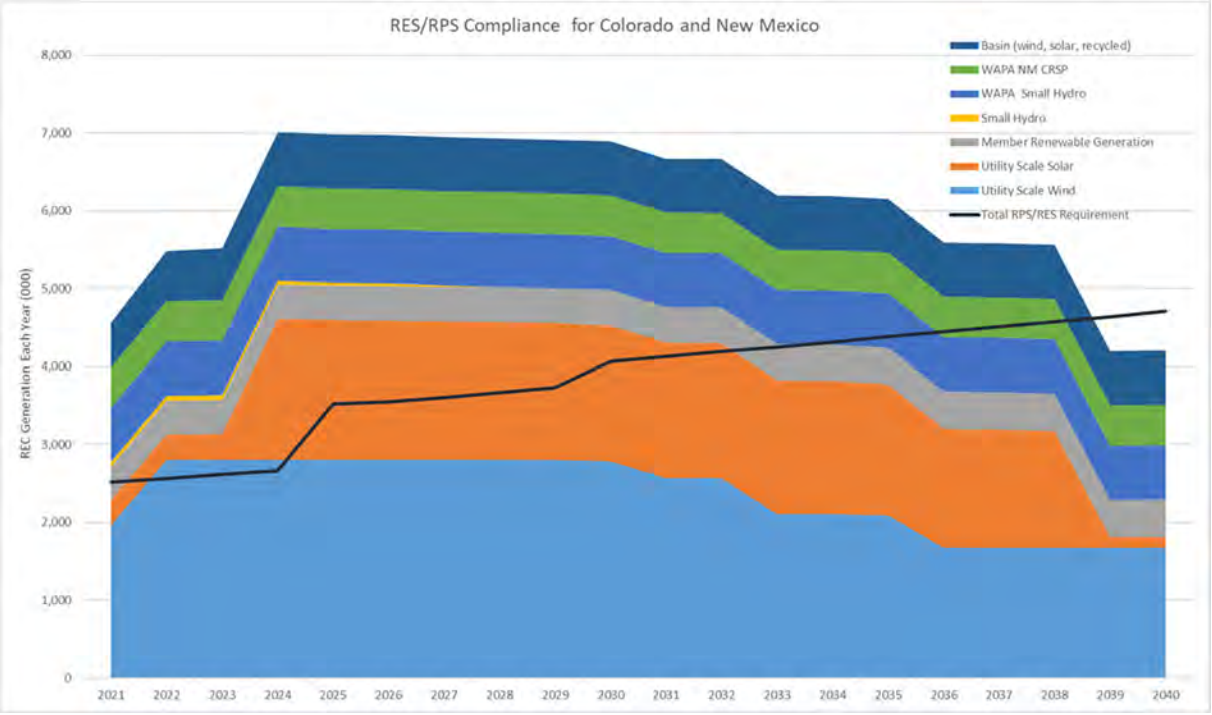
Q: IS TRI-STATE PRESENTING A PREFERRED PLAN IN ITS 2020 ERP?

A: Yes. Tri-State's preferred plan, which is forecast to result in an 80% CO_2 reduction as previously described, is detailed in Ms. Tiffin's testimony.

Q: DOES THE PREFERRED PLAN ENABLE TRI-STATE TO COMPLY WITH ITS COLORADO RENEWABLE ENERGY STANDARD OBLIGATIONS AND SUPPORT ITS COLORADO UTILITY MEMBERS' OWN RENEWABLE ENERGY STANDARD AND RENEWABLE PORTFOLIO STANDARD OBLIGATIONS?

A: Yes. Given that Tri-State operates an integrated generation and transmission system, the preferred plan will provide for compliance with Tri-State's and the Utility Members' RES and RPS obligations in Colorado and New Mexico. Figure 4 graphically depicts Tri-State's compliance with Colorado's RES and New Mexico's RPS.

Figure 4. RES/RPS Compliance for Colorado and New Mexico



RES and RPS compliance issues are discussed in greater detail in Ms. Tiffin's testimony.

Q: ARE YOU FAMILIAR WITH THE RECENT HEARING AND DECISION BY THE COLORADO AIR QUALITY CONTROL COMMISSION IN CONNECTION WITH THE STATE IMPLEMENTATION PLAN FOR REGIONAL HAZE?

A: I did not participate in that hearing and am not directly responsible for issues related to Tri-State's compliance with the Regional Haze State Implementation Plan. I am, however, generally familiar with the Colorado Air Quality Control Commission's ("AQCC") actions at its recent hearing. Mr. Berger discusses the AQCC's actions in more detail in his testimony.

Q: PLEASE DESCRIBE HOW THE RECENT ACTIONS BY THE AQCC MIGHT INFLUENCE TRI-STATE'S 2020 ERP.

A: On Friday, November 20, 2020, the AQCC took action in a Regional Haze proceeding that would call for the retirement of Craig Unit 3 and several other coal-fired generating units in Colorado by December 31, 2028. The AQCC characterized its action as a "preliminary final action"; as such, the AQCC's decision is not final as of the date of Tri-State's ERP filing, and it is unclear at this time whether the AQCC's final decision will be the same as what was discussed at the recent hearing and, if so, when the final decision will be issued.

While Tri-State will continue to evaluate options related to the AQCC's action, if this action does, in fact, require the retirement of Craig Unit 3 by December 31, 2028, that retirement date would be inconsistent with certain analyses contained in this ERP filing. Specifically, the scenarios in this ERP (except for those requiring consideration of the social cost of carbon) provide for the retirement of Craig Unit

3 one year later, by December 31, 2029. Tri-State will address the AQCC's final decision, as appropriate, during Phase 1 of this ERP proceeding.

Q: DOES TRI-STATE'S 2020 ERP FILING COMPLY WITH THE COMMISSION'S ERP RULES?

A: Yes. Tri-State's 2020 ERP complies with all of the requirements of new Commission Rule 3605. A Compliance Table is included at page 4 in the ERP report.

Q: WHAT APPROVAL IS TRI-STATE REQUESTING IN THIS PROCEEDING?

A: Tri-State requests approval of its 2020 ERP, including Tri-State's assessment of need for additional resources during the current resource acquisition period, Tri-State's plans for acquiring such additional resources, and the proposed RFP to be used in conjunction with such resource acquisitions.

Q: DOES THAT CONCLUDE YOUR TESTIMONY?

A: Yes.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

PROCEEDING NO. 20A-0528E

APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2020 ELECTRIC RESOURCE PLAN

VERIFICATION

STATE OF Colorado)
) ss:
COUNTY OF Adams)

I, Brad Nebergall, being duly sworn, do hereby depose and state that I have read the foregoing Direct Testimony, and the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Signed this 24th day of November, 2020, at Westminster, Colorado.

Subscribed and sworn to before me this 24th day of November, 2020.

Witness my hand and official seal.

Notary Public Faith Warner

My Commission expires: September 7, 2022

FAITH WARNER
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20184035614
MY COMMISSION EXPIRES SEPTEMBER 7, 2022

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-21

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit K: NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2024 Long-Term Reliability Assessment

December 2024

Corrected July 11, 2025



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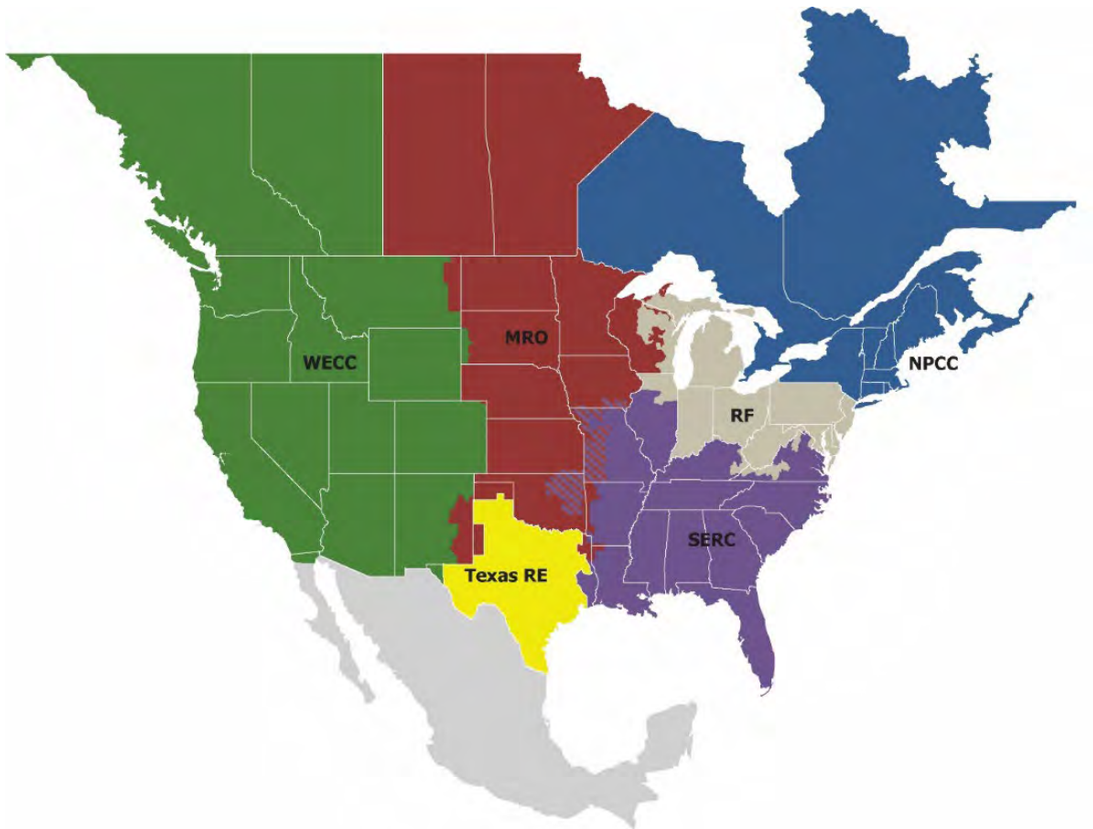
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer-review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer-review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the *Long-Term Reliability Assessment* (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations;[3] this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2024 about known system changes with updates incorporated prior to publication. This *2024 LTRA* assessment period includes projections for 2025–2034; however, some figures and tables examine data and information for the 2024 year. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Demand Assumptions and Resource Categories** section of this report. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; it is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policymakers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

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[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the How NERC Defines BPS Reliability section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

[5] ERO Reliability Assessment Process Document

Assumptions

In this *2024 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2024. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

1. **A reliability assessment of the North American BPS with the following goals:**
   a. Evaluate industry preparations that are in place to meet projections and maintain reliability
   b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
   c. Identify emerging reliability issues
   d. Focus the industry, policymakers, and the general public's attention on BPS reliability issues
   e. Make recommendations based on an independent NERC reliability assessment process
2. **A regional reliability assessment that contains the following:**
   a. A 10-year data dashboard
   b. Summary assessments for each assessment area
   c. A focus on specific issues identified through industry data and emerging issues
   d. A description of regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

In the *2024 LTRA*, NERC finds that most of the North American BPS faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal generators announce plans for retirement. New solar PV, battery, and hybrid resources continue to flood interconnection queues, but completion rates are lagging behind the need for new generation. Furthermore, the performance of these replacement resources is more variable and weather-dependent than the generators they are replacing. As a result, less overall capacity (dispatchable capacity in particular) is being added to the system than what was projected and needed to meet future demand. **The trends point to critical reliability challenges facing the industry: satisfying escalating energy growth, managing generator retirements, and accelerating resource and transmission development.**

This *2024 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next 10 years; it also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS. The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used both a probabilistic assessment and a reserve margin analysis to assess the risk of future electricity supply shortfalls. Both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development.

Areas categorized as **High Risk** fall below established resource adequacy criteria in the next five years. High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Extreme weather, producing wide-area heat waves or deep-freeze events, poses an even greater threat to reliability. **Elevated-Risk** areas meet resource adequacy criteria, but analysis indicates that extreme weather conditions are likely to cause a shortfall in area reserves. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions. The results of the risk assessment are depicted in **Figure 1**.

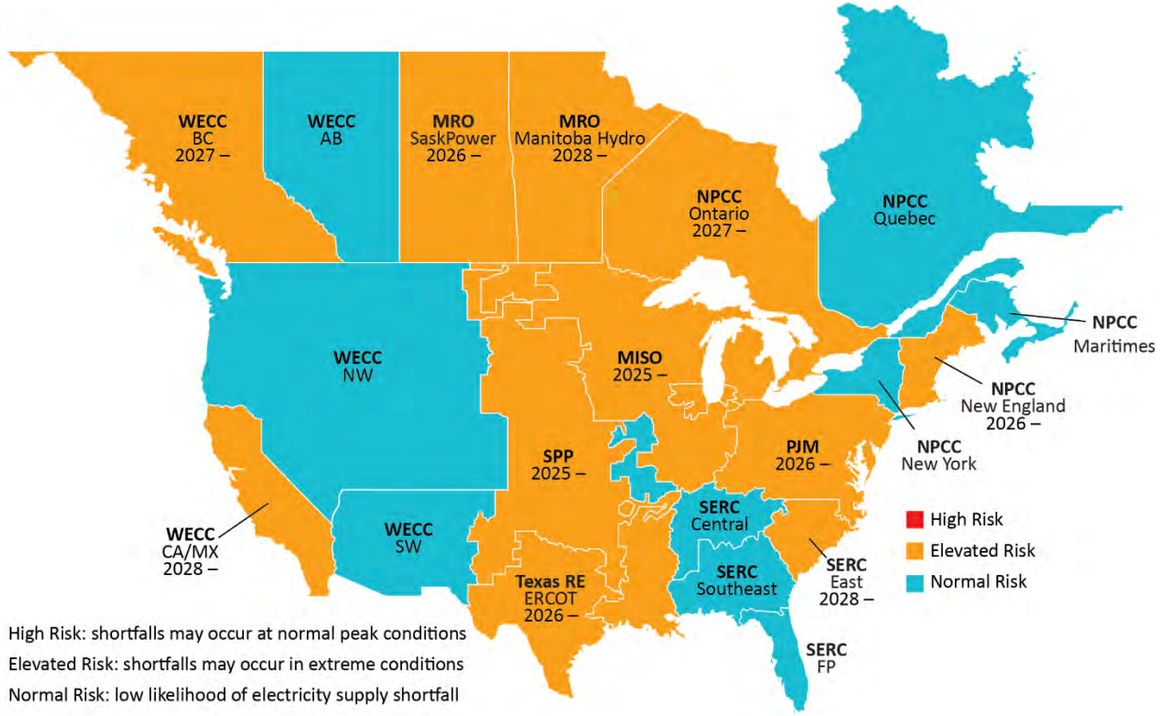


Figure 1: Risk Area Summary 2025–2029 (Corrected July 2025)

Regional Assessments Dashboards

The **Regional Assessments Dashboards** section contains dashboards and summaries for each of the 20 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic Assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Table 1: Capacity and Energy Risk Assessment Area Summary (Corrected June 2025)			
Area	**Risk Level**	**Years**	**Risk Summary**
MISO	Elevated	2025 -	Uncertainty around new resource additions and existing generator retirements results in resource adequacy risks. Above-normal generator outages during extreme weather can result in unserved energy or load loss.
Manitoba	Elevated	2028 -	Potential resource shortfalls in low-hydro conditions, driven by rising demand.
SaskPower	Elevated	2026 -	Risk of insufficient generation during fall and spring when more generators are off-line for maintenance.
Southwest Power Pool (SPP)	Elevated	2025 -	Potential energy shortfalls during peak summer and winter conditions arise from low wind conditions and natural gas fuel risk.
New England	Elevated	2026 -	Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of supply shortfalls in extreme winter conditions.
Ontario	Elevated	2027 -	Reserve margins fall below RMLs as nuclear units undergo refurbishment and some current resource contracts expire. Demand growth is also adding to resource procurement needs.
PJM	Elevated	2026 -	Resource additions are not keeping up with generator retirements and demand growth. Winter seasons replace summer as the higher-risk periods due to generator performance and fuel supply issues.
SERC-East	Elevated	2028 -	Demand growth and planned generator retirements contribute to growing energy risks. Load is at risk in extreme winter conditions that cause demand to soar while supplies are threatened by generator performance, fuel issues, and inability to obtain emergency transfers.
ERCOT	Elevated	2026 -	Surging load growth is driving resource adequacy concerns as the share of dispatchable resources in the mix struggles to keep pace. Extreme winter weather has the potential to cause the most severe load-loss events.
California-Mexico	Elevated	2028 -	Demand growth and planned generator retirements can result in supply shortfalls during wide-area heat events that limit the supply of energy available for import.
British Columbia	Elevated	2027 -	Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Risk from Additional Generator Retirements

Plans for generator retirements continue at similar pace and scale to levels reported in the *2023 LTRA*. Confirmed generator retirements (52 GW by 2029 and 78 GW over the 10-year period) are accounted for in the Capacity and Energy Risk Assessment above. Economic, policy, and regulatory factors spur further fossil-fired generators to retire in the 10-year horizon. Announced retirements, which include many generators that have not begun formal deactivation processes with planning entities, total 115 GW over the 10-year period. The effect of all retirements on the assessment area Planning Reserve Margins (PRM) can be seen in **Figure 2**. On-peak reserve margins fall below RMLs; the levels required by jurisdictional resource adequacy requirements) in the next 10 years in almost every assessment area, signaling an accelerating need for more resources.

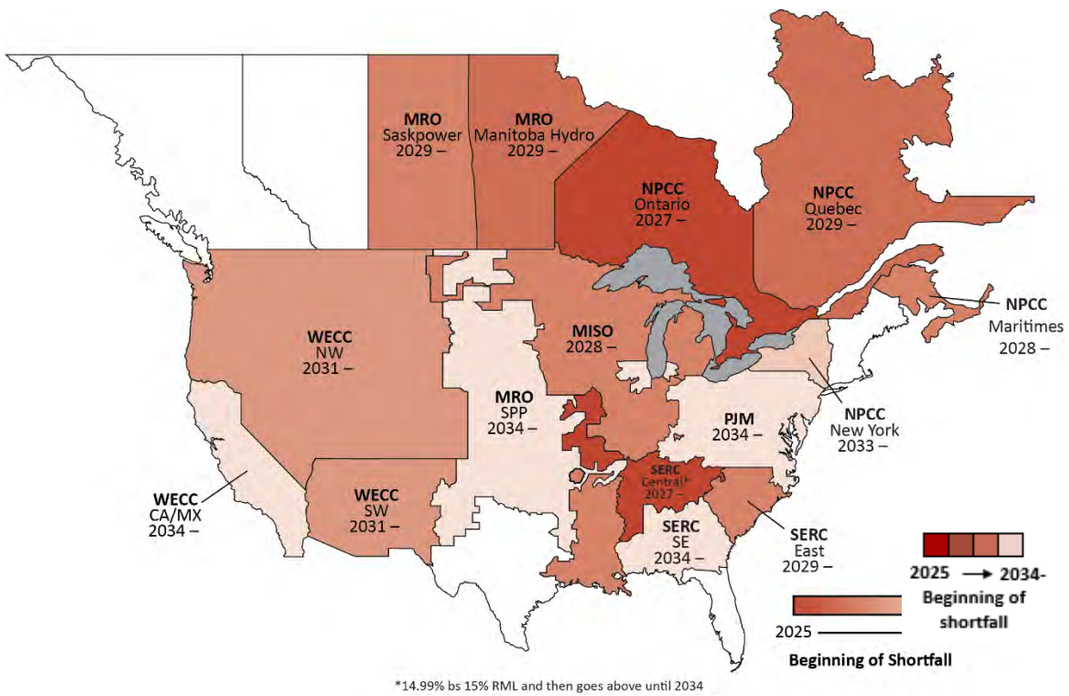


Figure 2: Projected Reserve Margin Shortfall Areas with Announced Generator Retirements (Corrected July 2025)

Changing Resource Mix and Reliability Implications

New resource additions continue at a rapid pace. Solar PV remains the overwhelmingly predominant generation type being added to the BPS followed by battery and hybrid resources, natural-gas-fired generators, and wind turbines. New resource additions fell short of industry's projections from the *2023 LTRA* with the notable exception of batteries, which added more nameplate capacity than was reported in development last year.

As older fossil-fired generators retire and are replaced by more solar PV and wind resources, the resource mix is becoming increasingly variable and weather-dependent. Solar PV, wind, and other variable energy resources (VER) contribute some fraction of their nameplate capacity output to serving demand based on the energy-producing inputs (e.g., solar irradiance, wind speed). The new resources also have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. As generators are deactivated and replaced by new types of resources, ERS must still be maintained for the grid to operate reliably.

Natural-gas-fired generators are a vital BPS resource. They provide ERSs by ramping up and down to balance a more variable resource mix and are a dispatchable electricity supply for winter and times when wind and solar resources are less capable of serving demand. Natural gas pipeline capacity additions over the past seven years are trending downward, and some areas could experience insufficient pipeline capacity for electric generation during peak periods.

Trends and Reliability Implications

Demand and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the **Demand Trends and Implications** and **Transmission Development and Interregional Transfer Capability** sections.

Demand Trends

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb; demand growth is now higher than at any point in the past two decades. Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. The size and speed with which data centers (including crypto and AI) can be constructed and connect to the grid presents unique challenges for demand forecasting and planning for system behavior. Additionally, the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America. The aggregated BPS-wide projections for both winter and summer have increased massively over the 10-year period:

- The aggregated assessment area summer peak demand forecast is expected to rise by 15% for the 10-year period: 132 GW this LTRA up from over 80 GW in the *2023 LTRA*.
- The aggregated assessment area winter peak demand forecast is expected to rise over almost 18% for the 10-year period: 149 GW this LTRA up from almost 92 GW in the *2023 LTRA*.

Transmission Trends

For the first time in recent years, transmission projections reported for the LTRA reflect a significant increase in transmission development. This year's cumulative level of 28,275 miles of transmission (>100 kV) in various stages of development for the next 10 years is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning stages of development.

New transmission projects are being driven to support new generation and enhance reliability. Transmission development continues to be affected by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, 68 projects totaling 1,230 miles of new transmission are delayed by siting and permitting issues, according to data collected for the LTRA. Questions of cost allocation and recovery can also challenge transmission development when the benefits apply to more than one area, as often occurs with projects that enhance interregional transfer capability.

In NERC's separate Interregional Transfer Capability Study (ITCS), which was performed to meet requirements contained in the Fiscal Responsibility Act of 2023, NERC found that an additional 35 GW of transfer capability across the United States would strengthen energy adequacy under extreme conditions. Increasing transfer capability between neighboring transmission systems has the potential to alleviate energy shortfalls in some areas identified in this LTRA's **Capacity and Energy Risk Assessment**. Conversely, when resource plans are developed that address these same energy shortfalls, such as through resource additions, demand-side management initiatives, or changes to generator retirement plans, the need for increased transfer capability will also change. Planners have options for reducing energy adequacy risks from extreme weather. Selecting the best course of action will depend on weighing these options against various engineering, economic, policy, reliability, and resilience objectives.

The ITCS provides foundational insights that facilitate stakeholder analysis and actions; it is not a transmission plan. In the future, NERC will extend the study beyond the congressional mandate to include transfer capabilities from the United States to Canada and among Canadian provinces.

Emerging Issues

The **Emerging Issues** section discusses developments and trends that have the potential to substantially change future long-term demand and resource projections, resource availability, and reliable operations of the BPS. Topics include data centers and large industrial loads, battery energy storage systems, electric vehicles and load, and energy drought. NERC's RSTC has formed new task forces where needed to address emerging issues.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **Integrated Resource Planners, market operators, and regulators: Carefully manage generator deactivations.** Independent System Operator/Regional Transmission Organizations (ISO/RTOs) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations must use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be developed and placed in service.

2. **NERC and Regional Entities: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year's LTRA. To be more effective in using energy criteria and outputs of probabilistic analysis, NERC must specify consistent methods and assumptions for assessment areas to follow in preparing the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC's LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy. Finally, NERC should work with the Regional Entities to perform wide-area energy analysis with modeled interregional transfer capability. Wide-area energy analysis will support the evaluation of extreme weather and regional fuel supply issues on an interconnection level.

3. **Regulators and Policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, delays from siting and permitting activities will need to be reduced. These are the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.

4. **Regulators, electric industry, and gas industry member organizations: Implement a framework for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** Various initiatives were launched in the past year to address the reliability needs that arise from the complexity of interconnecting natural gas and electric infrastructure. Voluntary actions taken by the natural gas industry in response to the North American Energy Standards Board (NAESB) Forum report are a positive step toward improving winter readiness. The National Association of Regulatory Utility Commissioners (NARUC) launched its Gas-Electric Alignment for Reliability (GEAR) task force this year and recently created the Natural Gas Readiness Forum. For its part, NERC continues to collaborate extensively with industry and policymakers. NERC has enhanced its Reliability Standards requiring generators to prepare for winter extremes, implement training, and establish communication protocols between generators and grid operators. Current standards projects encompass extreme weather planning and energy assurance requirements. NERC will continue to provide full support to initiatives aimed at achieving a reliable interconnected energy system and urges regulators and policymakers to support needed avenues of coordination between the two sectors.

5. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure essential reliability services are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.[7] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. All recommendations are listed in the **Recommendations and ERO Actions Summary** section.

[7] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Capacity and Energy Assessment

The resource mix transformation is making traditional capacity-based adequacy criteria obsolete. Resource Planners and state and provincial policymakers use resource adequacy criteria to ensure sufficient resources are available to meet demand. In their application, current capacity-based adequacy criteria were not designed to differentiate between the scenarios, size, frequency, duration, and timing of energy shortfalls. This has become increasingly important as the resource transformation evolves from capacity-based resources with assured and stored energy supplies to energy-constrained resources that are increasingly impacted by weather and environmental conditions. Therefore, supplemental criteria must be adapted to properly assess system adequacy and help determine appropriate solutions. This year's LTRA includes probabilistic indices to measure these additional dimensions of risk and provide a more robust approach to understanding risk of inadequacy in future plans.

Assessment Approach

NERC is using two approaches in this LTRA to assess future resource capacity and energy risk; both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development:

- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours. This approach identifies high-risk periods and potential energy constraints resulting in load-loss events. The 2024 ProbA is performed for each assessment area and examines the system as planned for the years 2026 and 2028. Loss-of-load hours (LOLH) and expected unserved energy (EUE) from NERC's ProbA are used to identify risk levels.
- Comparing the margin between projected resources and peak net demand, or reserve margin, to a reserve margin target (known as RML) that represents the accepted level of risk based on a probability-based loss-of-load analysis.

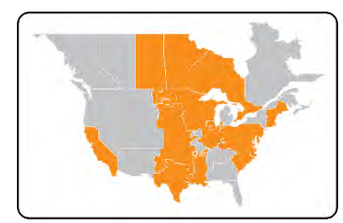
See the **Demand Assumptions and Resource Categories** for further details on these approaches. Assessment area dashboards (see **Regional Assessments Dashboards**) provide resource capacity and energy risk assessment results for all areas.

Risk Categories

An assessment area is **high risk** when established resource adequacy targets or requirements are not met during this assessment period. Regulatory authorities or market operators establish resource adequacy targets. Most targets in North America are currently based on a 1-day/event load loss in a 10-year planning requirement. See the **Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area**. Recently, regulators and policymakers in many states and market areas have begun considering or developing resource adequacy targets based on additional criteria that can better address energy risks and extreme weather-related supply disruption.[8] High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Unusual heat waves or deep-freeze events pose an even greater threat to reliability.

For the *2024 LTRA*, assessment areas are classified as high risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH exceeds 2.4 hours/year for one or more years in the ProbA.
- Annual normalized EUE exceeds 0.002% (20 ppm) for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are not met.

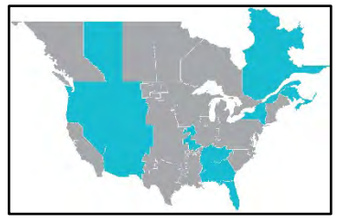


An assessment area is considered an **elevated risk** when it meets the established resource adequacy target or requirement, but probabilistic or deterministic analysis of conditions that are plausible but more extreme than normal seasonal peaks are likely to cause shortfall in area reserves. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. In the analysis, elevated risk may be found by modeling above-normal demand and low resource availability. The risk can also be identified by examining output data from probabilistic analysis tools to determine the underlying conditions for load-loss events. Simply put, elevated-risk areas meet resource adequacy requirements but may face challenges meeting load under extreme conditions. For the *2024 LTRA*, assessment areas are classified as elevated risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is between 0.1 and 2.4 hours/year for one or more years in the ProbA.

[8] See the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid*.

- Annual normalized EUE is less than 0.002% (20 ppm) but non-zero for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are met, but plausible scenarios of above-normal demand and/or low-resource conditions associated with a once-per-decade event indicate risk of load loss.



NERC assesses areas as **normal risk** when resource adequacy criteria are met and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas categorized as normal risk are expected to have sufficient resources for plausible extreme[9] conditions, they are not immune to the effects of high-impact, low-frequency weather events that affect demand and generation simultaneously. For the *2024 LTRA*, assessment areas are classified as normal risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is below 0.1 hours/year.
- Annual normalized EUE is negligible or zero.
- Resource adequacy target(s) established by regulatory authority or market operator are met and reserves are expected to be available in plausible scenarios of above normal demand and/or low resource conditions associated with a once-per-decade event indicate risk of load loss.

Application of the Risk Criteria: NERC uses industry-provided demand and resource information and the results from probabilistic assessments performed by NERC Regional Entities, ISO/RTOs, and regulated utilities to determine risk of energy and capacity shortfalls. The methods, assumptions, and approaches used by entities to perform probabilistic assessments affect the results and outputs. In this year's LTRA, NERC incorporated new probabilistic assessment criteria (LOLH and EUE) from the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid* alongside established reserve margin criteria. In instances where an assessment area's probabilistic assessment results and reserve margins give mixed indications as to the risk category, adherence to resource adequacy targets (e.g., required RML and load-loss criteria) established by regulatory jurisdictions took precedence. Any other apparent contradictions with metrics and criteria were generally assessed according to results of all-hours probabilistic analysis.

Elevated-Risk Area Details

The below areas are projected to meet resource adequacy criteria and have energy and capacity for normal forecasted conditions but are at risk of supply shortfall in extreme conditions. Areas are listed in order of appearance in the **Regional Assessments Dashboards** section.

MISO

MISO has experienced slower resource additions due to market pressures and constraints faced by projects with signed interconnection agreements. MISO has highlighted uncertainties with a large number of new resources that have signed interconnection agreements (Tier 1 additions) and are expected to come on-line in the next several years.[10] Resource adequacy risks could grow over time absent the new capacity reflected in the Tier 1 additions and the deferral of announced retirements (see **Risk from Additional Generator Retirements**).

PRMs in MISO with resource additions are shown in **Figure 3** and **Figure 4**. MISO reports 56 GW of nameplate generating capacity, predominantly solar and batteries, with signed generation interconnection agreements (qualifying as Tier 1 and reflected in the ARM in **Figure 3** and **Figure 4**) as of July 2024 that can help meet resource adequacy needs if connection is completed. If resource additions remain at or near historically average levels (approximately 2.3 GW/year average over the last 3 years), PRMs in MISO will fall below the RML reserve margin requirements much faster. Summer PRMs with average resource additions are shown in **Figure 3** as **Reserve Margin-Avg Addition**.

[9] Plausible extreme conditions considered by NERC in this assessment are similar to those experienced during Winter Storm Elliott, Winter Storm Uri, and the 2020 Western Wide Area Heat Dome.
[10] See results from the 2024 Organization of MISO States (OMS)-MISO Survey.

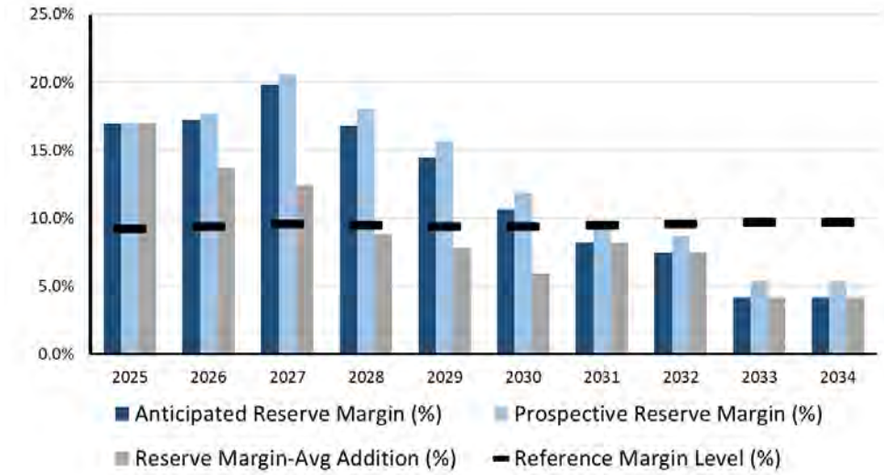


Figure 3: MISO Planning Reserve Margin–Summer

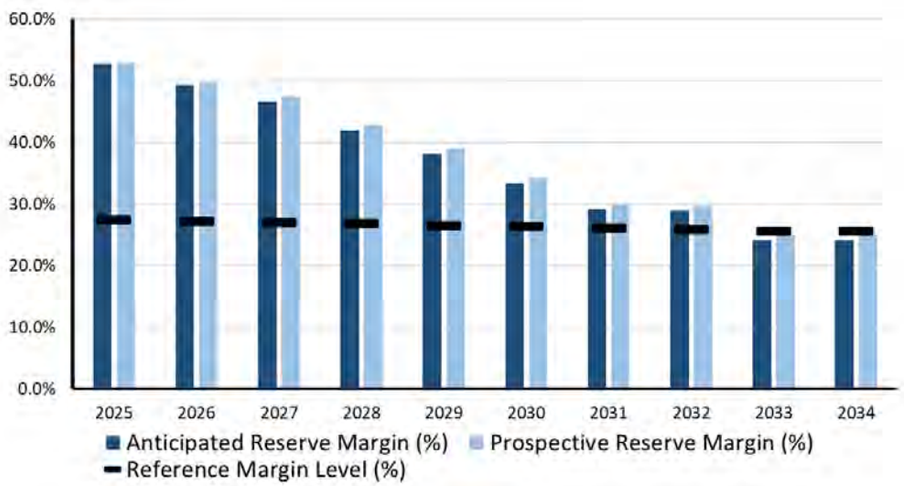


Figure 4: MISO Planning Reserve Margin–Winter

To establish the RMLs that define the minimum reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. The study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they define the minimum PRM that will meet an LOLE of 1 day in 10 years. See the **MISO** assessment area pages.

MISO is an elevated risk in the *2024 LTRA* because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below RMLs within the next five years.

MRO-Manitoba Hydro

The electricity demand forecast in the province of Manitoba has increased since the *2023 LTRA*, driven by expected economic activity and adoption of electric vehicles. Resource projections have not changed significantly.

As in prior probabilistic assessments, Manitoba Hydro's 2024 ProbA indicates that there is some risk of load loss and unserved energy associated with very low hydro conditions (see **Table 2**). Electricity demand peaks in winter, making this the higher-risk season. However, electricity supplies could fall short during either peak summer or winter conditions should an extreme and prolonged drought affect hydro production.

Table 2: MRO-Manitoba Hydro ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	7.23	**4.71**	**68.87**
EUE (PPM)	0.29	**0.18**	**2.50**
LOLH (hours per year)	0.01	**0.06**	**0.91**
Operable On-Peak Margin	13.5%	**18.8%**	**15.6%**

** Year 2026 Results from the 2022 ProbA provided for trending*

MRO-SaskPower

Resource projections for Saskatchewan over the 10-year period have increased since the *2023 LTRA*, rising to just over 1 GW and include two new 377 MW gas-fired generation facilities, expansion of existing gas-fired generation facilities, and new geothermal resources. The peak demand forecast growth rate (1.35% annually) has changed little since the *2023 LTRA*.

The ProbA for SaskPower indicates there is some risk of load loss and unserved energy that diminishes with the new resource additions that are planned for 2027 (**Table 3**). Saskatchewan is a winter-peaking system; however, the unserved energy risks are more closely associated with the planned outages of large generators that typically occur in the fall and spring shoulder periods. The months of September and October are the highest risk periods because of the potential for high temperatures to unexpectedly extend beyond summer and into the maintenance period.

Table 3: MRO-SaskPower ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	117.0	**75.64**	**8.55**
EUE (PPM)	4.4	**2.81**	**0.30**
LOLH (hours per year)	0.9	**0.54**	**0.08**
Operable On-Peak Margin	24.6%	**24.8%**	**30.8%**

** Year 2026 Results from the 2022 ProbA provided for trending*

MRO-SPP

New resource capacity in the interconnection queue—primarily solar, battery, and wind—is currently projected to keep up with rising peak demand forecasts. DR programs are also increasing over the next 10 years. Resource adequacy issues can arise, however, if generators retire earlier than anticipated or new resource additions connect more slowly. Currently, there are over 8 GW of coal and gas-fired generators that have indicated that they may retire within the next 10 years, making the resource outlook unclear. SPP's summer reserve margins, based on installed generator capacity, remain above RMLs through 2029 (see **Figure 5**).

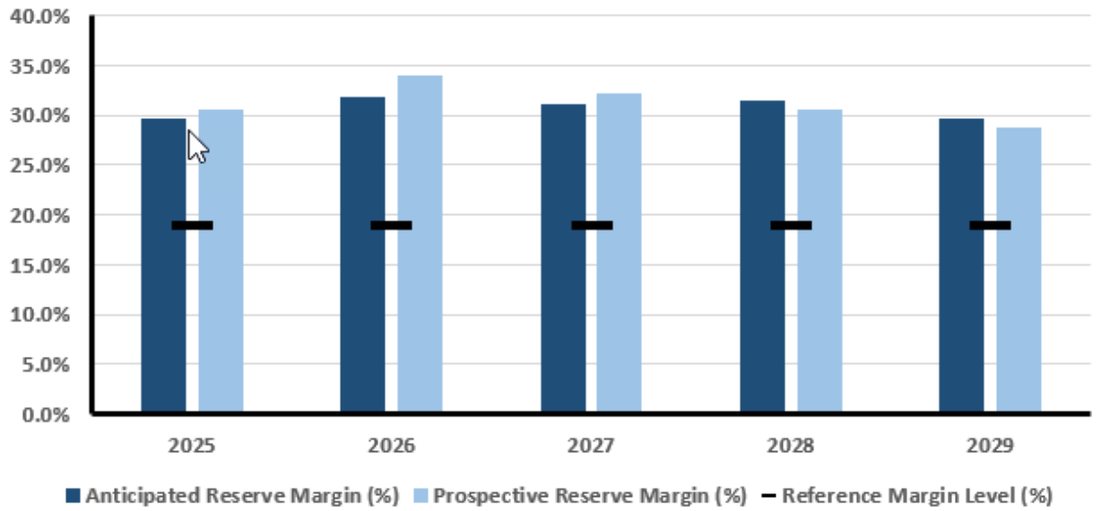


Figure 5: MRO-SPP Five-Year Planning Reserve Margin–Summer

All-hours probabilistic analysis performed by SPP shows that resource adequacy challenges are shifting from summer (when area demand is at its highest) to winter months (when the new resource mix is less capable of performing reliably). Annual results of the ProbA are in **Table 4** below. SPP's 2023 loss-of-load expectation (LOLE) study results indicate that a separate RML and seasonal resource capacity contributions are needed for the summer and winter seasons to effectively provide for resource adequacy.

Table 4: MRO-SPP ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.84	**0.00**	**6.61**
EUE (PPM)	0.00	**0.00**	**0.02**
LOLH (hours per year)	0.00	**0.00**	**0.01**
Operable On-Peak Margin	19.6%	**19.5%**	**16.0%**

** Year 2026 Results from the 2022 ProbA provided for trending*

NPCC-New England

New England is forecasting unprecedented demand growth driven by electrification of heating and transportation. Wind, solar, and batteries make up the projected resource additions, along with growth in distributed energy resources. Since the *2023 LTRA*, the peak demand forecast is relatively unchanged. New England has among the strongest winter demand forecast growth rates of any assessment area, rising over 7 GW in the 10-year period, or 35% from its current peak demand forecast.

The 2024 ProbA for NPCC-New England reveals increasing risk of load loss and unserved energy compared to the 2022 ProbA (see **Table 5**). Higher-demand forecast and replacement of dispatchable resources with more VERs contribute to this trend. In the ProbA modeling, supply shortfall risk is limited to the summer months and is associated with periods of above-normal demand and low resource output (e.g., low wind, solar, or high thermal outages).

Table 5: NPCC-New England ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.55	**10.69**	**67.40**
EUE (PPM)	0.00	**0.09**	**0.06**
LOLH (hours per year)	0.00	**0.07**	**0.03**
Operable On-Peak Margin	27.8%	**12.4%**	**13.7%**

** Year 2026 Results from the 2022 ProbA provided for trending*

While NPCC's ProbA results indicate that the risk of unserved energy in New England is concentrated in summer months, a persistent concern is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell or a series of cold spells given the existing resource mix and regional fuel delivery infrastructure. Potential natural gas transportation constraints can affect supply to generators during extreme cold temperatures, when natural gas demand for space heating is also peaking. Most natural-gas-fired generators in the area do not have firm natural gas transportation service and can be subject to supply curtailment during peak conditions. Many natural-gas-fired generators in New England can also operate with stored oil, providing for assured electricity supply in extreme winter conditions while oil stores are procured and maintained. Scenarios of extended and extreme cold weather that affect the availability of natural gas and oil replenishments present a reliability risk but were not within the scope of the 2024 ProbA.

NPCC-Ontario

Near- and long-term resource adequacy challenges continue in the NPCC-Ontario assessment area as the Independent Electricity System Operator (IESO) manages lengthy refurbishment outages at nuclear generators and demand growth driven by agriculture and electrification. The beginning of projected shortfalls occurs in 2027 when some contracts for firm capacity are set to expire (see **Figure 6**). However, a number of resources with expiring contracts between 2026 and 2029 are anticipated to be re-committed for five-year terms through the IESO's second medium-term procurement, which is underway. As such, Ontario's Anticipated Reserve Margins (ARM) and Prospective Reserve Margins shown in **Figure 6** (which do not include this set of expiring resources) are conservative. Recommitment of these resources is expected to raise margins above the reference level in 2029 and help maintain reliability through the end of the decade. In May 2024, the IESO finalized long-term commitments for new-build battery storage facilities (1,784 MW) and new-build natural gas and biogas facilities (411 MW). Early operation incentives anticipated to bring a portion of these resources online as early as 2027 could help alleviate the reserve margin gap. The IESO also launched procurements for new capacity and energy-producing resources to be online as early as 2029. In addition, the IESO finalized an agreement with Hydro-Québec for capacity sharing in November 2024, providing 600 MW of firm imports to Ontario starting in Summer 2025 through Summer 2031. This capacity is also expected to help alleviate shortfalls indicated in 2027.

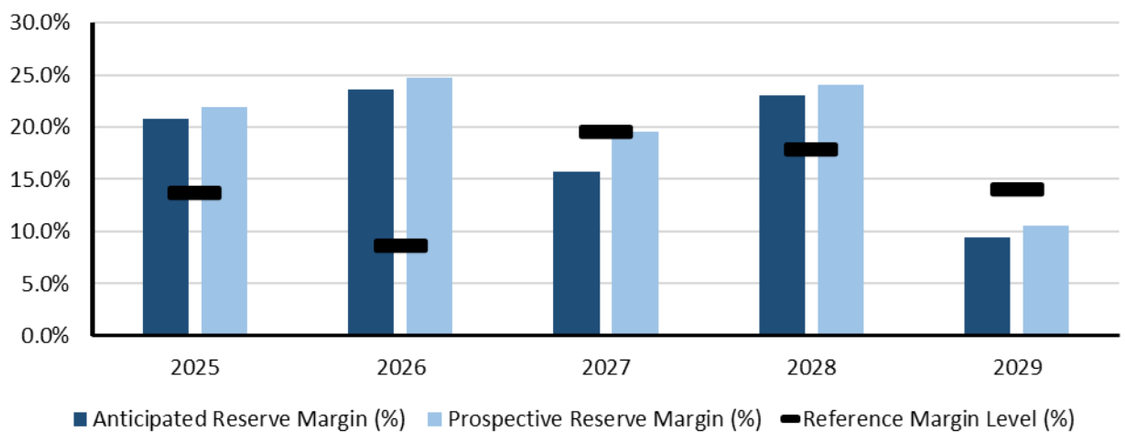


Figure 6: NPCC-Ontario Five-Year Planning Reserve Margin–Summer

The probabilistic assessment for Ontario performed by NPCC provides further insights into the potential for load loss and unserved energy. There is negligible risk of unserved energy and load loss in 2026 and earlier years; however, a small risk of load loss (< 0.01 hours) emerges after 2026 (Table 6). The 2024 ProbA study included only years 2026 and 2028, both of which have projected capacity surpluses above RMLs (see Figure 6). If 2027 and 2029 had been included in the ProbA, it can be expected that there would have been higher amounts of LOLH and unserved energy. ProbA results are also helped by the inclusion of electricity transfers from neighboring areas and modeling for some operating procedures used to manage supply shortfalls.

Table 6: NPCC-Ontario ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	72.16	**0.04**	**4.97**
EUE (PPM)	0.49	**0.00**	**0.03**
LOLH (hours per year)	0.44	**0.00**	**0.01**
Operable On-Peak Margin	-6.7%	**13.3%**	**9.5%**

** Year 2026 Results from the 2022 ProbA provided for trending*

PJM

PJM's projections for generator additions in 2025 and 2026 are scaled back dramatically from the *2023 LTRA* while demand forecasts continue to rise. As a result, ARMs for future years have fallen by as much as nine percentage points from last year. The trends in demand growth and resource additions create resource adequacy and system planning challenges for PJM as it carefully manages generator deactivation requests from the aging fossil and nuclear fleet.

PJM's ProbA results provide indication of the increasing resource adequacy risk to the system (see Table 7). EUE and LOLH are found in both ProbA assessment years (2026 and 2028) with risk concentrated in the winter months (especially January). The risk occurs on days where temperatures are very low across the entire PJM area, which results in high loads. While normal resource performance can meet these demand forecasts, resource performance from thermal resources on very cold days has historically been below normal due to freezing and fuel supply issues. Furthermore, solar resources are not likely to contribute during some of the coldest hours, resulting in very low total electricity supply and thus projections of load loss. ProbA analysis shows some summer load-loss and unserved energy risk but at much lower levels. Summer shortfall events are most likely to occur during wide-area heat events that coincide with low wind and low solar output, or very high outage and derates in the thermal generation.

Table 7: PJM ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.00	**537.52**	**1,043.44**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.12**	**0.22**
Operable On-Peak Margin	29%	**17.8%**	**17.7%**

** Year 2026 Results from the 2022 ProbA provided for trending*

SERC-East

The addition of solar resources is helping to raise summer on-peak reserve margins in the assessment area, despite rising demand forecasts and additional coal-fired generator retirements. Since the *2023 LTRA*, solar PV resources have grown from 1.5 GW to an expected 4.7 GW by the end of 2024. An additional 2 GW of solar PV resources are in the process of connecting. The summer peak demand forecast has also risen since the *2023 LTRA*, increasing by 2.8 GW (6.3%) over last year's projection. The area reserve margins have increased in the near term as a result of the solar resource additions then drop off after 2028 due to higher demand forecasts and planned generator retirements.

Despite these resource additions and higher summer reserve margins, the 2024 ProbA reveals growing resource adequacy risk in SERC-East (see Table 8). Measures of unserved energy and load-loss have increased since the 2022 ProbA as demand has risen and the resource mix has changed. SERC-East has changed from a summer-peaking area to one with peak electricity demand occurring in both the summer and winter seasons. This change is the result of added solar PV generation that shaves off summer peak demand and trends toward electrification in heating that drives up winter peak demand. The ProbA shows that the risk of unserved energy and load loss is concentrated in winter (January–February) months when wide-area extreme cold weather can affect electricity demand, generator performance, generator fuel supplies, and the availability of electricity imports. Based on current forecasts, resource adequacy risk will increase in SERC-East after 2028 due to the planned retirement of over 1,800 MW in coal-fired generation and continued load growth.

Table 8: SERC-East ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	92.49	**143.35**	**207.26**
EUE (PPM)	0.40	**0.60**	**0.81**
LOLH (hours per year)	0.08	**0.09**	**0.17**
Operable On-Peak Margin	16.1%	**14.2%**	**11.1%**

** Year 2026 Results from the 2022 ProbA provided for trending*

Texas RE-ERCOT

ERCOT is forecasting explosive demand growth, driven by data center projects, Bitcoin operations, development in oil- and natural-gas-producing areas, and industrial facilities. Over 20 GW of newly contracted large loads, in addition to other organic load growth, is projected to be added to ERCOT by 2028. Substantial amounts of solar PV and battery resources are being added to help meet rising demand, but there are significant reliability challenges to address during this period of rapid growth. Resource adequacy risks are mounting as fewer dispatchable resources comprise the resource mix. One of the strategies to address this risk is state implementation of a dispatchable resource generation loan program called the Texas Energy Fund. Furthermore, the forecasted growth in loads and resources poses significant challenges for transmission system planners.

Load growth and the characteristics of the resource mix are contributing to higher levels of unserved energy and load loss in probabilistic analysis (see **Table 9**). In the 2024 ProbA, EUE for the analyzed 2026 ERCOT system has risen to 19 ppm (0.0019 %) of the total annual supplied energy compared to the same analysis in the 2022 ProbA. The 2024 ProbA shows an improving trend in the analyzed 2028 ERCOT system, enabled by additional generation capacity from ERCOT scenarios developed to support rapid growth in large loads.[11]

A deeper analysis of the probabilistic assessment results reveals the unique characteristics of winter and summer risk. While peak winter loads can persist for 48 hours or longer, peak summer periods generally only last for a few hours. This is manifested in the duration and depth of the winter firm load-shed events that appear in the ProbA and has significant implications for the reliability contribution of energy-limited and non-dispatchable resources. The most extreme winter event modeled for 2026 was 16 hours in duration and up to 29 GW in load loss. In contrast, most summer unserved energy events were 1–2 hours in duration.

Table 9: Texas RE-ERCOT ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	1,235	**11,090**	**781**
EUE (PPM)	2.63	**18.95**	**1.12**
LOLH (hours per year)	0.30	**1.57**	**0.16**
Operable On-Peak Margin	35.9%	**28.8%**	**46.9%**

** Year 2026 Results from the 2022 ProbA provided for trending*

A key conclusion from the Texas RE-ERCOT 2024 ProbA is that matching the area's demand growth with a resource mix that is more variable and less fully dispatchable is increasing the risk of supply shortfalls that can result in load loss and unserved energy. When the seasonal characteristics of demand and resources are considered, Resource Planners can appropriately focus efforts to reduce the risk of potentially severe, long-duration winter shortfall events. The Public Utility Commission of Texas established a Reliability Standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude.

WECC-CA/MX

Resource additions continue to improve the overall resource adequacy outlook for the WECC California-Mexico assessment area. Since the 2022 ProbA, the planned extension of the Diablo Canyon nuclear plant (2.2 GW) and resource additions (over 5 GW nameplate in batteries, 3.3 GW nameplate in solar PV, and 0.2 GW in natural-gas-fired and geothermal generation) have alleviated supply shortfalls that were driving unserved energy and load-loss metrics in year 2026, as shown in the results of the 2024 ProbA performed by WECC (see **Table 10**).

Table 10: WECC-CA/MX ProbA Case Summary of Results

	2026*	2026	2028
EUE (MWh)	37,305	0	19,662
EUE (PPM)	136	0	70.07
LOLH (hours per year)	0.72	0	0.38
Operable On-Peak Margin	30.7%	43.2%	41.2%

** Year 2026 Results from the 2022 ProbA provided for trending*

Demand growth and planned generator retirements cause energy adequacy risks to re-emerge in future years. With a resource portfolio that includes a substantial amount of solar PV, the risk of supply shortfall is associated with summer evening periods when demand is high and solar output is diminished. WECC's analysis for the 2024 ProbA found only a small occurrence (<1 hour) of resources falling below margin levels for reliability in the 2028 study year. WECC further observed that load-loss and unserved energy risk was localized in the Mexico portion of the assessment area, reflecting localized resource and transmission system constraints.

[11] Due to the inclusion of an additional 20 GW of large loads based on newly signed interconnection agreements, study-year 2028 included additional generation capacity from the "High Large Load Adoption" scenario of the ERCOT 2024 Long-Term System Assessment (LTSA), which included 22 GW of combustions turbines (CT) and 4 GW of combined cycles (CC).

The CA/MX 2028 system analyzed by WECC for the 2024 ProbA reflects the continued rapid transformation of the power grid. The analysis assumes forecasted demand growth of 3.5 GW, substantial resource additions (4.6 GW of solar PV, 7.6 GW in batteries, and 0.8 GW of natural-gas-fired generation imported from repowered coal units in Utah), and the retirement of over 3 GW of gas-fired generation. As demand grows and the resource mix becomes increasingly variable, periods of supply shortfalls can emerge. Battery additions and transfers help make up for energy shortfalls that can arise during evening solar down ramps.

WECC-BC

BC has a predominantly hydroelectric generation system with vast amounts of energy storage provided by its reservoirs. Winter peak demand in the province is forecast to grow modestly over the next 10 years, from 11,966 MW this winter to 12,305 MW at the end of the 10-year period. Since the *2023 LTRA*, the winter peak demand compound annual growth rate (CAGR) has fallen from 1.0% to 0.3%. Growth rate and reserve margins are higher. While the overall resource adequacy outlook has improved, the 2024 ProbA indicates the area continues to be at an elevated risk of supply shortfall during extreme conditions. Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Western Interconnection-wide probabilistic analysis performed by WECC for the 2024 ProbA reveals that risk of reserve shortages emerges after 2026, potentially resulting in unserved energy and load-loss events during extreme weather. WECC's analysis identified over five hours in 2028 when high demand and low supply from WECC-BC's internal resources were not able to be remedied with imports from neighboring areas experiencing similar conditions (see **Table 11**). In contrast, 2026 had no unserved energy or load-loss periods. An examination of hourly results showed that imports from neighbors were more available in 2026 to cover periods of potential shortfalls in BC Hydro's internal resources.

Table 11: WECC-BC ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	24	**0**	**103,132**
EUE (PPM)	0.71	**0**	**1,456**
LOLH (hours per year)	0.00	**0**	**5.52**
Operable On-Peak Margin	12.7%	**16.9%**	**9.4%**

** Year 2026 Results from the 2022 ProbA provided for trending*

WECC's interconnection-wide analysis simulates the probabilistic performance of resource types using historic hourly output data to identify future risk periods. Operators of systems with large hydroelectric storage facilities make adjustments to generation based on the level of demand and shape the water use within the day, week, month, or between years. These actions help posture hydroelectric generation for expected conditions and can reduce energy shortfall risks.

BC's supply margins relative to demand are lowest during winter peak demand periods. Imports from neighbors in the U.S. Northwest are common during these periods, and often during the overnight hours of 23:00 to 4:00 local. WECC's analysis shows the need for imports growing year to year throughout most of the LTRA forecast horizon. A widespread, extreme cold weather event in the Northwest that limits transfer capability is thus a risk to BC. Even though WECC-BC is expecting only moderate demand growth and relatively few retirements, diminished surplus capacity in neighboring areas is negatively affecting the resource adequacy outlook.

Normal-Risk Area Details

All other assessment areas (see **Figure 1**) are assessed as normal risk. In these areas, resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance).

Resource and Demand Projections

The **Capacity and Energy Assessment** section in this LTRA is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. Later sections in this report describe important trends in each of these forecast areas. The future electricity supply will come from a resource mix that is more variable, weather-dependent, and reliant on natural gas for fuel, requiring broad coordination and careful attention to manage reliability risks. Future electricity demand is being shaped by many factors that collectively influence peak demand forecast levels, peak seasons, and hourly profiles. Peak demand and energy forecasts are projected to continue rising dramatically over the *2024 LTRA* assessment period, exceeding their highest rates in recent years. Ongoing challenges with resource and transmission development and the continued pace of generator retirements raise concerns that, in the future, the risk assessment map will expand with more elevated and high-risk areas.

Risk from Additional Generator Retirements

Accelerated retirements of the existing coal, natural gas, and nuclear generators can have a profound and negative effect on the resource adequacy and reliability of the BPS in the next 10 years. In this preceding **Capacity and Energy Assessment** NERC accounted for nearly 79 GW of fossil-fired and nuclear generator retirements that are anticipated through 2034. Environmental regulations and energy policies have the potential to influence generators to seek deactivation during the 10-year assessment period.[12] An additional 43 GW of fossil-fired generators have announced plans to retire over the decade but have yet to enter deactivation processing with the planning authorities. These retirements, along with the confirmed retirements, contribute to declining reserve margins in the assessment areas over the next 10 years (see **Table 12**). As a result of demand growth and generator retirements, ARM is projected to fall below RML in 18 of the 20 assessment areas by 2034. While forecasts such as this factor into resource planning and market mechanisms to obtain resources needed for resource adequacy, it underscores the significant resource growth needed across North America. The lack of dispatchable resources and diverse generator fuel types in the interconnection processes makes the future resource mix look alarmingly unreliable. The potential for capacity and energy shortfalls and a higher-risk resource mix is heightened by economic and policy factors that place pressure on existing thermal generators.

The yearly projections of future retirements and an assessment area view are provided in the **Risk from** Additional Generator Retirements section.

[12] The Environmental Protection Agency (EPA) issued a final rule on May 9, 2024, establishing Greenhouse Gas Standards and Guidelines for Power Plants (the "GHG Rule"). This rule was released concurrently with three other EPA regulations that impact fossil-fueled power generation: Coal Combustion Residuals, Effluent Limitations Guidelines, and Mercury and Air Toxics Standards. Collectively, these four new regulations impose considerable financial and operational challenges on coal-fired generators.

Table 12: Anticipated Reserve Margins with Announced Retirements											
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MISO[13]	17.7%	10.3%	10.3%	13.2%	8.6%	7.1%	10.6%	8.2%	7.5%	4.2%	-2.5%
MRO-Manitoba	12.5%	21.3%	18.4%	18.0%	15.0%	9.8%	0.5%	-0.6%	-1.7%	-2.9%	-4.2%
MRO-SaskPower	28.9%	27.8%	26.6%	31.1%	29.4%	7.0%	28.8%	28.0%	26.7%	26.8%	1.2%
MRO-SPP	28.3%	26.7%	26.0%	25.0%	20.8%	19.1%	26.7%	24.9%	23.5%	22.4%	8.1%
NPCC-Maritimes	18.9%	20.6+%	25.5%	25.1%	18.6%	3.9%	23.4%	20.7%	19.1%	17.7%	-1.5%
NPCC-New England	20.4%	25.0%	25.0%	26.3%	24.9%	23.5%	22.0%	20.1%	19.7%	17.1%	14.6%
NPCC-New York	18.4%	17.1%	21.4%	22.5%	22.4%	21.6%	20.7%	18.3%	16.7%	14.9%	13.6%
NPCC-Ontario	22.5%	20.8%	23.6%	15.7%	23.0%	9.5%	5.1%	-0.2%	-1.4%	-3.9%	-5.5%
NPCC-Quebec	12.5%	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
PJM	29.8%	34.9%	35.7%	28.1%	21.4%	18.2%	23.1%	21.6%	20.1%	18.5%	10.3%
SERC-C	28.2%	18.9%	18.9%	15.0%	16.0%	15.2%	17.3%	17.1%	18.4%	21.1%	11.8%
SERC-E	30.4%	27.3%	25.8%	24.6%	20.6%	14.4%	14.3%	10.2%	6.3%	4.6%	-2.2%
SERC-FP	27.0%	25.4%	26.0%	23.2%	22.1%	20.9%	18.4%	22.0%	20.4%	18.2%	16.0%
SERC-SE	44.9%	39.9%	35.9%	31.5%	24.5%	21.4%	27.7%	25.8%	24.7%	23.7%	13.0%
TRE-ERCOT	24.3%	30.2%	32.5%	29.7%	25.6%	25.4%	27.8%	28.0%	28.4%	28.9%	24.9%
WECC-AB	36.3%	35.8%	35.7%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
WECC-BC	20.9%	25.2%	25.2%	15.8%	15.9%	22.3%	22.1%	21.6%	21.2%	13.4%	19.9%
WECC-CA/MX	38.6%	45.5%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
WECC-NW	34.5%	40.3%	38.9%	35.6%	30.7%	24.5%	18.3%	12.2%	10.2%	8.1%	5.9%
WECC-SW	28.6%	37.0%	35.6%	31.6%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-9.6%

Reducing Resource Capacity and Energy Risk

The risk of electricity supply shortfalls in the assessment period can be lowered through the concerted efforts of resource and system planning stakeholders. The actions taken in electricity markets and regulatory jurisdictions with the improving trends noted previously provide examples of what can work: obtaining additional firm resources to meet resource adequacy targets, delaying generation retirements when reliability needs dictate, and using capacity targets and energy risk metrics based on better resource and demand models. Specific and actionable recommendations are contained in the Executive Summary.

[13] MISO reserve margins in this table reflect MISO Seasonal Accredited Capacity for summer. Adjustments and derates are applied to account for factors affecting expected resource output, resulting in unforced capacity (UCAP) reserve margins that are lower compared to installed capacity (ICAP) values. For more information see the **MISO assessment area** page.

Resource Mix Changes

Capacity Versus Energy: Changes in the Way to Plan for Resource Adequacy

Industry's methods of planning for resource adequacy need to change. The modern power system requires the enhancement of assumptions and supplementation of risk information for a better characterization of the risk. Historically, the resource adequacy criterion has been based on the LOLE metric, which should be no more than 1 event-day in 10 years when the generating resources are less than load (commonly known as "1-day-in-10"). This has been a design basis for the U.S. electric grid for at least 70 years (with its first formal mention in a 1951 American Institute of Electrical Engineers paper by C. W. Watchorn) and has historically served the industry well. Two important related but separate discussion topics include considerations for assumptions in the calculation of LOLE and other metrics and the establishment of the resource adequacy criteria (i.e., traditionally in terms of LOLE-1-day-in-10). The 1-day-in-10 LOLE criterion is commonly converted into a minimum capacity requirement resulting in a target or RML. In doing this, planners determine the minimum PRM required to maintain a 1-day-in-10 LOLE level. Historically, systems with an actual PRM above the minimum generally have sufficient resources and provide adequate energy and ERSs that operators need to reliably operate the BPS. Issues can arise in resource adequacy planning processes when planners solely rely on the RML comparison as the system transforms from an era of certain to more uncertain fuel sources and load behavior. In recent years, NERC has documented warnings of potential energy shortages in its reliability assessments, while in many cases the RML comparison indicates no shortfall. Substantial uncertainty has been introduced into planning the system with the addition of energy-constrained resources (variable energy resources such as wind and solar, and, at times, just-in-time fuels such as natural gas) that are highly dependent on weather and environmental conditions. Uncertainty in energy sufficiency is increasing as the types of resources change, leaving fewer resources that can be dispatched (dispatchable resources) in response to the variable resource availability and greater exposure to constraints in fuel supplies, reservoir levels, or battery discharge capabilities. Historical generator reliability assumptions based on the idea of well-maintained, well-invested units with an anticipated long life are no longer adequate. This increases uncertainty as a greater proportion of fossil-fueled resources continue to be retired, often with little notice to system planners. Nameplate values of variable energy resources are not as meaningful as projected energy availability, and environmental conditions can adversely impact the simultaneous availability of thousands of megawatts.

Probabilistic analysis enhances deterministic transmission planning from an energy adequacy standpoint given the following factors:

- Considers likelihood of events: It uses historical data to estimate how often different outages and weather conditions might occur.
- Provides more information: It calculates the average impact of these events, including how often and how long power outages might last.
- Helps compare options: It enables the selection of the upgrade(s) that provide the best balance between cost and reliability over time to be chosen.

Detailed recommendations are included in a recently published NERC report:
Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report, June 2024

Changes in Existing BPS Resource Capacity

Thermal generator retirements and new resource additions continue at a rapid pace. Since the *2023 LTRA*, over 8 GW of coal-fired generation has been retired, while substantial solar and battery resources have connected to the grid (see **Table 13**). From a strictly on-peak capacity perspective, there has been little change (8,348 MW is 0.8% of the total BPS summer on-peak resource capacity.)

Table 13: Existing BPS Resource On-Peak Capacity

	2023 Capacity (MW)	2024 Capacity (MW)	Difference (MW)
Coal	188,856	180,402	-8,454
Petroleum	32,107	30,987	-1,120
Natural Gas	483,391	484,148	757
Biomass	7,273	7,381	108
Solar[14]	52,998	66,293	13,295
Wind[15]	32,320	31,370	-950
Geothermal	4,319	3,881	-438
Conventional Hydro	103,368	105,792	2,424
Run of River Hydro	1,565	2,047	482
Pumped Storage	19,463	19,422	-41
Nuclear	106,173	105,385	-788
Hybrid & Battery	5,593	9,909	4,316
Other	2,217	774	-1,443
Total	1,039,643	1,047,791	8,348

This year-on-year change in on-peak capacity continues the general trend of declining baseload and dispatchable generation—which includes coal-fired, natural gas, and nuclear generators—and rising VERs. **Figure 7** shows the trend continuing through 2034, where 20% of the generating capacity will be provided by VERs. Focusing on the relatively small change in total on-peak capacity since 2023 can mask risks to reliability that result when important attributes of the retiring generation resources are not inherent in the replacement resource mix. Thermal generation resources, such as coal-fired generators, have the capability to be dispatched when needed and provide system inertia, dynamic reactive support, and frequency response for stable grid operation. Most types of replacement resources have limited or none of these attributes. Further, retirements in the thermal generator fleet are making the resource mix less effective in meeting winter energy needs.



Figure 7: North America Total Generation Capacity in 2024 and 2034

Capacity Additions

New generation is added to the BPS through the area interconnection planning processes. Solar PV is the overwhelmingly predominant generation type being added to the BPS, followed by battery and natural-gas-fired generators, wind turbines, and hybrid resources. Batteries are now the second most predominant resource in the North America BPS interconnection queues. A summary of generation resources in the interconnection planning queues is shown in **Figure 8**.

Capacity in planning has grown since the *2023 LTRA* by over 44 GW (12%). In general, **Tier 1** resources are in the final stages for connection, while **Tier 2** resources are further from completion (see text box). Some projects that are in the earlier stages of the interconnection queue process will be withdrawn before completion due to supply chain issues, planning and siting challenges, and business or economic factors. While interconnection queues continue to swell, considerable uncertainty

[14] The capacity values in this table represent the on-peak contribution of solar resources. The total installed (nameplate) capacity of BPS solar in 2024 is 111,102 MW. See Table 11.
[15] The capacity values in this table represent the on-peak contribution of wind resources. The total installed (nameplate) capacity of BPS wind in 2024 is 176,636 MW. See Table 11.

surrounds the timing and amount of resource additions. (See an analysis of projected and actual additions on the next page).

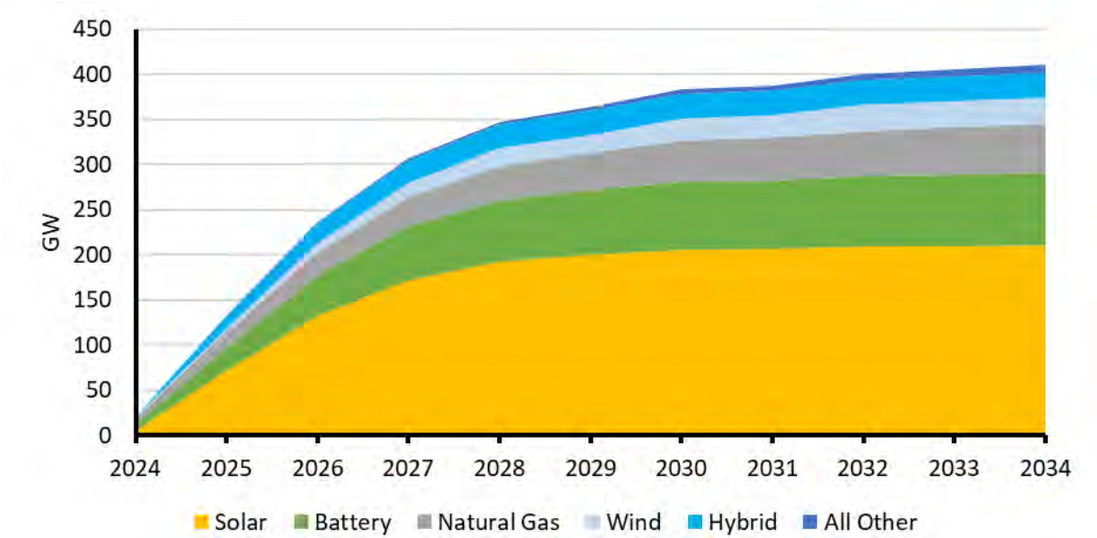


Figure 8: Tier 1 and 2 Planned Resources Projected Through 2034

Solar PV and wind nameplate capacity, both existing and planned, vary widely by area. Figure 9 and Figure 10 show current solar PV and wind installed capacities and the capacity in the planning process through 2034 for assessment areas with significant amounts. In addition, hybrid generation resources, which combine energy storage with a generating plant (i.e., a wind or solar farm), are connecting to the grid in parts of North America, and many more projects are in BPS planning processes.

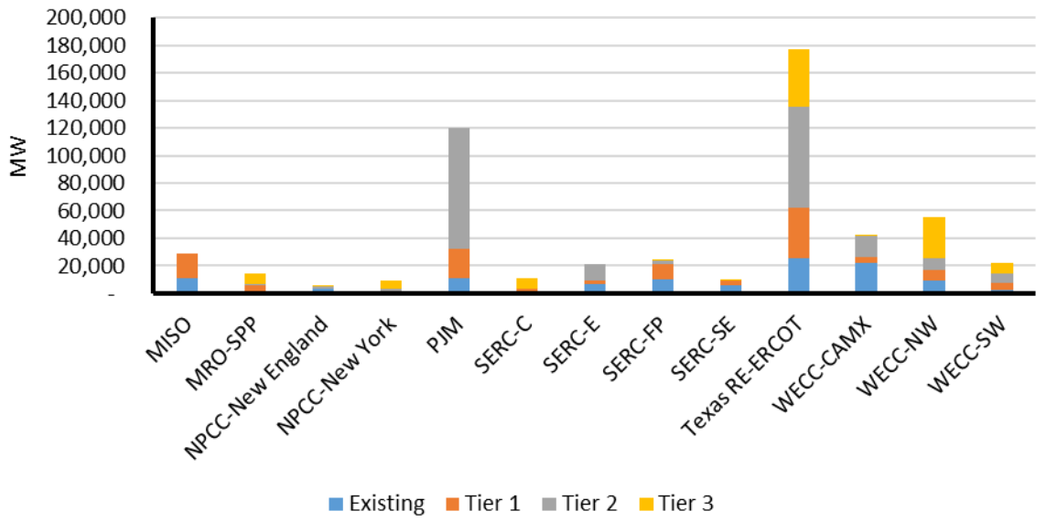


Figure 9: Solar Nameplate Capacity Existing and Planned through 2034

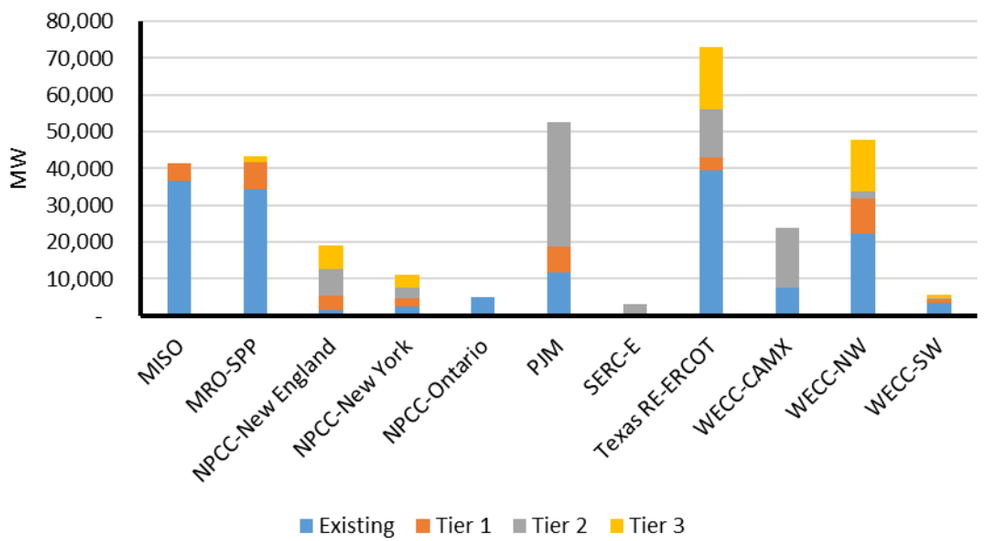
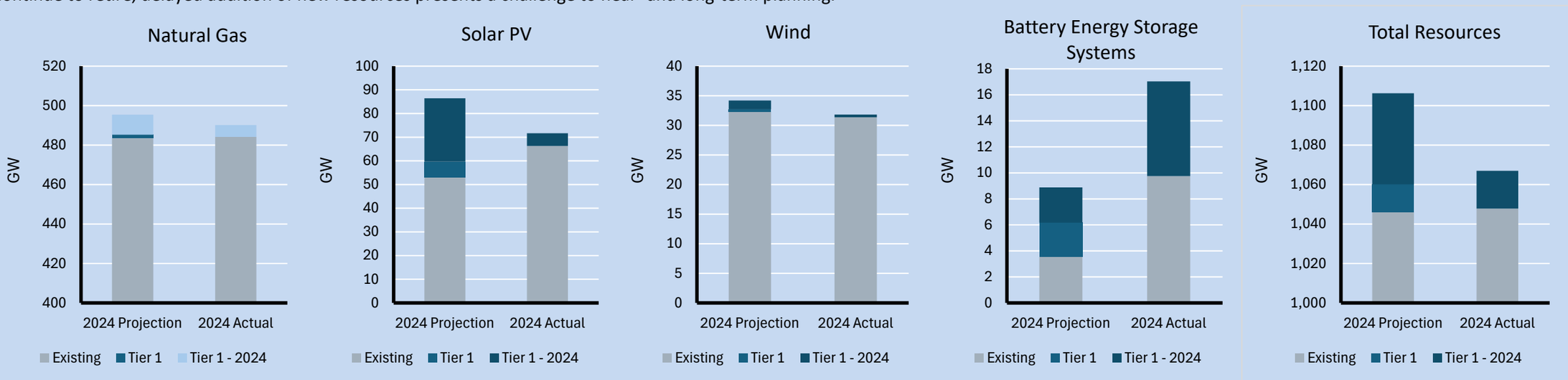


Figure 10: Wind Nameplate Capacity Existing and Planned through 2034

Resource Additions – How Much and When?

The added resource capacity on the BPS over the past year fell short of industry's projections, raising concerns that demand growth has the potential to outpace supply resources. The figures below compare the *2023 LTRA* projection of this year's installed capacity against the actual current installed capacity derived from data collected for this LTRA. Natural gas, solar PV, and wind resources were all over-projected last year. This gives evidence to industry reports of construction delays that prevented the expected interconnection of new resources. To a lesser extent, project withdrawals prior to commercial operation also contributed to lower-than-expected resource additions. One key exception—battery energy storage systems (BESS)—came in higher than last year's projections. As baseload and dispatchable generation continue to retire, delayed addition of new resources presents a challenge to near- and long-term planning.



Comparison of Projected Capacity from the 2023 LTRA to the Actual Capacity in the *2024 LTRA*

The sluggish rate at which new generation moves through the interconnection queue and begins service has been a cause for concern for long-term reliability planning. The Lawrence Berkeley National Laboratory published the results of an interconnection queue study in April 2024 assessing that less than one-fifth of generation capacity projects seeking interconnection between 2000 and 2018 actually came to fruition by the end of 2023.[16] Wait times have also been on the rise: According to the same study, the time from initiating a request for interconnection to the start of commercial operations has increased from less than two years, as was the case from 2000–2007, to more than four years from 2018–2023. The delay in bringing new generation capacity online in assessment areas that are anticipating steady or accelerated thermal capacity retirements, as well as increased demand, presents a significant reliability risk.

In recognition of the interconnection backlog risk, some regional transmission organizations have taken steps to address the lagging completion rates. MISO has assigned multiplication factors to generator requests based on the study phase and the likelihood of that resource coming on-line to more accurately gauge the likely incremental capacity in its footprint.[17] MISO also continues to advance the Joint Targeted Interconnection Queue (JTIQ) with SPP to resolve binding constraints that have delayed the interconnection process. PJM analyzed the completion rate of its interconnection queue and reported that less than 16% of resources submitted into the queue between 1999 and 2023 went into operation. The ISO has also applied a reduction to the nameplate capacity of value of Tier 1 resources to reflect the historical addition rate of new generation. PJM's interconnection process subcommittee is working on enhancements for new generation to interconnect as a capacity resource. These measures and others are examples of the broader effort to streamline generator additions and thus offset retiring capacity.

Offshore wind plants are increasingly entering interconnection queues, located around the Northeastern United States. **Figure 11** shows the current planned capacity in the planning process through 2034 by assessment area. Currently, the existing offshore wind nameplate capacities are small in comparison: a single 29 MW plant in NPCC-New England and a 12 MW plant in PJM.

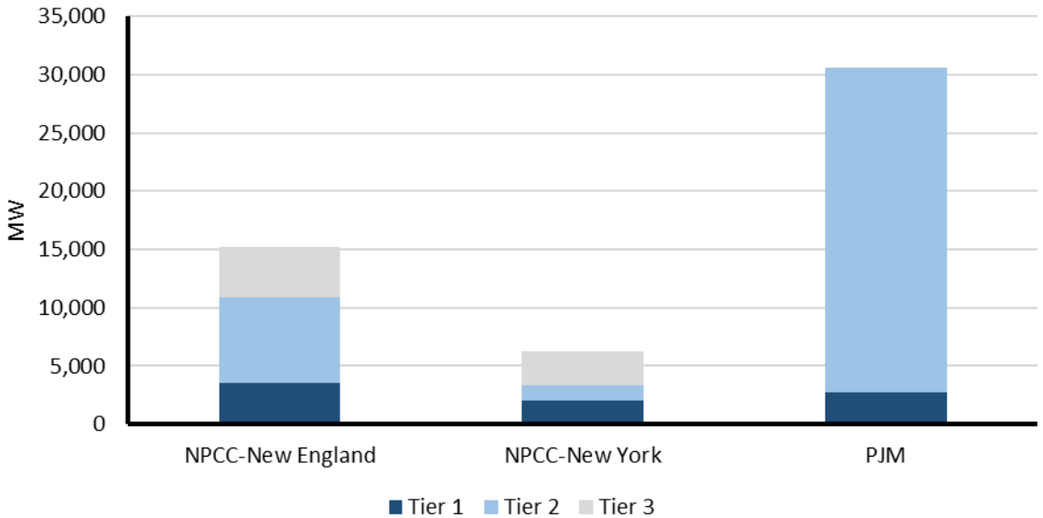


Figure 11: Offshore Wind Capacity Planned through 2034

Battery Resources

As the BPS increases the share of energy provided by VERs, the ability to provide energy by BESS or hybrid-solar PV and wind plants is increasingly important. While currently installed capacity totals just over 17 GW, an additional 306.5 GW of BESS are in planning. **Figure 12** shows the nameplate capacity of BESS resources currently in operation and in planning for connection to the BPS through 2034.

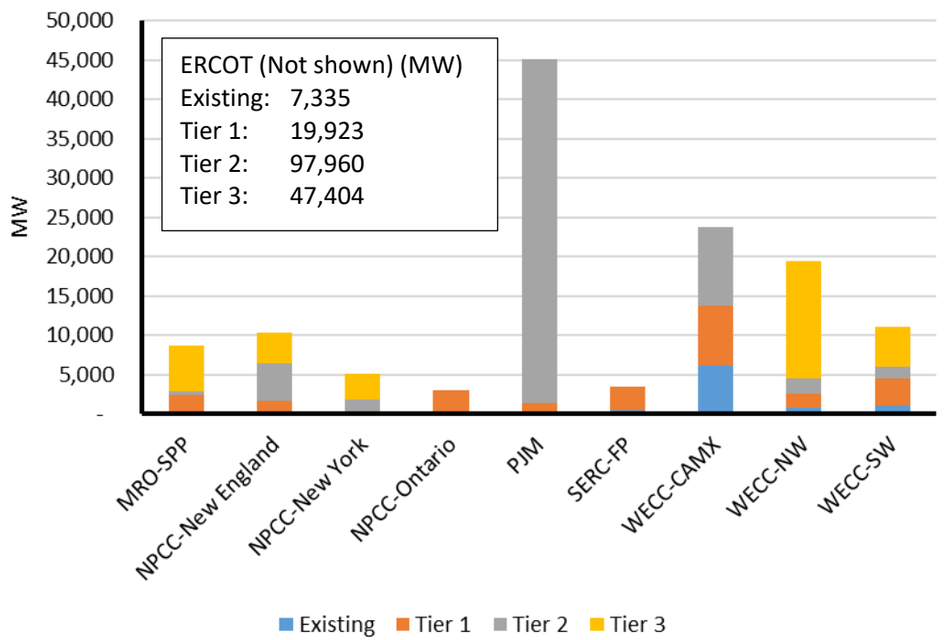


Figure 12: Battery Resource Capacity Existing and Planned through 2034

BESS are improving reliability by helping to offset the variability and uncertainty of inverter-based resources (IBR). BESS are, however, a relatively new type of grid resource with unique operating characteristics. The joint *NERC-WECC Staff Report: 2022 California Battery Energy Storage System Disturbances*[18] highlights an event when a BESS, like some other IBRs, failed to properly ride through a normal system fault. This indicates that BESS must be included in the currently underway strategies to address IBR performance issues.

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. **Table 14** shows the nameplate value and the capacity contribution of existing wind, solar PV, hydro, and energy storage systems resources at the peak demand hour for each assessment area. During risk periods after peak demand (e.g., U.S. assessment areas in WECC), contributions of solar PV resources output is diminished during evening periods and additional resources are needed.

[18] NERC–WECC *2022 California Battery Energy Storage System Disturbances*

Table 14: BPS Wind, Solar, Hydro, and Battery Generation Resources by Assessment Area Year 2024												
Assessment Area	Wind			Solar			Hydro			Energy Storage Systems		
	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)
MISO	41,349	5,715	13.8%	30,502	5,305	17.4%	2,450	1,576	64.3%	401	84	21.0%
MRO-Manitoba Hydro		52	-	-	-	-	6,434	5,704	88.7%	-	-	-
MRO-SaskPower	815	164	20.1%	30	-	-	864	862	99.8%	-	-	-
MRO-SPP	34,475	5,134	14.9%	703	275	39.1%	5,633	4,079	72.4%	2	2	100%
NPCC-Maritimes	-	261	-	-	5.1	-	1,361	1,312	96.4%	-	-	-
NPCC-New England	2,548	127	5.0%	3,361	308	9.2%	1,917	1,469	76.6%	26	9	34.9%
NPCC-New York	2,706	461	17.1%	1,039	240	23.1%	4,915	3,736	76.0%	60	30	50.2%
NPCC-Ontario	4,943	1,364	28%	478	-	0.0%	8,748	6,215	71.0%	18	-	0.0%
NPCC-Québec	3,820	1,375	36.0%	10	-	0.0%	40,907	39,354	96.2%	-	-	-
PJM	11,701	1,760	15.0%	10,735	4,808	44.8%	3,071	2,367	77.1%	222	100	44.8%
SERC-C	982	172	17.5%	2,308	771	33.4%	4,995	3,364	67.4%	100	50	50.0%
SERC-E	-	-	-	6,777	4,753	70.1%	3,170	3,016	95.1%	15	6	38.4%
SERC-FP	-	-	-	10,121	5,618	55.5%	-	-	-	538	523	97.2%
SERC-SE	-	-	-	7,267	5,414	74.5%	3,293	3,260	99.0%	115	40	34.9%
Texas RE-ERCOT	39,532	11,062	28.0%	31,058	19,098	61.5%	583	458	78.6%	10,720	-	0.0%
WECC-AB	5,559	1,867	33.6%	3,042	-	0.0%	894	285	31.9%	270	264	97.8%
WECC-BC	776	279	36.0%	2	-	0.0%	16,902	12,623	74.7%	-	-	-
WECC-CA/MX	7,694	1,158	15.0%	24,905	14,641	58.8%	10,211	3,582	35.1%	11,883	11,155	93.9%
WECC-NW	23,518	3,489	14.8%	12,787	6,877	53.8%	41,257	21,168	51.3%	1,909	1,231	64.5%
WECC-SW	3,784	628	16.6%	5,944	2,527	42.5%	1,025	721	70.3%	2,997	2,592	86.5%

Solar PV Distributed Energy Resource Growth

Behind-the-meter (BTM) solar PV generators are solar PV resources connected on the distribution system, such as residential rooftop solar systems. The rapid growth of BTM solar PV continues with cumulative levels expected to reach over 123 GW by the end of this 10-year assessment period (up from 89 GW reported in the *2023 LTRA*, an increase of 38%). There are currently 58.7 GW of installed BTM solar PV across the North American BPS.

BTM solar PV generators, like grid-connected solar PV, are also VERs. In large penetrations, their predictable change in output from the time of day contributes to steep ramps in demand. As the sun sets and output diminishes, grid resources must make up for the decrease in solar generation and increase in demand that was being served. The opposite ramp occurs during morning hours; it may be less impactful to reliability but can be challenging for grid-connected generator scheduling and dispatch. **Figure 13** shows the current and projected BTM solar PV by area through 2034.

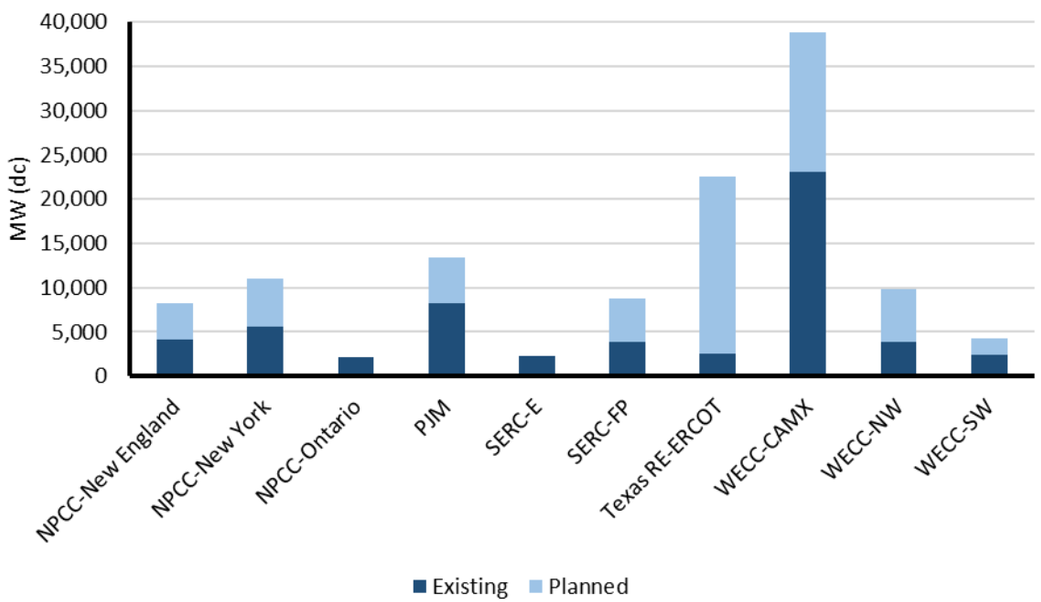


Figure 13: Solar PV DER Capacity Existing and Planned through 2034

Generation Retirements

The total capacity of traditional baseload generation fuel types will continue to decline as older generators retire. Generators become confirmed for retirement according to various processes in place in the Interconnections, such as regional planning tariffs in the wholesale electricity market areas or the integrated resource planning process in vertically integrated states. Properly designed mechanisms can prevent generators from retiring before planners can study and address reliability issues that could occur.

Currently, over 79 GW of fossil-fired and nuclear generating capacity is being retired over this assessment period (see **Figure 14**), a small decrease from the 83 GW in retirements reported in the *2023 LTRA*. This capacity includes generators that are confirmed for retirement through retirement planning processes or that have indicated plans to retire to an ISO/RTO or Planning Coordinator.

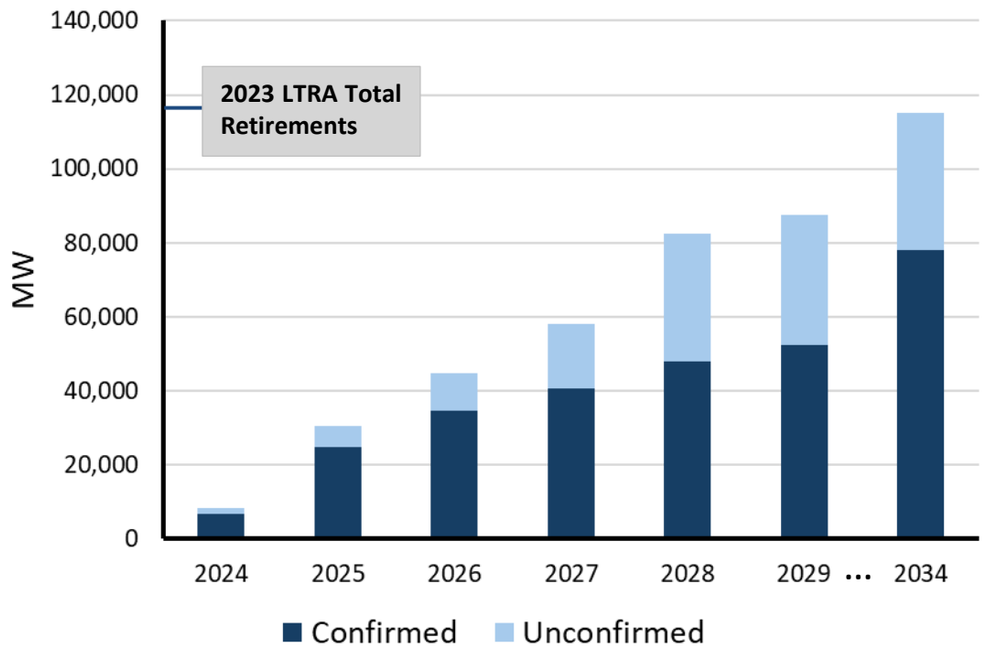


Figure 14: Projected Generation Retirement Capacity through 2034

Additional fossil-fired generator retirements are expected and would result in further loss of existing capacity. Generator Owners often announce plans to retire generator units before initiating the

interconnection planning process, and the announced plans or timing may be subject to change before the retirement is confirmed. Wholesale electricity market areas, where merchant electric generators make up a large part of the generating fleet, have more uncertainty around future generator retirements, making resource planning and adequacy assessment difficult. **Figure 15** shows the total capacity of reported retirements (i.e., reported to ISO/RTOs and planning entities) as well as owner-announced, unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next 10 years in each assessment area.[19] This total of confirmed and announced-potential retirements over the next 10 years is over 115 GW (3 GW lower than 10-year projections in the *2023 LTRA*).

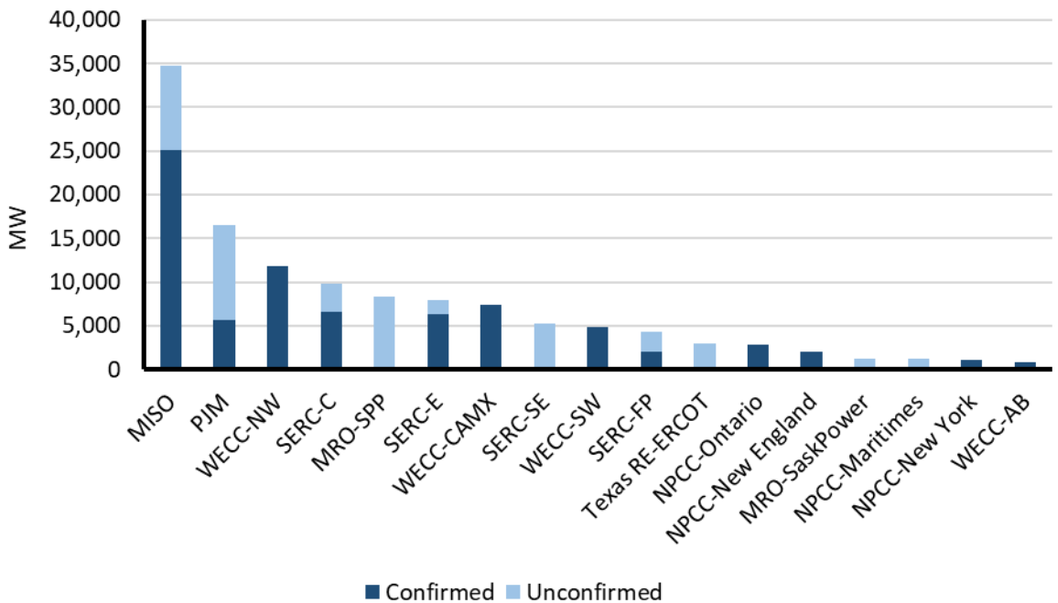


Figure 15: Projected Capacity Retirements of Nuclear and Fossil Generation 2024–2034

Natural Gas Fuel Reliance Trends

Natural-gas-fired generators are and will remain a critical resource for BPS reliability in many areas over the 10-year assessment period, especially during winter. These generators provide many necessary reliability attributes that are exiting the system as traditional generators retire and inverter-based renewable resources take their place in the resource mix. Natural-gas-fired generators are dispatchable and provide the ERSs of inertia, frequency response, and ramping flexibility. In winter, when peak demand in most areas occurs during early morning hours, natural-gas-fired generation is at its highest contribution to the resource mix in many areas. Severe winter weather events in 2021 and 2022 provided stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure supplies during times of extreme electricity demand.

As the generation resource mix evolves and becomes more weather-dependent, fuel assurance becomes increasingly critical when conducting reliability assessments. Until recently, comparing seasonally available capacity to a predetermined PRM level has sufficed as a means to assess resource adequacy. However, resource adequacy is now only the first step of a meaningful reliability assessment. Energy adequacy must now be layered on top to assess the risk that available capacity may be rendered unavailable due to phenomena including low wind or solar output and/or natural gas supply and transportation issues.

This year, the Energy Information Administration (EIA) projected that more than 40% of delivered natural gas would be consumed by power generators, more than 0.6 Bcf/d higher than was consumed by power generators in 2023 and 7% higher than what the EIA had projected for 2024 in the fall of last year. Natural-gas-fired power plants generated 42% of the electrical energy consumed by end-use electricity customers in 2023 and are on track to maintain that share of generation this year. A significant percentage of natural-gas-fired power plants rely upon as-available, non-firm gas supply and transportation arrangements. Non-firm natural gas supply and transportation is generally sufficient for electric generators most of the year. However, during extreme cold weather, demand for natural gas by both generators and natural gas distribution companies (generally firm shippers) can at the same time dramatically increase. In these instances, generators that lack firm supply and transport arrangements are at risk of fuel unavailability, and when winter weather impacts gas production facilities, the resulting imbalance in pipeline injections and withdrawals can put at risk even firm pipeline customers as preparatory linepack is rapidly depleted.

[19] Confirmed generator retirements are reported to NERC by each assessment area in this *2024 LTRA* development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

The *2024 LTRA* projects that an additional 6,500 MW of new natural-gas-fired generation will be added in North America over the next five years. While some assessment areas project net decreases in natural-gas-fired capacity, other areas report increases ranging from 3% to over 50%.

In the United States, 8 out of 13 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years, amounting to over 10 GW of new natural-gas-fired power capacity. Altogether, those additions translate to an increase in natural gas use for power generation of more than 84 Bcf (245 MMcf/d). Whether this increase in natural gas generation capacity is sufficient to meet the increase in net internal demand projected for these same assessment areas remains to be seen, but based on the capacity additions alone, some areas are set to see an insufficient increase in gas pipeline capacity, as per the EIA's database of nationwide U.S. gas pipeline projects. (see **Figure 16**).

PJM is one such area, projected to see a 3% increase in natural-gas-fired generation capacity (+2,500 MW). Net internal electricity demand in PJM is forecasted to rise by 25 GW over the planning horizon at the same time that non-variable resources are expected to shrink their share of the capacity mix from 96% to 88%. To the extent that variable resources are uncertain during times of peak stress on the grid, there is a risk of gas delivery capacity being insufficient for the amount of natural gas supply that could be required to meet the demand increase. SPP is another assessment area where natural-gas-fired power capacity is set to rise, by 5%, or roughly 1,500 MW. In both PJM and SPP, there is a risk of a shortfall in natural gas pipeline capacity that could facilitate delivery of the additional fuel that is necessary to meet their capacity expansion plans.

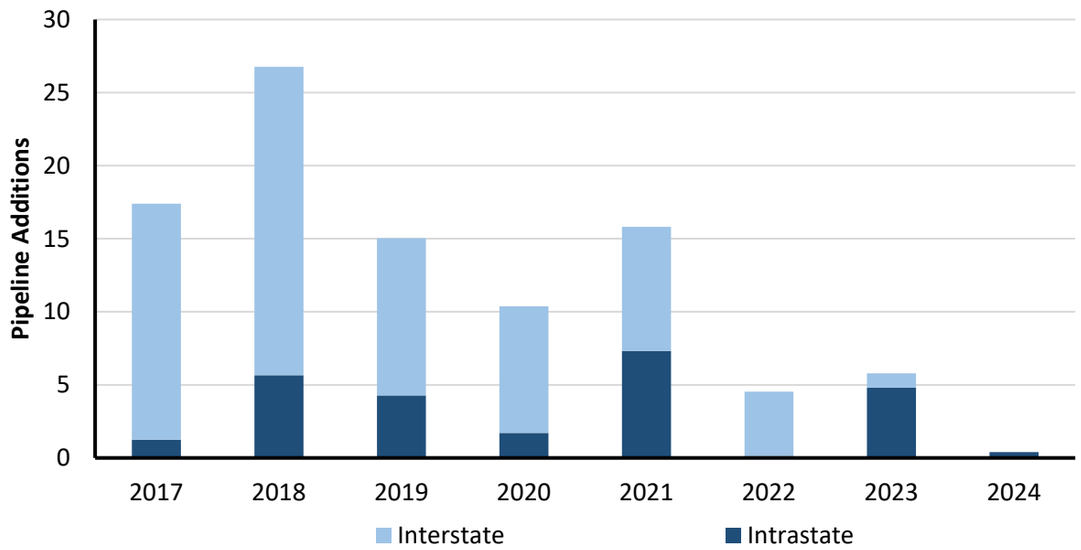


Figure 16: Annual U.S. Natural Gas Pipeline Capacity Additions by Type (2017–2024) Bcf/d (Source: U.S. Energy Information Administration)

Reliability Implications

The addition of variable resources, primarily wind and solar PV, and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. With electricity supplies coming increasingly from VERs and natural-gas-fired generators, there is a growing risk that supplies can fall short of demand during some periods. Geographically diverse wind and solar resources and loads can help reduce these risks, but they require robust transmission networks, comprehensive energy and transfer capability analysis, and effective operating procedures and market mechanisms.

Maintaining ERSs for Grid Support

For the grid to operate reliably, it needs resources that are not only sufficient for meeting demand and energy requirements but also capable of controlling voltages, maintaining stable frequency across the system, and flexibly ramping up or down to dispatch control at all times. Conventional generators, such as nuclear, coal, and natural gas-fired generators, provide much of the ERSs that support reliable operation today. New resources on the grid are almost all IBRs, which have different physical and operating characteristics that affect the level of ERSs that they can provide. Without the spinning mass or traditional excitation systems providing the voltage control of a hydroelectric or thermal generator,

most IBRs have limited capability for maintaining system voltages and stability. Batteries, with their fast response time, have some ERS capability that wind and solar do not. They are useful in regulating system frequency and are helping to balance variability from VERs in ERCOT and California where wind and solar make up a large portion of the resource mix.[20] As generators are deactivated and replaced by new types of resources, ERSs must still be maintained for the grid to operate reliably.

Accelerated generator retirements, especially unanticipated requests for deactivation, can cause ERS-related reliability issues in parts of the system due to the future loss of the generator's reliability attributes. This reduction in the level of ERSs can result in voltage violations or system instability. System planning and generator deactivation processes evaluate these changes to the system and ensure plans proceed only when reliability criteria, including ERS-related considerations, are met. For example, PJM's deactivation process identified reliability concerns to the system as a result of the requested deactivation of the Brandon Shores power plant (1,280 MW) in 2023. Until necessary system upgrades are completed to address identified system voltage and other reliability issues that would occur with the deactivation, PJM has requested that the Brandon Shores generators at the plant remain in service through the reliability-must-run process.[21]

To ensure the future system can operate reliably, market operators, system planners, regulators, and policymakers need to ensure effective mechanisms are in place to provide for the ERS needs of the future system. Long-term activities can provide incentives to generators with needed reliability attributes. Effective backstops will also be needed to prevent the loss of critical generators when analysis finds deactivation would violate reliability criteria.

Specific and actionable recommendations are contained in the **Recommendations and ERO Actions Summary** section of this report.

[20] See the *2023 Special Report on Battery Storage* from the California ISO.
[21] Information on this and other proposed deactivations in PJM are found on PJM's Generator Deactivations page.

Demand Trends and Implications

Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. The aggregated assessment area summer peak demand forecast is expected to rise by over 132 GW, and aggregated winter peak demand forecasts are increasing by 149 GW. The growth rates of forecasted peak demand (see **Figure 17**) and energy (see **Figure 18**) continue to rise sharply since the 2022 LTRA, reversing an almost two-decade trend of falling or flat growth rates. See **Figure 17** for seasonal peak demand growth over the current and prior assessment periods and **Figure 18** for net energy growth. A map of the primary demand drivers for the North American BPS is illustrated for each assessment area in **Figure 19**.

Electrification and Demand Growth

Electrification of household appliances (e.g., heat pumps for household heating) and projections for electric vehicle growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the *2023 LTRA*, peak season CAGR has risen in all assessment areas except two: NPCC-Maritimes' winter CAGR fell from 0.98% to 0.63% and WECC-BC's winter CAGR fell from 1.05% to 0.28%. Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

Large Commercial and Industrial Loads

Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. Emerging large loads, such as data centers (including crypto and AI) and hydrogen fuel plants, present unique challenges to forecasting and planning for increased demand. Earlier this year, NERC's RSTC established a Large Loads Task Force to better understand the reliability implications of growth in large loads and develop solutions.

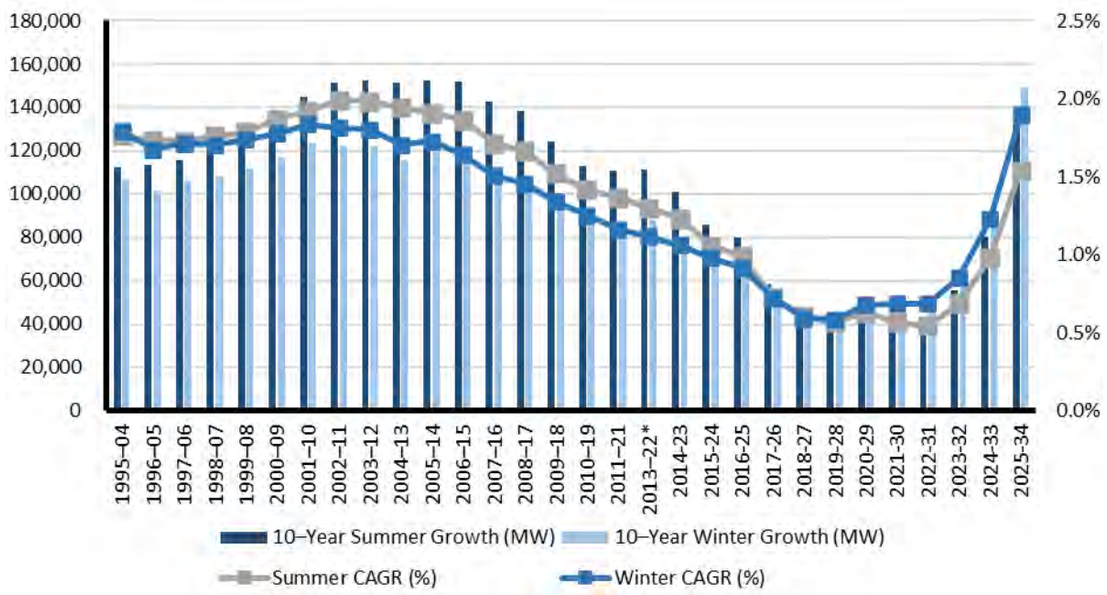


Figure 17: 10-Year Summer and Winter Peak Demand Growth and Rate Trends



Figure 18: Net Energy for Load Growth and Rate Projections

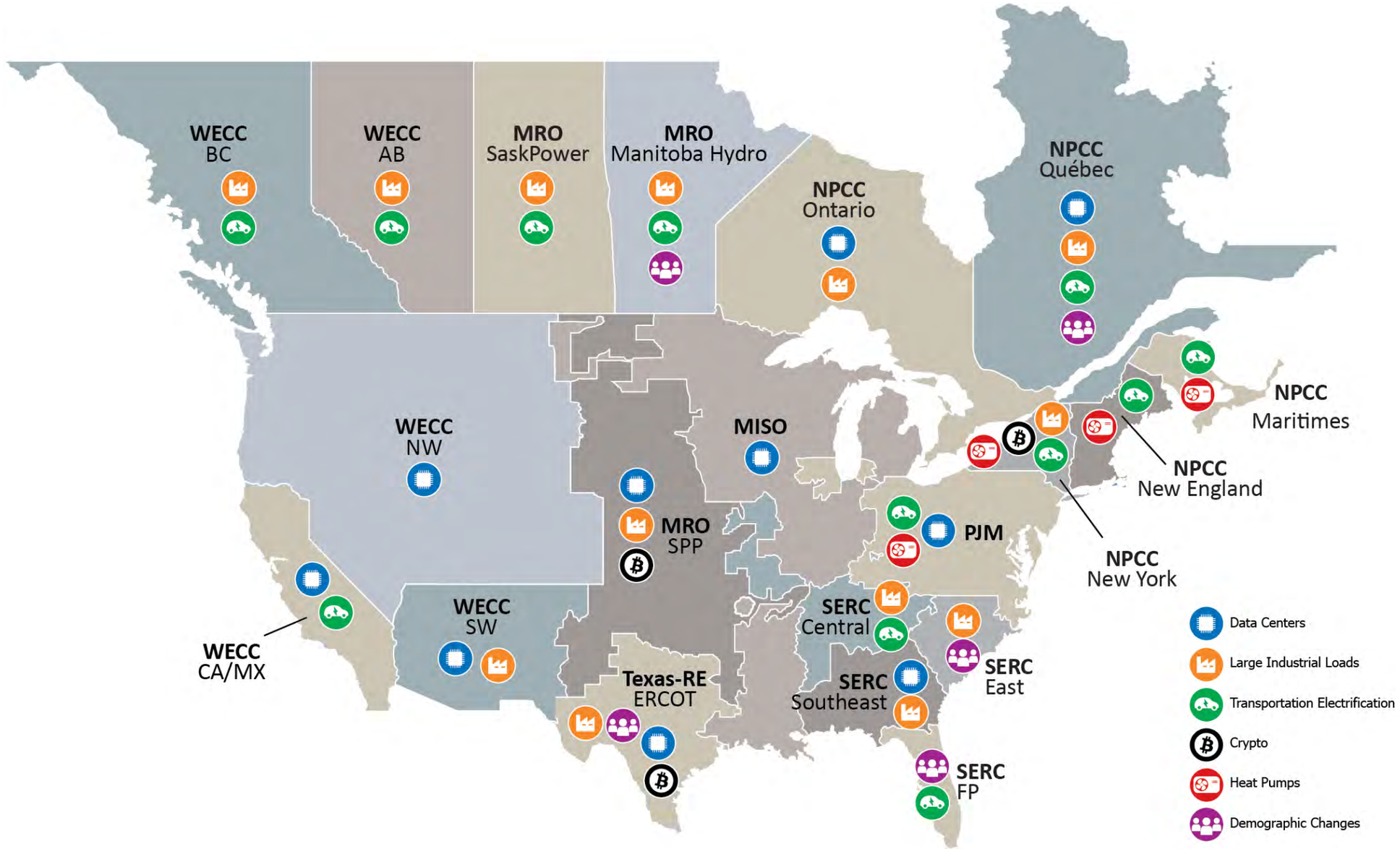


Figure 19: Primary Demand Drivers by Assessment Area

Peak Season Transition

Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as electrification in heating systems and transportation influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Electrification of heating systems and the anticipated growth of electric vehicles (which are expected to charge overnight and coincide with periods of electricity demand for heating) are driving factors. Such changes have wide-ranging implications for how the grid and resources are planned and operated. For example, resource output and fuel risks are significantly different in winter, requiring the focus of resource adequacy processes to change. The following are the areas that anticipate a change from a summer-peaking system to a winter-peaking (or dual-season peaking) system and the approximate year of the transition:

- NPCC-New England (mid-2030s)
- NPCC-New York (mid to late-2030s)
- NPCC-Ontario (2030)

In the U.S. Southeast, SERC-Central and SERC-East became dual-peaking systems in recent years. SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer.

Reliability Implications

Demand and energy growth projections in this assessment period provide both challenges and opportunities for electric grid reliability. Planning for resource and transmission adequacy requires accurate long-term forecasting, but future demand and energy use will be influenced by many factors, including the economy, energy policies, technology development, weather, and consumer preferences. Changing patterns in electricity use, load behavior, and distributed energy resource performance affect the accuracy of operational load forecasts that are essential to grid operators. Large flexible loads and demand-side management programs hold promise for peak load management capabilities that can reduce the risk of firm load interruption.

Anticipating large commercial and industrial loads, electrification, electric vehicle adoption, and the impacts of energy transition programs on future demand and energy needs will require even more focus for planners and operators. Peak demand forecast changes in the past year had a noticeable effect on resource adequacy for many areas. A confluence of factors (economic, energy policies, technology development, and consumer preferences) has the potential to fuel continued growth.

Transmission Development and Interregional Transfer Capability

Transmission Projects

This year's cumulative level of 28,275 miles of transmission (>100 kV) in construction or stages of development for the next 10 years (see **Figure 20**) is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning phases.

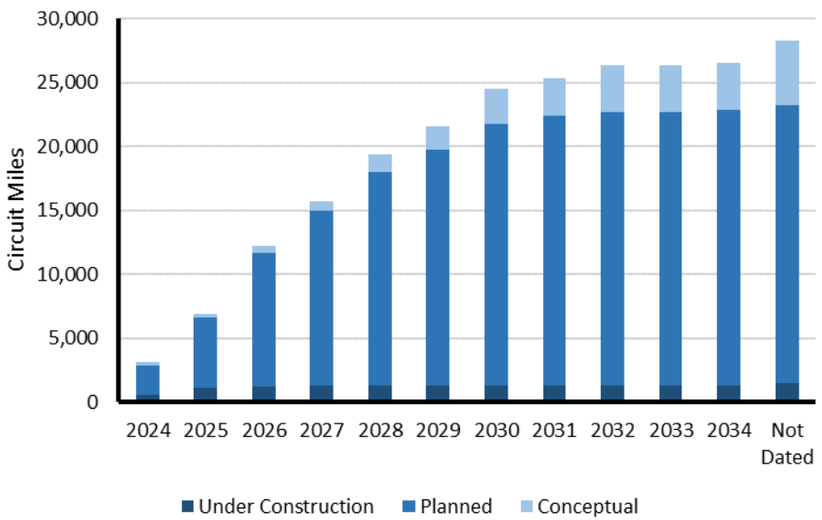


Figure 20: Future Transmission Circuit Miles >100 kV by Project Status

New transmission projects are being driven to support new generation and enhance reliability. **Figure 21** shows the percentage of future transmission circuit miles by primary driver. Most projects reported this year have been initiated for the purpose of grid reliability, which generally includes transmission projects that are needed to ensure that the BPS operates within established limits and design criteria. Some substantial new projects to integrate renewable generation are also in development or are entering planning processes. Nearly 70 of the 1,160 transmission projects in development are for tie-lines and tie-line upgrades, which support transfer capability between neighboring Balancing Authority areas. See the transmission summaries at the end of each assessment area's pages (in the **Regional Assessments Dashboards**) for current transmission development details.

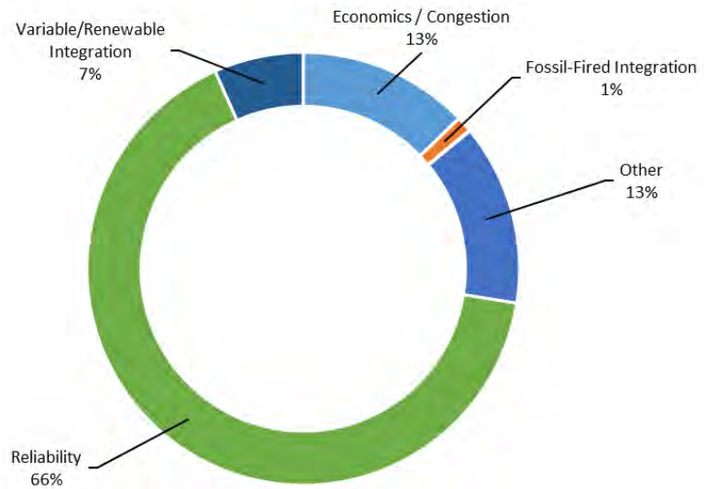


Figure 21: Future Transmission Circuit Miles by Primary Driver

Transmission development in some areas is hampered by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, over 110 projects are currently delayed from their expected in-service dates. Siting and permitting issues are the most common cause for delays, affecting 68 projects (totaling 1,230 miles of new transmission). Other reasons for delays include economic impacts, planning and construction issues, or changing needs.

Interregional Transfer Capability Study (ITCS)

The Fiscal Responsibility Act of 2023[22] required NERC to conduct a comprehensive study of existing and future interregional transfer capability between each Transmission Planning Region[23] (TPR) to make recommendations for prudent additions to the amount of power that can be moved or transferred between neighboring TPRs and to make recommendations on how to meet and maintain transfer capability. In addressing this legislation, NERC identified additions to transfer capability that could support energy adequacy.[24] NERC filed the completed study report with FERC on November 19, 2024.[25]

Transfer Capability is the measure of the ability of the interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all the transmission lines (or paths) between those areas under specific system conditions. The units of transfer capability are in terms of electric power, generally expressed in MW.

To provide further opportunities for stakeholder engagement and consultation, the project was divided into several stages, each with an accompanying report.

- **Overview of Study Need and Approach[26]:** Provided background and context regarding transfer capability calculations and the approach for recommending prudent additions, laying the foundation for the ITCS as a whole and its associated methods. (published in June 2024)
- **Transfer Capability Analysis (Part 1)[27]:** Addressed the first part of the congressional directive, which mandated a transfer capability analysis between each pair of neighboring TPRs, as well as the simultaneous import capability of each TPR. (published in August 2024)
- **Prudent Additions Recommendations (Part 2) and Meet/Maintain Recommendations (Part 3)**: Contained an energy margin analysis and resulting recommendations for prudent[28] additions to the transfer capability between neighboring TPRs to improve energy adequacy during, for example, extreme weather events. It also discussed how to meet and maintain transfer capability as enhanced by these prudent additions.
- **Canadian Analysis:** Due to the interconnected nature of the BPS, NERC will extend the study beyond the congressional mandate to identify and make recommendations to transfer capabilities from the United States to Canada and among Canadian provinces.[29]

Transfer Capability Analysis (Part 1)

Adequate transfer capability is fundamental to the reliable operation of the BPS. Balancing Authorities may rely on their neighbors to supply energy for various purposes, including economic or policy reasons. Transfer capability is also essential under stressed operating conditions, allowing Balancing Authorities to maintain reliability by importing needed energy from their neighbors. As the resource mix becomes increasingly dependent on just-in-time and weather-dependent fuel and energy for wind and solar, the ability to transfer electrical energy from areas of surplus to areas experiencing fuel or energy constraints has become essential to maintaining reliable delivery of electricity to end-use customers.

The ITCS is a congressionally mandated study to evaluate transfer capability and recommend additions to strengthen reliability.

A holistic view of the interconnected system and a thorough understanding of its behavior are essential when calculating or increasing transfer capability. When neighboring TPRs transfer energy over a highly interconnected system, the energy flows over many different lines based on the electrical characteristics, or impedance, of traveling each route, unless there is specific equipment used to control flows. As a result, energy typically flows not only across the tie lines that directly connect the exporting (source) TPR to the importing (sink) TPR but over many routes, some of which

[22] H.R.3746 - 118th Congress (2023–2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress
[23] For the purposes of the ITCS, this term refers to the study regions as described in ITCS Overview of Study Need and Approach, Chapter 2.
[24] As evidenced during recent operational events including Western Interconnection Heatwave (2020), Winter Storm Uri (2021) and Winter Storm Elliott (2022), more needs to be done to support energy adequacy to be able to continuously meet customer demand. This is the reliability risk that the ITCS seeks to identify and mitigate through additions to transfer capability.
[25] NERC filing of the Interregional Transfer Capability Study, FERC Docket AD25-4-000.
[26] The ITCS Overview of Study Need and Approach can be found here.
[27] The ITCS Transfer Capability Analysis (Part 1) report can be found here.
[28] FERC defines prudence as the determination of whether a reasonable entity would have made the same decision in good faith under the same circumstances at the relevant point in time. See, e.g., New England Power Co., 31 FERC ¶61,047 at p. 61,084 (1985); and PotomacAppalachian Transmission Highline, LLC, 140 FERC ¶61,229 at P 82 2012 (Sept. 20, 2012).
[29] The ITCS Part 1 evaluated transfer capability from Canada into the United States.

may be running through third-party systems. The way electrical energy flows has broad implications for calculating and using transfer capability in an interconnected system, especially when traveling over long distances. For example, maintaining and increasing transfer capability may be highly dependent on the system conditions within the source and sink TPRs as well as surrounding areas. Likewise, transfer capability does not correlate one-to-one with the rating of new or upgraded transmission facilities.

Part 1 Key Findings

- Transfer capability varies seasonally and under different system conditions that limit transmission loading—it cannot be represented by a single number.
- Transfer capability varies widely across North America, with total import capability varying between 1% and 92% of peak load.
- Observed transfer capabilities are generally higher in the West Coast, Great Lakes, and Mid-Atlantic areas but relatively lower in the Mountain States, Great Plains, Southeast, and Northeast. There is limited transfer capability between interconnections

The transfer capability results in the Part 1 report reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. This study used a set of cases representative of stressed system conditions most relevant for the Part 2 analysis. As such, the study did not attempt to maximize transfer capability values for each interface through optimal generation re-dispatch, system topology changes, or other operational measures. Consequently, higher transfer capabilities may be available under different conditions. Changes to future resource additions, resource retirements, load forecast changes, and/or transmission expansion plans have the potential to significantly alter the study results.

Recommendations for Prudent Additions (Part 2) and to Achieve Transfer Capability (Part 3)

Part 2 of the ITCS evaluated the energy adequacy of the BPS should past weather conditions occur again in 2033. Specifically, the study applied 12 past weather years to the 2033 loads and resource mix using the current transfer capabilities as calculated in Part 1. The Part 2 study then evaluated the impact that additional transfer capability could have in mitigating the identified resource deficiencies[30] during extreme events, thereby improving energy adequacy. Using a six-step process, the ITCS developed a list of recommended additions to transfer capability. **Figure 22** shows the existing and potential new interfaces where additional transfer capability is recommended. While there are several factors that Transmission Planners consider, including reliability, economics, and policy objectives, given NERC's role as the ERO, the ITCS focused solely on reliability, specifically in terms of energy adequacy, for these recommendations.

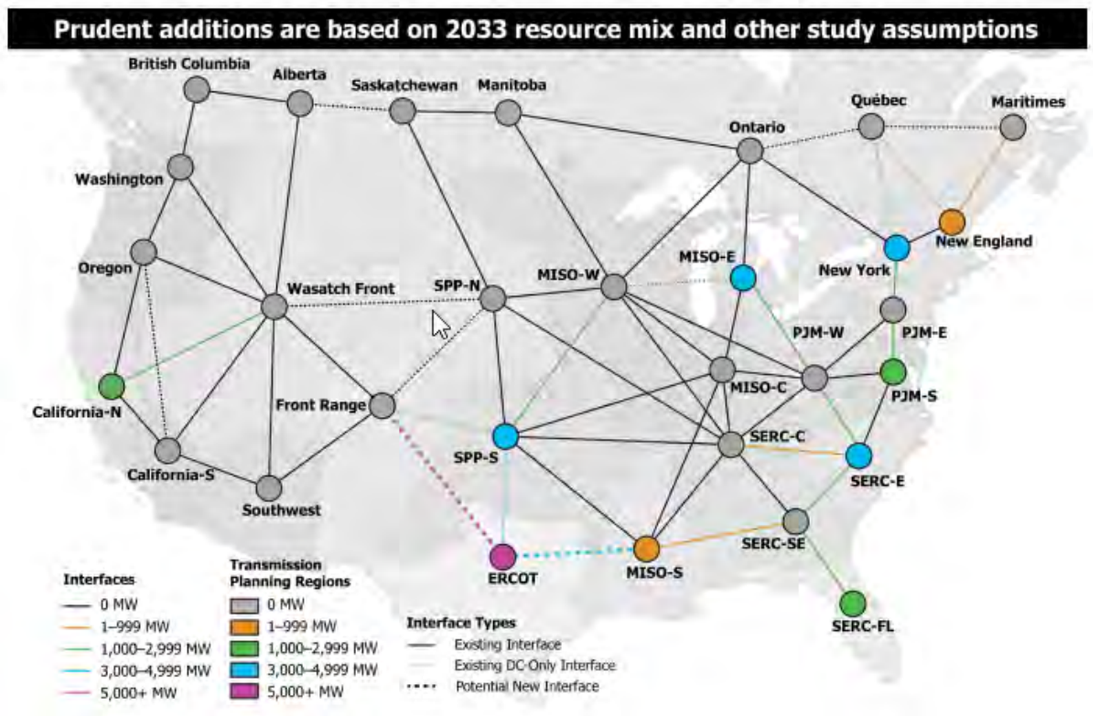


Figure 22: Prudent Additions to Transfer Capability

[30] For the purposes of this study, "resource deficiency" is used to describe instances where available resources, including energy transfers from neighbors, are insufficient to meet the projected demand plus minimum margin level.

The resulting recommendations for prudent additions to transfer capability (Part 2 study) were published in a report along with recommendations to meet and maintain transfer capability as enhanced by the prudent additions (Part 3).[31] Planners have multiple options for reducing the energy adequacy and extreme weather risks. In addition to the transmission enhancements that were in scope for the ITCS, due consideration should also be given to constructing local generation and storage, demand-side management approaches, and grid resilience projects. The ITCS recommended that planners consider all options and balance reliance on external resources vs. internal resources, noting that there may be better options than an over-reliance on one or the other.

Part 2 Key Findings

- Import capability required to reliably serve customers during extreme conditions varied significantly across the country, so a one-size-fits-all requirement would be inefficient and ineffective.
- Transmission limitations and the potential for energy inadequacy were identified in all 12 years studied.
- 35 GW of additional transfer capability is recommended across the United States to improve energy adequacy under extreme conditions.
- Some identified transmission needs could be alleviated by projects already in the planning, permitting, or construction phases. If completed, these projects could mitigate several risks highlighted by the ITCS, reinforcing their importance for grid resilience.
- The ITCS provides foundational insights for further discussion, and decisions. Transmission upgrades alone will not fully address all risks, and a broader set of solutions should be considered, emphasizing the need for local resources, energy efficiency, demand-side, and storage solutions.

See the *ITCS Final Report* for Detailed Key Findings

[31] The ITCS report *Recommendations for Prudent Additions to Transfer Capability (Part 2) and Recommendations to Meet and Maintain Transfer Capability (Part 3)* can be found here.

Emerging Issues

While developing this LTRA, NERC and the industry considered trends and developments that have the potential to impact the future reliability of the BPS over the next 10 years and beyond. Discussed below are emerging issues and trends not previously covered in this report that have the potential to impact future long-term projections or resource availability and operations.

Data Centers and Large Industrial Load

Growth in large load parcels like data centers and industrial facilities pose various challenges for system planners and operators, in addition to fueling rapid demand growth discussed elsewhere in this report. **Figure 23** shows one estimate of data center growth in the United States by 2027.[32] Other types of large industrial loads include smelters, manufacturing centers, hydrogen electrolyzers, and future electrified mass transit or shipping charging stations. Adding large parcels of load on the system can add new uncertainties to peak and hourly load forecasting. For example, data centers have longer operating hours and require more heating and cooling than other commercial buildings. In Texas, crypto mining facilities have connected in recent years that scale their operations (and thus electricity demand) depending on electricity prices. The behavior of large data centers during normal grid faults is also an emerging concern because customer-initiated automatic disconnecting of sizeable load can cause operating issues. Sudden and unexpected disconnecting load during a grid fault is analogous to well-known IBR performance issues and poses similar reliability risks. Planners and operators need to consider the characteristics of these loads as they begin to proliferate and support NERC RSTC's Large Loads Task Force to share best practices.

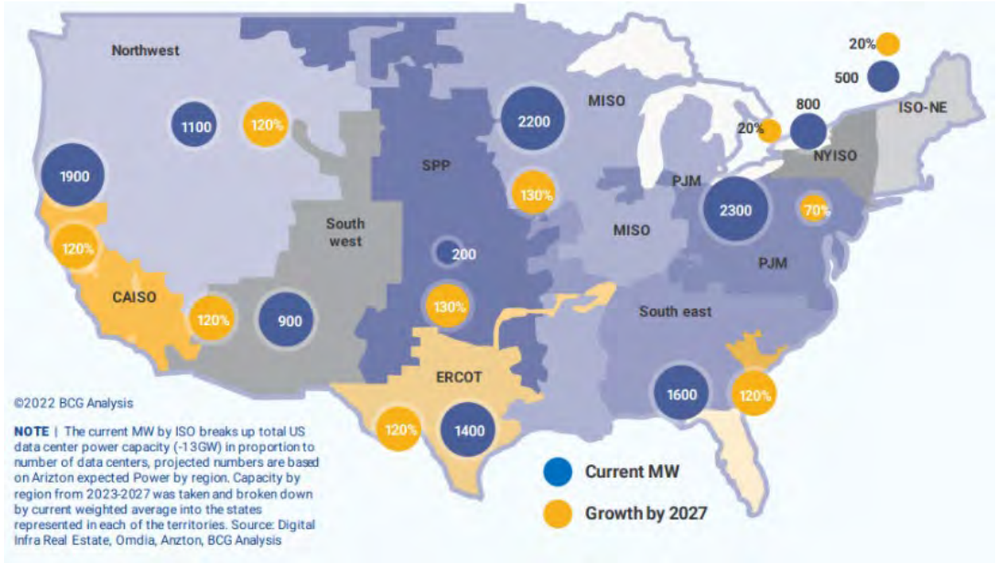


Figure 23: Projected Growth in Data Centers in the United States

Battery Energy Storage Systems

Planners and operators are focused on requirements to model, study, and operate the BPS with increased BESS and hybrid resources. BESS are increasingly being relied upon in areas with substantial amounts of solar PV resources to reduce ramping requirements on other resources by discharging in late afternoon as solar PV output rapidly declines. BESS are also often used for ancillary services, such as frequency response. Accurately accounting for BESS in operating and planning studies is a challenge because it requires assumptions and modeling capabilities for battery charging and discharging behavior. In real-time operations, system operators often do not have visibility into battery state-of-charge, a necessary condition for reliably integrating batteries into system operating plans. Without such information, operators may be surprised should battery resources fail to deliver when needed. In Texas, where battery resource growth is among the highest in North America, ERCOT uses a battery storage data collection program to obtain operational information and is pursuing market rules for state-of-charge accounting in unit commitment processes. System planners in many areas will be counting on new BESS facilities to manage variability and demand and resources. Obtaining the benefits of these resources requires careful integration into operating, planning, and market designs.

[32] *Grid Strategies: The Era of Flat Power Demand is Over*: https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

Electric Vehicles and Electric Load

With increased adoption of electric vehicles (EV), which use batteries to store energy, there is a need to understand the impact of battery charging on system performance. EV forecasting is important for resource adequacy and system planning to account for changing load and load patterns. It is also important for system studies to include EV modeling and parameterization that account for the behavior of battery charging systems on system performance. In January 2024, NERC released the *EV Charging Study*, noting that the behavior of large amounts of EV chargers in operation can affect the BPS response to common outages. The RSTC established an EV Task Force to promote collaboration among the electric power industry and automotive representatives on areas of grid reliability.

Energy Drought

More reliance on wind, solar, and hydro resources in the resource mix has the potential to expose the electric system to supply shortages under abnormal weather patterns. When two or more resource types are simultaneously affected by conditions that cause below-normal resource output, operators can face challenges in meeting demand. Analysis of U.S. historical hourly generator data indicates that there are regional patterns to energy drought that can be expressed in terms of duration, magnitude, and seasonality (See **Figure 24**). There is also a higher likelihood for energy droughts to be more likely occur during high-load periods than at other times, underscoring the importance in considering such events in planning for resource and storage needs.[33]

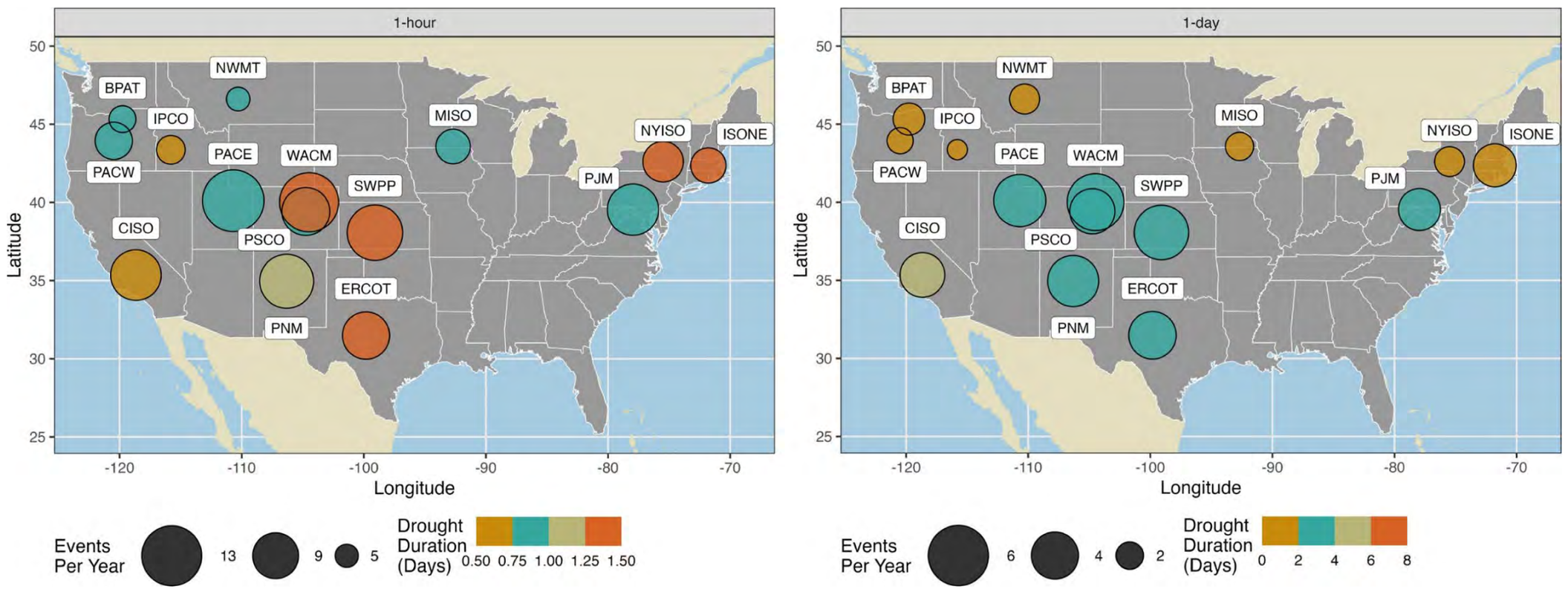
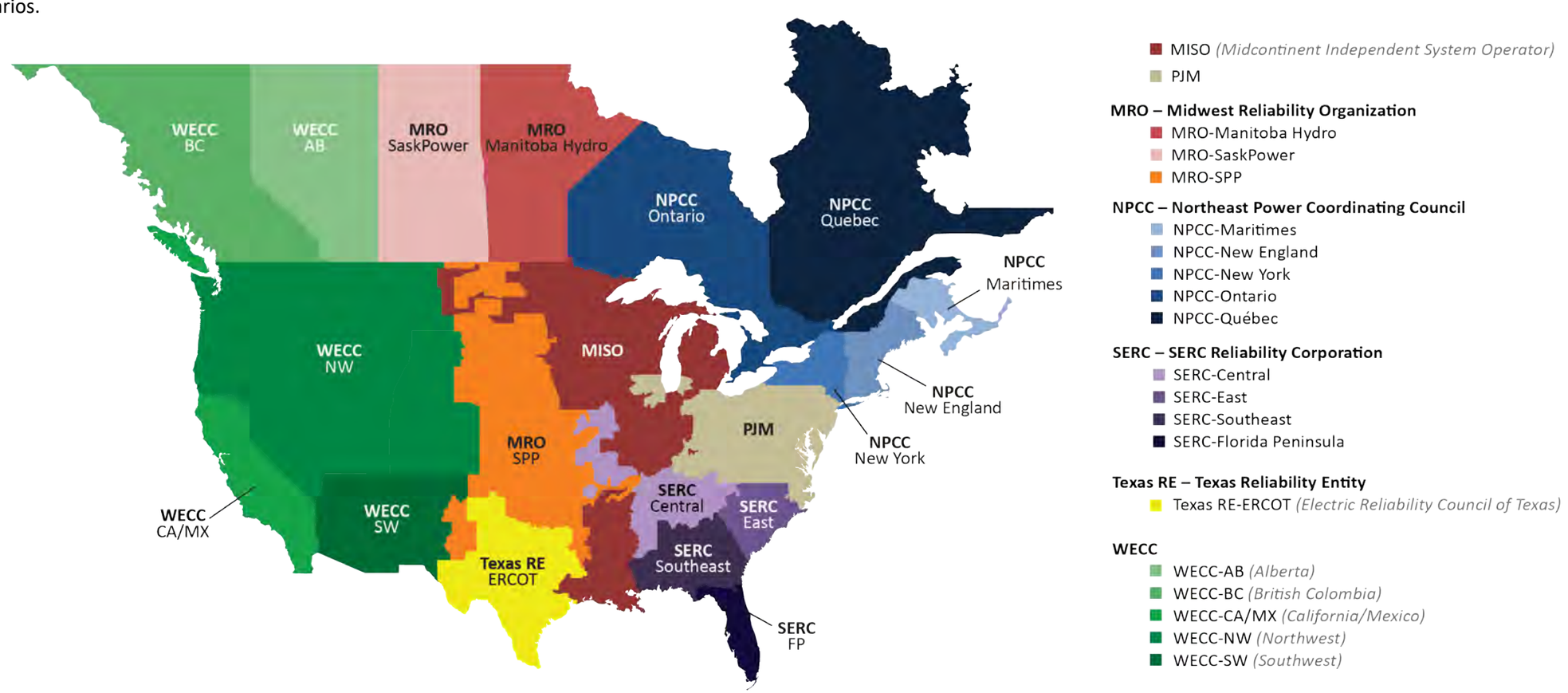


Figure 24: Frequency and Duration of Hourly (Left Panel) and Daily (Right Panel) Energy Droughts. Source: Pacific Northwest National Laboratory

[33] See Standardized benchmark of historical compound wind and solar energy droughts across the Continental United States

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Demand Assumptions and Resource Categories** table. On-Peak Reserve Margin bar charts show the ARM compared to the RML established for the area to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the Demand and Resource Tables), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the Demand and Resource Tables) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios.





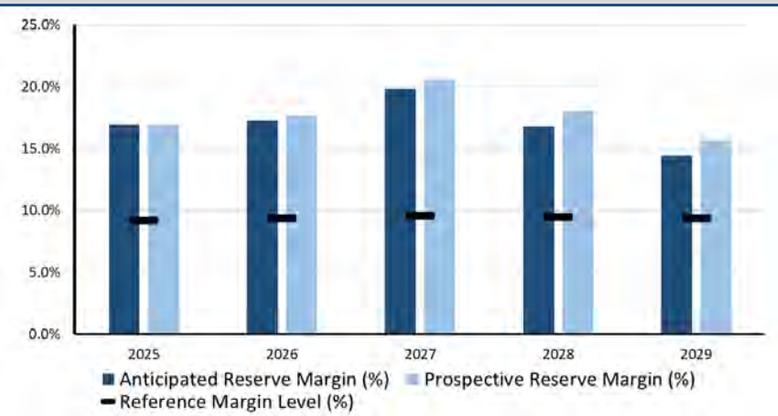
MISO

Midcontinent Independent System Operator, Inc. (MISO) is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

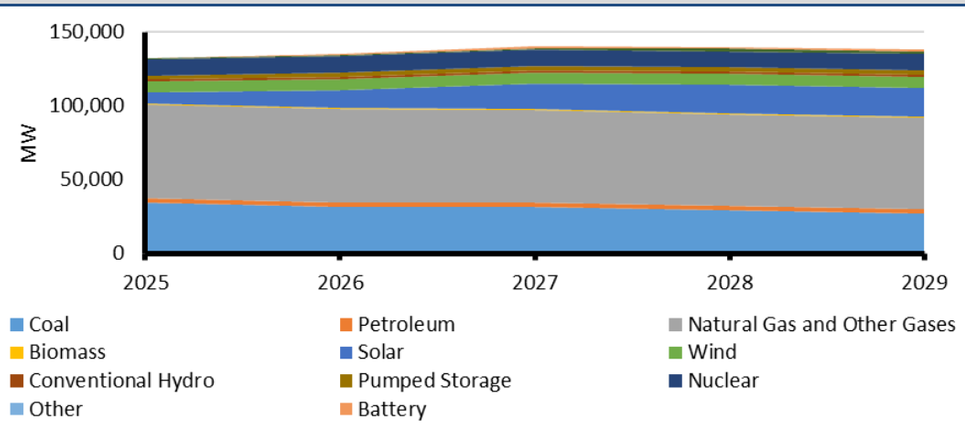
Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	122,328	124,343	126,073	128,700	129,401	130,120	130,493	131,327	131,952	131,952
Demand Response	8,205	8,221	8,058	8,065	8,074	8,077	8,079	8,075	8,075	8,075
Net Internal Demand	114,122	116,122	118,015	120,635	121,327	122,043	122,414	123,252	123,877	123,877
Additions: Tier 1	4,959	11,376	18,275	21,501	22,205	22,205	22,205	22,205	22,205	22,205
Additions: Tier 2	19	464	916	1,486	1,486	1,486	1,486	1,486	1,486	1,486
Additions: Tier 3	803	3,686	8,252	13,017	15,546	16,399	16,542	16,608	16,659	16,659
Net Firm Capacity Transfers	1,320	1,270	1,165	925	855	750	549	549	549	549
Existing-Certain and Net Firm Transfers	128,520	124,787	123,153	119,397	116,669	112,823	110,273	110,273	106,838	106,838
Anticipated Reserve Margin (%)	17.0%	17.3%	19.8%	16.8%	14.5%	10.6%	8.2%	7.5%	4.2%	4.2%
Prospective Reserve Margin (%)	17.0%	17.7%	20.6%	18.0%	15.7%	11.9%	9.4%	8.7%	5.4%	5.4%
Reference Margin Level (%) (Summer)	9.2%	9.4%	9.6%	9.5%	9.4%	9.4%	9.5%	9.6%	9.7%	9.7%

Note: See **Figure 3** for summer reserve margins with historically average resource additions in MISO based on results from the 2024 Organization of MISO States (OMS)-MISO Survey.



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MISO's capacity resource turnover continues to occur with coal unit contributions being primarily replaced by solar, wind, and battery facilities. Furthermore, generation installation delays result in uncertainty throughout the assessment timeframe. As a result of these factors, MISO is facing capacity shortfalls in the next five years.
- MISO's reduction in capacity resources since the *2023 LTRA* has primarily been in the coal fleet with a reduction of 6,200 MW in the first year of the assessment.
- MISO has continued the seasonal capacity auction construct and has found growing evidence of risk in non-peak (e.g., spring and fall) seasons. Countering the risk during these off-peak seasons requires more resources to be available, and this can result in less opportunity for generators to pursue their maintenance needs. During peak seasons when high levels of generator availability are expected, short-notice unplanned outages and higher forced outages could occur as a result of deferred maintenance and challenge reliability.

MISO Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	34,637	31,706	31,618	29,067	26,841
Coal*	27,450	24,362	23,203	17,977	16,744
Petroleum	3,065	3,058	3,060	3,050	3,050
Petroleum*	2,992	2,990	2,992	2,992	2,992
Natural Gas	63,051	62,977	62,616	62,394	62,009
Natural Gas*	62,576	61,543	62,396	62,394	62,009
Biomass	577	571	553	481	481
Solar	8,091	12,538	17,318	19,174	19,763
Wind	6,954	7,236	7,536	7,632	7,660
Conventional Hydro	1,527	1,527	1,527	1,527	1,527
Pumped Storage	2,528	2,528	2,578	2,578	2,578
Nuclear	11,027	11,127	11,127	11,127	11,127
Other	72	72	72	72	72
Battery	208	582	1,011	1,358	1,377
Total MW	132,159	134,892	140,263	139,973	138,018
Total MW*	124,423	126,048	131,562	128,826	127,864
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to MISO are removed from the resource projection where marked.					

MISO Assessment

Planning Reserve Margins

The planning reserves across the MISO footprint in the summer are projected to fall below reserve margin requirements as new generation coming on-line could be insufficient to make up for generator retirements and load growth. It is important to note that there is 56 GW of generation with signed generation interconnection agreements that are yet to come on-line as of July 5, 2024, so there is an opportunity to accelerate installation speeds. However, if resource additions remain at or near historically average levels (approximately 2.3 GW/year average over the last 3 years), PRMs in MISO will fall below the RML reserve margin requirements much faster. Summer PRMs with average resource additions are shown in **Figure 3** as **Reserve Margin-Avg Addition**.

Increased coordination between MISO and its members will be critical to ensuring reliability throughout this resource transition of integrating new intermittent resources and continuing to retire conventional resources. Resource adequacy is a key function of MISO, and the MISO annual planning resource auction (PRA) provides a mechanism for capacity sellers to provide resources that meet the needs of load-serving entities for each of the four seasons in the upcoming year. MISO's resource adequacy construct complements the jurisdiction that regulatory authorities have in determining the necessary level of adequacy.

Note: Capacity values for existing resources in tables on p. 41–42 reported by MISO reflect the Seasonal Accredited Capacity (SAC) for Summer. Adjustments and derates are applied to account for factors affecting expected resource output. The RML in the Demand, Resources, and Reserve Margins table on p. 41 is the Unforced Capacity (UCAP) RML, consistent with the reported capacity values.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The introduction of the seasonal PRA and inputs to the process provide more granularity and reliability planning for non-peak hour times during the year. In addition to that change, MISO conducts seasonal resource assessments evaluating generation availability, outage rates, and forecasted load variation across all four seasons. Refer to MISO's Resource Adequacy page.

Probabilistic Assessments

To establish RMLs that define the minimum reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. In recent years, MISO improved its LOLE study modeling by including seasonal outage rates, correlated cold weather outage adder profiles, a probabilistic distribution of non-firm support, and 30 years of hourly wind and solar profiles. The LOLE study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they prescribe the minimum PRM that will meet an LOLE of 1 day in 10 years. For more information on the seasonal LOLE Study, visit: https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf.

MISO also performed a probabilistic analysis for the 2024 ProbA. Because MISO used the same model for both the ProbA and the LOLE study, transmission limitations were not included explicitly in the simulations. It is appropriate for MISO to make this assumption for the LOLE study and for determining capacity needs in the MISO system because MISO accounts for transmission limitations elsewhere in the resource adequacy process. However, for an adequacy assessment like the ProbA, the assumption can overvalue resource performance by not accounting for transmission constraints on the deliverability of energy resources. The resulting 2024 ProbA metrics in the table below can understate the risk of unserved energy and load loss.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	68.8	**0.000**	**0.000**
EUE (PPM)	0.108	**0.000**	**0.000**
LOLH (hours per year)	0.393	**0.000**	**0.000**
Operable On-Peak Margin	13.9%	**11.3%**	**11.3%**

* Provides the 2022 ProbA Results for Comparison

MISO is an elevated risk in the *2024 LTRA* because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. All-hours probabilistic studies of the MISO system performed apart from the 2024 ProbA show that shortfall risks can also occur during spring and fall in months that are not peak demand seasons for MISO. The 2022 NERC ProbA Regional Risk Scenario Sensitivity Case included seasonal forced-outage rates and correlated cold weather outages instead of annual average outage rates. MISO found that not only did EUE increase in this sensitivity, but it was also spread throughout the year. Since this study, MISO implemented enhancements to its LOLE study and PRA to address seasonal resource needs.

Demand

The peak demand forecast has increased from the *2023 LTRA* by close to 3 GW (~2.5%), and, while the load forecasts still vary across year to year, the load at the end of the study horizon is ~5 GW higher (~4%). Load-serving entities do not include DR resources in the load forecast, and MISO does not have much insight into the amount of electrification built into the load forecasts. There are other studies at MISO investigating electrification and transportation industry impacts to load forecasts

through the MTEP report. MISO contracted with Applied Energy Group (AEG) to evaluate the MISO footprint's electrification potential. This is documented in the report and has been utilized to update the MISO Futures Report.

Demand-Side Management

DR programs continue to play a significant role in providing capacity to MISO. DR is steady around 8 GW in the summer and 6.5 GW in the winter and is projected to remain constant during the study horizon. MISO's transition to seasonal auctions highlights accreditation of DR and availability during non-summer seasons.

Distributed Energy Resources

Behind-the-meter generation (BTMG) resources contribute about 4.2 GW of capacity across the study horizon, of which ~1.2 GW are distributed PV. MISO's transition to seasonal auctions highlights the availability of DERs across the four seasons, and MISO is working with stakeholders to derive adequate methods of aggregating, reporting, and allowing DER participation in MISO markets.

Generation

The departure of MISO's coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years. Solar continues to rise in capacity contributions with a growth of 1,200 MW since the *2023 LTRA* and growth of 3,200 MW in the first year of the study.

There are ~56 GW installed capacity (ICAP) of generation (predominantly solar and battery) with signed generation interconnection agreements in MISO that are projected to come on-line over the next few years. There have been some supply chain and tariff issues that have delayed the commercial operation of these resources.

Due to the large size in the MISO interconnection queue, in the 2022 LTRA (similarly to the OMS-MISO Survey), prospective generation in the queue gets multiplied by a factor based on the study phase and likelihood of that resource coming on-line and gets added into the footprint over time. This reduction is utilized to minimize the impact of prospective generation projects that will not come to fruition through the queue cycle. MISO continues to pursue queue reform efforts to expedite the process by ensuring projects being studied are of adequate certainty.

Transmission

The MISO Transmission Expansion Plan (MTEP) 2021 included the Long-Range Transmission Plan (LRTP) tranche 1 projects totaling $10.3 billion in investment for reliability and economic benefits estimated at $23–52 billion across the MISO footprint while also facilitating the integration of ~53 GW of new resources. In MTEP22, $4.3 billion in transmission projects were approved with $550 million going toward integrating new resources, $550 million going toward baseline reliability projects, and the age and condition category for the rest. MTEP23 includes a further $9 billion investment into the MISO footprint to address the local needs of the region. MISO is also pursuing LRTP tranche 2 with an expected investment of $18-23 billion to implement a 765 kV backbone into the northern portion of the footprint. These projects are expected to be included as part of MISO's MTEP24 project portfolio. In MTEP24, $6.7 billion in transmission projects have been submitted for board approval. MISO is also pursuing LRTP tranche 2.1 with an expected investment of $21.8 billion to implement a 765 kV backbone into the midwestern portion of the footprint. Tranche 2.1 brings reliability and economic benefits estimated at $51.7–101 billion across the MISO Midwest footprint, facilitating integration of ~115.7 GW of new resources.

Energy Storage

MISO's energy storage resources are still primarily in the future with only 84 MW of on-line storage. The MISO interconnection queue does have a significant amount of energy storage upcoming, but these are primarily Tier 3 resources at present.

Capacity Transfers

MISO benefits from significant transfer capacity with neighboring assessment areas due to the geographic location. MISO and SPP continue to finalize the Joint Targeted Interconnection Queue (JTIQ) portfolio to resolve the binding constraints that have traditionally delayed the interconnection process. MISO's utilization of capacity transfers is identified in the LOLE report and memorialized through the MISO PRA.

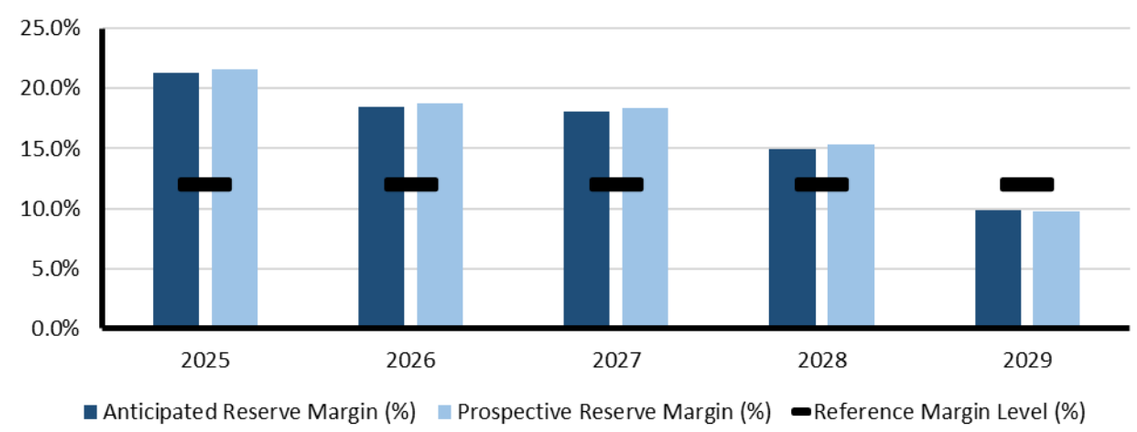


MRO-Manitoba Hydro

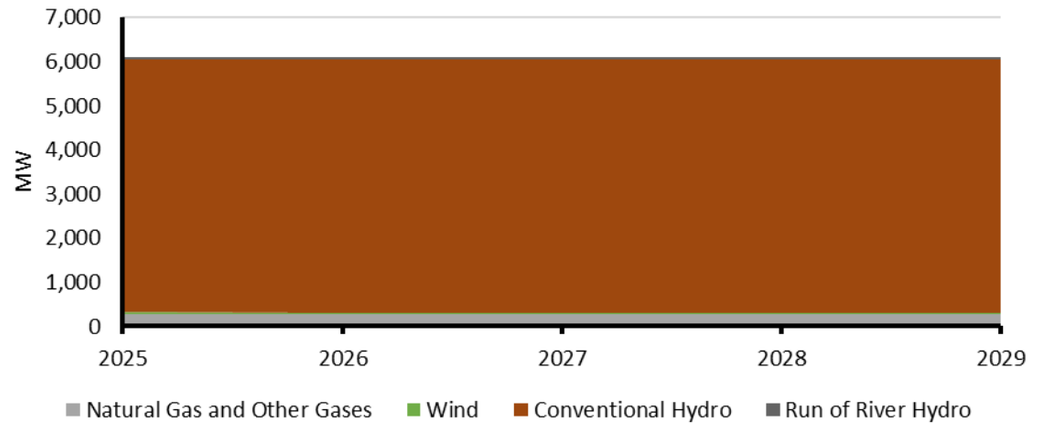
Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 616,000 electric customers in Manitoba and provides approximately 296,000 customers with natural gas in southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	4,797	4,923	4,968	5,037	5,268	5,366	5,427	5,486	5,556	5,629
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,797	4,923	4,968	5,037	5,268	5,366	5,427	5,486	5,556	5,629
Additions: Tier 1	30	51	64	64	64	64	64	64	64	64
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-113	-113	-93	-167	-172	-565	-565	-565	-565	-565
Existing-Certain and Net Firm Transfers	5,786	5,780	5,800	5,726	5,721	5,328	5,328	5,328	5,328	5,328
Anticipated Reserve Margin (%)	21.3%	18.4%	18.0%	15.0%	9.8%	0.5%	-0.6%	-1.7%	-2.9%	-4.2%
Prospective Reserve Margin (%)	21.6%	18.8%	18.4%	15.3%	9.8%	0.5%	-0.6%	-1.7%	-3.0%	-4.2%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The electricity demand forecast in the province of Manitoba has increased since the *2023 LTRA*, driven by expected economic activity and adoption of EVs. Resource projections have not changed significantly.
- The ARM falls below the RML of 12% beginning in Winter 2029–2030 due to load growth and the reduction of winter import capacity transfers. Manitoba Hydro is performing analysis to inform its integrated resource plan and support future decisions for resources.

MRO-Manitoba Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**
Natural Gas	278	278	278	278	278
Wind	52	31	31	31	31
Conventional Hydro	5,705	5,726	5,739	5,739	5,739
Conventional Hydro*	5,705	5,726	5,739	5,739	5,721
Run of River Hydro	856	856	856	856	856
Total MW	6,094	6,094	6,107	6,107	6,107
Total MW*	6,094	6,094	6,107	6,107	6,089
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

MRO-Manitoba Hydro Assessment

Planning Reserve Margins

The winter ARM falls below the Reference Margin Level of 12% in 2029–2030. No resource adequacy issues are anticipated until Winter 2029–2030. A Tier 1 project to replace eight older and smaller hydro units is being planned for the Pointe du Bois Generating Station. The Pointe du Bois Renewable Energy Project (PREP), approximately 50 MW, replaces the original hydro units that were mothballed or retired based on economics/end of life after about 100 years of operation. No Tier 2 or Tier 3 resources have been assumed to come into service during the assessment period.

The ARM falls below the Reference Margin Level of 12% beginning in Winter 2029–2030 due to net load growth and the reduction of winter import capacity transfers. Manitoba Hydro's Integrated Resource Plan was published in Summer 2023. Further analysis is underway and will help inform Manitoba Hydro's future resource decisions for resources in the 2029 timeframe.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Under normal water conditions, over 95% of the generation in Manitoba Hydro's system is from renewable energy—primarily hydro generation and wind generation. As the operator of a predominantly hydro system, Manitoba Hydro frequently performs an all-hours energy adequacy analysis of the near-term through seasonal time periods to manage reservoir energy storage and meet system demand. Additionally, Manitoba Hydro conducts specific analyses to determine short-term storage and minimum flow requirements for maintaining Manitoba and extra-provincial resource adequacy obligations. As there are modest levels of wind and solar on the Manitoba Hydro system, the resource adequacy risk on the Manitoba Hydro system over the next five years and under normal water conditions is expected to coincide with peak demand hours**.**

There are a number of influencing factors associated with Manitoba Hydro's resource adequacy performance, such as the water resource conditions, energy and capacity exchanges with neighboring jurisdictions, forecast load level, uncertainties in load forecast and load variation profiles, demand responses, wind penetration, and generation fleet availability. Most of Manitoba Hydro's generating facilities are use-limited or energy-limited hydro units. The annual energy output of these facilities is mostly dependent on the availability of the water resource. In the 2024 ProbA, Manitoba Hydro examines the impact of the most significant factor over the long run—variations in water conditions.

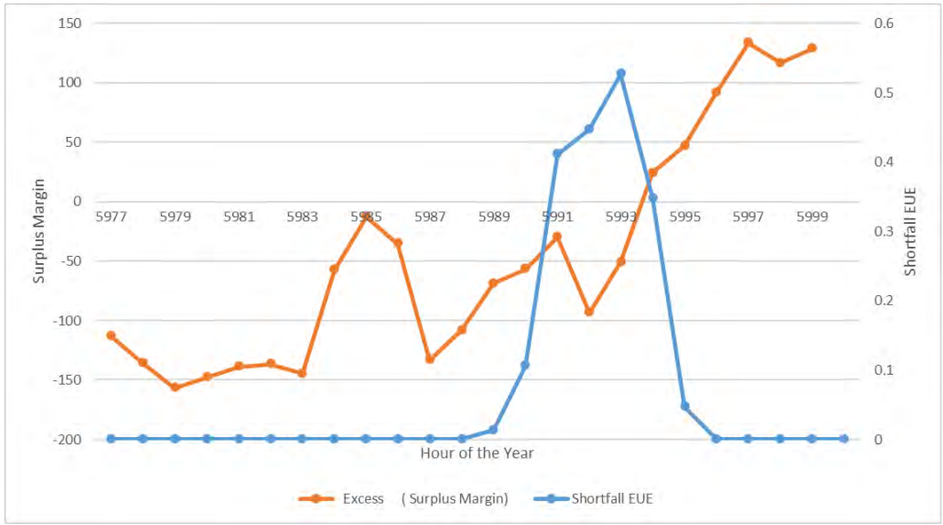
Nonzero LOLH and EUE are observed for both reporting years of 2026 and 2028 and shown in the table below. The LOLH and EUE indices are higher compared to the 2022 assessment mainly due to the increase in the forecast peak demand. Water flow conditions of 10th percentile or lower tend to increase the LOLH and EUE. As a small winter-peaking system on the northern edge of a large summer peaking system (MISO), there generally is assistance available, particularly in MISO's off-peak hours, to provide energy to supplement hydro generation in low-flow conditions in winter. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low water flow conditions.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	7.23	**4.711**	**68.870**
EUE (PPM)	0.29	**0.176**	**2.504**
LOLH (hours per year)	0.01	**0.059**	**0.914**
Operable On-Peak Margin	13.5%	**18.8%**	**15.6%**

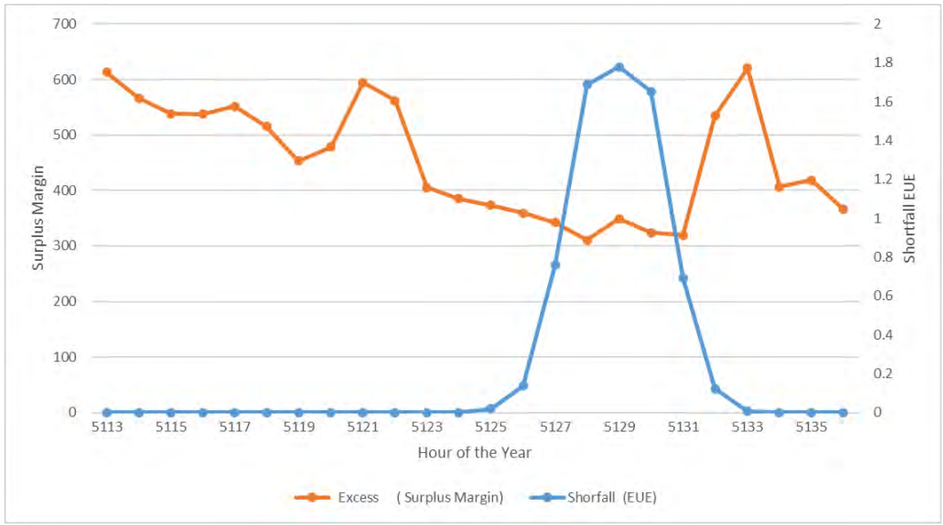
* Provides the 2022 ProbA Results for Comparison

The Monthly EUE and LOLH for 2026 and 2028 show that the highest LOLH and EUE contribution are from July and November, respectively, for 2026 and 2028.

The two graphs below show the hourly energy availability on the Manitoba Hydro system during the ProbA's highest risk days in 2026 and 2028. Surplus energy and shortfall EUE are plotted for the day when the highest loss of load event happens in the ProbA analysis. The Probability Weighted Average (PWA) surplus margin is negative, which indicates possible loss of loads for 2026. However, the PWA surplus energy is higher for 2028 during the day when the highest loss of load event is observed. This is because the surplus is an average for different water year data and the average surplus may not represent the event when loss of load occurs.

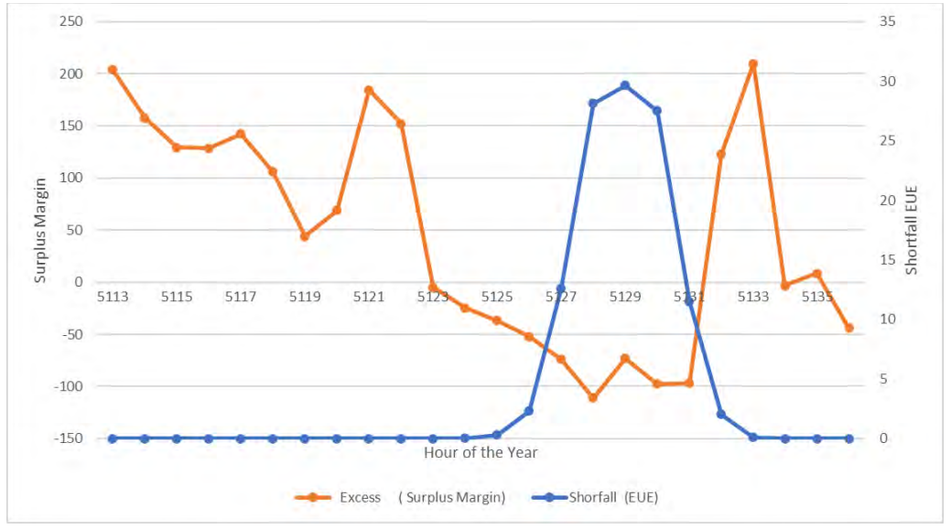


Hourly PWA Surplus Margin and Shortfall EUE for 2026 Representative Risk Day (Summer)



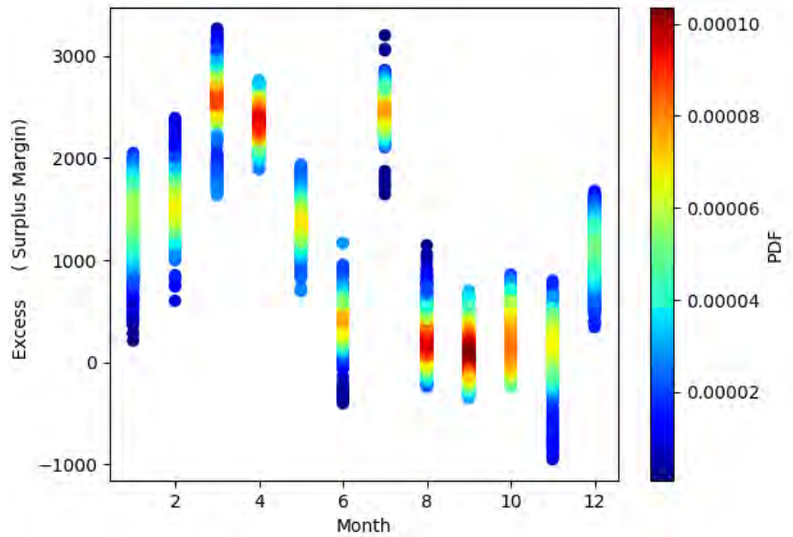
Hourly PWA Surplus Margin and Shortfall EUE for 2028 Representative Risk Day (Summer)

The figure below shows the surplus margin and shortfall EUE for 2028 under extreme drought conditions. It can be seen that the loss-of-load event occurs when the surplus margin becomes negative. This surplus energy shown in the figure is the average value for this hour for the entire simulation. It may not represent each individual loss-of-load event during simulation. By plotting the hourly surplus and unserved energy for the low-water years, it is possible to see what risk periods are likely to emerge during extreme drought.



Hourly PWA Surplus Margin and Shortfall EUE for 2028 Representative Risk Day (Summer) During Extreme Drought Condition

The scatter plots of surplus energy vs. month for 2026 and 2028 are shown in the figures below. In the months of June and August to November, the PWA surplus energy is relatively lower compared to the other months due to less import from MISO. The PWA surplus energy in July 2026 is high due to higher hydro energy availability for July. However, since PWA is the result of averaging, positive surplus energy does not mean that there will be no loss-of-load events.



PWA Surplus Energy Versus Month for 2026

Demand

Manitoba Hydro's load-growth forecast is up around 3.2% over the assessment period in comparison with the forecast used for the *2023 LTRA*. Factors considered in load-growth projections include economic activity, EV adoption, and demand-side management programs in Manitoba operated by Efficiency Manitoba. EV adoption in Manitoba is being driven in part by proposed federal regulations that are expected to require that at least 20 percent of new vehicles sold in Canada will be zero-emission by 2026, at least 60 percent by 2030, and 100 percent by 2035.

Manitoba Hydro is anticipating load growth of 1.3% over the last half of the assessment period. Limited surplus firm generation resources (resource adequacy) have the potential to slow the connection of very large new industrial loads. In order to limit load growth, Manitoba Hydro has been directed by the Province of Manitoba to suspend processing of cryptocurrency load connections until 2026.

Demand-Side Management

Manitoba Hydro currently does not have any form of directly controllable and dispatchable DR programs. Manitoba Hydro does have an indirectly controllable and dispatchable DR program called the Curtailable Rate Program.

The Curtailable Rate Program provides approximately 160 MW of load reduction through up to 16 load curtailments of 4¼ hours each on five minutes notice. The program is intended for peak load management. In addition, one product provides 50 MW of contingency reserves, also on five minutes' notice.

The terms and conditions of the Curtailable Rate Program were updated in August 2023 to require an annual curtailment test, increase the number of possible curtailments, extend the notice period for conversion to firm service, and make minor editorial changes.

Distributed Energy Resources

Manitoba is not currently experiencing large additions of wind and solar resources being seen in other regions; hence, emerging reliability issues arising from such large wind and solar resource additions are not anticipated in the next five years. Additions of energy storage resources in the next 10 years are not anticipated at this time. There is a potential for significant solar DER resources in the latter half of the assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system. The potential for future solar DER may be dependent on solar PV subsidies and/or incentives.

Generation

Manitoba Hydro is monitoring federal and provincial policy/strategies/regulations related to electricity/energy. The Canadian federal government is considering significant carbon emission regulations. Through Environment and Climate Change Canada, it is taking multiple steps to develop clean electricity regulations that aim for Canadian electricity generation to achieve net-zero greenhouse gas emissions by 2035 by requiring generating units to meet a stringent emissions intensity standard (measured in tons CO2 equivalent per GWh) and pay a price for any remaining emissions. The proposed regulations are still in development and not proposed to be fully implemented until 2035, so it is too early to determine any potential impacts. The Province of Manitoba is developing a provincial energy strategy/policy which may be released in Fall 2024. As details are not yet available, it is too early to determine any potential impacts.

Energy Storage

Manitoba Hydro currently has no energy storage resources, and none have been committed to over the next 10-year period.

The hydro generation resources, while not storing electricity directly, do store water in a reservoir for conversion to electricity and have been in use for over 100 years. For most hours of the year, the only dispatchable resources online are hydro generation resources which therefore serve most operational, reliability, and economic functions.

Capacity Transfers

Manitoba Hydro has coordination and tie-line agreements with neighboring assessment areas, such as MISO, SaskPower, and the IESO. In accordance with these agreements, planning- and operating-related issues are discussed and coordinated through respective committees. In addition to this planning and operating committee work, Manitoba Hydro engages with the neighboring utilities of Minnesota Power, Xcel Energy, Otter Tail Power, Minnkota Power Cooperative, SaskPower, and Hydro One regularly to share information, discuss issues, and coordinate activities. Manitoba Hydro also coordinates planning studies (for example, transmission service request studies and requests for generation interconnections) with its neighboring assessment areas. In addition, capacity transfers are verified from a resource adequacy perspective with adjacent regions/entities. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts but only in extreme conditions occurring simultaneously.

Transmission

Manitoba Hydro has identified aging components of its HVdc system as a potential reliability issue that is unique to the assessment area. The concern is that the oldest HVdc system components could be approaching end of life. Studies have been initiated to study/evaluate modernization options and alternatives. The studies and procurement of replacement equipment could take up to 10 years to implement based on the current HVdc market capability. There is currently spare capacity on the HVdc system, and the end-of-life failure of a single pole would not create reliability issues. The further end-of-life failure of a second pole, while believed to be a very low probability, has the potential to create reliability concerns under peak winter loads if mitigation measures are not implemented. Mitigation measures to minimize the likelihood of experiencing this quantity of long-term outages are being actively pursued.

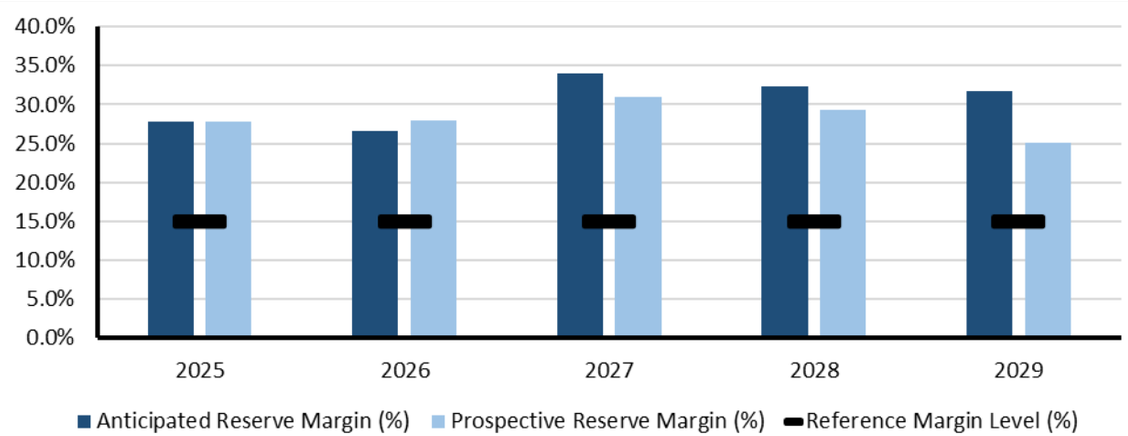


MRO-SaskPower

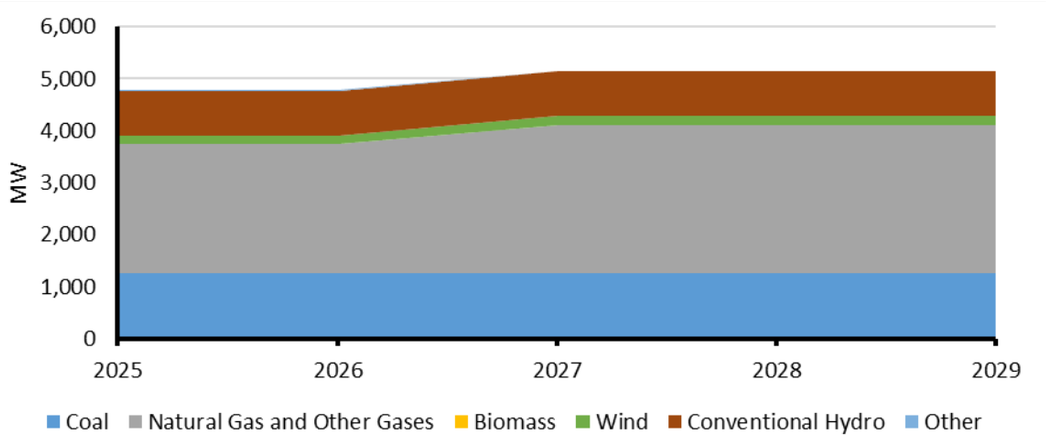
MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles), with a population of 1.2 million and approximately 550,000 customers. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown Corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	3,917	4,025	4,149	4,189	4,210	4,242	4,271	4,315	4,359	4,408
Demand Response	72	72	72	72	72	72	72	72	72	72
Net Internal Demand	3,845	3,953	4,077	4,117	4,138	4,170	4,199	4,243	4,287	4,336
Additions: Tier 1	507	507	883	883	883	883	883	883	883	883
Additions: Tier 2	0	55	175	175	928	928	928	928	928	928
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	290	290	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,407	4,497	4,582	4,566	4,566	4,489	4,490	4,490	4,552	4,566
Anticipated Reserve Margin (%)	27.8%	26.6%	34.0%	32.4%	31.7%	28.8%	28.0%	26.6%	26.8%	25.7%
Prospective Reserve Margin (%)	27.8%	28%	31.0%	29.3%	25.1%	22.3%	20.8%	19.5%	19.8%	18.7%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- SaskPower's ARM is above the RML throughout the assessment period. No resource adequacy issues are anticipated.
- Saskatchewan is adding approximately 1,064 MW of generation under Tier 1 within the next five years. This includes a 200 MW wind generation facility, two new 377 MW gas generation facilities, and the expansion of two existing natural gas facilities totaling 90 MW. The remaining capacity addition comes from geothermal and flare gas.

MRO-SaskPower Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Coal	1,249	1,249	1,249	1,249	1,249
Coal*	1,249	1,249	1,088	1,088	188
Natural Gas	2,487	2,487	2,863	2,863	2,863
Biomass	3	3	3	3	3
Wind	164	164	162	162	162
Conventional Hydro	856	856	856	856	856
Other	22	17	17	1	1
Total MW	4,781	4,775	5,150	5,134	5,134
Total MW*	4,781	4,775	4,989	4,973	4,073
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

MRO-SaskPower Assessment

Planning Reserve Margins

Saskatchewan uses a criterion of 15% as the reference reserve margin and has assessed its PRM for the upcoming 10 years considering the summer and winter peak hour loads, available existing and anticipated generation resources, firm capacity transfers, and available demand response for each year. Saskatchewan's ARM ranges from approximately 19% to 34% and does not fall below the Reference Margin Level.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Saskatchewan performs energy assessments using probabilistic methods to inform the area's resource adequacy requirements. Saskatchewan evaluates non-peak hour risks and diminishing capacity credits associated with higher penetration levels of VERs as part of the long-term planning process.

Results of the 2024 ProbA are provided in the table below. Based on the deterministic calculations within this assessment, Saskatchewan's ARM is 27.8% and 34.0% for years 2026 and 2028, respectively. Since the 2022 ProbA, the reported forecast reserve margin for 2026 has remained consistent. The minor variation in the reserve margin is due to a slight change in the schedule of generator outages. EUE is also comparable to the 2022 ProbA, with some variation attributed to updated hydro energy dispatch, which is able to reduce the EUE in the months where it was highest in the prior ProbA.

Base Case Summary of Results			
	2026*	2026	2026
EUE (MWh)	117.0	**75.641**	**8.553**
EUE (PPM)	4.4	**2.807**	**0.300**
LOLH (hours per year)	0.9	**0.547**	**0.078**
Operable On-Peak Margin	24.6	**24.4%**	**30.5%**

* Provides the 2022 ProbA Results for Comparison

Saskatchewan does not anticipate resource adequacy issues during its off-peak hours. Currently, its resource mix consists of baseload and fast ramping generation resources, with little penetration of VERs. The main factor contributing to EUE is the amount of planned generator outages. When these short-term reliability issues are identified in advance, they can be mitigated by rescheduling the maintenance. The hourly EUE heat maps in the following figures show that risk of unserved energy is at its highest in the summer months. Risk can also be found in months before or after summer and be driven by unseasonable temperatures driving above-normal demand that coincides with generator maintenance periods. Winter risks of shortfall are associated with extreme cold weather and unexpected generator outages.

Hourly EUE Heat Map : 2026																								
EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Feb-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mar-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May-26	1.2	1.2	1.1	1.2	1.2	1.3	1.3	1.3	1.4	1.5	1.6	1.8	1.8	1.7	1.7	1.6	1.6	1.6	1.5	1.5	1.5	1.6	1.5	1.3
Jun-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jul-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0
Aug-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0
Sep-26	0.5	0.6	0.6	0.6	0.6	0.5	0.6	0.7	0.7	0.8	0.9	1.2	1.2	1.3	1.4	1.5	1.5	1.6	1.4	1.5	1.7	1.3	1.0	0.7
Oct-26	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.4	0.3	0.3
Nov-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Dec-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.1

Hourly EUE Heat Map : 2028																								
EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feb-28	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mar-28	0.0	0.0	0.0	-	-	-	-	0.0	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jun-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Jul-28	0.0	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
Aug-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sep-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oct-28	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1
Nov-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Dec-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0

Hourly EUE Heat Maps (in MWh)

Demand

Saskatchewan experiences its peak-season in the winter. Saskatchewan's system peak load forecast is based on econometric variables, weather normalization, and individual level forecasts for large industrial customers. The average annual summer and winter peak demand growth is expected to be approximately 1.35% throughout the assessment period.

Demand-Side Management
Saskatchewan's EE and energy conservation programs include incentive-based and education programs focusing on installed measures and products that provide verifiable, measurable, and permanent reductions in electrical energy, and demand reductions during peak hours.

Saskatchewan's DR consists of contracts with industrial customers for interruptible load based under conditions specified in demand response programs. The first of these programs provides a curtailable load, currently up to 72 MW, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load requiring up to two hours notification time.

Distributed Energy Resources
The current BTM DER installed capacity in Saskatchewan is approximately 50 MW, which includes approximately 48 MW of solar PV and the remaining approximately 2 MW of distributed wind projects. An additional 25 MW of DER solar PV are expected to be added in the next five years. BTM DER installations are incorporated into the load forecast models, which are used in supply and transmission planning study models.

Small power producers contribute an additional 5 MW installed DER capacity (non-BTM) in Saskatchewan. There is currently an existing 8 MW and a potential for up to 20 MW of DERs being added in the next 2 years based on the currently approved Power Generation Partner program. These projects are included as generation additions, but currently their capacity is not considered in reliability planning.

Generation
Saskatchewan is adding approximately 1,064 MW into its resource mix of generation under the Tier 1 category within the next five years. The includes a 200 MW wind generation facility, expansion of two existing natural gas facilities totaling 90 MW, two new natural gas facilities totaling 754 MW, 15 MW of flare gas generation, and 5 MW of geothermal generation.

Under Tier 2, over 1,717 MW of new generation is projected in the assessment period. This includes 754 MW of natural gas, 600 MW of wind generation, 300 MW of utility-scale solar generation, and 63 MW of co-generation.

Generating resources being planned as Tier 2 and Tier 3 will replace generators planned for retirement prior to deactivation. Therefore, Saskatchewan is not expecting any long-term reliability impacts due to generation retirements.

Energy Storage
SaskPower currently has its first battery storage system, a 20 MW/20 MWh unit, under commissioning. There are plans to expand this site by an additional 60 MW/60MWh capacity. The prevalent use for the planned energy storage is to provide regulating reserve, peak capacity and energy reduction, net demand ramping control, reactive power/voltage control, primary frequency control, and blackstart.

Capacity Transfers
SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is the largest of the three interfaces and is the only interface with long-term firm contracts. Capacity transfers from Manitoba would be limited in the event of a prior outage of tie lines between SaskPower and Manitoba Hydro, as well as nearby transmission facilities supporting the interface. This could only impact reliability if it is coincident with the extreme winter or summer peak demand and a prior outage of one or more larger generating units in Saskatchewan. Risk mitigation is in place through SaskPower's emergency operating procedure that will allow one or more measures such as short-term imports from other available interfaces (for example Alberta or SPP), initiating demand response and short-term load shedding.

Transmission
SaskPower's major transmission projects in the first five years of the assessment period are related to the interconnection expansion with SPP and the 650 MW of new transmission service. This includes two new international power lines between Saskatchewan and North Dakota. Within Saskatchewan, a total of approximately 180 kilometers of new 230 kV lines, a new 230 kV transmission station, expansion of several existing transmission stations, and installation of two phase-shifting transformer interfaces and two static var systems are being added.

The remaining other transmission projects (approximately 460 circuit kilometers) are under the planning and conceptual phase in the 5-to-10-year planning horizon. These projects are driven by load growth, new generation additions, and reliability needs.

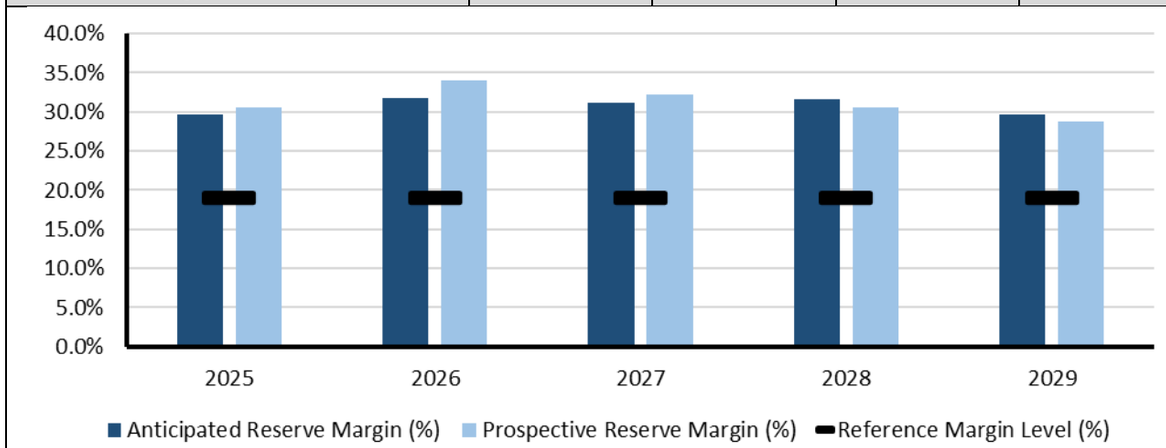


MRO-SPP

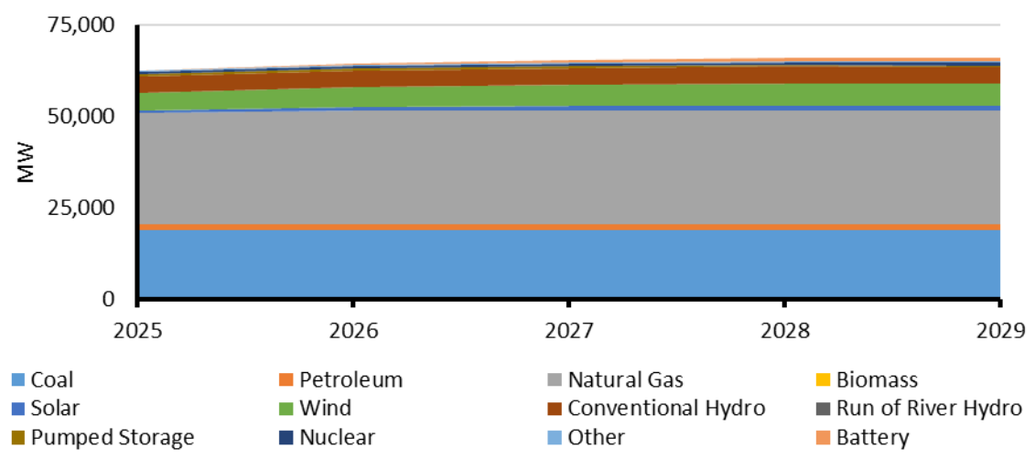
The Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	55,669	57,171	59,031	59,764	60,596	61,963	62,490	63,287	63,764	64,172
Demand Response	1,463	1,771	2,057	2,124	2,172	2,222	2,259	2,465	2,467	2,472
Net Internal Demand	54,206	55,400	56,975	57,640	58,424	59,741	60,231	60,822	61,297	61,700
Additions: Tier 1	2,123	4,966	6,750	7,843	7,957	7,957	7,957	7,957	7,957	7,957
Additions: Tier 2	1,239	2,454	2,756	2,756	2,756	2,756	2,756	2,756	2,756	2,756
Additions: Tier 3	6,823	16,770	22,655	28,948	28,948	28,948	28,948	28,948	28,948	28,948
Net Firm Capacity Transfers	-1,097	-1,077	-1,136	-1,131	-1,131	-1,131	-1,131	-1,133	-1,133	-1,133
Existing-Certain and Net Firm Transfers	68,157	68,039	67,981	67,984	67,799	67,749	67,253	67,175	67,055	67,094
Anticipated Reserve Margin (%)	29.7%	31.8%	31.2%	31.6%	29.7%	26.7%	24.9%	23.5%	22.4%	21.6%
Prospective Reserve Margin (%)	30.6%	34.1%	32.2%	30.6%	28.7%	25.2%	23.3%	22.0%	20.6%	19.6%
Reference Margin Level (%)	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- There are over 8 GW of coal and gas-fired generators that have indicated they plan to retire over the next 10 years in SPP. Without sufficient dispatchable generation, SPP can experience energy shortages when output from wind resources is low.

MRO-SPP Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	18,952	18,952	18,919	18,919	18,919
Coal*	17,934	16,647	16,614	14,062	14,062
Petroleum	1,629	1,629	1,631	1,631	1,631
Petroleum*	1,629	1,629	1,575	1,575	1,575
Natural Gas	30,471	31,098	31,098	31,098	31,098
Natural Gas*	29,896	30,220	29,924	29,812	29,812
Biomass	20	20	20	20	20
Solar	495	864	1,149	1,283	1,283
Wind	4,974	5,456	5,928	6,117	5,909
Conventional Hydro	4,526	4,541	4,573	4,605	4,628
Pumped Storage	472	472	472	472	472
Nuclear	769	769	769	769	769
Other	281	281	281	281	281
Battery	41	290	555	930	1,044
Total MW	62,630	64,370	65,392	66,124	66,053
Total MW*	61,037	61,188	61,858	59,925	59,855
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to SPP are removed from the resource projection where marked.					

Planning Reserve Margins

The Existing-Certain and Net Firm Transfers Reserve Margin for the SPP assessment area is projected to fall below the current coincident summer season RML of 19% in 2027. The current summer season reserve margin target for SPP is 15%, but that is based on the non-coincident peak demand of load-responsible entities (LRE) in the SPP assessment area. For purposes of NERC assessments, the 15% target is converted, along with forecasted demand values, to an SPP coincident peak representation based on the latest calculated diversity factor. This results in an RML of 19%. Based on resources submitted in the ARM calculation, including the impact of retirements, SPP is forecasted to be above the 19% RML for the 10-year horizon.

Like the generation unavailability scenario in NERC's *2024 Summer Reliability Assessment*, SPP shows the potential to utilize all the current projected capacity and there could be times of capacity shortfall based on performance impacts during high-load periods. While the potential to all available capacity has a lower probability, the assumptions and projections are based around historical unavailability during peak periods. Current LTRA projections are based on the latest resource adequacy data submittals, which are provided by the LREs and Generator Owners in SPP.

SPP performs a biennial LOLE study to establish a reserve margin target such that the LOLE for the applicable planning year (3- and 6-year study) does not exceed 1 day in 10 years, or 0.1 day per year. The target is determined using probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand with load uncertainty to ensure that the LOLE does not exceed 0.1 day per year.

SPP's 2023 LOLE study results indicate that separate PRMs and capacity requirements are needed for the summer and winter seasons to recognize the seasonal balance of risk. Also, as colder temperature outages increase with the incorporation of additional wind and solar resources, the loss-of-load risk shifts to the winter season. Due to the shift in seasonal risk, it would be appropriate to consider a maximum LOLE threshold for the winter season or incorporation of an EUE reliability metric to complement the LOLE metric.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

As the resource mix continues to change from a standard base load conventional thermal and hydro resources to VERs and short-term energy storage resources (ESR), SPP is incorporating energy adequacy metrics (i.e., EUE) in the determination of PRMs, RMLs, additional reliability policies, and resource accreditation enhancements.

SPP will begin performing a yearly energy adequacy assessment and assessment of reliability attributes (inertia, primary frequency response, ramp, regulation, contingency reserves, voltage and reactive support capability, fuel assurance, flexibility, and blackstart capability). Results of the analysis will be presented annually to SPP stakeholders. The results will also be used to identify needs for new market products, changes to market functionality, or changes to resource adequacy policies and requirements.

The 2024 ProbA performed for the NERC LTRA used assumptions and methods that reflect SPP's Loss of LOLE studies. Results are shown in the following table.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.84	0.00	6.61
EUE (PPM)	0.00	0.00	0.02
LOLH (hours per year)	0.00	0.00	0.01
Operable On-Peak Margin	19.6%	19.5%	16.0%

*Provides the 2022 ProbA Results for Comparison

With the current SPP fleet, there was no loss of load for the 2026 study that included Tier 1 resource additions and 600 MW in generator retirements. The 2028 analysis included both Tier 1 and Tier 2 resource additions and 2,700 MW in generator retirements. The result was a small amount of EUE (6.61MWh) and LOLH (0.01hr/year). The loss of load/hour occurred mostly during the summer season (0.007hr/yr), while the winter season had 0.0004hr/yr. SPP is a summer-peaking region, and the results also supported that. The demand was highest in the afternoons between 13:00 and 19:00 during July and August.

Study improvements for 2024 from the previous NERC ProbAs include additional weather years, seasonal forced-outage modeling, and incremental cold weather outages.

SPP uses the Strategic Energy & Risk Valuation Model (SERVM) for the ProbA. It is a production-cost modeling tool that uses the Monte Carlo method to solve LOLE. Each weather year was simulated 300 times to simulate a multitude of random forced outage draws. Taking 300 draws for each weather year (43) and multiplying by 8,760 hours gets to a total of over 113 million simulated hours, from 1980 to 2022. Each iteration was performed on an 8,760-hour basis.

The study input model consisted of multiple modeling assumptions including multiple historical weather years (1980–2022); hourly load, solar, and wind profiles; load forecast uncertainty; random forced outages draws and variability; physical and economic resource parameters; resource retirements; future resource additions; zonal transmission limitations; and incremental conventional resource forced outages due to extreme cold temperature.

The generating resources modeled in the Probabilistic Assessment reflect the data supplied in the *2024 LTRA*. Existing and projected resources were included in the Probabilistic Assessment along with reported confirmed retirements. As mentioned previously, wind and solar resources, as well as historical weather years, were modeled at historical hourly values using 2012 to 2022 weather years. There were six study zones, and SPP modeled a projected 8,760 hourly demand profile for each area to provide load variability and volatility for chronological hours during simulation. Each local resource zone was modeled with an import and export limit based on a separate power flow transfer analysis. SPP used unit-specific outage rates within the analysis based on NERC Generation Availability Data System (GADS) data from 2015 to 2022. External assistance only included firm contracts from external entities with firm transmission service.

Demand

SPP peak load occurs during the summer season; the 2024 net internal demand forecast is projected to peak at 53,094 MW, which is projected to increase compared to the previous year's LTRA forecast for the 2022 summer season. The diversity factor used to convert the non-coincident peak demand forecast to an SPP coincident peak demand forecast was consistent with the ~3.5% applied in the *2023 LTRA*. SPP forecasts the coincident annual peak growth based on member submitted data over the 10-year assessment timeframe. One risk that SPP has noted is that the aggregated noncoincident demand forecast submitted by members in recent years, which is based on a 50/50 forecast and is weather normalized, is tracking at a lower demand level than what the BA has observed.

Demand-Side Management

SPP's energy efficiency (EE) and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP assessment area's long-term reliability related to the forecasted increase in EE and DR across the assessment area. In addition, SPP is constructing a new policy to more appropriately categorize DR based on the flexibility of the program, which will ultimately be reflected in the accreditation process.

Distributed Energy Resources

The SPP Model Development, Economic Studies, and Supply Adequacy working groups are developing policies and procedures around DERs. SPP resource adequacy implemented policies for DERs that mandate certain testing, reporting, and document requirements for resources and programs not registered in the SPP Integrated Market. Accreditation methodology policies are being constructed and are planned to be approved in late 2024.

Generation

SPP currently has approximately 900 MW of installed solar generating facilities. In the ARM calculation, SPP is reporting nameplate capacity of approximately 11 GW of Tier 1, 2, and 3 wind resources, approximately 18 GW of Tier 1, 2, and 3 solar resources, approximately 9.8 GW of Tier 1, 2, and 3 battery resources and approximately 2.7 GW of Tier 1, 2, and 3 gas resources.

In 2024, SPP filed conventional based performance accreditation and effective load carrying capability (ELCC) methodology for wind and solar resources. The goal is for these policies to become effective in the 2026/2027 timeframe for both the summer and winter seasons.

There are concerns of drought conditions impacting the Missouri River and other water sources for generation resources that rely on once-through cooling processes. Low water can impact the generation's capacity output and reduce its ability to support congestion management and serve load. An additional concern could be the impact of river conditions on coal shipments, which could cause generators to run at a derated level to conserve supplies.

Energy Storage

Currently, SPP is studying approximately 17,000 MWs of energy storage and hybrid resource projects in the generator interconnection queue process. There are approximately 50 MWs of energy storage under contract by SPP members. These resources are being modeled as generation in the planning assumptions both near and long term.

Capacity Transfers

The SPP assessment area coordinates with neighboring areas to ensure that adequate transfer capabilities will be available for capacity transfers. On an annual basis during the model build season, SPP staff coordinate the modeling of transfers between Planning Coordinator footprints. The modeled transactions are fed into the models created for the SPP planning process.

SPP and ERCOT executed a Coordination Plan that superseded the prior coordination agreement. The Coordination Plan addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers (BLT), and switchable generation resources (SWGR). Under the terms of the Coordination Plan, SPP has priority to recall the capacity of any SWGRs that have been committed to satisfying the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff. Annually, SPP and ERCOT update the

Coordination Plan based on the latest discussions and business decisions, and it was updated in June 2024.

Transmission

In the 2023 ITP Assessment, SPP approved 44 transmission projects, including 150 miles of new transmission. Additionally, the study calls for 93 miles of transmission to be rebuilt.

SPP is observing a number of transmission projects that are currently delayed. SPP is actively tracking these projects and discussing them throughout its stakeholder process. Many delays are driven by supply chain issues or increasing length of construction times. The delays of these transmission projects do not currently seem to be driving reliability issues.

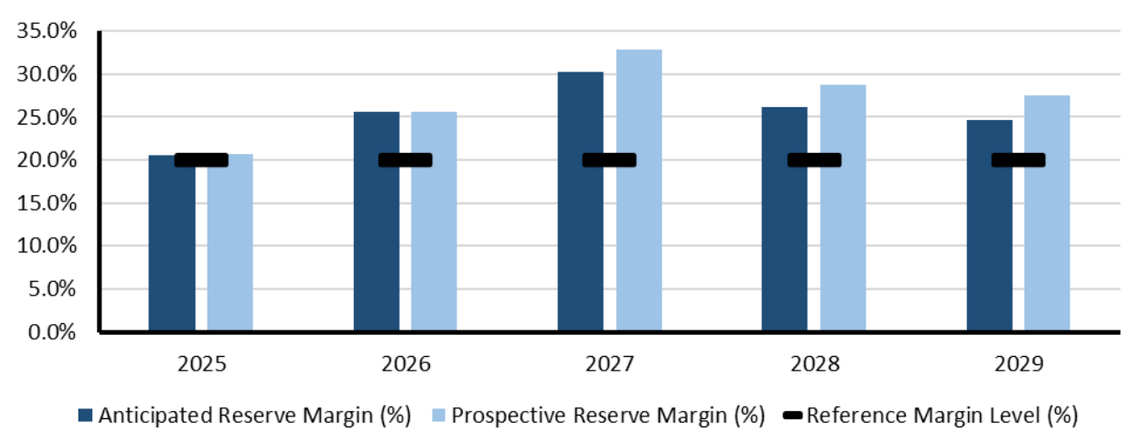


NPCC-Maritimes

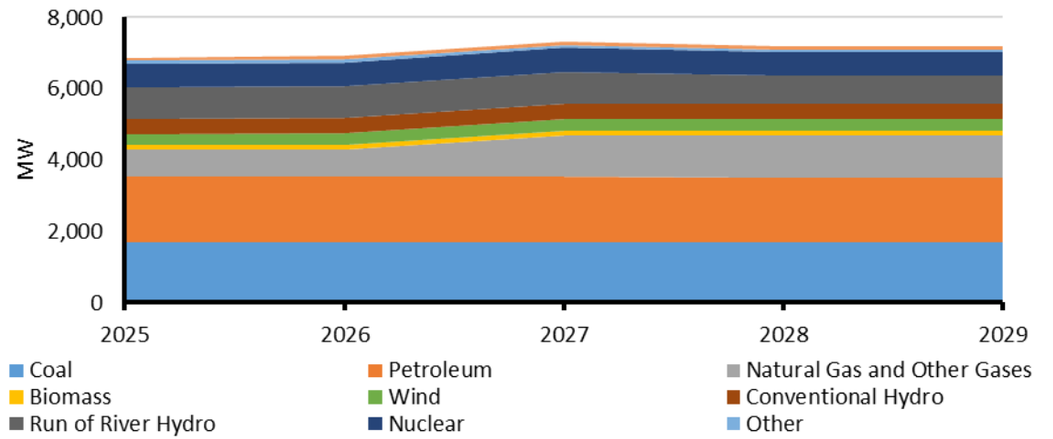
The Maritimes assessment area is a winter peaking NPCC sub-region with a single Reliability Coordinator and two Balancing Authority Areas (New Brunswick and Nova Scotia). It is comprised of the Canadian provinces of New Brunswick (NB), Nova Scotia (NS), and Prince Edward Island (PEI) and the northern portion of Maine (NM), which is radially connected to NB. The area covers 58,000 square miles with a total population of 2 million people.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	6,201	6,056	6,095	6,141	6,216	6,272	6,331	6,398	6,474	6,560
Demand Response	274	293	309	317	317	317	317	317	317	318
Net Internal Demand	5,927	5,763	5,786	5,825	5,899	5,954	6,014	6,081	6,157	6,242
Additions: Tier 1	108	171	579	579	579	579	579	579	579	579
Additions: Tier 2	6	4	447	600	1,398	1,398	1,398	1,398	1,398	1,398
Additions: Tier 3	0	13	80	127	197	255	267	279	291	291
Net Firm Capacity Transfers	289	322	215	145	145	145	145	145	145	145
Existing-Certain and Net Firm Transfers	7,038	7,063	6,959	6,771	6,771	6,771	6,679	6,665	6,665	6,752
Anticipated Reserve Margin (%)	20.6%	25.5%	30.3%	26.2%	24.6%	23.4%	20.7%	19.1%	17.7%	17.4%
Prospective Reserve Margin (%)	20.7%	25.6%	32.8%	28.8%	27.5%	26.3%	23.5%	21.9%	20.4%	20.1%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Since the *2023 LTRA*, the overall resource outlook has improved with expected new natural-gas-fired generators coming into service in 2027. Winter peak demand forecasts for this assessment area have risen through 2030; however, ARMs are currently projected to remain above the RML of 20% until 2031 when the ARM dips to 19.7%.

NPCC-Maritimes Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**
Coal	1,696	1,696	1,696	1,696	1,696
Coal*	1,696	1,696	1,396	1,248	467
Petroleum	1,831	1,831	1,825	1,819	1,819
Natural Gas	757	757	1,157	1,157	1,157
Biomass	148	148	148	148	148
Solar	5	5	5	5	5
Wind	293	321	329	329	329
Conventional Hydro	412	412	412	412	412
Run of River Hydro	902	902	902	791	791
Nuclear	663	663	671	671	671
Other	77	77	77	77	77
Battery	72	99	99	99	99
Total MW	6,856	6,911	7,321	7,204	7,204
Total MW*	6,856	6,911	7,021	6,756	5,975
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

NPCC-Maritimes Assessment

Planning Reserve Margins

The NPCC-Maritimes assessment area is comprised of NB, NS, PEI, and NM. The RML for the assessment area is 20%; however, this reserve margin is not mandated. The ARM over the study period for the Maritimes area ranges between 17% and 30% during the winter period and between 88% and 93% during the summer period.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

During off-peak hours, the Maritimes area has surplus generation and no constraints with converting the capacity to energy.

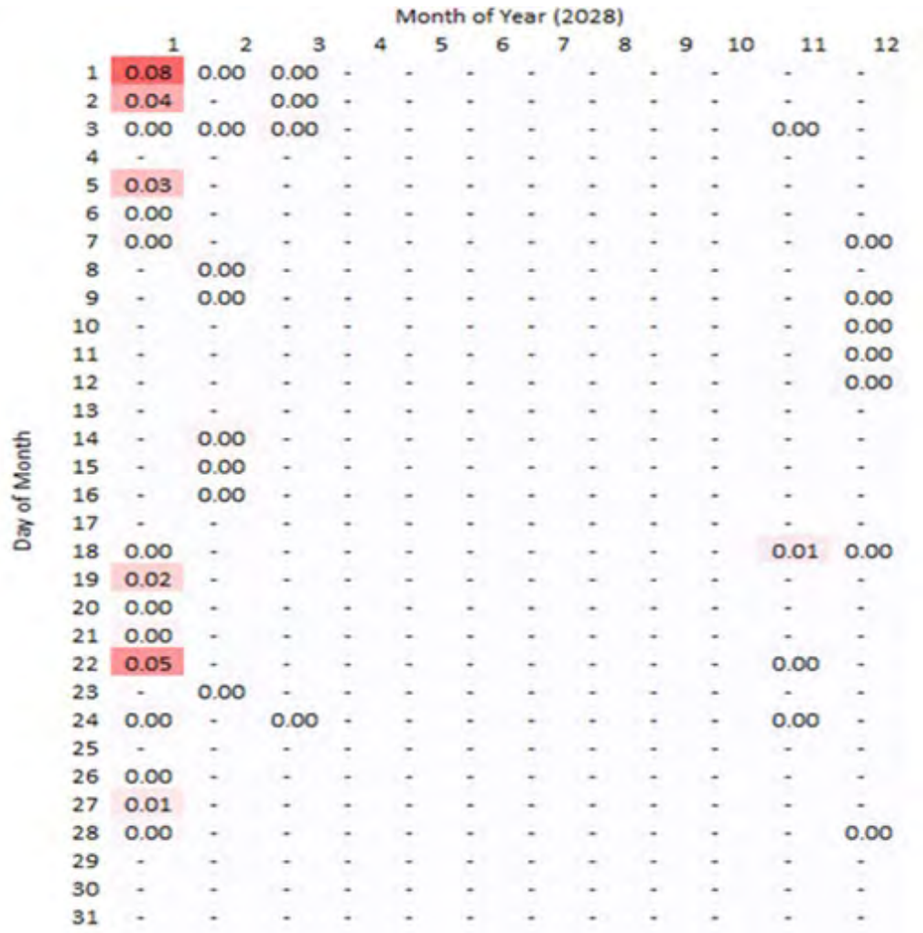
Probabilistic Assessments

Two Balancing Authorities within the Maritimes area are members of NPCC and jointly prepare annual probabilistic assessments that cover three- to five-year forward-looking periods and evaluate the adequacy of the Maritimes' transmission system and resources. In addition, the Maritimes area also supports NERC's annual seasonal ProbAs, which provides an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves. Results of the 2024 ProbA are in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	3.87	**5.02**	**0.28**
EUE (PPM)	0.14	**0.17**	**0.01**
LOLH (hours per year)	0.07	**0.09**	**0.02**
Operable On-Peak Margin	22.9%	**17.9%**	**29.0%**

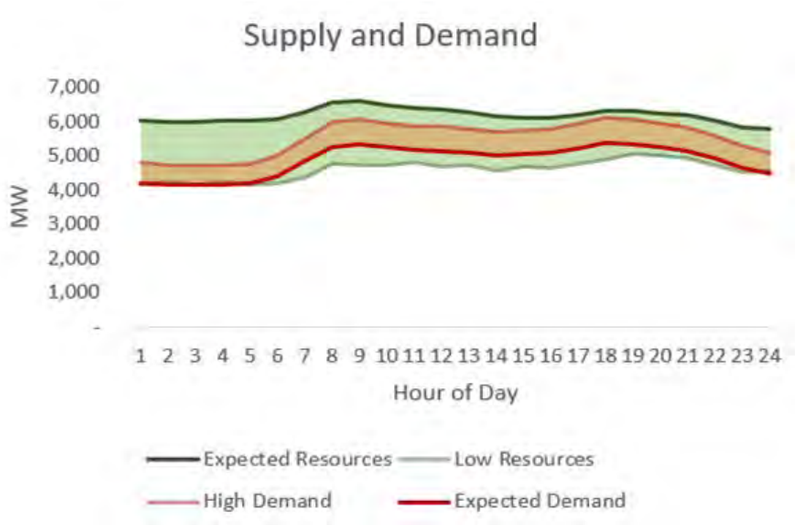
* Provides the 2022 ProbA Results for Comparison

The following table of LOLH for 2028 provides a depiction of risks across the calendar year and highlights the concentration of risk in winter. Most load-loss risk occurs in winter months of December–February, with some additional risk occurring in shoulder months. 2026 has a similar risk distribution.



Day of Month	1	2	3	4	5	6	7	8	9	10	11	12
1	0.08	0.00	0.00	-	-	-	-	-	-	-	-	-
2	0.04	-	0.00	-	-	-	-	-	-	-	-	-
3	0.00	0.00	0.00	-	-	-	-	-	-	-	0.00	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	0.03	-	-	-	-	-	-	-	-	-	-	-
6	0.00	-	-	-	-	-	-	-	-	-	-	-
7	0.00	-	-	-	-	-	-	-	-	-	-	0.00
8	-	0.00	-	-	-	-	-	-	-	-	-	-
9	-	0.00	-	-	-	-	-	-	-	-	-	0.00
10	-	-	-	-	-	-	-	-	-	-	-	0.00
11	-	-	-	-	-	-	-	-	-	-	-	0.00
12	-	-	-	-	-	-	-	-	-	-	-	0.00
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	0.00	-	-	-	-	-	-	-	-	-	-
15	-	0.00	-	-	-	-	-	-	-	-	-	-
16	-	0.00	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-
18	0.00	-	-	-	-	-	-	-	-	-	0.01	0.00
19	0.02	-	-	-	-	-	-	-	-	-	-	-
20	0.00	-	-	-	-	-	-	-	-	-	-	-
21	0.00	-	-	-	-	-	-	-	-	-	-	-
22	0.05	-	-	-	-	-	-	-	-	-	0.00	-
23	-	0.00	-	-	-	-	-	-	-	-	-	-
24	0.00	-	0.00	-	-	-	-	-	-	-	0.00	-
25	-	-	-	-	-	-	-	-	-	-	-	-
26	0.00	-	-	-	-	-	-	-	-	-	-	-
27	0.01	-	-	-	-	-	-	-	-	-	-	-
28	0.00	-	-	-	-	-	-	-	-	-	-	0.00
29	-	-	-	-	-	-	-	-	-	-	-	-
30	-	-	-	-	-	-	-	-	-	-	-	-
31	-	-	-	-	-	-	-	-	-	-	-	-

Hourly demand and resource projections for a typical risk-day in 2026 are shown in the figure below. Expected resource contributions are observed to cover expected demand on the risk day. However, the greatest risk for this assessment area is in the form of lower-than-expected resource contributions. If this were to occur, expected demand for all hours would not be met. This risk would be exaggerated by the addition of a higher-than-expected demand event. Reliance on external assistance may be necessary in these events. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of NB and NS, which are historically highly coincidental. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period. The area peak loads are expected to increase by 4.2% during summer and by 6.4% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 0.4% in summer and 0.6% in winter. The Maritimes Area annual energy forecasts are expected to increase by a total of 5.9% during the 10-year assessment period for an average growth of 0.6% per year.

Demand-Side Management

Plans to develop up to 100 MW by 2030/2031 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway but no specific annual demand and energy saving targets currently exist. During the 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 20 MW to 169 MW while the annual amounts for winter peak demand reductions rise from 168 MW to 629 MW.[34]

Distributed Energy Resources

The DER installed capacity in NS is approximately 245 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff, and BTM solar.

LTRA wind capacity for NB, NS, and PEI is derated between 18% and 33% using probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding NM, which uses seasonal capacity factors. BTM solar is assumed to have an ELCC of 0% during winter period. The Maritimes area has shown embedded BTM solar PV projections of 149 MW in 2024 rising to 881 MW by 2034. These projects include distributed small-scale solar (mainly rooftop) that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of the area's system peak, which occurs either before sunrise or after sunset in the winter period.

Generation

NB assumes extending 28 MW of diesel-fired generator starting in 2025 and recently upgraded 290 MW of natural-gas-fueled resource completed in 2023. There are 25.2 MW of wind power purchase agreements (PPA) also slated to start in 2025. An anticipated replacement PPA contract, a long-term firm energy contract from a neighboring jurisdiction, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain the overall resource adequacy.

NB Tier 1 resources include 71 MW of wind and 400 MW of combustion turbines. Tier 2 resources include 200 MW of wind resources and Tier 3 includes 400 MW of wind.

In NS, Tier 1 resources include wind projects with a total nameplate capacity of 473 MW phased in from 2024–2027 with an ELCC of 10%, 150 MW battery storage, 4 MW tidal power, 2 MW biomass unit, and a small 0.14 MW solar farm. Tier 2 resources in NS include 250 MW of battery storage (2026–2032), 600 MW of combustion turbines (2027–2033), a 150 MW conversion of a coal-fired unit to natural gas (2028), 450 MW in conversion of coal-fire units to oil (2030), 220 MW of solar generation,

[34] Current and projected energy efficiency effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

and 416 MW of wind generation. Tier 3 resources in NS include natural gas additions (combustion turbines) of 50 MW in 2029 and new wind generation with a nameplate capacity of 850 MW phased in from 2026–2033. These Tier 3 resource additions are anticipated to facilitate the retirement of additional coal-fired generation by 2030. However, these retirements have not been included in the assessment due to their uncertainty.

Small amounts of new solar generation capacity (Tier 1) of up to 21 MW were being installed in PEI in 2024, along with 10 MW of new hybrid energy storage (Tier 1). PEI also has 30 MW of Tier 2 wind, 111 MW Tier 3 wind, and 140 MW of Tier 3 petroleum-based generation and 10 MW of Tier 3 batteries.

NB derates its wind capacity using a calculated year-round equivalent capacity of 22%. NS and PEI derate wind capacity to 18% and 17%, respectively, of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub areas. The peak capacity contribution of grid-based solar is estimated at zero since the Maritimes area peak occurs in the winter either before sunrise or after sunset.

Energy Storage

NS Power includes a 150 MW (4-hour duration) nameplate standalone battery resource as a Tier 1 resource and a 250 MW (4-hour duration) nameplate capacity standalone battery resource added as a Tier 2 resource phased in from 2026 through 2032. This grid-scale project will support the integration of new renewable generation, provide energy arbitrage and resiliency services, and provide firm capacity and fuel savings.

PEI includes a 10 MW nameplate capacity hybrid energy storage as a Tier 1 resource starting summer of 2024 and another 10 MW nameplate capacity energy storage system as a Tier 3 resource. This project will provide a storage option for the output from the 10 MW solar facility that is planned to come online during the same time frame. This project will provide fuel savings and may assist in providing additional reliability if a generation outage occurs.

NB Power has not included any energy storage resources in the *2024 LTRA* submission; however, the value of energy storage options is expected to increase as the technology improves and as NB's smart grid network develops. NB Power issued a request for expressions of interest for new renewable generation sources including 200 MW of wind, 15 MW of solar, 5 MW of tidal, and 50 MW of 4-hour duration battery storage in February 2023. Under this program, NB Power expects uptake in new energy storage projects in the coming years. Internal pilot projects and studies are underway to understand the economics, application, and performance of battery storage resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks and/or balance intermittent resources, such as wind, to provide additional flexibility to the system.

Capacity Transfers

ProbA studies show that the Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

Transmission

NS has multiple new transmission line projects compared to the *2023 LTRA*; most being shorter runs to enable the connection of renewable resources, with one major project of 165 miles designed to improve the reliability of the existing tie between NS and NB.

Reliability Issues

The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (derated), dual fuel oil/gas, tie benefits, and biomass with no single one type feeding more than about 27% of the total capacity in the area. The Maritimes area does not anticipate fuel disruptions that pose significant challenges for resources during this assessment period.



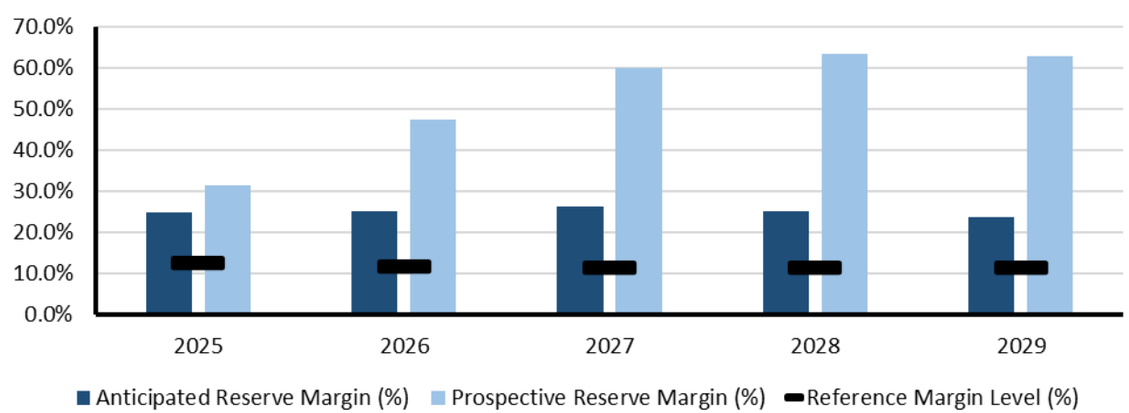
NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England Inc. (ISO-NE). ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS. Note: Northern Maine is not directly connected to the transmission system administered by ISO-NE.

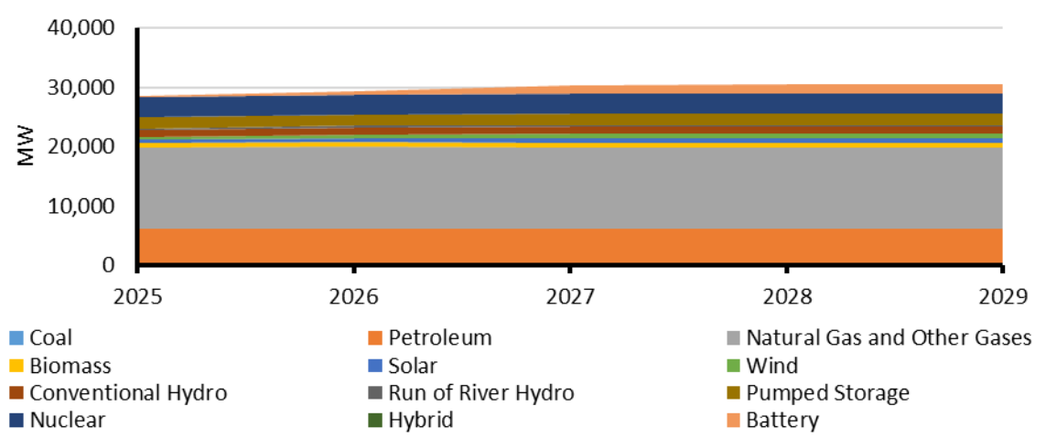
The New England BPS serves approximately 15.1 million customers over 68,000 square miles.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	24,579	24,702	24,845	25,076	25,364	25,706	26,100	26,547	27,052	27,567
Demand Response	566	588	544	544	544	544	544	544	544	544
Net Internal Demand	24,013	24,114	24,301	24,532	24,820	25,162	25,556	26,003	26,508	27,023
Additions: Tier 1	660	1,492	2,374	2,748	2,748	2,748	2,748	3,168	3,168	3,168
Additions: Tier 2	337	3,089	5,911	7,084	7,425	7,766	7,766	7,766	7,766	7,766
Additions: Tier 3	1,404	1,765	5,106	7,906	9,221	9,355	9,721	10,432	10,432	10,432
Net Firm Capacity Transfers	1,248	567	465	84	84	84	84	84	0	0
Existing-Certain and Net Firm Transfers	29,354	28,658	28,327	27,946	27,946	27,946	27,946	27,946	27,862	27,862
Anticipated Reserve Margin (%)	25.0%	25.0%	26.3%	25.1%	23.7%	22.0%	20.1%	19.7%	17.1%	14.8%
Prospective Reserve Margin (%)	31.4%	47.3%	60.1%	63.3%	62.8%	62.0%	59.5%	58.3%	55.0%	52.0%
Reference Margin Level (%)	12.7%	11.8%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- New England is forecast to have sufficient ARMs to meet consumer demand for electric energy for the first five years (2025–2029) of the assessment period and not require any Tier 2 resources.
- ISO-NE is addressing the issues brought on by grid transformation through several planning, operational, and market measures. A significant project is the redesign of the capacity market from a forward, annual auction to a prompt, seasonal auction with resource accreditation. The Capacity Auction Reforms (CAR) project began in Q2 2024 and is expected to be in place for the 19th Capacity Commitment Period (CCP 19) beginning on June 1, 2028. Additionally, New England has made tariff modifications to its Longer-Term Transmission Planning process to facilitate the New England states' achievement of their policy-based goals by enabling the development of transmission infrastructure. ISO-NE is also working with regional stakeholders to develop a regional energy shortfall threshold (REST) that defines the region's tolerance for energy shortfalls during low-probability extreme weather conditions.

NPCC-New England Projected Generating Capacity by Energy Source in Megawatts (MW)[35]					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	541	541	541	541	541
Coal*	445	445	445	7	7
Petroleum	5,703	5,703	5,687	5,687	5,687
Natural Gas	13,651	13,724	13,708	13,708	13,708
Biomass	780	780	780	780	780
Solar	533	663	663	663	663
Wind	391	594	819	819	819
Conventional Hydro	1,209	1,209	1,209	1,209	1,209
Run of River Hydro	289	289	289	289	289
Pumped Storage	1,860	1,860	1,860	1,860	1,860
Nuclear	3,331	3,331	3,331	3,331	3,331
Hybrid	34	35	35	35	35
Other	74	74	74	74	74
Battery	159	584	1,242	1,616	1,616
Total MW	28,553	29,385	30,237	30,611	30,611
Total MW*	28,458	29,290	30,141	30,077	30,077
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to ISO-NE are removed from the resource projection where marked.					

[35] MW totals reflect Existing and Tier 1 generation. Generator retirements in this timeframe would be captured if a resource submits a retirement request through the ISO-NE capacity market.

NPCC-New England Assessment

Planning Reserve Margins

ISO-NE's installed capacity requirement (ICR) is based on the capacity needed to meet the ISO-NE and NPCC resource adequacy reliability criterion of an LOLE of 0.1 day/year. The ICR varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, in advance of the capacity auctions for each Capacity Commitment Period. The latest ICR calculations result in an annual RML of 12.70% in 2025, 11.82% in 2026, and 11.33% in 2027, expressed in terms of the annual 50/50 peak demand forecast published in the *2024 Capacity, Energy, Loads, and Transmission (CELT) Report*. For the years 2028 through 2034, which are beyond the current forward capacity market timeframe, ISO-NE continued to use the last available RML value of 11.33%. The ISO-NE RML is relatively low compared to other regions due to the impact of reflecting external assistance from neighboring control areas and the continued increase in BTM solar facilities.

Non-Peak Hour Risk, Energy Assurance, and Probabilistic-Based Assessments

ISO-NE routinely prepares 21-day energy forecasts. These forecasts incorporate weather, transmission topology, resource capability and availability, fuel inventories and constraints, and projected imports/exports. If the forecasted regional supply/demand balance is negative, projected energy deficiencies can trigger energy alerts or energy emergencies that are then disseminated to market participants and federal and state regulators. This early notification of potential energy shortfalls is expected to inform market participants such that actions can be taken to increase the expected availability of generating resources as needed.

ISO-NE recently completed work with the Electric Power Research Institute (EPRI) to develop the Probabilistic Energy Adequacy Tool (PEAT) framework. This tool is a framework that has three major steps (weather modeling, risk screening/scenario generation, and 21-day energy assessment), which were subsequently applied to assess the summers and winters of 2027 and 2032.

Probabilistic Assessments

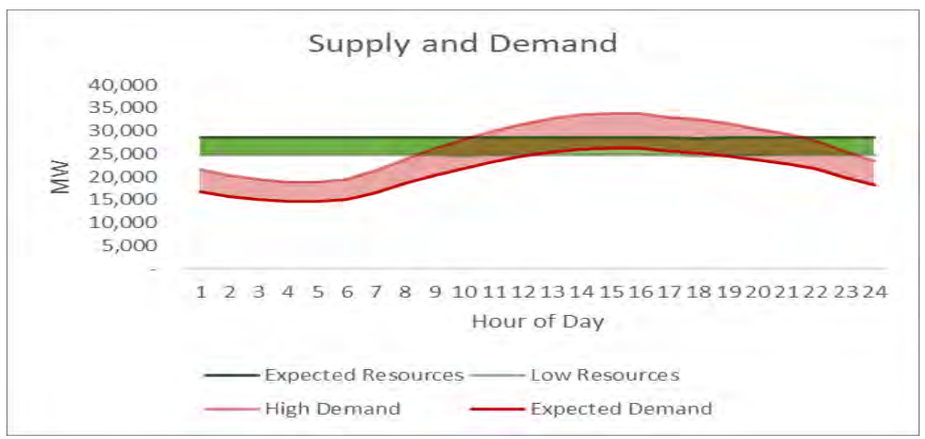
ISO-NE conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC/NERC reliability requirements. In the transmission assessment domain, revisions to ISO-NE planning processes reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated planning activities with neighboring systems will continue and help support the New England states' policy objectives of providing access to a greater diversity of clean resources to meet environmental compliance obligations. Results from the 2024 ProbA, shown in the table below, reveal a slight increase in load-loss and unserved energy risk from the 2022 analysis, but values remain small. ISO-NE is considered to have sufficient resources for the planning horizon to meet NPCC resource adequacy criteria.

Base Case Summary 2024 ProbA of Results			
	2026*	2026	2028
EUE (MWh)	0.551	**10.69**	**7.40**
EUE (PPM)	0.004	**0.09**	**0.06**
LOLH (hours per year)	0.002	**0.07**	**0.03**
Operable On-Peak Margin	27.8%	**12.4%**	**13.7%**

* Provides the 2022 ProbA Results for Comparison

NPCC's ProbA results indicate that the risk of unserved energy in New England is concentrated in summer months (June–August).

Hourly demand and resource projections for a typical summer risk day in 2026 are shown in the figure below. Although expected resource contributions meet expected demand, there is risk that above-normal peak demand could exceed resources. Demand could be 25–30% higher than expected, which could cause strain on the system from the hours beginning 10:00 a.m. through 10:00 p.m. Also, below-normal resource performance from unexpected generator outages or low solar output could also cause supply shortfalls. If resource contributions are less than expected, strain on the system could be seen from the hour beginning 12:00 p.m. through 7:00 p.m. on a typical peak day. Reliance on external assistance may be necessary in these extreme conditions. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

Fuel availability during extreme winter conditions is a persistent reliability concern in New England that is not modeled in detail in the ProbA. Potential natural gas transportation constraints can affect supply to generators during extreme cold temperatures, when natural gas demand for space heating is also peaking. Most natural-gas-fired generators in the area do not have firm natural gas transportation service and can be subject to supply curtailment during peak conditions. Many natural-gas-fired generators in New England can also operate with stored oil, providing for assured electricity supply in extreme winter conditions while oil stores are procured and maintained. Scenarios of extended and extreme cold weather that affect the availability of natural gas and oil replenishments present a reliability risk and were not modeled in the 2024 ProbA.

Demand

Over the 10-year LTRA planning horizon, the forecast net internal summer peak demand increases by 2,988 MW from 24,579 MW in 2025 to 27,567 MW in 2034 (roughly 2% decrease from the 2023 forecast in the later years). The corresponding net internal winter peak demand increases by 7,342 MW from 20,639 MW in 2025–2026 to 27,981 MW in 2034–2035 (roughly a 2.5% decrease from the 2023 forecast). Net energy for load is forecast to grow by 24,701 GWh from 119,285 GWh in 2025 to 143,986 GWh in 2034 (roughly 10% decrease from the 2023 forecast). The changes from the 2023 forecast were in part due to continued enhancements of the heating and transportation electrification forecasts.

The higher winter peak growth rate due to anticipated electrification results in significant convergence with summer peak projections by the end of the 10-year period, such that New England's transition to a winter-peaking system is currently anticipated by the mid-2030s. It is also expected that the timing of the peaks will likely occur in the morning by this time, with heating electrification in particular inducing a greater tendency for morning peaks due to electrified residential and commercial heating.

Demand-Side Management

For the summer of 2025, ISO-NE forecasts 566 MW of controllable and dispatchable demand-side management (DSM) resources, and that amount is projected to decrease by 22 MW to 544 MW by 2034. For the summer of 2025, ISO-NE forecasts 1,873 MW of passive DSM resources (EE and conservation). Demand-side resources are projected to peak in 2030 at 2,117 MW and then begin to decrease to 1,978 MW by 2034. This decrease in the later years is due to expiring EE measures outpacing new passive DSM additions.

Distributed Energy Resources

For summer months, the BTM PV forecast is incorporated as estimated reductions to the ISO-NE gross demand forecast. In 2025, New England forecasts 1,141 MW of peak load reduction (4,533 MW nameplate) of BTM PV. BTM PV is forecast to grow to 1,299 MW of peak load reduction (8,217 MW nameplate) by 2034. The BTM PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages include the effect of diminishing PV production at the time of the system peak as increasing PV penetrations shift the timing of peaks later in the day. The BTM peak load reduction decreases from 25.2% of nameplate in 2025 to 15.8% in 2034.

ISO-NE recently adopted a new planning procedure (PP12) to formalize and standardize data collection for DERs. Under this procedure, distribution providers would be responsible for providing installation-level data on DERs connected to their system. Additionally, transmission providers would be responsible for providing basic data to translate feeder IDs into substation names and other useful identifying information. Among the other benefits that this procedure will lead to is "*proper accounting for the location, size, and type of DER which will lead to more accurate study outcomes.*"

Generation

The largest change that will impact New England's generation fleet is ISO-NE's CARs.

Specifically, to better ensure power system reliability and cost efficiency as New England's resource mix evolves, ISO-NE is proposing a CAR that would transition the capacity market from a forward/annual market to a prompt/seasonal market with accreditation reforms. This initiative has three primary components that would be in place for the Capacity Commitment Period (CCP) scheduled to start on June 1, 2028.

- Prompt auction: Instead of taking place three years in advance, the capacity auction would take place shortly before the CCP, reflecting more accurate information about projected electricity supply and demand.
- Seasonal CCP: The CCP changes from annual to sub-annual (seasonal) commitment periods to better address the distinct reliability challenges of winter and summer, as well as variations in resource performance from season to season.
- Accreditation reforms: Work began in 2022 via the former "Resource Capacity Accreditation in the Forward Capacity Market" project to identify and implement methodologies that will more accurately reflect resource contributions to resource adequacy in the capacity market. It is critical to the reliable and efficient clean-energy transition that the accreditation methodologies are updated to reflect resources' capabilities and how those capabilities contribute to resource adequacy. This work continues through CAR in the context of the proposed market constructs.

Energy Storage

New England currently has a total of 1,899 MW of energy storage capacity. This number includes about 39 MW of battery storage (BESS) and hybrid solar/battery storage. The largest energy storage resource(s) in New England are three pumped-storage hydro-electric facilities that can supply a combined 1,860 MW of quick-start 10-minute operating reserve capability, and with full reservoirs, and can deliver over 11,800 MWh of energy to the BPS.

Over the next five years (2025–2029), the nameplate capacity of energy storage devices (BESS, integrated-hybrid, and co-located-hybrid) are projected to increase significantly (Tier #1 [1,607 MW], Tier #2 [5,047 MW], and Tier #3 [4,955 MW]). No new pumped-storage facilities are planned for the region. Over the next 10 years, those total Tier 1–3 capacities do not increase from the five-year projection. All the above capacity totals reflect summer seasonal claimed capability ratings.

Capacity Transfers

New England is interconnected with the three BAs of Québec, the Maritimes, and New York. ISO-NE considers the tie benefits associated with these BAs within its capacity market methodology to reduce the installed capacity requirement to meet the regional resource adequacy criterion. Assumed assistance from tie benefits ranges from 1,830 MW in 2025 to 2,115 MW in 2027. Aside from such assistance, ISO-NE's firm capacity imports are projected to range from a maximum of 1,248 MW in the summer of 2025 down to 465 MW in the summer of 2027. There is one long-term firm import contract of 84 MW that extends through the summers of 2028 through 2032. There are currently no firm imports projected for the summers of 2033 and 2034. In addition, there are no firm exports identified over the 10-year assessment.

Transmission

Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of DERs and VERs using IBRs, and changes to mandatory planning criteria promulgated by NERC, NPCC, and regional stakeholders have driven the need for longer-term transmission assessments.

The future reliable and economic performance of the BPS is expected to be maintained as a result of approximately $1.5 billion of planned transmission upgrades over the next 10 years. Generator retirements, the integration of many DERs and VERs, the use of IBR technologies, and issues rising from minimum load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. Interregional import capability will also increase with the completion of the 1,200 MW HVdc New England Clean Energy Connect (NECEC) tie line between Québec and Maine, scheduled to be in service by the beginning of 2026.

In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy and serve increased load as transportation and heating are electrified. Transmission assessments and resultant plans are being developed throughout the region to meet these future system needs.

Reliability Issues

New England's BPS is transitioning to a system with unprecedented demand growth, due to electrification of heating and transportation, and a growing number of renewables, clean energy resources, VERs, and DERs. ISO-NE is engaged in the implementation of revised interconnection standards for VERs and DERs that will ensure overall BPS reliability and facilitate the economic development of IBRs.

ISO-NE has observed some delays in projected in service dates for system upgrades due to supply chain issues. In these cases, ISO-NE develops operating plans to work around any issues caused by these delays. Additionally, the New England Transmission Owners have indicated that supply chain issues are causing a notable increase in project costs.

New England has already experienced constraints on electric energy production due to constraints on fuel infrastructure that have an impact on the power sector during winter. In response, ISO-NE has been a key player at the national level in promoting BPS reliability through sharing of lessons learned, best practices, and, more recently, through the performance of more detailed and in-depth BPS energy assessments. Additionally, to address winter energy security challenges, ISO-NE and regional stakeholders developed and put in place a two-year program to compensate certain resources that provide energy security during the winters of 2023–2024 and 2024–2025 (from December to February). ISO-NE's Inventoried Energy Program (IEP) is a voluntary program designed to provide incremental, winter-period compensation for participants that maintain inventoried energy for their assets during extreme cold periods when energy security is most stressed.

The just-in-time delivery of a generator's fuel supply, whether natural gas, wind, or solar, is creating the need for the electric sector to quickly develop ways to retain access to flexible, stored energy—either through long-term energy storage solutions that can capture and store renewable power or through the use of dispatchable resources.

ISO-NE is actively working on numerous major projects to prepare for the clean energy transition and ensure continued reliability. The following is a short list of major projects in which ISO-NE has engaged:

- **CAR Project**
- **Operational Impacts of Extreme Weather Events**
- **Regional Energy Shortfall Threshold**
- **Day-Ahead Ancillary Services Initiative**
- **Economic Planning for the Clean Energy Transition (EPCET)**
- **Extended-Term Transmission Planning Tariff Changes**
- **Longer-Term Transmission Studies**
- **Storage As Transmission Only Asset (SATOA)**
- **FERC Order No. 1920 Project**
- **FERC Order No. 2023 & 2023-A Project**
- **FERC Order No. 2222 Project**
- **FERC Order No. 881 Project**

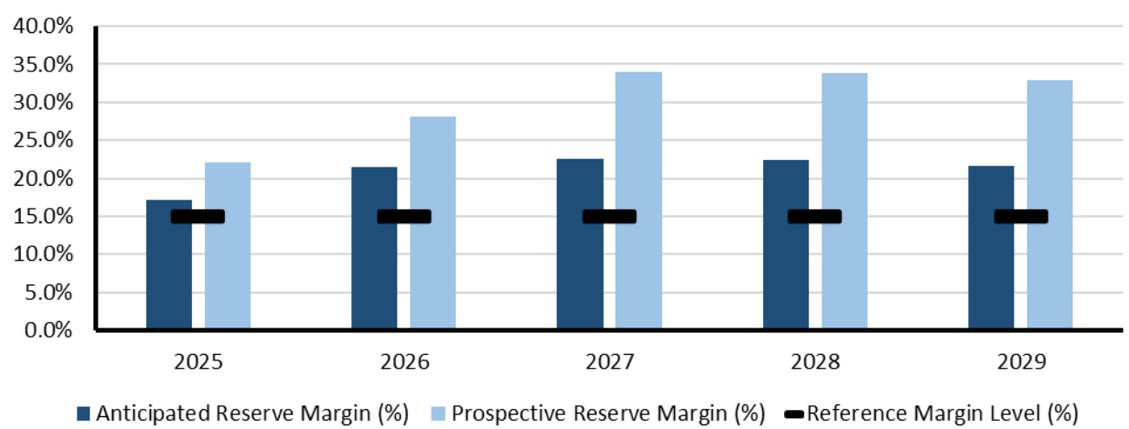


NPCC-New York

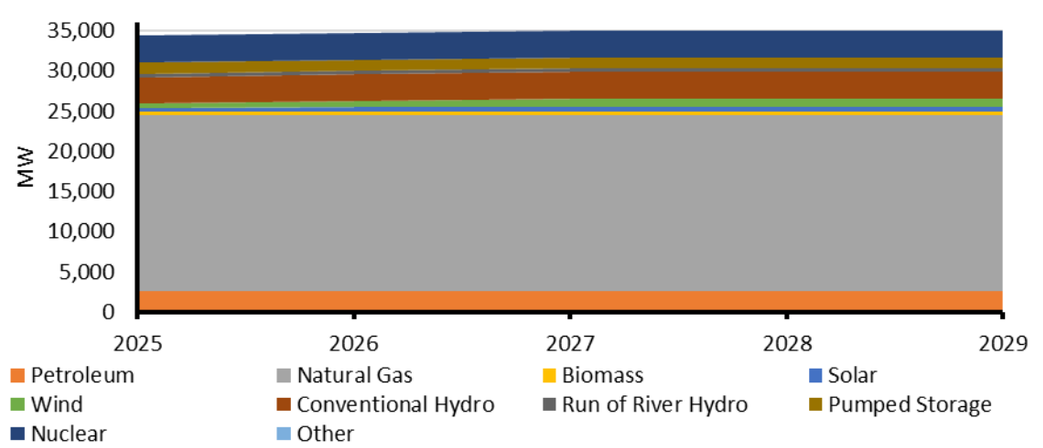
NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only Balancing Authority within the state of New York. The BPS encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this LTRA, the established RML is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). The NYSRC approved the 2025–2026 IRM at 24.4%.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	31,650	31,900	32,110	32,130	32,340	32,580	32,880	33,320	33,830	34,210
Demand Response	897	897	897	897	897	897	897	897	897	897
Net Internal Demand	30,754	31,004	31,214	31,234	31,444	31,684	31,984	32,424	32,934	33,314
Additions: Tier 1	495	858	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144
Additions: Tier 2	1,558	2,090	3,572	3,572	3,572	3,572	3,572	3,572	3,572	3,572
Additions: Tier 3	1,381	4,384	6,384	7,928	8,383	8,383	8,383	8,383	8,383	8,383
Net Firm Capacity Transfers	1,600	2,880	3,186	3,186	3,186	3,186	3,186	3,186	3,186	3,186
Existing-Certain and Net Firm Transfers	35,511	36,790	37,096	37,097	37,097	37,097	36,687	36,687	36,687	36,687
Anticipated Reserve Margin (%)	17.1%	21.4%	22.5%	22.4%	21.6%	20.7%	18.3%	16.7%	14.9%	13.6%
Prospective Reserve Margin (%)	22.1%	28.2%	34.0%	33.9%	33.0%	32.0%	29.5%	27.7%	25.7%	24.3%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Public policies, such as New York state's 2019 Climate Leadership and Community Protection Act (CLCPA), are driving rapid changes in New York's electric system, impacting how electricity is produced, transmitted, and consumed. The transition to a cleaner grid in New York is leading to an electric system that will be increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation.
- Recent assessments reveal that reliability margins are shrinking. Electrification programs are increasing the demand for electricity and placing New York on a trajectory to be a winter-peaking system in the future. Largely in response to public policies, fossil fuel generators are retiring at a faster pace than new renewable supply is entering service. The potential for delays in construction of new supply and transmission, higher than forecasted demand, and extreme weather could threaten reliability and resilience of the New York grid.
- NYISO's reliability studies identified actionable reliability needs starting 2025 in New York City. The reliability need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by state legislation and regulations promulgated by the New York State Department of Environmental Conversation, commonly known as the Peaker Rule,[36] to limit emissions. Following a solicitation for proposed solutions to the reliability need, NYISO retained several plants in New York City that would have otherwise been deactivated to comply with the Peaker Rule. NYISO's 2024 Reliability Needs Assessment (RNA), targeting completion in the fourth quarter of 2024, identifies transmission security violations of reliability criteria primarily driven by a combination of forecasted increases in peak demand, limited additional supply, and the assumed retirement of generation in New York City in response to state law and regulations.
- Driven by public polices, new supply, large loads, and transmission projects are seeking to interconnect to the grid at record levels. NYISO's interconnection process balances developer needs with grid reliability. Efforts are underway to make this process more efficient while protecting grid reliability. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway in NYISO's Public Policy Transmission Planning Process.
- To achieve the mandates of the CLCPA, new dispatchable emission-free resources (DEFR) with the necessary reliability services will be needed to replace the capabilities and attributes of today's generation. These types of resources, which can achieve the necessary attributes by a combination of solutions, must be significant in capacity and have attributes similar to traditional generation plants, such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, provide ERSs, and adapt to meet rapid, steep ramping needs. Such new emission-free supply is not yet available on a commercial scale.
- New wholesale electricity market rules are supporting the grid in transition. These markets are critical for a reliable transition. Wholesale electricity markets are open to significant investment in wind, solar, and battery storage as well as distributed energy resources. Demand management programs are also under development as a measure to facilitate achievement of CLCPA targets. By lowering the peak load and avoiding system buildout to serve the highest demand hour, fewer DEFRs will be needed and fewer fossil fuel-fired plants will be needed to meet lower peaks during the transition.

[36] Subpart 227-3 of Title 6 of the New York Codes, Rules an3,323d Regulations.

NPCC-New York Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Petroleum	2,631	2,631	2,631	2,631	2,631
Petroleum*	2,628	2,628	2,628	2,628	2,628
Natural Gas	21,907	21,907	21,907	21,907	21,907
Biomass	334	334	334	334	334
Solar	545	586	586	586	586
Wind	461	785	1,070	1,070	1,070
Conventional Hydro	3,323	3,323	3,323	3,323	3,323
Run of River Hydro	413	413	413	413	413
Pumped Storage	1,410	1,410	1,410	1,410	1,410
Nuclear	3,330	3,330	3,330	3,330	3,330
Battery	50	50	50	50	50
Total MW	34,405	34,769	35,054	35,054	35,054
Total MW*	34,401	34,765	35,051	35,051	35,051
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to NYISO are removed from the resource projection where marked.					

NPCC-New York Assessment

Planning Reserve Margins

The LTRA anticipated and prospective margins are above 15% with the exception of year 9 (2033) and year 10 (2034). However, the system margins are narrowing throughout the assessment period. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 event-days/year probability of unplanned load loss. NYISO's 2024 Reliability Needs Assessment, which is underway and targets completion in Q4 2024, will likely identify reliability criteria violations.

NYISO also provides support to the NYSRC in conducting an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the NPCC and NYSRC resource adequacy criterion of "1 day in 10 years." The current IRM for the 2024–2025 capability year is 22% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15% to 22%. Additionally, the NYISO performs an annual study to identify the locational minimum installed capacity requirements (LCR) for the upcoming capability year.

Energy Assessment, Including Non-Peak Hour Risk

New York State's CLCPA mandates to decarbonize span over all major industries and are a main driver for the electric system changes. NYISO staff in system operations, planning, and markets will continue to assess the system changes to prepare for the grid's transformation.

With high penetration of renewable intermittent resources, the system will need dispatchable emission-free resources (DEFR) and long-duration resources to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of future offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range assessments (10-year and beyond planning horizon), and certain energy aspects are accounted for in the hourly modeling and simulations performed under the resource adequacy studies through NYISO's reliability planning processes along with the production cost simulations performed under its System and Resource Outlook.

NYISO performs and supports energy assessments, including a fuel and energy security study, a study assessing potential impacts related to climate change, and weekly analysis of fuel and energy security based on load profiles and fuel inventories reported through NYISO's Generator and Fuel Emissions Reporting (GFER) data portal. These assessments are based on data and information provided by resources on an annual, weekly, and as-needed basis considering system operating conditions. These assessments have the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security. Additionally, the New York City and Long Island areas have a loss of gas supply dual-fuel requirement and certain combined cycle gas units participate in a "Minimum Oil Burn" program. While oil accounts for a relatively small percentage of the total energy production in New York, it is often called during critical periods, such as when severe cold weather limits access to natural gas.

Probabilistic Assessments (NERC ProbA and Other Studies)

NYISO performs probabilistic assessments using GE's Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes as well as to determine annual IRM LCRs. NYISO also pursued capacity accreditation market rules to more accurately reflect capacity market suppliers' contributions to resource adequacy. These new market rules align compensation for capacity suppliers with an individual resource's expected reliability benefit to consumers and uses the probabilistic models from the LCR process to define capacity accreditation factors (CAF) for various capacity accreditation resource classes. The groundbreaking proposal was accepted by FERC in May 2022. The CAFs will reflect the marginal reliability contribution of the ICAP Suppliers within each Capacity Accreditation Resource Class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that began in May 2024.

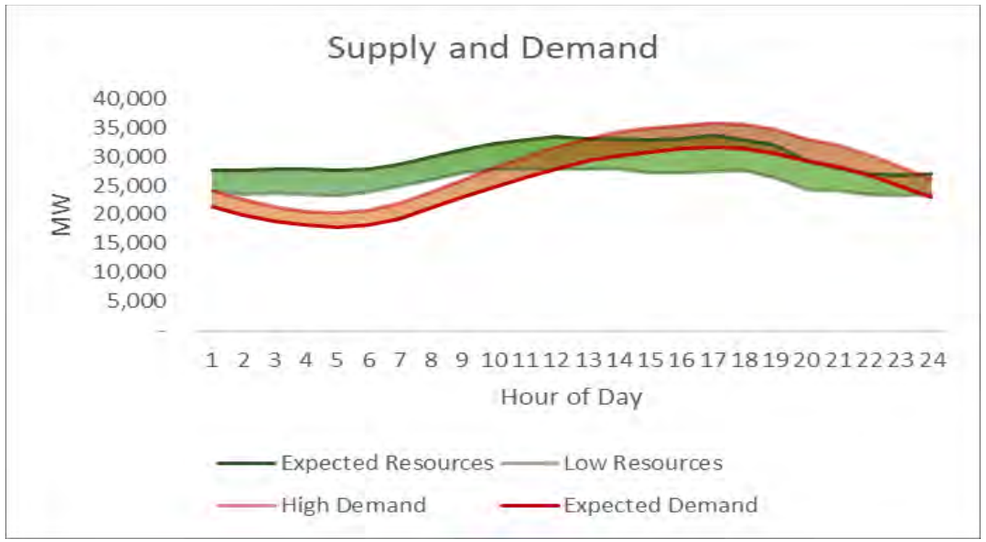
Additionally, NPCC provides results into NERC's ProbA process under the LTRA. The results from the ProbA performed in 2024 by NPCC are shown below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.06	1.91	1.30
EUE (PPM)	0.00	0.01	0.01
LOLH (hours per year)	0.00	0.01	0.01
Operable On-Peak Margin	16.7%	14.0%	15.0%

* Provides the 2022 ProbA Results for Comparison

Most load-loss and unserved energy risk is in the summer months of late June through August.

Hourly demand and resource projections for a typical summer risk day in 2026 are shown in the figure below. Although expected resource contribution is enough to meet expected demand, there is risk that above-normal peak demand could exceed resources. Demand could be 10–13% higher than expected, which could cause strain on the system from the hours beginning 2:00 p.m. through 11:00 p.m. Also, below-normal resource performance from unexpected generator outages or low-solar output could also cause supply shortfalls. If resource contributions are less than expected, strain on the system could be seen from hour beginning 12:00 p.m. through 12:00 a.m. on a typical peak day. Reliance on external assistance may be necessary in these events. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

NPCC's Directory 1 defines a compliance obligation for the NYISO, as a Resource Planner and Planning Coordinator, to perform a resource adequacy study evaluating a five-year planning horizon. NYISO delivers a report every year under this study process to verify the system against the 1-day-in-10-years LOLE criterion, which is usually based on NYISO's latest available reliability assessment results and assumptions. NYSRC Reliability Rules have recently included a requirement defining NYISO's obligation to deliver a Long-Term Resource Adequacy Assessment Report every year during which the NYISO publishes a Reliability Needs Assessment (RNA) and an annual update in the intervening year between RNAs.

Demand

NYISO employs a multi-stage process to develop load forecasts for each of the 11 zones within the New York Control Area (NYCA). The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of BTM energy storage resources are deducted from the peak forecasts.

Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak is projected to shift into the evening as additional BTM solar is added to the system and as EV charging impacts increase during the evening hours. Because the hour of the summer peak shifts into the evening over the course of the forecast horizon, BTM solar generation becomes less coincident with the NYCA peak hour, and BTM solar coincident peak reductions are forecasted to decrease in later years. The forecast of solar PV-related reductions to the winter peak is zero because the system typically peaks after sunset.

Trended weather conditions from the Climate Impact Study Phase I report are included in NYISO's end-use models and are reflected in the baseline, policy scenario, and percentile forecasts. NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

The 10-year annual average energy (+1.7%) and summer peak demand (+0.8%) growth rates are higher than last year's forecast. Increases in growth rates relative to the prior forecast are primarily attributed to the significant impacts of interconnecting large load projects. Baseline energy and coincident peak demand increase significantly throughout the 30-year forecast period, driven largely by large load project growth in the early forecast years and electrification of space heating, non-weather sensitive appliances, and EV charging in the outer forecast years. New York is projected to become winter-peaking in future decades due to space heating electrification and EV penetration. To account for forecast uncertainty during winter due to electrification and large loads, NYISO implemented a winter dynamic load forecast uncertainty in the resource adequacy models for its 2024 RNA.

Demand-Side Management

NYISO is working on developing market concepts to encourage the participation of flexible load, which will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increase in response to the state's climate and clean energy policies. Many of New

York's utilities are piloting several load management programs (e.g., smart EV charging, home-thermostat use, and integration of BTM storage for local peak demand modulation). As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed and significant impacts on demand are included in the load forecast.

DR participation for the summer capability period has increased slightly from 1,234 MW to 1,281 MW since the *2023 LTRA*. There are currently 425 MW of DR participating in ancillary services programs and providing either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

NYISO has implemented in 2024 a plan to integrate DERs, including DR resources, into the markets it administers. The DER Participation Model project aims to enhance participation of DERs in the competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. This project, which began in 2017, provides a single participation model for DER DR resources to provide energy, ancillary services, and installed capacity through an aggregation. The market rules for the DER and aggregation participation model were accepted by FERC in January 2020. NYISO filed additional proposed tariff revisions with FERC in June 2023 to clarify and enhance these market rules. NYISO deployed its DER participation model in 2024.

Generation

The pace of renewable project development and existing generation retirement is unprecedented and driving a need to increase the pace of transmission expansion, clean dispatchable generation, and demand management programs development. In general, resource and transmission expansion take many years from development to deployment. Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. Significant new resource development will be required to achieve energy targets under the CLCPA. The total installed generation capacity to meet policy objectives within New York is projected to range between 111 GW and 124 GW by 2040. At least 95 GW of this capacity will consist of new generation projects and/or modifications to existing plants. Even with these additions, New York still may not be sufficient to maintain the reliable electricity supply. The sheer scale of resources needed to satisfy system reliability and policy requirements within the next 20 years is unparalleled.

Currently, NYISO's interconnection process contains a significant number of proposed projects in various stages of development with only a fraction in more advanced stages included in the reliability planning models. However, the grid will evolve to achieve the policy mandates, and those changes will affect the nature and amount of resources.

For the 2024 RNA, gas availability is derated during winter to further account for cold weather risks.

To achieve the CLCPA mandate of an emission-free grid by 2040, DEFRs must be developed and deployed throughout New York. DEFRs that provide sustained on-demand power and system stability will be essential to meeting policy objectives while maintaining a reliable electric grid. While essential to the grid of the future, such DEFR technologies are not commercially available today.

ERSs usually provided to the system by synchronous fossil generation will continue to be necessary. New technology is being developed to allow for a reliable transition to a clean grid. Grid-forming inverter capabilities, as well as DEFRs, will likely be part of this transformation. In May 2023, the New York State Public Service Commission (PSC) initiated a process to examine the need for resources to ensure the reliability of the CLCPA mandate for a zero-emissions electric grid by 2040. The PSC seeks to identify innovative technologies to ensure the reliability of a zero-emissions electric grid. Numerous other initiatives at both state and federal levels are in progress and may impact the grid of the future.

Energy Storage

Storage resources can help to fill in voids created by reduced output from renewable resources. However, sustained periods of reduced renewable generation can rapidly deplete storage capabilities. NYISO has implemented its Co-Located Storage Resources model to allow wind or solar resources that are interconnected with an energy storage resource the ability to participate in the markets while respecting a shared interconnection limitation. NYISO is developing a model for hybrid storage resources to allow multiple technologies at the same point of interconnection to participate in the market as a single resource. Additionally, the resource adequacy simulation tools (such as GE's MARS) used in system planning by NYISO and for setting the IRMs were enhanced to include energy-limited resources models that allow for charging and discharging and also include temporal constraints (e.g., hours/days or hours/month).

Capacity Transfers

The models used for NYISO's reliability planning studies include firm capacity transactions (purchases and sales) with the neighboring systems as a base-case assumption. Proposed projects that are in a more advanced stage are included. One such project is the 1,250 MW HVdc line from Québec to New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model that NYISO uses to assess the adequacy of resources in the reliability planning processes employs several methods aimed at preventing overreliance on the external systems support. For example, NYISO employs limiting emergency assistance from neighbors by modeling a total limit of 3,500 MW, modeling five simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, and not modeling emergency operating procedure steps for the neighbors.

New York is fortunate to have strong interconnections with neighboring regions and has enjoyed reliability and economic benefits from such connections. As the energy policies in neighboring regions evolve, New York's imports and exports of energy could vary significantly due to the resulting changes in neighboring grids. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. As New York's and other regions' grids evolve, continuous monitoring and collaboration with our neighboring states will be required.

Transmission

Significant new transmission is being built across New York, but more investment is necessary to support, among other things, the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest.

Key transmission projects under development and accounted for in the reliability models include the following:

- The Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central New York
- The 1,250 MW Champlain-Hudson Power Express HVdc line from Hydro-Québec to New York City
- The AC Public Policy Transmission Projects that consist of upgrading transmission corridors in central New York and the lower Hudson Valley, which projects target completion of the majority of the components by December 2023
- The transmission project selected to address the Long Island Offshore Wind Expert Public Policy Transmission Need and that adds three new dc tie lines and a 345 kV backbone across western/central Long Island with an in-service date in 2030

Additionally, there are significant transmission projects either recently selected or under study that have not yet met the criteria to be in the reliability model. For instance, the PSC recently identified a new public policy transmission planning need for NYISO to solicit proposed solutions and that is intended to support the integration of 4.7 GW of wind resources in New York City.

Furthermore, in 2020, the PSC ordered the New York utilities to undertake planning assessments and make investment proposals to facilitate the cost-effective development of renewable and emissions-free resources while maintaining the reliability of New York's electric grid. The Coordinated Grid Planning Process (CGPP) was approved by the PSC in August 2023. The process is designed to assess the state's electric grid using a 20-year planning horizon. The CGPP is intended to identify electric grid expansions that can aid in unlocking renewable generation capacity and provide energy headroom for the purpose of meeting New York's clean energy goals while providing value to customers. Moreover, the CGPP is designed to identify opportunities for expansion of the bulk transmission system to advance the mandates of CLCPA. This provides another opportunity to inform the PSC's consideration of whether to establish a public policy transmission need for NYISO to solicit and evaluate proposed solutions.

Reliability Issues

The 2024 RNA, targeting completion in the fourth quarter of 2024, identifies transmission security violations of reliability criteria primarily driven by a combination of forecasted increases in peak demand, limited additional supply, and the assumed retirement of generation in New York City in response to state law and regulations. Accounting for these factors, the planned bulk power transmission system will not be able to securely and reliability serve the forecasted demand in New York City. When accounting for forecasted economic growth and policy-driven increases in demand, the New York City (Zone J) will be deficient starting in summer 2033 by as much as 17 MW for 1 hour and increasing to 97 MW for 3 hours in summer 2034 on the peak day during expected weather conditions. The Reliability Need occurs within the transmission district owned by Consolidated Edison Company of New York, Inc. ("Con Edison"). Con Edison is designated as the Responsible Transmission Owner in the NYISO's transmission planning process and required to submit a regulated backstop solution to address the need, which may be triggered if sufficient market-based solutions do not materialize.

Prior to the 2024 RNA, the NYISO completed the 2023 Q2 STAR on July 14, 2023. This assessment found a reliability need beginning in summer 2025 in New York City primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by the New York Department of Environmental Conservation (DEC) Peaker Rule. The reliability need is a deficiency in the transmission security margin. Specifically, the New York City zone is deficient by as much as 446 MW for a duration of nine hours on the peak day during expected weather conditions (95 degrees Fahrenheit) when accounting for forecasted economic growth and policy-driven increases in demand. To ensure the continued reliability of electric service in New York City, NYISO designated the generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges as necessary for reliability to temporarily remain in operation after the Peaker Rule compliance date until permanent solutions to the need are in place, for an initial period of up to two years (May 1, 2027).

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation and may lead to increasing reliability issues on the New York system. Reliability margins are shrinking. Generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher-than-expected demand, and extreme weather could threaten reliability and resilience in the future. The

system is projected to become winter-peaking in the next decade due to electrification and decarbonization policies. Large loads are being proposed to interconnect to the system. New York's current reliance on neighboring systems is expected to continue through the next 10 years. A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. Such resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. New transmission is being built but more investment is necessary to support the delivery of offshore wind energy to connect new resources located in upstate to downstate load centers where demand is greatest.

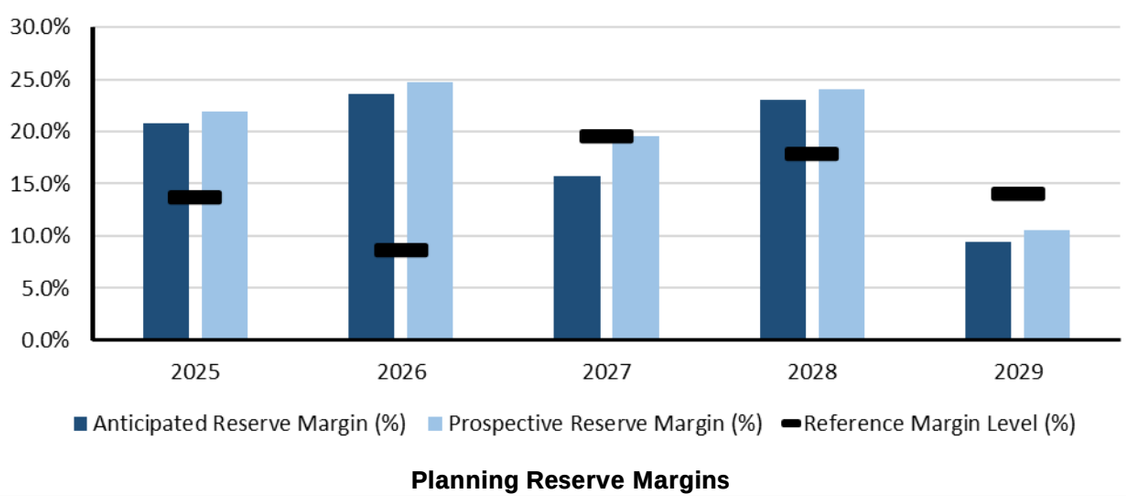


NPCC-Ontario

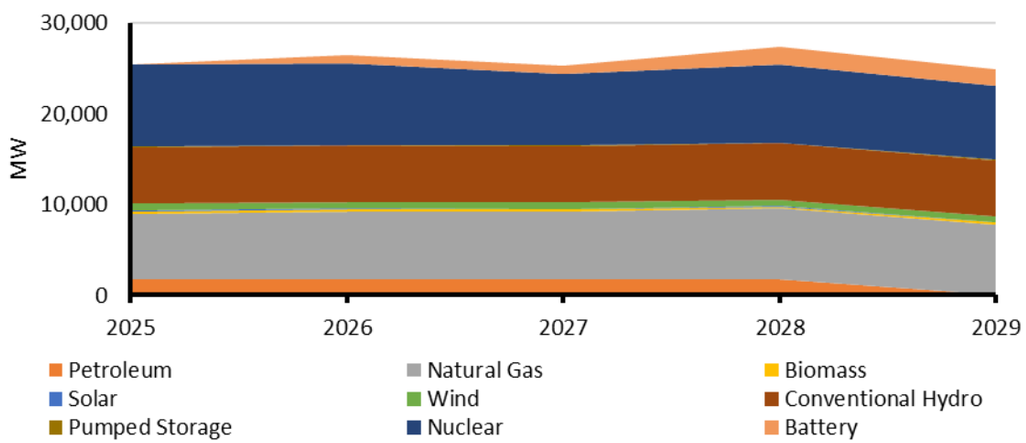
NPCC-Ontario is an assessment area in the Ontario province of Canada. The IESO is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	23,385	23,860	24,264	24,627	25,248	26,038	26,473	27,373	27,974	28,789
Demand Response	1,791	1,914	1,914	1,914	1,914	1,914	1,914	1,914	1,914	1,914
Net Internal Demand	21,594	21,946	22,350	22,713	23,333	24,123	24,559	25,458	26,060	26,875
Additions: Tier 1	617	1,737	1,735	3,012	3,302	3,300	3,843	4,385	4,384	5,128
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	600	600	500	600	600	600	600	0	0	0
Existing-Certain and Net Firm Transfers	25,470	25,394	24,133	24,924	22,242	22,051	20,660	20,705	20,671	20,257
Anticipated Reserve Margin (%)	20.8%	23.6%	15.7%	23.0%	9.5%	5.1%	-0.2%	-1.4%	-3.9%	-5.5%
Prospective Reserve Margin (%)	22.0%	24.8%	19.5%	24.1%	10.5%	6.1%	0.8%	-0.5%	-2.9%	-4.6%
Reference Margin Level (%)	13.7%	8.6%	19.5%	17.8%	14.1%	9.4%	17.2%	8.1%	6.8%	8.5%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- While potential reserve margin shortfalls are forecast for 2027 and 2029, they are mainly driven by changes in the IESO's resource adequacy assessment methodology since the *2023 LTRA*. Last year, reserve margin calculations included the continuation of existing resources (following contract expiry) for the entire outlook period. For this LTRA, reserve margins reflect the contribution of existing resources only until the end of their contract or commitment period. This change to the methodology is more conservative and helps to better identify system needs in the IESO's planning assessments to establish resource acquisition targets and address anticipated needs.
- The IESO has two capacity sharing agreements with Hydro-Québec providing firm summer capacity, which will help to address future shortfalls this decade.
- The IESO has completed a broad set of actions to secure new capacity for this decade to ensure that Ontario's power system needs are met during a period of nuclear retirements and refurbishments and economy-wide demand growth. This includes securing long-term commitments amounting to 2,195 MW of new capacity to be on-line by 2028, with early operation incentives anticipated to bring a portion on-line as early as 2027 to help alleviate the reserve margin gap.
- The annual capacity auction, which helps to meet needs in the short term by securing capacity for up to one year at a time, has historically secured more capacity than targeted. Trends suggest that this should continue, as the November 2024 auction (which will help to ensure reliability through summer 2025 and winter 2025–2026) also secured more capacity than targeted.
- The IESO is taking steps that will address future shortfalls around the end of this decade and heading into the 2030s. The next round of medium- and long-term procurements was recently launched to ensure that capacity and energy needs continue to be met. The second medium-term procurement aims to re-commit existing resources with contracts expiring over the 2026–2029 period, while the second long-term procurement aims to secure capacity and energy from new resources (to be online as early as 2029), to meet needs emerging in the early 2030s.
- The IESO is also responsible for implementing new provincial policy as outlined in the Ontario government's July 2023 Powering Ontario's Growth report, which includes developing new nuclear projects, transmission expansions, and expanded conservation and demand management programs. The IESO will also incorporate changes stemming from the federal release of the final Clean Electricity Regulations, anticipated toward the end of 2024.

NPCC-Ontario Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Petroleum	1,695	1,695	1,695	1,695	5
Natural Gas	7,275	7,465	7,465	7,847	7,761
Biomass	297	294	257	209	209
Solar	100	100	100	100	100
Wind	743	722	711	711	602
Conventional Hydro	6,215	6,212	6,212	6,212	6,202
Pumped Storage	38	38	38	38	38
Nuclear	9,008	9,008	7,895	8,639	8,142
Battery	118	998	996	1,886	1,885
Total MW	25,487	26,531	25,368	27,336	24,944

Planning Reserve Margins

The ARM falls below the RML starting in 2027. While expected nuclear retirements, the ongoing nuclear refurbishment program, and demand growth are resulting in increased needs this decade, the reserve margin shortfalls indicated in 2027 and 2029 are primarily driven by the change in the IESO's resource adequacy assessment methodology described above.

Mid-decade capacity needs that were identified in the 2022 *Annual Acquisition Report* have been met through a series of competitive procurements. Since May 2023, the IESO has secured over 3,600 MW of new capacity from battery storage, natural gas, and biogas facilities, expected to come on-line between 2025 and 2028. In addition, the 2023 capacity auction secured 1,867 MW of summer capacity and 1,311 MW of winter capacity above targets of 1,400 and 850 MW, respectively. The IESO continues to actively procure existing and new resources to meet longer-term needs, using the mechanisms in the Resource Adequacy Framework.

Ongoing refurbishments at Bruce Nuclear Generating Station (NGS) and Darlington NGS will see between one and three reactors concurrently off-line through Summer 2033. Refurbishments remain on or ahead of schedule and outages continue to be managed to limit impacts to the grid. Following the return to service of refurbished units at Bruce, each unit is expected to be uprated, with the additional capacity anticipated to be available in the early 2030s.

The Ontario government has also announced a plan to deliver three additional small modular reactors in addition to the 300 MW unit already underway (anticipated on-line in 2029). The provincial government's July 2023 Powering Ontario's Growth plan directed the IESO to conduct an impact assessment on potentially adding 4,800 MW of large-scale nuclear capacity to Bruce NGS. Approval was granted from the federal nuclear regulator in October 2024 to extend operation of four units at Pickering NGS (previously scheduled for decommissioning in 2025) through September 2026. The government is also supporting the refurbishment of the four units at Pickering, with refurbishment of the first unit anticipated to be completed in 2031.

To address resource adequacy needs emerging mid-decade due to the combined effect of nuclear retirements and refurbishments, as well as expiring generation contracts, the IESO has employed competitive acquisition mechanisms from the Resource Adequacy Framework in part via the capacity auction referenced above. The IESO's first long-term procurement concluded in May 2024 and secured long-term commitments from 10 battery storage facilities for 1,784 MW of new capacity and three natural gas/biogas facilities for 411 MW of new capacity. Facilities are anticipated to be in service as early as May 2027.

The IESO calculates the reserve margin requirement on an annual basis and publishes this in the Annual Planning Outlook (APO). The requirement is calculated for each year for net demand at the time of the annual demand peak to provide an LOLE that is at or below 0.1 days per year. The reserve margin requirement in the *2024 LTRA* is derived from the capacity requirement in the 2024 APO, plus any material changes to demand and supply following APO publication.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Energy adequacy assessments are conducted annually for the APO by using a deterministic approach in the IESO's economic dispatch model. In addition, the IESO's capacity adequacy assessments consider the system's ability to serve load in all hours of the year (i.e., during peak hours as well as non-peak load hours).

As demand requirements increase, nuclear refurbishments continue, and some units at the Pickering NGS retire in 2024, Ontario's energy needs are expected to be met this decade by the resources secured through the IESO's recently completed procurements. The second medium-term procurement, which was recently launched, aims to secure capacity and energy from existing resources reaching contract end; this is expected to help alleviate energy risks in the latter half of this decade. The second long-term procurement that is underway aims to acquire new capacity and energy-producing resources and is anticipated to alleviate energy risks in the early 2030s.

Factors that could increase energy adequacy risks include aging resources and the potential for decreased performance, market exit of resources reaching contract end, extreme weather, and decarbonization policies and risks presented by new resources, including in-service delays or a high risk of forced outages during the initial period of operation. Deliverability challenges for new resources and long lead times required to build new transmission may also increase energy adequacy risks. Demand-side factors include materialization of data centers, increased industrial automobile production and EV supply chain loads, and climate change impacts on weather-sensitive load.

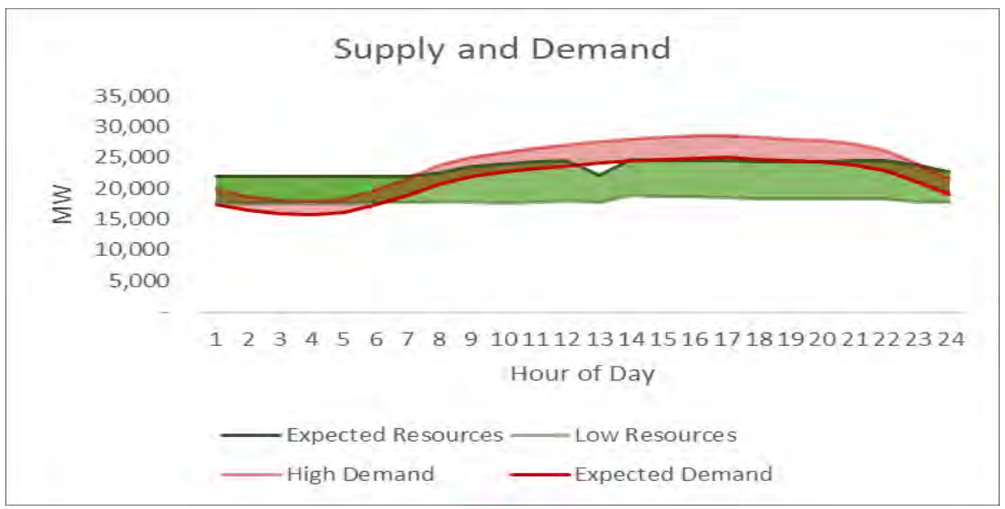
Looking forward, with the federal government's proposed Clean Electricity Regulations to decarbonize Canada's electric system by 2050, the IESO is assessing the role of natural gas generation as a flexible resource in the interim as new sources of non-emitting supply are added to the system.

The IESO conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC and NERC reliability requirements. Results from the 2024 ProbA are shown in the table on the next page. The low risk of unserved energy is concentrated in the summer peak period, which typically occurs in late August.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	72.16	**0.04**	**4.97**
EUE (PPM)	0.49	**0.00**	**0.03**
LOLH (hours per year)	0.44	**0.00**	**0.01**
Operable On-Peak Margin	-6.7%	**13.3%**	**9.5%**

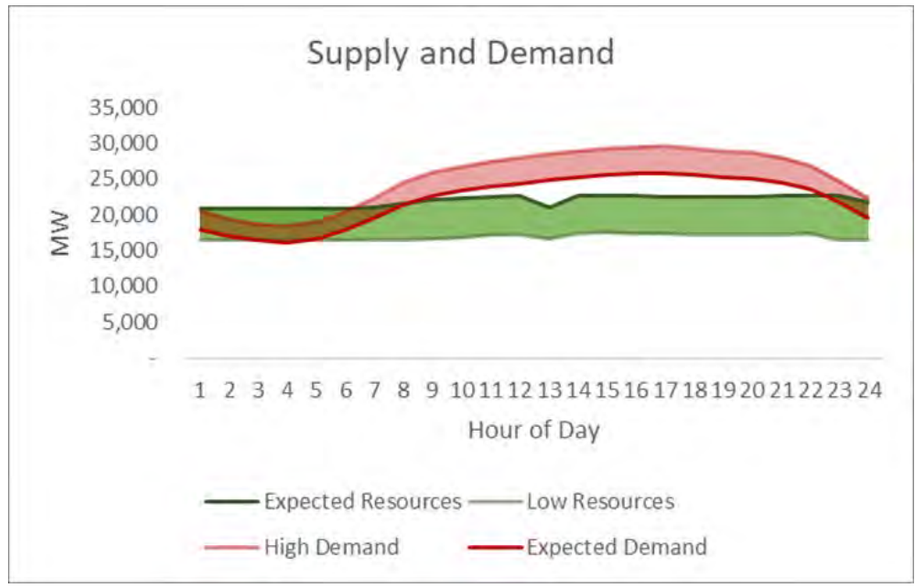
* Provides the 2022 ProbA Results for Comparison

Hourly demand and resource projections for a representative summer risk-day in 2026 are shown in the figure below. Expected resource contributions are not sufficient to meet expected demand on the risk day. The risk could be exacerbated by either a lower-than-expected resource contribution event or a higher-than-expected demand event, with greater risk being due to a larger variability in resource contribution. There is expected strain on the system from the hours beginning 12:00 p.m. through 8:00 p.m. If resource contributions are less than expected, strain on the system at expected demand conditions could be seen for almost all hours of the day beginning at 7:00 a.m. Reliance on external assistance may be necessary during peak conditions.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

In 2028, the EUE and LOLH are higher than 2026. Risk occurs during the same summer peak period but also during winter peak conditions in December. Demand growth that is forecasted to occur between 2026 and 2028 contributes to higher loss-of-load risk compared to the 2026 result. The risk day in 2028 has the same drivers as the 2026 result noted above.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2028

Demand

Forecasted demand for this *2024 LTRA* outlook period (relative to the *2023 LTRA* outlook period) indicates 10% higher annual energy demand, 8% higher summer peak demand, and 9% higher winter peak demand.

With an expanding agricultural and greenhouse sector, along with increasing electricity use for home heating and transportation, summer and winter peaks are anticipated to converge over the forecast period, leading Ontario to be dual-peaking by 2030. In the near term, the peak magnitude is expected to increase slightly as the province exits the remnants of the post-pandemic inflationary cycle, and new industrial projects supporting decarbonization begin commercial operation. Over this assessment period, the IESO projects total internal demand growth to increase at a compound annual growth rate of 2.34% for summer and 2.75% for winter. Offsetting the growth in demand are reductions from conservation, including savings from EE programs and codes and standards regulations, electricity price responsiveness and increased output by embedded generation.

Ontario's Industrial Conservation Initiative (ICI) acts as a critical peak pricing program leading to reductions in demand at peak and is expected to reduce around 1,500 MW if the hour of annual system peak demand occurs in the summer or around 1,000 MW if it occurs in the winter. It is expected to scale based on increased industrial growth in future years, with reductions in 2034 of 2,000 MW for a summer peak demand hour and over 1,400 MW for a winter peak demand hour.

Demand-Side Management

DR capacity, from both dispatchable loads and hourly DR resources (e.g., residential or commercial and industrial load), is procured through the IESO's annual capacity auction. Starting with the 2023 capacity auction, the IESO implemented a capacity qualification process for all resource types eligible to participate, which applies resource-specific calculation methodologies to determine the amount of unforced capacity (UCAP) each resource is eligible to offer into the auction.

In June 2023, the IESO launched Peak Perks, a residential DR program where participants help reduce demand by up to 150 MW through brief, time-limited thermostat adjustments during periods of peak electricity demand in the summer months.

In July 2023, the IESO launched an interruptible rate pilot to provide large-load customers with an interruptible rate in exchange for agreeing to temporarily reduce demand when directed by the IESO. The pilot spans a three-year period and up to 15 events of up to four-hour duration can be called, primarily in the day-ahead timeframe but also on shorter notice.

Forecast savings from the IESO's 2021–2024 Conservation and Demand Management Framework were included in the forecast and resulted in a decrease in demand. Savings from the 2021–2024 CDM framework are expected to persist beyond the end of 2024. In February 2024, Ontario's minister of energy asked the IESO to examine options and analysis for a post-2024 EE framework and programs.

Distributed Energy Resources

The IESO estimates that contracted DERs contributed more than 3,400 MW of capacity and 5.3 TWh of energy in 2023, more than half of which is solar PV, one-third wind, and modest contributions from hydroelectric and biomass resources. While the IESO has little insight into uncontracted DERs, it has observed energy contributions of approximately 2 TWh in 2023.

Generation

Recent generation procurements are provided in the PRM section.

The transmission-connected supply mix in Ontario has shifted over the past decade from having only synchronous generation facilities to one with more IBRs including wind, solar, and storage. Previous assessments performed by the IESO indicate that Ontario is expected to have sufficient inertia and frequency response to ensure stable operation up to 2025.

Going forward, the addition of over 2,900 MW of new battery storage resources in the next few years will increase the proportion of IBRs on the system. With the shift toward a higher proportion of IBRs, further areas that will be explored include the sufficiency of the resource mix to provide system inertia, primary frequency response, operating reserve, ramping capability, reactive support, and voltage control. If needs are identified, the IESO's procurements may be used as one avenue to acquire resources that can provide the required services.

The IESO has also been taking a proactive approach to dealing with challenges posed by IBRs. This includes working to optimize the location of IBR resources acquired through the IESO's procurements to minimize performance issues and initiating a review of the IESO's Market Rules to align with the latest IEEE 2800 standard, which aims to establish uniform technical minimum requirements for interconnection, capability, and lifetime performance of IBRs.

Energy Storage

By May 2028, over 2,900 MW of new battery storage resources are expected to come on-line, including the 250 MW/1,000 MWh Oneida battery storage facility (expected to be operational in June 2025), and 2,714 MW of battery storage resources secured through the IESO's first set of long-term procurements. Of this, 930 MW is expected to reach commercial operation by May 2026 and the remaining 1,784 MW by May 2028. These standalone battery storage resources (with a minimum four-hour duration) are expected to support the reliable operation of Ontario's electric system through the ability to be dispatched by the IESO and ramp up and down quickly. The resources are also located in areas of Ontario where transmission security or resource adequacy needs were identified.

Newly acquired energy storage facilities through the IESO's first set of long-term procurements will be required to be available during peak hours.

Capacity Transfers

Firm capacity imports and exports with neighboring jurisdictions are included in the IESO's planning studies. For non-firm imports, the IESO assumes a limited amount for the purposes of its reliability assessments. Non-firm imports are assumed to be 250 MW for summer and 240 MW for winter, an amount considered likely to flow throughout the year, including under tight supply conditions and prices.

In November 2024, the IESO and Hydro-Québec finalized a new capacity sharing agreement for a swap of a minimum of 600 MW of capacity per season. Under this agreement, the IESO will deliver capacity

to Québec during the winter period and Hydro-Québec will deliver capacity to Ontario during the summer period. The agreement commences in the Winter 2024–2025 season and runs to October 2031, with an option for an extension for an additional three years. Other terms of the agreement are expected to include the option for the IESO to increase the minimum amount provided to Québec each year and to bank any amount of the 600 MW from Québec for use in a future summer period over the term of the agreement.

The 2023 capacity auction secured 300 MW of system-backed imports from Québec for the Summer 2024 obligation period. As part of the 2016 capacity sharing agreement between Ontario and Québec, the IESO may call on a total of 500 MW of firm imports from Hydro-Québec, which may be requested all in one summer or in smaller amounts over multiple summers. The IESO's recent assessments indicate the intention to utilize the 500 MW of firm imports from June to September 2027 to help meet resource adequacy needs. However, depending on the outcomes of the ongoing procurements and changes to Ontario's resource adequacy outlook, the IESO may choose to utilize this capacity in another year.

Transmission

The existing transmission system in northeastern Ontario has insufficient capability to reliably supply forecasted load growth; as such, the IESO has recommended several new transmission reinforcements in the region to address this need. Several of the recommended reinforcements are in the early project development stage and one is undergoing a transmitter selection process.

The IESO recently recommended additional transmission reinforcements in southwest Ontario to support the area's medium-term needs, including a double circuit, 230 kV line from Lambton transmission station to Chatham substation, expected in-service by 2028, and a new 500 kV transmission line connecting Longwood and Lakeshore transmission stations, to be in-service by 2030. These projects will ensure that transfer capability continues to be sufficient as additional load continues to connect in the area.

Reliability Issues

Nuclear refurbishment over the next decade is a major resource risk that requires additional attention. The IESO has regular meetings with nuclear operators to assess probable delays and take appropriate mitigation actions.

For long-term planning purposes, the IESO carries an additional level of nuclear refurbishment reserve to account for the risk of refurbishment delays and increased forced outage rates pre- and post-refurbishment. In addition, advanced outage approvals are provided solely when Ontario is adequate under extreme weather.

Other factors that may pose reliability risks include supply chain issues, conditions in neighboring jurisdictions, extreme weather, decarbonization-driven changes to supply and demand, policy and regulatory uncertainty, asset health, and potential market exit of existing resources.

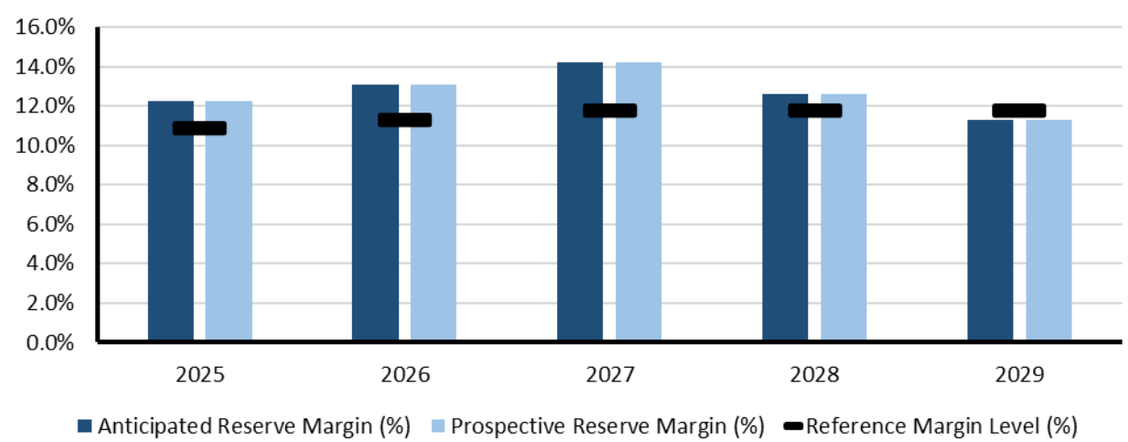


NPCC-Québec

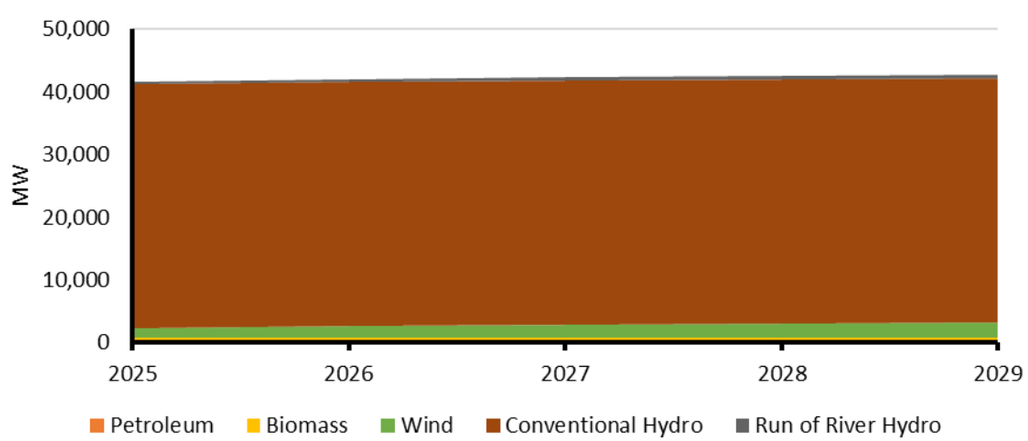
The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of 8.5 million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVdc ties, radial generation, or load to and from neighboring systems.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	41,497	41,954	42,476	43,385	44,070	44,784	45,577	46,635	47,828	49,041
Demand Response	4,732	4,896	5,068	5,258	5,322	5,377	5,388	5,388	5,388	5,388
Net Internal Demand	36,765	37,058	37,408	38,127	38,748	39,408	40,189	41,247	42,440	43,652
Additions: Tier 1	73	469	665	835	1,016	1,016	1,016	1,016	1,016	1,016
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-390	-145	455	455	455	600	0	0	0	0
Existing-Certain and Net Firm Transfers	41,185	41,429	42,066	42,103	42,103	42,256	41,656	41,656	41,656	41,656
Anticipated Reserve Margin (%)	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
Prospective Reserve Margin (%)	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
Reference Margin Level (%)	10.9%	11.3%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM and PRM remain above the RML until 2029 (winter 2029–3030).
- A total of 4,048 MW wind generation capacity (1,016 MW capacity value at peak time) is expected to be in service by 2030.
- Two new transmission projects connecting Québec with New England and New York are expected to be in service by the end of 2025 and May 2026, respectively.

NPCC-Québec Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Petroleum	429	429	429	429	429
Biomass	400	400	400	400	400
Wind	1,449	1,807	2,002	2,173	2,354
Conventional Hydro	38,925	38,962	38,999	39,036	39,036
Run of River Hydro	446	446	446	446	446
Total MW	41,648	42,043	42,276	42,483	42,664

NPCC-Québec Assessment

Planning Reserve Margins

The ARM is based on existing and anticipated generating capacity and firm capacity transfers. The Québec area projects an ARM above the RML over the first five winters of the assessment period (2024–2025 to 2028–2029). The ARM is under the RML for the winters 2029–2030 to 2034–2035 mainly due to the demand growth.

The RML is derived from the NPCC 2023 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee on December 5, 2023. The demand uncertainty captured in the reserve ratio reflects both weather and economic uncertainty. The methods and assumptions can be found in the *Comprehensive Review* report available on the NPCC website.

The assumptions used for this assessment, including demand forecast and resources, are consistent with the Hydro-Québec 2023 Supply Plan update, which was filed with the Régie de l'énergie on November 1, 2023.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

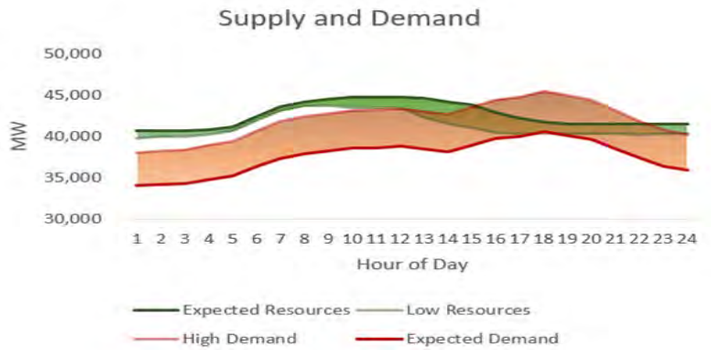
The main energy risk for the Québec area is associated with a series of dry years, hence the energy reliability criterion established by the Régie de l'énergie. This risk surpasses the energy risk associated with the other renewable resources over the horizon of this study. The potential impact of climate change on the water inflows could be an issue for energy reliability and is therefore the subject of various ongoing internal studies.

Hydro-Québec conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and comply with NPCC and NERC reliability requirements. Results from the 2024 ProbA are shown in the table below. The low risk of unserved energy is concentrated in the winter peak period, which typically occurs in late January to early February.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**8.21**	**4.97**
EUE (PPM)	0.00	**0.04**	**0.03**
LOLH (hours per year)	0.00	**0.01**	**0.01**
Operable On-Peak Margin	-2.3%	**9.8%**	**11.9%**

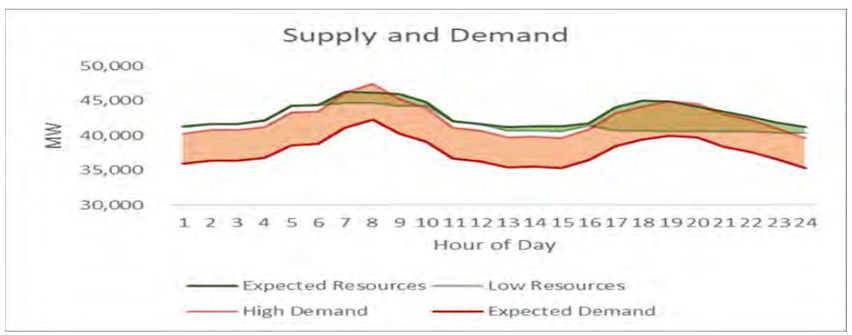
* Provides the 2022 ProbA Results for Comparison

Hourly demand and resource projections for a typical winter risk day in 2026 are shown in the figure below. Although expected resource contribution is expected to be enough to meet expected demand, there is risk that above-normal demand could exceed resources. Demand could be 10–15% higher than expected, which could strain the system from the hours beginning 3:00 p.m. through 10:00 p.m. Also, if resource contributions are less than expected, the peak hour beginning at 6:00 p.m. could lead to a loss-of-load situation. Reliance on external assistance may be necessary in these events.



Hourly Probabilistic Assessment Results | Representative Winter Risk Day 2026

Hourly demand and resource projections for a typical winter risk day in 2028 are shown in the figure below.



Hourly Probabilistic Assessment Results | Representative Winter Risk Day 2026

Demand

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand.

Demand-Side Management

The Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 2,784 MW on winter 2024–2025 peak demand. The area is also expanding its existing interruptible load program for commercial buildings, which will grow from 611 MW in 2024–2025 to 889 MW by the end of the period study. Another similar program for residential customers is in operation and should gradually rise from 166 MW for Winter 2024–2025 to 621 MW for Winter 2028–2029.

New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 371 MW for Winter 2024–2025 and 445 MW for Winter 2034–2035. Moreover, data centers specializing in blockchain applications are required to reduce their demand during peak hours at Hydro-Québec's request. Their contribution as a resource is expected to be around 269 MW over the study period. Finally, another DR resource consists in a voltage reduction scheme allowing for a 250 MW peak demand reduction. EE and conservation programs are integrated in the assessment area's demand forecasts.

Distributed Energy Resources

Total installed BTM capacity (solar PV) is expected to increase to 862 MW in 2035. Solar PV is accounted for in the load forecast. Nevertheless, since Québec is a winter-peaking area, DERs' on-peak contribution ranges from 2 MW for Winter 2024–2025 to 5 MW for the last winter period. No potential operational impacts of DERs are expected in the Québec area considering their low contribution.

Generation

Four wind projects with a total installed capacity of 4,000 MW are expected to be commissioned during the assessment period. The first project, Apuiat (204 MW), is expected to be commissioned in 2024–2025. The second project (1,144 MW divided into 6 wind farms) is expected to be commissioned in December 2026. The third project is Des Neiges (1,200 MW) and is divided into three phases (400 MW each). The first phase is expected to be operational in the winter of 2026–2027. The second and third phases are expected to be in service for the 2027–2028 and 2028–2029 winters, respectively. The fourth project is made of 1,500 MW divided into 8 wind farms, which are expected to be operational in the winters of 2027–2028, 2028–2029 and 2029–2030, depending on the location.

In addition to wind projects, unit replacement projects at existing hydroelectric facilities are being studied. Up to 2,000 MW of capacity could be added by replacing generating units with most recent models, as outlined in Hydro-Québec's Action Plan 2035.

Energy Storage

No energy storage facilities are planned to be commissioned during the assessment period.

Capacity Transfers

The governments of Québec and Ontario have signed an MOU of an agreement that allows a seasonal capacity exchange between the two areas for the next seven years except for the year 2027 (no exchange is allowed). The technical details of the agreement will be completed by Fall 2024 and will be in place from Winter 2024–2025 to winter 2030–2031. This agreement will be firm and allow Québec to import 600 MW from November to April. In summer, Québec will export 600 MW of firm capacity to Ontario from May to October.

Transmission

Appalaches-Maine Interconnection

This project, expected to increase transfer capability between Québec and Maine by 1,200 MW, has resumed construction. The project will connect to the New England Clean Energy Connect project (NECEC) in Maine. It involves the construction of a ±320 kV dc transmission line about 100 kilometers (62 miles) long from the Des Appalaches 735/230 kV substation to the Canada-United States. border. From the international border crossing, the dc transmission line will be extended 145 miles to a substation in Lewiston, ME, where the power will be converted from dc to ac. The project in Québec also includes the construction of an dc to dc converter at the Des Appalaches substation and triggers the need of thermally upgrade two 735 kV lines in the south of the system. The project is expected to be in service in December 2025.

Hertel-New York Interconnection (CHPE)

This project, expected to increase transfer capability between Québec and New York by 1,250 MW, is under construction. It involves the construction of a ±400 kV dc underground transmission line about 60 kilometers (37 miles) long from the Hertel 735/315 kV substation just south of Montréal to the Canada-United States border. The project will connect to the Champlain Hudson Power Express project (CHPE) in New York state. From the international border crossing, the dc transmission line will be extended 339 miles to a substation in Astoria, NY, where the power will be converted from dc to ac. The project in Québec also includes the construction of an ac to dc converter at the Hertel substation. The project is expected to be in service in May 2026.

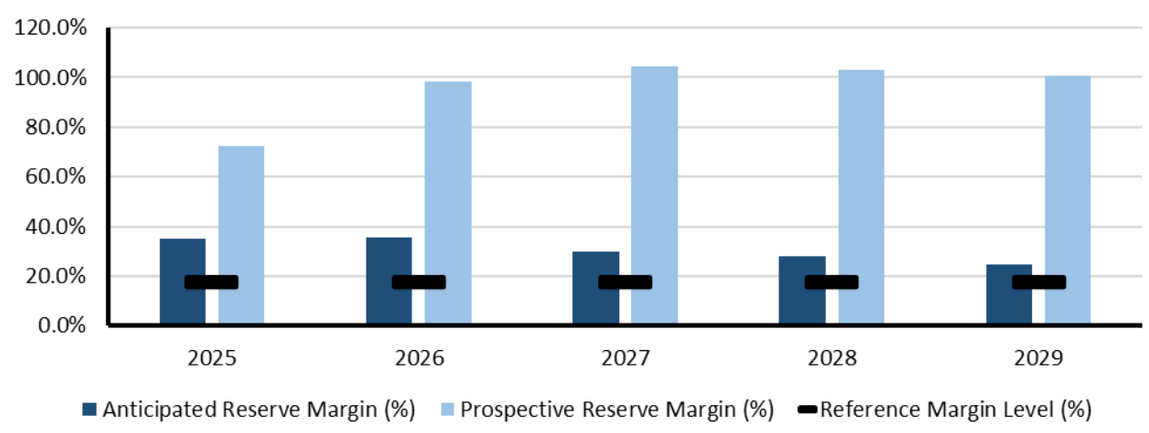


PJM

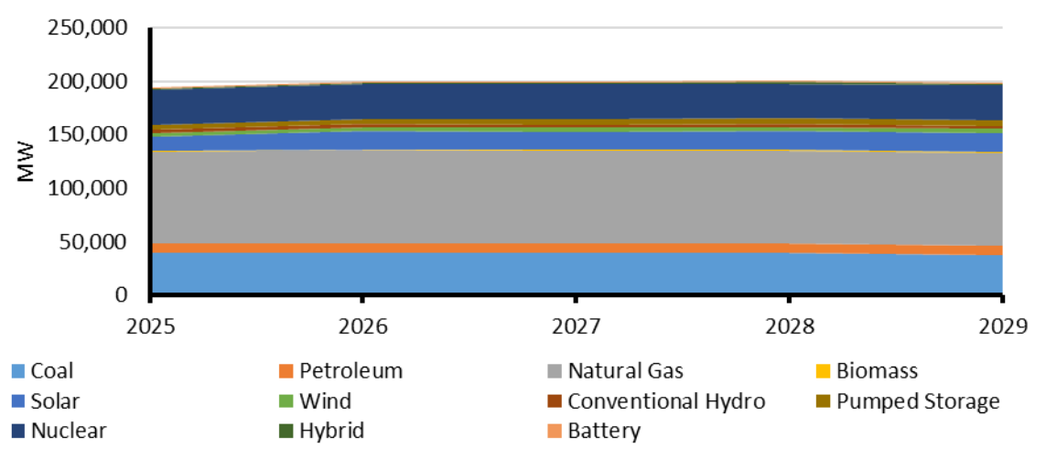
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	153,493	156,803	159,859	162,972	165,681	167,873	170,008	172,109	174,366	176,822
Demand Response	7,554	7,693	7,808	7,913	8,000	8,083	8,162	8,230	8,312	8,400
Net Internal Demand	145,939	149,110	152,051	155,059	157,681	159,790	161,846	163,879	166,054	168,422
Additions: Tier 1	11,056	17,047	17,139	17,784	17,911	18,155	18,155	18,155	18,155	18,155
Additions: Tier 2	55,112	93,845	112,827	122,781	127,059	131,113	131,287	133,652	133,652	133,652
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	4,502	4,347	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	185,828	185,270	180,552	180,552	178,577	178,577	178,577	178,577	178,577	178,577
Anticipated Reserve Margin (%)	34.9%	35.7%	30.0%	27.9%	24.6%	23.1%	21.6%	20.0%	18.5%	16.8%
Prospective Reserve Margin (%)	72.4%	98.3%	104.7%	103.3%	100.5%	96.5%	94.1%	92.9%	82.1%	79.5%
Reference Margin Level (%)	17.7%	17.7%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the RML until 2034 when it falls below the 17.6% RML level.
- PJM implemented a number of changes to the 2023 load forecasting process to improve model accuracy, switching from an annual to monthly end-use model for PJM's sector models to better determine heating, cooling, and other non-weather-sensitive load and moving to an hourly model to better capture new technologies and peak shifting. Additionally, higher expectations for data center loads now incorporate 15-year forecasts from impacted electric distribution companies (EDC).
- PJM's review of recent policies (e.g., state laws and federal environmental initiatives) indicates over 32 GWs of potential deactivations through 2034. The pace of retirements is being driven in large part by these state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generation to comply or retire. Conversely, there are multiple mandates with renewable portfolio standards (RPS) that account for the majority of over 150 GWs submitted projects.

PJM Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	39,735	39,735	39,325	39,325	37,747
Coal*	39,394	39,394	33,313	28,240	25,124
Petroleum	8,810	8,514	8,514	8,514	8,117
Natural Gas	85,541	87,245	87,245	87,245	87,245
Natural Gas*	85,541	87,245	87,228	87,228	87,228
Biomass	928	928	928	928	928
Solar	13,349	16,770	16,908	17,621	17,754
Wind	3,017	3,512	3,507	3,507	3,507
Conventional Hydro	2,934	2,922	2,934	2,934	2,944
Pumped Storage	5,189	5,189	5,189	5,189	5,189
Nuclear	32,535	32,535	32,535	32,535	32,535
Hybrid	1,315	1,742	1,739	1,739	1,739
Battery	393	982	982	994	994
Total MW	193,747	200,074	199,807	200,532	198,699
Total MW*	193,406	199,733	193,779	189,430	186,060
*** Capacity with additional generator retirements.** Generators that are forecasted to retire by PJM are removed from the resource projection where marked.					

PJM Assessment

Planning Reserve Margins

The ARM does not fall below the RML in PJM until 2034. PJM's growing demand profile and a change in resource mix that favors VERs, however, present a new level of risk.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

PJM is forecasting around 30% installed reserves (including expected committed demand resources), which is well above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. Due to the current low penetration of energy-limited and VERs in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand. To address future reliability concerns due to growing VER penetration and limitations associated with the performance of those resources, PJM's Effective Load Carrying Capability methodology calculates the reliability and energy contribution of limited and variable resources.

Some of PJM's assumptions for determining the resource mix to use in the ProbA differ from those used in developing the LTRA. Only a portion of the Tier 1 resource additions are used in the ProbA to more accurately reflect historical rates of development. Additionally, more generator retirements are used in the ProbA based on PJM's generator forecasting. These assumptions are more consistent with the assumptions included in official studies performed by PJM to support its capacity market. In addition, the information in the ProbA for winter seasons refers to the Winter 2026–2027 and Winter 2028–2029 because PJM's studies are based on "delivery years," which start on June 1 of a year and end on May 31 of the subsequent year.

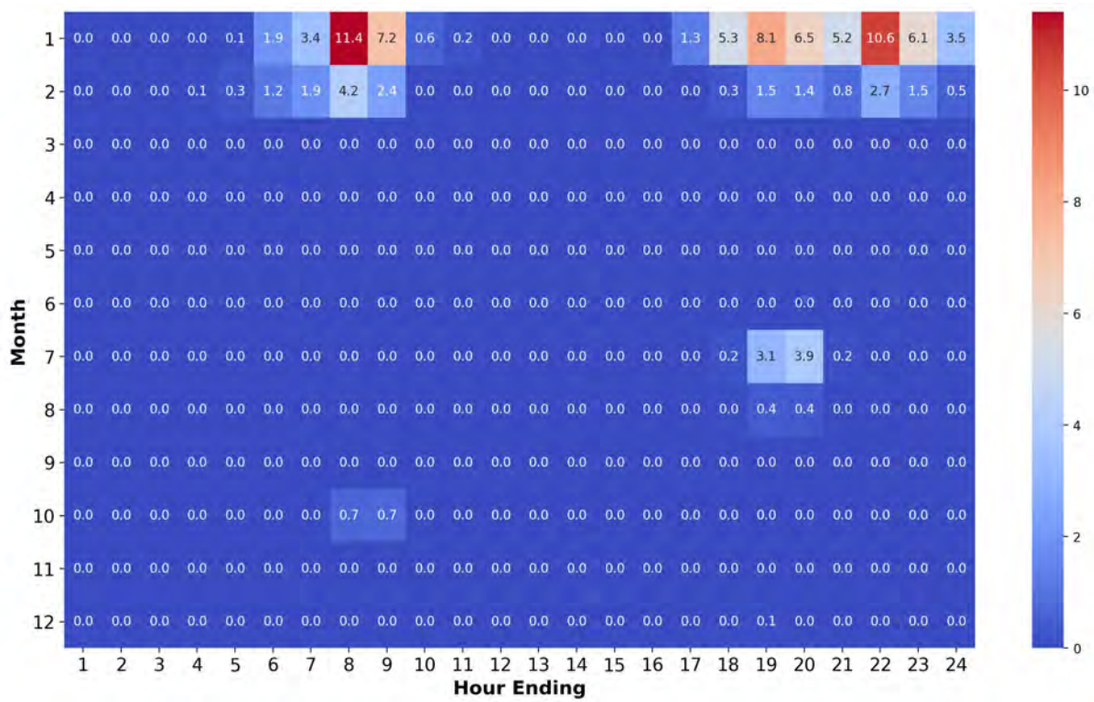
Results of the 2024 ProbA are provided in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**537.52**	**1043.44**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.11**	**0.22**
Operable On-Peak Margin	29.0%	**17.8%**	**17.7%**

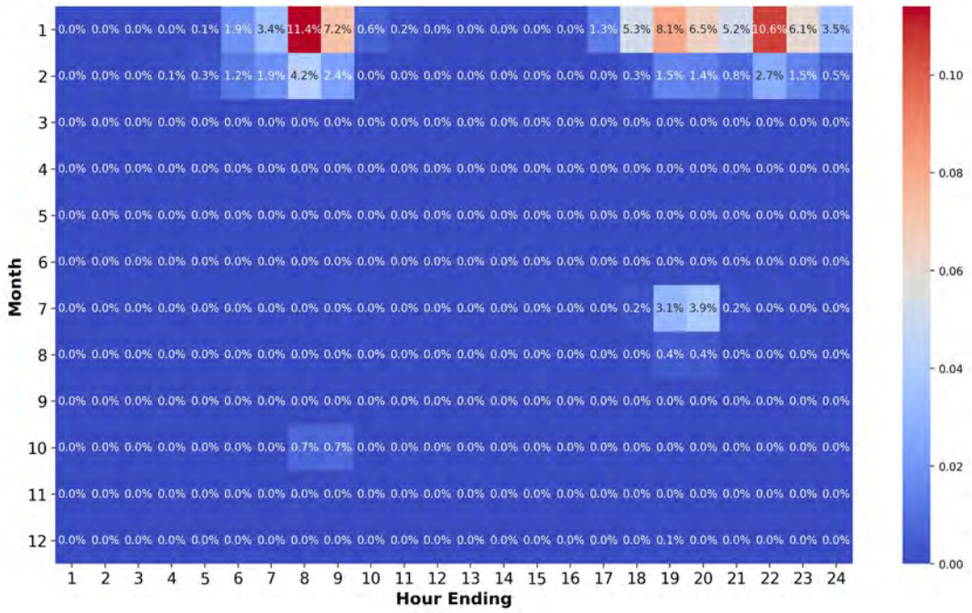
* Provides the 2022 ProbA Results for Comparison

In both 2026 and 2028, most EUE and LOLH are concentrated in the winter months (especially January), as shown in the following EUE heat maps. The risk occurs in days when temperatures are very low, which results in high loads across the assessment area. If resource performance were to occur at the levels expected during average winter days, the system should be able to serve these high loads. However, resource performance from thermal resources on very cold days, especially natural gas resources, is more likely to be poor. This, coupled with poor performance from solar resources, results in very low total electricity supply and causes loss-of-load events in the ProbA analysis. The winter load-loss events tend to occur during morning and evening demand peaks and coincide with poor thermal performance and poor solar performance.

The smaller shares of EUE and LOLH observed in the summer period for 2026 and 2028 are associated with high temperatures and high loads across the assessment area that drive load-loss events in the evening (hours ending 19 and 20) as grid-connected and BTM solar resource output declines. Low performance of wind resources and, to a lesser extent, slightly worse performance of thermal resources, also contribute to the load-loss events in the analysis.



2026 EUE Heat Map (Share of Annual EUE in %)



2028 EUE Heat Map (Share of Annual EUE in %)

PJM implemented capacity reforms (approved by FERC) at the start of 2024, which include using the loss-of-load model employed to perform the ProbA, as well as accreditation reforms based on the risk patterns identified by said model, for the capacity auctions starting with delivery year 2025–2026.

Demand

PJM is experiencing large growth in data centers that are in turn driving higher demand forecasts. Loudoun County, Virginia, in the PJM assessment area, is home to "Data Center Alley," the largest concentration of data centers in the world. Electrification in transportation, heating, and industrial sectors is also spurring demand growth.

The PJM Interconnection produces an independent peak load forecast of total internal demand using econometric regression models with daily load as the dependent variable and independent variables including calendar effects, weather, economics, and end-use characteristics. PJM annually reviews its load forecast methodology and implements changes when improvements are identified.
Summer peak load growth in PJM is projected to average 1.6% per year over the next 10-year period and 1.6% over the next 15 years. The PJM summer peak is forecasted to be 176,822 MW in 2034, a 10-year increase of 25,575 MW, and reaches 190,752 MW in 2039, a 15-year increase of 39,505 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.5% with a median of 0.5%.

Winter peak load growth for PJM is projected to average 1.9% per year over the next 10-year period and 1.8% over the next 15 years. The PJM regional transmission organization winter peak load in 2033–2034 is forecasted to be 163,069 MW, a 10-year increase of 28,410 MW, and reaches 176,195 MW in 2038–2039, a 15-year increase of 41,536 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.0% with a median of 0.7%.

Net energy for load growth for PJM is projected to average 2.3% per year over the next 10-year period and 2.2% over the next 15 years. Total PJM energy is forecasted to be 1,021,955 GWh in 2034, a 10-year increase of 208,627 GWh, and reaches 1,120,928 GWh in 2039, a 15-year increase of 307,600 GWh. Annualized 10-year growth rates for individual zones range from 0.1% to 7.3% with a median of 0.7%.

Demand-Side Management

DR resources can participate in all PJM markets—capacity, energy, and ancillary services. DR is forecast to grow during summer peak season from 7,550 MW in 2025 to 8,400 MW in 2034.

Distributed Energy Resources

PJM expects 4,470 MW of solar DERs at the time of the peak in 2029 and 5,103 MW in 2034. The effects of solar DERs are included in the load forecast for PJM. No effect of solar DERs is incorporated in the winter load forecast since winter expected peak occurs after sundown.

Generation

Overall, new generation is coming on-line slower than anticipated. Generator retirements are outpacing the new generation replacing them. As a result, PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load. PJM could be at risk of facing resource adequacy challenges if these trends continue. PJM has applied an 11% reduction to the nameplate value of Tier 1 resources to reflect the historical rate of slower-than-anticipated addition of new generation.

PJM reviews the progression of generation interconnection to understand overall developer trends more fully and their impact on the interconnection process. Of new and expanded generation resources submitted in Queue A (1999) through December 31, 2023, 74,294 MW (or 15.8%) reached commercial operation, 33,166 MW (or 7%) were withdrawn from the interconnection process after Interconnection Service Agreement (ISA) execution, and 1,560 MW (or 0.3%) were withdrawn after wholesale market participant agreement (WMPA) execution but before construction. Overall, 20.4% of projects that requested uprates to existing capacity reached commercial operation.

Stakeholders at the June 6, 2023, Interconnection Process Subcommittee meeting approved an issue charge to examine how to enhance transfer of CIRs, which allow new generation to interconnect as a capacity resource, from deactivating resources to new generation. The goal is to develop a solution that both improves the efficiency of the process and clarifies that it applies to all energy-injecting capacity resource types. The existing provisions in the PJM Tariff, and related defined terms included in the Reliability Assurance Agreement (RAA), governing the CIR transfer process will be clarified to reduce confusion as to which capacity resource types the transfer process applies.

PJM's existing installed capacity reflects a fuel mix consisting of approximately 48% natural gas, 22% coal, and 18% nuclear. Hydro, wind, solar, oil, and waste fuels constitute the remaining 12%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility. Totaling nearly 125,000 MW of CIRs, renewable and hybrid fuels are changing the landscape of PJM's interconnection process. Solar energy makes up 40% of the new service requests in PJM's generation interconnection queue. State policies encouraging renewable generation are contributing to the rise in solar generation interconnection requests.

PJM's review of recent policies indicates over 32 GWs of potential deactivations through 2034. The pace of retirements is being driven in large part by state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generators to comply or retire. See *Energy Transition in PJM: Resource Retirements, Replacements, and Risks* (February 2023). Conversely, there are multiple mandates with RPS that account for the majority of over 150 GWs in submitted projects. Growing levels of intermittent and limited duration resources, such as wind, solar, and battery storage, do not replace conventional large-scale generation installations megawatt-for-megawatt but rather require multiple megawatts to replace one megawatt of dispatchable generation due to their limited availability in certain hours of the day and seasons of the year. Many megawatts from a range of generation technologies, available at different times, are required to replace a megawatt of thermal generating capacity. Looking out over the next 8 to 10 years of the energy resource transition, maintaining an adequate level of generation resources with operational and physical characteristics that support reliability will be crucial for PJM's ability to serve electrical demand reliably.

Energy Storage

Energy storage development continues in PJM. As solar generation increases in PJM, growth of storage is expected to follow since storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility. Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, Department of Energy (DOE) national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.

Today, there are approximately 177 GWs of solar, wind, battery, and hybrid in the PJM interconnection queue. Hybrid resources make up approximately 26 GWs and standalone storage makes up approximately 28 GWs.

Some developers are pairing storage with variable, renewable generation, such as solar or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land but each has its own connection to the grid) or hybrid (in which the storage facility and generator share a common connection to the grid).

Capacity Transfers

PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer (total transmission interchange capability) into PJM would amount to less than 2% of PJM's internal generation capability. At no time within this assessment period does the ARM get anywhere near 2%. PJM reliability would not be negatively affected if transfers were dropped to zero.

Transmission

PJM's Regional Transmission Expansion Plan (RTEP) continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by new wind and solar generating units driven by federal and state renewable incentives, generating plant deactivations, and market impacts introduced by DR and EE programs. As of December 31, 2023, renewable resources continue to represent a significant portion of PJM's new services requests.

The PJM board approved 48 new baseline projects during 2023 at an estimated $6.6 billion to ensure that fundamental system reliability criteria across the grid are met. The board also approved the inclusion of 93 new network transmission projects at an estimated $180 million into the RTEP.

Reliability Issues

PJM's 2023 *Load Forecast Report* addressed the impact of industry changes that are reshaping system hourly loads. As a result, the level and timing of coincident peak and non-coincident peak demands across PJM have begun to shift. Solar-power penetration, expected impacts of EVs, state electrification programs, home battery storage, and a significant increase in data center loads are markedly increasing the complexity of PJM's load forecasting process. Driven by discrete and localized load growth, like Data Center Alley in Loudoun County, Virginia, in 2022, PJM and stakeholders conducted a review of data center load growth and identified growth rates of over 300% in some instances. As a result, the 2023 PJM *Load Forecast Report* incorporates adjustments to specific zones for data center load growth.

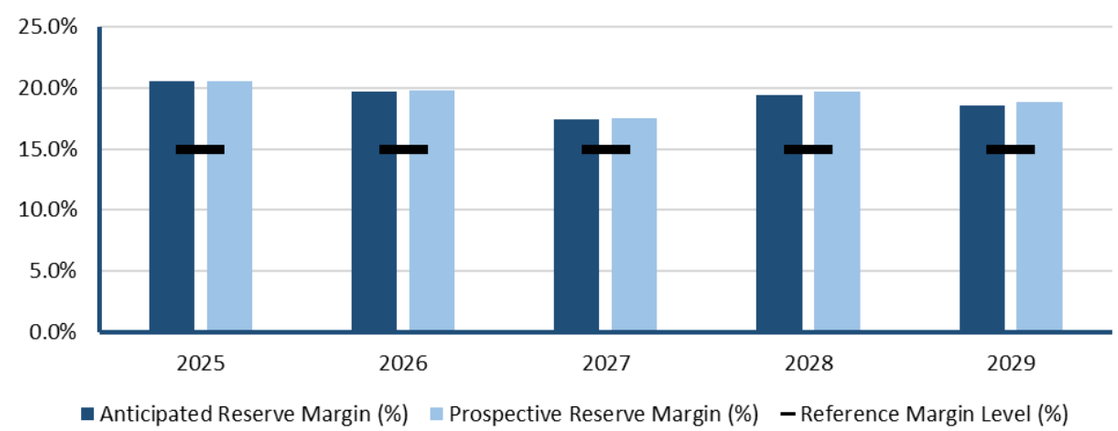


SERC-Central

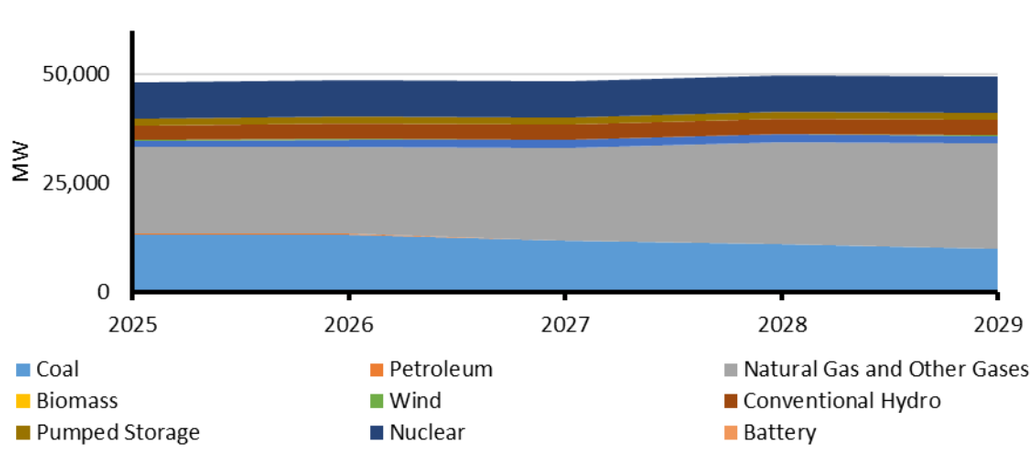
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	42,983	43,202	43,399	43,384	43,440	43,636	43,725	43,913	44,077	44,316
Demand Response	1,859	1,856	1,852	1,849	1,847	1,844	1,842	1,840	1,839	1,837
Net Internal Demand	41,124	41,346	41,547	41,535	41,593	41,792	41,883	42,074	42,239	42,479
Additions: Tier 1	1,123	1,540	2,970	4,983	5,841	5,841	5,841	7,609	8,935	9,598
Additions: Tier 2	20	20	20	120	120	120	120	120	120	120
Additions: Tier 3	135	263	415	1,118	3,395	4,198	4,965	5,368	5,745	6,198
Net Firm Capacity Transfers	1,240	765	190	-288	-288	-288	-288	-287	-287	-287
Existing-Certain and Net Firm Transfers	48,437	47,962	45,813	44,608	43,478	43,191	43,191	42,224	42,224	41,153
Anticipated Reserve Margin (%)	20.5%	19.7%	17.4%	19.4%	18.6%	17.3%	17.1%	18.4%	21.1%	19.5%
Prospective Reserve Margin (%)	20.8%	20.0%	17.7%	19.7%	18.9%	17.6%	17.4%	18.8%	21.4%	19.8%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.
- Projected coal generation retirements total 4,399 MW in the next 10 years. Resource additions include 6,838 MW of natural gas, 75 MW of BESS, and 760 MW of solar generation over the next 10 years.
- New transmission line additions total 209 miles through 2028. The entities also plan to upgrade 185 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows.

SERC-Central Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,348	13,348	11,774	11,047	9,917
Coal*	13,048	13,348	11,146	10,013	8,883
Petroleum	148	148	148	148	148
Natural Gas	19,857	19,857	21,287	23,300	24,158
Natural Gas*	19,476	19,476	20,906	22,919	23,777
Biomass	36	36	36	36	36
Solar	1,338	1,706	1,706	1,706	1,706
Wind	172	172	172	172	172
Conventional Hydro	3,393	3,393	3,393	3,393	3,393
Pumped Storage	1,673	1,673	1,673	1,673	1,673
Nuclear	8,280	8,280	8,280	8,280	8,280
Battery	75	125	125	125	125
Total MW	48,319	48,737	48,593	49,879	49,607
Total MW*	47,639	48,356	47,584	48,464	48,192
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Central Assessment

Planning Reserve Margins
The future reserve margins are above the RML for SERC-Central.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
The 2024 ProbA results shown in the table below indicate negligible unserved energy and load-loss. Analysis of detailed ProbA outputs shows that that this negligible risk occurring in 2026 is associated with hot summer conditions and upper levels of economic load forecast models.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**0.10**	**0.00**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.00**	**0.00**
Operable On-Peak Margin	18.4%	**13.2%**	**14.9%**

* Provides the 2022 ProbA Results for Comparison

Demand
Drivers of load growth are commercial expansion, electrification of heating and transportation, and growth in residential load. Entities expect to continue to have increased economic growth that will drive both population and employment to the SERC-Central assessment area, but these gains in employment are slightly offset by improvements in efficiency.

Distributed Energy Resources
SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation
Projected coal generation retirements total 4,399 MW in the next 10 years. Resource additions include 6,838 MW of natural gas, 75 MW of BESS, and 760 MW of solar generation over the next 10 years.

Generator retirements are carefully managed by entities in the SERC-Central assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Capacity Transfers
Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission
The entities reported a total addition of 209 miles of new transmission lines until 2028. The entities are also planning to upgrade 185 miles of transmission lines in the next 10 years to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts on reliability.

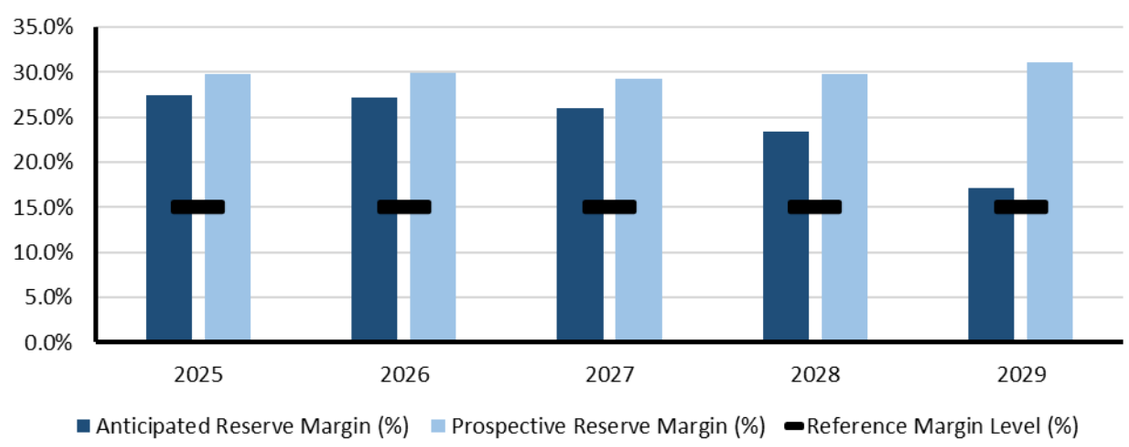


SERC-East

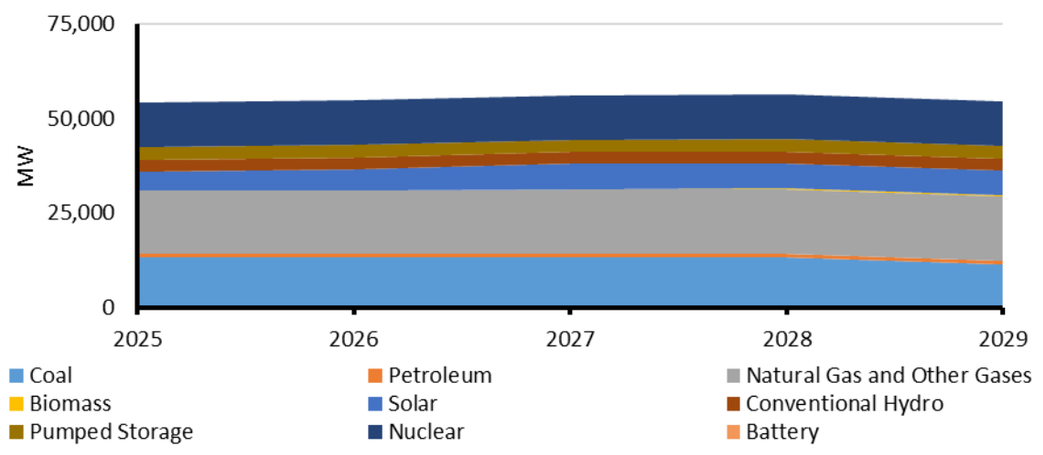
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	44,099	44,789	46,308	47,378	48,286	49,533	50,349	50,896	51,741	52,155
Demand Response	1,092	1,186	1,214	1,225	1,228	1,229	1,230	1,231	1,232	1,233
Net Internal Demand	43,007	43,603	45,094	46,153	47,058	48,304	49,119	49,665	50,509	50,922
Additions: Tier 1	772	1,330	2,777	2,818	2,818	2,818	2,818	2,818	2,818	2,818
Additions: Tier 2	38	217	506	1,975	5,577	8,032	9,766	11,595	13,978	16,767
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	593	593	593	593	593	593	593	593	593	593
Existing-Certain and Net Firm Transfers	54,039	54,129	54,045	54,118	52,301	52,395	51,316	49,998	49,998	48,636
Anticipated Reserve Margin (%)	27.4%	27.2%	26.0%	23.4%	17.1%	14.3%	10.2%	6.3%	4.6%	1.0%
Prospective Reserve Margin (%)	29.8%	30.0%	29.3%	29.8%	31.1%	33.0%	32.1%	31.7%	34.2%	35.9%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the RML until 2030 when it falls below the 15.0% RML level.
- Since the *2023 LTRA*, solar PV resources have grown from 1.5 GW to an expected 4.7 GW by the end of 2024.

SERC-East Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,150	13,150	13,150	13,150	11,333
Coal*	13,108	12,564	12,564	11,910	10,093
Petroleum	1,044	1,044	992	992	992
Petroleum*	1,044	1,044	868	868	868
Natural Gas	16,627	16,717	17,061	17,121	17,121
Natural Gas*	16,601	16,691	17,061	17,121	17,121
Biomass	176	176	176	176	176
Solar	4,995	5,553	6,624	6,665	6,665
Conventional Hydro	3,102	3,102	3,102	3,102	3,102
Pumped Storage	3,324	3,324	3,324	3,324	3,324
Nuclear	11,795	11,795	11,795	11,808	11,808
Battery	6	6	6	6	6
Total MW	54,218	54,866	56,229	56,343	54,526
Total MW*	54,150	54,254	55,519	54,979	53,162
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-East Assessment

Planning Reserve Margins
The ARM falls below the RML starting in 2030 for SERC-East. Projected demand is expected to increase around 8.75% from 2024 to 2028 in the footprint.

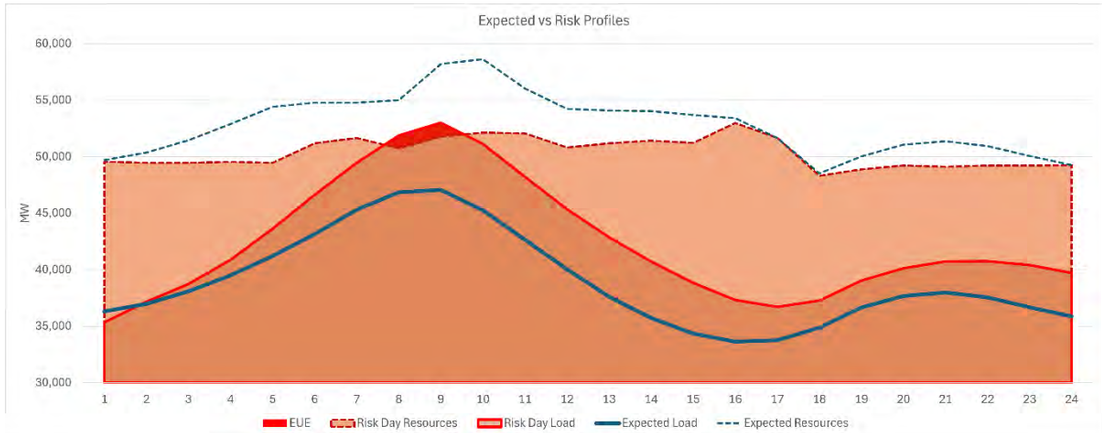
Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
SERC-East has an elevated risk of energy shortages based on results of the 2024 ProbA shown in the table below.

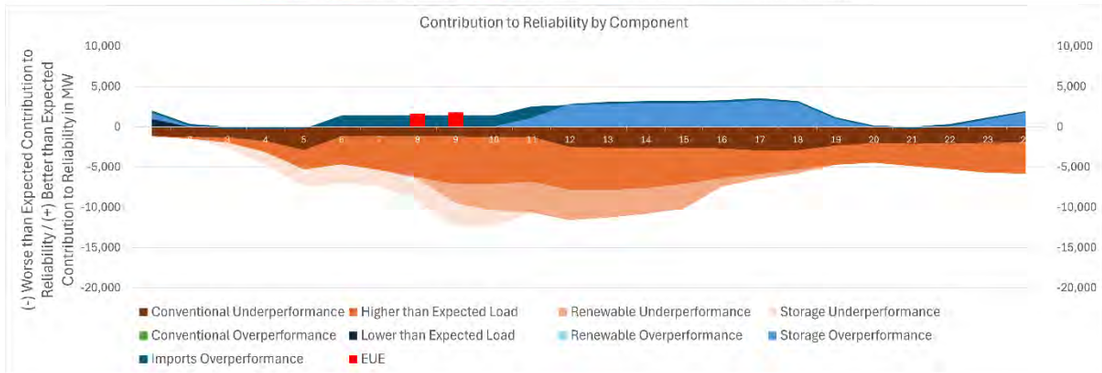
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	92.49	**143.35**	**207.26**
EUE (PPM)	0.39	**0.60**	**0.81**
LOLH (hours per year)	0.08	**0.09**	**0.17**
Operable On-Peak Margin	16.1%	**14.2%**	**11.1%**

* Provides the 2022 ProbA Results for Comparison

SERC-East has changed from a summer-peaking assessment area to a dual-peaking assessment area, with both a summer and winter peak. The addition of solar PV generation shaves off summer peak demand, and a trend toward electrification of heating drives up winter peak demand. The ProbA results for 2026 indicate some risk for SERC-East in the winter months of January and February. The annual EUE is 143.35 MWh but for a very short, expected duration of 0.09 hours. The risk occurs during winter morning hours around 8:00 a.m. due to a combination of higher loads and solar resources not yet ramped up. For extreme cold weather events that might impact a wide geographical footprint, there is also a limit on imports from neighboring areas.

For 2028, SERC-East continues to show winter risk with 207.26 MWh of EUE and 0.17 hours of LOLH. The load is expected to grow by over 2%. The load-loss events in the analysis are for very few hours and short duration, occur around 8:00 a.m., and are tied to extreme weather, higher forecasted load levels, and lower resource performance. This can be seen in the following figures showing the risk profile and resource performance for a likely event-day.





Demand
Population growth is driving demand forecast increases in SERC-East. Entities expect faster-than-average growth in the urban areas and overall increasing energy and demand in the 10-year forecast. While the economic indicators used in the forecast have growth rates that vary during each year, the economic outlook will contribute to increased energy and demand over the 10-year forecast. Some entities project their EE adoption to impact roughly 1% of annual retail sales (after opt-outs) during the 10-year forecast.

There are also many large commercial/industrial loads accounted for in the forecast that have been announced or in discussions with the entities to locate in the service territory. If the large sites come to fruition, it will drive significant increases in energy and demand during the later part of the 10-year forecast.

The projected EV adoptions are driving energy and demand increases during the later part of the 10-year forecast window. EVs are currently the most significant contributor of all electrification sources (e.g., heating, industrial) in the 10-year forecast.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 286 miles of new transmission lines through 2028. The entities are also planning to upgrade 515 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts on reliability.

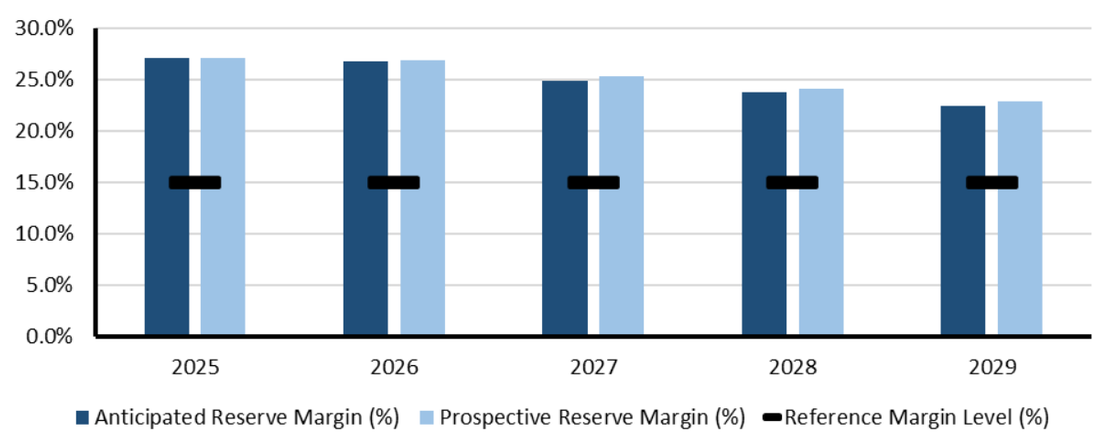


SERC-Florida Peninsula

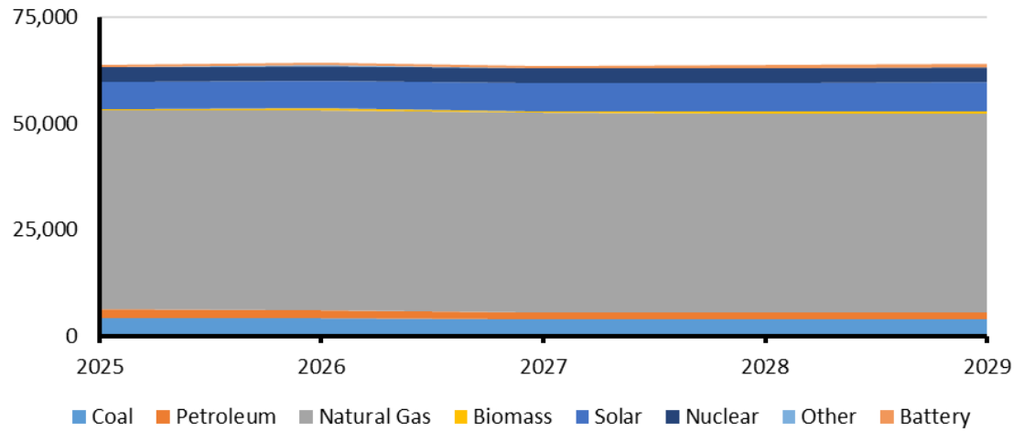
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	53,509	53,795	54,015	54,551	55,250	55,879	56,593	57,612	58,631	59,679
Demand Response	2,840	2,834	2,837	2,820	2,806	2,795	2,783	2,771	2,761	2,748
Net Internal Demand	50,669	50,961	51,178	51,731	52,444	53,084	53,810	54,841	55,870	56,931
Additions: Tier 1	871	1,497	1,573	1,785	2,018	3,421	3,927	4,545	4,547	4,549
Additions: Tier 2	0	40	200	200	200	200	200	200	200	200
Additions: Tier 3	0	39	39	39	39	39	39	39	39	39
Net Firm Capacity Transfers	494	293	293	200	200	200	200	200	200	200
Existing-Certain and Net Firm Transfers	63,521	63,121	62,366	62,230	62,230	61,725	61,725	61,493	61,493	61,493
Anticipated Reserve Margin (%)	27.1%	26.8%	24.9%	23.7%	22.5%	22.7%	22.0%	20.4%	18.2%	16.0%
Prospective Reserve Margin (%)	27.1%	26.9%	25.3%	24.1%	22.9%	23.1%	22.4%	20.8%	18.6%	16.4%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.
- Projected coal generation retirements total 459 MW in the next 10 years. Tier 1 additions include 484 MW of natural gas, 1,560 MW of BESS, and 1,792 MW of solar generation over the next 10 years.
- New transmission line additions total 668 miles through 2030. The entities also plan to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows.

SERC-Florida Peninsula Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	4,367	4,367	3,908	3,908	3,908
Coal*	3,341	3,779	2,851	2,851	2,851
Petroleum	1,957	1,852	1,724	1,724	1,724
Petroleum*	1,892	1,786	1,477	1,477	1,477
Natural Gas	46,860	47,012	46,844	46,801	46,801
Biomass	310	310	310	310	310
Solar	6,255	6,635	6,711	6,853	6,997
Nuclear	3,502	3,502	3,502	3,502	3,502
Other	9	9	9	9	9
Battery	638	638	638	708	797
Total MW	63,898	64,324	63,646	63,815	64,048
Total MW*	62,807	63,671	62,343	62,512	62,745
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Florida Peninsula Assessment

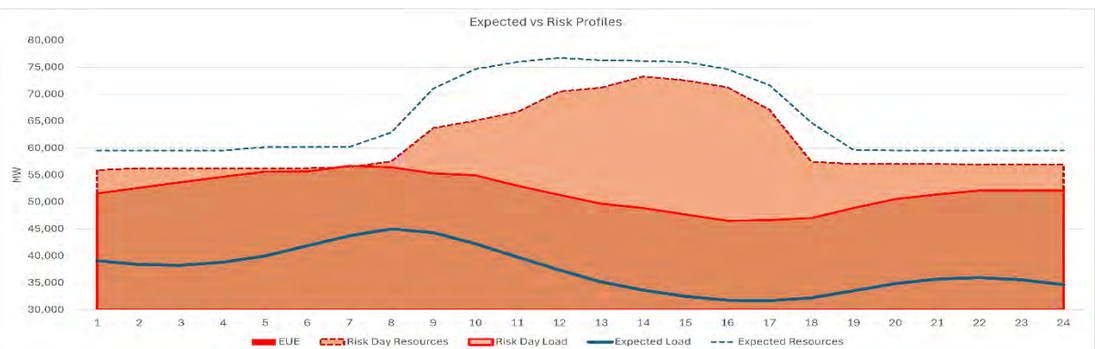
Planning Reserve Margins
The ARM is not expected to fall below the RML for any period of the assessment period.

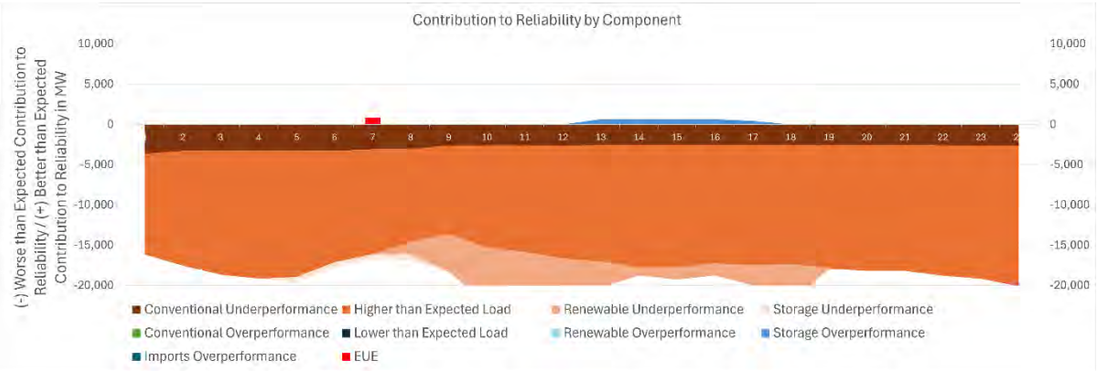
Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss. Analysis of detailed ProbA outputs shows that that the negligible risk in year 2026 is associated with hot late-summer or early fall conditions, high generator forced outages, and upper levels of economic load forecast models. The risk occurs in evening hours around 7:00 p.m. when contribution from solar generation is limited.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1.13	**2.18**	**16.28**
EUE (PPM)	0.00	**0.01**	**0.06**
LOLH (hours per year)	0.00	**0.01**	**0.02**
Operable On-Peak Margin	18.6%	**19.2%**	**16.3**

* Provides the 2022 ProbA Results for Comparison

For study year 2028, the ProbA results shows very low risk with 16.28 MWh of EUE and 0.02 LOLH hours. The driver of the risk is mainly extreme winter weather, similar to conditions from 1989, when Florida experienced one of the worst winter freezes on record. With higher load levels and lower resources in 2028, the low risk shifts to late December, occurring in morning hours when contribution from solar generation is limited, and is associated with winter freeze events that limit imports.





Demand
The individual entities within the FL-Peninsula Subregion develop their load forecasts and the Florida Reliability Coordinating Council (FRCC) then aggregates these forecasts to calculate a non-coincident seasonal peak for the subregion. Each entity adjusts their forecasts annually to account for their actual peak demands, updated economic outlooks, population growth, weather patterns, conservation and energy efficiency efforts, and electric appliances usage patterns. Based on the data reported in the 2023 FRCC Regional Load and Resource Plan, the net energy for load (NEL) and summer peak demands are forecasted to grow when compared to previous forecasts. The current average annual growth rate for the NEL is 0.97% per year. Firm summer and winter peak demand growth are expected to increase to 1.19% and 1.17%, respectively.

Demand-Side Management
Controllable DR from interruptible and dispatchable load management programs within the FL-Peninsula Subregion is treated as a load-modifier, and it is projected to be constant at approximately 6% of the summer and winter total peak demands for all years of the assessment period.

Distributed Energy Resources
SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation

Generator retirements are carefully managed by entities in the SERC-Florida Peninsula assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Energy Storage

Electricity storage (ES) is still a growing capacity contributor in the assessment area. Over the next 10 years, a total of approximately 2,900 MW of ES generation is projected to be in service by 2032 and is included in the utilities' 10-year site plans (approximately 775 MW by 2029).

Individual entities in the assessment area that have installed or are projecting the installation of ES are developing operating protocols on the use and dispatch of these facilities. ES units are studied as part of the normal generation interconnection process and included in other FRCC studies and processes with members providing individual dispatch profiles and study levels in order to identify potential operational impacts.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 668 miles of new transmission lines through 2030. The entities are also planning to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

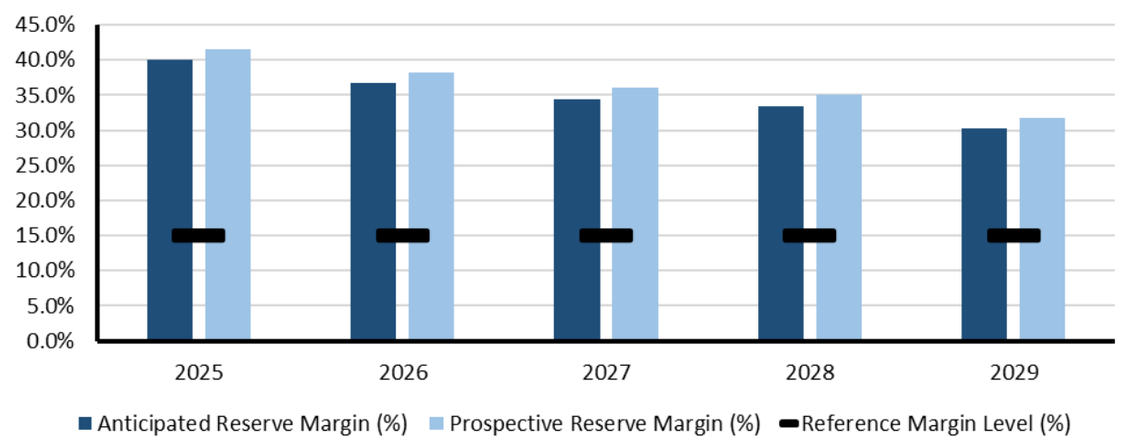


SERC-Southeast

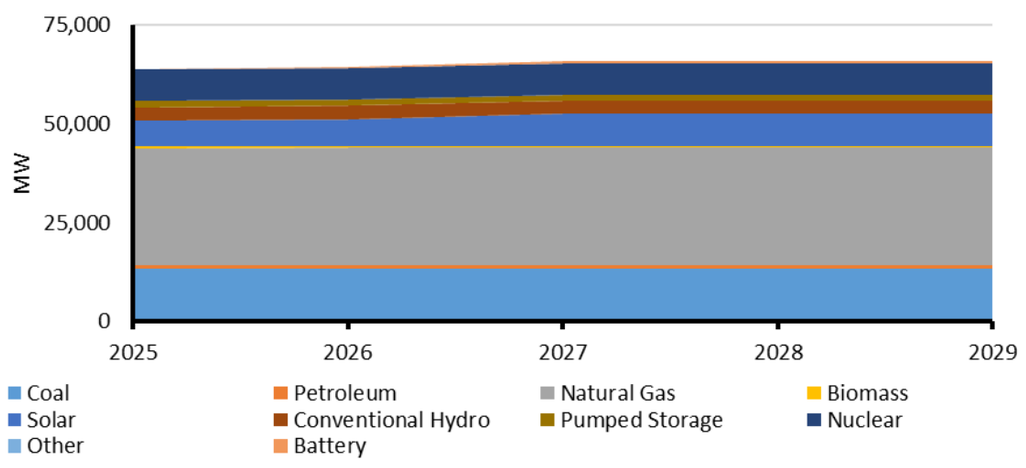
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	46,984	48,384	50,467	50,852	51,974	53,031	53,794	54,233	54,677	55,078
Demand Response	1,633	1,666	1,723	1,755	1,875	1,876	1,875	1,875	1,876	1,876
Net Internal Demand	45,351	46,718	48,744	49,097	50,099	51,155	51,919	52,358	52,801	53,202
Additions: Tier 1	1,248	1,486	3,050	3,050	3,050	3,129	3,129	3,129	3,129	3,129
Additions: Tier 2	105	105	218	218	218	218	218	218	218	218
Additions: Tier 3	366	366	366	366	366	366	366	366	366	366
Net Firm Capacity Transfers	-392	-392	-392	-392	-684	-684	-684	-684	-684	-684
Existing-Certain and Net Firm Transfers	62,257	62,413	62,472	62,472	62,180	62,180	62,180	62,180	62,180	62,180
Anticipated Reserve Margin (%)	40.0%	36.8%	34.4%	33.5%	30.2%	27.7%	25.8%	24.7%	23.7%	22.8%
Prospective Reserve Margin (%)	41.5%	38.2%	36.0%	35.0%	31.7%	29.2%	27.3%	26.2%	25.1%	24.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.

SERC-Southeast Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,275	13,275	13,275	13,275	13,275
Coal*	13,275	13,275	12,271	10,321	10,321
Petroleum	915	915	915	915	915
Petroleum*	915	915	915	899	899
Natural Gas	29,639	29,795	29,854	29,854	29,854
Natural Gas*	29,564	29,387	29,446	28,426	28,426
Biomass	424	424	424	424	424
Solar	6,597	6,835	8,021	8,021	8,021
Conventional Hydro	3,293	3,293	3,293	3,293	3,293
Pumped Storage	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018
Battery	105	105	483	483	483
Total MW	63,897	64,291	65,914	65,914	65,914
Total MW*	63,822	63,883	64,502	61,516	61,516
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Southeast Assessment

Planning Reserve Margins

The future reserve margins are above the RMLs for SERC-Southeast.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**0.00**	**0.00**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.00**	**0.00**
Operable On-Peak Margin	30.8%	**29.6%**	**25.6%**

* Provides the 2022 ProbA Results for Comparison

Demand

Data centers, cryptocurrency facilities, and large commercial and industrial load are driving demand forecast growth in the assessment area. Metro areas are experiencing a higher growth rate compared to rural areas.

Demand-Side Management

Entities within the SERC-Southeast assessment area use a variety of controllable and dispatchable DR programs to reduce peak demand. One entity manages a voluntary DSM water heater program designed to allow system operators to control the appliances' usage during peak demand periods. Another entity monitors and dispatches DR programs commensurate with contract terms. Annual ELCC simulations are performed to determine the capacity value for each unique and active DR program. An adjustment to that capacity value is then made based on predicted customer response when the program is called or dispatched.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation

Generator retirements are carefully managed by entities in the SERC-Southeast assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 1,078 miles of new transmission lines in the next 10 years. The entities are also planning to upgrade 694 miles of transmission lines during this time to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

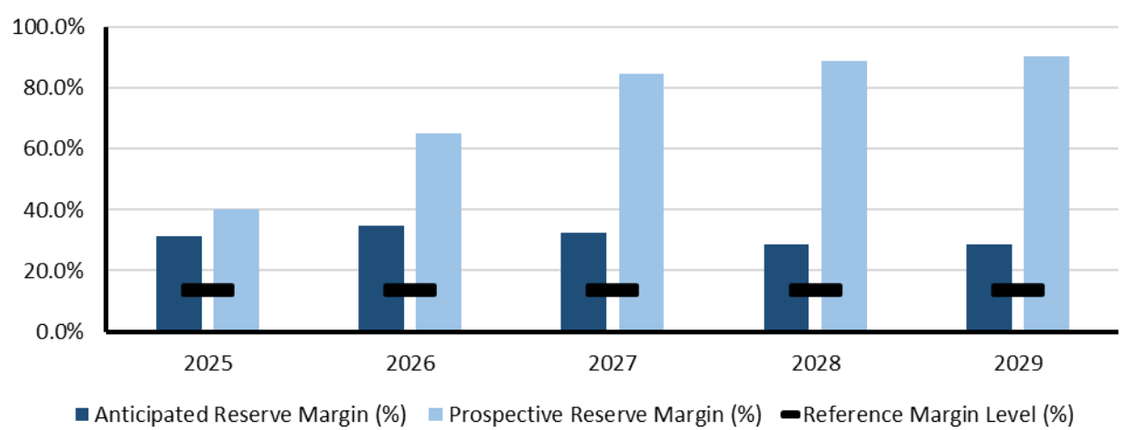


Texas RE-ERCOT

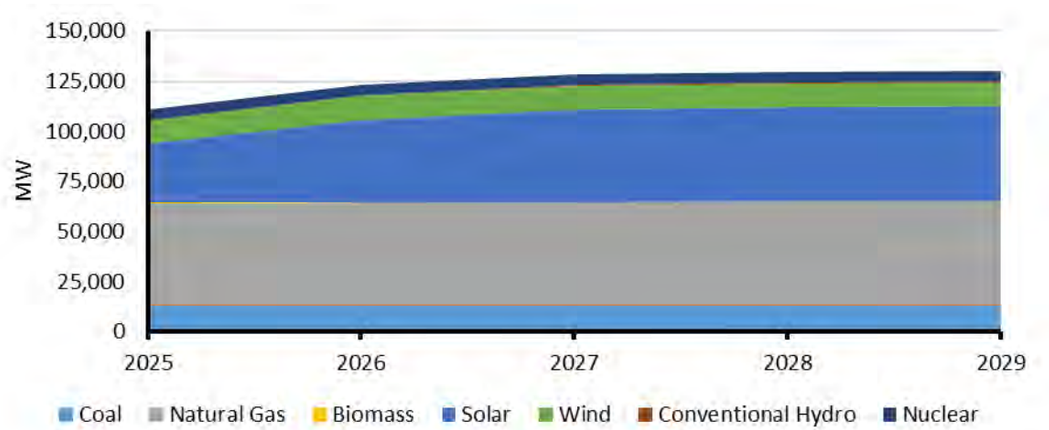
The Electric Reliability Council of Texas (ERCOT) is the ISO for the Texas Interconnection and is located entirely in the state of Texas; it operates as a single BAand performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million people. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	88,873	95,721	101,405	105,417	106,365	106,951	106,772	106,463	106,062	106,961
Demand Response	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652
Net Internal Demand	86,220	93,069	98,753	102,765	103,713	104,298	104,119	103,811	103,410	104,309
Additions: Tier 1	11,187	23,684	28,725	29,226	29,903	29,903	29,903	29,903	29,903	29,903
Additions: Tier 2	7,281	27,876	51,414	62,225	65,786	65,939	65,939	65,939	65,939	65,939
Additions: Tier 3	7,252	17,627	29,082	41,174	45,318	47,062	47,062	47,062	47,062	47,062
Net Firm Capacity Transfers	20	20	20	20	20	20	20	20	20	20
Existing-Certain and Net Firm Transfers	101,906	101,645	102,003	103,088	103,338	103,338	103,338	103,338	103,338	103,338
Anticipated Reserve Margin (%)	31.2%	34.7%	32.4%	28.8%	28.5%	27.8%	28.0%	28.3%	28.8%	27.7%
Prospective Reserve Margin (%)	40.3%	65.2%	84.6%	88.8%	90.3%	88.8%	89.1%	89.7%	90.4%	88.8%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Generation resources, primarily solar PV, continue to be added to the grid in Texas in large quantities, increasing ARMs but also elevating concerns of energy risks that result from the variability of these resources and the potential for delays in implementation. The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2025–2034). The ARM peaks at 34.7% by Summer 2026, reflecting the expected addition of about 23,680 MW of Tier 1 capacity, most of which is solar PV.

- The Public Utility Commission of Texas (PUCT) established a reliability standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude. ERCOT will begin performing reliability assessments required by the new standard in 2026.

- ERCOT's summer peak demand is forecast to increase by 4.6% per year from 2025 through 2029. In comparison, the five-year summer peak demand growth projection for the *2023 LTRA* was 1.1%. This high growth level is driven by a large amount of newly contracted loads planned for interconnection during this period. These contracted loads are mainly comprised of Permian Basin oil and gas production facilities, data centers, crypto-mining operations, and industrial facilities.

Texas RE-ERCOT Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	13,568	13,568	13,568	13,568	13,568
Coal*	13,568	13,568	12,913	12,353	12,353
Petroleum	10	10	10	10	10
Natural Gas	50,568	50,694	50,845	51,458	51,458
Natural Gas*	49,709	49,928	48,823	49,436	49,436
Biomass	163	163	163	163	163
Solar	29,557	41,201	45,984	46,485	47,163
Wind	11,332	11,908	12,166	12,166	12,166
Conventional Hydro	458	458	458	458	458
Nuclear	4,973	4,973	4,973	4,973	4,973
Total MW	110,628	122,975	128,167	129,281	129,958
Total MW*	109,769	122,208	125,490	126,044	126,721
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2025–2034). The ARM peaks at 34.7% by Summer 2026, reflecting the expected addition of about 23,680 MW of Tier 1 capacity, most of which is solar PV. However, the high reserve margin belies concerns over the continuing trend toward less fully dispatchable resources and more IBRs like solar PV and wind. While thermal resource availability and adequate gas supplies are still concerns during extreme winter weather events, the fleet performed well during Winter Storm Heather in January 2024, indicating that new weatherization standards, fully implemented in 2023, are effective.

Non-Peak Hour Risk and Energy Assurance

The PUCT established a reliability standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude. The latter two measures have an "exceedance tolerance," which is the maximum acceptable percentage frequency of loss-of load events that exceed the permissible thresholds based on a probabilistic simulation.

For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours—peaking at hour ending (HE) 9:00 p.m.—based on probabilistic modeling of monthly peak load days. The elevated risk is due to the drop-off in solar generation and continued higher loads during those hours. The summer peak load hour continues to be 5:00 p.m. For winter, the peak load hour is HE 8:00 a.m. Risk modeling indicates elevated reserve scarcity risk for the morning hours (HE 7:00 a.m. to 9:00 a.m.) as well as the early evening hours.

ERCOT is experiencing transmission limitations as a result of load growth and resource development that affect energy delivery. On March 1, 2024, ERCOT introduced four new Interconnection reliability operating limits (IROL) in the South Texas region. This consists of two South Texas import constraints and two South Texas export constraints, which, if violated, could result in a thermal cascading condition. This is the first thermal IROL that could lead to a cascading condition in the Texas RE-ERCOT Region and has been attributed to the increase in generation capacity in South Texas and the rapid load growth in central Texas. To manage the South Texas export constraint, generation in South Texas must be curtailed to maintain transmission line flows below 100% of the impacted lines' thermal ratings. The risk of such curtailments, which is highest for the hours with the highest net peak loads (early evening), is included in the monthly probabilistic reserve risk assessments. ERCOT has approved two San Antonio Reliability projects that are expected to be completed in 2027 and should help alleviate some of risk drivers associated with these IROLs.

Probabilistic Assessment

Results of the 2024 ProbA are shown in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,235	**11,090**	**781**
EUE (PPM)	2.63	**18.95**	**1.12**
LOLH (hours per year)	0.30	**1.57**	**0.16**
Operable On-Peak Margin	35.9%	**28.8%**	**46.9%**

* Provides the 2022 ProbA Results for Comparison

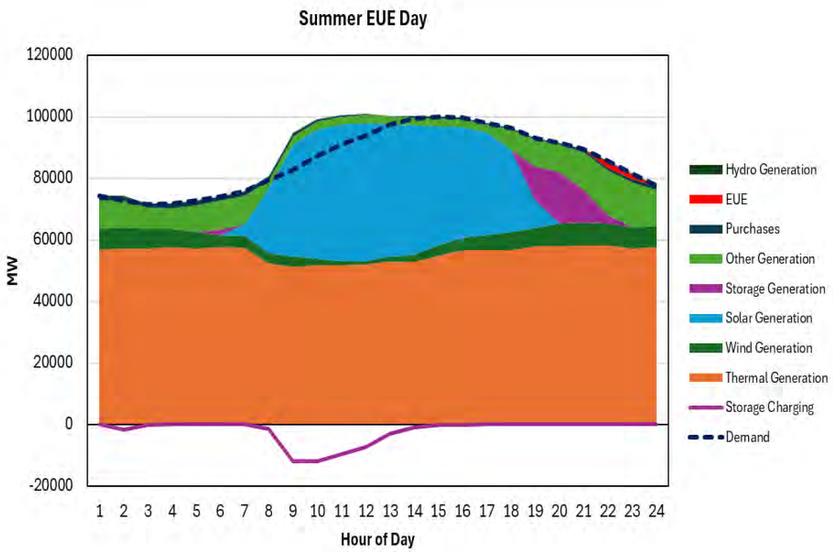
Increasing reliability risk in ERCOT is primarily driven by increasing large load demand anticipated from data centers, Bitcoin operations, continued load growth in oil and gas-producing areas (such as the Permian Basin), and growth in industrial facilities. Over 20 GW of newly contracted large loads, in addition to other organic load growth, is projected to be added to ERCOT by 2028. ERCOT also anticipates 1,860 MW of fossil-fueled plant capacity to be retired by Summer 2028. New planned units are primarily renewable and storage, which exhibit declining marginal reliability contributions. The reliability forecasts provided by this ProbA assessment for 2028 include resource capacity contributions from expansion planning analysis conducted for ERCOT's 2024 *Long-Term System Assessment*. While there is uncertainty around the deployment of these resources, the large load demand growth is also uncertain and large loads are subject to various requirements for being integrated into the grid.

All SERVM simulations for ERCOT and surrounding regions impose all relevant generator temporal constraints, including operating limitations on conventional units as well as state-of-charge on batteries, so this assessment accounts for energy adequacy. However, this assessment does assume fuel for conventional units will be available when needed.[37]

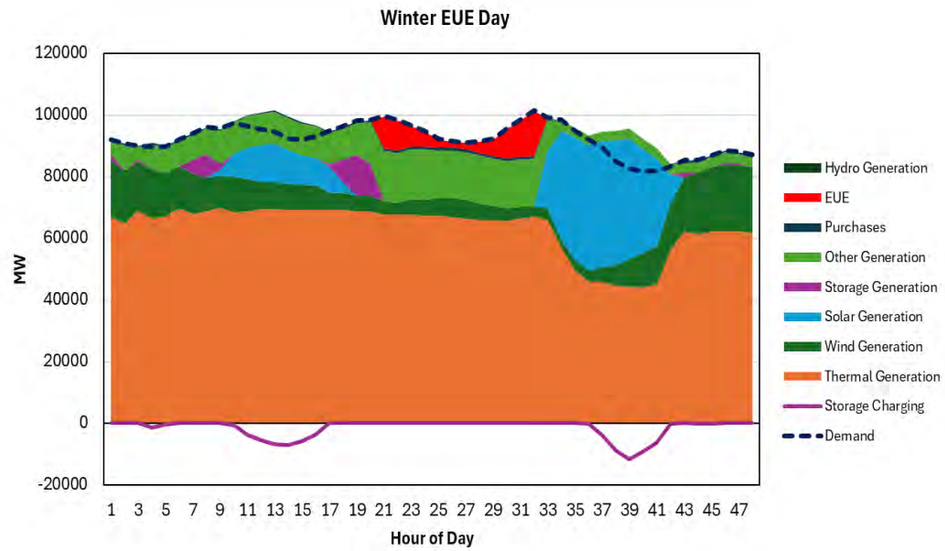
The unique characteristics of winter risk vs. summer risk can be seen in the following charts of a representative risk day. While peak winter loads can persist for 48 hours or longer, peak summer

[37] ERCOT and several other entities used SERVM software tool to perform the ProbA. Information about SERVM can be found at the company's website.

periods generally only last for a few hours. This has significant implications for the duration and depth of firm load-shed events in the winter as well as for the reliability contribution of energy limited and non-dispatchable resources. The most extreme winter event modeled for 2026 was 16 hours in duration and 29 GW in depth. The illustration below indicates a winter EUE event with duration >12 hours while most summer events were 1–2 hours in duration.



Metric	2026 Summer	2026 Winter	2028 Summer	2028 Winter
LOLE (days/year)	0.38	0.51	0.05	0.04
LOLH (hours/year)	1.41	1.57	0.18	0.16
EUE (MWh)	10,985	11,090	857	781
Max Hourly EUE (MWh)	29,124	29,266	17,762	16,851
Max EUE Duration (Hr)	15	16	12	11



From the hourly event data, ERCOT provided a multi-metric summary of the largest event showing the highest magnitude and longest-duration, as shown in the following figure.

Demand

ERCOT's long-term load forecast consists of the following individual components: (1) a base forecast that uses an econometric model with estimation data comprising 15 historical weather years, economic drivers, calendar information, and historical loads, (2) a roof-top PV forecast, (3) an EV forecast, a large flexible load forecast (crypto-mining facilities), and new "large loads" with a signed interconnection contract with their transmission or distribution service provider. Forecasts are provided for eight weather zones as well as system coincidental and non-coincidental demands. ERCOT's summer peak demand is forecast to increase by 4.6% per year from 2025 through 2029. In

comparison, the five-year summer peak demand growth projection for the *2023 LTRA* was 1.1%. This high growth level is driven by a large amount of newly contracted loads planned for interconnection during this period. These contracted loads are mainly comprised of Permian Basin oil and gas production facilities, data centers, crypto-mining operations, and industrial facilities. (A negligible amount of new contracted loads reported by transmission service providers occur past 2029). The base peak load, which excludes these new contracted loads as well as load reductions due to rooftop solar installations, grows at a more modest 1.4%.

A major load forecasting change from last year is a new Texas Legislature requirement to include non-contracted loads in transmission planning studies. Non-contracted loads lack a signed Interconnection or facility expansion agreement. ERCOT's previous practice had been to exclude these more speculative loads from the load forecast. The non-contracted loads total about 3.6 GW for summer 2025 and reach about 31.7 GW by 2029. The non-contracted loads are not included in the LTRA's peak load forecast. ERCOT is evaluating how these non-contracted forecasted loads will be handled for future resource adequacy and other planning activities.

Demand-Side Management

Most of the demand-side resources available to ERCOT are dispatchable in the form of noncontrollable load resources providing responsive reserve service and ERCOT's Emergency Response Service. The ERCOT Emergency Response Service consists of 10- and 30-minute ramping DRs and distributed generation that can first be deployed when physical responsive reserves drop to 3,000 MW and are not projected to be recovered above 3,000 MW within 30 minutes following the deployment of non-spin reserves. Responsive reserve is provided by industrial loads and is procured on an hourly basis in the day-ahead market. During 2023, load resources started to participate in two other ancillary services, the Non-Spinning Reserve Service and ERCOT Contingency Reserve Service (ECRS), which are used to help balance the system during periods when there may be net-load ramps that cannot be met with conventional supply-side resources.

The remaining dispatchable DR available to ERCOT is from the transmission and distribution service providers' (TDSP) load management programs. These programs provide price incentives for voluntary load reductions from commercial, industrial, and residential loads during energy emergency alert events.

Distributed Energy Resources

DERs that register with ERCOT to participate in wholesale energy and/or ancillary services markets are modeled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources participating in those markets. For DERs not participating in those markets, ERCOT relies on member TDSPs to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year timeframe.

A bill was approved in the 88th Texas Legislature (HB 3390) that outlines new DER reporting responsibilities. The bill authorizes ERCOT to require TDSPs to provide unregistered DER information that ERCOT deems necessary for grid reliability assessment. ERCOT is now developing annual data collection and maintenance processes.

A multi-phase aggregated DER (ADER) pilot program was implemented in 2022. As of May 2024, there were two ADERs with 13 MW of dispatchable capability actively participating in the pilot project with another nine ADERs in various stages of registration/qualification.

Generation

Natural-gas-fired generation makes up approximately 45% of the available generation inside the ERCOT footprint. Approximately 6% of the natural-gas-fired generation demonstrates firm fuel capabilities as part of ERCOT's Firm Fuel Supply Service required by the PUCT.

ERCOT has established formal working relationships with grid generators' fuel suppliers to gather operational and delivery information useful for its control room operators. ERCOT has focused the efforts on two fronts: (1) obtaining real-time (or near real-time) information on the health of the natural gas systems that serve the generators and (2) maintaining communication with pipelines to notify ERCOT of any planned or unplanned events that could impact deliveries to generators.

After the 2021 Odessa event, ERCOT intensified its efforts to find corrective measures to enhance the ride-through performance of IBRs and improve overall system resilience. The study, which recommended installing synchronous condensers at six locations in West Texas, has been completed, and the ERCOT board of directors endorsed the project in December 2023. The project is expected to be in service in 2027.

ERCOT has proposed new grid code requirements for IBRs to improve voltage ride-through (VRT) performance to align with IEEE Standard 2800. The proposed grid code requirements are continuing to go through ERCOT's stakeholder approval process. Until new rules go into effect, IBRs will be expected to maximize VRT capability and address existing performance failures (such as by reducing maximum output).

To provide an incentive to build new dispatchable resources, the PUCT adopted a new rule to establish a generation loan program, one of four incentive programs under the recently established Texas Energy Fund (TEF). The other three programs within the TEF include completion bonus grants for new dispatchable generation projects that consistently provide power generation over a 10-year period, grants for companies to establish or secure backup power resources, and grants to improve the resiliency and availability of electric utility service outside the ERCOT region. The TEF has $5 billion

available for all four programs. These loans and grants have thus far resulted in 72 applications seeking funding under the TEF loan program. The PUCT staff-recommended portfolio represents 9,781 MW in potential new generation if all recommended applicants were to execute a loan agreement at the requested loan amounts.

Energy Storage

The current installed BESS capacity is 9,149 MW. These systems participate in ERCOT's Energy and Ancillary Service markets. Most have durations in the one-to-two-hour range. ERCOT is seeing an increase in longer-duration systems (three to four hours) to take advantage of energy-shifting and capacity-firming opportunities arising from continued high renewable generation penetration. For the first half of 2024, energy storage provided 87% of ERCOT's regulation up and 91% of responsive reserve service from primary frequency response (RRS-PFR). In June 2023, ERCOT implemented a new ancillary service, the ERCOT Contingency Reserve Service (ECRS), which, in part, is designed to address the ramping needs of the system. This ancillary service product provides additional opportunities for BESS ancillary service participation. To support larger BESS penetration levels, ERCOT submitted new proposed rules for state-of-charge accounting in energy dispatch and reliability unit commitment that are planned for implementation this year.

Based on the latest developer information for projects that are in the interconnection queue, ERCOT expects about 10,500 MW of additional battery energy storage capacity to be operational by year-end 2025. This capacity constitutes projects for which developers have posted financial security to build the interconnection facilities. By year-end 2029, the additional cumulative Tier 1 planned capacity reaches about 20,000 MW.

ERCOT currently assigns a 0% on-peak contribution for battery energy storage. ERCOT has changed its rule to adopt an ELCC methodology for battery storage of various durations. Extending the proposed ELCC methodology for BESS to current and forecasted resources in ERCOT would improve the anticipated reserve margins in the future.

Capacity Transfers

ERCOT has coordination plans in place with neighboring grids. These plans cover dc tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers.

Transmission

In September, the PUCT approved ERCOT's Permian Basin Reliability Plan. The plan consists of new and upgraded local transmission projects as well as building new import paths to load centers in other areas of the Texas RE-ERCOT region, including options for extra high voltage (EHV) infrastructure operating at 345 kW or 765 kV. The plan supports Permian Basin load growth that is currently expected to reach 24 GW by 2030 and over 26 GW by 2038.

ERCOT's 2023 Regional Transmission Plan (RTP) identified 173 reliability projects, with the majority consisting of 138 kV and 345 kV system upgrades. The 2023 RTP also included an economic assessment of the ERCOT transmission system for years 2025 and 2028 using production cost savings and generator revenue reduction tests.

The substantial increase in new loads from a year ago is expected to present challenges for transmission planning. The forecasted pace of the load growth could exceed the pace at which transmission capacity can be built to support it. ERCOT is working on major changes to its transmission planning process to address these challenges. For example, ERCOT is investigating a "generation hub" concept to indicate optimal generation location to address regional load growth and optimize transmission investments.

A new biennial report on grid resiliency—the Grid Reliability and Resiliency Assessment—evaluates extreme weather scenarios considering different levels of thermal and renewable generation availability and the potential outages caused by extreme weather conditions. The assessment also includes proposed transmission projects that may mitigate regional resiliency risks. The first report will be released by December 31, 2024.

New minimum deliverability criteria were included in ERCOT's 2023 RTP to ensure the deliverability of 100% of generation resource capacity and energy storage resources with a duration greater than or equal to two hours. For storage systems with a duration less than two hours, a prorated deliverability was ensured. Corrective action plans (CAP) were proposed to address any reliability violations under the contingencies defined for the minimum deliverability criteria.

ERCOT has also started implementing the PUCT's amended rules relating to certification criteria and is in the process of integrating a new congestion cost savings test for economic projects evaluation.

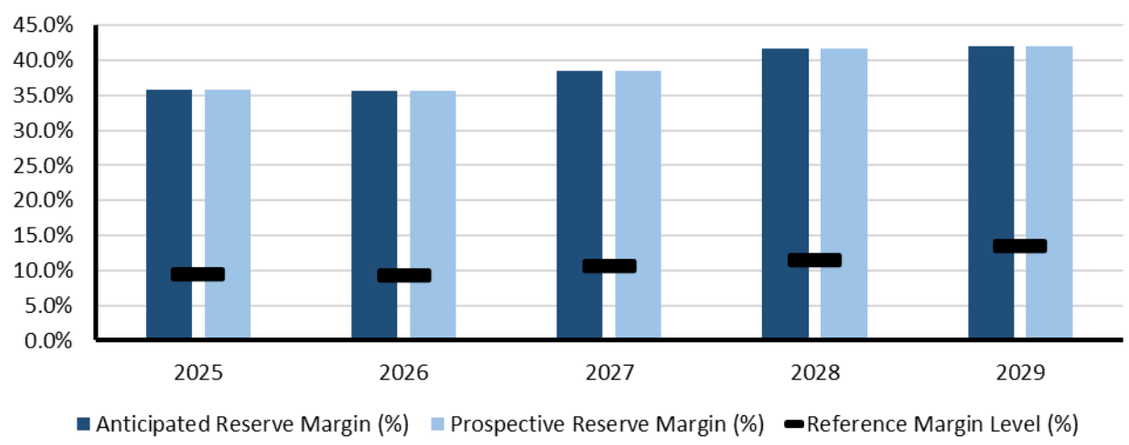


WECC-AB

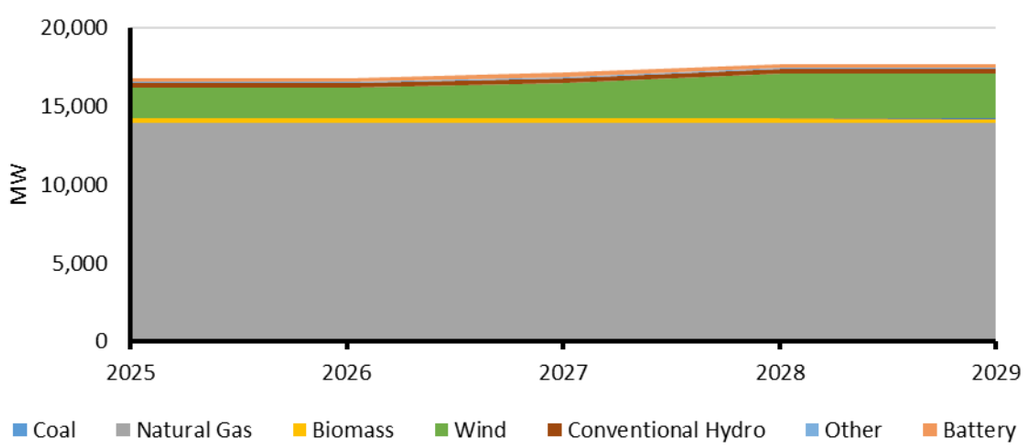
WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and BC in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	12,411	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,411	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076
Additions: Tier 1	3,275	3,275	3,405	3,541	3,537	3,342	3,537	3,441	3,273	3,273
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	1,031	1,680	1,824	2,247	2,700	2,502	3,068	3,096	2,744	2,744
Net Firm Capacity Transfers	43	96	69	0	68	396	409	0	0	0
Existing-Certain and Net Firm Transfers	13,578	13,631	13,822	14,182	14,244	13,931	14,585	13,867	13,330	13,330
Anticipated Reserve Margin (%)	35.8%	35.6%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
Prospective Reserve Margin (%)	35.8%	35.6%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
Reference Margin Level (%)	9.4%	9.4%	10.6%	11.5%	13.6%	9.2%	13.2%	11.3%	9.0%	9.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML during the 2024–2034 timeframe.
- The peak hour of demand for Alberta occurs in the winter. The peak hour for total internal demand is expected to grow from about 12.3 GW in 2024 to 13.1 GW in 2034, a 6.5% load growth over the forecast horizon. The average year-to-year growth rate is 0.62%. There is a slight increase in the load forecast for this year's LTRA versus last year's.
- Despite low resource adequacy risk, operational risk is still present. Ensuring sufficient frequency response capability has been identified as the region's highest priority. Frequency response has been declining in the region due to the increasing share of IBR resources and declining baseload resources. This under frequency load shedding risk is exacerbated in islanded or near-islanded situations.
- Alberta's two remaining coal-fired generators completed their conversion to natural gas this year.

WECC-AB Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Natural Gas	13,932	13,932	13,941	13,930	13,920
Biomass	336	336	336	336	336
Wind	1,912	1,912	2,232	2,811	2,799
Conventional Hydro	285	285	303	302	312
Other	81	81	81	81	81
Battery	264	264	264	264	263
Total MW	16,810	16,810	17,157	17,723	17,713

WECC-AB Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2024–2034 timeframe. From the 2032–2033 winter onward, Alberta shows a shortfall of existing-certain and net firm transfers. This indicates that imports may be necessary during this timeframe if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the one-day-in-ten-year (ODITY) level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

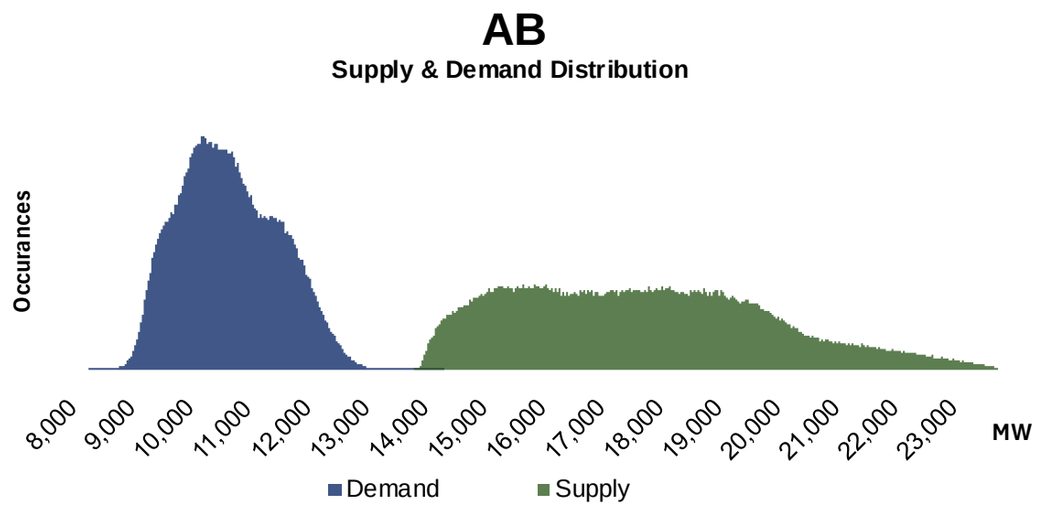
Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0	0	0
EUE (PPM)	0	0	0
LOLH (hours per year)	0	0	0
Operable On-Peak Margin	26.1%	41.6%	42.4%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the Multi-Area Variable Resource Integration Convolution (MAVRIC) model. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment. WECC also produces an annual reliability assessment called the *Western Assessment of Resource Adequacy* (WARA).[38]

The availability and demand distributions in the ProbA simulations do not overlap, indicating an extremely low probability of Alberta not being resource adequate over the next four years. For 2026 and 2028, the peak hour occurs in December at HE 18:00. Alberta does not show LOLH nor EUE in the LTRA forecast horizon. The gap between the demand distribution and the supply distribution shown in the figure below emphasizes that there is minimal resource adequacy risk in Alberta. The ARM appears to further validate this, as it is far above the RML for 2026 and 2028.



Demand

Peak demand for Alberta occurs in the winter. The peak hour for total internal demand is expected to grow from about 12.3 GW in 2024 to 13.1 GW in 2034, a 6.5% load growth over the forecast horizon. The average year-to-year growth rate is 0.62%. There is a slight increase in the load forecast for this year's LTRA versus last year's. Near-term load growth is driven by industrial loads, such as oil sands production, pulp and paper mills, and gas and oil processing. Long-term demand growth is driven by electrification of transportation and buildings as well as potential growth in emerging industries, such as hydrogen production.

[38] See WECC Reliability Assessments.

Distributed Energy Resources
BTM DERs are difficult to measure due to data gathering barriers. AESO released its updated 2022 Plan for DER Roadmap Integration Activities.

Generation
Over 6 GW of nameplate capacity are being added in Alberta through the end of 2028. There is significantly more solar, wind, and energy storage in this year's planned capacity additions than in the last LTRA. Additionally, several states and provinces in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions. Alberta's two remaining coal units have been converted to natural gas this year.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
In WECC's analysis, Alberta is not showing significant changes to capacity transfers. There is a slight increase in exports between 5:00 p.m. and 10:00 p.m. and in the later years of the assessment period.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

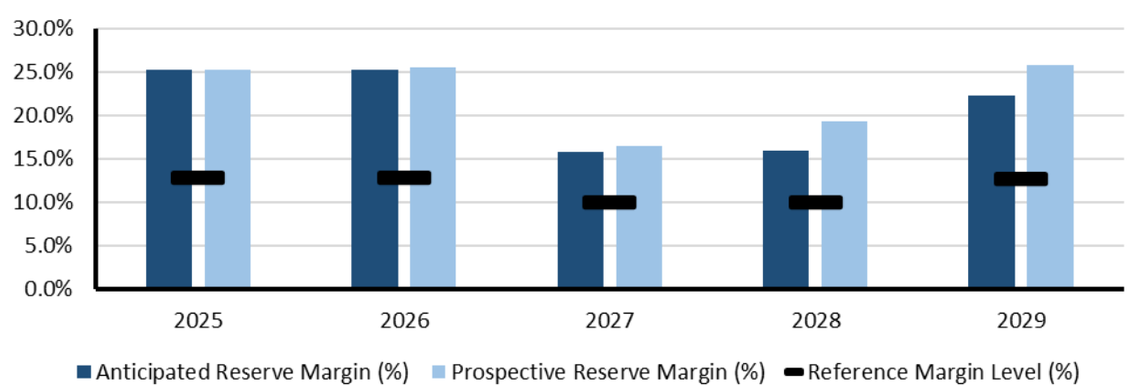


WECC-BC

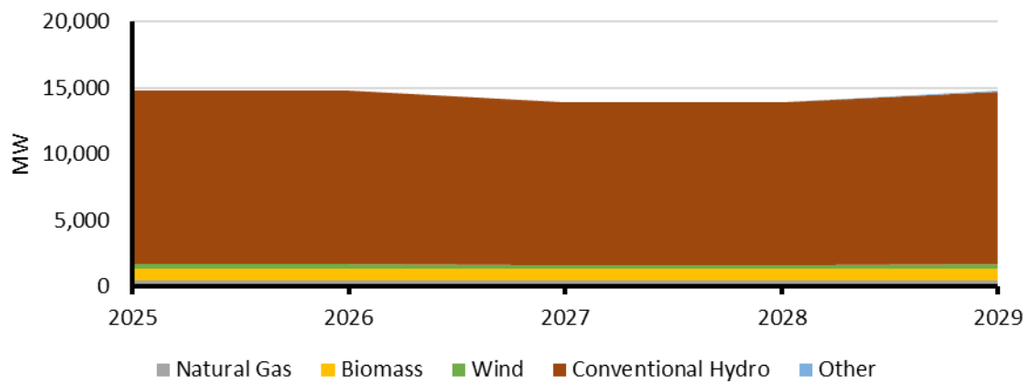
WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of BC, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and BC in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	11,986	11,959	12,015	11,983	12,075	12,082	12,130	12,174	12,237	12,305
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,986	11,959	12,015	11,983	12,075	12,082	12,130	12,174	12,237	12,305
Additions: Tier 1	956	956	893	893	956	956	956	956	893	956
Additions: Tier 2	0	41	79	398	419	748	1,077	1,077	1,012	1,405
Additions: Tier 3	0	5	5	5	6	6	59	59	56	59
Net Firm Capacity Transfers	184	188	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	14,054	14,022	13,019	12,998	13,812	13,795	13,795	13,795	12,982	13,795
Anticipated Reserve Margin (%)	25.2%	25.2%	15.8%	15.9%	22.3%	22.1%	21.6%	21.2%	13.4%	19.9%
Prospective Reserve Margin (%)	25.2%	25.6%	16.5%	19.2%	25.8%	28.3%	30.5%	30.0%	21.7%	31.3%
Reference Margin Level (%)	12.8%	12.8%	10.0%	10.0%	12.7%	12.7%	12.6%	12.6%	9.8%	12.5%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML during the 2024–2034 timeframe.
- BC shows a shortfall of existing-certain and net firm transfers for the 2027–2028 winter and the 2028–2029 winter. Shortfalls are also projected from the winter of 2033–2034 onward. This indicates that imports may be necessary during these periods if new resources were to be significantly delayed.
- The peak hour of demand for BC occurs in the winter. BC shows the lowest demand growth rate in the west. The peak demand is expected to grow from about 12.0 GW in 2024 to 12.3 GW in 2034, slightly less than in the previous LTRA forecast. This is an average annual growth rate of 0.28%, and a 2.8% load growth over the forecast horizon.
- BC is showing hours of demand at risk that are not fully mitigated by the addition of Tier 3 resources. Supply chain performance will play a significant role in BC's ability to reliably meet energy needs. Seasonal and daily fluctuations of hydro resource availability is also a risk. LOLH and EUE correlate with periods when river flows are at their lowest.

WECC-BC Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Natural Gas	459	459	456	456	459
Biomass	920	920	914	914	920
Wind	279	279	268	268	279
Conventional Hydro	13,145	13,110	12,253	12,232	13,087
Other	22	22	22	22	22
Total MW	14,825	14,790	13,912	13,891	14,768

WECC-BC Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2024–2034 timeframe. BC shows a shortfall of existing-certain and net firm transfers for the 2027–2028 winter and the 2028–2029 winter. Shortfalls are also projected from winter of 2033–2034 onward. This indicates that imports may be necessary during these periods if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk in 2026. In 2028, however, WECC's analysis identified over five hours where resources, including imports from neighbors, fall below margins for system reliability.

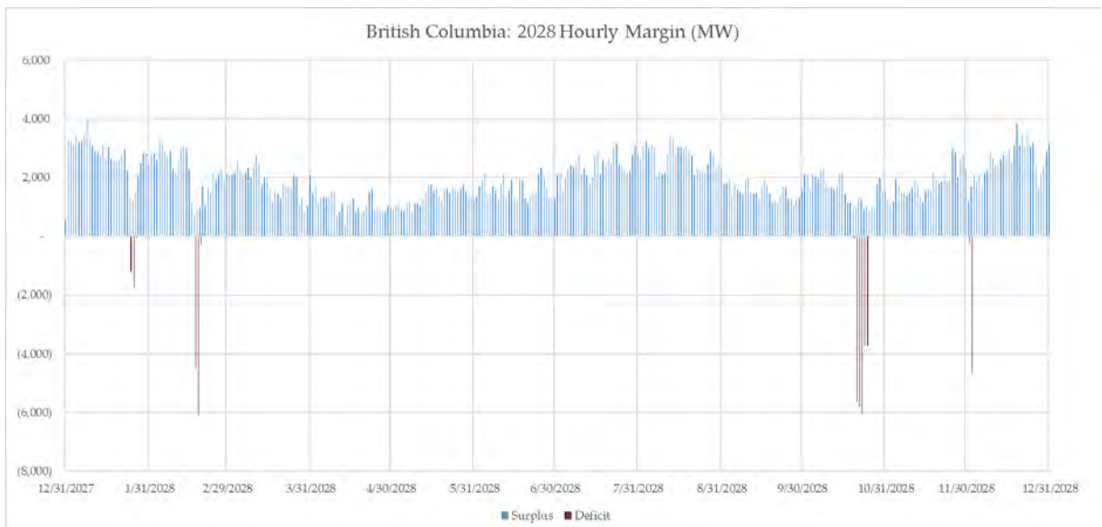
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	24	0	103,132
EUE (PPM)	0.71	0	1,457
LOLH (hours per year)	0.002	0	5.52
Operable On-Peak Margin	12.7%	16.9%	9.4%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

For both 2026 and 2028, the peak hour occurs in December at HE 19:00. LOLH and EUE are not forecast in 2026 but do appear in 2028. No LOLH or EUE occurs at the peak hour. 88% of the EUE in 2028 occurs overnight between the hours of 23:00 and 4:00.

In 2026, the peak summer hour is HE 17:00 in September, and in 2028 the peak hour is HE 17:00 in August. There is no LOLH projected for 2026 or during peak hours. LOLH occurs in 2028 between the hours of 17:00 and 20:00.



Icicle Plot with Hourly Surplus and Deficits for British Columbia in 2028

WECC's interconnection-wide analysis simulates the probabilistic performance of resource types using historic hourly output data to identify future risk periods. Operators of systems with large hydroelectric storage facilities make adjustments to generation based on the level of demand and shape the water use within the day, week, month, or between years. These actions help posture hydroelectric generation for expected conditions and can reduce energy shortfall risks.

	1	2	3	4	5	6	7	8	9	10	11	12
0	(0)	(5)	-	-	-	-	-	-	-	(10)	-	-
1	(1)	(5)	-	-	-	-	-	-	-	(12)	-	-
2	(1)	(6)	-	-	-	-	-	-	-	(20)	-	-
3	(3)	(5)	-	-	-	-	-	-	-	(14)	(0)	-
4	(0)	(1)	-	-	-	-	-	-	-	(0)	(0)	-
5	-	(0)	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	(0)	-	-
8	-	(0)	-	-	-	-	-	-	-	(0)	-	(0)
9	(0)	(0)	-	-	-	-	-	-	-	-	-	(0)
10	-	(0)	-	-	-	-	-	-	-	-	-	(0)
11	-	-	-	-	-	-	-	-	-	-	-	(1)
12	-	-	-	-	-	-	-	-	-	-	-	(3)
13	-	(0)	-	-	-	-	-	-	-	-	-	(5)
14	-	-	-	-	-	-	-	-	-	-	-	(1)
15	-	(0)	-	-	-	-	-	-	-	-	-	(0)
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-	-	-	-
20	-	(0)	-	-	-	-	-	-	-	-	-	-
21	-	(0)	-	-	-	-	-	-	-	-	-	-
22	-	(0)	-	-	-	-	-	-	-	(0)	-	(0)
23	-	(2)	-	-	-	-	-	-	-	(5)	-	-

2028 Heat Map EUE (GW) - British Columbia

Demand

BC's average annual load growth in its forecast has fallen to a rate below Alberta's. The peak hour total internal demand for BC occurs in the winter. The peak demand is expected to grow from about 12.0 GW in 2024 to 12.3 GW in 2034, slightly less than in the last forecast. This is an average annual growth rate of 0.28% and a 2.8% load growth over the forecast horizon. BC's load growth is lower due to updated monthly profiles that reflect current trends and aggressive DSM which it includes as a demand reduction in the demand forecasts provided to WECC. Load growth in BC is primarily driven by EV and gas sector load growth and is partially offset by a decline in demand from the forestry sector.

Distributed Energy Resources

BTM DERs are difficult to measure due to data-gathering barriers. BC Hydro has net metering. Net metering for residential and commercial customer projects are up to 100 kW. The net metering program has no annual energy volume target.

Generation

Across WECC, several states and provinces as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

In BC, hydro and wind resources are being added to the system. The BC Hydro Authority (BCHA) is taking steps to mitigate risks associated with climate change by improving coastal watershed inflow forecasting to an hourly level and increasing investment in capital projects to increase the resiliency of its hydro-dominant portfolio. Drought conditions in BC have led to water conservation measures, such as encouraging generation at facilities located in less drought-impacted areas, revising discharge plans at storage capable sites, and importing power when available to reduce water consumption.

Capacity Transfers

WECC's probabilistic analysis indicates that BC's need for imports is increasing during the assessment period.

Transmission

Three transmission projects with voltage design of 500 kV and higher are planned in the BC region.

Reliability Issues

WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

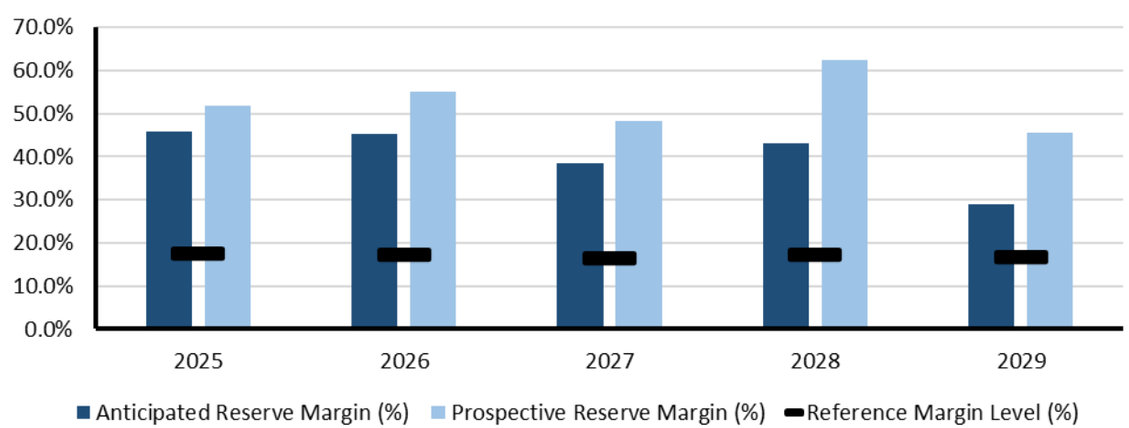


WECC-CA / MX

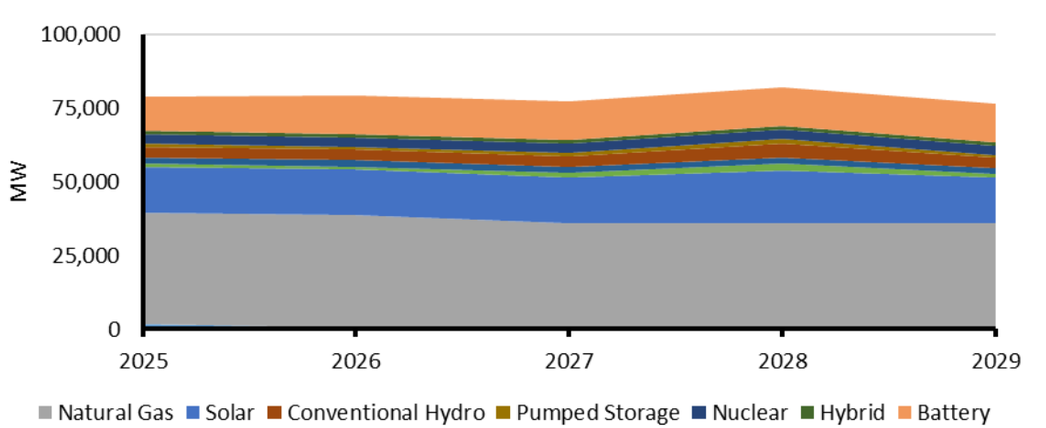
WECC-CA/MX (California/Mexico) is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	56,619	57,274	59,291	60,131	61,289	61,067	62,336	65,876	67,251	69,064
Demand Response	795	797	793	793	793	794	794	794	794	794
Net Internal Demand	55,824	56,477	58,499	59,338	60,496	60,273	61,542	65,082	66,457	68,269
Additions: Tier 1	9,700	11,074	11,128	11,546	11,074	11,990	11,990	12,437	12,047	11,990
Additions: Tier 2	3,349	5,628	5,727	11,483	10,121	17,017	17,017	22,135	23,212	24,650
Additions: Tier 3	9	19	19	22	19	321	321	326	322	321
Net Firm Capacity Transfers	1,509	1,828	2,760	1,953	448	357	342	898	317	314
Existing-Certain and Net Firm Transfers	71,707	70,921	69,827	73,373	66,866	66,142	63,916	68,939	64,533	63,888
Anticipated Reserve Margin (%)	45.8%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
Prospective Reserve Margin (%)	51.8%	55.1%	48.2%	62.5%	45.6%	57.9%	51.0%	59.0%	50.2%	47.3%
Reference Margin Level (%)	17.4%	17.4%	16.4%	17.4%	16.6%	16.4%	16.1%	16.3%	14.9%	15.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML in Summer 2034, but the RML is covered by the PRM, which includes Tier 2 resource additions.
- Starting in Summer 2029 onward, CA/MX shows a shortfall of existing-certain and net firm transfers. However, with planned generation resource additions the shortfalls are eliminated. Imports may be necessary if the new resources were to be significantly delayed. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 2 resources and primarily correspond with the evening down ramp of solar and lingering demand after peak.
- The peak hour of demand for CA/MX occurs in the summer. Total internal demand at peak hour is expected to grow from about 56.4 GW in 2024 to 69.1 GW in 2034, a 22.5% load growth over the forecast horizon. The average annual growth rate is 2.07%.
- Diablo Canyon, a 2.2 GW nuclear site, will no longer be retired by 2025 and is now slated to be retired in 2030.

WECC-CA/MX Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	1,572	466	466	465	466
Coal*	1,122	16	16	15	16
Petroleum	185	185	185	184	185
Natural Gas	38,180	38,180	35,565	35,504	35,506
Biomass	726	726	727	726	726
Solar	15,464	15,464	15,501	17,990	15,464
Wind	1,158	1,158	1,428	2,144	1,158
Geothermal	2,004	2,059	2,061	2,056	2,059
Conventional Hydro	3,582	3,582	3,838	4,727	3,582
Pumped Storage	889	889	951	1,710	889
Nuclear	3,282	3,282	3,287	3,283	3,282
Hybrid	32	32	34	39	32
Other	32	32	32	32	32
Battery	12,792	14,111	14,119	14,106	14,111
Total MW	79,898	80,166	78,194	82,967	77,492
Total MW*	79,448	79,716	77,744	82,517	77,042
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

The ARM falls below the RML in the summer of 2034. With the addition of Tier 2 resources, reserve margins remain above RML. Starting in Summer 2029 onward, CA/MX shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

The California Independent System Operator (CAISO) is responsible for much of the BPS that is in CA/MX. CAISO manages the transmission system, oversees transmission planning, and operates the wholesale electricity market for its territory. Other entities in CA/MX include the Balancing Authority of Northern California (BANC), the Imperial Irrigation District (IID), and Mexico's National Center for Energy Control (CENACE), which operates the connected Baja California system.

CAISO Only: The ARM falling below the RML in Summer 2034 and the shortfall of existing-certain and net firm transfers in Summer 2029 is consistent when looking at CA/MX or solely at CAISO. The RML of CAISO averages 0.7% higher than the CA/MX region RML over the LTRA horizon. This is due to the exclusion of natural gas and coal resource energy contributions from CA/MX entities outside of CAISO. Decreasing baseload generators results in increased variability, which in turn requires a greater RML to maintain the ODITY threshold. However, the gap between the anticipated, prospective, and existing reserve margins and the RML for CAISO are greater than the broader CA/MX region. The proportion of energy availability to anticipated net internal demand is larger for CAISO, accounting for this increase.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk in 2026. After 2026, however, WECC's analysis identified periods of unserved energy and load loss in CA/MX during June through October. Of note, this risk is limited to the Mexico portion of CA/MX (i.e., ProbA results for the CAISO do not indicate LOLH or EUE) until 2029, when the risk extends across the entire assessment area.

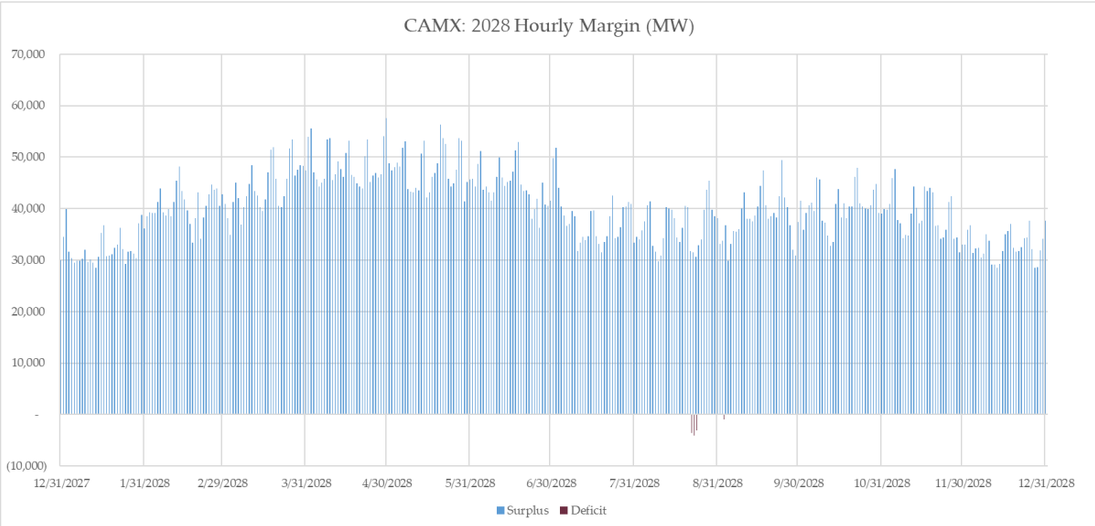
Base Case Summary of Results

	2026*	2026	2028
EUE (MWh)	37,305	0	19,662
EUE (PPM)	136	0	70.07
LOLH (hours per year)	0.721	0	0.38
Operable On-Peak Margin	30.7%	43.2%	41.2%

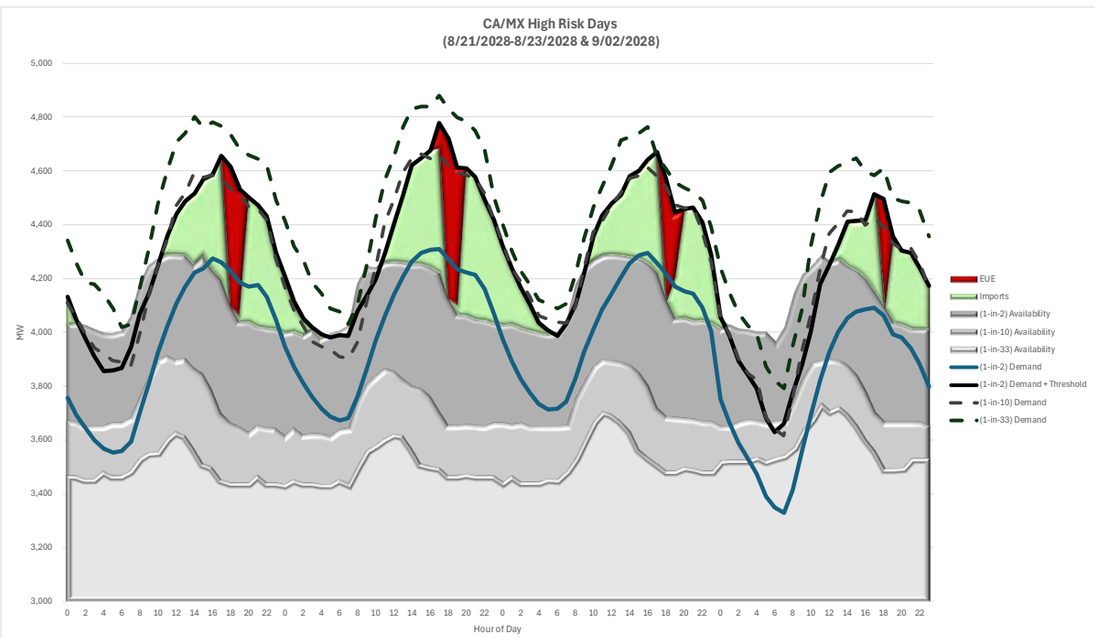
* Provides the 2022 ProbA Results for Comparison

Though the hour and month of peak demand are the same for both CAISO and the broader CA/MX region, CAISO shows the greatest amount of EUE and LOLH in September, whereas CA/MX shows the greatest amount of EUE and LOLH in August. This coincides with the seasonal reduction of solar irradiance in the fall and CAISO having a proportionally larger share of solar resources than the CA/MX region. Excluding regions external to CAISO results in a 96% reduction in LOLH events and EUE over the LTRA horizon.

The hour of peak demand in summer occurs at 5:00 p.m. The hours of highest risk, however, occur during periods after the peak demand hour as solar PV resource output diminishes. There is no LOLH projected for 2026; however in 2028, the ProbA reveals some LOLH between the hours of 5:00 and 8:00 p.m.



Icicle Plot with Hourly Surplus and Deficits for CA/MX in 2028



Demand

The peak demand for CA/MX occurs in the summer. The peak hour for total internal demand is expected to grow from about 56.4 GW in 2024 to 69.1 GW in 2034, a 22.5% load growth over the forecast horizon. The average annual growth rate is 2.07%. Transportation and building electrification are the primary drivers of demand growth.

CAISO Only: The demand forecast for CAISO grows at a slightly higher rate than the broader CA/MX region, with a load growth of 25.2% over the LTRA forecast horizon, and an average annual rate of 2.1%.

Demand-Side Management

A portion of the near-term decline in controllable and dispatchable DR for Summer 2024 is partly driven by regulatory changes in the CA/MX region. This includes making resource adequacy DR crediting adjustments based on historical performance and increasing DR availability requirements. The California Public Utilities Commission (CPUC) determined resource adequacy values of utility DR were overestimated during high load days. In response, the CPUC removed transmission gross-ups and some credits from utility DR resource adequacy values starting in 2024. The CPUC also directed that DR resource adequacy capacity must be available during all days the ISO calls a flex alert or issues a grid warning or on which the governor's office has issued an emergency notice, representing a significant increase in required availability. In addition, the CPUC now requires all DR capacity to be available a minimum of three days per week for at least four hours per day.

For CAISO, energy efficiency and conservation drops significantly when excluding non-CAISO entities from the CA/MX region. The entities outside of CAISO account for an average of 70% of the energy efficiency and conservation DSM for the CA/MX region for the LTRA timeframe.

Distributed Energy Resources

BTM DERs are difficult to measure due to data-gathering barriers. CAISO allows seven DER aggregators as market participants for energy and ancillary services. Additionally, PG&E's Partnership Pilot includes new or existing solar, storage, energy efficiency and demand response used via third party DER providers, vendors, or aggregators.

Generation

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand caused by increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
CA/MX is showing increasing amounts of exports to the northwest, especially during winter months.

Transmission
Seventeen transmission projects with 500 kV and higher are planned.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

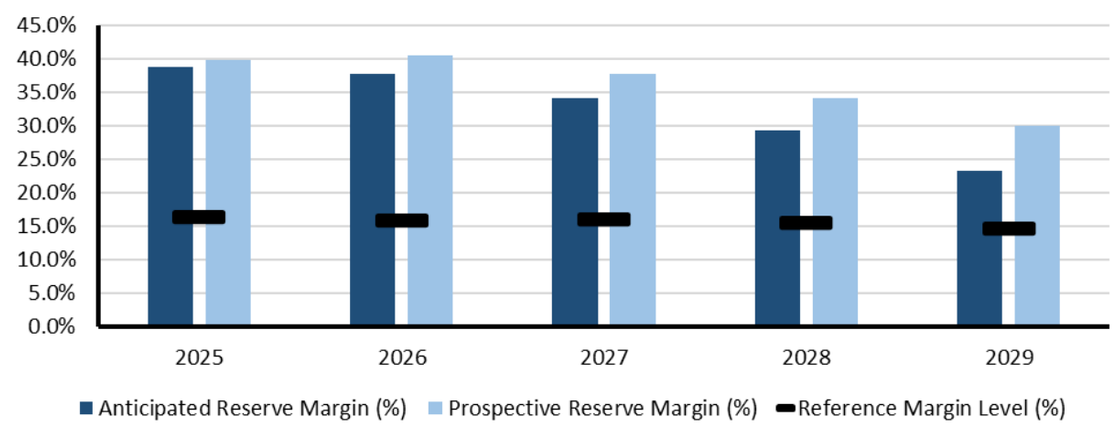


WECC-NW

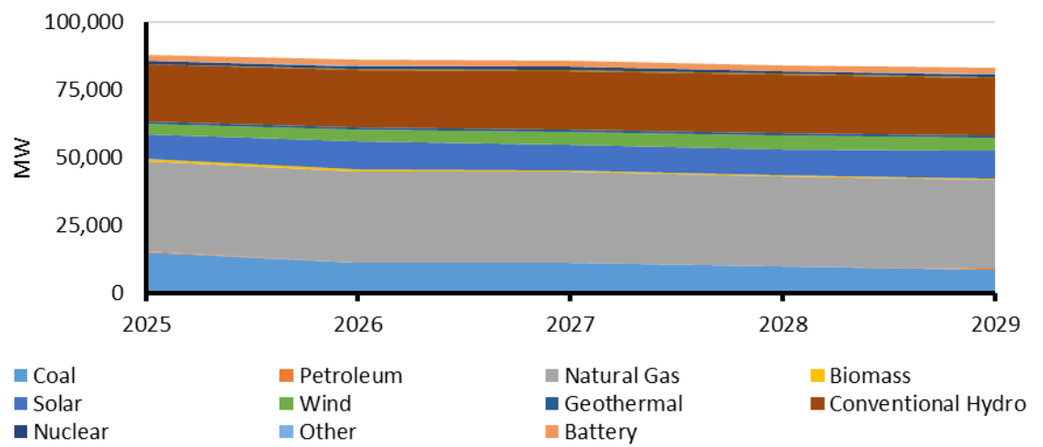
WECC-NW (Northwest) is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	68,274	69,745	71,580	73,626	75,079	75,917	76,736	77,462	78,316	78,835
Demand Response	806	808	811	814	806	809	812	814	817	820
Net Internal Demand	67,469	68,936	70,768	72,811	74,273	75,108	75,925	76,647	77,499	78,016
Additions: Tier 1	7,000	9,386	9,295	9,489	9,752	9,752	10,141	10,141	9,915	10,141
Additions: Tier 2	788	1,955	2,628	3,595	5,046	6,593	7,258	7,273	6,935	7,253
Additions: Tier 3	2,945	8,874	14,008	21,247	28,296	33,802	40,239	42,260	41,876	43,809
Net Firm Capacity Transfers	5,627	8,796	9,087	9,863	8,462	6,037	2,783	2,423	2,370	2,140
Existing-Certain and Net Firm Transfers	86,609	85,564	85,605	84,618	81,788	78,094	74,003	73,297	72,810	71,446
Anticipated Reserve Margin (%)	38.7%	37.7%	34.1%	29.3%	23.3%	17.0%	10.8%	8.9%	6.7%	4.6%
Prospective Reserve Margin (%)	39.9%	40.6%	37.8%	34.2%	30.0%	25.7%	20.4%	18.4%	15.7%	13.9%
Reference Margin Level (%)	16.3%	15.8%	15.9%	15.4%	14.7%	14.5%	14.3%	14.2%	14.4%	13.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the RML for all years in the LTRA time horizon.
- Starting in Summer 2029 onward, the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed. Five GW of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar and wind, supported by BESS. Supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 3 resources.
- The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. Probabilistic modeling efforts show a peak in the summer for this LTRA. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034, which is lower than in the previous LTRA. This represents a nearly 18.7% load growth over the forecast horizon, with an average growth rate of 1.73%.

WECC-NW Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	14,965	11,031	11,021	9,667	8,761
Coal*	14,661	10,223	10,607	9,349	8,060
Petroleum	321	321	319	319	316
Natural Gas	33,452	33,636	33,304	32,954	32,749
Biomass	729	723	683	683	604
Solar	9,086	10,191	9,350	9,431	10,379
Wind	3,924	4,566	4,939	4,939	4,561
Geothermal	884	934	933	1,007	997
Conventional Hydro	21,003	21,000	21,542	21,522	20,958
Pumped Storage	373	373	375	375	373
Nuclear	1,096	1,096	1,096	1,096	1,096
Other	64	64	64	64	64
Battery	2,084	2,219	2,188	2,188	2,219
Total MW	87,981	86,154	85,814	84,245	83,077
Total MW*	87,679	85,346	85,398	83,926	82,377
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-NW Assessment

Planning Reserve Margins

The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the Reference Margin for all years in the LTRA time horizon. Starting in Summer 2029 onward, the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,722	0	1
EUE (PPM)	4	0	0
LOLH (hours per year)	0.04	0	0
Operable On-Peak Margin	37.6%	36.1%	27.8%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

Imports to the Northwest from the CA/MX region grow throughout the LTRA forecast horizon. A calm, cloudy, extreme heat event occurring in the Northwest and CA/MX regions simultaneously poses a risk to the Northwest by limiting surplus energy in CA/MX to send northward.

Energy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio. More variability in energy output requires a greater reserve margin to maintain resource adequacy.

For 2026 and 2028, the peak hour occurs in August at HE 17:00. LOLH and EUE are not forecast in 2026 and only occur for a single hour in 2028. The LOLH occurred in August at HE 19:00, slightly after peak. The LOLH corresponds with the declining solar availability in the evening while demand remains high.

Demand

The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. Probabilistic modeling efforts show a peak in the summer for this LTRA. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034, which is lower than in the previous plan. This represents a nearly 18.7% load growth over the forecast horizon, with an average growth rate of 1.73%. There are significant differences between balancing areas, with some showing large load growth impacts while others showing a slight decrease in demand. Entities reporting large load growth cite new data centers as a primary driver.

Demand-Side Management

In the Northwest, Idaho Power implements a substantial dispatchable DR program focused on the agricultural sector with its Irrigation Peak Rewards Programs. This allows Idaho Power to remotely turn off specific irrigation pumps a minimum of four times during the summer. Participation varies year to year based on factors such as the availability of water and program parameters. In 2022, the utility lengthened the season and included additional evening hours, which drove some reduction in participation that carried over to the Summer 2024 availability.

PacifiCorp states in its most recent Integrated Resource Plan (IRP) that it hopes to reach 1,123 MW of demand response by 2042 in its preferred portfolio plan, which is a 21% increase by 2042 from its previous plan. PacifiCorp's dispatchable DR programs include residential, small commercial air-conditioner load control, irrigation load management, and 203 MW of interruptible contracts.

The Public Service Company of Colorado (PSCo) also offers a wide array of DR programs, such as Saver's Switch, which is a program where the air-conditioning unit of a customer may be controlled

remotely and cycled during extreme heat events. Peak Day Partners allows for the direct load control and reduction of customers 0.5 MW or greater in size when system peaking conditions are met. The Interruptible Service Credit Option (ISOC) is a program where customers agree to reduce consumption in return for a rate discount with non-compliance being met with a fee.

Distributed Energy Resources
BTM DERs are difficult to measure due to data-gathering barriers. One example is Idaho Power's filing of annual DER Resources Status Reports by customer class and resource type, such as in 2023.

Generation
Five GW of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and BESS, further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high.

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
The Northwest is showing greatly increasing import needs over the 10-year time horizon, especially in the winter months. Most of the imports in the model simulations come from CA/MX, with a smaller portion coming from BC**.**

Transmission
Twelve transmission projects with 500 kV and higher are planned.

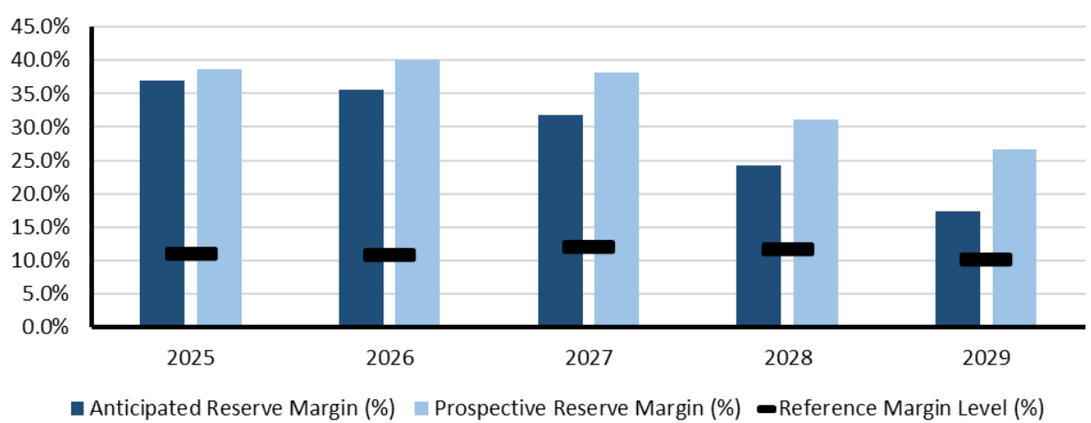


WECC-SW

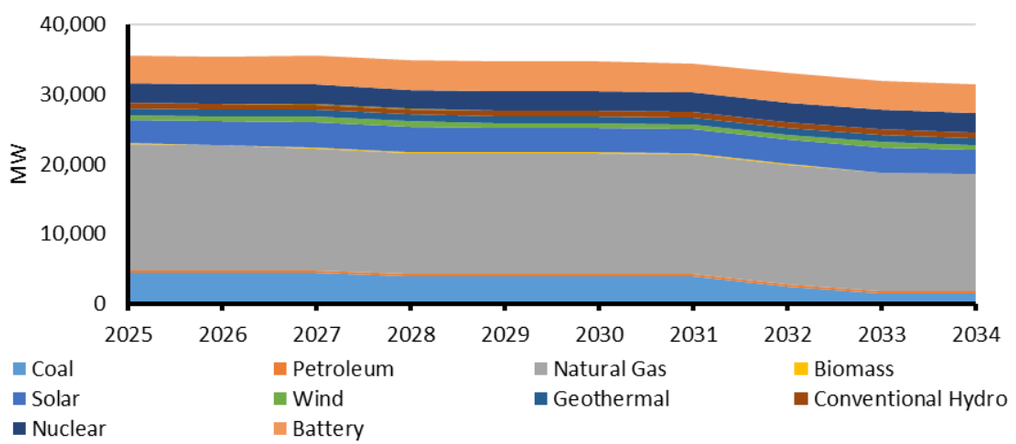
WECC-SW (Southwest) is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	28,347	29,184	30,098	30,905	31,684	32,401	33,082	33,676	34,301	34,886
Demand Response	417	392	396	424	373	389	392	396	424	373
Net Internal Demand	27,930	28,792	29,702	30,481	31,311	32,012	32,690	33,279	33,876	34,512
Additions: Tier 1	5,140	5,251	5,656	5,656	5,557	5,557	5,557	5,557	5,656	5,557
Additions: Tier 2	475	1,305	1,899	2,079	2,932	2,932	2,966	2,984	3,221	2,984
Additions: Tier 3	40	677	1,148	2,589	3,113	4,438	5,734	7,479	8,960	10,027
Net Firm Capacity Transfers	2,651	3,556	3,554	2,966	2,045	928	716	320	322	0
Existing-Certain and Net Firm Transfers	33,110	33,784	33,491	32,212	31,187	30,070	29,644	27,787	26,645	25,956
Anticipated Reserve Margin (%)	36.9%	35.6%	31.8%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-8.7%
Prospective Reserve Margin (%)	38.6%	40.1%	38.2%	31.1%	26.7%	20.4%	16.8%	9.2%	4.9%	0.0%
Reference Margin Level (%)	11.0%	10.8%	12.0%	11.7%	10.2%	10.1%	9.9%	9.7%	10.8%	9.4%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML until Summer 2031, and the PRM falls below the RML in Summer 2032.
- Starting in Summer 2028 onward, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 3 resources. Both supply chain and zoning issues have been cited as inhibiting project completion.
- The Southwest's peak demand in summer is forecast to grow at an average of 2.49%. Over the LTRA horizon, the forecast grows by a total of 27.8%, which is the highest forecasted growth in the WECC region. The Southwest's total internal demand forecast is nearly the same as last year's over the near and medium term, with a slight drop from last year's in the longer term, growing from a summer peak of 27.3 GW in 2024 to 34.9 GW by 2034.
- Natural gas derates during extreme heat events are a risk for the Southwest as these resources make up a large share of the resource portfolio in the area.

WECC-SW Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	4,436	4,436	4,432	3,939	3,941
Coal*	4,432	4,432	4,148	3,655	3,657
Petroleum	323	323	322	322	323
Natural Gas	18,165	17,933	17,520	17,323	17,343
Biomass	82	82	82	82	82
Solar	3,354	3,354	3,628	3,628	3,479
Wind	628	695	799	799	695
Geothermal	1,047	1,047	1,047	1,047	1,047
Conventional Hydro	721	721	721	721	721
Pumped Storage	104	104	104	104	104
Nuclear	2,724	2,724	2,711	2,711	2,724
Battery	4,016	4,061	4,226	4,226	4,240
Total MW	35,599	35,479	35,593	34,902	34,698
Total MW*	35,595	35,475	35,309	34,618	34,414
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

The ARM does not fall below the RML until Summer 2031, and the PRM falls below the RML in Summer 2032. This indicates that imports may be necessary if new resources were to be significantly delayed, as Tier 3 resources will be required for reserve margins to meet the RML. Starting in Summer 2028 onward, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	84	0	19
EUE (PPM)	1	0	0.13
LOLH (hours per year)	0.003	0	0.00
Operable On-Peak Margin	18.3%	33.8%	22.5%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment. Another report produced is a WECC report called the WARA.

For 2026 and 2028, the peak hour occurs in July at HE 17:00. LOLH and EUE are not anticipated in 2026 and are minimal in 2028. LOLH was only observed in August at HE 19:00. The LOLH corresponds with the evening down ramp of solar and lingering demand after peak.

Due to the significant share of natural gas resources in the Southwest portfolio, a concern for the Southwest is natural gas derates during extreme heat events. A strategy to assist with resource planning is to construct derate curves for natural gas resources as a function of temperature. Resource procurement practices have also changed to focus on adding resources that have no dependence on temperature.

Demand

The Southwest has the highest rate of load growth in the Western Interconnection for the LTRA horizon. Large industrial and commercial load additions, such as data centers, have been cited as the reason for this growth.

The Southwest's peak demand in summer is forecast to grow at an average of 2.49%. Over the LTRA horizon, the forecast grows by a total of 27.8%. The Southwest's total internal demand forecast is nearly the same as last year's over the near and medium term, with a slight drop from last year's in the longer term, growing from a summer peak of 27.3 GW in 2024 to 34.9 GW by 2034.

Demand-Side Management

Arizona Public Service (AZPS) has numerous DSM pilots and programs, such as the Residential Energy Storage Pilot and Commercial Advanced Rooftop Controls. In the Residential Energy Storage Pilot, residents may install a small BESS at their residence and enable it to be dispatched by AZPS in response to grid needs 100 times a year, but not below 20% of its capacity. AZPS is projecting an almost 50 MW increase in available DR from 2024 to 2025.

In 2023, the Salt River Project (SRP) subscribed 87 MW of DR capability through the installation of 76,143 smart thermostats and enrolled over 500 businesses as interruptible customers providing 41 MW of controllable DR capacity. The SRP aims to achieve 300 MW of dispatchable DR capability by 2035.

The Public Service Company of New Mexico (PNM) operates the Peak Saver and Power Saver programs. Peak Saver reduces demand from commercial customers greater than 50 kW in size during peak demand periods, and the Power Saver program cycles the compressor of air conditioners to reduce peak demand in the summer. One hundred hours of curtailment are available for both

programs with a four-hour limit per curtailment, and it was found that both programs combined reduce peak demand by an average of 45 MW per curtailment event.

El Paso Electric (EPE) operates a smart thermostat program to cycle air conditioners with the potential to achieve 50 MW of relief by 2040.

Additionally, AZPS, SRP, PNM, and EPE all offer time of use (TOU) rate structures for their customers.

Distributed Energy Resources
BTM DERs are difficult to measure due to data gathering barriers. In the Southwest, NV Energy has added DER plans to its triennial IRPs.

Generation
Southwest entities have slightly under 10 GW of nameplate capacity Tier 1 solar resources planned between 2024 and 2028. Supply chain issues resulting in project delays or failure of completion are a concern for the Southwest. Zoning issues prohibiting the construction of new solar assets are also an issue.

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand caused by increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
The Southwest is not showing a significant increase in reliance on imports in the model, with peak exports occurring between 5:00 p.m. and 10:00 p.m.

Transmission
Twelve transmission projects with 500 kV and higher are planned.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[39] for the summer and winter of each year.[40] Projected total internal demand is based on normal weather (50/50 distribution)[41] and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[42]**	**Load Forecasting Entity**
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
MRO-SPP	Summer	Noncoincident	SPP LSEs
NPCC-Maritimes	Winter	Noncoincident	Maritimes sub-areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro-Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AB	Winter	Noncoincident	WECC BAs, aggregated by WECC
WECC-BC	Winter	Noncoincident	
WECC-CA/MX	Summer	Noncoincident	
WECC-NW	Summer	Noncoincident	

[39] Glossary of Terms Used in NERC Reliability Standards.

[40] The summer season represents June–September and the winter season represents December–February. In this assessment, the year of a winter period is referred to by the year of the month of December (e.g., Winter 2025 is December 2025 – February 2026).

[41] Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.

[42] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval. This is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[42]**	**Load Forecasting Entity**
WECC-SW	Summer	Noncoincident	

Resource Categories

NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.

Anticipated Resources[43]

- Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct.
- Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements
- Firm capacity transfers (Imports minus Exports): transfers with firm contracts
- Less confirmed retirements[44]

Prospective Resources: Includes all "anticipated resources" plus the following:

- Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons.
- Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements
- Expected (non-firm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation.
- Less unconfirmed retirements.[45]

[43] Projected capacities are inputs to reserve margin calculations and probabilistic assessments. Projections are dependent on official retirement notices to system operators. If no notice is given, capacity projections assume no retirements, even if established trends for resource retirements show declines over past years

[44] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

[45] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Resource Categories

Generating Unit Status: Status at time of reporting:

- Existing: It is in commercial operation.
- Retired: It is permanently removed from commercial operation.
- Mothballed: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to "Existing" with capacity contributions entered in "Expected-Other." Once a "mothballed" unit is confirmed to be capable for commercial operation, capacity contributions should be entered in "Expected-Certain."
- Cancelled: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- Tier 1: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[46]
  - Construction complete (not in commercial operation)
  - Under construction
  - Signed/approved Interconnection Service Agreement (ISA)
  - Signed/approved Power Purchase Agreement (PPA) has been approved
  - Signed/approved Interconnection Construction Service Agreement (CSA)
  - Signed/approved Wholesale Market Participant Agreement (WMPA)
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[47]
  - Signed/approved Completion of a feasibility study
  - Signed/approved Completion of a system impact study
  - Signed/approved Completion of a facilities study
  - Requested Interconnection Service Agreement
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- Tier 3: A units in an interconnection queue that do not meet the Tier 2 requirement.

[46] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[47] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

Reserve Margin Descriptions
Planning Reserve Margins: The primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile
Anticipated Reserve Margin (ARM): The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand
Prospective Reserve Margin (PRM): The amount of prospective resources less net internal demand calculated as a percentage of net internal demand
Reference Margin Level (RML): The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, system planners use this metric is to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of this assessment period or may be different for the summer and winter seasons. If an RML is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Methods and Assumptions

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

- **Adequacy:** The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components
- **Operating Reliability:** The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfall, system operators take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment[48]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location.

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[49] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[50] which is defined by the following characteristics.

- **Adequate Level of Reliability:** It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:
  - The BES does not experience instability, uncontrolled separation, cascading,[51] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[52]
  - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.

[48] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: NERC Glossary of Terms
[49] BES Definition
[50] NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability, Docket Number RR06-1, May 10, 2013.
[51] NERC's Glossary of Terms defines Cascading: "Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."
[52] NERC's Glossary of Terms defines Disturbance: "1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load."

- Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. Each assessment area has a peak season, summer or winter, for which its peak demand is higher. PRMs used throughout this LTRA are for each assessment area's peak season listed in the load forecasting table of the **Demand Assumptions and Resource Categories**.

NERC assesses resource adequacy by evaluating each assessment area's PRMs relative to its RML—a "target" or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Based on the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

Adequate: The ARM is greater than RML.

Marginal: The ARM is lower than the RML and the PRM is higher than RML.

Inadequate: The ARM and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment: Biennially, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment and publishes results in the LTRA.

Loss-of-Load Hours: LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve).

LOLH is evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study periods. LOLH does not inform of the magnitude or the frequency of loss-of-load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs that can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
- EE programs that can be modeled as reductions to load with an hourly load shape impact
- Distributed resources (e.g., BTM solar PV) that can be modeled as reductions to load with an hourly load shape impact
- VERs can be modeled probabilistically with multiple hourly profiles

Expected Unserved Energy: EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs. This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss-of-load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is useful for estimating the size of loss-of-load events so the planners can estimate the cost and impact. EUE can be used as a basis for reference reserve margin to determine capacity credits for VERs. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.[53] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

On the basis of the two years of the ProbA results, NERC determines the risk in terms of the following:

Normal Risk: Negligible amounts of LOLH and EUE.

Periods of Risk: LOLH < 2 Hours and EUE < 0.002% of total annual net energy.

Significant Risk: LOLH > 2 Hours and EUE > 0.002% of total annual net energy.

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electric industry continues to monitor electricity use and generally revise its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically “equal probability” forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of DSM programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.

Future Transmission Project Categories

- **Under Construction:** Construction of the line has begun.
- **Planned** (any of the following):
  - Permits have been approved to proceed
  - Design is complete
  - Needed in order to meet a regulatory requirement

- **Conceptual** (any of the following):
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL standard or power-flow model and cannot be categorized as “Under Construction” or “Planned”

Other projected lines that do not meet requirements of “Under Construction” or “Planned”

[53] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2025–2029)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
MISO	2024-2025 Summer: 9.0% Fall: 14.2% Winter: 27.4% Spring (2025): 26.7%	Planning Reserve Margin	Yes: Established Annually[54]	0.1 day/Year Loss of Load Expectation (LOLE)	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	15.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
MRO-SPP	19.0%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP Staff, Stakeholders, SPP Regional State Committee.
NPCC-Maritimes	20.0%[55]	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	11.3–12.7%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	15.0%[56]	Installed Reserve Margin	Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC, NPCC Criteria
NPCC-Ontario	8.6–19.5%	Reserve Margin Requirement	Yes: established annually for all years	0.1 day/Year LOLE	IESO, NPCC Criteria
NPCC-Québec	10.9–11.8%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro-Québec, NPCC Reliability Coordinating Committee
PJM	17.6–17.7%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers, ReliabilityFirst BAL-502-RFC-02 Standard
SERC-Central	15.0%[57]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities

[54] In MISO, the states can override the MISO PRM.

[55] The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

[56] The NERC LTRA RML for NY is 15%; however, there is no PRM criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2025/2026 IRM at 24.4%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

[57] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2025–2029)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
SERC-East	15.0%[58]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-Florida Peninsula	15.0%[59]	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-Southeast	15.0%[60]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustment for non-modeled market considerations	ERCOT Board of Directors
WECC-AB	9.0–13.6%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[61]
WECC-BC	9.8–12.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-CA/MX[62]	14.9–17.4%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-NW	13.8–16.3%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-SW	9.4–12.0%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]

[58] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[59] SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.
[60] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[61] WECC's RML in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.
[62] California is the only state in the Western Interconnection that has a wide-area RML, currently 17.5%: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage,

Recommendations and ERO Actions Summary

In addition to the recommendations in the Executive Summary, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. The ERO, industry, vendors/manufacturers, and stakeholders should continue acting on the following recommendations to inform system and operations planning, develop the transmission network, and address resource performance issues attributed to IBR characteristics, cold weather, and fuel supply limitations. The ERO has a range of activities underway to monitor, assess, and reduce long-term BPS reliability risks. The selected ERO activities summarized below will result in new or enhanced Reliability Standards requirements, reliability guidelines, resources, or significant findings and actionable steps for stakeholders to address reliability risks.

LTRA Recommendations and Ongoing ERO Actions

Add new resources with needed reliability attributes and make existing resources more dependable.

1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric criteria applied to results from probabilistic studies that include load loss, unserved energy, event magnitude, and event duration will support achieving the levels of reliability that are required for modern society.
2. **Address performance deficiencies with existing and future inverter-based resources:** Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing. IBRs include most solar and wind generation as well as new BESS or hybrid generation and account for 85% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred in new geographic areas as recently as the summer of 2023.[63] A common thread with these events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. Based on the findings of a recent NERC alert, more ride-through and ERS capabilities can be enabled within existing solar PV resources to improve performance and support the reliable operation of the BPS.[64] Industry adoption of the recommended practices set forth in NERC reliability guidelines and the NERC alert will reduce risks from IBR performance issues to the grid as NERC also develops mandatory Reliability Standards based on those reliability guidelines. It is also critically important for interconnection processes to include accurate modeling and studies requirements.[65] Guided by NERC's comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 901, the ERO, industry, and manufacturers should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[66,67]
3. **Improve the performance of the generating fleet in extreme cold temperatures:** The ERO and industry need to complete enhanced requirements for generator cold-weather performance to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.[68] Revisions to Reliability Standard EOP-012-2 will improve the effectiveness of the standard and speed the implementation of corrective actions necessary to address unacceptable freezing issues. Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.[69]

[63] See the ERO's extensive IBR event reporting here: NERC Major Event Reports
[64] The NERC Level 2 alert to gather data from solar PV resource owners and issue recommendations can be found here: *Industry Recommendation: Inverter-Based Resource Performance Issues*.
[65] NERC's comprehensive initiatives to reduce IBR risks are detailed here: IBR Quick Reference Guide
[66] NERC IBR Activities
[67] Order No. 901 Work Plan
[68] *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report*
[69] *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott*

LTRA Recommendations and Ongoing ERO Actions

4. **Mitigate fuel-related risks to electricity generation (fuel assurance):** In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource that enables reliable integration of VERs into the dispatch. As a result, the BES has never been more dependent upon the round-the-clock continuity of just-in-time natural gas delivery. The past two winters have seen interruptions of natural gas delivery to generators that resulted in energy deficiencies. Collaborative assessments involving NERC, the Regional Entities, the National Labs, and natural gas and electric power industry participants are needed to identify natural gas fuel supply needs for reliable operation of the BPS. NERC strongly endorses actions to establish reliability rules for the natural gas infrastructure necessary to support the grid as recommended in the Winter Storm Elliott report. Additionally, as part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[70]

Initiative	Description	Product/Reliability Solution
Cold Weather Reliability Standards and Activities	New cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. Generator Owners and Generator Operators are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their Reliability Coordinators, Transmission Operators, and Balancing Authorities for use in operating plans. Additional Reliability Standard requirements have been developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity staff report—The February 2021 Cold Weather Outages in Texas and Southcentral United States.* The NERC Board adopted these requirements in October 2023 and directed NERC to file them with regulatory authorities for approval and industry implementation. NERC and the industry are currently developing the remaining Reliability Standard enhancements to address the staff report. Refer to *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* on NERC's standards development page.[71]	Reliability Standards NERC Alerts Event Analysis Reports Lessons Learned
Inverter-Based Resources Strategy	NERC's IBR strategy includes four key focus areas: Risk Analysis, Interconnection Process Improvements, Sharing Best Practices and Industry Education, and Regulatory Enhancements. The statuses of NERC's extensive activities in each area are described in detail in the *IBR Activities Reference Guide*.[72] NERC has investigated and analyzed IBR performance issues during grid disturbances dating back to 2016. Since that time, NERC and its technical groups have published a range of reliability guidelines for studying, modeling, controlling, and interconnecting IBRs. In partnership with many experts from across the industry, NERC maintains an active campaign of education, awareness, and outreach to support its strategy and reduce IBR performance risks. NERC and the RSTC recognized that Reliability Standard requirements would be needed as part of a comprehensive approach to reliability and undertook a full review of existing standards to identify gaps. Several reliability standards projects were initiated following this review. In October 2023, FERC issued Order No. 991, which provided clear direction for the industry to develop requirements that address reliability gaps related to IBR in data sharing, model validation, planning and operational studies, and performance requirements.	Reliability Standards NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned Educational Webinars

[70] Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised Guideline also identifies as fuel risks requiring evaluation many of the scenarios industry has encountered during recent periods of extreme cold weather and high demand for natural gas. The revised guideline is under review with the Reliability and Security Technical Committee. The approved and revised draft guideline can be found on the RSTC website: NERC Reliability and Security Guidelines

[71] Project 2021-07

[72] IBR Activities

LTRA Recommendations and Ongoing ERO Actions		
	FERC issued an order in 2022 directing NERC to identify and register owners and operators of currently unregistered bulk power system-connected IBRs.[73] Working closely with industry and stakeholders, NERC is executing a FERC-approved work plan to achieve the identification and registration directive by 2026. Resources are also posted on the Registration page of the NERC website.	
Natural Gas-Electric Interdependence Initiatives	Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised guideline also identifies the fuel risks encountered by industry during recent periods of extreme cold weather and high demand for natural gas. These natural gas supply risks can inform industry's development of planning scenarios. The revised guideline is under review with the RSTC. Refer to the RSTC-Approved Documents page.[74]	Reliability Guideline
Expand the transmission network to deliver supplies from new resources and locations to serve changing loads. 5. **Develop the transmission network:** ISOs and RTOs should continue looking for opportunities to streamline transmission planning processes and reduce the time required for transmission development. However, addressing the siting and permitting challenges that are the most common cause for delayed transmission projects will require regulators and policymakers at the federal, state, and provincial levels to focus attention and provide support.		
Initiative	**Description**	**Product/Reliability Solution**
Interregional Transfer Capability Study (ITCS)	NERC completed the ITCS required by the Fiscal Responsibility Act of 2023 and filed the final report with FERC on November 19, 2024. The ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. However, the ITCS is not a transmission plan or blueprint. Transmission expansion analysis, resource plans, and other inputs must be considered in effective system planning. The ITCS is designed to provide foundational insights that facilitate stakeholder analysis and actions. Due to the interconnected nature of the BPS, NERC will extend the study beyond the congressional mandate to identify and make recommendations for transfer capabilities from the United States to Canada and among Canadian provinces. The Canadian analysis will be published in 2025. See **Interregional Transfer Capability Study (**ITCS).	ERO Study and Recommendations

[73] FERC Order Issued November 17, 2022
[74] RSTC Approved Documents

LTRA Recommendations and Ongoing ERO Actions

Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.

6. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric approaches to resource adequacy using load loss, unserved energy, and event magnitude and duration criteria and results from probabilistic studies will support achieving the levels of reliability that are required for modern society.

7. **Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models:** Resource Planners and wholesale market designers must use appropriate methods for determining the contribution of resources to meeting demand. Weather-dependent resources, fuel supplies, and demand profiles result in seasonal risks. This can be seen in the increasing winter resource adequacy risks observed in the 2024 ProbA for many traditionally summer-peaking areas. ISO/RTOs can help reduce seasonal risks by implementing seasonal resource adequacy procurement (e.g., spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. The explosive growth of BESS and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, BESS duration, and BESS operating mode.

8. **Maintain sufficient amounts of flexible resources and essential reliability services:** To maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, dispatchable generators must be available and capable of following changing electricity demand. Retirements of fossil-fired generators are reducing the amounts of dispatchable generation in many areas. As more solar PV and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. Natural-gas-fired generators and hydro generators have traditionally provided this ERS. Battery resources can provide flexibility during short durations, while new wind and solar PV have minimal assured flexibility. Maintaining ERSs is critically important. Resource Planners and wholesale electricity market operators should ensure resources are procured and made available in the long-range resource portfolio as part of the planning process; markets and other mechanisms need to be in place to deliver weather-ready resources with sufficient energy and ERS capabilities to the operators. [75]

9. **Include energy risks and extreme weather scenarios in resource and system planning:** Industry and regulators need to conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme conditions in integrated resource planning and wholesale market designs. While more sophisticated capabilities for assessing extreme event risk are being developed, scenario planning can be more readily incorporated in resource and system planning. Scenarios should consider the potential effects of wide-area, long-duration extreme weather events, including the impact they can have on natural gas fuel supplies and on the interconnected energy system. NERC and the industry should continue to prioritize completion of new reliability standards supporting energy assurance in operating and planning time horizons, and for the assessment of extreme heat and cold weather events in transmission system planning.

10. **Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distributed resources is a priority for most areas. Data sharing, models, and information protocols are needed to support BPS planners and operators. Industry must continue to evaluate potential reliability concerns associated with increasing DER penetration and DER performance and, when necessary, develop reliability standards requirements to address identified gaps. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. ISO/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations.[76]

[75] NERC ERS Measure 6 Forward Tech Brief

[76] A comprehensive guide to ERO activities on DERs can be found here: DER Activities

LTRA Recommendations and Ongoing ERO Actions		
Initiative	**Description**	**Product/Reliability Solution**
Energy Assessments Initiatives	NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this *2024 LTRA* to advise industry and stakeholders of findings on BPS adequacy, including energy adequacy. In recent years, NERC has enhanced the energy risk analysis in seasonal assessments by incorporating deterministic energy risk scenarios and introducing probability-based assessments. NERC's ProbA uses hourly simulations to examine the ability of resources to meet demand over the entire study year, helping to identify energy risks that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis. NERC reliability assessments continue to evolve as more sophisticated energy assessment tools, models, and capabilities are developed. The RSTC created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.[77] The working group is developing a technical reference document to inform registered entities on approaches and considerations for assessing and reducing the risk of energy shortfalls. New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 *Energy Assurance with Energy Constrained Resources.*[78] In other Reliability Standard development work, Project 2023-07 *Transmission System Planning Performance Requirements for Extreme Weather* requirements are being developed that will ensure entities consider extreme heat and cold weather scenarios in BPS planning, including the expected availability of the future resource mix.[79]	Reliability Assessments Reliability Standards
Distributed Energy Resources Strategy	NERC has proactively worked with industry stakeholders to identify BPS reliability risks associated with the increasing DER levels and has initiated actions to support broad awareness and education as well as to provide guidance for industry and enhance Reliability Standards where gaps exist. The status of NERC's extensive activities in each area are described in detail in the *DER Activities Reference Guide*.[80]	Reliability Standards Reliability Guidelines Educational Webinars
4: Strengthen relationships among reliability stakeholders.		
Initiative	**Description**	**Product/Reliability Solution**
Ongoing Strategic Engagements	NERC and the Regional Entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels.	Constructive Partnerships

[77] ERAWG
[78] Project 2022-03
[79] Project 2023-07
[80] DER Activities

Errata

In June 2025, NERC, MRO, and MISO determined that incorrect RMLs were used in the 2024 LTRA for MISO.[81] After applying the correct RMLs, the following changes have been made:

- Figure 1 Risk Area Summary 2025–2029 (p. 6) | MISO changed from High Risk to Elevated Risk
- Table 1: Capacity and Energy Risk Assessment Summary (p. 7)| MISO changed from High Risk to Elevated Risk and Risk Summary updated
- Figure 2: Projected Reserve Margin Shortfall Areas with Announced Generator Retirements (p. 8) | MISO year of shortfall changed from 2025 to 2028 and caption updated
- High Risk Area Details and Elevated Risk Area Details (p. 12) | Removed the description of High Risk, moved relevant discussion of MISO risks to Elevated Risk Area Details, and updated text.
- Figures 3 and 4: MISO Planning Reserve Margins for Summer and Winter (p.13)| Updated with correct RMLs
- Table 12: Anticipated Reserve Margins with Announced Retirements (p. 40) | Footnote added to identify use of UCAP reserve margins for MISO
- MISO Demand, Resources and Reserve Margins (p. 41) | Updated the Reference Margin Level (%) row in the table and updated the Planning Reserve Margins bar graph with correct RMLs; added a note and reference to OMS-MISO Survey
- MISO Highlights (p. 42) | Changed MISO projected capacity shortfall from *2025* to *within the next five years* in the first bullet
- MISO Assessment (p. 43) | Removed the shortfall capacity value in the Planning Reserve Margins section and added a note on the capacity values for existing resources in the MISO tables; removed the statement of ARM falling below RML in the Probabilistic Assessments section

[81] See the *Statement on NERC's 2024 Long-Term Reliability Assessment* issued on June 17, 2025.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-21

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit KK: Division, *Operating Permit No. 96OPMF155* (July 1, 2021)



Colorado Department of Public Health and Environment

OPERATING PERMIT

Tri-State Generation & Transmission Association, Inc.

Craig Station

First Issued: May 1, 2005
Renewed: July 1, 2021

AIR POLLUTION CONTROL DIVISION
COLORADO OPERATING PERMIT

FACILITY NAME: Craig Station

OPERATING PERMIT NUMBER

96OPMF155

FACILITY ID: 081/0018

RENEWED: July 1, 2021
EXPIRATION DATE: July 1, 2026
MODIFICATIONS: See Appendix F of Permit

Issued in accordance with the provisions of Colorado Air Pollution Prevention and Control Act, 25-7-101 et seq. and applicable rules and regulations.

ISSUED TO:

Tri-State Generation & Transmission Association, Inc.
1100 W. 116th Street
Westminster, CO 80234

PLANT SITE LOCATIONS:

Craig Station
2101 S. Ranney Street
Craig, CO

INFORMATION RELIED UPON
Operating Permit Renewal Applications Received: May 1, 2009 and May 21, 2010
And Additional Information Received: Various

Nature of Business: Steam and Electricity Generation
Primary SIC: 4911

RESPONSIBLE OFFICIAL
Name: Barbara Walz
Title: Senior Vice President – Policy & Compliance Chief Compliance Officer
Phone: (303) 452-6111

FACILITY CONTACT PERSON
Name: Mike Tomasovic
Title: Environmental Supervisor
Phone: (970) 824-4411

SUBMITTAL DEADLINES –
Semi-Annual Monitoring Periods: January 1 – June 30, July 1 – December 31
Semi-Annual Monitoring Reports: Due February 1 & August 1
Annual Compliance Periods: January 1 – December 31
Annual Compliance Certification: Due February 1

Note that the Semi-Annual Monitoring Reports and Annual Compliance report must be received at the Division office by 5:00 p.m. on the due date. Postmarked dates will not be accepted for the purposes of determining the timely receipt of those reports.

SEE SECTION III OF THIS OPERATING PERMIT FOR ACID RAIN SUBMITTAL DEADLINES

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SECTION I - General Activities and Summary

1. Permitted Activities

1.1 The Tri-State Generation and Transmission Association Craig Station (herein, Source) is a coal-fired power plant with a total gross electric generating capacity of 1,375 MW. The facility operates consisting of three, pulverized coal, dry-bottom boilers: Units 1 and 2, rated at 4,318 MMBtu/hour each, were placed in service in 1980 and 1979, respectively; Unit 3, rated at 4,600 MMBtu/hour, was placed in service in 1984. All three units use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. Associated activities covered by the permit include three cooling towers, coal handling systems, ash handling systems, limestone handling systems, and lime handling systems.

Units 1 and 2 use limestone scrubbers to control SO_2 emissions; Unit 3 uses a lime spray-dryer scrubber to control SO_2 emissions. All three units use baghouses to control PM emissions, and low-NOx burners and overfire air (OFA) for NO_x emissions. Units 1 and 2 also use overfire air and related NO_x control upgrades; they are also subject to the requirements of special requirements from a 2001 revision to the Colorado State Implementation Plan. Unit 2 is equipped with a selective catalytic reduction (SCR) system, and Unit 3 is equipped with a selective non-catalytic reduction (SNCR) system for control of NO_x emissions to comply with the emission limits of the State of Colorado Regional Haze Program.

All three units are subject to the requirements of the Acid Rain Program.

The facility is located at 2101 S. Ranney Street, Craig, Colorado, Moffat County. The area in which the plant operates is designated as attainment for all criteria pollutants.

Wyoming is an affected state within 50 miles of the plant. There are two Federal Class I designated areas within 100 kilometers of the facility: Mount Zirkel National Wilderness Area and Flattops National Wilderness Area. Dinosaur National Monument is a Federal land area within 100 kilometers of the facility. Although it is not a Federal Class I area, Dinosaur has been designated by the State to have the same sulfur dioxide (SO_2) increment as a Federal Class I area.

1.2 Until such time as this permit expires or is modified or revoked, the Source is allowed to discharge air pollutants from this facility in accordance with the requirements, limitations, and conditions of this permit.

1.3 The Operating Permit incorporates the applicable requirements contained in the underlying construction permits, and does not affect those applicable requirements, except as modified during review of the application or as modified subsequent to permit issuance using the modification procedures found in Regulation No. 3, Part C. These Part C procedures meet all applicable substantive New Source Review requirements of Part B. Any revisions made using the provisions of Regulation No. 3, Part C shall become new applicable requirements for purposes of this Operating Permit and shall survive reissuance. This permit incorporates the applicable requirements (except as noted in Section II) from the following construction permits: 12MF322-1, 12MF322-2, 12MF322-3, 12MF322-4, 11MF415, 11MF332, 11MF276, 10MF579, 98MF0141, and 96MF195.

1.4 All conditions in this permit are enforceable by the United States Environmental Protection Agency (EPA), Colorado Air Pollution Control Division (hereinafter Division) and its agents, and citizens unless otherwise specified. **State-only enforceable conditions are:** Permit Condition Number(s): Section II, Conditions 3.6.3; Section V, Conditions 3.g (last paragraph), 14 & 18.

1.5 All information gathered pursuant to the requirements of this permit is subject to the Recordkeeping and Reporting requirements listed under Condition 22 of the General Conditions in Section V of this permit.

2. Alternative Operating Scenarios (AOS)

2.1 There are no AOS associated with permitted activities at the facility.

3. Prevention of Significant Deterioration (PSD)

3.1 This facility is located in an area designated attainment for all pollutants. It is categorized as a major stationary source (potential to emit ≥ 100 tons per year (tpy) for PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, and CO). Future modifications at this facility resulting in a significant net emissions increase (see Colorado Regulation No. 3, Part D, Sections II.A.27 and 44) for any pollutant as listed in Regulation No. 3, Part D, Section II.A.44 or a modification which is major by itself (i.e. a potential to emit ≥ 100 tpy of any pollutant listed in Regulation No. 3, Part D, Section II.A.44) may result in the application of the PSD review requirements.

3.2 There are no other Operating Permits associated with this facility for purposes of determining applicability of PSD regulations.

4. Accidental Release Prevention Program (112(r))

4.1 Based on the information provided by the Source, this facility is subject to the provisions of the Accidental Release Prevention Program in Section 112(r) of the Federal Clean Air Act (CAA).

5. Compliance Assurance Monitoring (CAM)

5.1 The following emission points at this facility use a control device to achieve compliance with an emission limitation or standard to which they are subject and have pre-control emissions that exceed or are equivalent to the major source threshold. They are therefore subject to the provisions of the CAM program as set forth in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV:

Unit 1: PM (baghouse), SO_2 (wet scrubber)

Unit 2: PM (baghouse), NO_x (SCR), SO_2 (wet scrubber)

Unit 3: PM (baghouse), NO_x (SNCR), SO_2 (lime spray-dryer)

P102 – Coal Handling System, S102d – Secondary Coal Crushing Building: PM (baghouse)

6. Summary of Emission Units

6.1 The emissions units regulated by this permit are the following:

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
Unit 1 Boiler	B001	001	S001	Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization	10MF579	Baghouse Wet SO_2 scrubber Low-NO_x burners with overfire air
Unit 2 Boiler	B002	002	S002	Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization		Baghouse Wet SO_2 scrubber Low-NO_x burners with overfire air SCR
Unit 3 Boiler	B003	003	S003	Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization	12MF322-1	Spray dryer Baghouse Low-NO_x burners with overfire air SNCR
Coal Handling – Units 1 & 2	P101	004	F101a	Coal hauling – Units 1 & 2	11MF276	$MgCl_2$, water, or equivalent application, as necessary
			F101b	Coal unloading to grizzly – Units 1 & 2		Water spray with surfactant, as necessary
			F101c	Coal surge pile		Water with surfactant, as necessary
			S101d	Primary coal crushing – Units 1 & 2		Baghouse
			S101e	Secondary coal crushing building – Units 1 & 2		Baghouse
			S101f	Common coal transfer building belt A		Baghouse
			S101g	Common coal transfer building belt B		Baghouse
			S101h	Coal stackout building – Units 1 & 2		Baghouse
			F101i	Coal stackout – Units 1 & 2		Telescopic chute
			F101j	Coal storage piles – Units 1 & 2		Water spray prior to stackout, as necessary
			S101k	Coal reclaim A – Units 1 & 2		Baghouse

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
			S101l	Coal reclaim B – Units 1 & 2		Baghouse
			S101m	Coal tripper deck & silos – Units 1 & 2		Baghouse
Ash Handling – Units 1 & 2	P203	016	S203a	Ash storage silo A – Units 1 & 2	11MF332	Baghouse (Shared with S203e)
			S203b	Ash storage silo B – Units 1 & 2		Baghouse (Shared with S203d)
			F203c	Ash truck loading – Units 1 & 2		Low dust unloading system
			S203d	Silo B dry ash unloading – Units 1 & 2		Baghouse (Shared with S203b)
			S203e	Silo A dry ash unloading – Units 1 & 2		Baghouse (Shared with S203a)
Limestone Handling – Units 1 & 2	P201	020	F201a	Limestone hauling	11MF415	Paved portions of road
			S201b	Limestone truck unloading		Baghouse
			S201c	Limestone silo #1 – Units 1 & 2		Baghouse
			S201d	Limestone silo #2 – Units 1 & 2		Baghouse
Coal Handling – Unit 3*	P102*	023	F102a	Coal train unloading – Unit 3	12MF322-2	Water spray
			S102b	Coal conveyor portal building – Unit 3		Baghouse
			S102c	Coal conveyor portal building – Unit 3		Baghouse
			S102d	Secondary coal crushing (2 crushers) – Unit 3		Baghouse
			S102e	Coal stackout building – Unit 3		Baghouse
			F102f	Coal stackout – Unit 3		Telescopic chutes
			F102g	Coal storage pile – Unit 3		PM control plan, including compaction, chemical use or watering, as necessary
			S102h	Coal reclaim system – Unit 3		Baghouse
			S102i	Coal tripper deck & silos – Unit 3		Baghouse
			S102j	Loadout coal to railcars – Unit 3		Baghouse
			S102k	Common coal transfer building extension		Baghouse
			F102l	Coal train loading		None
Ash Handing – Unit 3	P204	032	S204a	Ash storage silo – Unit 3	12MF322-3	Baghouse
			F204b	Ash truck loading (wet flyash and dry flyash) – Unit 3		Low dust loader (wet ash) Baghouse (dry flyash)

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
			S204c	Recycle ash tank		Baghouse
			F204d	Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3		$MgCl_2$ application on roads, as necessary
Lime Handling and Storage – Unit 3	P202	035	F202a	Lime hauling	12MF322-4	Paved portions of road
			S202b	Lime unloading		Baghouse
			S202c	Lime conveying and silo		Baghouse
			S202d	Lime day bin		Baghouse
Cooling Towers – Units 1 & 2	P401	040	S401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74, ten cells with BACT compliant drift eliminators	96MF195	Drift eliminators
	P402		S402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74, ten cells with BACT compliant drift eliminators		Drift eliminators
Unit 3 Cooling Tower	P403	044	S403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79, ten cells with BACT compliant drift eliminators	98MF0141	Drift eliminators
Emergency Diesel Fire-Pump Engine	N/A	N/A	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower	N/A	None
Units 1&2 Emergency Diesel Generator	N/A	N/A	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower	N/A	None
Unit 3 Emergency Diesel Generator	N/A	N/A	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower	N/A	None

*Note that the Unit 3 coal handling system is occasionally used to blend coal for Units 1 and 2

Table 1 - Craig Station Emission Unit Summary

SECTION II - Specific Permit Terms

1. Boiler B001 "Unit 1" – Coal-fired boiler, Babcock & Wilcox #NB24157, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	1.1	0.10 lb/MMBtu (NSPS Subpart D) 0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU)	Determined via Stack Testing	Baghouse O&M and Stack Testing	See Condition 1.1
SO_2	1.2	1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D) 0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV) 0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU) 100% of flue gas treated (SIP) 0.160 lb/MMBtu 30-boiler operating day rolling average (SIP) 0.130 lb/MMBtu 90-boiler operating day rolling average (SIP) 90% reduction of SO_2 on 90-boiler operating day rolling average (SIP) No more than 72 consecutive hours of operation without SO_2 control (SIP)		CEMS Coal Sampling Calculation Recordkeeping	Continuous Daily
NOx	1.3	0.7 lb/MMBtu 3-hour average (NSPS D) 0.30 lb/MMBtu calendar year average (SIP)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		0.28 lb/MMBtu 30-day rolling average (CO Reg. 23, IV.D.2.) 4,065 tpy calendar year basis (CO Reg. 23, Section IV.D.3., see Condition 1.10) 0.46 lb/MMBtu calendar year average (see Acid Rain requirements in Section III)			
VOC & CO	1.4		See Condition 1.4	Recordkeeping and Calculation	Annually
Opacity	1.5	Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1) Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, CO Reg. 6, Part A, SIP) Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP) Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP) Not to exceed 20% during shutdown (SIP)		COMS – May be verified by EPA Reference Method 9	Continuous, 6-Minute Intervals

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Coal Requirements	1.6	Coal consumption records Coal sampling		Recordkeeping ASTM Methods	Annually Quarterly
CEMS	1.7	Monitor: Opacity, NO_x, SO_2, diluent gas, flow		See Condition 1.7	
NSPS D	1.8	See Condition 1.8			
CO SIP	1.9	See Condition 1.9			
Regional Haze	1.10	PM: 0.03 lb/MMBtu (See Condition 1.1) SO_2: 0.11 lb/MMBtu 30-boiler operating day rolling average (See Condition 1.2) NO_x: 0.28 lb/MMBtu (Condition 1.3) NO_x: 4,065 tpy (Condition 1.3)		CEMS	Continuous
Acid Rain	1.11	See Section III of this Operating Permit		Certification	Quarterly and annually
MACT UUUUU (MATS)	1.12	See Condition 1.12 and 5			
CAM	1.13	See Condition 1.13			

Table 2 - Unit 1 Emissions and Requirements Summary

1.1 **Particulate matter (PM)** emissions must not exceed the following limits:

1.1.1 **0.10 lb PM/MMBtu heat input**, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

1.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 1 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

1.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.1.2 **0.03 lb PM/MMBtu heat input**, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3 **0.03 lb PM/MMBtu heat input**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

1.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

1.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 1.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 1.13 (Colorado Regulation No. 23, Section V.B.1.).

1.1.4 **0.03 lb PM/MMBtu heat input**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

1.1.5 To **demonstrate compliance** with the PM emission limits in Condition 1.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and conduct periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.1.6 Annual emissions of PM and PM_{10} for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 1.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. PM_{10} emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6, unless a PM_{10} emission factor was developed using source testing.

1.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

1.2.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

1.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

1.2.1.3 The SO_2 emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.2.2 **1.2 lb/MMBtu heat input, three-hour rolling average**, Colorado Regulation No. 1, Section VI.A.

1.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

1.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

1.2.3 **0.11 lb/MMBtu, 30-day rolling average**, Colorado Regulation No. 23, Section IV. – Regional Haze and Colorado Regional Haze SIP

1.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 1.2.5.

1.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.2.3.3 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.4 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.2.3.3, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.5 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.6 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.2.3.3. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.2.3.7 The Source must maintain records and follow the reporting requirements as described in Condition 1.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

1.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.2.4.1 The Source must **treat one hundred percent (100%) of the flue gas** from Unit 1 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the SO_2 emission limitations in this section (Condition 1.2.4) and emissions of SO_2 during any such period shall not be excluded from the determination of the Source's compliance with the SO_2 emission limitations.

Note that in determining compliance with the requirements of Condition 1.2.4, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions.

1.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with SO_2 in excess of the following limitations:

a. **0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis**;

b. **0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis**.

1.2.4.3 **SO_2 controls must achieve a ninety percent (90%) reduction of SO_2 on a 90 boiler-operating-day rolling-average basis** as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 1.6), a daily potential SO_2 emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily SO_2 emission rate, for each boiler operating day in an arithmetic average of the potential SO_2 emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the SO_2 rolling average basis that is referred to as E_i in the equation below. Each day's potential SO_2 emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis SO_2 stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the SO_2 rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days

(including the boiler operating day for which the calculation is being performed), will be used to calculate that day's SO_2 rolling average basis that is referred to as E_0 in the equation below. Each day's SO_2 stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 1.9;

c. The 90 day rolling average basis percent SO_2 reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

1.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 1.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the SO_2 control equipment is operating normally.

1.2.5 Compliance calculations for SO_2 requirements in Condition 1.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

1.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

1.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

1.2.6 Annual emissions of SO_2 for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

1.3 **Nitrogen oxides (NO_x)** emissions must not exceed the following limits:

1.3.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of 0.7 lb/MMBtu heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

1.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

1.3.1.3 The NO_x emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with NO_x in excess of **0.30 lb/MMBtu heat input on a calendar year annual average basis**. Upset conditions do not apply to this limit and emissions of NO_x during any such period shall not be excluded from the determination of the Source's compliance with the NO_x emission limit. Compliance shall be determined on a unit-specific basis using data from NO_x CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 1.7.

1.3.2.2 The Source must operate state-of-the-art low-NO_x burners utilizing two stage combustion with supplemental overfire air.

1.3.3 **0.28 lb/MMBtu, 30-day rolling average**, Colorado Regulation No. 23, Section IV.D.2. – Regional Haze, as provided for in Condition 1.10

1.3.3.1 The Source must comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.2 At all times, the Source must maintain, calibrate, and operate a CEMS in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.3.3.1, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source must calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.3 In determining compliance with the NO_x regional haze limit, all periods of emissions must be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.4 For any hour in which fuel is combusted, the Source must calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.3.3.1. These hourly averages must be used to determine compliance in accordance with the averaging period, as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source must calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.3.3.5 Compliance shall be monitored using the CEMS as described in Condition 1.3.5.

1.3.3.6 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.3.4 Craig Unit 1 must meet an **annual NO_x limit of 4,065 tons per year by December 31, 2020** on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.)

1.3.5 Compliance calculations for NO_x requirements in Condition 1.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

a. Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

1.3.5.2 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

1.3.6 Annual emissions of NO_x for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

1.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 1.6.1 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

1.5 **Opacity**

1.5.1 Colorado Regulation No. 1

1.5.1.1 Except as provided in Condition 1.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

1.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

1.5.2 40 CFR Part 60, Subpart D

1.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

1.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

1.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control

equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

1.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

1.5.3.3 An opacity reading in excess of the limitations in Condition 1.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 1.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

1.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

1.5.4 Compliance with the opacity emissions limitations in Condition 1.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an

intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4. (Colorado Regulation No. 3, Part C, Section V.C.5.)

1.5.4.1 The requirements for the COMS system are outlined in Condition 19.

1.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

1.5.5 **Partial streamlining of opacity limits into State Implementation Plan opacity limits** – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS Subpart D (Conditions 1.5.1 and 1.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 1.5.3), except as follows:

1.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 1.5.1 and 1.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

1.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 1.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 1.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

1.6 Coal Requirements

1.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.7 Continuous Emissions Monitoring Systems (CEMS)

1.7.1 For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

1.7.2 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

1.8 40 CFR Part 60, Subpart D

1.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

1.8.2 In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.

1.8.3 The Source shall determine compliance with the PM, SO_2, or NO_x standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

1.8.4 **[Excess emissions reports]** Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and monitoring system performance (MSP) report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

1.8.4.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

1.8.4.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 1.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

1.8.4.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 1.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

1.8.5 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

1.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 1 in a manner consistent with good air pollution control practices for minimizing emissions.

1.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

1.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

1.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, SO_2, NO_x quarterly excess emission and monitoring report;

b. The required reports for SO_2 emissions (including emissions during all excluded periods as well as SO_2 content calculated from coal for each day, the SO_2 stack emissions for each day, and each day's SO_2 percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for NO_x emissions.

1.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component, unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

1.10 Colorado Regulation No. 23, Regional Haze

1.10.1 Craig Unit 1 will close on or before December 31, 2025 (Colorado Regulation No. 23, Section IV.D.1.).

1.10.2 As provided in Condition 1.3.3, Craig Unit 1 will meet a **NO_x emission limit of 0.28 lb/MMBtu over a 30-day rolling average** going forward from January 1, 2017 (first compliance date January 31, 2017), until closure (Colorado Regulation No. 23, Section IV.D.2.).

1.10.3 As provided in Condition 1.3.4, Craig Unit 1 will meet an annual **NO_x limit of 4,065 tons per year by December 31, 2019** on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.).

1.10.4 Compliance with the 30-day rolling average and annual NO_x limits will be monitored using the CEMS as described in Condition 19.

1.10.5 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

1.10.5.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

1.10.5.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

1.10.5.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

1.10.5.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

1.10.5.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

1.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

1.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 1 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

1.13 Compliance Assurance Monitoring (CAM)

Unit 1 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 1.1, and the SO_2 emissions in Condition 1.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G and J.

2. Boiler B002 "Unit 2" – Coal-fired boiler, Babcock & Wilcox #NB24156, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	2.1	0.10 lb/MMBtu (NSPS Subpart D) 0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU)	Determined via Stack Testing	Baghouse O&M and Stack Testing	See Condition 2.1
SO_2	2.2	1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D) 0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV) 0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU) 100% of flue gas treated (SIP) 0.160 lb/MMBtu 30-boiler operating day rolling average (SIP) 0.130 lb/MMBtu 90-boiler operating day rolling average (SIP) 90% reduction of SO_2 on 90-boiler operating day rolling average (SIP) No more than 72 consecutive hours of operation without SO_2 control (SIP)		CEMS Coal Sampling Calculation Recordkeeping	Continuous Daily
NOx	2.3	0.7 lb/MMBtu 3-hour average (NSPS D) 0.30 lb/MMBtu calendar year average (SIP)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		0.08 lb/MMBtu 30-day rolling average (CO Reg. 23, Section IV) 0.46 lb/MMBtu (see Acid Rain requirements in Section III)			
VOC & CO	2.4		See Condition 2.4	Recordkeeping and Calculation	Annually
Opacity	2.5	Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1) Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, SIP) Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP) Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP) Not to exceed 20% during shutdown (SIP)		COMS – May be verified by EPA Reference Method 9	Continuous, 6-Minute Intervals
Coal Requirements	2.6	Coal consumption records Coal sampling		Recordkeeping ASTM Methods	Annually Quarterly
CEMS	2.7	Monitor: Opacity, NO_x, SO_2, diluent gas, flow		See Condition 2.7	
NSPS D	2.8	See Condition 2.8			

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
CO SIP	2.9	See Condition 2.9			
Regional Haze	2.10	PM: 0.03 lb/MMBtu (See Condition 2.1) SO_2: 0.11 lb/MMBtu 30-day rolling average (See Condition 2.2) NO_x: 0.08 lb/MMBtu 30-day rolling average (See Condition 2.3)		CEMS	Continuous
Acid Rain	2.10.2	See Section III of this Operating Permit		Certification	Quarterly and annually
MACT UUUUU (MATS)	2.12	See Condition 2.12 and 5			
CAM	2.13	See Condition 2.13			

Table 3 – Unit 2 Emissions and Requirements Summary

2.1 **Particulate matter (PM)** emissions must not exceed the following limits:

2.1.1 **0.10 lb/MMBtu heat input**, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

2.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 2 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

2.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.1.2 **0.03 lb/MMBtu heat input**, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3 **0.03 lb/MMBtu heat input**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 2.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 2.13 (Colorado Regulation No. 23, Section V.B.1.).

2.1.4 **0.03 lb PM/MMBtu heat input**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

2.1.5 To **demonstrate compliance** with the PM emission limits in Condition 2.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and by conducting periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.1.6 Annual emissions of PM and PM_{10} for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.).:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. PM_{10} emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6; unless a PM_{10} emission factor was developed using source testing.

2.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

2.2.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

2.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

2.2.1.3 The SO_2 emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.2.2 **1.2 lb/MMBtu, three-hour rolling average**, Colorado Regulation No. 1, Section VI.A.

2.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

2.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

2.2.3 **0.11 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 2.2.5.

2.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.2.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.2.3.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.2.3.4, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.6 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.7 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.2.3.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.2.3.8 The Source must maintain records and follow the reporting requirements as described in Condition 2.9.3, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

2.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.2.4.1 The Source must **treat one hundred percent (100%) of the flue gas** from Unit 2 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the SO_2 emission limitations in this section (Condition 2.2.4) and emissions of SO_2 during any such period shall not be excluded from the determination of the Source's compliance with the SO_2 emission limitations.

2.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with SO_2 in excess of the following limitations:

a. 0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis;

b. 0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis.

2.2.4.3 **SO_2 controls must achieve a ninety percent (90%) reduction of SO_2 on a 90 boiler-operating-day rolling-average basis** as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 2.6), a daily potential SO_2 emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily SO_2 emission rate, for each boiler operating day in an arithmetic average of the potential SO_2 emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the SO_2 rolling average basis that is referred to as E_i in the equation below. Each day's potential SO_2 emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis SO_2 stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the SO_2 rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed), will be used to calculate that day's SO_2 rolling average basis that is referred to as E_0 in the equation below. Each day's SO_2 stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 19.4;

c. The 90 day rolling average basis percent SO_2 reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

2.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 2.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the SO_2 control equipment is operating normally.

2.2.5 Compliance calculations for SO_2 requirements in Condition 2.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

2.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

2.2.6 Annual emissions of SO_2 for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

2.3 **Nitrogen oxides (NO_x)** emissions must not exceed the following limits:

2.3.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of 0.7 lb/MMBtu heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25

percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

2.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

2.3.1.3 The NO_x emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with **NO_x in excess of 0.30 lb/MMBtu heat input on a calendar year annual average basis**. Upset conditions do not apply to this limit and emissions of NO_x during any such period shall not be excluded from the determination of the Source's compliance with the NO_x emission limit. Compliance shall be determined on a unit-specific basis using data from NO_x CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 2.7.

2.3.2.2 The Source must operate state-of-the-art low-NO_x burners utilizing two stage combustion with supplemental overfire air.

2.3.3 **0.08 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV – Regional Haze, as provided for in Condition 2.9.3

2.3.3.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.3.3.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.3.3.2, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.4 In determining compliance with the NO_x regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.5 For any hour in which fuel is combusted, the Source shall calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.3.3.2. These hourly average

shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.3.3.6 Compliance shall be monitored using the CEMS as described in Condition 2.3.4.

2.3.3.7 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.102.9.3.

2.3.4 Compliance calculations for NO_x requirements in Condition 2.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.3.4.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.3.4.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

2.3.4.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

2.3.5 Annual emissions of NO_x for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

2.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

2.5 **Opacity**

2.5.1 Colorado Regulation No. 1

2.5.1.1 Except as provided in Condition 2.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

2.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

2.5.2 40 CFR Part 60, Subpart D

2.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

2.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

2.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

2.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

2.5.3.3 An opacity reading in excess of the limitations in Condition 2.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 2.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

2.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

2.5.4 Compliance with the opacity emissions limitations in Condition 2.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.5.4.1 The requirements for the COMS system are outlined in Condition 19.

2.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity

observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

2.5.5 **Partial streamlining of opacity limits into State Implementation Plan opacity limits** – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 2.5.1 and 2.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 2.5.3), except as follows:

2.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 2.5.1 and 2.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

2.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 2.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 2.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

2.6 Coal Requirements

2.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired

belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.7 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

2.7.1 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A. (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

2.8 40 CFR Part 60, Subpart D

2.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.

2.8.2 The Source shall determine compliance with the PM, SO_2, or NO_x standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

2.8.3 **[Excess emissions reports]** Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in

§60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

2.8.3.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

2.8.3.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 2.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

2.8.3.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 2.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

2.8.4 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

2.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 2 in a manner consistent with good air pollution control practices for minimizing emissions.

2.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

2.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

2.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, SO_2, NO_x quarterly excess emission and monitoring report;

b. The required reports for SO_2 emissions (including emissions during all excluded periods as well as SO_2 content calculated from coal for each day, the SO_2 stack emissions for each day, and each day's SO_2 percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for NO_x emissions.

2.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component, unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

2.10 **Colorado Regulation No. 23, Regional Haze**

2.10.1 Craig Unit 2 will close no later than September 30, 2028 (Colorado Regulation No. 23, Section IV.F.1.e.).

2.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

2.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

2.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

2.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

2.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

2.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

2.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

2.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 2 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

2.13 Compliance Assurance Monitoring (CAM)

Unit 2 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 2.1, the SO_2 limitations in Condition 2.2, and the NO_x limitations in Condition 2.3. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G, J, and L.

3. Boiler B003 "Unit 3" – Coal-fired boiler, Babcock & Wilcox #NB24602, 4600 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	3.1	443 tons/year, 12-month rolling total 0.03 lb/MMBtu (Filterable, MATS) 0.013 lb/MMBtu (Filterable, BACT and CO Reg 23) 0.018 lb/MMBtu (Filterable and condensable, BACT)	Stack Performance Testing	Baghouse O&M Stack Performance Testing	Continuous See Condition 3.1
PM_{10}		403 tons/year, 12-month rolling total 0.012 lb/MMBtu (Filterable, BACT and CO Reg 23) 0.018 lb/MMBtu (Filterable and condensable, BACT)			
SO_2	3.2	2,125 tons/year 0.20 lb/MMBtu, daily average, except one daily average per month which may exceed 0.20 lb/MMBtu (BACT) 80% reduction of potential emissions, 30-day average (BACT) 1.20 lb/MMBtu, 90% reduction of potential emissions; 70% reduction of potential emissions when emissions are less	CEMS	CEMS Stack Performance Testing Coal Sampling, Calculation, Recordkeeping	Continuous See Condition 3.2 Daily

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		than 0.60 lb/MMBtu, 30-day rolling average (NSPS Da) 0.4 lb/MMBtu, 3-hour rolling average (CO Reg 1) 0.15 lb/MMBtu, 30-day rolling average (CO Reg 23) 0.20 lb/MMBtu, 30-day rolling average (MATS)			
NOx	3.3	6,752 tons/year 0.50 lb/MMBtu, 30-boiler operating day rolling average (NSPS Da & BACT) 0.28 lb/MMBtu, 30-boiler operating day rolling average (CO Reg 23)	CEMS	CEMS	Continuous
CO	3.4	4,332 tons/year 1.25 lb/MMBtu, 8-hour rolling average (BACT)	CEMS	CEMS	Continuous
VOC	3.5	58 tons/year	0.003 lb/MMBtu, or AP-42, EPRI, stack test data	Recordkeeping and Calculation	Monthly
Lead (Pb)		0.054 tons/year	2.82 lb/TBtu, or AP-42, EPRI, stack test data		
Sulfuric Acid Mist (SAM)		0.10 tons/year	See Condition 3.5		
Fluorides		4.47 tons/year	232.74 lb/TBtu, or AP-42, EPRI, stack test data		
Opacity	3.6	Not to exceed 10% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT)		COMS – May be verified by EPA Reference Method 9	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		During startup and shutdown, not to exceed 20% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT) Not to exceed 20% except during certain operational condition during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg 1) Not to exceed 20% (CO Reg 6 – State-only)			
Coal Requirements	3.7	1,897,344 tons/year Coal sampling		Recordkeeping ASTM Methods	Monthly Quarterly
CEMS	3.8	Monitor: Opacity, NO_x, SO_2, CO, CO_2, diluent gas, flow		See Condition 3.8	
NSPS Da	3.9	See Condition 3.9			
Regional Haze	3.10	See Condition 3.10			
Acid Rain	3.10.2	See Section III of this Operating Permit		Certification	Quarterly and Annually
MACT UUUUU (MATS)	3.12	See Conditions 3.12 and 5			
CAM	3.13	See Condition 3.13			

Table 4 – Unit 3 Emissions and Requirements Summary

3.1 **Particulate matter (PM) and particulate matter less than or equal to 10 microns (PM_{10})** emissions must not exceed the following limits:

3.1.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for PM and PM_{10}. The Division and the EPA have determined that the following limits meet the

BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.1.1.1 **[Filterable only] 0.013 lb PM/MMBtu, 0.012 lb PM_{10}/MMBtu**

a. Compliance with the filterable PM limit will be monitored by stack testing as required in Condition 3.1.4. Compliance with the filterable PM_{10} limit will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.2 **[Total Filterable and Condensable] 0.018 lb PM/MMBtu heat input, 0.018 lb PM_{10}/MMBtu**

a. Compliance with these limits will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.3 **[Total Filterable and Condensable] 443 tons PM/year, 403 tons PM_{10}/year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Compliance with these limits will be monitored per the requirements in Condition 3.1.4.

3.1.2 **[Filterable only] 0.013 lb PM/MMBtu, 0.012 lb PM_{10}/MMBtu**, Colorado Regulation No. 23, Section IV.B.

3.1.2.1 Compliance with this limit will be monitored by the stack testing as required in Condition 3.1.4 and by demonstrating compliance with the CAM plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 3.13 (Colorado Regulation No. 23, Section V.B.1.).

3.1.2.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.1.2.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.B.3.).

3.1.3 **0.03 lb PM/MMBtu**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

3.1.4 To **demonstrate compliance** with PM and PM_{10} emission limits in Condition 3.1, the Source must:

3.1.4.1 For filterable $PM_{10,}$ and total filterable and condensable emission limitations compliance shall be monitored by conducting performance tests as required by Condition 17.

3.1.4.2 The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.1.4.3 For annual filterable and condensable emission limitations, compliance shall be monitored by calculating emissions using the total PM and PM_{10} emission factors from the most recent performance test, and the monthly quantity of heat input to the boiler in the following equation:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use} * \left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The monthly heat input to the boiler shall be determined using the monthly coal consumption and the average heat content of the coal, as determined by the coal sampling as required in Condition 3.7.3. Monthly emissions shall be used in a rolling twelve-month total to monitor compliance with the annual limitation. Each month a new twelve-month total shall be calculated using the previous twelve-months' data.

3.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

3.2.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for SO_2. The Division and the EPA have determined that the following limits meet the BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.2.1.1 **0.20 lb/MMBtu heat input**, as averaged over any calendar day, to be exceeded no more than once during any calendar month.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with this emission limitation is determined by calculating the arithmetic average emissions for any calendar day from the individual hourly values, for each Unit Operating Hour, defined as "a clock hour during which a unit combusts any fuel, either for part of the hour or for the entire hour," by 40 CFR Part 72, §72.2.

3.2.1.2 **80% reduction of the potential combustion concentration of SO_2**, as determined on a 30-day rolling average basis.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with the percentage reduction requirement is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day, and a new 30-boiler operating day rolling average emission rate and a new percent reduction for SO_2 are calculated to show compliance with the standards (40 CFR Part 60, §60.48Da(b)).

c. Compliance is determined by calculating the arithmetic average of all valid hourly emission rates for SO_2 for the 30 successive boiler operating days. Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.1.3 **2,125 tons of SO_2 per year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

3.2.1.4 Compliance with these limits shall be monitored using the CEMS as required in Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.2.2 40 CFR Part 60, Subpart Da, §60.43Da

3.2.2.1 When combusting solid fuel, as applicable, the Source shall not emit into the atmosphere any gases which contain SO_2 emissions in excess of either (40 CFR Part 60, §60.43Da(a):

a. 520 ng/J (**1.20 lb/MMBtu**) heat input and 10 percent of the potential combustion concentration (**90 percent reduction**) (40 CFR Part 60, §60.43Da(a)(1));

b. 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(2));

c. 180 ng/J (1.4 lb/MWh) gross energy output (40 CFR Part 60, §60.43Da(a)(3)); or

d. 65 ng/J (0.15 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(4)).

3.2.2.2 This SO_2 emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.2.2.3 Compliance with the applicable SO_2 emission limit and percentage reduction requirements under 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for SO_2 and a new percent reduction for SO_2 are calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.2.2.4 Compliance with the applicable 30-boiler operating day rolling average for SO_2 emission limits is determined by calculating the arithmetic average of all hourly emission rates for SO_2 for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.2.2.5 Compliance with the applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.2.6 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.2.2.7), compliance with the SO_2 emission requirements in §60.43Da (Condition 3.2.2.1) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part

60, §60.48Da(h)).

3.2.2.7 The Source shall calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, as follows: (40 CFR Part 60, §60.49Da(b)).

a. Sulfur dioxide emissions are monitored at both the inlet and outlet of the SO_2 control device (40 CFR Part 60, §60.49Da(b)(1)).

b. For a facility that qualifies under the numerical limit provisions of §60.43Da, SO_2 emissions are only monitored as discharged to the atmosphere (40 CFR Part 60, §60.49Da(b)(2)).

c. An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of Appendix A to 40 CFR Part 60 may be used to determine potential SO_2 emissions in place of a continuous SO_2 emission monitor at the inlet to the SO_2 control device as required under §60.49Da(b)(1) (Condition 3.2.2.7.a.) (40 CFR Part 60, §60.49Da(b)(3)).

d. If the Source has installed and certified an SO_2 CEMS according to the requirements of §75.20(c)(1) of 40 CFR Part 75 and Appendix A of Part 75, and is continuing to meet the ongoing QA requirements of 40 CFR Part 70, §75.21 and Appendix B of Part 75, that CEMS may be used to meet the requirements of §60.49Da(b) (Condition 3.2.2.7), provided that the following conditions are met (40 CFR Part 60, §60.49Da(b)(4)):

(i) A CO_2 or O_2 (continuous monitoring system) CMS is installed, calibrated, maintained and operated at the same location, according to §60.49Da(d) (Condition 3.2.2.7.e.) (40 CFR Part 60, §60.49Da(b)(4)(i)); and

(ii) For Sources subject to an SO_2 emission limit in lb/MMBtu under §60.43Da (40 CFR Part 60, §60.49Da(b)(4)(ii)):

a) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously (40 CFR Part 60, §60.49Da(b)(4)(ii)(A)); and

b) In addition to meeting the applicable SO_2 and CO_2 (or O_2) relative accuracy specifications in Figure 2 of 40 CFR Part 75, Appendix B, the relative accuracy standard in section 13.2 of Performance Specification 2 in Appendix B to Part 75 is met when the relative accuracy is calculated on a lb/MMBtu basis (40 CFR Part 60, §60.49Da(b)(4)(ii)(B)); and

(iii) The reporting requirements of §60.51Da are met. The SO_2 and, if required, CO_2 (or O_2) data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures of 40 CFR part 75, nor shall the SO_2 data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 75, §60.49Da(b)(4)(iii)).

e. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or CO_2 content of the flue cases at each location where SO_2 emissions are

monitored. For affected facilities subject to a lb/MMBtu SO_2 emission limit under §60.43Da (Condition 3.2.2.1), if the Source has installed and certified a CO_2 or O_2 monitoring system according to 40 CFR Part 75, §75.20(c) and Appendix A to Part 75 and the monitoring system continues to meet the applicable QA provisions of 40 CFR Part 75, §75.21 and Appendix B of Part 75, that CEMS may be used together with the Part 75 SO_2 concentration monitoring system described in §60.49Da(b) (Condition 3.2.2.7), to determine the SO_2 emission rate in lb/MMBtu. SO_2 data used to meet the requirements of §60.51Da (Condition 3.9.2) shall not include substitute data values derived from the missing data procedures in 40 CFR Part 75, Subpart D, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(d)).

f. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

g. Additional CEMS requirements are described in Condition 3.8.

3.2.2.8 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for SO_2. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.2.2.9 The Source shall demonstrate compliance with the SO_2 standards in 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) as described in §60.50Da(c)(1) through (5) (40 CFR Part 60, §60.50Da(c)).

3.2.2.10 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.2.3 **0.4 lb/MMBtu heat input, 3-hour rolling average**, Colorado Regulation No. 1, Section VI.B.4.

3.2.3.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 0.4 lb SO_2/MMBtu heat input (Colorado Regulation No. 1, Section VI.B.4.a.(iii)).

3.2.3.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.B.2.).

3.2.4 **0.15 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV.B.

3.2.4.1 Compliance with this limit will be monitored by the CEMS as required in Condition 3.8 (Colorado Regulation No. 23, Section V.A.1.).

3.2.4.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.2.4.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.2.4.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.2.4.4, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.6 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.7 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.2.4.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.2.5 Compliance calculations for SO_2 requirements in Condition 3.2, with the exception of the annual emission limit in Condition 3.2.1.3, shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 3.8. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

3.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period

of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

3.2.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.2.1.3, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr SO_2 emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.2.6.1 Hourly mass SO_2 emissions (in lbs/hr) shall be determined by taking the hourly 40 CFR Part 75 SO_2 ppm value (which includes replaced or bias-adjusted data, as applicable), multiplying it by the hourly 40 CFR Part 75 stack flow rate (which includes replaced or bias adjusted data, as applicable) and the multiplying it by the applicable conversion factor. The resulting SO_2 lb/hr value (which is calculated using the appropriate equation in Appendix F of 40 CFR Part 75) is then multiplied by the unit operating time for that hour to produce a SO_2 lbs value. Hourly SO_2 mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly SO_2 emissions (in tons).

3.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

3.3 **Nitrogen oxides (NO_x)** emissions must not exceed the following limits:

3.3.1 **0.50 lb/MMBtu heat input, 30 consecutive boiler operating-day rolling average**, Colorado Construction Permit 12MF322-1 The Source must comply with Best Available Control Technology (BACT) requirements for NO_x. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

3.3.1.1 This NO_x emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.1.2 Compliance with the NO_x emission limitation is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day and a new 30 day average emission rate for nitrogen oxides is calculated to show compliance with the standard (40 CFR Part 60, §60.48Da(b)).

3.3.1.3 Compliance with the applicable 30-boiler operating day rolling average for NO_x emission limits is determined by calculating the arithmetic average of all hourly emission rates for NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.1.4 Compliance with this limit shall be monitored using the CEMS as required in

Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.3.2 **6,752 tons of NO_x per year**, Colorado Construction Permit 12MF322-1

3.3.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.8.

3.3.3 40 CFR Part 60, Subpart Da

3.3.3.1 For coal-derived solid fuels: **0.50 lb/MMBtu heat input**, 30-day rolling average (40 CFR Part 60, §60.44Da(a)(1) & §60.44Da(e)).

3.3.3.2 This NO_x emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.3.3 Compliance with the applicable NO_x emission limit requirements under 40 CFR Part 60, §60.44Da (Condition 3.3.3) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for NO_x is calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.3.3.4 Compliance with the applicable 30-boiler operating day rolling average for NO_x emission limits is determined by calculating the arithmetic average of all hourly emission rates for NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.3.5 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.3.3.6), compliance with the NO_x emission requirements in §60.44Da (Condition 3.3.3) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part 60, §60.48Da(h)).

3.3.3.6 The Source shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NO_x emissions discharged into the atmosphere (40 CFR Part 60, §60.49Da(c)(1)); or

If the Source has installed a NO_x emission rate CEMS to meet the requirements of 40 CFR Part 75 and is continuing to meet the ongoing requirements of 40 CFR Part 75, that CEMS may be used to meet the requirements of this section, except that the Source shall also meet the requirements of §60.51Da (Condition 3.9.2). Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in Subpart D of 40 CFR Part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(c)(2)).

a. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or CO_2 content of the flue cases at each location where NO_x emissions are monitored (40 CFR Part 60, §60.49Da(d)).

b. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

c. Additional CEMS requirements are described in Condition 3.8.

3.3.3.7 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for NO_x. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.3.3.8 The Source shall determine compliance with the NO_x standard in 40 CFR Part 60, §60.44Da (Condition 3.3.3) as follows (40 CFR Part 60, §60.50Da(d)):

a. The appropriate procedures in Method 19 of Appendix A of 40 CFR Part 60 shall be used to determine the emission rate of NO_x (40 CFR Part 60, §60.50Da(d)(1)).

b. The continuous monitoring system in 40 CFR Part 60, §60.49Da(c) & (d) (Condition 3.3.3.6) shall be used to determine the concentrations of NO_x and CO_2 or O_2 (40 CFR Part 60, §60.50Da(d)(2)).

3.3.3.9 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.3.4 **0.28 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV.B.

3.3.4.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.3.4.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.3.4.2, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.4 In determining compliance with the NO_x regional haze limit, all periods of emissions

shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.5 For any hour in which fuel is combusted, the Source shall calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.3.4.2. These hourly averages shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.3.4.6 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

3.3.5 Compliance calculations for NO_x requirements in Condition 3.3, with the exception of the annual emission limitation in Condition 3.3.2, shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the 30-day rolling average calculations.

3.3.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

3.3.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.3.2, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr NO_x emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.3.6.1 Hourly mass NO_x emissions (in lb/hr) shall be calculated by multiplying the hourly 40 CFR Part 75 NO_x lb/MMBtu value (which includes replaced or bias-adjusted data, as applicable) by the hourly heat input rate (MMBtu/hr) (which includes replaced and bias-adjusted data from the stack flow and % CO_2 measurements, as applicable). The hourly NO_x lb/MMBtu and heat input values are determined using the relevant equations in Appendix F of 40 CFR Part 75. The resulting NO_x lb/hr value is then multiplied by the unit operating time for that hour to produce a NO_x lbs value. Hourly

NO_x mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly NO_x emissions (in tons).

3.4 Carbon Monoxide (CO)

3.4.1 Colorado Construction Permit 12MF322-1

3.4.1.1 Good combustion practices shall be used to limit CO emissions to **1.25 lb/MMBtu on an 8-hour rolling average**. The Source must comply with Best Available Control Technology (BACT) requirements for CO. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

a. Compliance with this limit shall be monitored using the CO CEMS as required by Condition 3.4.2. The lb/MMBtu emission factor will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.4.1.2 **4,332 tons of CO per year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.4.2.

b. Monthly emissions shall be calculated by multiplying the average monthly emission rate in lb/MMBtu by the total monthly heat input in mmBtu, then converting to tons by dividing by 2000 lb//ton.

3.4.2 Compliance with the CO limits in Condition 3.4 must be monitored using a CO CEMS in accordance with the requirements of Conditions 3.8 and 19, and in accordance with the following:

3.4.2.1 For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average CO concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4.

3.5 Volatile Organic Compounds (VOC), Lead (Pb), Sulfuric Acid Mist (SAM), and Fluorides

3.5.1 The Source shall not cause to be emitted into the atmosphere VOC, Pb, SAM, or fluorides in excess of the following limits:

3.5.1.1 **VOC: 58 tons per year**

3.5.1.2 **Lead (Pb): 0.054 tons per year**

3.5.1.3 **Sulfuric Acid Mist (SAM): 0.10 tons per year**

3.5.1.4 **Fluorides: 4.47 tons per year**

3.5.2 Compliance with the annual limits in Condition 3.5.1 shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be calculated using actual fuel heating values as determined by the required testing in Condition 3.7.3, the actual fuel usage, and Division approved emission factors (the current emission factor as listed in Table 4, AP-42, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.), in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton}{month} = Emission\ Factor\ \left[\frac{lb}{MMBtu}\right] * Fuel\ Heat\ Content\ \left[\frac{MMBtu}{ton\ coal}\right] * Fuel\ Use\ \left[\frac{ton\ coal}{month}\right] * \frac{1\ ton}{2000\ lb}$$

3.6 **Opacity**

3.6.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for opacity. The Division and the EPA have determined that the following limits meet the BACT requirements and that the BACT limits apply at all times, as specified.

3.6.1.1 Except as provided for in Conditions 3.6.1.2 and 3.6.1.3, the Source may not allow or cause the emission into the atmosphere any gases in excess of 10 percent (%) opacity, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

3.6.1.2 During periods of startup and shutdown, opacity must not exceed 20%, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

a. "Startup" means the setting in operation of any air pollution source for any purpose. Startup commences when the ID/FD fans are started with the intent to purge the furnace prior to returning Unit 3 to service. Startup ends at such time when either a third scrubber reactor is placed online or when the average scrubber inlet temperature reaches 250 degrees Fahrenheit, or when the startup is stopped for any reason and the unit drops to zero load.

b. "Shutdown" means the cessation of operation of any air pollution source for any purpose. The cessation of operation for Unit 3 begins when the command signal is initiated by the unit operator to shutdown the unit and ends when fuel is no longer being fired and the fans have been shut off.

3.6.1.3 During the five-day period following the return of each and every baghouse compartment to service following bag replacement, reattachment, and retensioning, up to 20% opacity shall be allowed for no more than a total of 30 six-minute periods during each five-day period following such work, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

3.6.2 Colorado Regulation No. 1

3.6.2.1 Except as provided in Condition 3.6.2.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

3.6.2.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

3.6.3 Colorado Regulation No. 6 [State-only requirement]

3.6.3.1 The Source must not discharge, or cause the discharge into the atmosphere any particulate matter which is in excess of 20% opacity (Colorado Regulation No. 6, Part B. Section II.C.3.). This standard applies at all times except during periods of startup, shutdown, or malfunction

3.6.3.2 In addition, the requirements of Colorado Regulation No. 6, Part A, Subpart A; General Provisions, apply. These requirements include the 40 CFR Part 60, Subpart A, General Provisions which include but are not limited to the requirements described in Condition 18.

3.6.4 Compliance with the opacity emissions limitations in Condition 3.6 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4.

3.6.4.1 The requirements for the COMS system are outlined in Conditions 3.8 and 19.

3.6.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

3.7 Coal Requirements

3.7.1 Consumption of coal must not exceed 1,897,344 tons per year (Colorado Construction Permit 12MF322-1).

3.7.1.1 Compliance with the annual throughput limit shall be determined on a rolling twelve-month total. By the end of each new month a new twelve-month total is calculated based on the previous twelve-months' data.

3.7.2 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years.

3.7.3 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20.

3.8 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO, CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

3.9 40 CFR Part 60, Subpart Da

3.9.1 **Affirmative defense** for exceedance of emissions limit during malfunction, 40 CFR Part 60, §60.48Da(s)

3.9.1.1 In response to an action to enforce the standards set forth in 40 CFR Part 60, Subpart Da, §60.42Da, §60.43Da, §60.44Da, and §60.45Da, the Source may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by a malfunction, as defined at 40 CFR Part 60, §60.2. Appropriate penalties may be assessed, however, if the Source fails to meet the burden of proving

all of the requirements in the affirmative defense as specified in 40 CFR Part 60, §60.48Da(s)(1) and (2). The affirmative defense shall not be available for claims for injunctive relief (40 CFR Part 60, §60.48Da(s)).

3.9.2 **Reporting requirements**, 40 CFR Part 60, §60.51Da

For all reports required in this condition the Source shall submit the written reports required under 40 CFR Part 60, Subparts Da and A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period (40 CFR Part 60, §60.51Da(j)).

The Source may submit electronic quarterly reports for SO_2 and/or NO_x and/or opacity in lieu of submitting the written reports required under 40 CFR Part 60, §60.51Da(b) and (j). The format of each quarterly electronic report shall be coordinated with the Administrator. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the Source indicating whether compliance with the applicable emissions standards and minimum data requirements of 40 CFR Part 60, Subpart Da was achieved during the reporting period (40 CFR part 60, §60.51Da(k)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart Da.

3.9.2.1 For SO_2, NO_x, PM, and NO_x plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) shall be reported to the Division, as applicable (40 CFR Part 60, §60.51Da(a)).

3.9.2.2 For SO_2 and NO_x the information contained in 40 CFR Part 60, §60.51Da(b)(1) through (9) shall be reported to the Division for each 24-hour period (40 CFR Part 60, §60.51Da(b)).

3.9.2.3 If the minimum quantity of emission data as required by 40 CFR Part 60, §60.49Da is not obtained for any 30 successive boiler operating days, the information in §60.51Da(c)(1) through (5) as obtained under the requirements of §60.48Da(h) shall be reported to the Division for that 30-day period (40 CFR Part 60, §60.51Da(c)).

3.9.2.4 In addition to the applicable requirements in §60.7, the Source shall submit excess emission reports for any Method 9 opacity observation emissions in excess of the requirements of §60.43c(c) from the facility occur during the reporting period and shall maintain records according to the requirements specified in §60.51Da(d)(1) (40 CFR Part 60, §60.51Da(d)).

3.9.2.5 For any periods for which opacity, SO_2, or NO_x emissions data are not available, the Source shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation for the control system and affected

facility before and following the period of data unavailability (40 CFR Part 60, §60.51Da(f)).

3.9.2.6 The Source shall submit a signed statement indicating whether (40 CFR Part 60, §60.51Da(h)):

a. The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified (40 CFR Part 60, §60.51Da(h)(1)).

b. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of 40 CFR Part 60, Subpart Da and is representative of plant performance (40 CFR Part 60, §60.51Da(h)(2)).

c. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable (40 CFR Part 60, §60.51Da(h)(3)).

d. Compliance with the standards has or has not been achieved during the reporting period (40 CFR Part 60, §60.51Da(h)(4)).

3.9.2.7 For the purposes of the reports required under 40 CFR Part 60, §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Division each calendar quarter (40 CFR Part 60, §60.51Da(i)).

3.9.3 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

3.10 Colorado Regulation No. 23, Regional Haze

3.10.1 Craig Unit 3 will close no later than December 31, 2029 (Colorado Regulation No. 23, Section IV.F.1.f.).

3.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

3.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

3.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

3.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

3.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

3.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

3.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

3.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 3 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

3.13 Compliance Assurance Monitoring (CAM)

Unit 3 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM and PM_{10} limitations in Condition 3.1, the SO_2 limitations in Condition 3.2, and the NO_x limitations in Condition 3.3. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendices H, K, and M.

4. B001, B002, and B003 – Units 1, 2, and 3: Natural Gas, Propane, and Fuel Oil

The Source must maintain records of annual usage of natural gas, propane, and fuel oil, and the associated annual heat contents of each, as appropriate. If, for each boiler, the total annual heat content of these fuels combined exceeds 5% of the total heat content of all fuels combusted, this Operating Permit shall be reopened to incorporate the appropriate applicable requirements for combusting combined/alternative fuels.

5. 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Units 1, 2 and 3 are subject to the requirements of MACT UUUUU, also known as the mercury and air toxics (MATS) rule. The applicable requirements under the MATS rule are as follows. The requirements apply to Units 1, 2, and 3 unless otherwise specified.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart UUUUU published in the Federal Register on September 9, 2020. However, if revisions to this Subpart are published at a later date, the Source is subject to the applicable revised requirements.

As of the date of publication of this Operating Permit, Units 1, 2, and 3 all: comply with the low EGU emitter (LEE) requirements for PM; use SO_2 as a surrogate for HCl emissions and use an SO_2 CEMS; Units 1 and 2 use mercury (Hg) CEMS, and Unit 3 uses Hg sorbent traps to monitor compliance with the Hg emission limitations.

5.1 §63.9991 What emission limitations, work practice standards and operating limits must I meet?

5.1.1 At all times, the Source shall meet each emission limit and work practice standard in Table 1 through 3 of 40 CFR Part 63, Subpart UUUUU, as applicable, except as provided under §63.10009, and shall meet each operating limit in Table 4 of Subpart UUUUU, as applicable (40 CFR Part 63, §63.9991(a)(1) and (2)). These requirements are as follows:

5.1.2 The Source is subject to the following requirements from Table 2 of Subpart UUUUU:

Table 2.1 Requirements	Pollutant	Emission limits and work practice standards	Specific requirements for test methods in Table 5 of Subpart UUUUU
a.	Filterable PM	0.03 lb/MMBtu OR 0.3 lb/MWh (gross output)	Collect minimum of 1 dscm per run.
b.	Sulfur dioxide (SO_2)[1]	0.2 lb/MMBtu OR 1.5 lb/MWh	SO_2 CEMS
c.	Mercury (Hg)	1.2 lb/TBtu OR 0.013 lb/GWh	LEE testing for 30 days with a sampling period consistent with that given in 5.2.1 of Appendix A to Subpart UUUUU per Method 30B at Appendix A-8 to 40 CFR Part 60 run or HG CEMS or sorbent trap monitoring system only.

Table 5 - Subpart UUUUU Table 2 Requirements

5.1.3 The Source shall conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, as specified in §63.10021(e) (40 CFR part 63, Table 3.1).

5.1.4 The following work practice standards are required during startup (40 CFR Part 63, Table 3.3):

5.1.4.1 Note: The following two definitions of startup apply to this condition, as applicable (40 CFR Part 63, §63.10042):

a. Either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup; or

b. The period in which operation of an EGU is initiated for any purpose. Startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

5.1.4.2 The Source has the option of complying using either of the following work practice standards (40 CFR Part 63, Table 3.3.a):

a. If the Source chooses to comply using paragraph (1) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, the Source must use clean fuels as defined in §63.10042 for ignition. Once the Source converts to firing coal, residual oil, or solid oil-derived fuel, the Source must engage all of the applicable control technologies except dry scrubber and SCR. The Source must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The Source must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this Subpart UUUUU. The Source must keep records during startup periods. The Source must provide reports concerning activities and startup periods, as specified in §63.10011(g) and §63.10021(h) and (i) (Conditions 5.8.8 and 5.8.9). If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.a(1)).

b. If the Source chooses to comply using paragraph (2) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during startup. The Source shall also collect appropriate data, and shall calculate the pollutant emission rate for each hour of startup. For startup of an EGU, the Source shall use one or a combination of the clean fuels defined in §63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. The Source shall have sufficient clean fuel capacity to engage and operate the PM control device within one hour of adding coal to the unit. The Source shall meet the startup period work practice requirements as identified in §63.10020(e) (Condition 5.7.5). Once the Source stats firing coal, emissions shall be vented to the main stack(s). The Source shall comply with the applicable emission limits beginning with the hour after startup ends. The Source shall engage and operate the PM control(s) within 1 hour of first firing of coal. The Source shall start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than Subpart UUUUU that require operation of the control devices (40 CFR Part 63, Table 3.3.a(2)).

5.1.4.3 If the Source chooses to use just one set of sorbent traps to demonstrate compliance with the applicable emission limit, the Source shall comply with the limit at all times except for startup and shutdown periods (40 CFR Part 63, Table 3.3.c).

5.1.4.4 The Source shall collect monitoring data during startup periods as specified in §63.10020(a) and (e) (Condition 5.7.1 and 5.7.5). The Source shall keep records during startup periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). The Source shall provide reports concerning activities and startup periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.d).

5.1.5 The following work practice standards are required during shutdown (40 CFR Part 63, Table 3.4):

5.1.5.1 The Source shall operate all continuous monitoring systems (CMS) during shutdown. The Source shall collect appropriate data, and shall calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used.

5.1.5.2 While firing coal, the Source shall vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, the Source shall operate the controls when necessary to comply with other standards made applicable to the EGU

by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices.

5.1.5.3 If, in addition to the fuel used prior to the initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel shall be one or a combination of the clean fuels defined in §63.10042 and shall be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.

5.1.5.4 The Source shall comply with all applicable emission limits at all times except during startup and shutdown periods at which time the Source shall meet the requirements of the work practices described in Conditions 5.1.4 and 5.1.5. The Source shall collect monitoring data during shutdown periods, as specified in §63.10020(a) (Condition 5.7.1). The Source shall keep records during shutdown periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. The Source shall provide reports concerning activities and shutdown periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning shutdown periods as follows: For shutdown periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for shutdown periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i) (Condition 5.12.9).

5.1.6 As provided in 40 CFR Part 63, §63.6(g), the Administrator may approve the use of an alternative to the work practice standards required in §63.9991 (Condition 5.1) (40 CFR Part 63, §63.9991).

5.2 **§63.10000 What are my general requirements for complying with this subpart?**

5.2.1 The Source shall be in compliance with the emission limits and operating limits in Subpart UUUUU. These limits apply at all times except during periods of startup and shutdown; however the Source is required to meet the work practice requirements, items 3 and 4, in Table 3 of Subpart UUUUU (Conditions 5.1.4 and 5.1.5) during periods of startup or shutdown (40 CFR Part 63, §63.10000(a)).

5.2.2 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include but is not limited to monitoring results, review of operation and maintenance procedure, review of operation and maintenance records, and inspection of the source (40 CFR Part 63,§63.10000(b)).

5.2.3 Initial performance testing is required for all pollutants to demonstrate compliance with the applicable emission limits (40 CFR Part 63, §63.10000(c)(1)).

5.2.3.1 The Source may conduct initial performance testing in accordance with §63.10005(h) (Condition 5.3.6) to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs §63.10000(c)(1)(i)(A) and (B) (Conditions 5.2.3.1.a. and b.) (40 CFR Part 63, §63.10000(c)(1)(i)).

a. Except as provided in §63.10000(c)(1)(i)(c) (Condition 5.2.3.1.c.), the Source may not pursue the LEE option if the EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device (40 CFR Part 63, §63.10000(c)(1)(i)(A)).

b. The Source may not pursue the LEE option for Hg if the EGU is new (40 CFR Part 63, §63.10000(c)(1)(i)(B)).

c. The Source may pursue the LEE option provided that (40 CFR Part 63, §63.10000(c)(1)(i)(c)):

(i) The EGU's control device bypass emissions are measured in the bypass stack or duct, or the control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event (40 CFR Part 63, §63.10000(c)(1)(i)(c)(1)); or

(ii) Except for hours during which only clean fuel is combusted, the Source bypasses the EGU control device only during emergency periods for no more than a total of 2 percent (%) of the EGU's annual operating hours; the Source uses clean fuels to the maximum extent possible during an emergency period; and the Source prepares and submits a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. The Source shall include these emergency emissions along with performance test results in assessing whether the EGU maintains LEE status (40 CFR Part 63, §63.10000(c)(1)(i)(c)(2)).

5.2.3.2 For a qualifying LEE for Hg emissions limits, the Source shall conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(ii)).

5.2.3.3 For a qualifying LEE of any other applicable emissions limits, the Source shall conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(iii)).

5.2.3.4 If the EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable PM, the Source shall demonstrate compliance through an initial performance test and shall monitor continuous performance through either the use of a PM continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly (40 CFR Part 63, §63.10000(c)(1)(iv)).

5.2.3.5 If the EGU does not qualify as a LEE for hydrogen chloride (HCl), the Source may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B of Subpart UUUUU. As an

alternative to HCl CEMS, the Source may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If the EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), the Source may apply a second alternative to HCl CEMS by installing and operating a SO_2 CEMS installed an operated in accordance with 40 CFR part 75 to demonstrate compliance with the applicable SO_2 emission limit (40 CFR Part 63, §63.10000(c)(1)(v)).

5.2.3.6 If the EGU does not qualify as a LEE for Hg, the Source shall demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with Appendix A of Subpart UUUUU (40 CFR Part 63, §63.10000(c)(1)(vi)).

a. The Source may choose to use separate sorbent trap monitoring systems to comply with Subpart UUUUU: one sorbent trap monitoring system to demonstrate compliance with the numeric mercury emissions limit during periods other than startup or shutdown, and the other sorbent trap monitoring system to report average mercury concentration during startup periods or shutdown periods (40 CFR Part 63, §63.10000(c)(1)(vi)(A)).

b. The Source may choose to use one sorbent trap monitoring system to demonstrate compliance with the mercury emission limit at all times (including startup and shutdown periods) and to report average mercury concentration. The Source shall follow the startup or shutdown requirements that follow and are described in Table 3 of Subpart UUUUU (Conditions 5.1.3, 5.1.4, and 5.1.5) (40 CFR Part 63, §63.10000(c)(1)(vi)(B)).

5.2.4 If the Source demonstrates compliance with any applicable emissions limit through use of a CMS, where a CMS includes CPMS and CEMS, the Source shall develop a site-specific monitoring plan and submit it, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies if the Source elects to petition the Administrator for alternative monitoring parameters under §63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plants that apply to CEMS and CPMS prepared under Appendix B to 40 CFR Part 60 or Part 75, and that meet the requirements of §63.10010 (Condition 5.6). Using the process described in §63.8(f)(4), the Source may request approval of monitoring system quality assurance and quality control procedures to those specified in this condition and, if approved, include those in the site-specific monitoring plan. The monitoring plan shall address the provisions in §63.10000(d)(2) through (5) (40 CFR Part 63, §63.10000(d)(1)).

5.2.5 As part of the demonstration of continuous compliance, the Source shall perform periodic tune-ups of the EGU according to §63.00021(e) (Condition 5.8.4) (40 CFR Part 63, §63.10000(e)).

5.2.6 Except as provided in §63.10000(n) (Condition 5.2.16), the Source shall be subject to the requirements of Subpart UUUUU for at least 6 months following the last date it met the definition of an EGU subject to the Subpart (e.g., 6 months after a cogeneration unit provided

more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). The Source may opt to remain subject to the provisions of Subpart UUUUU beyond 6 months after the last date it met the definition of an EGU subject to the Subpart (40 CFR Part 63, §63.10000(f)).

5.2.7 Except as provided under §63.10000(n) (Condition 5.2.16), if the unit no longer meets the definition of an EGU subject to Subpart UUUUU the Source must be in compliance with any newly applicable standards on the date which it is no longer subject to the Subpart. The date the Source is no longer subject to the Subpart is a date selected by the source, that must be at least 6 months from the date the that unit last meet the definition of an EGU subject to the Subpart. The Source shall remain in compliance with Subpart UUUUU until the date it selected to cease complying with the Subpart (40 CFR Part 63, §63.10000(g)).

5.2.8 If the Source owns or operates an EGU that does not meet the definition of an EGU subject to Subpart UUUUU on April 16, 2015, and the Source commences or recommences operations that causes the Source to meet the definition of an EGU subject to Subpart UUUUU, the Source is subject to the provisions of Subpart UUUUU, including, but not limited to, the emission limitations and the monitoring requirements as of the first day the Source meets the definition of an EGU subject to Subpart UUUUU. The Source shall complete all initial compliance demonstrations for Subpart UUUUU applicable to the EGU within 180 days after commencing or recommencing operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU (40 CFR Part 63, §63.10000(h)(1)).

5.2.9 The Source shall provide 30 days prior notice of the date it intends to commence or recommence operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU. The notification must include the information in §63.10000(h)(2)(i) through (iv) (40 CFR Part 63, §63.10000(h)(2)).

5.2.10 If the EGU ceases to operate in a manner that causes the unit to meet the definition of an EGU subject to Subpart UUUUU, the Source must be in compliance with any newly applicable Clean Air Act (CAA) section 112 or 129 standards on the date the Source selected consistent with §63.10000(g) and (n) (Condition 5.2.7 and 5.2.16) (40 CFR Part 63, §63.10000(i)(1)).

5.2.11 The Source shall provide 30 days prior notice of the date the EGU will cease complying with Subpart UUUUU. The notification shall identify the content described in §63.10000(i)(2)(i) through (iv) (40 CFR Part 63, §63.10000(i)(2)).

5.2.12 All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart (40 CFR Part 63, §63.10000(j)).

5.2.13 All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU

shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart. All calibration and drift checks shall be performed as of the date the Source ceases to be or becomes subject to the Subpart. The Source shall also comply with provisions §63.10010, §63.10020, and §63.10021 of Subpart UUUUU (Conditions 5.6, 5.7, and 5.8). Relative accuracy tests shall be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under Subpart UUUUU (40 CFR Part 63, §63.10000(k)).

5.2.14 On or before the date an EGU is subject to Subpart UUUUU, the Source shall install, certify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals during startup periods and shutdown periods. The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods (40 CFR Part 63, §63.10000(l)).

5.2.15 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (see note in Condition 5.1.4), on or before the date the EGU is subject to Subpart UUUUU, the Source shall install, verify, operate, maintain, and quality assurance each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10000(m)).

5.2.15.1 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system (40 CFR Part 63, §63.10000(m)(1)).

5.2.15.2 The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup and shutdown periods (40 CFR Part 63, §63.10000(m)(2)).

5.2.16 If the Source has permanently converted the EGU from coal or oil to natural gas or biomass after the compliance date (or, if applicable, after the approved extended compliance date), as demonstrated by being subject to a permit provision or physical limitation (including retirement) that prevents the Source from operating in a manner that would subject the Source to Subpart UUUUU, the Source shall no longer be subject to Subpart UUUUU, notwithstanding the coal or oil usage in the previous calendar years. The date on which the Source is no longer subject to Subpart UUUUU is the date on which the Source converted to natural gas or biomass firing; it is also the date on which the Source must be in compliance with any newly applicable standards (40 CFR Part 63, §63.10000(n)).

5.3 **§63.10006 When must I conduct subsequent performance tests or tune-ups?**

5.3.1 For affected units meeting the LEE requirements of §63.10005(h), the Source must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 of Subpart UUUUU and §63.10007 (Condition 5.4). Should subsequent emissions testing results show the

unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur (40 CFR Part 63, §63.10006(b)):

5.3.1.1 For all pollutant emission limits except for Hg, the Source shall conduct emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(b)(1)).

5.3.1.2 For Hg, the Source shall install, certify, maintain, and operate a Hg CEMS or sorbent trap monitoring system in accordance with Appendix A to Subpart UUUUU, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the Source shall conduct Hg emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1). The Source must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status (40 CFR Part 63, §63.10006(b)(2)).

5.3.2 Except where §63.10006(a) or (b) (Condition 5.3.1) apply, or where the Source installs, certifies, and operates a PM CEMS to demonstrate compliance with a filterable PM emissions limit, the Source shall conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 of Subpart UUUUU, §63.10007, and §63.10000(c) (Conditions 5.4 and 5.2.3), except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(c)).

5.3.3 Except where §63.10006(b) (Condition 5.3.1) applies, for coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, the Source shall conduct all applicable periodic HCl emissions tests according to Table 5 of Subpart UUUUU and §63.10007 (Conditions 5.4) at least quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(d)).

5.3.4 **[Time between performance tests]**

5.3.4.1 Notwithstanding the provisions of §63.10021(d)(1) (Condition 5.8.4.1), the requirements listed in §63.10006 (h) (Condition 5.3.6), and the requirements of §63.10006(f)(3) (Condition 5.3.4.3), the Source shall complete performance tests for the EGU as follows (40 CFR Part 63, §63.10006(f)(1)):

a. At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter (40 CFR Part 63, §63.10006(f)(1)(i));

b. For annual testing (40 CFR Part 63, §63.10006(f)(1)(ii)):

(i) At least 320 calendar days, measured from the test's end date, must separate performance tests (40 CFR Part 63, §63.10006(f)(1)(ii)(A));

(ii) At least 320 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(B));

(iii) At least 230 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 90 boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(c)); and

c. At least 1,050 calendar days, measured from the test's end date, must separate performance tests conducted every 3 years (40 CFR Part 63, §63.10006(f)(1)(iii)).

5.3.4.2 For units demonstrating compliance through quarterly emission testing, the Source must conduct a performance test in the 4th quarter of a calendar year of the EGU has skipped performance tests in the first 3 quarters of the calendar year (40 CFR Part 63, §63.10006(f)(2)).

5.3.4.3 If the EGU misses a performance test deadline due to being inoperative and if 169 or more boiler operating hours occur in the next test period, the Source must complete an additional performance test in that period as follows (40 CFR Part 63, §63.10006(f)(3)):

a. At least 15 calendar days must separate two performance tests conducted in the same quarter (40 CFR Part 63, §63.10006(f)(3)(i)).

b. At least 107 calendar days must separate two performance tests conducted in the same calendar year (40 CFR Part 63, §63.10006(f)(3)(ii)).

c. At least 350 calendar days must separate two performance tests conducted in the same 3 year period (40 CFR Part 63, §63.10006(f)(3)(iii)).

5.3.5 If the Source elects to demonstrate compliance using emissions averaging under §63.10009 (Condition 5.5), the Source must continue to conduct performance stack tests at the appropriate frequency given in §63.10006(c) through (f) (Conditions 5.3.2 through 5.3.4) (40 CFR Part 63, §63.10009(g)).

5.3.6 If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if the Source chooses to reapply for LEE status, the Source must conduct performance tests at the appropriate frequency given in §63.10006(c) through (e) (Conditions 5.3.2 through 5.3.3) for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria (40 CFR Part 63, §63.10006(h)).

5.3.7 The Source shall conduct a performance tune-up according to §63.10021(e) (Condition 5.8.5) (40 CFR Part 63, §63.10006(i)).

5.3.7.1 For EGUs not employing a neural network combustion optimization during normal operation, each performance tune-up specified in §63.10021(e) must be no more than 36 calendar months after the previous performance tune-up (40 CFR Part 63, §63.10006(i)(1)).

5.4 §63.10007 What methods and other procedures must I use for the performance tests?

5.4.1 Except as otherwise provided in §63.10007 (Condition 5.4), the Source shall conduct all required performance tests according to §63.7(d), (e), (f), and (h). The Source must also

develop a site-specific test plan according to the requirements in §63.7(c) (40 CFR Part 63, §63.10007(a)).

5.4.1.1 If a CEMS is used (for Hg, HCl, SO_2, or other) to determine compliance with a 30- (or, if applicable, 90-) boiler operating day rolling average emission limit, the Source shall collect quality-assured CEMS data for all unit operating conditions, including startup and shutdown (see §63.10011(g) and Table 3 of Subpart UUUUU), except as otherwise provided in §63.10020(b) (Condition 5.7.2). Emission rates determined during startup periods and shutdown periods (as defined in §63.10042) are not to be included in the compliance determinations, except as otherwise provided in §63.10000(c)(1)(vi)(B) and §63.10005(a)(2)(iii) (Condition 5.2.3.6.b) (40 CFR Part 63, §63.10007(a)(1)).

5.4.1.2 If the Source conducts performance testing with test methods in lieu of continuous monitoring, the Source shall operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will generally be between 90 and 110 percent design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(2)).

5.4.1.3 For establishing operating limits with PM CPMS to demonstrate compliance with a PM or non-Hg metals emissions limit, the Source shall operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will generally be between 90 and 110 percent of design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(3)).

5.4.2 The Source shall conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements of Table 5 of Subpart UUUUU (40 CFR Part 63, §63.10007(b)).

5.4.3 If the Source chooses the filterable PM method to comply with the PM emission limit and demonstrates continuous compliance using a PM CPMS as provided for in §63.10000(c) (Condition 5.2.3), the Source must also establish an operating limit according to §63.10011(b), §63.10023 (Condition 5.10), and Tables 4 and 6 of Subpart UUUUU. Should the Source desire to have operating limits that correspond to loads other than maximum normal operating load, the Source must conduct testing at those other loads to determine the additional operating limits (40 CFR Part 63, §63.10007(c)).

5.4.4 Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, the Source shall conduct a minimum of three separate test runs for each performance test, as specified in §63.7(e)(3). Each test run shall comply with the minimum applicable sampling time or volume specified in Table 2 of Subpart UUUUU (Condition 5.1). Sections §63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or

sorbent trap monitoring systems, and for conducting emission tests for LEE qualification (40 CFR Part 63, §63.10007(d)).

5.4.5 To use the results of performance testing to determine compliance with the applicable emission limits in Table 2 of Subpart UUUUU (Condition 5.1), the Source shall follow the requirements in §63.10007(e)(1) through (3) (40 CFR Part 63, §63.10007(e)).

5.4.6 If the Source elects to (or is required to) use CEMS to continuously monitor Hg, HCl, HF, SO_2, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the default values are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). Default values for diluents cap values and for default gross output are described in §63.10007(f)(1) and (2). For the purposes of Subpart UUUUU, the default values are not considered to be substitute data (40 CFR Part 63, §63.10007(f)).

5.4.7 Upon request, the Source shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of §63.10007 (Condition 5.4) (40 CFR Part 63, §63.10007(g))

5.5 **§63.10009 May I use emissions averaging to comply with this Subpart?**

5.5.1 **[General eligibility]** The Source may use emissions averaging as described in §63.10009(a)(2) (Condition 5.5.2) as an alternative to meeting the requirements of §63.9991 for filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if (40 CFR Part 63, §63.10009(a)(1)):

5.5.1.1 The Source has more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control) (40 CFR Part 63, §63.10009(a)(1)(i)); and

5.5.1.2 The Source uses CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance (40 CFR Part 63, §63.10009(a)(1)(ii)).

5.5.2 The Source may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if the averaged Hg emissions for EGUs in the "unit designed for coal ≥8,300 Btu/lb" subcategory are equal to or less than 1.2 lb/TBtu or 1.3E-2 lb/GWh on a 30-boiler operating day basis or if the averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30-group boiler operating days (rolling daily) using data from CEMS and sorbent trap monitoring (for Hg), or a combination of data from CEMS and emissions testing (for other pollutants). The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh) from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory is 90-

group boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of data from CEMS and sorbent trap monitoring. For the purposes of this paragraph, 30- (or 90-) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group operates on each of the 30 or 90 days. The Source must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) of the preceding 30- (or 90-) group boiler operating days (40 CFR Part 63, §63.10009(a)(2)).

5.5.2.1 The Source may choose to have the EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant) (40 CFR Part 63, §63.10009(a)(2)(i)).

5.5.2.2 The Source may not mix bases within the EGU emissions averaging group (40 CFR Part 63, §63.10009(a)(2)(ii)).

5.5.2.3 The Source may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see §63.10009(m) (Condition 5.5.14)) (40 CFR Part 63, §63.10009(a)(2)(iii)).

5.5.3 **[Equations]** The Source must use the following equations when performing calculations for the EGU emissions averaging group (40 CFR Part 63, §63.10009(b)):

5.5.3.1 Group eligibility equations (40 CFR Part 63, §63.10009(b)(1))

$$WAER_m = \frac{(\sum_{j=1}^{p} Herm_j * Rmm_j) + \sum_{k=1}^{m} Ter_k * Rmt_k}{(\sum_{j=1}^{p} Rmm_j) + \sum_{k=1}^{m} Rmt_k} \quad \text{Eq. 1a}$$

Where:

$WAER_m$ = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{i,j}$ = Hourly emission rate (e.g., lb/MMBtu, lb/Mwh) from CEMS or sorbent trap monitoring as determined during the initial compliance determination from EGU j,

Rmm_j = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j,

p = Number of EGUs in emissions averaging group that rely on CEMS,

Ter_k = Emissions rate (lb/MMBtu or lb/MWh) as determined during the initial compliance determination for EGU k,

Rmt_k = Maximum rated heat input, MMbtu/h, or maximum rated gross output, MWh/h, for EGU k, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER_m = \frac{\sum[(\sum_{j=1}^{p} Herm_j)*Smm_j*Cfm_j)]+\sum_{k=1}^{m} Ter_k*Smt_k*Cft_k}{\sum(\sum_{j=1}^{p} Smm_j*Cfm_j)+\sum_{k=1}^{m} Smt_k*Cft_k}$$ Eq. 1b

Where:

Smm_j = Maximum steam generation, lb_{steam}/h or lb/gross output, for EGU j,

Cfm_j = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU j,

Smt_k = Maximum steam generation, lb_{steam}/h or lb/gross output, for EGU k, and

Cfm_k = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU k.

5.5.3.2 Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use Equation 2a or 2b of §63.10009(b)(2) to calculate the 30 day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(2)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{p}(Her_i*Rm_i))_p+\sum_{i=1}^{m}(Ter_i*Rt_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p+\sum_{i=1}^{m} Rt_i}$$ Eq. 2a

Where:

Her_i = Hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = Hourly heat input or gross output from unit i for the preceding 30-group boiler operating days,

p = Number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n= Number of hours that hourly rates are collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = Number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p + \sum_{i=1}^{m}(Ter_i * St_i * Cft_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p + \sum_{i=1}^{m} St_i * Cft_i}$$ Eq. 2b

Where:

Sm_i = Steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = Steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit I that uses emissions testing.

5.5.3.3 Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "coal-fired unit not low rank virgin coal" subcategory. Use equation 3a or 3b of §63.10009(b)(3) to calculate the 90-day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(3)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Rm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p}$$ Eq. 3a

Where:

Her_i = Hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = Hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,

p = Number of EGUs in emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p}$$ Eq. 3b

Where:

Her_I = Hourly emission rate from unit I's Hg CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Sm_i = Steam generation in units of pounds from unit i that uses CEMS or Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

p = Number of EGUs in the emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

5.5.4 **[Separate stack requirements]** For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, the Source may average filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to Subpart UUUUU if the Source satisfies the requirements in §63.10009(d) through (j) (Conditions 5.5.5 through 5.5.11) (40 CFR Part 63, §63.10009(c)).

5.5.5 For each existing EGU in the averaging group (40 CFR Part 63, §63.10009(d)):

5.5.5.1 The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 190 days after April 16, 2015, or the date on which emissions testing done to support the emissions averaging plan is complete (if the Administrator does not require submission and approval of the emissions averaging plan), or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(1)); or

5.5.5.2 The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(2)).

5.5.6 The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 of Subpart UUUUU at all times following the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(e)).

5.5.7 **[Emissions averaging group eligibility demonstration]** The Source must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to §63.10009(f)(1) and (2) (Conditions 5.5.7.1 and 5.5.7.2) using the maximum rated heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing the emissions averaging plan, the Source must conduct required emissions monitoring for 30- (or 90-) days of boiler operating and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with §63.10009. If, before the start of the initial compliance demonstration, the Administrator becomes aware

that the Source intends to use emissions averaging for that demonstration, or if the initial Notification of Compliance Status (NOCS) indicates that the Source intends to implement emissions averaging at a future date, the Administrator may require the Source to submit the proposed emissions averaging plan and supporting data for approval. If the Administrator requires approval of the plan, the Source may not being using emissions averaging until the Administrator approves the plan (40 CFR Part 63, §63.10009(f)).

5.5.7.1 The Source must use Equation 1a in §63.10009(b) (Condition 5.5.3.1) to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(1)).

5.5.7.2 If the Source is not capable of monitoring heat input or gross output, and the EGU generates steam for purposed other than generating electricity, the Source may use Equation 1b of §63.10009 (Condition 5.5.3.1) as an alternative to using Equation 1a of §63.10009 to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(2)).

5.5.8 The Source must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 group boiler operating day rolling average basis (or, if applicable, on a 90 group boiler operating day rolling average basis for Hg) according to §63.10009(g)(1) and (2) (Conditions 5.5.8.1 and 5.5.8.2). The First averaging period ends on the 30th (or, if applicable, 90th for the alternate Hg emission limit) group boiler operating day after the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(g)).

5.5.8.1 The Source must use Equation 2a or 3a of §63.10009(b) (Condition 5.5.3) to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option (40 CFR Part 63, §63.10009(g)(1)).

5.5.8.2 If the Source is not capable of monitoring heat input or gross output, the Source may use Equation 2b or 3b of §63.10009(b) (Condition 5.5.3) as an alternative to using Equation 2a of §63.10009(b) to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option (40 CFR Part 63, §63.10009(g)(2)).

5.5.9 **[CEMS (or sorbent trap monitoring use)]** If an EGU in the emissions averaging group using CEMS (or sorbent trap monitoring for Hg emissions) to demonstrate compliance, the Source must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(h)).

5.5.10 **[Emissions testing]** If the Source uses manual emissions testing to demonstrate compliance for one or more EGUs in the emissions averaging group, the Source must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. the Source may use CEMS or sorbent trap data in combination with data from the most recent manual

performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(i)).

5.5.11 **[Emissions averaging plan]** The Source must develop an implementation plan for emissions averaging according to the procedures and requirements in §63.10009(j)(1) and (2) (40 CFR Part 63, §63.10009(j)).

5.5.12 **[Common stack requirements]** For a group of two or more existing affected units, each of which vents through a single common stack, the Source may average emissions to demonstrate compliance with the limits in Table 2 of Subpart UUUUU if the Source satisfies the requirements of §63.10009(l) or (m) (Conditions 5.5.13 or 5.5.14) (40 CFR Part 63, §63.10009(k)).

5.5.13 For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, the Source may treat such averaging group as a single existing unit for purposes of Subpart UUUUU and comply with the requirements of Subpart UUUUU as if the group were a single unit (40 CFR Part 63, §63.10009(l)).

5.5.14 For all other groups of units subject to §63.10009(k) (Condition 5.5.12), the Source may elect to conduct manual performance tests according to procedures specified in §63.10007 (Condition 5.4) in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other nonaffected units all vent to the common stack, the Source must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, the Source may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. The Source may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis (40 CFR Part 63, §63.10009(m)).

5.5.15 **[Combination requirements]** The common stack of a group of two or more existing EGUs in the same subcategory subject to §63.10009(k) (Condition 5.5.12) may be treated as a single stack for purposes of §63.10009(c) (Condition 5.5.4) and included in an emissions averaging group subject to §63.10009(c) (40 CFR Part 63, §63.10009(n)).

5.6 **§63.10010 What are my monitoring, installation, operation, and maintenance requirements?**

5.6.1 Flue gases from the affected units under Subpart UUUUU exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configurations, or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under Subpart UUUUU, the CMS installation requirements for these exhaust configuration are described in §63.10010(a)(1) through (6) (40 CFR Part 63, §63.10010(a)).

5.6.2 If an oxygen (O_2) or carbon dioxide (CO_2) CEMS is used to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. The Source shall install, certify, maintain, and operate the CEMS according to 40 CFR Part 75. Only QA O_2 or CO_2 data in the emissions calculations shall be used; Part 75 substitute data values shall not be used (40 CFR Part 63, §63.10010(b)).

5.6.3 If the Source is required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain the monitoring system and conduct on-going QA testing of the system according to 40 CFR Part 75. The Source shall only use unadjusted, QA flow rate data in the emissions calculations. The Source shall not apply bias adjustment factors to the flow rate data and shall not use substitute flow rate data in the calculations (40 CFR Part 63, §63.10010(c)).

5.6.4 If the Source is required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain a moisture monitoring system in accordance with 40 CFR Part 75. Alternatively, for coal-fired units, the Source may use appropriate fuel-specific default moisture values from 40 CFR Part 75, §75.11(b) to estimate the moisture content of the stack gas. If the Source installs and operates a moisture monitoring system, the Source shall not use substitute moisture data in the emissions calculations (40 CFR Part 63, §63.10010(d)).

5.6.5 If the Source uses an HCl and/or HF CEMS, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix B of Subpart UUUUU. The Source shall calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of Appendix B to Subpart UUUUU) (40 CFR Part 63, §63.10010(e)).

5.6.6 If the Source uses an SO_2 CEMS:

5.6.6.1 The Source shall install the monitor at the outlet of the EGU, downstream of all emission control devices, and the Source shall certify, operated, and maintain the CEMS according to 40 CFR Part 75 (40 CFR Part 63, §63.10010(f)(1)).

5.6.6.2 For on-going QA, the SO_2 CEMS shall meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of Appendix B to 40 CFR Part 75, with the following addition: the Source shall perform the linearity checks required in section 2.2 of Appendix B of 40 CFR Part 75 if the SO_2 CEMS has a span value of 30 ppm or less (40 CFR Part 63, §63.10010(f)(2)).

5.6.6.3 The Source shall calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day.

Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly SO_2 emission rates in the 30-boiler operating day period (40 CFR Part 63, §63.10010(f)(3)).

5.6.6.4 The Source shall use only unadjusted, QA SO_2 concentration values in the emission calculations; the Source shall not apply bias adjustment factors to the Part 75 O_2 data and shall not use Part 75 substitute data values. For startup or shutdown hours (as defined in §63.10042) the default gross output and the diluents cap are available for use in the hourly SO_2 emission rate calculations, as described in §63.10007(f) (Condition 5.4.6). The Source shall use a flag to identify each startup or shutdown hour and report a special code if the diluents cap or default gross output is used to calculate the SO_2 emission rate for any of these hours (40 CFR Part 63, §63.10010(f)(4)).

5.6.7 If the Source uses and Hg CEMS or a sorbent trap monitoring system, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix A of Subpart UUUUU. The Source shall calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to Section 6.2 of Appendix A of Subpart UUUUU, is the average of all the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of Appendix A of Subpart UUUUU explains how to reduce sorbent trap monitoring system data to an hourly basis (40 CFR Part 63, §63.10010(g)).

5.6.8 If the Source uses a PM CPMS to demonstrate continuous compliance with an operating limit, the Source shall install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in §63.10010(h)(1) through (7) (40 CFR Part 63, §63.10010(h)).

5.6.9 If the Source chooses to comply with the PM filterable emission limit in lieu of metal HAP limits, the Source may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in §63.10010(i)(1) through (5). The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10010(i)).

5.6.10 The Source may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with §63.7(f) as an alternative to the performance test method specified in Subpart UUUUU. If approved to use a HAP metals CEMS, the compliance limit shall be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU. If approved, the Source may choose to install, certify, operated, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in §63.10010(j)(1) through (5) (40 CFR Part 63, §63.10010(j)).

5.6.11 If the Source chooses to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source must install, verify, operate, maintain, and QA each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice

standards required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10010(l)).

5.6.11.1 The Source shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods (40 CFR Part 63, §63.10010(l)(1)).

5.6.11.2 The Source shall submit the site-specific monitoring plan upon request by the Administrator (40 CFR Part 63, §63.10010(l)(2)).

5.6.11.3 The provisions of the monitoring plan must address the items in §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(3)).

5.6.11.4 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications to address §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(4)).

5.6.11.5 The Source shall operate and maintain the monitoring system according to the site-specific monitoring plan (40 CFR Part 63, §63.10010(l)(5)).

5.7 §63.10020 How do I monitor and collect data to demonstrate continuous compliance?

5.7.1 The Source must monitor and collect data according to §63.10020 and the site-specific monitoring plan required by §63.10000(d) (Condition 5.2.4) (40 CFR Part 63, §63.10020(a)).

5.7.2 The Source must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments, and any scheduled maintenance as defined in the site-specific monitoring plan. The Source is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable (40 CFR Part 63, §63.10020(b)).

5.7.3 The Source may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in §63.10000(c)(1)(vi)(B) (Condition 5.2.3.6b) and §63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system QA or QC activities may not be used in calculations used to report emissions or operating levels. The Source shall use all of the QA data collected during all other periods in assessing the operation of the control device and associated control system (40 CFR Part 63, §63.10020(c)).

5.7.4 Periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities excluding zero and span checks must be reported as time the monitor was inoperative (downtime) under 63.10(c). Failure to collect required quality-assured data during monitoring system malfunctions, monitoring system out-of-control periods, or repairs associated with

monitoring system malfunctions or monitoring system out-of-control periods is a deviation from the monitoring requirements (40 CFR Part 63, §63.10020(d)).

5.7.5 If the Source elects to reply on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (40 CFR Part 63, §63.10020(e)):

5.7.5.1 During each period of startup, the Source shall record the information in §63.10020(e)(1)(i) through (v) (40 CFR Part 63, §63.10020(e)(1)).

5.7.5.2 During each period of shutdown, the Source shall record the information in §63.10020(e)(2)(i) through (v) (40 CFR Part 63, §63.10020(e)(2)).

5.7.5.3 For PM or non-mercury HAP metals work practice monitoring during startup periods, the Source shall monitor and collect data according to §63.10020(e)(3)(i)(A) through (E) and the site-specific monitoring plan required by §63.10010(l) (Condition 5.6.11) (40 CFR Part 63, §63.10020(e)(3)).

5.8 §63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

5.8.1 The Source shall demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 2 through 4 of Subpart UUUUU, according to the monitoring specified in Tables 6 and 7 of Subpart UUUUU and §63.10021(b) through (g) (40 CFR Part 63, §63.10021(a)).

5.8.2 Except as otherwise provided in §63.10020(c) (Condition 5.7.3), if the Source chooses to use a CEMS to measure SO_2, PM, HCl, HF, or Hg, emissions, or using a sorbent trap monitoring system to measure Hg emissions, the Source must demonstrate continuous compliance by using all QA hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 8 of Subpart UUUUU (below) to determine the 30- (or, if applicable, 90-) boiler operating day rolling average (40 CFR Part 63, §63.10021(b)).

$$Boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n} \qquad \text{Eq. 8}$$

Where: Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

5.8.3 If the Source uses PM CPMS data to measure compliance with an operating limit in Table 4 of Subpart UUUUU, the Source must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. The Source shall demonstrate continuous compliance by using all QA hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30-operating day

rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 9 of Subpart UUUUU (below) to determine the 30-boiler operating day average (40 CFR Part 63, §63.10021(c)).

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n} \quad \text{Eq. 9}$$

Where: Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30-boiler operating days.

5.8.4 If the Source uses quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10021(d)), the Source

5.8.4.1 May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year (40 CFR Part 63, §63.10021(d)(1)).

5.8.4.2 Must conduct the performance test as defined in Table 5 of Subpart UUUUU and calculate the results of the testing in units of the applicable emissions standard (40 CFR Part 63, §63.10021(d)(2)); and

5.8.5 The Source shall conduct periodic performance tune-ups of the EGU, as specified in §63.10021(e)(1) through (9). For the first tune-up, the Source may perform the burner inspection any time prior to the tune-up or may delay the first burner inspection until the next schedule EGU outage provided the Source meets the requirements of §63.10005. Subsequently, the Source shall perform an inspection of the burner at least once every 48 calendar months. If the EGU is offline when a deadline to perform the tune-up passes, the Source shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit (40 CFR Part 63, §63.10021(e)).

5.8.6 The Source must submit the applicable reports and notifications required under 40 CFR 63.10031(a) through (k) (Condition 5.12) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. If the final date of any time period (or any deadline) for any of these submissions falls on a weekend or a Federal holiday, the time period shall be extended to the next business day. Moreover, if the EPA Host System supporting the ECMPS Client Tool is offline and unavailable for submission of reports for any part of a day when a report would otherwise be due, the deadline for reporting is automatically extended until the first business day on which the system becomes available following the outage. Use of the ECMPS Client Tool to submit a report or notification required under this subpart satisfies any requirement under subpart A of this part to submit that same report or notification (or the information contained in it) to the appropriate EPA Regional office or state agency whose delegation request has been approved (40 CFR Part 63, §63.10021(f)).

5.8.7 The Source shall report each instance in which it did not meet an applicable emissions limit or operating limit in Tables 2 through 4 of Subpart UUUUU or failed to conduct a required tune-

up. These instances are deviations from the requirements of Subpart UUUUU. These deviations shall be reported according to §63.10031 (Condition 5.12) (40 CFR Part 63, §63.10021(g)).

5.8.8 The Source shall follow the startup or shutdown requirements as given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10021(h)).

5.8.8.1 The Source may use the diluents cap and default gross output values, as described in §63.10007(f) (Condition 5.4.6), during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(1)).

5.8.8.2 The Source shall operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(2)).

5.8.8.3 The Source may choose to submit an alternative non-opacity emission standard, in accordance with the requirements contained in §63.10011(g)(4). Until promulgation in the Federal Register of the final alternative non-opacity emission standard, the Source shall comply with paragraph (1) of the definition of "startup" in §63.10042 (40 CFR Part 63, §63.10021(h)(4)).

5.8.9 If you are on paragraph 2 of the definition of startup in 40 CFR 63.10042, the Source must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in the semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, the Source must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i) (40 CFR Part 63, §63.10021(i)).

5.9 §63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

5.9.1 Following the compliance date, the Source must demonstrate compliance with Subpart UUUUU on a continuous basis by meeting the requirements of §63.10022(a)(1) through (4), as follows (40 CFR Part 63, §63.10022(a)).

5.9.1.1 For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.10009(f) and (g) (Conditions 5.5.7and 5.5.8) (40 CFR Part 63, §63.10022(a)(1));

5.9.1.2 For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test (40 CFR Part 63, §63.10022(a)(2));

5.9.1.3 For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 of

Subpart UUUUU that applies (40 CFR Part 63, §63.10022(a)(3)).

5.9.1.4 For each existing EGU participating in the emissions averaging option, operate in accordance with the startup or shutdown work practice requirements given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10022(a)(4)).

5.9.2 Any instance where the Source fails to comply with the continuous monitoring requirements in §63.10022(a)(1) through (3) (Conditions 5.9.1.1 through 5.9.1.3) is a deviation (40 CFR Part 63, §63.10022(b)).

5.10 §63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

5.10.1 During the initial performance test or any such subsequent performance test that demonstrates compliance with filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 2, the Source shall record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for three 3-hour test runs) (40 CFR Part 63, §63.10023(a)).

5.10.2 The Source shall determine the operating limit as provided in §63.10023(b)(1) and (2). The Source shall verify an existing or establish a new operating limit after each repeated performance test (40 CFR Part 63, §63.10023(b)).

5.10.2.1 The Source shall determine the operating limit according to the requirements of §63.10023(b)(i) through (vi)) (40 CFR Part 63, §63.10023(b)(2)).

5.10.3 The Source shall operate and maintain the process and equipment such that the 30 operating day average PM CMPS output does not exceed the operating limit determined in §63.10023(a) and (b) (40 CFR Part 63, §63.10023(c)).

5.11 §63.10030 What notifications must I submit and when?

5.11.1 The Source shall submit all of the notifications in §63.7(b) and (c), §63.8(e), (f)(4) and (6), and §63.9(b) through (h) that apply by the dates specified (40 CFR Part 63, §63.10030(a)).

5.11.2 As specified in §63.9(b)(2), if the Source commences startup on an affected EGU before April 16, 2012, the Source shall submit an Initial Notification not later than 120 days after April 16, 2012 (40 CFR Part 63, §63.10030(b)).

5.11.3 When the Source is required to conduct a performance test, the Source shall submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin (40 CFR Part 63, §63.10030(d)).

5.11.4 When the Source is required to conduct an initial compliance demonstration as specified in §63.10011(a), the Source shall submit a Notification of Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report shall contain all the information specified in §63.10030(e)(1) through (8), as applicable (40 CFR Part 63, §63.10030(e)).

5.11.5 The Source shall submit the notifications in §63.10000(h)(2) and (i)(2) (Conditions 5.2.8 and 5.2.10) that may apply by the dates specified (40 CFR Part 63, §63.10030(f)).

5.12 **§63.10031 What reports must I submit and when?**

5.12.1 The source must submit each report in §63.10031(a)(1) through (5) that applies (40 CFR Part 63, §63.10031(a)).

5.12.2 The source must submit semiannual compliance reports according to the requirements in §63.10031(b)(1) through (6) (40 CFR Part 63, §63.10031(b)).

5.12.3 The compliance report shall contain the information required in §63.10031(c)(1) through (10) (40 CFR Part 63, §63.10031(c)).

5.12.4 Excess emissions and deviation reporting. For EGUs whose owners or operators rely on a CMS to comply with an emissions or operating limit, the semiannual compliance reports described in §63.10031(c) (Condition 5.12.3) must include the excess emissions and monitor downtime summary report described in 40 CFR §63.10(e)(3)(vi). However, starting with the first calendar quarter of 2024, reporting of the information under 40 CFR §63.10(e)(3)(vi) (and under paragraph (e)(3)(v), if the applicable excess emissions and/or monitor downtime threshold is exceeded) is discontinued for all CMS, and the Source must, instead, include in the quarterly compliance reports described in paragraph §63.10031(g) (Condition 5.12.7) the applicable data elements in section 13 of Appendix E of Subpart UUUUU for any "deviation" (as defined in 40 CFR §63.10042 and elsewhere in Subpart UUUUU) that occurred during the calendar quarter. If there were no deviations, the Source must include a statement to that effect in the quarterly compliance report (40 CFR Part 63, §63.10031(d)).

5.12.5 Each affected source that has obtained a Title V Operating Permit pursuant to 40 CFR Part 70 or Part 71 must report all deviations as defined in Subpart UUUUU in the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A). If an affected source submits a semiannual compliance report pursuant to §63.10031(c) and (d) (Condition 5.12.3 and 5.12.4), or two quarterly compliance reports covering the appropriate calendar half pursuant to §63.10031(g) (Condition 5.12.7), along with, or as part of, the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A), and the compliance report(s) includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in Subpart UUUUU, submission of the compliance report(s) satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of the compliance report(s) does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority (40 CFR Part 63, §63.10031(e)).

5.12.6 For each performance stack test completed prior to January 1, 2024, (including 30- (or 90-) boiler operating day Hg LEE demonstration tests and PM tests to establish operating limits for PM CPMS), the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the testing is completed. For each test completed on or after January 1, 2024, in accordance with 40 CFR §63.10031(g)

(Condition 5.12.7), the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU along with the quarterly compliance report for the calendar quarter in which the test was completed (40 CFR Part 63, §63.10031(f)).

5.12.6.1 For each RATA of an Hg, HCl, HF, or SO_2 monitoring system completed prior to January 1, 2024, and for each PM CEMS correlation test, each relative response audit (RRA) and each response correlation audit (RCA) of a PM CEMS completed prior to that date, the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the test is completed. For each SO_2 or Hg RATA completed on or after January 1, 2024, the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E of Subpart UUUUU prior to or concurrent with the relevant quarterly emissions report. For HCl or HF RATAs, and for correlation tests, RRAs, and RCAs of PM CEMS that are completed on or after January 1, 2024, the Source must submit the appendix E reference method information together with the summarized electronic test results, in accordance with section 11.4 of Appendix B of Subpart UUUUU or section 7.2.4 of Appendix C of Subpart UUUUU, as applicable (40 CFR Part 63, §63.10031(f)(1)).

5.12.6.2 If, for a particular EGU or a group of EGUs serving a common stack, the Source has elected to demonstrate compliance using a PM CEMS, an approved HAP metals CEMS, or a PM CPMS, the Source must submit quarterly PDF reports in accordance with §63.10031(f)(6) (Condition 5.12.6.5), which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7). In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CEMS, the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7) must also include the 30- (or, if applicable 90-) boiler operating day rolling average emission rates for Hg, HCl, HF, and/or SO_2, if the Source has elected to (or are required to) continuously monitor these pollutants. Further, if the EGU or common stack is in an averaging plan, the quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group (40 CFR Part 63, §63.10031(f)(2)).

5.12.6.3 The Source must submit semiannual compliance reports as required under §63.10031(b) through (d) (Conditions 5.12.2 through 5.12.4), ending with a report covering the semiannual period from July 1 through December 31, 2023, and Notifications of Compliance Status as required under §63.10030(e) (Condition

5.12.5), as PDF files. Quarterly compliance reports shall be submitted in XML format thereafter, in accordance with §63.10031(g) (Condition 5.12.7), starting with a report covering the first calendar quarter of 2024 (40 CFR Part 63, §63.10031(f)(4)).

5.12.6.4 All reports required by Subpart UUUUU not subject to the requirements in §63.10031(f) and (f)(1) through (4) (Conditions 5.12.6 through 5.12.6.3) shall be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the Source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to §63.10031(f) and (f)(1) through (4) in paper format (40 CFR Part 63, §63.10031(f)(5)).

5.12.6.5 All reports and notifications described in §63.10031(f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA in the specified format and at the specified frequency, using the ECMPS Client Tool. Each PDF version of a stack test report, CEMS RATA report, PM CEMS correlation test report, RRA report, and RCA report must include sufficient information to assess compliance and to demonstrate that the reference method testing was done properly. Note that EPA will continue to accept, as necessary, PDF reports that are being phased out at the end of 2023, if the submission deadlines for those reports extend beyond December 31, 2023. The data elements in §63.10031(f)(6)(i) through (xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file (40 CFR Part 63, §63.10031(f)(6)).

5.12.7 Starting with a report for the first calendar quarter of 2024, the Source must use the ECMPS Client Tool to submit quarterly electronic compliance reports. Each quarterly compliance report shall include the applicable data elements in sections 2 through 13 of Appendix E to Subpart UUUUU. For each stack test summarized in the compliance report, the Source must also submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU. The compliance reports and associated appendix E information must be submitted no later than 60 days after the end of each calendar quarter. (40 CFR Part 63, §63.10031(g)).

5.12.8 On and after January 1, 2024, initial Notifications of Compliance Status (if any) shall be submitted in accordance with 40 CFR §63.9(h)(2)(ii), as PDF files, using the ECMPS Client Tool. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each Notification (40 CFR Part 63, §63.10031(h)).

5.12.9 If the Source has have elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown incidents that occur on or prior to December 31, 2023, the Source must include the information in 40 CFR §63.10031(c)(5) in the semiannual compliance report, in a PDF file. If the Source has elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, the Source must use the ECMPS Client Tool to submit the information in 40 CFR §63.10031(c)(5) and 40 CFR §63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each startup and shutdown report (40 CFR Part 63, §63.10031(i)).

5.12.10 If the Source elects to use a certified PM CEMS to monitor PM emissions continuously to demonstrate compliance with Subpart UUUUU and have begun recording valid data from the PM CEMS prior to November 9, 2020, the Source must use the ECMPS Client Tool to submit a detailed report of the PS 11 correlation test (see Appendix B to 40 CFR Part 63) in a PDF file no later than 60 days after that date. For a correlation test completed on or after November 9, 2020, but prior to January 1, 2024, the Source must submit the PDF report no later than 60 days after the date on which the test is completed. For a correlation test completed on or after January 1, 2024, the Source must submit the PDF report according to section 7.2.4 of Appendix C to Subpart UUUUU. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(j)).

5.12.11 If the Source elects to demonstrate compliance using a PM CPMS or an approved HAP metals CEMS, the Source must submit quarterly reports of the QA/QC activities (*e.g.,* calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CEMS is used for the compliance demonstration in that quarter. Otherwise, the Source must submit a report for the first calendar quarter in which the PM CPMS or HAP metals CEMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(k)).

5.13 **§63.10032 What records must I keep?**

5.13.1 The Source must keep records according to §63.10032(a)(1) and (2). If the Source is required to (or elects to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if the Source elects to use a PM CPMS, the Source must keep the records required under Appendix A and/or Appendix B and/or Appendix C and/or Appendix D to Subpart UUUUU. If the Source elects to conduct periodic (*e.g.,* quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, the source must keep records of the applicable data elements under 40 CFR §63.7(g). The Source must also keep records of all data elements and other information in Appendix E to Subpart UUUUU that apply to the compliance strategy (40 CFR Part 63, §63.10032(a)).

5.13.1.1 In accordance with 40 CFR §63.10(b)(2)(xiv), a copy of each notification or report that the Source submits to comply with this Subpart UUUUU. The Source must also keep records of all supporting documentation for the initial Notifications of Compliance Status, semiannual compliance reports, or quarterly compliance reports that you submit (40 CFR Part 63, §63.10032(a)(1)).

5.13.1.2 Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in §63.10(b)(2)(viii) (40 CFR Part 63, §63.10032(a)(2)).

5.13.2 For each CEMS and CPMS, the Source shall keep records according to §63.10032(b)(1) through (4) (40 CFR Part 63, §63.10032(b)).

5.13.2.1 Records as described in §63.10(b)(2)(vi) through (xi) (40 CFR Part 63,

§63.10032(b)(1)).

5.13.2.2 Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3) (40 CFR Part 63, §63.10032(b)(2)).

5.13.2.3 Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i) (40 CFR Part 63, §63.10032(b)(3)).

5.13.2.4 Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period (40 CFR Part 63, §63.10032(b)(4)).

5.13.3 The Source shall keep the records required in Table 7 of Subpart UUUUU including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit, as applicable (40 CFR Part 63, §63.10032(c)).

5.13.4 The Source shall also keep the records in §63.10032(d)(1) through (3) (Conditions 5.13.4.1 through 5.13.4.3) (40 CFR Part 63, §63.10032(d)).

5.13.4.1 The Source shall keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used (40 CFR Part 63, §63.10032(d)(1)).

5.13.4.2 If the Source combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR §241.3(b)(1), the Source shall keep a record which documents how the secondary material meets each of the legitimacy criteria. If the Source combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR §241.3(b)(2), the Source shall keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR §241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under §40 CFR §241.3(c), the Source shall keep a record which documents how the fuel satisfies the requirements of the petition process (40 CFR Part 63, §63.10032(d)(2)).

5.13.4.3 For an EGU that qualifies as a LEE under §63.10005(h), the Source shall keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions for the pollutant to increase within the last year (40 CFR Part 63, §63.10032(d)(3)).

5.13.5 If the Source elects to average emissions consistent with §63.10009 (Condition 5.5), the Source must additionally keep a copy of the emissions averaging implementation plan required in §63.10009(g), all calculations required under §63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with §63.10022 (Condition 5.9) (40 CFR Part 63, §63.10032(e)).

5.13.6 Regarding startup or shutdown periods (40 CFR Part 63, §63.10032(f)):

5.13.6.1 Should the Source choose to rely on paragraph (1) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of the occurrence and duration of each startup or shutdown (40 CFR Part 63, §63.10032(f)(1)).

5.13.6.2 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of (40 CFR Part 63, §63.10032(f)(2)):

a. The determination of the maximum possible clean fuel capacity for the EGU (40 CFR Part 63, §63.10032(f)(2)(i));

b. The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU (40 CFR Part 63, §63.10032(f)(2)(ii));

c. The information required in §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10032(f)(2)(iii)).

5.13.7 The source shall keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment (40 CFR Part 63, §63.10032(g)).

5.13.8 The Source shall keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b) (Condition 5.2.2), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation (40 CFR Part 63, §63.10032(h)).

5.13.9 The Source shall keep records of the type(s) and amount(s) of fuel used during each startup or shutdown (40 CFR Part 63, §63.10032(i)).

5.13.10 If the Source elects to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, the Source shall keep records of the type(s) and amounts(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met (40 CFR Part 63, §63.10032(j)).

5.14 **§63.10033 In what form and how long must I keep my records?**

5.14.1 Records shall be in a form suitable and readily available for expeditious review, according to §63.10(b)(1) (40 CFR Part 63, §63.10033(a)).

5.14.2 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.10033(b)).

5.14.3 The Source shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). The Source may keep the records off site for the remaining 3 years (40 CFR Part 63, §63.10033(c)).

5.15 §63.10040 What parts of the General Provisions apply to me?

5.15.1 Table 9 of Subpart UUUUU shows which parts of the General Provisions in 40 CFR Part 63, §63.1 through §63.15 apply to the Subpart UUUUU affected EGU.

6. P101 – Coal Handling System for Units 1 & 2

The coal handling system for Units 1 & 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F101a	Coal hauling – Units 1 & 2	$MgCl_2$ or equivalent application
F101b	Coal unloading to grizzly – Units 1 & 2	Water spray with surfactant
F101c	Coal surge pile	Water with surfactant, as necessary
S101d	Primary coal crushing – Units 1 & 2	Baghouse
S101e	Secondary coal crushing building – Units 1 & 2	Baghouse
S101f	Common coal transfer building belt A	Baghouse
S101g	Common coal transfer building belt B	Baghouse
S101h	Coal stackout building – Units 1 & 2	Baghouse
F101i	Coal stackout – Units 1 & 2	Telescopic chute
F101j	Coal storage piles – Units 1 & 2	Water spray prior to stackout, as necessary
S101k	Coal reclaim A – Units 1 & 2	Baghouse
S101l	Coal reclaim B – Units 1 & 2	Baghouse
S101m	Coal tripper deck & silos – Units 1 & 2	Baghouse

Table 6 - P101 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Coal Consumption	6.1	3,900,000 tons/year (through each P101 unit)			Recordkeeping	Annually
PM & PM_{10}	6.2	F101a		AP-42, 13.4.2	Recordkeeping and Calculation	Annually
		F101b S101f S101g S101h F101i S101k S101l S101m		PM: 2.22×10^{-4} lb/ton PM_{10}: 1.05×10^{-4} lb/ton		
		S101d		PM: 0.02 lb/ton PM_{10}: 0.009 lb/ton		
		S101e		PM: 0.05 lb/ton PM_{10}: 0.02 lb/ton		
		F101c F101j				
Opacity	6.3	Not to exceed 20% opacity except during certain operational activities at			EPA Reference Method 9	Semiannually See Condition 15

		which time not to exceed 30% opacity			
Fugitive Emissions	6.4	See Condition 6.4			
Equipment Operation	6.5	See Condition 6.5			
NSPS Y	6.6	Opacity not to exceed 20%		See Condition 6.6	

Table 7 - P101 Emissions and Requirements Summary

6.1 **Coal consumption must not exceed 3,900,000 tons per year, Colorado Construction Permit 11MF276**

6.1.1 Compliance with the annual limit shall be determined on an annual, calendar year basis. Sixty days after the end of the calendar year, a new annual total is calculated.

6.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Units 1 and 2.

6.1.3 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

6.1.4 Records of coal throughput and belt-scale calibrations must be maintained on site for Division inspection upon request.

6.2 **PM and PM_{10} emissions** shall be calculated using the annual coal throughput, emission factors from Table 7 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

6.2.1 For emissions estimates from units without emission factors in Table 7 (F101a, F101c and F101j), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

6.2.2 The Division has approved a 99.0% emission control efficiency for S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

6.3 **Opacity**

6.3.1 All emission units in this condition, with the exception of the fugitive emission units (F101a, F101b, F101c, F101i, and F101j), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

6.4 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 11MF276, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures shall be used to minimize fugitive particulate emissions:

6.4.1 Water with added surfactant must be applied at the grizzly (truck hopper).

6.4.2 The haul road used by coal trucks on the Craig Station property shall be treated with magnesium chloride (or equivalent) to control dust. The treatment material shall be applied as often as necessary to remain viable as a control measure.

6.4.3 The coal being loaded to live storage will be sprayed with water with added surfactant, on an as-needed basis.

6.4.4 Free fall from the stackout tower to the stockpile will be minimized by utilization of telescoping tubes.

6.4.5 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

6.5 All process equipment must be maintained and operated such that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control systems. The emission control equipment shall be maintained in accordance with the manufacturer's instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF276). This condition applies to emission units S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

6.6 **40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants**

The following emission units are subject to the requirements of NSPS Y: S101d, S101e, S101f, and S101g.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

6.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

6.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

7. P102 – Coal Handling System for Unit 3

P102 may be used at times for blending coal used in Units 1 and 2. The coal handling system for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F102a	Coal train unloading – Unit 3	Water spray
S102b	Coal conveyor portal building – Unit 3	Baghouse
S102c	Coal conveyor portal building – Unit 3	Baghouse
S102d	Secondary coal crushing (2 crushers) – Unit 3	Baghouse
S102e	Coal stackout building – Unit 3	Baghouse
F102f	Coal stackout – Unit 3	Telescopic chutes
F102g	Coal storage pile – Unit 3	PM control plan, including compaction, chemical use or watering, as necessary
S102h	Coal reclaim system – Unit 3	Baghouse
S102i	Coal tripper deck & silos – Unit 3	Baghouse
S102j	Loadout coal to railcars – Unit 3	Baghouse
S102k	Common coal transfer building extension	Baghouse
F102l	Coal train loading	N/A

Table 8 - P102 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Coal Consumption	7.1	4,500,000 tons/year (each unit but tripper deck) 1,897,344 tons/year (tripper deck) Coal Storage Pile: ≤ 14.5 acres			Recordkeeping	Monthly
PM & PM_{10}	7.2	F102a S102b S102c S102e F102f S102h S102k S102i S102j	PM: 1.7 tons/year (all units combined) PM_{10}: 0.7 tons/year (all units combined)	PM: 2.22×10^{-4} lb/ton PM_{10}: 1.05×10^{-4} lb/ton	Recordkeeping and Calculation	Monthly
		S102d		PM: 0.05 lb/ton PM_{10}: 0.02 lb/ton		

		F102g F102l				
Opacity	7.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9	Semiannually See Condition 15
Fugitive Emissions	7.4	See Condition 6.4				
Required Controls	7.5	See Condition 7.5				
NSPS Y	7.6	Opacity not to exceed 20%			See Condition 7.6	
CAM	7.7	Condition 7.7				

Table 9 - P102 Emissions and Requirements Summary

7.1 **Coal consumption, Colorado Construction Permit 12MF322-2**

Coal throughput must not exceed 4,500,000 tons per year (all units except for tripper deck)

Coal throughput through the tripper deck must not exceed 1,897,344 tons per year

Coal storage pile must not exceed 14.5 acres in size

7.1.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Unit 3. Throughput to the tripper deck must be monitored separately.

7.1.3 Compliance with the coal storage pile limit must be certified on a once per calendar year basis. The Source must provide to the Division the methodology for the measurement. At the Division's discretion, the Division may require an alternative methodology for the measurement.

7.1.4 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

7.1.5 Records of coal throughput, coal storage pile certifications, and belt-scale calibrations must be maintained on site for Division inspection upon request.

7.2 **PM emissions must not exceed 1.7 tons per year, PM_{10} emissions must not exceed 0.7 tons per year, Colorado Construction Permit 12MF322-2**

7.2.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.2.2 Emissions shall be calculated using the annual coal throughput, emission factors from Table 9 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

7.2.3 For emission estimates from units without emission factors in Table 9 (F102g, F102l), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

7.2.4 The Division has approved a 99.0% emission control efficiency for S102b, S102c, S102d, S102e, S102h, S102i, S102j, and S102k. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

7.3 **Opacity**

7.3.1 All emission units in this condition, with the exception of the fugitive emission units (F102a, F102f, F102g, and F102l), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

7.4 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 12MF322-2, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures represent BACT for PM and PM_{10} and must be used to minimize fugitive particulate emissions:

7.4.1 The train dump area must be equipped with water spray bars which shall be operated whenever a load of coal is dumped, as needed, to minimize fugitive dust emissions. The spray nozzles shall be positioned so as to achieve the greatest effectiveness in dust control.

7.4.2 Adjustable chutes must be used to transfer coal to the stockpiles. These chutes shall minimize the free fall distance from the chute outlet to the pile.

7.4.3 Control measures must be taken as necessary to minimize fugitive coal dust emissions from the coal storage pile. These control measures shall include compaction, spraying the piles with water, or if necessary, a chemical stabilizer.

7.4.4 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

7.5 Fabric filter baghouses shall be employed to control dust emissions from crushing operations, transferring operations, and reclaiming of coal (Colorado Construction Permit, 12MF322-2). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

7.6 **40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants**

The following emission units are subject to the requirements of NSPS Y: F102a, S102b, S102c, S102d, S102h, S102j, S102k, and F102l.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

7.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

7.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

7.7 **Compliance Assurance Monitoring (CAM)**

The secondary coal crushing building (S102d) is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 7.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendix I.

8. P201 – Limestone Handling and Storage Facility for Units 1 and 2

The limestone handling and storage facility for Units 1 and 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F201a	Limestone hauling	Paved portions of road
S201b	Limestone truck unloading	Baghouse
S201c	Limestone silo #1 – Units 1 & 2	Baghouse
S201d	Limestone silo #2 – Units 1 & 2	Baghouse
N/A	Limestone conveying	Building enclosure

Table 10 – P201 Emission Units Description

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Limestone Delivery	8.1			Recordkeeping	Annually
PM & PM_{10}	8.2	F201a	PM: Paved: 3.97 Unpaved: 10.3 PM_{10}: Paved: 0.79 Unpaved: 2.9 EF in lb per vehicle mile traveled	Recordkeeping and Calculation	Annual
		S201b S201c S201d	PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton		
Opacity	8.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
Baghouse	8.4	See Condition 8.4			
Equipment Operation	8.5	See Condition 8.5			
NSPS OOO (conveying only)	8.6	Opacity not to exceed 7%			

Table 11 – P201 Emissions and Requirements Summary

8.1 Records of the annual quantity (in tons) of limestone delivered for P201 must be maintained and made available for Division inspection upon request.

8.2 Emissions shall be calculated using the annual limestone throughput (estimated as limestone delivered to the facility), emission factors from Table 11 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

8.2.1 For F201a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 11. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

8.2.2 The Division has approved a 99.0% emission control efficiency for S201b, S201c, and S201d. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

8.3 **Opacity**

8.3.1 All emission units in this condition, with the exception of the fugitive emission units (F201a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

8.4 The unloading facilities (S201b) must be vented to a baghouse (Colorado Construction Permit 11MF415). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

8.5 All process equipment (S201b, S201c, S201d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF415). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

8.6 **40 CFR Part 60, Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants**

The following emission units are subject to the requirements of NSPS OOO: limestone belt conveyors. The applicability date for Subpart OOO was August 31, 1983; any facility which commenced construction, modification, or reconstruction after this date is subject. The Source must maintain a log of

which pieces of the limestone conveying system are subject to each of the following provisions of NSPS OOO for Division inspection upon request.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart OOO published in the Federal Register on April 28, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

8.6.1 If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in §60.672(a) and (b), or the building enclosing the affected facility or facilities must comply with the following emission limit (40 CFR Part 60, §60.672(e)):

8.6.1.1 Fugitive emissions from the building openings (except for vents as defined in §60.671) must not exceed 7 percent opacity (40 CFR Part 60, §60.672(e)(1)).

8.6.2 The Source must submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards set forth in in §60.672 of Subpart OOO, including reports of opacity observations made using Method 9 to demonstrate compliance with §60.672(b) and (e) (Condition 8.6.1) (40 CFR Part 60, §60.676(f)).

8.6.3 The conveyors subject to Subpart OOO in this condition are also subject to the provisions of 40 CFR Part 60, Subpart A, General Provisions as described in Condition 18.

9. P202 – Lime Handling and Storage Facility for Unit 3

The lime handling and storage facility for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F202a	Lime hauling	Paved portions of road
S202b	Lime unloading	Baghouse
S202c	Lime conveying and silo	Baghouse
S202d	Lime day bin	Baghouse

Table 12 – P202 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Lime Delivery	9.1	28,000 tons/year via truck 28,000 tons/year via rail			Recordkeeping	Monthly
PM & PM_{10}	9.2	F202a	PM: 14.9 tons/year, 12-month rolling total (all units combined) PM_{10}: 2.9 tons/year, 12-month rolling total (all units combined)	PM: Paved: 5.39 Unpaved: 11.84 PM_{10}: Paved: 1.08 Unpaved: 3.37 EF in lb per vehicle mile traveled	Recordkeeping and Calculation	Monthly
		S202b S202c S202d		PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton		
Opacity	9.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
12MF322-4 Baghouses	9.4	See Condition 9.4				
Equipment Operation	9.4.3	See Condition 9.4.3				

Table 13 – P202 Emissions and Requirements Summary

9.1 **Throughput of lime must not exceed 28,000 tons per year via truck, and 28,000 tons per year via rail (Colorado Construction Permit 12MF322-4)**

9.1.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data

9.1.2 Monthly records of the quantity (in tons) of lime throughput for P202 must be maintained and made available for Division inspection upon request. These records must specify whether the lime was delivered via truck or via rail.

9.2 **PM and PM_{10} emissions must not exceed 14.9 tons per year and 2.9 tons per year, respectively, for all P202 emission units combined (Colorado Construction Permit 12MF322-4)**

9.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

9.2.2 Emissions shall be calculated using the actual lime throughput (as required in Condition 9.1), emission factors from Table 13 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

9.2.3 For F202a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 13. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

9.2.4 The Division has approved a 99.0% emission control efficiency for S202b, S202c, and S202d, and a 90% emission control efficiency for F202a. The acceptance of these control efficiencies is contingent on continued routine maintenance of and operation procedures performed on the control devices in accordance with manufacture's specifications and good engineering practices. These procedures and maintenance schedules shall be maintained on site and provided for Division inspection upon request.

9.3 **Opacity**

9.3.1 All emission units in this condition, with the exception of the fugitive emission units (F202a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

9.4 **Colorado Construction Permit 12MF322-4**

9.4.1 The bulk lime unloading facilities (S202b) must be vented to a baghouse. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.2 The lime silo must be vented to a fabric filter baghouse to control emissions from unloading and working losses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.3 All process equipment (S202b, S202c, S202d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 12MF322-4). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

10. P203 – Ash Handling System for Units 1 & 2

The ash handling system for Units 1 & 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
S203a	Ash storage silo A – Units 1 & 2	Baghouse (Shared with S203e)
S203b	Ash storage silo B – Units 1 & 2	Baghouse (Shared with S203d)
F203c	Ash truck loading – Units 1 & 2	Low dust unloader
S203d	Silo B dry ash unloading – Units 1 & 2	Baghouse (Shared with S203b)
S203e	Silo A dry ash unloading – Units 1 & 2	Baghouse (Shared with S203a)

Table 14 – P203 Emission Units Description

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Ash Processed	10.1			Recordkeeping	Annually
PM & PM_{10}	10.2	S203a S203e S203b S203d	PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton	Recordkeeping and Calculation	Annually
		F203c	PM: 0.0005 lb/ton PM_{10}: 0.0002 lb/ton		
Opacity	10.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
11MF332 Process Requirements	10.4	See Condition 10.4			

Table 15 – P203 Emissions and Requirements Summary

10.1 Records of the estimated quantity (in tons) of ash processed for P203 must be maintained and made available for Division inspection upon request. Ash quantities are estimated from the number of trucks loaded and the average truck load capacity (Colorado Regulation No. 3, Part C, Section V.C.5.).

10.2 Emissions shall be calculated using the annual ash throughput, emission factors from Table 15 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

10.2.1 The Division has approved a 99.0% emission control efficiency for S203a and S203b. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

10.3 **Opacity**

10.3.1 All emission units in this condition, with the exception of the fugitive emission units (F203c) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

10.4 **Colorado Construction Permit 11MF332** (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

10.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

10.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 10.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

10.4.3 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

10.4.3.1 Ash for disposal must be loaded through chutes into the trucks. Ash leaving the chutes and loaded into trucks for disposal must be sufficiently wet to minimize fugitive dust emissions.

10.4.3.2 Deposition of mud and dirt on improved public streets and roads must be prevented, as necessary, to control fugitive dust emissions.

10.4.4 All process equipment (S203a, S203b, S203d, S203e) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

11. P204 – Ash Handling System for Unit 3

The ash handling system for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
S204a	Ash storage silo C – Unit 3	Baghouse
F204b	Ash truck loading (wet flyash and dry flyash) – Unit 3	Low dust loader (wet ash) Baghouse (Only for dry fly ash loading)
S204c	Recycle ash tank	Baghouse
F204d	Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3	$MgCl_2$ application on roads

Table 16 – P204 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Ash Throughput	11.1	Unit 3 flyash handling: 174,649 tons/year Unit 3 ash and scrubber sludge handling: 237,247 tons/year			Recordkeeping	Monthly
PM & PM_{10}	11.2	S204a S204c	PM: 76.6 tons/year (all units combined) PM_{10}: 16.1 tons/year (all units combined)	PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton	Recordkeeping and Calculation	Monthly
		F204b		Flyash loading: PM: 0.0005 lb/ton PM_{10}: 0.0002 lb/ton Dry ash unloading: PM: 0.081 lb/ton PM_{10}: 0.039 lb/ton From AP-42, 13.2.4 Assume: U = 8.1 mph, M = 0.25%	
		F204d		PM: Paved: 6.39 Unpaved: 12.76 PM_{10}: Paved: 1.28		

				Unpaved: 3.6 EF in lb per vehicle mile traveled		
Opacity	11.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
12MF322-3 Process Requirements	11.4	See Condition 11.4				

Table 17 – P204 Emissions and Requirements Summary

11.1 **Unit 3 flyash handling must not exceed 174,649 tons per year, Unit 3 ash and scrubber sludge handling must not exceed 237,247 tons per year, Colorado Construction Permit 12MF322-3**

11.1.1 Compliance with the annual throughput limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.1.2 Records of the quantity (in tons) of Unit 3 flyash handled and Unit 3 ash and scrubber sludge handled must be maintained and made available for Division inspection upon request.

11.2 **PM emissions must not exceed 76.6 tons per year, PM_{10} emissions must not exceed 16.1 tons per year, Colorado Construction Permit 12MF322-3**

11.2.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.2.2 Emissions shall be calculated using the annual ash throughputs, emission factors from Table 17 (AP-42, Section 13.2.4 (November 2006), note that F204b includes emission factors for both flyash loading and dry ash unloading), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

11.2.3 For emission estimates from units which reference AP-42, Section 13.4.2 (November, 2006) in Table 17, records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

11.2.4 The Division has approved a 99.0% emission control efficiency for S204a and S204c, a 90.0% emission control efficiency for F204d ash haul road, and 80% and 99% emission control efficiencies for F204b wet flyash loading, and F204b dry ash loading, respectively. The acceptance of these control efficiencies shall only be granted provided that the Source operates

and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

11.3 **Opacity**

11.3.1 All emission units in this condition, with the exception of the fugitive emission units (F204b ash truck loading, and F204d ash haul road) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

11.4 **Colorado Construction Permit 12MF322-3** (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

11.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

11.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 11.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

11.4.3 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

11.4.3.1 Ash loaded into trucks for disposal must be sufficiently wet to control fugitive dust emissions.

11.4.3.2 A low dust unloading system must be employed to load the ash hauling trucks for ash disposal. Ash leaving these unloaders must be sufficiently wet to minimize fugitive emissions.

11.4.3.3 All components of the ash conveying system must be dust tight to eliminate leaks in the system.

11.4.3.4 The scrubber sludge and ash haul road for Units 1, 2, and 3 must be treated with magnesium chloride ($MgCl_2$), or equivalent, as a dust suppressant. The $MgCl_2$ must be applied in accordance as necessary in accordance with good air pollution control practices to minimize the emission of fugitive dust.

11.4.4 All process equipment must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

12. S401 & S402 – Units 1 & 2 Cooling Towers

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Circulating Water Rate	12.1	Maximum Pumping Capacity: 180,000 gallons/minute (per tower)		Design Limitation Certification	Annually
Total Dissolved Solids	12.2	11,040 milligrams/liter		Sampling and Testing	Monthly
PM & PM_{10}	12.3	PM: 27.2 tons/year PM_{10}: 27.2 tons/year	TDS Sampling See Condition 12.3	Recordkeeping and Calculation	Annually
VOC	12.4	5.0 tons/year	0.0527 lb/10^6 gallons	Recordkeeping and Calculation	Annually
Opacity	12.5	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		See Condition 12.5	

Table 18 – S401 & S402 Emissions and Requirements Summary

12.1 **The cooling tower water flow rate must not exceed 180,000 gallons per minute (per tower), Colorado Construction Permit 96MF195**

12.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system (153,000 gallons per minute). The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

12.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

12.2 **Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 96MF195**

12.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

12.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division-approved test method.

12.2.2.1 Monthly samples must be taken at least seven (7) days apart.

12.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration shall be the average of all samples taken, as appropriate.

12.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 12.2), and results must be maintained and made available for Division inspection upon request.

12.3 **PM and PM_{10} emissions must not exceed 27.2 tons per year (combined emissions), Colorado Construction Permit 96MF195**

12.3.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

12.4 **VOC emissions must not exceed 5.0 tons per year (combined emissions), Colorado Construction Permit 96MF195**

12.4.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 18 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

12.5 **Opacity**

12.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as

records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

13. S403 – Unit 3 Cooling Tower

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Circulating Water Rate	13.1	Maximum Pumping Capacity: 180,000 gallons/minute		Design Limitation Certification	Annually
Total Dissolved Solids	13.2	11,040 milligrams/liter		Sampling and Testing	Monthly
PM & PM_{10}	13.2.2	PM: 13.6 tons/year PM_{10}: 13.6 tons/year	TDS Sampling See Condition 13.2.2	Recordkeeping and Calculation	Monthly
VOC	13.4	2.5 tons/year	0.0527 lb/10^6 gallons	Recordkeeping and Calculation	Monthly
Opacity	13.5	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		See Condition 13.5	

Table 19 – S403 Emissions and Requirements Summary

13.1 **The cooling tower water flow rate must not exceed 180,000 gallons per minute, Colorado Construction Permit 98MF0141**

13.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system. The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

13.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

13.2 **Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 98MF0141**

13.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

13.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division approved test method.

13.2.2.1 Monthly samples must be taken at least seven (7) days apart.

13.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration shall

be the average of all samples taken, as appropriate.

13.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 13.2), and results must be maintained and made available for Division inspection upon request.

13.3 **PM and PM_{10} emissions must not exceed 13.6 tons per year, Colorado Construction Permit 98MF0141**

13.3.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

13.4 **VOC emissions must not exceed 2.5 tons per year, Colorado Construction Permit 98MF0141**

13.4.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 19 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

13.5 **Opacity**

13.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance

procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

14. Emergency Diesel Engines

The emergency fire-pump engine, Units 1 & 2 emergency diesel generator engine, and the Unit 3 emergency diesel generator engine (see Table 1 for relevant make, model, and serial numbers) are emission units covered under this condition. At the time of issuance of this Operating Permit, these engines do not require emission limits because they are exempt under Colorado Regulation No. 3, Part C, Section II.E.3.nnn.(iii) since they have fewer than five (5) tons per year of actual emissions.

14.1 Except as provided in Condition 14.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity (Colorado Regulation No. 1, II.A.1.).

14.1.1 An EPA Reference Method 9 opacity observation shall be performed on this engine at least once per calendar year of operation when the engine is operating during conditions suitable for properly performing a valid Method 9 observation. If an engine has not been operated or if a valid Method 9 observation could not be performed when the engine did operate during the calendar year, the Source is not required to operate the engine for the sole purpose of obtaining an annual opacity observation.

14.1.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.1.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.1.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observation. These records and the copy of the certification shall be made available to the Division for review upon request.

14.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any pollutant resulting from start-up, which is in excess of 30% opacity for a period or period aggregated more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, II.A.4.).

14.2.1 A record shall be kept of the type, date, and time of the commencement and completion of each and every condition subject to Regulation No. 1, II.A.4. that results in an opacity exceedance. The records shall be made available to the Division upon request for review. A Method 9 observation shall be performed any time an engine start-up requires longer than ten (10) consecutive minutes.

14.2.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.2.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.2.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observations. The records and the copy of the certification shall be made available for to the Division upon request for review.

14.3 **40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [Federal-only requirement]**

The emergency diesel fire pump engine in the insignificant activities list is subject to the requirements in 40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines."

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart ZZZZ published in the Federal Register on 2/27/2014. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 63, Subpart ZZZZ.

The D.C. Circuit Court issued a mandate on May 4, 2016 for vacatur for certain requirements of allowing emergency engines to operate for limited hours for demand response. See EPA memorandum "Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines" published on April 15, 2016 for more information.

These requirements have not been adopted into Colorado Regulation no. 8, Part E as of the date of publication of this Operating Permit, and are therefore not state-enforceable. In the event that these requirements are adopted into Colorado Regulations, they will become state-enforceable.

14.3.1 Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions do not have to meet the requirements of Subpart ZZZ and of 40 CFR Part 63, Subpart A, including initial notification requirements (40 CFR Part 63, §63.6590(b)(3)(iv)). Under Subpart ZZZZ, the definition of a limited use stationary RICE means any stationary RICE that operates less than 100 hours per year (40 CFR Part 63, §63.6675). *Note that the Units 1&2, and the Unit 3 emergency engines may qualify for this exemption. The Source must maintain records which demonstrate that the annual hours of operation for each engine are under 100 if claiming this exemption.*

§63.6602 – What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

14.3.2 If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you (40 CFR Part 63, §63.6602). The applicable requirements of Table 2c are as follows:

14.3.2.1 Change oil and filter every 500 hours of operation or annually, whichever comes first. The Source has the option to utilize an oil analysis program as described in §63.6625(i) to extend the specified oil change requirement.

14.3.2.2 Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

14.3.2.3 Inspect all hoses and belts every 500 hours of operation, or annually, whichever comes first, and replace as necessary.

14.3.2.4 During periods of startup the Source must minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

§63.6605 – What are my general requirements for complying with this Subpart?

14.3.3 The Source shall be in compliance with the operating limitations and other requirements in Subpart ZZZZ that apply at all times (40 CFR Part 63, §63.6605(a)).

14.3.4 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the Source to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspections of the Source (40 CFR Part 63, §63.6605(b)).

§63.6625 – What are my monitoring, installation, collection, operation, and maintenance requirements?

14.3.5 The Source shall operate and maintain the engines according to the manufacturer's emission-related written instructions. Alternatively the Source shall develop a separate maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, §63.6625(e)(2)).

14.3.6 The Source shall install a non-resettable hour meter on each engine if not already installed (40 CFR Part 63, §63.6625(f)).

§63.6640 – How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

14.3.7 The Source shall demonstrate continuous compliance with each operating limitation, and other requirements in Tables 1a, 1b, 2a, 2b, 2c, and 2d of Subpart ZZZZ, as applicable, according to methods specified in Table 6 of Subpart ZZZZ, which are described as follows (40 CFR Part 63, §63.6640(a)):

14.3.7.1 For demonstrating compliance with work or management practices (40 CFR Part 63, Table 6, (9)(a)):

a. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions (40 CFR Part 63, Table 6, (9)(a)(i)); or

b. Develop and follow an alternative maintenance plan which must provide to the extent practicable for the maintenance and operation to the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, Table 6, (9)(a)(ii)).

14.3.8 The Source shall operate the engine according to the requirements in §63.6640(f)(1) through (4) (Conditions 14.3.8.1 through 14.3.8.2) for the engine to be considered emergency engine under Subpart ZZZZ. Any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in §63.6640(f)(1) through (4), is prohibited. If the Source does not operate the engine according to the requirements in §63.6640(f)(1) through (4), the engine will not be considered an emergency engine under Subpart ZZZZ and must meet all requirements for non-emergency engines (40 CFR Part 63, §63.6640(f)).

14.3.8.1 There is no time limit on the use of emergency stationary RICE in emergency situations (40 CFR Part 63, §63.6640(f)(1)).

14.3.8.2 The Source may operate the engine for the purposes specified in §63.6640(f)(2)(i) (Condition 14.3.8.2.a) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by §63.6640(f)(3) and (4) counts as part of the 100 hours per calendar year allowed by §63.6640(f)(2) (40 CFR Part 63, §63.6640(f)(2)).

a. Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator

maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year (40 CFR Part 63, §63.6640(f)(2)(i)).

§63.6655 – What records must I keep?

14.3.9 The Source shall keep records of the maintenance conducted on the engine to demonstrate that it was operated and maintained according to the maintenance plan (40 CFR Part 63, §63.6655(e)).

14.3.10 The Source shall keep records of the hours of operation of the engine as recorded on the non-resettable hour meter. The owner or operator shall document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation (40 CFR Part 63, §63.6655(f)).

§63.6660 – In what form and how long must I keep my records?

14.3.11 The records shall be in a form suitable and readily available for expeditious review according to §63.10(b)(1) (40 CFR Part 63, §63.6660(a)).

14.3.12 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.6660(b)).

14.3.13 The Source shall keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1) (40 CFR Part 63, §63.6660(c)).

§63.6665 – What parts of the General Provisions apply to me?

14.3.14 The engine is subject to the General Provisions of 40 CFR Part 63, Subpart A as are outlined in Table 8 of Subpart ZZZZ. These requirements include but are not limited to (40 CFR Part 63, §63.6665):

14.3.14.1 No owner or operator must operate any affected source in violation of the requirements of 40 CFR Part 63 (§63.4(a)(1)); and

14.3.14.2 No owner or operator shall fail to keep records, notify, report, or revise reports as required under 40 CFR Part 63 (§63.4(a)(2)).

15. Colorado Regulation No. 1, Section II – Opacity

These limits apply to the following emission units which reference this condition throughout the Operating Permit:

P101 – Coal Handling System for Units 1 & 2, not including fugitive sources (F101a, F101b, F101c, F101i, and F101j) (Condition 6)

P102 – Coal Handling System for Unit 3, not including fugitive sources (F102a, F102f, F102g, and F102l) (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, not including fugitive sources (F201a) (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, not including fugitive sources (F202a) (Condition 9)

P203 – Ash Handling System for Units 1&2, not including fugitive sources (F203c) (Condition 10)

P204 – Ash Handling System for Unit 3, not including fugitive sources (F204b and F204d) (Condition 11)

S401 & S402 – Units 1 & 2 Cooling Towers, compliance is presumed per Condition 12.5.1 (Condition 12)

S403 – Unit 3 Cooling Tower, compliance is presumed per Condition 13.5.1 (Condition 13)

15.1 Except as provided in Condition 15.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference method for visible emissions measurements on which these standards are based is EPA Method 9 (40 CFR Part 60, Appendix A (July. 1992)). (Colorado Regulation No. 1, Section II.A.1) Note: This opacity limit applies at all times including during periods of shutdown and to offline emissions except as specified in Condition 15.2.

15.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity as measured by EPA Method 9 (unless otherwise specified in this permit) for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes. (Colorado Regulation No. 1, II.A.4)

15.3 Unless specific conditions in this permit require otherwise, monitoring for sources subject to Condition 15 shall be performed as follows.

15.3.1 A U.S. EPA Reference Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A, as adopted by reference in Colorado Regulation No. 6, Part A) shall be

performed at least semiannually. If any such observation indicates an exceedance of the applicable limit, additional observations must be performed. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken the shows the opacity is less than the opacity limit. All Method 9 readings shall be conducted by a certified observer.

15.3.2 Records of the results of U.S. EPA Reference Method 9 readings and a copy of the U.S. EPA Reference Method 9 reader's certification shall be kept on site and made available to the Division for inspection upon request.

15.3.3 Copies of any observations exceeding the applicable standard(s) shall be submitted with the next scheduled semi-annual report.

15.3.4 At all other times, in the absence of credible evidence to the contrary, compliance with the opacity limits shall be assumed, provided the Operating and Maintenance Plan requirements for bagfilters / baghouses set forth in Condition 16 are met, as appropriate.

16. Periodic Monitoring and Operating and Maintenance (O&M) Requirements for Control Devices

These requirements apply to each bagfilter / baghouse and scrubber associated with the following emission units which vent to the control device/s, as appropriate (Colorado Regulation No. 3, Part C, Section V.C.5.):

B001 – Unit 1 Boiler, baghouse and scrubber (Condition 1)

B002 – Unit 2 Boiler, baghouse and scrubber (Condition 2)

B003 – Unit 3 Boiler, baghouse and scrubber (Condition 3)

P101 – Coal Handling System for Units 1 & 2, baghouse (Condition 6)

P102 – Coal Handling System for Unit 3, baghouse (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, baghouse (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, baghouse (Condition 9)

P203 – Ash Handling System for Units 1&2, baghouse (Condition 10)

P204 – Ash Handling System for Unit 3, baghouse (Condition 11)

16.1 Bagfilters / Baghouses

16.1.1 The baghouse shall be equipped with an operable pressure drop measuring device. Pressure drop and/or cycle-time set point shall be used as a parameter for initiating compartment cleaning cycles. Documentation of the manufacturer's recommended operating range shall be maintained and made available to the Division for inspection upon request. Readings that are outside the range shall be cause for investigation. The results of any related maintenance work performed shall be documented in either hardcopy or electronic form and made available to the Division for inspection upon request.

16.1.2 Routine maintenance of and operational procedures performed on the baghouse shall be conducted in accordance with manufacturer's specifications and good engineering practices. These procedures shall be in written format. Any maintenance work performed shall be documented and made available to the Division for inspection upon request.

16.1.3 The baghouse shall be periodically inspected for bag integrity and overall mechanical integrity. At a minimum, these checks will be performed whenever the unit is down for a Planned Maintenance Outage (PMO). In addition, an inspection and any necessary maintenance or repairs shall be made whenever an opacity spike is observed, or if there is reason to suspect a broken bag or other equipment malfunction. For purposes of this requirement, a "spike" is defined as a sudden or gradual increase in opacity that, based on the operator's experience, may indicate a possible control equipment of process problem. Repairs performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of

these inspections, shall be documented and made available to the Division for inspection upon request.

16.1.4 **[Unit 3 Baghouse Only]** The bag leak detector will be operated and maintained in accordance with manufacturer's recommendations and good engineering practices. In the event that the leak detector indicates a leak, the Source will make the necessary repairs to the baghouse as soon as safely practicable. Leaks and their associated repairs will be documented for Division inspection upon request.

16.1.5 All records associated with baghouse O&M requirements must be retained for a minimum of five years.

16.2 Scrubbers

16.2.1 The Source shall perform routine maintenance and inspections of the equipment. The routine maintenance will be based upon operating hours of the scrubber equipment. Repairs or adjustments performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of these inspections, shall be documented and made available to the Division for inspection upon request.

16.2.2 SO_2 readings from the CEMS will be used as an indicator of maintenance needs or operational changes to the scrubber. Repairs or adjustments performed (other than minor adjustments), as well as any repairs done as a result the SO_2 readings, shall be documented and made available to the Division for inspection upon request.

16.2.3 All records associated with scrubber O&M requirements must be retained for a minimum of five years.

17. Particulate Matter Stack Testing

These requirements apply to each PM emission unit in this permit which has been identified as requiring stack testing to demonstrate compliance with an applicable PM emission limit, as appropriate.

17.1 To demonstrate compliance with 40 CFR Part 60, Subpart Da PM emission limits, subsequent performance testing on Unit 3 for filterable PM emissions must be performed within 12 months of the previous performance test in accordance with the schedule outlined in §60.48Da(o), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.2 To demonstrate compliance with 40 CFR Part 63, Subpart UUUUU (MATS) and Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent MATS and Regional Haze performance testing on Units 1 and 2, and subsequent MATS performance testing on Unit 3 for filterable PM emission limits must be performed in accordance with the schedule specified under MATS, in accordance with the requirements of Conditions 1.1, 1.10, 2.1, 2.9.3, 3.1, 3.10, and 5, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3 To demonstrate compliance with the Best Available Control Technology (BACT) PM and PM_{10} filterable and condensable emission limits for Unit 3, performance testing must be performed annually (Colorado Construction Permit 12MF322-1), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3.1 If the results of the performance testing show that the PM and PM_{10} filterable and condensable emissions are less than 75% of the BACT limits, the next performance testing may be performed biennially instead of annually.

17.4 To demonstrate compliance with Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent performance testing on Unit 3 for filterable PM and PM_{10} emissions must be performed in accordance with the requirements and procedures set forth in EPA Test Method 5, and Method 201A, as set forth in 40 CFR Part 60, Appendix A. This performance testing must be performed annually, or in accordance with the following schedule, as applicable:

17.4.1 If any test results indicate emissions are less than or equal to 50% of the emission limit, the subsequent test shall be performed within five (5) years of the date of the test.

17.4.2 If any test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, the subsequent test shall be performed within three (3) years of the date of the test.

17.4.3 If any test results indicate emissions are greater than 75% of the emission limit, an annual test is required until either of the above test results are achieved. A performance test must consist of three (3) test runs, with each run at least 120 minutes in duration. Test results must be

converted to the applicable units and compliance with be based on the average of three (3) test runs.

17.5 For all compliance demonstrations in Condition 17:

17.5.1 The test protocol, test, and test report shall be in accordance with the requirements of the APCD Compliance Test Manual (https://www.colorado.gov/pacific/cdphe/air/compliance-enforcement). A compliance testing protocol shall be submitted for Division approval at least thirty (30) calendar days prior to any performance of the test required under this condition.

17.5.2 No compliance test required herein shall be performed without prior written approval of the protocol by the Division.

17.5.3 The Division reserves the right to witness the test. In order to facilitate the Division's ability to make plans to witness the test, notice of the date (s) for the stack test shall be submitted to the Division at least thirty (30) calendar days prior to the test.

17.5.4 The Division may for good cause shown, waive this thirty (30) day notice requirement. In instances when a scheduling conflict is presented, the Division shall immediately contact the permittee in order to explore the possibility of making modifications to the stack test schedule.

17.5.5 The compliance test results shall be submitted to the Division within sixty (60) calendar days of the completion of the test unless a longer period is approved by the Division.

17.5.6 Any stack test conducted to show compliance with an annual emission limitation shall multiply the results of the test (lb/MMBtu) by the annual permitted fuel usage to compare against the limitation.

17.5.7 Results of all tests conducted shall be kept on site and made available to the Division upon request.

17.5.8 The performance testing for filterable PM may be satisfied by the periodic PM testing required by 40 CFR Part 63, Subpart UUUUU (MATS) in accordance with the requirements of Condition 5, as appropriate.

17.6 During each of the Method 5 performance tests conducted on Unit 3 as required by this condition, a baseline opacity limit shall be established for the compliance assurance monitoring (CAM) requirements as specified in Conditions 3.13, and Appendix H. The value of the baseline opacity level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurement recorded during each of the test run intervals conducted for the performance test, and then adding an baseline opacity adjustment factor to the calculated average value for all of the test runs.

17.6.1 The baseline opacity adjustment factors are:

17.6.1.1 5.0% opacity addition to the test run opacity average if the results of the PM performance tests are less than or equal to 50% of the PM standard; or

17.6.1.2 3.5% opacity addition to the test run opacity average if the results of the PM performance test are greater than 50%, but less than or equal to 75% of the PM standard; or

17.6.1.3 2.5% opacity addition to the test run opacity average if the results of the PM performance test are greater than 75% of the PM standard.

17.6.2 If the calculated opacity value (COMS average plus adjustment factor) is less than 5.0%, then the opacity baseline level is set at 5.0%.

17.6.3 If the baseline opacities established under this condition from any subsequent PM performance test are less than the current baseline opacity levels minus 1%, the Source shall maintain the new baseline opacity used as the indicator range on site for Division inspection upon request.

17.6.4 If the baseline opacities established under this condition from any subsequent PM performance test are greater than or equal to the current baseline opacity level minus 1%, the Source shall maintain records of the new baseline opacity used as the indicator range on site and available for Division inspection upon request.

18. 40 CFR Part 60, Subpart A, General Provisions for New Source Performance Standards

Units subject to an NSPS under 40 CFR Part 60 are subject to the requirements under Subpart A, General Provisions, which include but are not limited to:

B001 – Unit 1 Boiler (Condition 1)

B002 – Unit 2 Boiler (Condition 2)

B003 – Unit 3 Boiler (Condition 3)

P101 – Coal Handling System for Units 1 & 2 – S101d, S101e, S101f, and S101g (Condition 6)

P102 – Coal Handling System for Unit 3 – F102a, S102b, S102c, S102d, S102h, S102j, S102k, and S102l (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2 – limestone belt conveyors (Condition 8)

18.1 At all times, including periods of startup, shutdown, and malfunction owners and operators shall to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source (40 CFR Part 60.11(d), as adopted by reference in Colorado Regulation No. 6, Part A).

18.2 The Source shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility; or any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or device is inoperative (40 CFR Part 60, §60.7(b), as adopted by reference in Colorado Regulation No. 6, Part A).

18.3 No article, machine, equipment or process shall be used to conceal an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gasses discharged into the atmosphere (40 CFR Part 60, §60.12, as adopted by reference in Colorado Regulation No. 6, Part A).

19. Continuous Opacity Monitoring Systems (COMS) and Continuous Emissions Monitoring Systems (CEMS)

The following requirements apply to the NO_x (including diluents: CO_2 or O_2), SO_2, CO_2, CO (Unit 3 only), and volumetric flow continuous emission monitoring systems (CEMS), and to the continuous opacity monitoring systems (COMS). Note that these requirements are in addition to those under the Acid Rain Program as set forth in Section III of this permit, those under 40 CFR Part 60, Subparts D and Da – Standards of Performance for Electric Utility Steam Generating Units, those under 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, and those under the Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001).

19.1 CEMS and COMS Quality Assurance and Quality Control (QA/QC) Requirements

19.1.1 Except as provided for below, the **Unit 3 CO CEMS** is subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation and performance specifications of 40 CFR Part 60 Appendix B, Performance Specification 4/4A. This CEMS are subject to the quality assurance/quality control requirements in 40 CFR Part 60, Appendix F and Subpart A, §60.13 and Condition 19.1.8 of this permit.

19.1.1.1 The CO data shall meet the applicable "primary equipment hourly operating requirements" for hourly average calculation methodology specified in 40 CFR Part 75, Subpart B, §75.10(d).

19.1.1.2 Relative accuracy test audit (RATA) frequency will be determined according to 40 CFR Part 60, Appendix F.

19.1.2 The **SO_2, NO_x (and diluent), CO_2, and flow monitors** are subject to the applicable requirements of 40 CFR Part 75. The monitoring systems shall meet the equipment, installation, and performance specification requirements in 40 CFR Part 75, Appendix A. These CEMS shall meet the QA/QC requirements in 40 CFR Part 75, Appendix B and the conversion procedures of Appendix F and Condition 19.1.8 of this permit.

19.1.3 The **Unit 3 stack inlet SO_2 and CO_2 monitors** are subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation, and performance specifications in 40 CFR Part 60, Appendix B, the QA/QC requirements in 40 CFR Part 60, Appendix F, and the conversion procedures of Condition 19.1.8.

19.1.4 The **COMS** are subject to the requirements of 40 CFR Part 75. Each COMS shall meet the design, installation, equipment, and performance specifications in 40 CFR Part 60, Appendix B, Performance Specification 1.

19.1.5 **QA/QC plans** shall be prepared for the NO_x (including diluents: CO_2 or O_2), SO_2, CO_2, CO (Unit 3 only), and volumetric flow CEMS in accordance with the requirements of 40 CFR Part 75, Appendix B. These plans shall be made available to the Division upon request. Revisions shall be made to the plans at the request of the Division.

19.1.6 **[Units 1 & 2 COMS]** The Source must follow the QA/QC procedures of 40 CFR Part 60, Subpart A, §60.13(d), and Subpart D, §60.45(c)(3).

19.1.7 **[Unit 3 COMS]** The Source shall follow the QA/QC requirements of 40 CFR Part 60, Subpart A, §60.13(d) and Subpart Da, §60.48Da(o)(2)(ii).

19.1.8 The **SO_2, NO_x, and CO CEMS** are subject to the following requirements:

19.1.8.1 **[Relative Accuracy Test Audits (RATA)]** RATA shall be conducted in the units of the emission limitation (e.g., lb/MMBtu) for all of the emission limitations that are applicable to the emissions unit. The RATA for emissions units that have annual emission limitations (tons/yr) will be conducted in terms of pounds per hour (lb/hr).

19.1.8.2 **[Data Acquisition and Handling System (DAHS)]** The DAHS shall be able to record and manipulate the data in the units of the emission limitation (e.g., lb/MMBtu) and meet the reporting requirements for all of the emissions limitations that are applicable to the emissions unit.

Note at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

19.2 **General Provisions**

19.2.1 The Source shall ensure that all CEMS and COMS required are in operation and monitoring unit emissions or opacity at all times that the associated boiler combusts any fuel, except as follows:

19.2.1.1 During gaseous fuel combustion provided special considerations are met as provided in 40 CFR Part 75, §75.11(e);

19.2.1.2 During the use of an alternative monitoring system as approved by the Administrator pursuant to the requirements in 40 CFR Part 75, Subpart E (see Condition 19.2.2);

19.2.1.3 During periods of calibration, quality assurance, or preventative maintenance performed pursuant to 40 CFR part 75, §75.21 and Appendix B;

19.2.1.4 During periods of repair, periods of backups of data from a data acquisition and handling system or recertification performed pursuant to 40 CFR Part 75, §75.20;

19.2.1.5 The Source shall also ensure, subject to the exceptions noted above, that the COMS required are in operation and monitoring opacity during the time following combustion when fans are still operating, unless fan operation is not required to be included under any other applicable requirement (40 CFR Part 75, §75.10(d)).

19.2.2 Alternative monitoring system, alternative reference method, or any other alternative for the required CEMS shall not be used without having obtained prior written approval from the appropriate agency, either the Division or the U.S. EPA, depending on which agency is authorized to approve such alternative under applicable law. Any alternative CEMS or COMS shall be certified in accordance with the requirements of 40 CFR Parts 60 or 75, as applicable, prior to use.

19.2.3 All test and monitoring equipment, methods, procedures, and reporting shall be subject to the review and approval by the Division, prior to any official use. The Division shall have the right to inspect such equipment, methods, and procedures and data obtained at any time. The Division may provide a witness(es) for any and all tests, at the Division's discretion.

19.2.4 A file shall be maintained of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by applicable portions of 40 CFR Part 60, Subparts A, D, Da, Appendices A, B, and F, and 40 CFR Part 75. This information must be recorded in a permanent form suitable for Division inspection (40 CFR Part 60, §60.7(f)).

19.2.5 Records shall be maintained of the occurrence and duration of any startup, shutdown, or malfunction, or emergency condition (as defined in Subpart Da) in the operation of the source; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative (40 CFR Part 60, §60.7(b)).

19.3 **Data Replacement Requirements**

19.3.1 **[CEMS]** For periods when QA data is not available from the CEMS, the data replacement procedures in 40 CFR Part 75, Subpart D shall be used for determining the total (annual) emissions. For purposes of monitoring compliance with the annual NOx and SO_2 emission limitations (tons/yr), replaced and bias-adjusted data shall be included when assessing compliance with the annual limitations.

Note that CO emissions are not specifically referenced in the Subpart D procedures, the CEMS DAHS is programmed to substitute CO emissions using the same procedures specified for NO_x. Additionally, since CO emissions are not subject to requirements in 40 CFR Part 75, the CO emission data is not required to be bias-adjusted.

19.3.2 **[COMS]** When the COMS is unable to provide QA data in accordance with 40 CFR Part 75 for more than eight (8) consecutive hours, the Source shall utilize either a backup opacity monitor, EPA Reference Method 9, or an "Operating Report During Monitor Unavailability" to satisfy the requirements for periodic monitoring under 40 CFR Part 70 and Colorado Regulation No. 3.

19.3.2.1 If backup monitors are used, the next quarterly report submitted by the Source shall identify the dates and times the backup monitors were in use.

19.3.2.2 If EPA Reference Method 9 observations are used, visual observations in accordance with the reference method shall be taken and recorded by the Source whenever the Source is in operation and while fuel is present in the boiler.

a. When such circumstances exist, the visual observations shall be performed by a certified opacity observer each 24 hour period thereafter over a thirty minute period until the opacity monitoring system is again able to provide QA data.

b. If a visual emissions observation cannot be performed in accordance with EPA Reference Method 9, the Source shall record the reasons why that is the case.

c. Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

19.3.2.3 If an "Operating Report During Monitor Unavailability" is used, the Source shall record the registered opacity monitor reading prior to the monitor unavailability period and that immediately follows such periods. A Source shall also record and maintain a description of a unit operating characteristics that demonstrate the likelihood of compliance with the applicable opacity limitation. Such operating circumstances shall be identified on a unit specific basis and provided to the Division and shall include information related to the operation of the control equipment and any other operational parameters that may affect opacity.

19.4 **Recordkeeping and Reporting Requirements**

19.4.1 The Source shall submit excess emissions and monitoring reports and/or summary reports as required by 40 CFR Part 60, Subpart A, §60.7(c) and (d). The frequency of submittal of such reports shall be quarterly, and such reports shall be submitted to the Division by the 30th day following the end of each calendar quarter. Reports shall consist of the following information for all pollutants monitored for the quarterly period and all applicable limits of this permit:

19.4.1.1 Excess emission reports shall include the following information:

a. The magnitude of excess emissions computed in accordance with §60.13(h) and Division guidelines, any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period (40 CFR Part 60, §60.7(c)(1)).

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunctions (if known), the corrective action take or preventative measures adopted (40 CFR Part 60, §60.7(c)(2)).

c. The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks and the nature of the system repairs or adjustments (40 CFR part 60, §60.7(c)(3)).

d. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report (40 CFR Part 60, §60.7(c)(4)).

19.4.1.2 The summary report form shall contain the information and be in the format shown in Figure 1 of 40 CFR Part 60, §60.7 unless otherwise specified by the Division. One summary report form shall be submitted for each pollutant monitored at the facility

(40 CFR Part 60, §60.7(d)).

a. If the total duration of excess emissions for the reporting period is less than 1 percent (%) of the total operating time for the reporting period, and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in §60.7(c) (Condition 19.4.1.1) need not be submitted unless requested by the Division (40 CFR Part 60, §60.7(d)(1)).

b. If the total duration of excess emissions for the reporting period is 1 percent (%) or greater of the total operating time for the reporting period, or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in §60.7(c) (Condition 19.4.1.1) shall both be submitted (40 CFR Part 60, §60.7(d)(2)).

19.5 **Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001), Units 1 and 2 only**

19.5.1 The SO_2 CEMS shall be placed in a location to accurately monitor 100% of the flue gas, including any periods of bypass.

19.5.2 The Source must continuously and accurately monitor and report to the Division, pursuant to Section IX of the SIP component, the hourly average pressure drop across the mist eliminator and the hourly average flow rate for each unit at Units 1 and 2. The Source's pressure monitoring system shall be of sufficient sensitivity and reliability to enable consistent, continuous, and effective monitoring of the pressure drop range. The Source must take all necessary corrective actions to maintain the pressure drop within the applicable range.

19.5.3 The Source must provide to the Division on a quarterly basis all excess emission reports (EERs) for Craig Units 1 and 2 that describe in the form required by Section IX of the July 5, 2001 Colorado State Implementation Plan component, all excess readings, all claimed exemptions, and all other information required by law.

19.5.4 The Source must maintain, calibrate, and operate a method of coal sampling and analysis to determine accurately, pursuant to methods identified in Section 8(b)(viii) of the SIP component (see Condition 20), the potential emissions from sulfur in the coal entering the boiler reported in lb of SO_2 per MMBtu heat input.

19.5.5 The Source shall report to the Division on a quarterly basis each 30 day rolling average and each 90 day rolling average during the prior quarter that exceeded or failed to comply with the SO_2 emission limitations in Conditions 1.2.4 and 2.2.4. Each quarterly report shall include a list of the hours excluded for any reason from the determination of the Source's compliance with the SO_2 limits, and a list of times in which flue gas is bypassed around the FGD.

19.5.6 The Source must calculate hourly average NO_x concentrations in lb/MMBtu, in accordance with the requirements of 40 CFR Part 75. The Source must use the hourly averages to calculate calendar year averages in accordance with the requirements of 40 CFR Part 75.

19.5.7 The Source must report to the Division on a quarterly basis the Source's year-to-date average NO_x emission rate for that calendar year.

19.5.8 For any hour that valid, quality-assured CEMS data for a unit is unavailable, SO_2, NO_x, and CO_2 emissions shall be calculated in accordance with the missing data substitution procedures contained in 40 CFR Part 75 (Condition 19.3). For any day in which daily coal sample data are not available, the average potential SO_2 emission rate of coal from the previous 30 days as calculated in Conditions 1.2.4 and 2.2.4 shall be substituted.

19.5.9 The Source shall be bound by the data from their COMS, SO_2, CEMS and coal sampling data, and NO_x CEMS. The Source may not challenge the accuracy or credibility of their COMS, SO_2 CEMS and coal sampling data, and NO_x CEMS in any enforcement action unless otherwise expressly allowed by statue or regulation.

20. Coal Sampling

20.1 Coal must be sampled on at least a quarterly basis and must be analyzed to determine the heat content, weight percent sulfur, weight percent ash, and moisture content of the coal. The Source must follow Division approved coal sampling plan as shown in Appendix N (Colorado Regulation No. 3, Part C, Section V.C.5.).

20.2 In the event that more than one coal sampling analysis is performed during a quarter, the results of the analyses shall be averaged to determine quarterly average values for heat content, weight percent sulfur, and weight percent ash in the coal. These average values shall be used for subsequent calculations and demonstrations of compliance.

20.3 Coal sampling will follow the most current version of ASTM D2234, *Standard Practice for Collection of a Gross Sample of Coal*. Sample preparation will follow the most current version of ASTM 2013, *Standard Method of Preparing Coal Samples for Analysis*. Sulfur analysis will follow the most recent version of ASTM D4239, *Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods* (Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)).

20.4 In lieu of sampling under Condition 20.1, 20.2, and 20.3, vendor receipts, invoices, contracts, or other information may be used to provide the values for sulfur, ash, moisture, and heat content. Such alternative information shall indicate that coal sampling and analyses have been performed in accordance with the ASTM procedures, or equivalent, as identified in Condition 20.3.

20.5 Records of all coal analyses and vendor provided information must be maintained for Division inspection upon request.

21. Emission Factors

The Source shall comply with the provisions of Regulation No. 3 concerning APEN reporting. Except as provided for below, emission factors and/or other emission estimating methods that are specified within this permit cannot be adjusted without requiring a permit modification. Emission factors and/or other emission estimating methods used only to comply with the reporting requirements of Colorado Regulation No. 3, Part A, Section II can be updated and modified as specified in that Section. These changes by themselves do not require any permitting activities though the resulting emission estimate may trigger permitting activities.

22. Compliance Assurance Monitoring (CAM) Requirements

The CAM requirements in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, apply to Units 1 (PM, SO_2), 2 (PM, SO_2, NO_x), and 3 (PM/PM_{10}, SO_2, NO_x), and to S102d, secondary coal crushing building (PM), as follows.

22.1 For Units 1 and 2 with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix G. Excursions, for purposes of reporting are as follows:

22.1.1 An opacity value greater than 15.0% occurring for 6 minutes or more.

22.2 For Units 1 and 2 with respect to emissions of SO_2, the Source shall follow the CAM plan provided in Appendix J .Excursions, for purposes of reporting are as follows:

22.2.1 Any 30-day average of SO_2 emissions that exceed 0.11 lb/MMBtu.

22.3 For Unit 2 with respect to emissions of NO_x, the Source shall follow the CAM plan provided in Appendix L. Excursions, for purposes of reporting are as follows:

22.3.1 Any 30-day average of NO_x emissions that exceed 0.08 lb/MMBtu.

22.4 For Unit 3 with respect to emissions of PM/PM_{10}, the Source shall follow the CAM plan provided in Appendix H. Excursions, for purposes of reporting are as follows:

22.4.1 An opacity value greater than 7.5% occurring for 6 minutes or more; or

22.4.2 Any 24-hour period in which the average opacity exceeds the baseline level established as required by Condition 17.6.

22.5 For Unit 3 with respect to emissions of SO_2, the Source shall follow the CAM plan provided in Appendix K. Exceedances, for the purposes of reporting are as follows:

22.5.1 Any 30-day average of SO_2 emissions that exceed 0.15 lb/MMBtu; or

22.5.2 Any daily average of SO_2 emissions that exceeds 0.20 lb/MMBtu.

22.6 For Unit 3 with respect to emissions of NO_x, the Source shall follow the CAM plan provided in Appendix M. Exceedances, for the purposes of reporting are as follows:

22.6.1 Any 30-day average of NO_x emissions that exceed 0.28 lb/MMBtu.

22.7 For S102d with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix I. Excursions, for purposes of reporting are as follows:

22.7.1 Any visible emissions seen during Method 22 visible emissions observations; or

22.7.2 A pressure differential of less than 5 inches of water, or greater than 8 inches of water.

22.8 Excursions and/or exceedances shall be reported as required by Section V, Conditions 21 and 22.d of this permit (Colorado Regulation No. 3, Part C, Section V.C.5.).

22.9 Operation of Approved Monitoring

22.9.1 At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment (40 CFR Part 64, §64.7(b), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.2 Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of these CAM requirements, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions (40 CFR Part 64, §64.7(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3 Response to excursions or exceedances

22.9.3.1 Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable (40 CFR Part 64, §64.7(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3.2 Determination of whether the owner of operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process (40 CFR Part 64, §64.7(d)(2), as adopted by

reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.4 After approval of the monitoring required under the CAM requirements, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the Division and, if necessary submit a proposed modification for this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters (40 CFR Part 64, §64.7(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10 Quality Improvement Plan (QIP) Requirements

22.10.1 Based on the results of a determination made under the provisions of Condition 22.9.3.2, the Division may require the owner or operator to develop and implement a QIP (40 CFR Part 64, §64.8(a), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.2 The owner or operator shall maintain a written QIP, if required, and have it available for inspection (40 CFR Part 64, §64.8(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3 The QIP initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

22.10.3.1 Improved preventative maintenance practices (40 CFR Part 64, §64.8(b)(2)(i), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.2 Process operation changes (40 CFR Part 64, §64.8(b)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.3 Appropriate improvements to control methods (40 CFR Part 64, §64.8(b)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.4 Other steps appropriate to correct control performance (40 CFR Part 64, §64.8(b)(2)(iv), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.5 More frequent or improved monitoring (only in conjunction with one or more steps under Conditions 22.10.3.1 through 22.10.3.4) (40 CFR Part 64, §64.8(b)(2)(v), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.4 If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the Division if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP

was determined (40 CFR Part 64, §64.8(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.5 Following implementation of a QIP, upon any subsequent determination pursuant to Condition 22.9.3.2, the Division or the U.S. EPA may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

22.10.5.1 Failed to address the cause of the control device performance problems (40 CFR Part 64, §64.8(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); or

22.10.5.2 Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions (40 CFR Part 64, §64.8(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.6 Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act (40 CFR Part 64, §64.8(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11 Reporting and Recordkeeping Requirements

22.11.1 Reporting Requirements: The reports required by Section V, Condition 22.d, shall contain the information specified in Appendix B of the permit and the following information, as applicable:

22.11.1.1 Summary information on the number, duration and cause (including unknown cause, if applicable), for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable) (40 CFR Part 64, §64.9(a)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); and

22.11.1.2 The owner or operator shall submit, if necessary, a description of the actions taken to implement a QIP during the reporting period as specified in Condition 22.10 of this permit. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring (40 CFR Part 64 § 64.9(a)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2 General Recordkeeping Requirements: In addition to the recordkeeping requirements in Section V, Condition 22.a through c.

22.11.2.1 The owner or operator shall maintain records of any written QIP required pursuant to Condition 22.10 and any activities undertaken to implement a QIP, and any supporting information required to be maintained under these CAM requirements

(such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions) (40 CFR Part 64 § 64.9(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2.2 Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements (40 CFR Part 64, §64.9(b)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12 Savings Provisions

22.12.1 Nothing in these CAM requirements shall excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act. These CAM requirements shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purposes of determining the monitoring to be imposed under separate authority under the federal clean air act, including monitoring in permits issued pursuant to title I of the federal clean air act. The purpose of the CAM requirements is to require, as part of the issuance of this Title V operating permit, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of CAM (40 CFR Part 64, §64.10(a)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.2 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to impose additional or more stringent monitoring, recordkeeping, testing or reporting requirements on any owner or operator of a source under any provision of the federal clean air act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.3 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to take any enforcement action under the federal clean air act for any violation of an applicable requirement or of any person to take action under section 304 of the federal clean air act (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

SECTION III - Acid Rain Requirements

1. Designated Representative and Alternate Designated Representative

Designated Representative
Name: Barbara Walz
Title: Senior Vice President – Policy & Compliance Chief Compliance Officer
Phone: (303) 452-6111

Alternate Designated Representative
Name: Barry Ingold
Title: Senior Vice President – Generation
Phone: (303) 452-6111

Note: Changes to the Designated and Alternative Designated Representatives shall be made according to the requirements of 40 CFR Part 72, §72.23.

2. Sulfur Dioxide Emission Allowances and Nitrogen Oxide Emission Limitations

	2016	2017	2018	2019	2020	2021
SO_2 Allowances, per 40 CFR Part 73.10(b), Table 2	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149
NO_X Limits	C1, C2, C3: 0.46 lb/MMBtu of heat input on annual average basis (40 CFR Part 76, §76.7(a)(2))					

Under the provisions of 40 CFR Part 72, §72.84(a) any allowance allocations to, transfers to and deductions from an affected unit's Allowance Tracking System account is considered an automatic permit amendment and as such no revision to the permit is necessary. Numerical allowances shown in this table are from the 2013 edition of the CFR.

3. Standard Requirements (40 CFR Part 72, §72.9)

Boilers C1, C2, and C3 (Units 1, 2, and 3) are subject to the provisions of the Acid Rain Program as described herein. The Source has certified that they will comply with the following standard conditions.

3.1 Permit Requirements

3.1.1 The designated representative of each affected source and each affected unit at the source shall:

3.1.1.1 Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR Part 72 in accordance with the deadlines specified in 40 CFR Part 72, §72.30; and

3.1.1.2 Submit in a timely manner a complete reduced utilization plan if required under 40 CFR Part 72, §72.43; and

3.1.1.3 Submit in a timely manner any supplemental information that the permitting authority

determines is necessary to review an Acid Rain permit application and issue or deny an Acid Rain permit.

3.1.2 The owners and operators of each affected source and each affected unit at the source shall:

3.1.2.1 Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the Division; and

3.1.2.2 Have an Acid Rain Permit.

3.2 Monitoring Requirements

3.2.1 The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75.

3.2.2 The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

3.2.3 The requirements of 40 CFR Parts 74 and 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Federal Clean Air Act and other provisions of the operating permit for the source.

3.3 Sulfur Dioxide Requirements

3.3.1 The owners and operators of each source and each affected unit at the source shall:

3.3.1.1 Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR Part 73, §73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and

3.3.1.2 Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

3.3.2 Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Federal Clean Air Act.

3.3.3 An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

3.3.3.1 Starting January 1, 2000, an affected unit under 40 CFR Part 72, §72.6(a)(2); or

3.3.3.2 Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR Part 75, an affected unit under 40 CFR Part 72, §72.6(a)(3).

3.3.4 Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

3.3.5 An allowance shall not be deducted in order to comply with the requirements under Condition 3.3.1 of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

3.3.6 An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR Part 72, §72.7 and §72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

3.3.7 An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

3.4 Excess Emissions Requirements

3.4.1 The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan to the Administrator of the U. S. EPA, as required under 40 CFR Part 77.

3.4.2 The owners and operators of an affected unit that has excess emissions in any calendar year shall:

3.4.2.1 Pay without demand, to the Administrator of the U.S. EPA, the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR Part 77; and

3.4.2.2 Comply with the terms of an approved offset plan, as required by 40 CFR Part 77.

3.5 Recordkeeping and Reporting Requirements

3.5.1 Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or the Division:

3.5.1.1 The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR Part 72, §72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

3.5.1.2 All emissions monitoring information, in accordance with 40 CFR part 75; provided that to the extent that Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

3.5.1.3 Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

3.5.1.4 Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

3.5.2 The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72, Subpart I and 40 CFR Part 75.

3.6 Liability

3.6.1 Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or a written exemption under 40 CFR Part 70, §72.7 or §72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to Section 113(c) of the Federal Clean Air Act.

3.6.2 Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to Section 113(c) of the Federal Clean Air Act and 18 U.S.C. 1001.

3.6.3 No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

3.6.4 Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

3.6.5 Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

3.6.6 Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.

3.6.7 Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Federal Clean Air Act.

3.7 Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or a written exemption under 40 CFR Part 72, §72.7 or §72.8 shall be construed as:

3.7.1 Except as expressly provided in Title IV of the Federal Clean Air Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Federal Clean

Air Act, including the provisions of Title I of the Federal Clean Air Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

3.7.2 Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Federal Clean Air Act;

3.7.3 Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

3.7.4 Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or

3.7.5 Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

4. Reporting Requirements

4.1 Reports shall be submitted to the addresses identified in Appendix D.

4.2 Pursuant to 40 CFR Part, §75.64 quarterly reports and compliance certification requirements shall be submitted to the Administrator **within 30 days after the end of the calendar quarter**. The contents of these reports shall meet the requirements of 40 CFR Part 75, §75.64.

4.3 Pursuant to 40 CFR Part 75, §75.65 excess emissions of opacity shall be reported to the Division. These reports shall be submitted in a format approved by the Division.

4.4 Revisions to this permit shall be made in accordance with 40 CFR Part 72, Subpart H, §72.80 through §72.85 (as adopted by reference in Colorado Regulation 18). Permit modification requests shall be submitted to the Division at the address identified in Appendix D.

5. Comments, Notes and Justifications

5.1 As set forth in 40 CFR Part 70, §72.22, the alternate designated representative may act on behalf of the designated representative for this Acid Rain Permit.

SECTION IV - Permit Shield

Regulation No. 3, 5 CCR 1001-5, Part C, §§ I.A.4, V.D. & XIII.B; § 25-7-114.4(3)(a), C.R.S.

1. Specific Non-Applicable Requirements

Based on the information available to the Division and supplied by the applicant, the following parameters and requirements have been specifically identified as non-applicable to the facility to which this permit has been issued. This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance. In addition, this shield does not protect the source from any violations that occur as a result of any modifications or reconstruction on which construction commenced prior to permit issuance.

Emission Unit Description & Number	Non-Applicable Requirement	Justification
B001 & B002 - Units 1 & 2	Construction Permit 10MF579 reference to May 1, 1973 Subpart D	The Units are subject to the most current version of Subpart D.
Facility-Wide	Colorado Regulation No. 1, V	Applies to coke ovens at Iron and steel plant operations only.
	Colorado Regulation No. 1, VII	Applies only to listed electric generating stations owned and operated by the Public Service Company of Colorado
	Colorado Regulation No. 1, VIII	Applies to listed stationary sources in the Denver PM_{10} nonattainment area only.
	Colorado Regulation No. 1, IX	Applies only to Refinery Fluid Bed Catalytic Cracking Units located in nonattainment areas for carbon monoxide
	Colorado Regulation No. 4, and General Condition 31 of this permit	Sale and use of wood burning devices does not apply to the Craig Station
	Colorado Regulation No. 7, except for Part B, Section III	Applies to sources in ozone nonattainment area. Part B, Section V applies in attainment areas, but diesel storage is exempt. Section V applies in attainment areas, but applies to crude oil storage tanks having a capacity of greater than 40,000 gallons. Part D, Section II, III, IV, and V apply in attainment areas, but contain provisions applicable to the oil and gas industry only.
	Colorado Regulation No. 8, Part D	Applies only to existing sources wishing to obtain a compliance extension and the Craig facility has not triggered this provision
	Colorado Regulation No. 9 – Open Burning, Prescribed Fire, and Permitting	Subject matter does not cover the Craig facility.
	Colorado Regulation No. 10 - Conformity Determinations Respecting Federal Actions	Subject matter does not cover the Craig facility.
	Colorado Regulation No. 11 - Motor Vehicle Emissions Inspection Program	Subject matter does not cover the Craig facility.

	Colorado Regulation No. 12 - Reduction of Diesel Vehicle Emissions	Geographic area of applicability does not include the Craig facility.
	Colorado Regulation No. 13 - The Oxygenated Fuels Program	Area of geographic applicability does not include the Craig facility.
	Colorado Regulation No. 16 - Street Sanding	Geographic area of applicability does not include the Craig facility.
	5CCR 1001-20 - Nonattainment Areas	Craig facility is not located in geographic areas classified as nonattainment.
	Colorado Regulation No. 19 - Lead Based Paint Abatement	Applies only to homes constructed prior to 1978, child-occupied facilities, and only those projects where the intent is to abate lead-based paint hazards
	40 CFR Part 55 - Outer Continental Shelf Air Regulations	Craig facility is outside the geographic scope of this provision.
	40 CFR Part 56 - Regional Consistency	Relates to authorities within the various offices of the EPA.

2. General Conditions

Compliance with this Operating Permit shall be deemed compliance with all applicable requirements specifically identified in the permit and other requirements specifically identified in the permit as not applicable to the source. This permit shield shall not alter or affect the following:

2.1 The provisions of §§ 25-7-112 and 25-7-113, C.R.S., or § 303 of the federal act, concerning enforcement in cases of emergency;

2.2 The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

2.3 The applicable requirements of the federal Acid Rain Program, consistent with § 408(a) of the federal act;

2.4 The ability of the Air Pollution Control Division to obtain information from a source pursuant to §25-7-111(2)(I), C.R.S., or the ability of the Administrator to obtain information pursuant to § 114 of the federal act;

2.5 The ability of the Air Pollution Control Division to reopen the Operating Permit for cause pursuant to Regulation No. 3, Part C, § XIII.

2.6 Sources are not shielded from terms and conditions that become applicable to the source subsequent to permit issuance.

3. Stream-lined Conditions

The following applicable requirements have been subsumed within this operating permit using the pertinent streamlining procedures approved by the U.S. EPA. For purposes of the permit shield,

compliance with the listed permit conditions will also serve as a compliance demonstration for purposes of the associated subsumed requirements.

Emission Unit Description & Number	Applicable Requirement	Justification
Section II, Conditions 1.2.5.2, 1.3.5.1, 2.2.5.2 and 2.3.4.2 (Units 1 & 2)	Colorado SIP, April 19, 2001 – Definition of "boiler operating day"	The Source requested that the definition of "boiler operating day" be "whenever coal is combusted" instead of what was defined in the CO SIP which was less stringent.
Section II, Conditions 3.2.2 & 3.3.3	NSPS Da definition of "boiler operating day"	The Source requested that the definition of "boiler operating day" use the most stringent definition of "whenever fossil fuel is combusted" in lieu of the NSPS definition.
Section II, Condition 1.9.3 & 2.9.3 (Units 1 & 2)	Colorado SIP, April 19, 2001 – Required quarterly reports	The included reporting requirement is more stringent since reports may be requested at any time by the Division with seven (7) days notice.
Section II, Condition 3.6 (Unit 3)	40 CFR Part 60, Subpart Da, §60.42Da(b) – Opacity not to exceed 20%, except for one 6-minute period per hour of not more than 27%	This requirement is less strict than the BACT limit.
Section II, Condition 3.1 (Unit 3)	40 CFR Part 60, Subpart Da, §60.42Da(c)(1) – PM emissions not to exceed 0.015 lb/MMBtu	This requirement is less strict than the BACT PM limit.
Section II, Condition 3.1 (Unit 3)	40 CFR Part 60, Subpart Da, §60.48Da(g) and (p) §60.49Da(t) and (v) – Options for PM CEMS to demonstrate compliance with NSPS Da PM requirements	Since the PM limit has been streamlined, so have these options which would have otherwise been included in the permit to demonstrate compliance with said limit.
Section II, Condition 3.1 (Unit 3)	40 CFR Part 60, Subpart Da, §60.48Da(o)(1) and (2) – PM monitoring with annual stack test and 24-hour opacity option for compliance demonstration with NSPS Da limits	Since the PM and opacity limits have been streamlined, so have these options which would have otherwise been included in the permit to demonstrate compliance with said limits.
Section II, Condition 3.6 (Unit 3)	40 CFR Part 60, Subpart Da, §60.52Da – Recordkeeping requirements for opacity observations	The opacity condition has been streamlined out under BACT wherein records are already required
Section II, Conditions 1.1, 2.1, 3.1 (Units 1, 2, & 3)	Colorado Regulation No. 1, Section II.A.1.c – PM emissions shall not exceed 0.1 lb/MMBtu	This limit is less strict than the Regional Haze (Units 1 & 2) and BACT (Unit 3) limits.
Section II, Condition 4 (Units 1, 2, & 3)	NSPS D/Da requirements associated with combusting non-coal fuels (40 CFR Part 60, Sections §60.43(a)(1), §60.43(b), §60.43(c), §60.44(a)(1), §60.44(a)(2), §60.44(b), §60.43Da(b), §60.43Da(b)(1)/(2), §60.44Da(a)(1), §60.44Da(a)(2)	So long as the fuel heat input limit under Condition 4 is met, these NSPS limits will change less than 2% as compared to the only-coal combustion requirements.

Section II, Condition 13.1	Colorado Construction Permit 98MF0141 – Annual Circulating Water Throughput: 94,608 * 10^6 gallons/year	This limit is merely the annualized PTE of the short term limit.
Section II, Condition 17.2 (Units 1 & 2)	Colorado Regulation No. 23, Section V.B.1. – Regional Haze stack testing	Testing under 40 CFR Part 63, Subpart UUUUU (MATS) is more stringent.
Section II, Condition 19 (Units 1, 2, & 3)	Colorado Regulation No. 1, Section IV – COMS and CEMS	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the CO Reg 1 requirements.
Section II, Condition 19 (Units 1, 2, & 3)	40 CFR Part 60, Subpart D, §60.45 – COMS and CEMS	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the CO Reg 1 requirements.
Section II, Condition 19 (Units 1 & 2)	Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001), Section VI.13 – CEMS for Units 1 and 2 (NO_x, SO_2, CO_2, and flow)	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the SIP requirements.
Section II, Condition 19 (Units 1 & 2)	Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) Section VI.10 – COMS for Units 1 and 2	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the SIP requirements.

SECTION V - General Permit Conditions (ver 1/21/2020)

1. Administrative Changes

Regulation No. 3, 5 CCR 1001-5, Part A, § III.

The permittee shall submit an application for an administrative permit amendment to the Division for those permit changes that are described in Regulation No. 3, Part A, § I.B.1. The permittee may immediately make the change upon submission of the application to the Division.

2. Certification Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.9., V.C.16.a.& e. and V.C.17.

a. Any application, report, document and compliance certification submitted to the Air Pollution Control Division pursuant to Regulation No. 3 or the Operating Permit shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

b. All compliance certifications for terms and conditions in the Operating Permit shall be submitted to the Air Pollution Control Division at least annually unless a more frequent period is specified in the applicable requirement or by the Division in the Operating Permit.

c. Compliance certifications shall contain:

(i) the identification of each permit term and condition that is the basis of the certification;

(ii) the compliance status of the source;

(iii) whether compliance was continuous or intermittent;

(iv) method(s) used for determining the compliance status of the source, currently and over the reporting period; and

(v) such other facts as the Air Pollution Control Division may require to determine the compliance status of the source.

d. All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

e. If the permittee is required to develop and register a risk management plan pursuant to § 112(r) of the federal act, the permittee shall certify its compliance with that requirement; the Operating Permit shall not incorporate the contents of the risk management plan as a permit term or condition.

3. Common Provisions

Common Provisions Regulation, 5 CCR 1001-2 §§ II.A., II.B., II.C., II.E., II.F., II.I, and II.J

a. To Control Emissions Leaving Colorado

When emissions generated from sources in Colorado cross the State boundary line, such emissions shall not cause the air quality standards of the receiving State to be exceeded, provided reciprocal action is taken by the receiving State.

b. Emission Monitoring Requirements

The Division may require owners or operators of stationary air pollution sources to install, maintain, and use instrumentation to monitor and record emission data as a basis for periodic reports to the Division.

c. Performance Testing

The owner or operator of any air pollution source shall, upon request of the Division, conduct performance test(s) and furnish the Division a written report of the results of such test(s) in order to determine compliance with applicable emission control regulations.

Performance test(s) shall be conducted and the data reduced in accordance with the applicable reference test methods unless the Division:

(i) specifies or approves, in specific cases, the use of a test method with minor changes in methodology;

(ii) approves the use of an equivalent method;

(iii) approves the use of an alternative method the results of which the Division has determined to be adequate for indicating where a specific source is in compliance; or

(iv) waives the requirement for performance test(s) because the owner or operator of a source has demonstrated by other means to the Division's satisfaction that the affected facility is in compliance with the standard. Nothing in this paragraph shall be construed to abrogate the Commission's or Division's authority to require testing under the Colorado Revised Statutes, Title 25, Article 7, and pursuant to regulations promulgated by the Commission.

Compliance test(s) shall be conducted under such conditions as the Division shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Division such records as may be necessary to determine the conditions of the performance test(s). Operations during period of startup, shutdown, and malfunction shall not constitute representative conditions of performance test(s) unless otherwise specified in the applicable standard.

The owner or operator of an affected facility shall provide the Division thirty days prior notice of the performance test to afford the Division the opportunity to have an observer present. The Division may waive the thirty day notice requirement provided that arrangements satisfactory to the Division are made for earlier testing.

The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(i) Sampling ports adequate for test methods applicable to such facility;

(ii) Safe sampling platform(s);

(iii) Safe access to sampling platform(s); and

(iv) Utilities for sampling and testing equipment.

Each performance test shall consist of at least three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic mean of results of at least three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the owner or operator's control, compliance may, upon the Division's approval, be determined using the arithmetic mean of the results of the two other runs.

Nothing in this section shall abrogate the Division's authority to conduct its own performance test(s) if so warranted.

d. Affirmative Defense Provision for Excess Emissions during Malfunctions

An affirmative defense to a claim of violation under these regulations is provided to owners and operators for civil penalty actions for excess emissions during periods of malfunction. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of evidence that:

(i) The excess emissions were caused by a sudden, unavoidable breakdown of equipment, or a sudden, unavoidable failure of a process to operate in the normal or usual manner, beyond the reasonable control of the owner or operator;

(ii) The excess emissions did not stem from any activity or event that could have reasonably been foreseen and avoided, or planned for, and could not have been avoided by better operation and maintenance practices;

(iii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded;

(iv) The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

(v) All reasonably possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence;

(viii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(ix) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This section is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement; and

(x) During the period of excess emissions, there were no exceedances of the relevant ambient air quality standards established in the Commissions' Regulations that could be attributed to the emitting source.

The owner or operator of the facility experiencing excess emissions during a malfunction shall notify the division verbally as soon as possible, but no later than noon of the Division's next working day, and shall submit written notification following the initial occurrence of the excess emissions by the end of the source's next reporting period. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to failures to meet federally promulgated performance standards or emission limits, including, but not limited to, new source performance standards and national emission standards for hazardous air pollutants. The affirmative defense provision does not apply to state implementation plan (sip) limits or permit limits that have been set taking into account potential emissions during malfunctions, including, but not necessarily limited to, certain limits with 30-day or longer averaging times, limits that indicate they apply during malfunctions, and limits that indicate they apply at all times or without exception.

e. Circumvention Clause

A person shall not build, erect, install, or use any article, machine, equipment, condition, or any contrivance, the use of which, without resulting in a reduction in the total release of air pollutants to the atmosphere, reduces or conceals

an emission which would otherwise constitute a violation of this regulation. No person shall circumvent this regulation by using more openings than is considered normal practice by the industry or activity in question.

f. Compliance Certifications

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in the Colorado State Implementation Plan, nothing in the Colorado State Implementation Plan shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. Evidence that has the effect of making any relevant standard or permit term more stringent shall not be credible for proving a violation of the standard or permit term.

When compliance or non-compliance is demonstrated by a test or procedure provided by permit or other applicable requirement, the owner or operator shall be presumed to be in compliance or non-compliance unless other relevant credible evidence overcomes that presumption.

g. Affirmative Defense Provision for Excess Emissions During Startup and Shutdown

An affirmative defense is provided to owners and operators for civil penalty actions for excess emissions during periods of startup and shutdown. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of the evidence that:

(i) The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design;

(ii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation or maintenance;

(iii) If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(iv) The frequency and duration of operation in startup and shutdown periods were minimized to the maximum extent practicable;

(v) All possible steps were taken to minimize the impact of excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence; and,

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This subparagraph is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement.

The owner or operator of the facility experiencing excess emissions during startup and shutdown shall notify the Division verbally as soon as possible, but no later than two (2) hours after the start of the next working day, and shall submit written quarterly notification following the initial occurrence of the excess emissions. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to State Implementation Plan provisions or other requirements that derive from new source performance standards or national emissions standards for hazardous air pollutants, or any other federally enforceable performance standard or emission limit with an averaging time greater than twenty-four

hours. In addition, an affirmative defense cannot be used by a single source or small group of sources where the excess emissions have the potential to cause an exceedance of the ambient air quality standards or Prevention of Significant Deterioration (PSD) increments.

In making any determination whether a source established an affirmative defense, the Division shall consider the information within the notification required above and any other information the Division deems necessary, which may include, but is not limited to, physical inspection of the facility and review of documentation pertaining to the maintenance and operation of process and air pollution control equipment.

4. Compliance Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.C.9., V.C.11. & 16.d. and § 25-7-122.1(2), C.R.S.

a. The permittee must comply with all conditions of the Operating Permit. Any permit noncompliance relating to federally-enforceable terms or conditions constitutes a violation of the federal act, as well as the state act and Regulation No. 3. Any permit noncompliance relating to state-only terms or conditions constitutes a violation of the state act and Regulation No. 3, shall be enforceable pursuant to state law, and shall not be enforceable by citizens under § 304 of the federal act. Any such violation of the federal act, the state act or regulations implementing either statute is grounds for enforcement action, for permit termination, revocation and reissuance or modification or for denial of a permit renewal application.

b. It shall not be a defense for a permittee in an enforcement action or a consideration in favor of a permittee in a permit termination, revocation or modification action or action denying a permit renewal application that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

c. The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of any request by the permittee for a permit modification, revocation and reissuance, or termination, or any notification of planned changes or anticipated noncompliance does not stay any permit condition, except as provided in §§ X. and XI. of Regulation No. 3, Part C.

d. The permittee shall furnish to the Air Pollution Control Division, within a reasonable time as specified by the Division, any information that the Division may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Division copies of records required to be kept by the permittee, including information claimed to be confidential. Any information subject to a claim of confidentiality shall be specifically identified and submitted separately from information not subject to the claim.

e. Any schedule for compliance for applicable requirements with which the source is not in compliance at the time of permit issuance shall be supplemental, and shall not sanction noncompliance with, the applicable requirements on which it is based.

f. For any compliance schedule for applicable requirements with which the source is not in compliance at the time of permit issuance, the permittee shall submit, at least every 6 months unless a more frequent period is specified in the applicable requirement or by the Air Pollution Control Division, progress reports which contain the following:

   (i) dates for achieving the activities, milestones, or compliance required in the schedule for compliance, and dates when such activities, milestones, or compliance were achieved; and

   (ii) an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

g. The permittee shall not knowingly falsify, tamper with, or render inaccurate any monitoring device or method required to be maintained or followed under the terms and conditions of the Operating Permit.

5. Emergency Provisions

Regulation No. 3, 5 CCR 1001-5, Part C, § VII

An emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed the technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. "Emergency" does not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error. An emergency constitutes an affirmative defense to an enforcement action brought for noncompliance with a technology-based emission limitation if the permittee demonstrates, through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. an emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. the permitted facility was at the time being properly operated;

c. during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

d. the permittee submitted oral notice of the emergency to the Air Pollution Control Division no later than noon of the next working day following the emergency, and followed by written notice within one month of the time when emissions limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

This emergency provision is in addition to any emergency or malfunction provision contained in any applicable requirement.

6. Emission Controls for Asbestos

Regulation No. 8, 5 CCR 1001-10, Part B

The permittee shall not conduct any asbestos abatement activities except in accordance with the provisions of Regulation No. 8, Part B, “asbestos control.”

7. Emissions Trading, Marketable Permits, Economic Incentives

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.13.

No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are specifically provided for in the permit.

8. Fee Payment

C.R.S §§ 25-7-114.1(6) and 25-7-114.7

a. The permittee shall pay an annual emissions fee in accordance with the provisions of C.R.S. § 25-7-114.7. A 1% per month late payment fee shall be assessed against any invoice amounts not paid in full on the 91st day after the date of invoice, unless a permittee has filed a timely protest to the invoice amount.

b. The permittee shall pay a permit processing fee in accordance with the provisions of C.R.S. § 25-7-114.7. If the Division estimates that processing of the permit will take more than 30 hours, it will notify the permittee of its estimate of what the actual charges may be prior to commencing any work exceeding the 30 hour limit.

c. The permittee shall pay an APEN fee in accordance with the provisions of C.R.S. § 25-7-114.1(6) for each APEN or revised APEN filed.

9. Fugitive Particulate Emissions

Regulation No. 1, 5 CCR 1001-3, § III.D.1.

The permittee shall employ such control measures and operating procedures as are necessary to minimize fugitive particulate emissions into the atmosphere, in accordance with the provisions of Regulation No. 1, § III.D.1.

10. Inspection and Entry

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.16.b.

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Air Pollution Control Division, or any authorized representative, to perform the following:

a. enter upon the permittee's premises where an Operating Permit source is located, or emissions-related activity is conducted, or where records must be kept under the terms of the permit;

b. have access to, and copy, at reasonable times, any records that must be kept under the conditions of the permit;

c. inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the Operating Permit;

d. sample or monitor at reasonable times, for the purposes of assuring compliance with the Operating Permit or applicable requirements, any substances or parameters.

11. Minor Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, §§ X. & XI.

The permittee shall submit an application for a minor permit modification before making the change requested in the application. The permit shield shall not extend to minor permit modifications.

12. New Source Review

Regulation No. 3, 5 CCR 1001-5, Parts B & D

The permittee shall not commence construction or modification of a source required to be reviewed under the New Source Review provisions of Regulation No. 3, Parts B and/or D, as applicable, without first receiving a construction permit.

13. No Property Rights Conveyed

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.11.d.

This permit does not convey any property rights of any sort, or any exclusive privilege.

14. Odor

Regulation No. 2, 5 CCR 1001-4, Part A

As a matter of state law only, the permittee shall comply with the provisions of Regulation No. 2 concerning odorous emissions.

15. Off-Permit Changes to the Source

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.B.

The permittee shall record any off-permit change to the source that causes the emissions of a regulated pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from the change, including any other data necessary to show compliance with applicable ambient air quality standards. The permittee shall provide contemporaneous notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permit shield shall not apply to any off-permit change.

16. Opacity

Regulation No. 1, 5 CCR 1001-3, §§ I., II.

The permittee shall comply with the opacity emissions limitation set forth in Regulation No. 1, §§ I.- II.

17. Open Burning

Regulation No. 9, 5 CCR 1001-11

The permittee shall obtain a permit from the Division for any regulated open burning activities in accordance with provisions of Regulation No. 9.

18. Ozone Depleting Compounds

Regulation No. 15, 5 CCR 1001-19

The permittee shall comply with the provisions of Regulation No. 15 concerning emissions of ozone depleting compounds. Sections I., II.C., II.D., III. IV., and V. of Regulation No. 15 shall be enforced as a matter of state law only.

19. Permit Expiration and Renewal

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.6., IV.C., V.C.2.

a. The permit term shall be five (5) years. The permit shall expire at the end of its term. Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application is submitted.

b. Applications for renewal shall be submitted at least twelve months, but not more than 18 months, prior to the expiration of the Operating Permit. An application for permit renewal may address only those portions of the permit that require revision, supplementing, or deletion, incorporating the remaining permit terms by reference from the previous permit. A copy of any materials incorporated by reference must be included with the application.

20. Portable Sources

Regulation No. 3, 5 CCR 1001-5, Part C, § II.D.

Portable Source permittees shall notify the Air Pollution Control Division at least 10 days in advance of each change in location.

21. Prompt Deviation Reporting

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.7.b.

The permittee shall promptly report any deviation from permit requirements, including those attributable to malfunction conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken.

"Prompt" is defined as follows:

a. Any definition of "prompt" or a specific timeframe for reporting deviations provided in an underlying applicable requirement as identified in this permit; or

b. Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

   (i) For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report shall be made within 24 hours of the occurrence;

(ii) For emissions of any regulated air pollutant, excluding a hazardous air pollutant or a toxic air pollutant that continue for more than two hours in excess of permit requirements, the report shall be made within 48 hours; and

(iii) For all other deviations from permit requirements, the report shall be submitted every six (6) months, except as otherwise specified by the Division in the permit in accordance with paragraph 22.d. below.

c. If any of the conditions in paragraphs b.i or b.ii above are met, the source shall notify the Division by telephone (303-692-3155) or facsimile (303-782-0278) based on the timetables listed above. *[Explanatory note: Notification by telephone or facsimile must specify that this notification is a deviation report for an Operating Permit.]* A written notice, certified consistent with General Condition 2.a. above (Certification Requirements), shall be submitted within 10 working days of the occurrence. All deviations reported under this section shall also be identified in the 6-month report required above.

"Prompt reporting" does not constitute an exception to the requirements of "Emergency Provisions" for the purpose of avoiding enforcement actions.

22. Record Keeping and Reporting Requirements

Regulation No. 3, 5 CCR 1001-5, Part A, § II.; Part C, §§ V.C.6., V.C.7.

a. Unless otherwise provided in the source specific conditions of this Operating Permit, the permittee shall maintain compliance monitoring records that include the following information:

(i) date, place as defined in the Operating Permit, and time of sampling or measurements;

(ii) date(s) on which analyses were performed;

(iii) the company or entity that performed the analysis;

(iv) the analytical techniques or methods used;

(v) the results of such analysis; and

(vi) the operating conditions at the time of sampling or measurement.

b. The permittee shall retain records of all required monitoring data and support information for a period of at least five (5) years from the date of the monitoring sample, measurement, report or application. Support information, for this purpose, includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the Operating Permit. With prior approval of the Air Pollution Control Division, the permittee may maintain any of the above records in a computerized form.

c. Permittees must retain records of all required monitoring data and support information for the most recent twelve (12) month period, as well as compliance certifications for the past five (5) years on-site at all times. A permittee shall make available for the Air Pollution Control Division's review all other records of required monitoring data and support information required to be retained by the permittee upon 48 hours advance notice by the Division.

d. The permittee shall submit to the Air Pollution Control Division all reports of any required monitoring at least every six (6) months, unless an applicable requirement, the compliance assurance monitoring rule, or the Division requires submission on a more frequent basis. All instances of deviations from any permit requirements must be clearly identified in such reports.

e. The permittee shall file an Air Pollutant Emissions Notice ("APEN") prior to constructing, modifying, or altering any facility, process, activity which constitutes a stationary source from which air pollutants are or are to be emitted, unless such source is exempt from the APEN filing requirements of Regulation No. 3, Part A, § II.D or as provided for in Regulation No. 3, Part A, § II.A.2 for oil and gas well production facilities. A revised APEN shall be filed

annually whenever a significant change in emissions, as defined in Regulation No. 3, Part A, § II.C.2., occurs; whenever there is a change in owner or operator of any facility, process, or activity; whenever new control equipment is installed; whenever a different type of control equipment replaces an existing type of control equipment; whenever a permit limitation must be modified; or before the APEN expires. An APEN is valid for a period of five years. The five-year period recommences when a revised APEN is received by the Air Pollution Control Division. Revised APENs shall be submitted no later than 30 days before the five-year term expires. Permittees submitting revised APENs to inform the Division of a change in actual emission rates must do so by April 30 of the following year. Where a permit revision is required, the revised APEN must be filed along with a request for permit revision. APENs for changes in control equipment must be submitted before the change occurs, except an APEN shall be filed once per year for control equipment at condensate storage tanks located at oil and gas exploration and production facilities subject to Regulation No. 7, Part D § I. Annual fees are based on the most recent APEN on file with the Division.

23. Reopenings for Cause

Regulation No. 3, 5 CCR 1001-5, Part C, § XIII.

a. The Air Pollution Control Division shall reopen, revise, and reissue Operating Permits; permit reopenings and reissuance shall be processed using the procedures set forth in Regulation No. 3, Part C, § III., except that proceedings to reopen and reissue permits affect only those parts of the permit for which cause to reopen exists.

b. The Division shall reopen a permit whenever additional applicable requirements become applicable to a major source with a remaining permit term of three or more years, unless the effective date of the requirements is later than the date on which the permit expires, or unless a general permit is obtained to address the new requirements; whenever additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program; whenever the Division determines the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or whenever the Division determines that the permit must be revised or revoked to assure compliance with an applicable requirement.

c. The Division shall provide 30 days' advance notice to the permittee of its intent to reopen the permit, except that a shorter notice may be provided in the case of an emergency.

d. The permit shield shall extend to those parts of the permit that have been changed pursuant to the reopening and reissuance procedure.

24. Requirements for Major Stationary Sources

Regulation No. 3, 5 CCR 1001-5, Part D, §§ V.A.7.c & d, VI.B.5 & VI.B.6

The following provisions apply to projects at existing emissions units at a major stationary source (other than projects at a source with a PAL) that are not part of a major modification and where the owner or operator relies on projected actual emissions. The definitions of baseline actual emissions, major modification, major stationary source, PAL, projected actual emissions, regulated NSR pollutant and significant can be found in Regulation No. 3, Part D, § II.A.

a. Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

(i) a description of the project;

(ii) identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

(iii) a description of the applicability test used to determine the project is not a major modification for any regulated NSR pollutants, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded and an explanation for why such amount was excluded, and any netting calculations, if applicable.

b. The owner or operator shall monitor emissions of any regulated NSR pollutant that could increase as a result of the project from any emissions units identified in paragraph a.(ii) and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operation after the change, or for a period of ten (10) years following resumption of regular operation after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

c. For existing electric utility steam generating units the following requirements apply:

(i) Before beginning actual construction, the owner or operator shall provide a copy of the information required by paragraph a above to the Division. The owner or operator is not required to obtain a determination from the Division prior to beginning actual construction.

(ii) The owner or operate shall submit a report to the Division within sixty days after the end of each year during which records must be generated under paragraph b above setting out the unit's annual emissions during the calendar year that preceded submission of the report.

d. For existing emissions units that are not electric utility steam generating units, the owner or operator shall submit a report to the Division if the annual emissions from the project, in tons per year, exceed the baseline actual emissions (documented and maintained per paragraph a(iii)) by a significant amount for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection (documented and maintained per paragraph a.(iii)). Such report shall be submitted to the Division within sixty days after the end of such year. The report shall contain the following:

(i) The name, address and telephone number of the owner or operator;

(ii) The annual emissions as calculated per paragraph b; and

(iii) Any other information that the owner or operator wishes to include in the report.

e. The owner of operation of the source shall make the information in paragraph a available for review upon request to the Division or the general public.

25. Section 502(b)(10) Changes

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.A.

The permittee shall provide a minimum 7-day advance notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permittee shall attach a copy of each such notice given to its Operating Permit.

26. Severability Clause

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.10.

In the event of a challenge to any portion of the permit, all emissions limits, specific and general conditions, monitoring, record keeping and reporting requirements of the permit, except those being challenged, remain valid and enforceable.

27. Significant Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, § III.B.2.

The permittee shall not make a significant modification required to be reviewed under Regulation No. 3, Part B ("Construction Permit" requirements) without first receiving a construction permit. The permittee shall submit a complete Operating Permit application or application for an Operating Permit revision for any new or modified source within twelve months of commencing operation, to the address listed in Item 1 in Appendix D of this permit. If the permittee chooses to use the "Combined Construction/Operating Permit" application procedures of Regulation No. 3, Part C, then the Operating Permit must be received prior to commencing construction of the new or modified source.

28. Special Provisions Concerning the Acid Rain Program

Regulation No. 3, 5 CCR 1001-5, Part C, §§ V.C.1.b. & 8

a. Where an applicable requirement of the federal act is more stringent than an applicable requirement of regulations promulgated under Title IV of the federal act, 40 Code of Federal Regulations (CFR) Part 72, both provisions shall be incorporated into the permit and shall be federally enforceable.

b. Emissions exceeding any allowances that the source lawfully holds under Title IV of the federal act or the regulations promulgated thereunder, 40 CFR Part 72, are expressly prohibited.

29. Transfer or Assignment of Ownership

Regulation No. 3, 5 CCR 1001-5, Part C, § II.C.

No transfer or assignment of ownership of the Operating Permit source will be effective unless the prospective owner or operator applies to the Air Pollution Control Division on Division-supplied Administrative Permit Amendment forms, for reissuance of the existing Operating Permit. No administrative permit shall be complete until a written agreement containing a specific date for transfer of permit, responsibility, coverage, and liability between the permittee and the prospective owner or operator has been submitted to the Division.

30. Volatile Organic Compounds

Regulation No. 7, 5 CCR 1001-9, Part B, §§ I & III.

The requirements in paragraphs a, b and e apply to sources located in the Denver 1-hour ozone attainment/maintenance area, any nonattainment area for the 1-hour ozone standard and to the 8-hour Ozone Control Area and on a state-only basis to sources located in any ozone nonattainment area, which includes areas designated nonattainment for either the 1-hour or 8-hour ozone standard, unless otherwise specified in Regulation No. 7, Part A, Section I.A.1.c. The requirements in paragraphs c and d apply statewide.

a. All storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g. maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

   Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. Testing shall be conducted as in Regulation No. 7, Part B, Section VI.C.3.

b. Except as otherwise provided by Regulation No. 7, all volatile organic compounds, excluding petroleum liquids, transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

c. No person shall dispose of volatile organic compounds by evaporation or spillage unless Reasonably Available Control Technology (RACT) is utilized.

d. No owner or operator of a bulk gasoline terminal, bulk gasoline plant, or gasoline dispensing facility as defined in Colorado Regulation No. 7, Part B, Sections IV.C.2., IV.C.3. and VII.A.3., shall permit gasoline to be intentionally

spilled, discarded in sewers, stored in open containers, or disposed of in any other manner that would result in evaporation.

e. Beer production and associated beer container storage and transfer operations involving volatile organic compounds with a true vapor pressure of less than 1.5 psia actual conditions are exempt from the provisions of paragraph b, above.

31. Wood Stoves and Wood burning Appliances

Regulation No. 4, 5 CCR 1001-6

The permittee shall comply with the provisions of Regulation No. 4 concerning the advertisement, sale, installation, and use of wood stoves and wood burning appliances.

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DISCLAIMER: None of the information found in these Appendices shall be considered to be State or Federally enforceable, except as otherwise provided in the permit, and is presented to assist the source, permitting authority, inspectors, and citizens.

A. Appendix A - Inspection Information

A.I. Directions to Plant:

The facility is located approximately 5 miles south of Craig, CO near Highway 13. Ranney Street, which goes south from the town of Craig, also leads to Craig Station

A.II. Safety Equipment Required:

Eye Protection; Hard Hat; Safety Shoes; Hearing Protection

A.III. Facility Plot Plan:

The attached Figures (following the insignificant activities list) shows the plot plan as submitted via email on March 20, 2018.

A.IV. List of Insignificant Activities:

The following list of insignificant activities was provided by the source to assist in the understanding of the facility layout. Since there is no requirement to update such a list, activities may have changed since the last filing.

For insignificant activities marked with an asterisk (*) the owner or operator must maintain sufficient recordkeeping to verify that the exemption applies (e.g., annual throughput is less than 400,000 gallons). Such records shall be made available for Division review upon request (Colorado Regulation No. 3, Part C, Section II.E).

A.IV.1. Noncommercial (in-house) experimental and analytical laboratory equipment which is bench scale in nature including quality control/quality assurance laboratories, process support laboratories, environmental laboratories supporting a manufacturing or industrial facility, and research and development laboratories (Colorado Regulation No. 3, Part C, Section II.E.3.i.(i))

A.IV.2. *Disturbance of surface areas for purposes of land development, which do not exceed 25 contiguous acres and which do not exceed six months in duration. (This does not include mining operations or disturbance of contaminated soil.) (Section II.E.3.j.)

A.IV.3. *Each individual piece of fuel burning equipment, other than smokehouse generators and internal combustion engines, which uses gaseous fuel, and which has a design rate less than or equal to 5 million Btu per hour. (See definition of fuel burning equipment, Common Provisions Regulation) (Section II.E.3.k.)

A.IV.4. *Chemical storage tanks or containers that hold less than 500 gallons, and which have a daily throughput less than 25 gallons per day (Section II.E.3.n.)

A.IV.5. *Landscaping and site housekeeping devices equal to or less than 10 HP in size (lawnmowers, trimmers, snow blowers, etc.) (Section II.E.3.bb.)

A.IV.6. *Chemical storage areas where chemicals are stored in closed containers, and where total storage capacity does not exceed 5000 gallons. This exemption applies solely to storage of such chemicals. This exemption does not apply to transfer of chemicals from, to, or between such containers. (Section II.E.3.mm.)

A.IV.7. Storage of butane, propane, or liquefied petroleum gas in a vessel with a capacity of less than 60,000 gallons, provided the requirements of Regulation No. 7, Section IV are met, where applicable. (Section II.E.3.zz.)

A.IV.8. Storage tanks of capacity less than 40,000 gallons of lubricating oils. (Section II.E.3.aaa.)

A.IV.9. Fuel storage and dispensing equipment in ozone attainment areas operated solely for company-owned vehicles where the daily fuel throughput is no more than 400 gallons per day, averaged annually. (Section II.E.3.ccc.)

A.IV.10. *Storage tanks meeting all of the following criteria (Section II.E.3.fff.):

A.IV.10.i. Annual throughput is less than 400,000 gallons; and

A.IV.10.ii. The liquid is one of the following:

(a) Diesel fuels 1-D, 2-D or 4-D;

(b) Fuel oils #1 through #6;

(c) Gas turbine fuels 1-GT through 4-GT;

(d) An oil/water mixture with a vapor pressure lower than that of diesel fuel (Reid vapor pressure of 0.025 PSIA).

A.IV.11. Each individual piece of fuel burning equipment which uses gaseous fuel, and which has a design rate less than or equal to 10 million Btu per hour, and which is solely for heating buildings for personal comfort. (Section III.E.3.ggg.)

A.IV.12. Stationary Internal Combustion Engines which (Section II.E.3.nnn.):

A.IV.12.i. Power portable drilling rigs; or

A.IV.12.ii. Are emergency power generators which have a rated horsepower of less than 260; or operate no more than 250 hours per year and have a rated horsepower of less than 737; or operate no more than 100 hours per year and have a rated horsepower of less than 1840; or

A.IV.12.iii. Have actual emissions less than five tons per year or rated horsepower of less than 50.

A.IV.13. *Air pollution emission units, operations or activities with emissions less than the appropriate de minimis reporting level. (Section II.E.3.a.)

A.IV.14. *Emergency diesel fire-pump engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 1,068 hours per year.)

A.IV.15. *Unit 1 & 2 emergency diesel generator engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 389 hours per year.)

A.IV.16. *Unit 3 emergency diesel generator engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 764 hours per year.)

A.IV.17. 3,200 Btu/hr propane space heater @ west warehouse (Section III.E.3.ggg.)

A.IV.18. 500 gallon propane tank @ east warehouse (Section II.E.3.zz.)

A.IV.19. No. 2 Fuel Oil Tank - 500,000 gallons (Section II.E.3.fff.)

A.IV.20. No. 2 Fuel Oil Tank - 500,000 gallons (Section II.E.3.fff.)

A.IV.21. *Plant Solvent Parts Cleaners (Section II.E.3.a.)

A.IV.22. *Emergency Generator Fuel Oil Day Tank Vent (100 gal) (Section II.E.3.a.)

A.IV.23. *Aboveground Diesel Tank Vent - Diesel (12,000 gal) (Section II.E.3.a.)

A.IV.24. *Aboveground Gasoline Tank Vent (10,000 gal) (Section II.E.3.a.)

A.IV.25. Chemical Laboratory (Section II.E.3.i.(i))

A.IV.26. 8,500 gallon #2 Diesel Tank (Section II.E.3.fff.)

A.IV.27. 8,500 gallon #2 Diesel Tank (Section II.E.3.fff.)

A.IV.28. *Hauling Miscellaneous Wet Wastes (Section II.E.3.a.)

A.IV.29. *Bottom Ash Storage and Handling (Section II.E.3.a.)

A.IV.30. *Dry Outage Waste Handling/Hauling (Section II.E.3.a.)

A.IV.31. *Gritblasting and sandblasting activities during outages (Section II.E.3.a.)

A.IV.32. Street and Parking Lot Striping (Section II.E.3.s.)

A.IV.33. Aerosol Can Usage (Section II.E.3.u.)

A.IV.34. Road and Lot Paving (Section II.E.3.x.)

A.IV.35. *Limestone Handling/Hauling for Road Repair and Pond Rip-Rap (Section II.E.3.a.)

A.IV.36. *Limestone Storage Piles (Section II.E.3.a.)

A.IV.37. Welding Operations (Section II.E.3.r.)

A.IV.38. *Used Oil Space Heater (Section III.E.3.a.)

A.IV.39. *Various Oil or Propane-Fired Heaters ranging from 500,000 to 900,000 Btu/hr (Section III.E.3.a.)

A.IV.40. *Unit 1 and 2 Limestone Transfer Conveyors (Section II.E.3.a.)

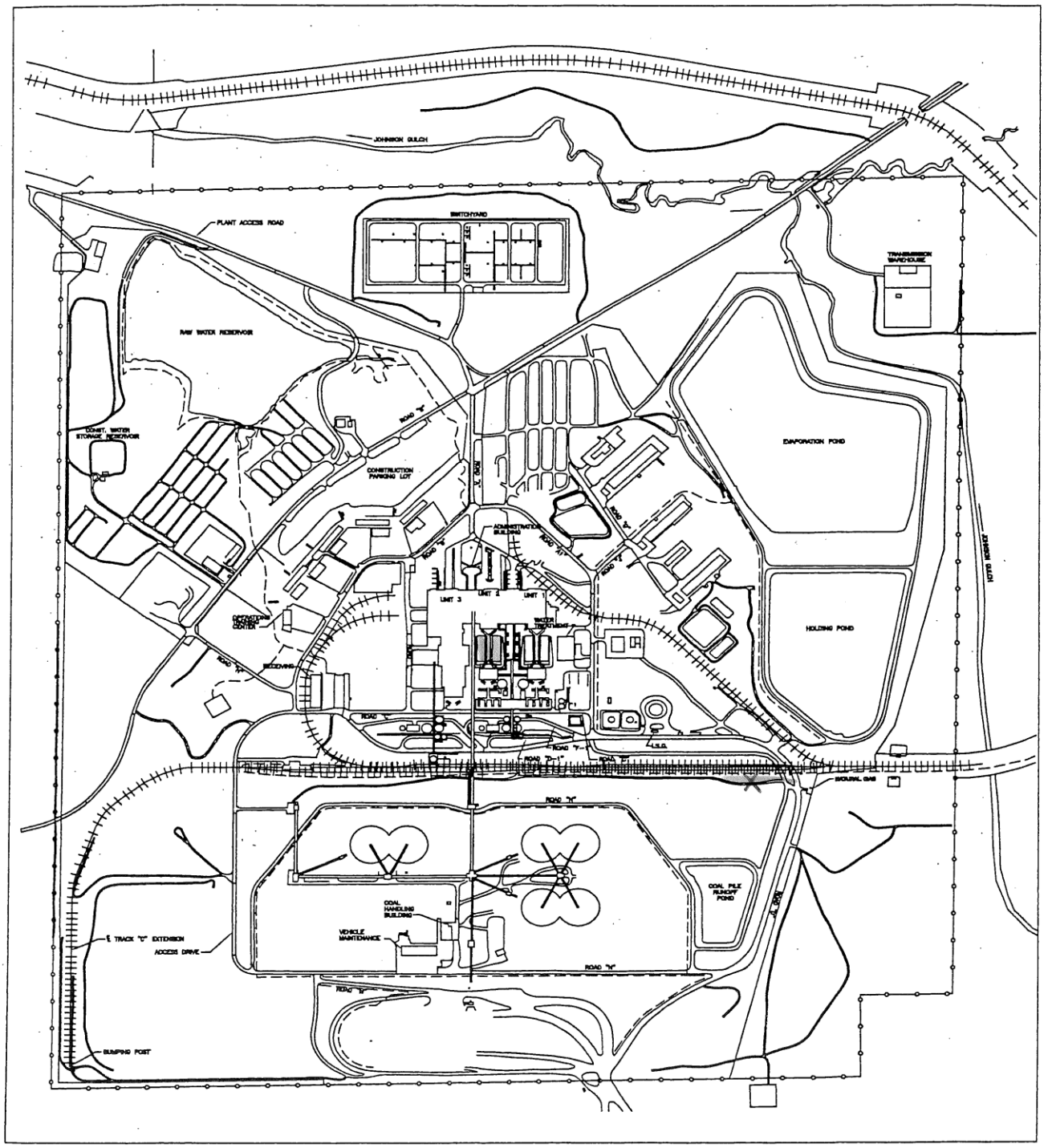
A.IV.41. *Dry Sorbent Injection Silo (Section II.E.3.a.)

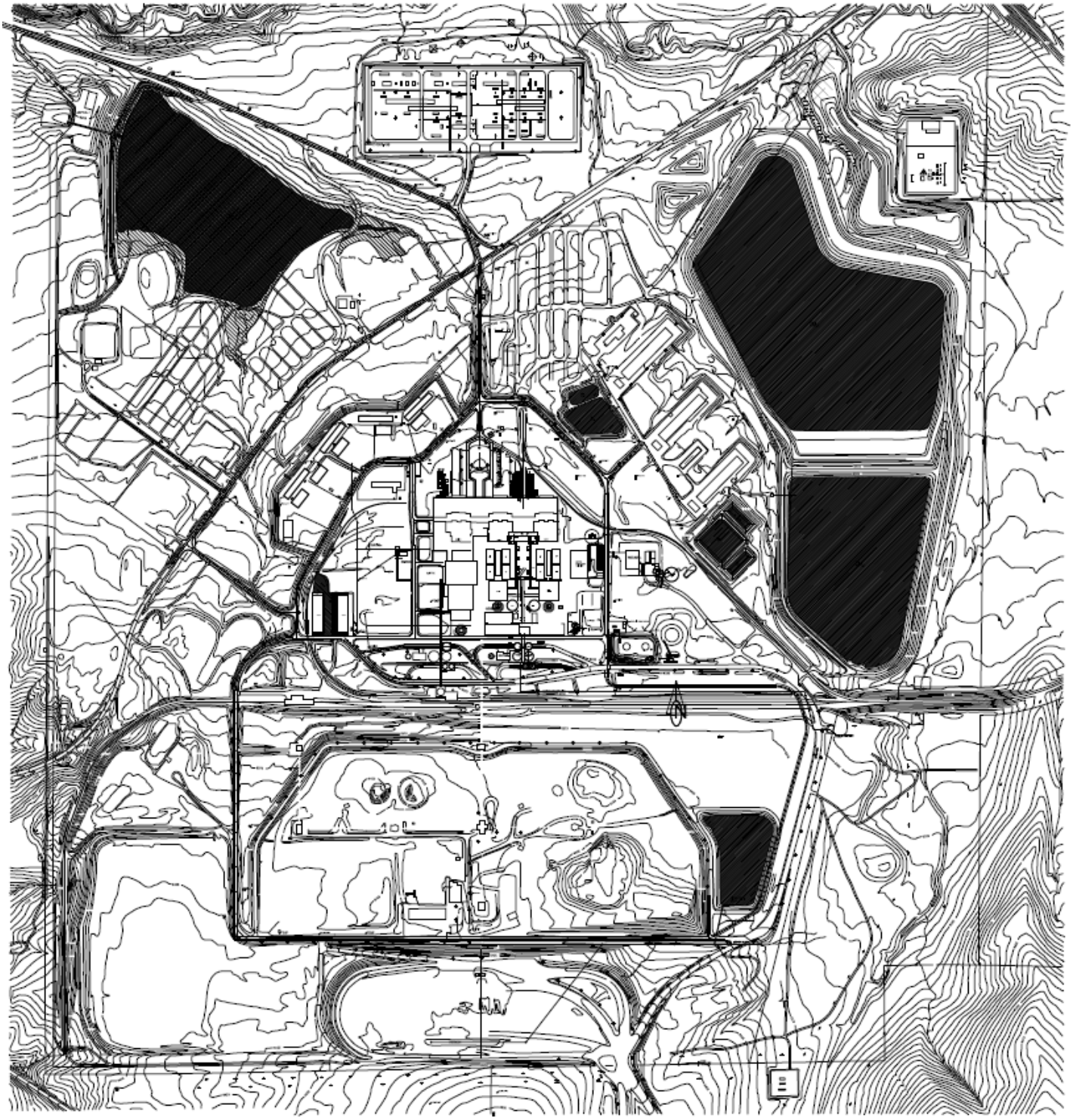
A.IV.42. *Anhydrous Ammonia Storage (Two 50,000 Gallon Tanks) and Transport System (Section II.E.3.a.)

A.IV.43. *Urea Storage and Transport System (Section II.E.3.a.)

A.IV.44. *Common Coal Drive House (Section II.E.3.a.)

A.IV.45. *Light Plants and Small Portable Generators and Welders (Section II.E.3.a.)


JOHNSON GULCH
PLANT ACCESS ROAD
SWITCHYARD
TRANSMISSION WAREHOUSE
RAW WATER RESERVOIR
CONST. WATER STORAGE RESERVOIR
CONSTRUCTION PARKING LOT
EVAPORATION POND
ADMINISTRATION BUILDING
UNIT 3
UNIT 2
UNIT 1
WATER TREATMENT
HOLDING POND
RECEIVING
ROAD "A"
ROAD "B"
ROAD "C"
ROAD "D"
ROAD "E"
ROAD "F"
ROAD "G"
ROAD "H"
ROAD "I"
ROAD "J"
ROAD "K"
ROAD "L"
ROAD "M"
ROAD "N"
ROAD "O"
ROAD "P"
ROAD "Q"
ROAD "R"
ROAD "S"
ROAD "T"
ROAD "U"
ROAD "V"
ROAD "W"
ROAD "X"
ROAD "Y"
ROAD "Z"
COAL HANDLING BUILDING
VEHICLE MAINTENANCE
COAL PILE RUNOFF POND
TRACK "C" EXTENSION
ACCESS DRIVE
BUNSPND POST



B. Appendix B – Reporting Requirements and Definitions

Version 8/20/2014, with codes

Please note that, pursuant to 113(c)(2) of the federal Clean Air Act, any person who knowingly:

(A) Makes any false material statement, representation, or certification in, or omits material information from, or knowingly alters, conceals, or fails to file or maintain any notice, application, record, report, plan, or other document required pursuant to the Act to be either filed or maintained (whether with respect to the requirements imposed by the Administrator or by a State);

(B) Fails to notify or report as required under the Act; or

(C) Falsifies, tampers with, renders inaccurate, or fails to install any monitoring device or method required to be maintained or followed under the Act shall, upon conviction, be punished by a fine pursuant to title 18 of the United States Code, or by imprisonment for not more than 2 years, or both. If a conviction of any person under this paragraph is for a violation committed after a first conviction of such person under this paragraph, the maximum punishment shall be doubled with respect to both the fine and imprisonment.

The Source must comply with all conditions of this operating permit. Any permit noncompliance constitutes a violation of the Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

The Part 70 Operating Permit program requires three types of reports to be filed for all permits. All required reports must be certified by a responsible official.

Report #1: Monitoring Deviation Report (due at least every six months)

For purposes of this operating permit, the Division is requiring that the monitoring reports are due every six months unless otherwise noted in the permit. All instances of deviations from permit monitoring requirements must be clearly identified in such reports.

For purposes of this operating permit, monitoring means any condition determined by observation, by data from any monitoring protocol, or by any other monitoring which is required by the permit as well as the recordkeeping associated with that monitoring. This would include, for example, fuel use or process rate monitoring, fuel analyses, and operational or control device parameter monitoring.

Report #2: Permit Deviation Report (must be reported "promptly")

In addition to the monitoring requirements set forth in the permits as discussed above, each and every requirement of the permit is subject to deviation reporting. The reports must address deviations from permit requirements, including those attributable to malfunctions as defined in this Appendix, the probable cause of such deviations, and any corrective actions or preventive measures taken. All deviations from any term or condition of the permit are required to be summarized or referenced in the annual compliance certification.

For purposes of this operating permit, "malfunction" shall refer to both emergency conditions and malfunctions. Additional discussion on these conditions is provided later in this Appendix.

For purposes of this operating permit, the Division is requiring that the permit deviation reports are due as set forth in General Condition 21. Where the underlying applicable requirement contains a definition of prompt or otherwise specifies a time frame for reporting deviations, that definition or time frame shall govern. For example, quarterly Excess Emission Reports required by an NSPS or Regulation No. 1, Section IV.

In addition to the monitoring deviations discussed above, included in the meaning of deviation for the purposes of this operating permit are any of the following:

(1) A situation where emissions exceed an emission limitation or standard contained in the permit;

(2) A situation where process or control device parameter values demonstrate that an emission limitation or standard contained in the permit has not been met;

(3) A situation in which observations or data collected demonstrates noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit; or,

(4) A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred. (only if the emission point is subject to CAM)

For reporting purposes, the Division has combined the Monitoring Deviation Report with the Permit Deviation Report. All deviations shall be reported using the following codes:

1 = Standard:	When the requirement is an emission limit or standard
2 = Process:	When the requirement is a production/process limit
3 = Monitor:	When the requirement is monitoring
4 = Test:	When the requirement is testing
5 = Maintenance:	When required maintenance is not performed
6 = Record:	When the requirement is recordkeeping
7 = Report:	When the requirement is reporting
8 = CAM:	A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other:	When the deviation is not covered by any of the above categories

Report #3: Compliance Certification (annually, as defined in the permit)

Submission of compliance certifications with terms and conditions in the permit, including emission limitations, standards, or work practices, is required not less than annually.

Compliance Certifications are intended to state the compliance status of each requirement of the permit over the certification period. They must be based, at a minimum, on the testing and monitoring methods specified in the permit that were conducted during the relevant time period. In addition, if the

owner or operator knows of other material information (i.e. information beyond required monitoring that has been specifically assessed in relation to how the information potentially affects compliance status), that information must be identified and addressed in the compliance certification. The compliance certification must include the following:

- The identification of each term or condition of the permit that is the basis of the certification;
- Whether or not the method(s) used by the owner or operator for determining the compliance status with each permit term and condition during the certification period was the method(s) specified in the permit. Such methods and other means shall include, at a minimum, the methods and means required in the permit. If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Federal Clean Air Act, which prohibits knowingly making a false certification or omitting material information;
- The status of compliance with the terms and conditions of the permit, and whether compliance was continuous or intermittent. The certification shall identify each deviation and take it into account in the compliance certification. Note that not all deviations are considered violations.[1]
- Such other facts as the Division may require, consistent with the applicable requirements to which the source is subject, to determine the compliance status of the source.

The Certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred (only for emission points subject to CAM).

Note the requirement that the certification shall identify each deviation and take it into account in the compliance certification. Previously submitted deviation reports, including the deviation report submitted at the time of the annual certification, may be referenced in the compliance certification.

[1] For example, given the various emissions limitations and monitoring requirements to which a source may be subject, a deviation from one requirement may not be a deviation under another requirement which recognizes an exception and/or special circumstances relating to that same event.

Startup, Shutdown, Malfunctions and Emergencies,

Understanding the application of Startup, Shutdown, Malfunctions and Emergency Provisions, is very important in both the deviation reports and the annual compliance certifications.

Startup, Shutdown, and Malfunctions

Please note that exceedances of some New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards that occur during Startup, Shutdown or Malfunctions may not be considered to be non-compliance since emission limits or standards often do not apply unless specifically stated in the NSPS. Such exceedances must, however, be reported as excess emissions per the NSPS/MACT rules and would still be noted in the deviation report. In regard to compliance certifications, the permittee should be confident of the information related to those deviations when making compliance determinations since they are subject to Division review. The concepts of Startup, Shutdown and Malfunctions also exist for Best Available Control Technology (BACT) sources, but are not applied in the same fashion as for NSPS and MACT sources.

Emergency Provisions

Under the Emergency provisions of Part 70 certain operational conditions may act as an affirmative defense against enforcement action if they are properly reported.

DEFINITIONS

Malfunction (NSPS) means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Malfunction (SIP) means any sudden and unavoidable failure of air pollution control equipment or process equipment or unintended failure of a process to operate in a normal or usual manner. Failures that are primarily caused by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

Emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

B.I. Appendix B – Monitoring and Permit Deviation Report - Part I

B.I.1. Following is the **required** format for the Monitoring and Permit Deviation report to be submitted to the Division as set forth in General Condition 21. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

B.I.2. Part II of this Appendix B shows the format and information the Division will require for describing periods of monitoring and permit deviations, or malfunction or emergency conditions as indicated in the Table below. One Part II Form must be completed for each Deviation. Previously submitted reports (e.g. EER's or malfunctions) may be referenced and the form need not be filled out in its entirety.

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:_____ (see first page of the permit for specific reporting period and dates)

Emission Unit	Facility ID	Unit Description	Deviations noted During Period?[1]		Deviation Code [2]	Malfunction/Emergency Condition Reported During Period?	
			YES	NO		YES	NO
Unit 1	B001	Coal-Fired Boiler: Babcock & Wilcox #NB24157					
Unit 2	B002	Coal-Fired Boiler: Babcock & Wilcox #NB24156					
Unit 3	B003	Coal-Fired Boiler: Babcock & Wilcox #NB24602					
Coal Handling – Units 1 & 2	P101	F101a – Coal hauling – Units 1 & 2					
		F101b – Coal unloading to grizzly – Units 1 & 2					
		F101c – Coal surge pile					
		S101d – Primary coal crushing – Units 1 & 2					
		S101e – Secondary coal crushing building – Units 1 & 2					
		S101f – Common Coal Transfer Building Belt A					
		S101g – Common Coal Transfer Building Belt B					
		S101h – Coal stackout building – Units 1 & 2					
		F101i – Coal stackout – Units 1 & 2					
		F101j – Coal storage piles – Units 1 & 2					
		S101k – Coal reclaim A – Units 1 & 2					

		S101l – Coal reclaim B – Units 1 & 2					
		S101m – Coal tripper deck & silos – Units 1 & 2					
Ash Handling – Units 1 & 2	P203	S203a – Ash storage silo A – Units 1 & 2					
		S203b – Ash storage silo B – Units 1 & 2					
		F203c – Ash truck loading – Units 1 & 2					
		S203d – Silo B dry ash unloading – Units 1 & 2					
		S203e – Silo A dry ash unloading – Units 1 & 2					
Limestone Handling – Units 1 & 2	P201	F201a – Limestone hauling					
		S201b – Limestone truck unloading					
		S201c – Limestone silo #1 – Units 1 & 2					
		S201d – Limestone silo #2 – Units 1 & 2					
Coal Handling – Unit 3	P102	F102a – Coal train unloading – Unit 3					
		S102b – Coal conveyor portal building – Unit 3					
		S102c – Coal conveyor portal building – Unit 3					
		S102d – Secondary coal crushing (2 crushers) – Unit 3					
		S102e – Coal stackout building – Unit 3					
		F102f – Coal stackout – Unit 3					
		F102g – Coal storage pile – Unit 3					
		S102h – Coal reclaim system – Unit 3					
		S102i – Coal tripper deck & silos – Unit 3					
		S102j – Loadout coal to railcars – Unit 3					
		S102k – Common coal transfer building extension					
		F102l – Coal train loading					
Ash Handling – Unit 3	P204	S204a – Ash storage silo – Unit 3					
		F204b – Ash truck loading – Unit 3					
		S204c – Recycle ash truck					
		F204d – Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, and 3					
Lime Handling – Unit 3	P202	F202a – Lime hauling					
		S202b – Lime unloading					
		S202c – Lime conveying and silo					

		S202d – Lime day bin					
Cooling Towers – Units 1 & 2	P401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74					
	P402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74					
Cooling Tower – Unit 3	P403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79					
Emergency Fire-Pump Engine	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower					
Units 1&2 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower					
Unit 3 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower					
General Conditions							
Insignificant Activities							

[1] See previous discussion regarding what is considered to be a deviation. Determination of whether or not a deviation has occurred shall be based on a reasonable inquiry using readily available information.

[2] Use the following entries, as appropriate

1 = Standard: When the requirement is an emission limit or standard
2 = Process: When the requirement is a production/process limit
3 = Monitor: When the requirement is monitoring
4 = Test: When the requirement is testing
5 = Maintenance: When required maintenance is not performed
6 = Record: When the requirement is recordkeeping
7 = Report: When the requirement is reporting
8 = CAM: A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other: When the deviation is not covered by any of the above categories

B.II. Appendix B – Monitoring and Permit Deviation Report - Part II

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:

Is the deviation being claimed as an: Emergency _____ Malfunction_____ N/A

(For NSPS/MACT) Did the deviation occur during: Startup _____ Shutdown _____ Malfunction ____

Normal Operation _____

OPERATING PERMIT UNIT IDENTIFICATION:

Operating Permit Condition Number Citation

Explanation of Period of Deviation

Duration (start/stop date & time)

Action Taken to Correct the Problem

Measures Taken to Prevent a Reoccurrence of the Problem

Dates of Malfunctions/Emergencies Reported (if applicable)

Deviation Code _____ Division Code QA: _____

SEE EXAMPLE ON THE NEXT PAGE

EXAMPLE

FACILITY NAME: U.S.S. Enterprise
OPERATING PERMIT NO: 64OPZZXXX
REPORTING PERIOD: 1/1/2369 - 6/30/2369

Is the deviation being claimed as an: Emergency / **Malfunction** / N/A

(For NSPS/MACT) Did the deviation occur during: Startup / Shutdown / **Malfunction** / Normal Operation

OPERATING PERMIT UNIT IDENTIFICATION:

Holodeck generator with nanobot-repaired filtration system – Unit TNG

Operating Permit Condition Number Citation

Section II, Condition 3.1 - Opacity Limitation

Explanation of Period of Deviation

Tribbles in the console

Duration

START- 1730 4/10/2369
END- 1800 4/10/2369

Action Taken to Correct the Problem

Transported Tribbles to Klingon vessel.

Measures Taken to Prevent Reoccurrence of the Problem

Permanent ban of Tribbles as pets. Increased structural integrity of console.

Dates of Malfunction/Emergencies Reported (if applicable)

5/30/2369 to J.L. Picard, APCD

Deviation Code _____ Division Code QA: _____

B.III. Appendix B – Monitoring and Permit Deviation Report - Part III

REPORT CERTIFICATION

SOURCE NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station

FACILITY IDENTIFICATION NUMBER: 081-0018

PERMIT NUMBER: 96OPMF155

REPORTING PERIOD:_____ (see first page of the permit for specific reporting period and dates)

All information for the Title V Semi-Annual Deviation Reports must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B. This signed certification document must be packaged with the documents being submitted.

STATEMENT OF COMPLETENESS

I have reviewed the information being submitted in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this submittal are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in Sub-Section 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of Sub-Section 25-7 122.1, C.R.S.

Printed or Typed Name Title

Signature of Responsible Official Date Signed

Note: Deviation reports shall be submitted to the Division at the address given in Appendix D of this permit. No copies need be sent to the U.S. EPA.

C. Appendix C – Required Format for Annual Compliance Certification Reports

Following is the format for the Compliance Certification report to be submitted to the Division and the U.S. EPA annually based on the effective date of the permit. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:

I. Facility Status

___ During the entire reporting period, this source was in compliance with **ALL** terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference. The method(s) used to determine compliance is/are the method(s) specified in the Permit.

___ With the possible exception of the deviations identified in the table below, this source was in compliance with all terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference, during the entire reporting period. The method used to determine compliance for each term and condition is the method specified in the Permit, unless otherwise indicated and described in the deviation report(s). Note that not all deviations are considered violations.

Emission Unit	Facility ID	Unit Description	Deviations Reported [1]		Monitoring Method per Permit?[2]		Was compliance continuous or intermittent?[3]	
			Previous	Current	YES	NO	YES	NO
Unit 1	B001	Coal-Fired Boiler: Babcock & Wilcox #NB24157						
Unit 2	B002	Coal-Fired Boiler: Babcock & Wilcox #NB24156						
Unit 3	B003	Coal-Fired Boiler: Babcock & Wilcox #NB24602						
Coal Handling – Units 1 & 2	P101	F101a – Coal hauling – Units 1 & 2						
		F101b – Coal unloading to grizzly – Units 1 & 2						
		F101c – Coal surge pile						
		S101d – Primary coal crushing – Units 1 & 2						
		S101e – Secondary coal crushing building – Units 1 & 2						
		S101f – Common Coal Transfer Building Belt A						
		S101g – Common Coal Transfer Building						

		Belt B						
		S101h – Coal stackout building – Units 1 & 2						
		F101i – Coal stackout – Units 1 & 2						
		F101j – Coal storage piles – Units 1 & 2						
		S101k – Coal reclaim A – Units 1 & 2						
		S101l – Coal reclaim B – Units 1 & 2						
		S101m – Coal tripper deck & silos – Units 1 & 2						
Ash Handling – Units 1 & 2	P203	S203a – Ash storage silo A – Units 1 & 2						
		S203b – Ash storage silo B – Units 1 & 2						
		F203c – Ash truck loading – Units 1 & 2						
		S203d – Silo B dry ash unloading – Units 1 & 2						
		S203e – Silo A dry ash unloading – Units 1 & 2						
Limestone Handling – Units 1 & 2	P201	F201a – Limestone hauling						
		S201b – Limestone truck unloading						
		S201c – Limestone silo #1 – Units 1 & 2						
		S201d – Limestone silo #2 – Units 1 & 2						
Coal Handling – Unit 3	P102	F102a – Coal train unloading – Unit 3						
		S102b – Coal conveyor portal building – Unit 3						
		S102c – Coal conveyor portal building – Unit 3						
		S102d – Secondary coal crushing (2 crushers) – Unit 3						
		S102e – Coal stackout building – Unit 3						
		F102f – Coal stackout – Unit 3						
		F102g – Coal storage pile – Unit 3						
		S102h – Coal reclaim system – Unit 3						
		S102i – Coal tripper deck & silos – Unit 3						
		S102j – Loadout coal to railcars – Unit 3						
		S102k – Common coal transfer building extension						
		F102l – Coal train loading						
Ash Handling – Unit 3	P204	S204a – Ash storage silo – Unit 3						
		F204b – Ash truck loading – Unit 3						

		S204c – Recycle ash truck						
		F204d – Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, and 3						
Lime Handling – Unit 3	P202	F202a – Lime hauling						
		S202b – Lime unloading						
		S202c – Lime conveying and silo						
		S202d – Lime day bin						
Cooling Towers – Units 1 & 2	P401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74						
	P402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74						
Cooling Tower – Unit 3	P403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79						
Emergency Fire-Pump Engine	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower						
Units 1&2 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower						
Unit 3 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower						
General Conditions								
Insignificant Activities[4]								

[1] If deviations were noted in a previous deviation report , put an "X" under "previous". If deviations were noted in the current deviation report (i.e. for the last six months of the annual reporting period), put an "X" under "current". Mark both columns if both apply.

[2] Note whether the method(s) used to determine the compliance status with each term and condition was the method(s) specified in the permit. If it was not, mark "no" and attach additional information/explanation.

[3] Note whether the compliance status with of each term and condition provided was continuous or intermittent. "Intermittent Compliance" can mean either that noncompliance has occurred or that the owner or operator has data sufficient to certify compliance only on an intermittent basis. Certification of intermittent compliance therefore does not necessarily mean that any noncompliance has occurred.

NOTE:

The Periodic Monitoring requirements of the Operating Permit program rule are intended to provide assurance that even in the absence of a continuous system of monitoring the Title V source can demonstrate whether it has operated in continuous compliance for the duration of the reporting period. Therefore, if a source 1) conducts all of the monitoring and recordkeeping required in its permit, even if such activities are done periodically and not continuously, and if 2) such monitoring and recordkeeping does not indicate non-

compliance, and if 3) the Responsible Official is not aware of any credible evidence that indicates non-compliance, then the Responsible Official can certify that the emission point(s) in question were in continuous compliance during the applicable time period.

[4] Compliance status for these sources shall be based on a reasonable inquiry using readily available information.

II. Status for Accidental Release Prevention Program:

A. This facility _____ is subject _____ is not subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act)

B. If subject: The facility _____ is _____ is not in compliance with all the requirements of section 112(r).

1. A Risk Management Plan _____ will be _____has been submitted to the appropriate authority and/or the designated central location by the required date.

III. Certification

All information for the Annual Compliance Certification must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B. This signed certification document must be packaged with the documents being submitted.

I have reviewed this certification in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this certification are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in § 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of § 25-7 122.1, C.R.S.

Printed or Typed Name Title

Signature Date Signed

NOTE: All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

D. Appendix D – Notification Addresses

D.I. Air Pollution Control Division

Colorado Department of Public Health and Environment
Air Pollution Control Division
Operating Permits Unit
APCD-SS-B1
4300 Cherry Creek Drive S.
Denver, CO 80246-1530
ATTN: Matt Burgett

D.II. United States Environmental Protection Agency

Compliance Notifications:

Office of Enforcement, Compliance and Environmental Justice
Mail Code 8ENF-AT
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

502(b)(10) Changes, Off Permit Changes:

Office of Partnerships and Regulatory Assistance
Mail Code 8P-AR
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

E. Appendix E – Permit Acronyms

Listed Alphabetically:

AIRS -	Aerometric Information Retrieval System
AP-42 -	EPA Document Compiling Air Pollutant Emission Factors
APEN -	Air Pollution Emission Notice (State of Colorado)
APCD -	Air Pollution Control Division (State of Colorado)
ASTM -	American Society for Testing and Materials
BACT -	Best Available Control Technology
BTU -	British Thermal Unit
CAA -	Clean Air Act (CAAA = Clean Air Act Amendments)
CCR -	Colorado Code of Regulations
CEM -	Continuous Emissions Monitor
CF -	Cubic Feet (SCF = Standard Cubic Feet)
CFR -	Code of Federal Regulations
CO -	Carbon Monoxide
COM -	Continuous Opacity Monitor
CRS -	Colorado Revised Statute
EF -	Emission Factor
EPA -	Environmental Protection Agency
FI -	Fuel Input Rate in MMBtu/hr
FR -	Federal Register
G -	Grams
Gal -	Gallon
GPM -	Gallons per Minute
HAPs -	Hazardous Air Pollutants
HP -	Horsepower
HP-HR -	Horsepower Hour (G/HP-HR = Grams per Horsepower Hour)
LAER -	Lowest Achievable Emission Rate
LBS -	Pounds
M -	Thousand
MM -	Million
MMscf -	Million Standard Cubic Feet
MMscfd -	Million Standard Cubic Feet per Day
N/A or NA -	Not Applicable
NOx -	Nitrogen Oxides
NESHAP -	National Emission Standards for Hazardous Air Pollutants
NSPS -	New Source Performance Standards
P -	Process Weight Rate in Tons/Hr
PE -	Particulate Emissions
PM -	Particulate Matter
PM_{10} -	Particulate Matter Under 10 Microns
PSD -	Prevention of Significant Deterioration
PTE -	Potential To Emit

RACT - Reasonably Available Control Technology
SCC - Source Classification Code
SCF - Standard Cubic Feet
SIC - Standard Industrial Classification
SO_2 - Sulfur Dioxide
TPY - Tons Per Year
TSP - Total Suspended Particulate
VOC - Volatile Organic Compounds

F. Appendix F – Permit Modifications

DATE OF REVISION	TYPE OF REVISION	SECTION NUMBER, CONDITION NUMBER	DESCRIPTION OF REVISION

G. Appendix G – Units 1 and 2 Baghouses Particulate Matter Compliance Assurance Monitoring Plan

G.I. Background

G.I.1. Emission Unit Description

G.I.1.i. Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

G.I.1.ii. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

G.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM requirements:

G.I.2.i. Unit 1:

(a) 0.10 lb/MMBtu heat input, 40 CFR Part 60, Subpart D, §60.42 (Condition 1.1.1);

(b) 0.03 lb/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) (Condition 1.1.2); and

(c) 0.03 lb PM/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze (Condition 1.1.3).

G.I.2.ii. Unit 2:

(a) 0.10 lb/MMBtu heat input, 40 CFR Part 60, Subpart D, §60.42 (Condition 2.1.1);

(b) 0.03 lb/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) (Condition 2.1.2); and

(c) 0.03 lb/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze (Condition 2.1.3).

G.I.3. Monitoring Requirements

G.I.3.i. Visible emissions (opacity).

G.I.4. Control Technology

G.I.4.i. Each boiler is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouses have a particulate removal efficiency greater than 99%.

G.II. Monitoring Approach

	Indicator 1
I. Indicator	Visible Emissions (Opacity)
Measurement Approach	Opacity emissions will be monitored by a Continuous Opacity Monitor System (COMS).
II. Indicator Range	An excursion is defined as an opacity value greater than 15.0% for 6 minutes or more. When this occurs, the Source will perform an investigation to ascertain the cause of the excursion. In addition to the above, when an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	An increase in visible emissions (opacity) under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The COM equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Part 60 and the internal CEM Quality Control/Quality Assurance program developed in accordance with 40 CFR Part 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	Opacity measurements will be performed in accordance with the requirements in 40 CFR Part 60, Subpart A, §60.13. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	COM data shall be reduced to 6-minute averages as required by 40 CFR Part 60, Subpart A, § 60.13.

G.III. Justification

G.III.1. Background

G.III.1.i. The large pollutant specific emission units (PSEU) are two (2) coal fired boilers, that burn natural gas for startup, shutdown and/or flame stabilization. Each boiler is equipped with a baghouse to control particulate matter emissions.

G.III.1.ii. Particulate matter removal is accomplished by passing the flue gases through a porous fabric material. The solid particles buildup on the fabric surface to form a

thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

G.IV. Rationale for Selection of Performance Indicators

G.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

G.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

G.IV.2.i. Visible Emissions (Opacity)

Based on the relationship between particulate matter in a flue gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

G.V. Rationale for Selection of Indicator Ranges

G.V.1. Visible Emissions (Opacity)

G.V.1.i. In their May 1, 2009 Operating Permit renewal application, a CAM plan was submitted (with respect to PM emission limitations) for Units 1 and 2. In the application, the Source proposed visible emissions (short-term opacity) as an indicator. The Source proposed that an opacity reading greater than 15%, is an indication of potential reduction in baghouse performance. In response to this indicator, an investigation is triggered to locate the cause of the excursion. If the maintenance actions are taken, the results of the work performed are to be documented.

H. Appendix H – Unit 3 Baghouse Particulate Matter Compliance Assurance Monitoring Plan

H.I. Background

H.I.1. Emission Unit Description

H.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

H.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM/PM_{10} requirements:

H.I.2.i. Unit 3:

(a) 443 tons PM/year, 403 tons PM_{10}/year, Colorado Construction Permit 12MF322-1 (Condition 3.1.1.3) (Note that this limit includes both filterable and condensable PM/PM_{10}, but only the filterable portion of the emissions are subject to the CAM requirements as there is no control device for the condensable portion of the limit);

(b) 0.013 lb PM/MMBtu, 0.012 lb PM10/MMBtu, Colorado Construction Permit 12MF322-1 (Condition 3.1.1.1);

(c) 0.013 lb PM/MMBtu, 0.012 lb PM10/MMBtu, Colorado Regulation No. 23, Section IV.B – Regional Haze (Condition 3.1.2).

H.I.3. Monitoring Requirements:

H.I.3.i. Visible emissions (opacity).

H.I.4. Control Technology:

H.I.4.i. The boiler is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouse has a particulate removal efficiency greater than 99%.

H.II. Monitoring Approach

	Indicator 1
I. Indicator	Visible Emissions (Opacity)
Measurement Approach	Opacity emissions will be monitored by a Continuous Opacity Monitor System (COMS).

	Indicator 1
II. Indicator Range	An excursion is defined as an opacity value greater than 7.5% for 6 minutes or more. When this occurs, the Source will perform an investigation to ascertain the cause of the excursion. An excursion is also defined as any 24-hour period in which the average opacity exceeds the baseline level established as required by Condition 17.6. In addition to the above, when an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	An increase in visible emissions (opacity) under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The COM equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Part 60 and the internal CEM Quality Control/Quality Assurance program developed in accordance with 40 CFR Part 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	Opacity measurements will be performed in accordance with the requirements in 40 CFR Part 60 Subpart A § 60.13. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	COM data shall be reduced to 6-minute averages as required by 40 CFR Part 60 Subpart A § 60.13. All 6-minute averages in each 24-hour period (midnight to midnight) will be averaged together to get a 24-hour average.

H.III. Justification

H.III.1. Background

H.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a baghouse to control particulate matter emissions.

H.III.1.ii. Particulate matter removal is accomplished by passing the flue gases through a porous fabric material. The solid particles buildup on the fabric surface to form a thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

H.IV. Rationale for Selection of Performance Indicators

H.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the

monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

H.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

H.IV.2.i. Visible Emissions (Opacity)

(a) Based on the relationship between particulate matter in a flue gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

H.V. Rationale for Selection of Indicator Ranges

H.V.1. Visible Emissions (Opacity)

H.V.1.i. In the May 21, 2010 application to modify the Title V permit to incorporate the Unit 3 requirements, the Source submitted a CAM plan with respect to PM emission limitations. In the May 21, 2010 application, the Source proposed using a baseline opacity monitoring method, akin to the requirements in 40 CFR Part 60, Subpart Da, as an indicator. This method involves establishing a baseline opacity during PM performance testing and then comparing the 24-hour average opacity against the baseline. Any 24-hour average opacity value that exceeds the baseline level shall be cause for investigating the control device.

H.V.1.ii. The inclusion of the short-term opacity indicator of 7.5% over 6 minutes was chosen to reflect the necessity for continuous monitoring which was not completely covered by the Source's request for the baseline opacity monitoring method. A short-term opacity indicator is standard for this size of industrial boiler. The 7.5% value was chosen because it is below the BACT limit of 10% specified in Colorado Construction Permit 12MF322-1. If the baghouse is operating properly, opacity should be below 7.5%. The short-term opacity indicator serves to provide an indication of proper baghouse operation and can be a reasonable indicator that Unit 3 is in compliance with the PM limitations.

I. Appendix I – Coal Handling System for Unit 3 (P102), Secondary Coal Crushing Building (S102d) Particulate Matter Compliance Assurance Monitoring Plan

I.I. Background

I.I.1. Emission Unit Description

I.I.1.i. S102d – Secondary Coal Crushing Building for the P102 Coal Handling System for Unit 3. The building contains two crushers which process coal for Unit 3. The system can also process coal for Units 1 and 2, as necessary.

I.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM requirements:

I.I.2.i. S102d:

(a) 1.7 tons PM/year, Colorado Construction Permit 12MF322-2 (Condition 7.2).

I.I.3. Monitoring Requirements:

I.I.3.i. Visible emissions; and

I.I.3.ii. Differential pressure monitoring.

I.I.4. Control Technology:

I.I.4.i. The secondary coal crushing building is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouse has a particulate removal efficiency greater than 99%.

I.II. Monitoring Approach

	Indicator 1	Indicator 2
I. Indicator	Visible Emissions	Differential Pressure Monitoring
Measurement Approach	Visible emissions from the baghouse will be monitored monthly by conducting a six-minute visible emission observation in accordance with the procedures in Method 22 while the crushers are active.	The pressure drop across the baghouse will be monitored on a daily basis. Pre-baghouse and post-baghouse pressures will be reported to a system which will trigger an investigation should the differential pressure exceed the indicator threshold.

	Indicator 1	Indicator 2
II. Indicator Range	An excursion is defined as any visible emissions seen during the Method 22 test. When an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.	An excursion is defined as a pressure differential of less than 5 inches of water or greater than 8 inches of water. When an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria		
a. Data Representativeness	Visible emissions from the baghouse under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.	Measurements taken pre- and post-baghouse are used to calculate the differential pressure, indicating proper operation of the control device.
b. Verification of Operational Status	The Source will maintain documentation to verify that the Method 22 has been performed while the system is in operation.	The pressure measurement system will alert the operator if the system is not functioning properly.
c. QA/QC Practices and Criteria	Certification is not required for Method 22 observations, but personnel shall be trained in general procedures for the determination of visible emissions. Persons performing visible emission observations shall be trained in determining the presence of visible emissions. A list of observers trained to perform the visible emission observations shall be maintained.	The pressure monitors will be calibrated maintained, and operated according to manufacturer's specifications. Documentation of all required calibrations and maintenance in accordance with these specifications shall be maintained by the Source.
d. Monitoring Frequency	Monthly	Daily
e. Data Collection Procedures	The EPA Reference Method 22 procedures shall be followed.	The pressure monitors will report on a daily basis to the operator via digital or analog signal. The data will be logged.
f. Averaging Time	N/A	N/A

I.III. Justification

I.III.1. Background

I.III.1.i. The pollutant specific emission unit is a coal processing building which houses two coal crushers. The building is equipped with a baghouse to control particulate matter emissions.

I.III.1.ii. Particulate matter removal is accomplished by passing the particulate laden gases through a porous fabric material. The solid particles buildup on the fabric surface

to form a thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

I.IV. Rationale for Selection of Performance Indicators

I.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

I.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

I.IV.2.i. Visible Emissions

(a) Based on the relationship between particulate matter in a particulate laden gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

I.IV.2.ii. Differential Pressure

(a) The physical action of forcing particulate laden air through the baghouse filters causes a pressure drop of the gas stream. This differential pressure is indicative of normal operation of the baghouse when it remains in a specific range. If the pressure drops below the normal range, it could indicate a preferential pathway through the baghouse. If the pressure rises above the normal range, it could indicate that particulate cake has built up in the system which restricts flow and could cause issues in normal operation.

I.V. Rationale for Selection of Indicator Ranges

I.V.1. Visible Emissions

I.V.1.i. If the control device is operating properly, no visible emissions should be seen during the Method 22 test.

I.V.2. Pressure Differential

I.V.2.i. In the May 1, 2009 application to modify the Title V permit the Source submitted a CAM plan with respect to PM emission limitations for S102d. In the May 1, 2009 application, the Source proposed using differential pressure monitoring. Values outside of the normal operating range of 5 to 8 inches of water shall be cause for investigating the control device. This indicator range is the normal operating range for the baghouse as recommended by the operator.

J. Appendix J – Units 1 and 2 Wet Limestone SO_2 Scrubbers Compliance Assurance Monitoring Plan

J.I. Background

J.I.1. Emission Unit Description

J.I.1.i. Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

J.I.1.ii. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

J.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable SO_2 requirements:

J.I.2.i. Unit 1:

(a) 0.11 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV (Condition 1.2.3)

J.I.2.ii. Unit 2:

(a) 0.11 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV (Condition 2.2.3)

J.I.3. Monitoring Requirements:

J.I.3.i. Continuous SO_2 emissions monitoring.

J.I.4. Control Technology:

J.I.4.i. Units 1 and 2 are equipped with flue gas desulfurization devices (FGD – wet limestone scrubbers) to control SO_2 emissions.

J.II. Monitoring Approach

	Indicator 1
I. Indicator	SO_2 Emissions
Measurement Approach	SO_2 emissions will be monitored using a continuous emissions monitoring system (CEMS)

	Indicator 1
II. Indicator Range	An excursion is defined as any 30-day average of SO_2 emissions that exceed 0.11 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the wet scrubber performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	SO_2 emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	SO_2 emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in daily and 30-day rolling averages.

J.III. Justification

J.III.1. Background

J.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a wet scrubber to control SO_2 emissions. The scrubber also controls acid gas emissions to some extent; however, the control of acid gases was not the primary design consideration for the control device and CAM does not apply to those emissions.

J.III.1.ii. The limestone reacts with SO_2 in the exhaust gases to form calcium sulfate and calcium sulfite which becomes entrained in the gas stream to be captured by the downstream baghouse.

J.IV. Rationale for Selection of Performance Indicators

J.IV.1. Units 1 and 2 are equipped with SO_2 CEMS and are equipped with wet limestone scrubbers which are operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the SO_2 Regional Haze limits is acceptable monitoring for CAM.

J.V. Rationale for Selection of Indicator Ranges

J.V.1. Ongoing monitoring with the CEMS for Units 1 and 2 which shows emissions below the applicable standards presumes continued and successful operation of the wet scrubbers.

K. Appendix K – Unit 3 Lime Spray Dryer SO_2 Compliance Assurance Monitoring Plan

K.I. Background

K.I.1. Emission Unit Description

K.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

K.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable SO_2 requirements:

K.I.2.i. Unit 3:

(a) 0.20 lb/MMBtu heat input, daily average, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.1);

(b) 80% reduction of potential combustion concentration of SO_2, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.2);

(c) 2,125 tons of SO_2 per year, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.3);

(d) 0.4 lb/MMBtu heat input 3-hour rolling average, Colorado Regulation No. 1, Section VI.B.4. (Condition 3.2.3);

(e) 0.15 lb/MMBtu heat input, 30-day rolling average, Colorado Regulation No. 23, Section IV.B (Condition 3.2.4);

(f) As applicable, the Source shall not emit into the atmosphere any gases which contain SO_2 emissions in excess of either (40 CFR Part 60, §60.43Da(a) (Condition 3.2.2):

(i) 520 ng/J (1.2 lb/MMBtu) heat input and 10 percent of potential combustion concentration (90 percent reduction) (40 CFR Part 60, §60.43Da(a)(1));

(ii) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(2));

(iii) 180 ng/J (1.4 lb/MWh) gross energy output (40 CFR Part 60, §60.43Da(a)(3)); or

(iv) 65 ng/J (0.15 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(4)).

K.I.3. Monitoring Requirements:

K.I.3.i. Continuous SO_2 emissions monitoring.

K.I.4. Control Technology:

K.I.4.i. Unit 3 is equipped with a flue gas desulfurization device (FGD – lime spray dryer) to control SO_2 emissions.

K.II. Monitoring Approach

	Indicator 1
I. Indicator	SO_2 Emissions
Measurement Approach	SO_2 emissions will be monitored using a continuous emissions monitoring system (CEMS)
II. Indicator Range	An excursion is defined as any 30-day average of SO_2 emissions that exceed 0.15 lb/MMBtu or any daily average of SO_2 emissions that exceeds 0.20 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the lime spray dryer performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	SO_2 emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	SO_2 emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in daily and 30-day rolling averages.

K.III. Justification

K.III.1. Background

K.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a lime spray dryer to control SO_2 emissions. The spray dryer also controls acid gas emissions to some extent; however, the control of acid gases was not the primary design consideration for the control device and CAM does not apply to those emissions.

K.III.1.ii. The lime reacts with SO_2 in the exhaust gases to form calcium sulfate and calcium sulfite which becomes entrained in the gas stream to be captured by the downstream baghouse.

K.IV. Rationale for Selection of Performance Indicators

K.IV.1. Unit 3 is equipped with an SO_2 CEMS and is equipped with a lime spray-dryer which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the SO_2 BACT and Regional Haze limits are acceptable monitoring for CAM.

K.V. Rationale for Selection of Indicator Ranges

K.V.1. Ongoing monitoring with the CEMS for Unit 3 which shows emissions below the applicable standards presumes continued and successful operation of the lime spray-dryer.

L. Appendix L – Unit 2 SCR Compliance Assurance Monitoring Plan

L.I. Background

L.I.1. Emission Unit Description

L.I.1.i. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

L.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable NO_x requirements:

L.I.2.i. Unit 2:

(a) 0.08 lb/MMBtu, 30-day rolling average, Regional Haze, Colorado Regulation No. 23, Section IV (Condition 2.3.3)

L.I.3. Monitoring Requirements:

L.I.3.i. Continuous NO_x emissions monitoring.

L.I.4. Control Technology:

L.I.4.i. Unit 2 is equipped with a selective catalytic reduction system for control of NO_x emissions.

L.II. Monitoring Approach

	Indicator 1
I. Indicator	NO_x Emissions
Measurement Approach	NO_x emissions will be monitored using a continuous emissions monitoring system (CEMS)
II. Indicator Range	An excursion is defined as any 30-day average of NO_x emissions that exceed 0.08 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the SCR performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	NO_x emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous

	Indicator 1
e. Data Collection Procedures	NO_x emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in 30-day rolling averages.

L.III. Justification

L.III.1. Background

L.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a selective catalytic reduction system to control NO_x emissions.

L.III.1.ii. NO_x emissions are chemically reduced to N_2 and H_2O using ammonia injected into the exhaust stream. The reaction is aided by flowing the gas stream through a catalyst. Over time, the catalyst becomes plugged and degraded and requires replacement.

L.IV. Rationale for Selection of Performance Indicators

L.IV.1. Unit 2 is equipped with a NO_x CEMS and is equipped with a SCR system which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the NO_x Regional Haze limits are acceptable monitoring for CAM.

L.V. Rationale for Selection of Indicator Ranges

L.V.1. Ongoing monitoring with the CEMS for Unit 2 which shows emissions below the applicable standards presumes continued and successful operation of the SCR.

M. Appendix M – Unit 3 SNCR Compliance Assurance Monitoring Plan

M.I. Background

M.I.1. Emission Unit Description

M.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

M.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable NO_x requirements:

M.I.2.i. Unit 3:

(a) 0.28 lb/MMBtu, 30-day rolling average, Regional Haze, Colorado Regulation No. 23, Section IV.B (Condition 3.3.4)

M.I.3. Monitoring Requirements:

M.I.3.i. Continuous NO_x emissions monitoring.

M.I.4. Control Technology:

M.I.4.i. Unit 3 is equipped with a selective non-catalytic reduction system for control of NO_x emissions.

M.II. Monitoring Approach

	Indicator 1
I. Indicator	NO_x Emissions
Measurement Approach	NO_x emissions will be monitored using a continuous emissions monitoring system (CEMS)
II. Indicator Range	An excursion is defined as any 30-day average of NO_x emissions that exceed 0.28 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the SNCR performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	NO_x emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous

	Indicator 1
e. Data Collection Procedures	NO_x emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in 30-day rolling averages.

M.III. Justification

M.III.1. Background

M.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a selective non-catalytic reduction system to control NO_x emissions.

M.III.1.ii. NO_x emissions are chemically reduced to N_2 and H_2O using ammonia injected into the exhaust stream.

M.IV. Rationale for Selection of Performance Indicators

M.IV.1. Unit 3 is equipped with a NO_x CEMS and is equipped with a SNCR system which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the NO_x Regional Haze limits are acceptable monitoring for CAM.

M.V. Rationale for Selection of Indicator Ranges

M.V.1. Ongoing monitoring with the CEMS for Unit 3 which shows emissions below the applicable standards presumes continued and successful operation of the SNCR.

N. Coal Sampling Plan

Rev. 6 – 6/5/2020

Note: Tri-State G & T follows ASTM procedures for coal sampling, sample preparation and sample analyses. In general, Tri-State will endeavor to use the latest revisions of the appropriate ASTM procedures for the equipment in use.

N.I. Coal Sampling

N.I.1. Background

Craig Station operates and maintains three coal sampling systems: A2, A3 and B3. Two of the systems (A3 and B3) are “As Fired” systems that are utilized to sample the day's coal burn in each of the three boilers. The “As Fired” sample results may be used to calculate the potential combustion concentration, or average inlet emission rate, of sulfur dioxide derived from the burning of coal in the boilers. This coal sampling plan therefore, describes the sampling, analysis and data management for the "As Fired” Samples.

Coal is delivered to Craig Station by truck and train. Each delivery is processed through the station's coal handling system. Coal from any delivery system can be used in any one, or all three, of the station's coal fired boilers.

N.I.2. A3 - As Fired Sampling System

This sampling system is located on A5 conveyor system that sends coal to the coal storage bunkers of each unit for firing the boilers Coal is delivered to this system from the coal yard. It may be coal from a single source or a combination of sources. It is referred to as the A3 Sampling System because it samples coal that is weighed by scales located on the A3 conveyor system.

N.I.3. B3 - As Fired Sampling System

This sampling system is located on B5 conveyor system that sends coal to the coal storage bunkers of each unit for firing the boilers. Coal is delivered to this system from the coal yard. It may be coal from a single source or a combination of sources. It is referred to as the B3 Sampling System because it samples coal that is weighed by scales located on the B3 conveyor system.

N.I.4. Coal Sampler Operation And Maintenance

All of the station coal samplers are set up and operated using the practices defined in ASTM D2234-99, Standard Practice for Collection of a Gross Sample of Coal.

Coal Handling Operators monitor the coal sampler operation. When the Samplers are in-service they discharge samples into heavy plastic bags attached to the sampler discharge. When the sampling is complete the Operator seals the sample bag, weighs the total sample, and labels each sample bag. The sample label identifies the Date, Belt, Sample Weight, Ending Tonnage, Number of Sample Bags, and the Operator's Name. The Operator then transfers the sealed and labeled sample bags to a protective container in a secured area to await pickup by a Laboratory Technician.

N.II. Sample Preparation and Laboratory Analyses

N.II.1. Sample Pickup and Preparation

Laboratory Technician retrieves the coal samples from the protected storage, checks the sample bags for damage, checks the labeling and rechecks the sample weight. The Technician then moves the samples to the Coal Preparation Laboratory where they are logged into the laboratory operation. Each sample is assigned a Laboratory Number and Sample ID. The Technician records this information, the Sample Weight and the Technician's name on the Fuels Analysis Sample Prep Log Sheet.

The Technician prepares the samples for analysis in the Coal Preparation Laboratory in accordance with ASTM 2013-00, Standard Method of Preparing Coal Samples for Analysis.

N.II.2. Coal Preparation Laboratory Sample Analyses

The Technician analyzes the samples for moisture using the procedures defined in ASTM D3302-00a, Standard Test Method for Total Moisture in Coal.

N.II.3. Main Chemistry Laboratory Sample Analyses

The 60 mesh samples prepared in the Coal Preparation Laboratory are taken to the Main Chemistry Laboratory where they are analyzed as described in the ASTM procedures as cited below.

N.II.3.i. ASTM D3173-00, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke

N.II.3.ii. ASTM D5865-00, Standard Test Method for Gross Calorific Value of Coal and Coke

N.II.3.iii. ASTM D3174-00, Standard Test for Ash in the Analysis Sample of Coal and Coke from Coal

N.II.3.iv. ASTM D4239-00, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High-Temperature Tube Furnace Combustion Methods

N.II.4. Laboratory Data Management

Laboratory data and results from the sample analyses for moisture, calorific value, ash and sulfur are entered and maintained in the Tri-State G & T Fuels Data Management System. The tonnage from vendor coal deliveries and daily coal burns are also maintained within the data management System.

N.III. Chain-Of-Custody Method

N.III.1. The sample chain-of-custody begins with each of the coal sampling systems described above. Prior to starting a sampling system, the Coal Board Operator identifies the origin of the coal to be sampled. This information is noted on sample identification labels. The sampling process is started and the Coal Handling Operator monitors the sampler system until sampling is complete.

N.III.2. When the sampling is completed the Coal Handling Operator seals the sample bags and labels the sample bags with the following information: Date, Belt, Sample Weight, Ending Tonnage, Number of Sample Bags, and the Operator's Name. The samples are then placed in a secure and protected location until a Laboratory Technician retrieves them.

N.III.3. When a Laboratory Technician retrieves the samples from the sampler area, and moves them to the Coal Preparation Laboratory, they are logged into the laboratory operation. Each sample is assigned a Laboratory Number and Sample ID. The Technician records this information along with Sample Weight and the Technician's name on the Fuels Analysis Sample Prep Log Sheet. This process identifies the sample label information as well as who is now handling the samples in the Coal Preparation Laboratory.

N.III.4. When the prepared samples are moved to the Main Chemistry Laboratory for analysis, they are transferred in sealed sample bottles labeled with the Sample ID. In the Main Laboratory the samples are analyzed according to the Sample ID and the names of the Technician(s) performing the analyses are noted on the Fuels Analysis Sample Prep Log Sheet.

N.III.5. The Technician who enters the laboratory data and results from the sample analyses into the Tri-State G & T Fuels Data Management System enters their name as Data Entry Technician on the Fuels Analysis Sample Prep Log Sheet.

N.IV. Coal Shipment and Sample Analysis Records

N.IV.1. Coal shipment and sample analysis records are maintained by the TriState G & T Craig Station and are available for review by the Division upon request. Craig Station maintains paper copies of the records for one year. The records are also kept electronically in Tri-State G & T's Fuels Data Management System.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-21

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit L: NERC, *2025-2026 Winter Reliability Assessment* (Nov. 2025)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025–2026 Winter Reliability Assessment

November 2025



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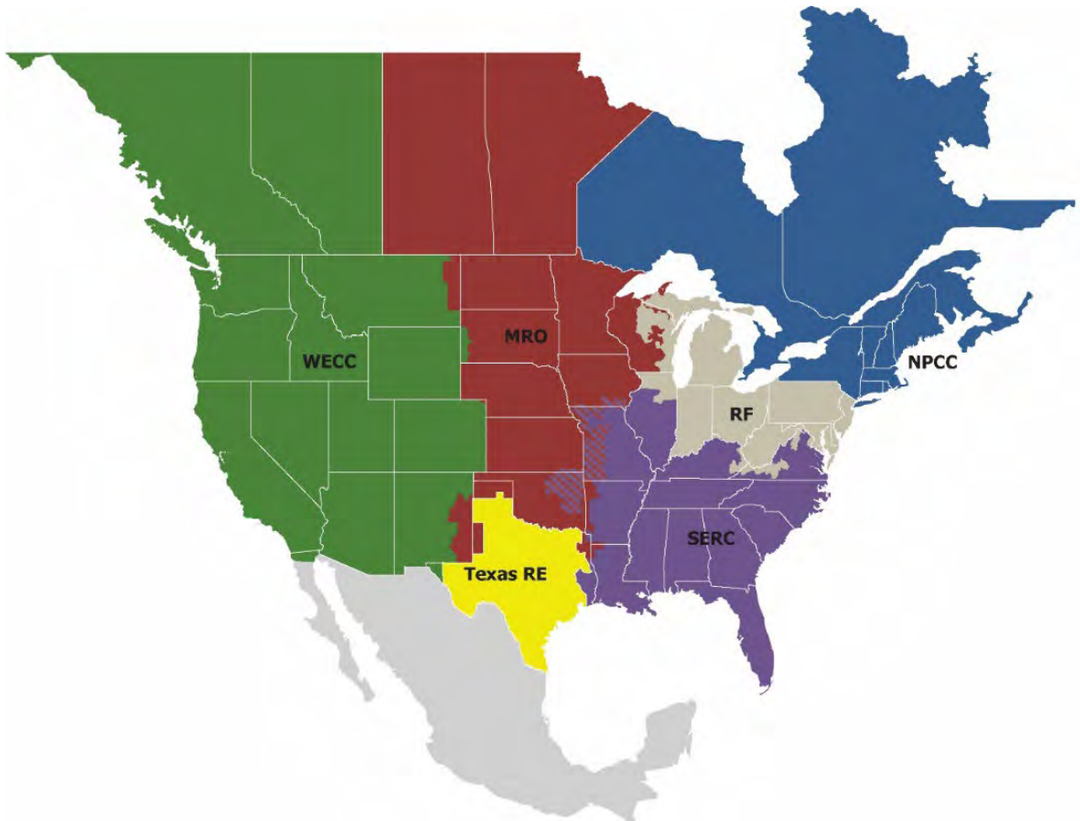
Preface

Electricity is a key component of the fabric of modern society, and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

About this Assessment

NERC's *2025–2026 Winter Reliability Assessment* (WRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the WRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS.

The reliability assessment process is a coordinated evaluation between the Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas.

This report reflects an independent assessment by the ERO Enterprise (i.e., NERC and the six Regional Entities) and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

This WRA covers the upcoming three-month (December–February) winter period, providing an evaluation of the generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional risks. The following findings are the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as the potential operational concerns that may need to be addressed for the upcoming winter.

Two trends affecting resource adequacy across the BPS for the upcoming winter are rising electricity demand forecasts and a continued shift in the resource mix characterized by the retirement of thermal generators and growth in battery resources. After years of flat or low (~1%) peak demand growth, the aggregate peak demand for all NERC assessment areas has risen by 20 GW (2.5%) since the previous winter. Nearly all assessment areas are reporting year-on-year demand growth; some are forecasting increases near 10%. Total BPS resources have also increased since last winter, but by a smaller amount of 9.4 GW. This number includes the net change in generating capacity as well as additional demand response. These demand and resource changes are described in **Escalating Winter Demand** and **Resource Trends** sections.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operating concerns that should receive attention for Winter 2025–2026:

1. **All areas are assessed as having adequate resources for normal winter peak-load conditions (i.e., the area's 50-50 peak forecast). However, more extreme winter conditions extending over a wide area could result in electricity supply shortfalls.** Prolonged, wide-area cold snaps can drive sharp increases in electricity demand and threaten reliable BPS generation and the availability of fuel supplies for natural-gas-fired generation. Four severe arctic storms have descended to cover much of North America since 2021, causing regional demand for electricity and heating fuel to soar and exposing generation and fuel infrastructure in temperate areas to freezing conditions.[1] The following areas face risks of electricity supply shortfalls during periods of more extreme conditions this winter (see **Figure 1**):

    - **NPCC-Maritimes**: The peak demand forecast has fallen slightly (-1.6%) in the NPCC-Maritimes assessment area, contributing to higher reserves compared to the 2024–2025 winter. Maritimes is projected to have an Anticipated Reserve Margin (ARM) of 16.9%, which is 270 MW below the area's Reference Margin Level of 20% . New Brunswick has long-term energy contracts that can be used to mitigate resource adequacy challenges through the purchase of energy on a day-ahead basis. NPCC's all-hours probabilistic assessment for the NPCC Region included the simulation of both a base case (i.e., normal 50/50 demand) and highest peak load scenario (having an approximate 7% chance of occurring), for both an expected and a low-likelihood, reduced-resource condition. The preliminary results of this assessment indicate that operators in Maritimes are likely to require emergency operating mitigations and/or energy emergency alerts (EEA) during above-normal demand or low-resource output conditions.
    - **NPCC-New England**: A lower peak demand forecast and additional resources from demand response and firm imports offset recent generator retirements, resulting in little change to the NPCC-New England ARM for this winter. New England continues to closely monitor regional energy adequacy, particularly during extended cold snaps where constrained natural gas pipelines contribute to rapid depletion of stored fuel supplies. ISO-NE's deterministic winter scenario analysis shows limited exposure to energy shortfalls this winter. In New England, winter energy concerns are highest in scenarios when stored fuels are rapidly depleted; during these periods, timely replenishment is critical to minimizing the potential for energy shortfalls.
    - **SERC-East**: The winter peak demand forecast has increased by 700 MW (1.6%) since last winter, while winter firm capacity has declined, resulting in lower reserves. SERC-East has changed from a summer-peaking area to potentially peaking during both summer and winter. This is due to the continued addition of solar photovoltaic (PV) generation that shaves off summer peak demand and a trend toward electrification of heating that drives up winter peak demand. All-hours probabilistic analysis from SERC found some load-loss hours (<0.1 hrs) and small amounts of expected unserved energy, with the highest risk occurring during above-normal peak demand and early morning hours when solar output is absent.
    - **SERC-Central:** Additional demand response and flat load growth since last winter is offsetting declining resource capacity (down 1,120 MW), resulting in little change to the ARM at 30.5%. There are adequate resources for normal winter peak demand; however, higher levels of demand that can occur during extreme cold temperatures can result in insufficient reserves that operators would need to manage with non-firm imports and potential energy emergencies.
    - **Texas RE-ERCOT:** Strong load growth from new data centers and other large industrial end users is driving higher winter electricity demand forecasts and contributing to continued risk of supply shortfalls. For the upcoming winter season, Texas RE-ERCOT is expected to continue facing reserve shortage risks during the peak load hour and high-

[1] See detailed reports on the January 2024 and January 2025 Arctic Storms, Winter Storm Elliott, and Winter Storm Uri.

net-load hours, particularly under extreme load conditions that accompany freezing temperatures. Elevated forced outage of thermal resources and reduced output from intermittent resources during these conditions exacerbates the risk of supply shortfalls. In winter, peak demands typically occur before sunrise and after sunset coinciding with the unavailability of solar generation making the system dependent on wind generation and dispatchable resources. Data centers are altering the daily load shape due to their round-the-clock operating pattern, lengthening peak demand periods. Additional battery storage and demand-response resources since last winter help mitigate shortfall risks. However, with the continued flattening of the load curve, maintaining sufficient battery state of charge will become increasingly challenging for extended periods of high loads, such as a severe multi-day storm like Winter Storm Uri.

- **WECC-Basin**: There is sufficient capacity in the area for expected peak conditions; however, Balancing Authorities (BA) are likely to require external assistance during extreme winter weather that causes thermal plant outages, adverse wind turbine conditions, and natural gas fuel supply issues for area internal resources. External assistance may not be available during region-wide extreme winter conditions. With an expected winter peak demand of 11.1 GW, under an extreme combination of generator derates and outages, the region could be short 1.6 GW before imports. Forecasted net internal demand has increased 1% since last year, with little change in winter capacity. Note that the WECC-Basin assessment area includes Utah, southern Idaho, and a portion of western Wyoming. In prior WRA reports, this part of the BPS was included as part of the WECC-NW assessment area. The *2025–2026 WRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.
- **WECC-NW**: Like WECC-Basin, there is sufficient capacity in the area for expected peak conditions; however, BAs are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year. Over 3 GW of new resources have been in development for the assessment area this year, primarily battery storage, solar PV, and wind resources. Delays that threaten timely completion of these resource additions will make the area more reliant on imports to meet peak demand.

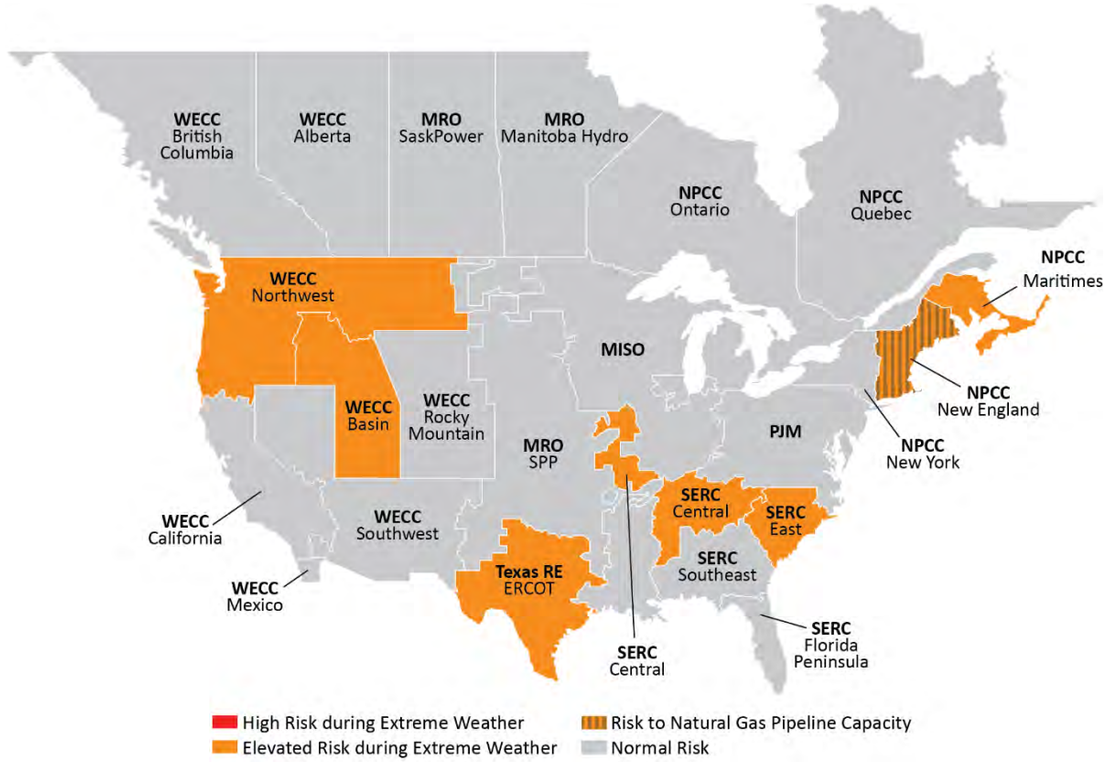


Figure 1: Winter Reliability Risk Area Summary

2. **The performance of natural gas production and supply infrastructure during peak winter conditions will again have a significant effect on BPS reliability.** Natural gas is an essential fuel for electricity generation in winter. Winter fuel supplies for thermal generators must be readily available during the periods of high electricity and natural gas demand that accompany extreme cold weather. Yet these periods are the most challenging for natural-gas-fired Generator Operators to obtain sufficient fuel and delivery. Natural gas production often falls off in extreme winter temperatures as supply infrastructure is affected by freezing issues, and Generator Operators that fail to secure firm fuel delivery are frequently unable to access fully subscribed pipelines. Evidence from the past two winters indicates notable improvement in the delivery of natural gas to BPS generators since winter storms Elliott and Uri with overall less natural gas production decline during cold weather and fewer natural gas infrastructure

force majeures.[2] Still, natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America, resulting in uneven application of protections and continued supply risks during extreme conditions. Furthermore, timing misalignments between the natural gas and electric markets continue to challenge generator fuel procurement in advance of severe winter conditions that occur over winter holiday weekends. As winter approaches, NERC encourages all entities across the gas-electric value chain—from production to the burner tip—to take all necessary preparations for extreme cold and keep natural gas flowing and the lights on.

3. **Cold weather Reliability Standards first introduced in 2023 have been improved prior to the upcoming winter and address recommendations from winter storms Elliott and Uri.** In September 2025, the Federal Energy Regulatory Commission (FERC) approved EOP-012-3 with an effective date of October 1, 2025, concluding the development of Reliability Standards for generator cold weather preparedness.[3] The EOP-012 Reliability Standard contains requirements for generator freeze protection measures, cold weather preparedness plans, and operator training. Among the improvements in the new version are enhanced and expanded requirements to ensure that Generator Owners (GO) are implementing corrective actions to address known issues affecting their ability to operate in cold weather in a timely manner. NERC collects data on the winterization of generating units, which, in conjunction with NERC's monitoring of BPS performance and analysis of cold weather events, helps determine the effectiveness of Reliability Standards. NERC submitted to FERC its first annual *Cold Weather Data and Analysis* informational filing in October 2025.[4] Based on the data reported this year, 96% of the total net winter capacity reported extreme cold weather temperatures (ECWT) at or below 32 degrees Fahrenheit, triggering winter preparedness measures under the Cold Weather Preparedness Standard, and 99% of total net winter capacity in the continental US reporting the ability to operate at the calculated ECWT. As the first such report, this *Cold Weather Data and Analysis* filing provides a benchmark for future analysis.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- Reliability Coordinators (RC), BAs, and Transmission Operators (TOP) in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should review NERC's Resources on Cold Weather Preparations.
- GOs should complete winter readiness plans and checklists prior to December, deploy weatherization packages well in advance of approaching winter storms, and frequently check and maintain cold weather mitigations while conditions persist.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies. Proactive issuance of winter advisories and other steps directed at generator availability contributed to improved reliability during cold weather events of the past two winters.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- Generator Owners/Operators of natural-gas-fired units should maintain awareness of potential extreme cold weather developing over holiday weekends and the implications for fuel planning and procurement that may result given the natural gas purchase close dates that precede long holiday weekends.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by maintaining awareness of BA, natural gas pipeline, and gas local distribution company (LDC) operational public announcements and notices, amplifying public appeals for electricity and natural gas conservation, and supporting requested environmental and transportation waivers.

[2] See *January 2025 Arctic Events | A System Performance Review*, April 2025
[3] See NERC's Statement on FERC September Open Meeting for summary and link to FERC's order.
[4] See 2025 Cold Weather Data Collection and Analysis Informational Filing

Risk Highlights

Escalating Winter Demand

Winter electricity demand is rising at the fastest rate in recent years, particularly in areas where data center development is occurring. After several years of low (~1%) growth, total internal demand for the BPS is forecast to increase by 20.2 GW (2.5%) over last winter's forecast. The changes in forecasted net internal demand for each assessment area are shown in **Figure 2** below.[5] Assessment areas develop these forecasts based on historical load and weather information as well as future projections. Most assessment areas are projecting an increase in peak demand. SaskPower, PJM, the U.S. Southeast, and parts of the U.S. West have the largest increase in peak demand forecasts.

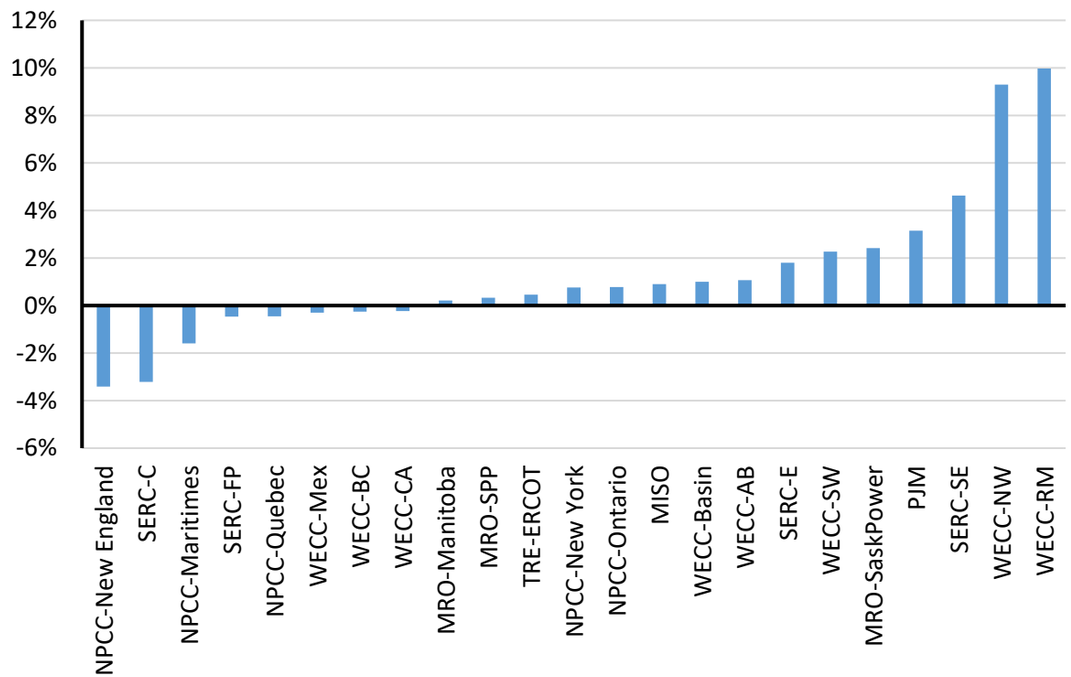


Figure 2: Change in Net Internal Demand—Winter 2025–2026 Forecast Compared to Winter 2024–2025 Forecast

[5] See **Data Concepts and Assumptions** section for demand definitions.

Resource Trends

BPS resources are growing, but at a slower rate than demand is rising. Battery and solar facilities were the leading resource types added to the BPS since last winter. Solar resources, however, often do not supply output during hours of peak winter demand. Growth in demand response is also contributing to BPS resources for the upcoming winter. **Table 1** shows the total change in BPS resources since last winter. For battery, solar, and wind resources, the table includes change in both nameplate (installed) capacity as well as the change in on-peak demand capacity, which is the capacity that resources are expected to provide in their area during the time of peak demand. For assessment-area specific information see **Variable Energy Resource Contributions** section.

Table 1: BPS Resource Change from Winter 2024–2025 to Winter 2025–2026

Resource	Net Change Nameplate Capacity (MW)	Net Change Peak Demand Capacity (MW)
Total Generator Capacity		1,335
Battery	19,659	11,121
Solar	11,097	1,176
Wind	-562	-14,238
Thermal and Hydro		3,276
Demand Response		8,112
Total Resources		9,447

Total BPS resources for serving winter peak demand, including generating capacity and demand response, have increased since last winter by 9,447 MW. Sizeable additions in battery resources and some new natural gas-fired generators contribute to the increase in resource capacity. However, the increase is offset by lower on-peak capacity values for wind resources, which are the result of revised valuations of wind resource capability at peak demand hours in some areas.[6] As a result, BPS generator capacity for winter peak demand makes up only a small portion of the total BPS increase. Generation accounts for 1,335 MW of the total 9,445 MW increase, while the larger share comes from demand response programs. Area specific information on demand response is provided in the **Demand and Resource Tables**.

The recent trend in resource additions is contributing to higher risk of electricity supply shortfalls in winter. BA operators are likely to face higher winter demand without a comparable increase in supply resources. Furthermore, the types of resources that are growing the most-- battery resources and

[6] Since last winter, ERCOT and MISO have implemented new methods for determining capacity contributions that result in lower wind and solar resources contributions at peak demand. See ERCOT's Resource Adequacy page and MISO's *Planning Year 2025-2026 Wind and Solar Capacity Credit Report*.

demand response—have unique characteristics that operators will need to account for and could limit the use of these resources in extreme winter conditions. Battery energy is reliable when it can be dispatched and has sufficient charge for the period it is needed, yet little time to recharge can be expected during extreme winter weather. System operators will need good visibility on battery state of charge and should anticipate that some extreme winter events will cause these resources to become depleted when needed. Demand response is limited by contract terms, which typically specify how often and for how long the resource may be used. Other resource types are also challenged in winter (see **Thermal Generator Fuel Adequacy and Security**). As BAs grapple with higher demand in most parts of the BPS, they will do so with resources that are becoming increasingly complex to dispatch especially in winter.

Thermal Generator Fuel Adequacy and Security

The performance of the thermal generator fleet remains critical to winter BPS operations. Winter fuel supplies for thermal generators must be readily available during periods of high demand and extreme cold weather. Generally, fuel adequacy for the thermal generating fleet is bolstered through strategic infrastructure investments and fuel stockpiling that increases the certainty of having fuel on hand that can be converted to electricity when needed. Because of this, winter performance of thermal generators is inextricably linked to extraction, processing, storage, and delivery infrastructure for a variety of fuels. Fuel supply risks have been noted in recent years' WRAs related to coal and natural gas availability and illustrate the interconnected nature of these critical energy infrastructure systems.

BPS stakeholders across North America note multiple fuel-related issues that are being monitored entering the winter season. For example, while coal represents a waning share of the overall resource mix, it continues to play an important role in meeting demand during extreme winter weather events, and oil inventories at dual-fuel gas-oil generators lessen risks related to natural gas deliverability in infrastructure-constrained regions, especially during the winter. Notably, it is infeasible or prohibitively costly to stockpile natural gas locally at power plants, and this exposes the BPS to the risk profile of the constituent systems that comprise the supply and delivery of this just-in-time fuel.

Natural Gas Generator Fuel Supplies

Natural gas generators remain a crucial part of on-peak resources meant to meet winter electricity demand across much of North America. While many Generator Owners and Operators secure backup fuel supplies at critical gas-fired generators, particularly in the northeastern United States and Florida, large contributions to the on-peak winter resource mix by single-fuel natural-gas-fired generators remain across North America (see **Figure 3**).

Natural gas generator performance can be threatened when natural gas supplies are insufficient or when natural gas infrastructure is unable to maintain the flow of fuel to critical generators. Grid operators continue to acknowledge and enhance their winter planning processes to firm up their fuel supplies and guard against natural gas disruptions, but winter storms Uri and Elliott demonstrated that combinations of natural gas flow restrictions and supply insufficiency can occur regardless of whether cold temperatures are common or uncommon in the region and can affect more than one BA area concurrently.

Many BPS areas that regularly experience cold weather events, like New England, have adopted mitigating technologies to lessen the impact of natural gas shortages through generator dual-fuel capability and stored backup fuel. In those areas, prolonged cold weather events present a risk of rapid depletion of stored backup fuel. Robust regional and distributed storage investments and winter planning for timely fuel replenishment are critical to minimizing potential energy shortfalls in the operational time frame in these areas.

Natural gas and electricity infrastructures have the added complexity of interdependence. Electricity is used to power some facilities, such as compressor stations and processing plants that make up natural gas infrastructure. These interdependencies mean that reliability events that originate on one system have the potential to affect the other and worsen the overall event magnitude or duration.

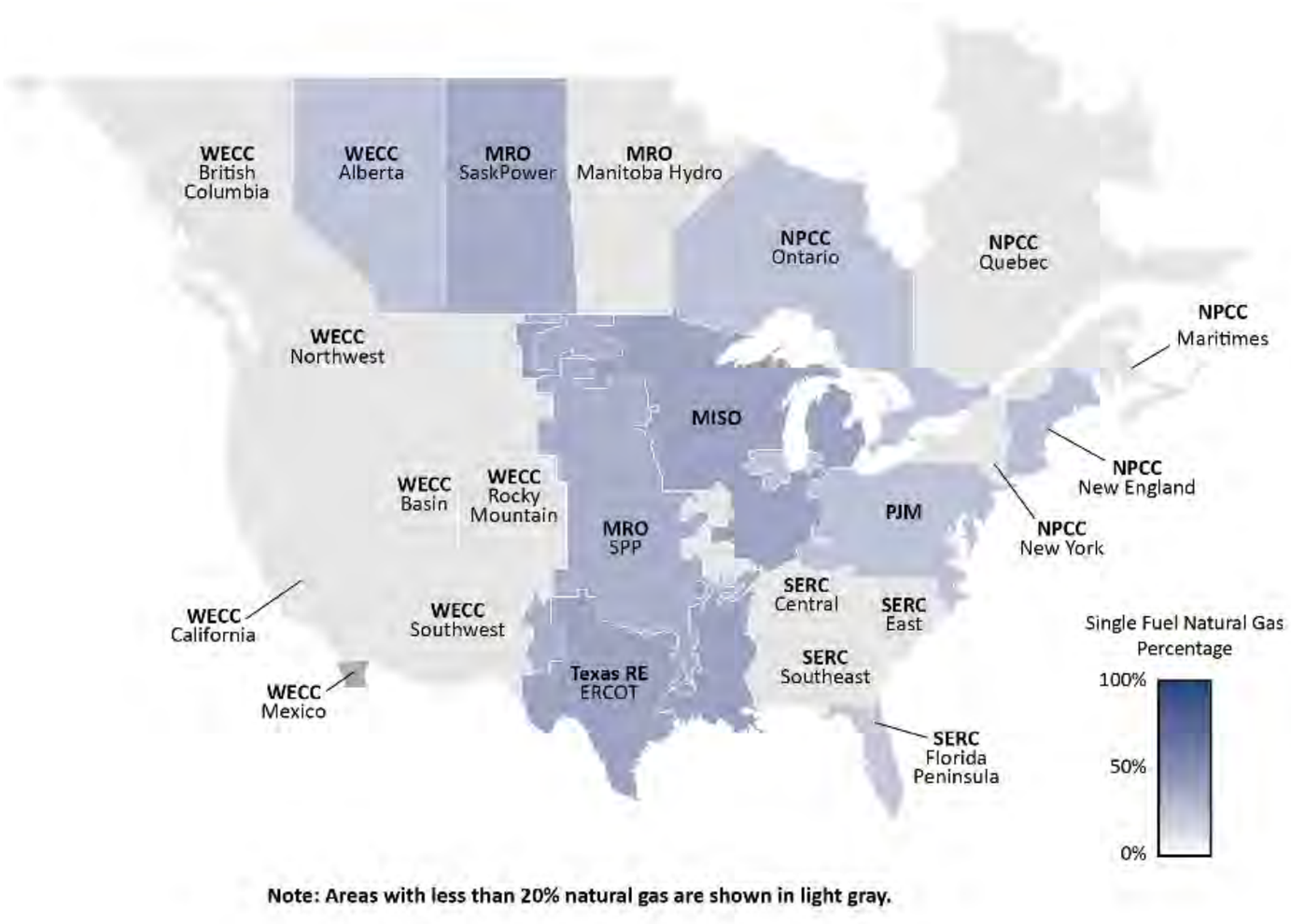
Natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America. Texas is an exception, where the Railroad Commission of Texas adopted rules to require critical natural gas facilities to implement weather-related emergency preparation measures.[7] Lack of consistent standards for natural gas infrastructure protections will result in uneven application of freeze protections and continued supply risks during extreme conditions in many areas.

These considerations have driven higher levels of coordination to ensure sustained reliable operation of the natural gas and electricity systems. While a FERC and ERO staff review of system performance during the January 2025 arctic events[8] details improvements in electric and natural gas coordination since winter storms Uri and Elliott, the review also identifies continuing gaps between the electricity and natural gas industries that remain entering the 2025–2026 Winter season. These include natural gas scheduling challenges during winter holiday weekends, market time frame and process incompatibility, and electric power entities' lack of visibility into operational impact data from natural gas producers and suppliers.

[7] See Railroad Commission of Texas weatherization rule.

[8] FERC, NERC Issue Report on System Performance During the January 2025 Arctic Weather | Federal Energy Regulatory Commission

The U.S. Energy Information Administration (EIA)[9] anticipates a slightly milder winter than last year across much of the United States, especially in the Northeast, leading to a projection that households will consume approximately 2% less natural gas than last winter. Working natural gas storage inventories are about 5% above the previous five-year average in the United States heading into the winter season. The EIA attributes this relative surplus in part to robust production this summer and lower-than-expected natural gas consumption by power generators.



Single-Fuel Natural-Gas-Fired Generation

	Winter Capacity (GW)	Contribution to Total Winter Resource Mix
MISO	63.9	38%
TRE-ERCOT	53.0	38%
WECC-MX	2.2	34%
MRO-SaskPower	2.5	34%
SPP	33.4	32%
NPCC-New England	12.1	24%
PJM	60.9	23%
WECC-AB	13.9	23%
NPCC-Ontario	8.0	23%
SERC-FP	45.6	21%
WECC-CA	35.9	18%
WECC-SW	21.5	17%
WECC-Basin	4.9	16%
WECC-RM	6.2	14%
SERC-C	17.0	13%
SERC-SE	21.5	13%
WECC-NW	8.7	12%
SERC-E	11.3	9%
NPCC-New York	5.0	8%
NPCC-Maritimes	0.5	7%
MRO-Manitoba	0.3	4%
WECC-BC	0.1	1%
NPCC-Quebec	0.0	0%

Figure 3: Single-Fuel Natural-Gas-Fired Generation Capacity Contribution to the 2025–2026 Winter Generation Mix

[9] See the U.S. Energy Information Administration's Winter Fuels Outlook 2025–26

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 2.

Table 2: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels (RML); or • Probabilistic indices exceed benchmarks, e.g., loss of load hours (LOLH) of 2.4 hours over the season; or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season); or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions);[2] or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins (ARM), which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins with typical forced outage levels and for the most extreme seasonal risk scenarios are provided in Table 3.

Table 3: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Reserve Margin with Typical Outages	Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	49.5%	22.3%	3.7%
MRO-Manitoba	13.7%	11.4%	6.1%
MRO-SaskPower	35.1%	29.0%	16.1%
MRO-SPP	56.5%	29.4%	16.9%
NPCC-Maritimes	16.9%	12.5%	-4.7%
NPCC-New England	58.9%	45.4%	8.7%
NPCC-New York	78.2%	52.4%	16.2%
NPCC-Ontario	28.6%	21.8%	13.2%
NPCC-Québec	15.2%	15.1%	5.0%
PJM	35.6%	24.8%	15.6%
SERC-C	30.5%	22.4%	-0.9%
SERC-E	21.9%	17.5%	3.0%
SERC-FP	41.7%	28.3%	25.6%
SERC-SE	39.7%	24.7%	17.7%
TRE-ERCOT	36.0%	25.2%	-20.0%
WECC-AB	35.2%	32.4%	10.0%
WECC-Basin	29.6%	19.7%	-21.1%
WECC-BC	25.9%	25.8%	15.4%
WECC-CA	82.3%	73.7%	57.9%
WECC-Mex	83.1%	79.4%	52.9%
WECC-NW	30.9%	29.5%	-8.5%
WECC-RM	61.7%	53.2%	10.0%
WECC-SW	104.4%	90.1%	50.1%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential winter peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 3**, each assessment area's ARMs are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Areas highlighted in orange in **Figure 1** above have been identified as having resource adequacy or energy risks for the winter and are included in the **Key Findings** section's discussion that follows. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced-outage margin is the same as the ARM, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the winter season. Results are summarized in **Table 5**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), loss of load hours (LOLH), expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) declarations (see **Table 4** for a description of EEA levels).

Table 4: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required operating reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum operating reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum operating reserve requirements.

Energy Emergency Alerts

The combination of above-normal generation outages, low resource output, and peak loads as occurred during the extreme cold weather events of Winter Storm Uri in 2021 and Winter Storm Elliott in 2022 are ongoing winter reliability risks. When supply resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ EEAs to maintain balance between available capacity and energy and real-time demand. A description of each EEA level is provided above.

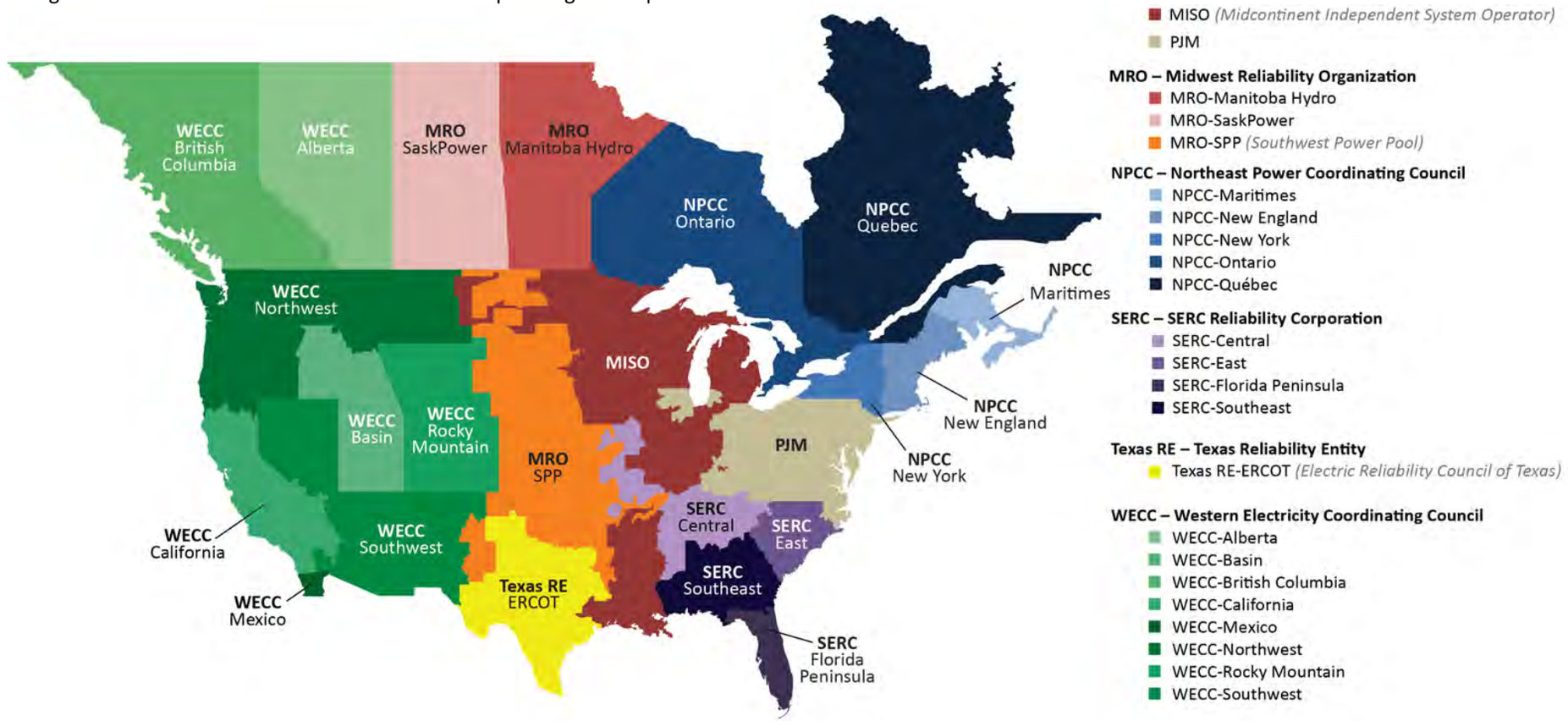
Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	Deterministic	MISO does not provide a probabilistic assessment for the WRA. MISO applies a deterministic look at expected system conditions, looking at generation availability under typical and extreme outages and looking at a typical 50/50 load forecast and an extreme 90/10 load forecast. For the upcoming winter season, under an extreme outage and extreme 90/10 load forecast, this is the riskiest scenario for the MISO footprint. This scenario produces the shortest actual reserve margin for January.
MRO-Manitoba	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 *Long-Term Reliability Assessment* (LTRA) found no load-loss or unserved energy hours for 2026.
MRO-SaskPower	Probability-based capacity adequacy assessment	SaskPower's probabilistic assessment for the 2025–2026 Winter indicates that risk of shortfalls is lower than the previous winter. LOLH for an elevated risk scenario for the 2025–2026 Winter season is 0.08 hours. The month with the highest LOLH is December (0.05 hours).
MRO-SPP	NERC 2024 ProbA	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that included detailed neighbor modeling and consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The assessment evaluates the probabilistic indices of LOLE, LOLH, and EUE. The highest peak load scenario has an approximately 7% probability of occurring.	
NPCC-Maritimes	The Maritimes Area low-likelihood resource case assumed: wind derated by 50% for every hour in December through February and a 50% natural gas capacity curtailment for December through February (dual-fuel units assumed reverting to oil) and reduced transfer capabilities.	The preliminary assessment indicates that established operating procedures are not sufficient to maintain a balance between electricity supply and demand. Under highest peak load levels, the Maritimes Area shows a notable likelihood of utilizing its operating procedures such as reducing 30-minute reserves, initiating interruptible loads, and reducing 10-minute reserves to maintain system reliability during the upcoming winter period.
NPCC-New England	The New England Area low-likelihood resource case assumed: 500 MW of additional maintenance outages, ~4,513 MW of gas-fired generation unavailable due to fuel supply constraints, and 50% reduced import capabilities of external ties.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand
NPCC-New York	The New York Area low-likelihood resource case assumed: ~500 MW of extended maintenance in southeastern New York, 600 MW of cable transmission reduction across HVdc facilities, and ~5,000 MW of generation unavailable due to fuel delivery issues.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period, for all the scenarios modeled.
NPCC-Ontario	An energy assessment for the Ontario Assessment Area was conducted for two scenarios: firm resources and firm demand with expected weather, and planned resources with planned demand with expected weather.	No cumulative LOLH or EUE risks were identified over the entire November-to-April winter season for both scenarios modeled.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Québec	The Québec Area low-likelihood resource case assumed 1,000 MW of generation reductions.	The preliminary results of this assessment indicate that established operating procedures are sufficient to maintain a balance between electricity supply and demand if needed. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period for all the scenarios modeled
PJM	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic study for 2025–2026 Winter is not provided for the WRA. PJM performed probabilistic analysis for 2026-2027 winter as part of the 2024 ProbA summarized in NERC's 2024 LTRA. The results of this study indicate risk of load loss (<0.1 hours) and unserved energy during winter months. For the upcoming winter, load-loss hours are expected to be less than this value because forecasted load is lower and anticipated resource capacity is higher than the case studied for the 2024 ProbA.
SERC	Based on the 2024 NERC Probabilistic Assessment (ProbA) base-case result. SERC's assessment used 38 years of historical load shapes to assess the resource adequacy of years 2026 and 2028, primarily based on data from the 2024 Long Term Reliability Assessment (LTRA).	
SERC-Central		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
SERC-East		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found a small number of load-loss hours (<0.1) and EUE (61 MWh / 1 ppm) for 2026.
SERC-Florida Peninsula		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found negligible load-loss hours and EUE.
SERC-Southeast		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
WECC	The resource adequacy work performed at WECC used the Multi-Area Variable Resource Integration Convolution (MAVRIC) model for the 2025 LTRA. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and ProbA.	
WECC-AB		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Basin		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-BC		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-CA		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Mexico		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Rocky Mountain		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-NW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026. Results for a case where new resource additions are not completed for the upcoming winter found some EUE and LOLH.
WECC-SW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-Peak Reserve Margin bar charts show the ARM compared to a reference margin level (RML) that is established for each area to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods vary by assessment area and provide further insights into the risk conditions forecasted for this upcoming winter period.



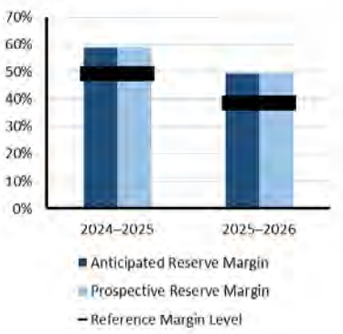


MISO

The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations as well as energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 Local BAs and more than 550 market participants. MISO operates one of the world's largest organized electricity markets, with its members operating a system that consists of over 77,000 miles of transmission lines and approximately 1,888 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO's footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

- MISO expects limited risk in the 2025–26 Winter season as MISO was able to procure 6.1% more resources through the annual planning reserve auction than required by its minimum resource adequacy target. A further 3.3 GW of resources were available but not chosen to be committed for the winter season.
- Some risk has been identified for this upcoming winter season. In a high generation outage and high winter load scenario reliability is expected to be maintained by reliance upon operational mitigations that include non-firm energy transfers into the system, energy-only resources not subject to a must-offer requirement that may still offer into the energy markets, load-modifying resources, and internal transfers that exceed the Sub-Regional Import/Export Constraint (SRIC/SREC) between the MISO North/Central and South areas.
- MISO continues to coordinate with neighboring RCs and BAs to improve situational awareness and vet any needs for energy transfers to address extreme system conditions.
- MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency.
- MISO has implemented a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons.

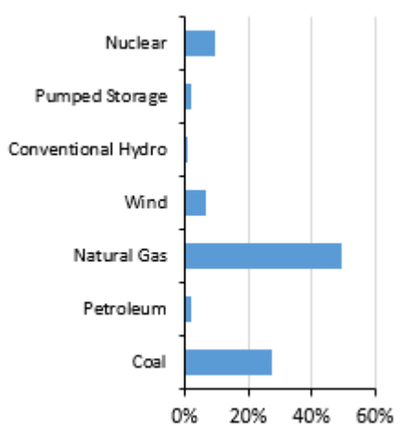
On-Peak Reserve Margin[10]



Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with generator outages from freezing or fuel supply issues and low wind output result in the need to employ operating mitigations (i.e., demand response and transfers).

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: 50/50 net internal demand and additional demand during extreme weather conditions (e.g., Winter Storm Enzo) using member submitted data and historical load data

Typical Maintenance Outages: Rolling three-year winter average of peak-day maintenance and planned outages

Typical Forced Outages: Three-year average of all peak-day outages that were not planned

Resource Derates for Extreme Conditions: Represents derates aligning with the most extreme hour of each of the past 3 years,

Operational Mitigations: Non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement, or internal transfers that exceed the SRIC/SREC between the MISO North/Central and South regions

[10] The MISO Risk Scenario Assessment for the 2025-26 Winter Season is not directly comparable to that for the 2024-25 Winter Season as methodology improvements have been implemented.



MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator (PC) and Balancing Authority (BA). Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

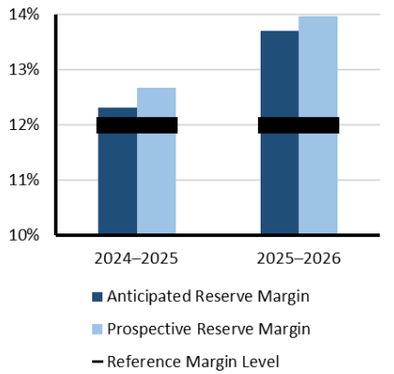
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Winter 2025–2026.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even under continued drought conditions.
- Manitoba Hydro is experiencing well below-average water supply conditions; however, the Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought.
- The ARM for Winter 2025–26 exceeds the 12% RML.

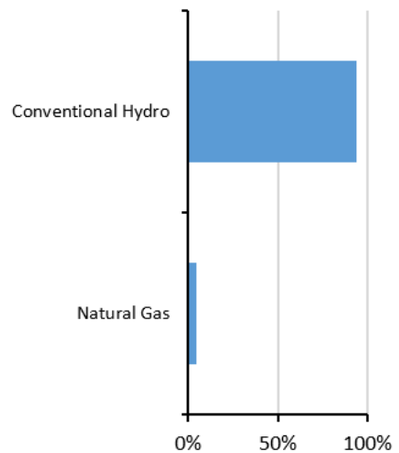
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

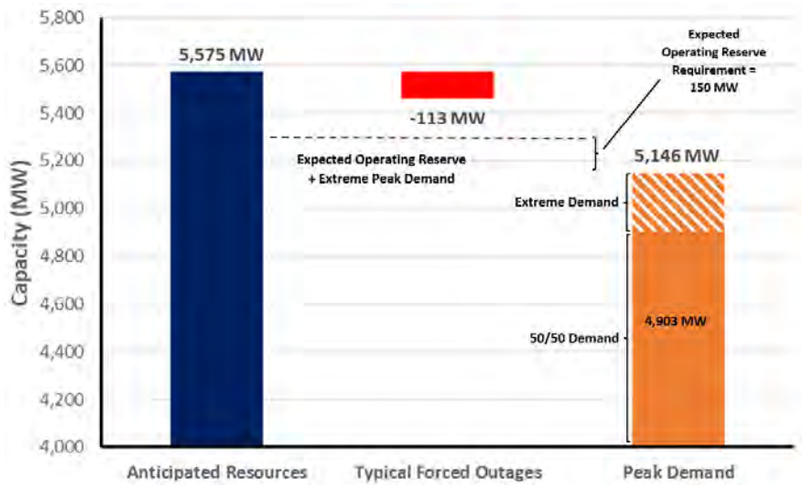
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of weather data

Typical Forced Outages: Accounts for average forced outages



MRO-SaskPower

MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

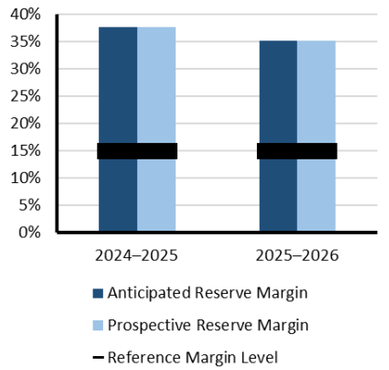
Highlights

- Saskatchewan experiences its peak load during the winter months due to extreme cold weather.
- Based on the planned maintenance, typical forced outages from historical data, and expected renewable generation under the normal and extreme demand conditions, SaskPower does not anticipate any reliability issues during the 2025–2026 Winter.
- During extreme winter conditions, SaskPower would utilize available demand-response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions to manage the situation.

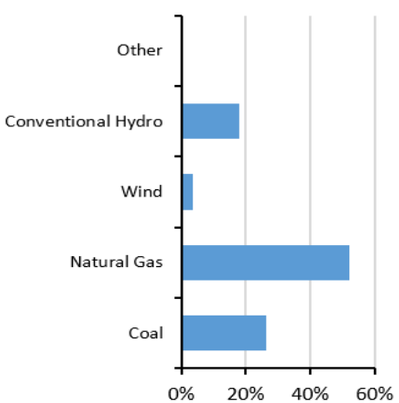
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

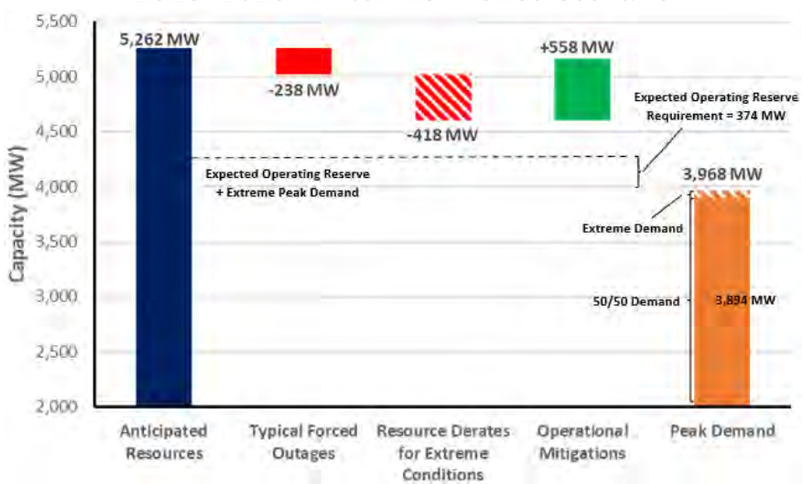
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Based on the historical load variability, SaskPower calculates a probability density function for load to simulate various scenarios that include extreme conditions.

Typical Forced Outages: Estimated using SaskPower forced outage model

Resource Derates for Extreme Conditions: Wind capacity is derated by 96% due to the cut-out of most wind farms below -30°C. Solar generation is expected to be fully unavailable under extreme conditions.

Operational Mitigations: Includes the non-firm import capability (360 MW) and generators in layup status (167 MW) that can be brought online with one to five days' notice; additional demand-side resources are estimated based on other demand response programs and non-firm loads that require 15 minutes to 2 hours of notification



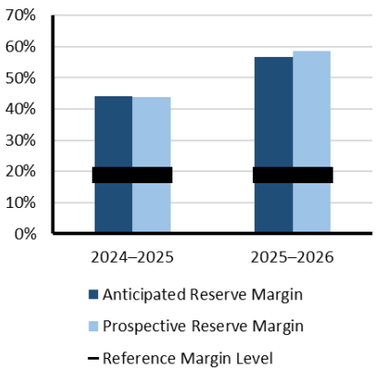
MRO-SPP

SPP's footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Highlights

- SPP anticipates that planning reserves are adequate for the upcoming winter season even as SPP continues to set new winter season load records.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2025–2026 Winter season but realizes that interruptions to fuel supply combined with higher penetration of variable energy resources could create unique operation challenges.
- SPP continues to work at enhancing communications and operator preparedness with neighboring regions to address potential electric deliverability issues associated with extreme weather events.
- To minimize conservative operations, EEAs, and mid-range forecast error uncertainty response in wind forecasts, SPP implemented several new operational mitigation processes and procedures to deal with high-impact real-time areas of reliability concern.
- SPP has proposed numerous resource adequacy initiatives, including addressing EUE standards, fuel assurance, winter planning reserve margins, outage policies, demand response, and accreditation; all were recently approved by FERC.

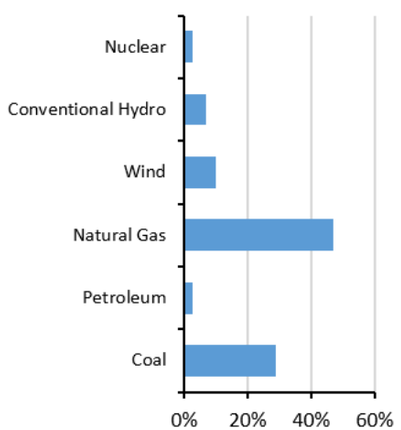
On-Peak Reserve Margin



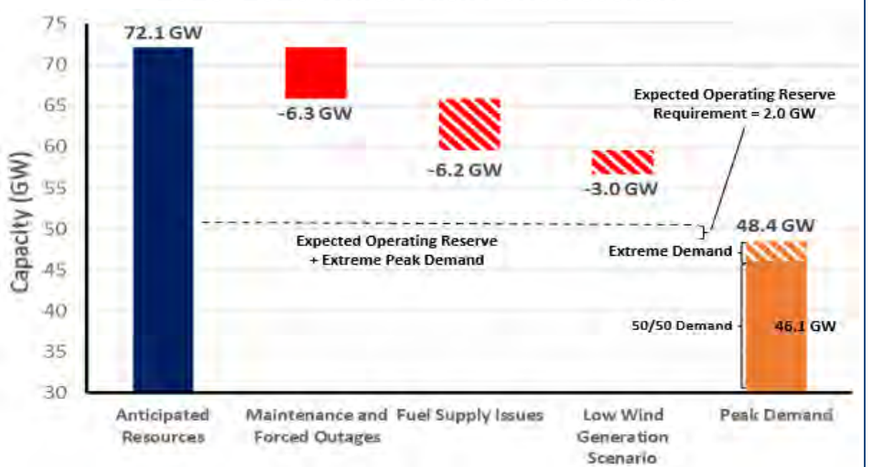
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast using historical data

Maintenance and Forced Outages: A capacity derate of 6.3 GW for maintenance outages, forced outages, and performance in extreme weather based on historical data

Fuel Supply Issues: BA derate of 6.2 GW based on MW capacity of gas-fired generators experiencing fuel supply issues in winter storm Elliott.

Low Wind Generation Scenario: 3 GW of wind potentially off-line when temperatures fall below their cold weather performance packages



NPCC-Maritimes

NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. state of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the balancing authority for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the balancing authority for Nova Scotia. NB Power's system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

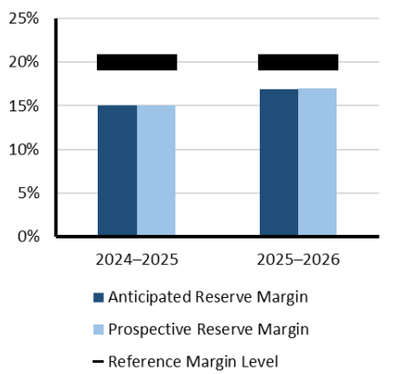
Highlights

- The Maritimes has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind, dual-fuel oil/gas, tie benefits, and biomass with no one type making up more than about 27% of the total capacity in the area.
- The Maritimes has long-term energy contracts in place for its winter supply and can purchase additional energy in the day-ahead and in real time as required.
- As part of the winter planning and preparation process, dual-fueled units will have sufficient supplies of heavy fuel oil stored on site to enable sustained operation in the event of natural gas supply interruptions.

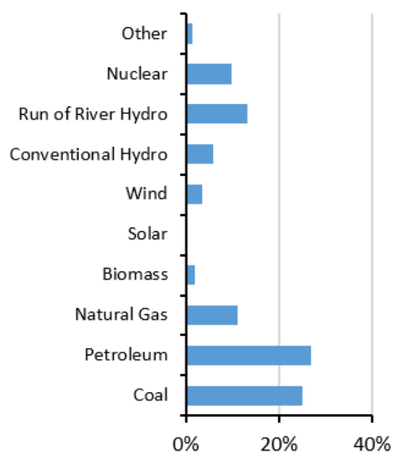
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates some risk of unserved energy and LOLH under high demand or low resource scenarios.

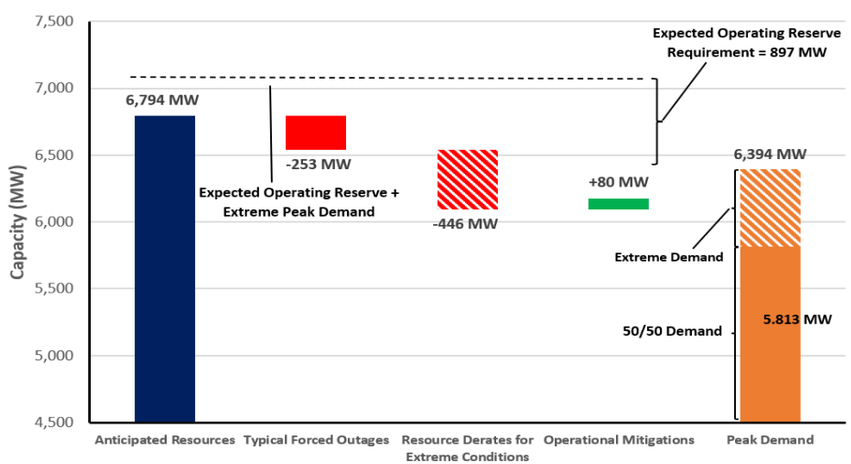
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Scenario peak load with adjustment calculated by adding a 10% margin of error to the peak internal demand forecast taken from the *Long-Term Reliability Assessment* (LTRA) for the 2025–2026 Winter period (aligns with the all-time winter peak, which occurred on February 4, 2024)

Typical Forced Outages: Based on historical operating experience

Resource Derates for Extreme Conditions: Based on ambient temperature thermal derates, wind derated to zero, as well as natural gas capacity derated by 50% due to supply issues

Operational Mitigations: Based on emergency operations and planning procedures in place including fuel switching



NPCC-New England

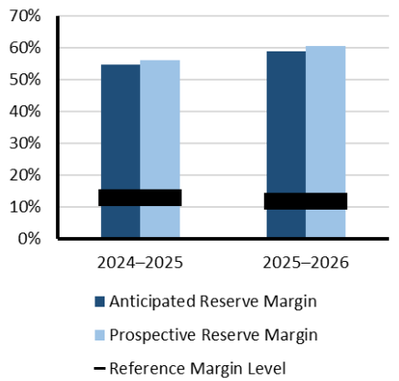
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2025–2026 Winter operating period without calling upon operating procedures to maintain a balance between electricity supply and demand.
- A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold spell given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquefied natural gas (LNG)).
- ISO-NE expects to have sufficient capacity resources to meet the 2025–2026 50/50 and 90/10 winter peak demand forecast of 19,616 MW and 21,125 MW, respectively, for the weeks beginning January 10, January 17, and January 24.
- ISO-NE has recently developed the Regional Energy Shortfall Threshold (REST) as an effort to quantify the tolerable risk of energy shortfall during extreme events. Within the 0.25% highest-risk scenarios, the REST thresholds are 3.0% normalized EUE over 72-hour periods and 18.0 hours over 21-day periods.
    - ISO-NE does not anticipate exceeding the REST criteria for Winter 2025–2026.

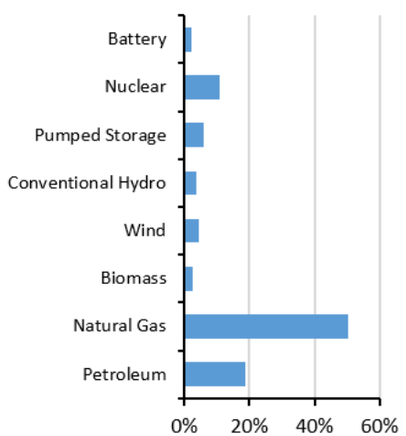
On-Peak Reserve Margin



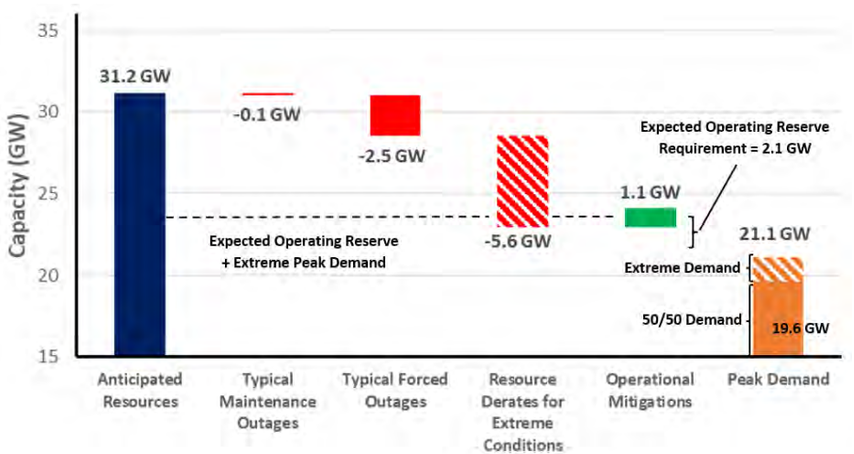
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with high generator outages could result in the need for operating mitigations (i.e., demand response and transfers). Prolonged extreme cold weather events that result in depletion of stored fuels can lead to resource shortfalls.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast capturing the region's coldest day in the last 30 years using current and future load models

Typical Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Resource Derates for Extreme Conditions: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather-related outages

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this WRA, the established RML is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

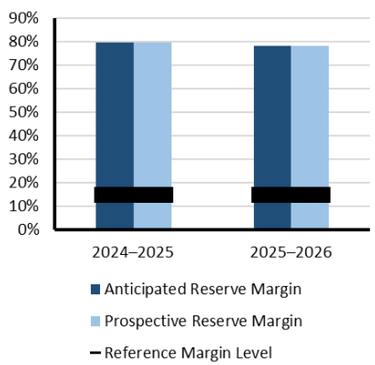
Highlights

- New York is presently a summer-peaking area, and no emerging reliability issues are anticipated during the 2025–26 Winter assessment period.
- Expected resources meet operating reserve requirements under the assessed demand and resource scenarios. A scenario involving an extended cold snap that causes above-normal demand and diminished natural gas supplies would result in low but sufficient reserves.
- The preliminary results of the NPPCC winter probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOL,H or EUE risks were indicated over the December–February winter period for all the scenarios modeled.

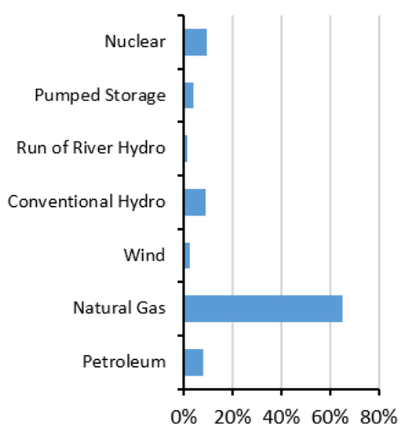
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed demand and resource scenarios.

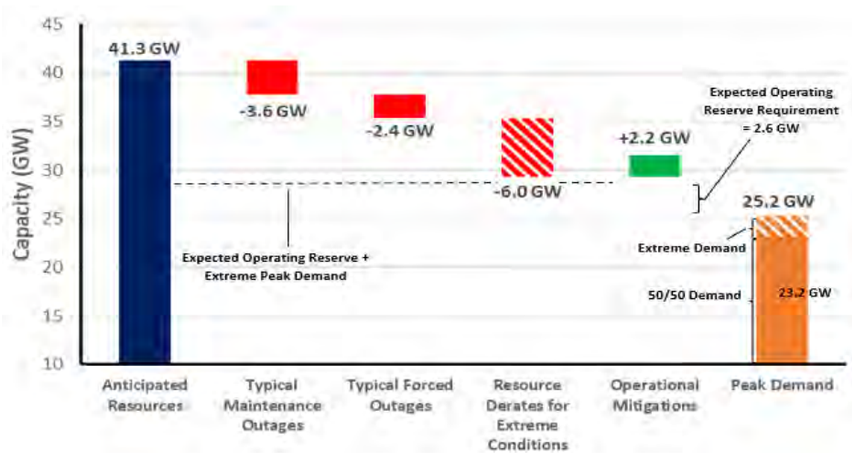
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Maintenance Outages: Based on planned scheduled maintenance

Typical Forced Outages: Based on 5–year averages from GADS data.

Resource Derates for Extreme Conditions: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather. Based on a 2025 analysis, approximately 6,307 MW of gas generation with non-firm fuel supplies could be unavailable.

Operational Mitigations: Based on NYISO operating procedures



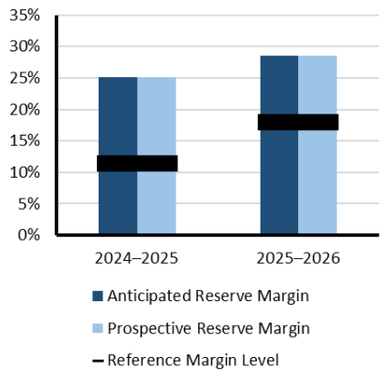
NPCC-Ontario

NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of almost 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

Highlights

- As Ontario is a summer-peaking province, there is typically a lower risk of reliability issues during the winter than the summer. However, Ontario regularly experiences extreme cold weather in the winter.
- NPCC-Ontario is well prepared for Winter 2025–2026, and IESO expects that the electric system will remain reliable with reserve margins well above required levels.
- Operators and forecasters in Ontario work closely with neighboring jurisdictions to manage extreme weather events.
- Natural-gas-fired generators in Ontario are supplied by pipelines with access to the Enbridge Gas Dawn Hub and its associated storage facilities, which significantly reduces natural gas deliverability and reliability concerns by connecting those systems to several major gas transportation corridors, enabling access to multiple supply basins.

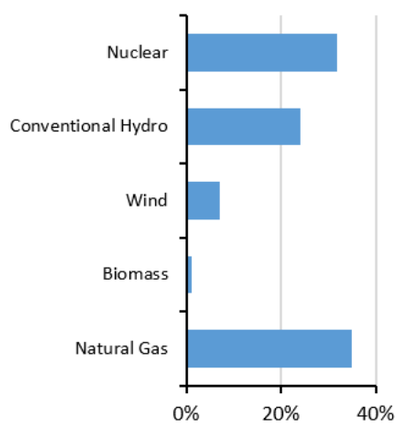
On-Peak Reserve Margin



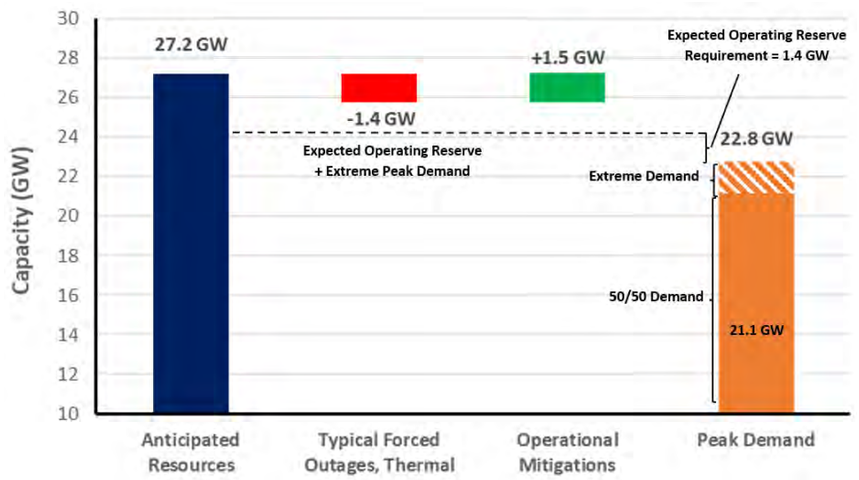
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand from 31 years of winter demand history

Typical Forced Outages, Thermal: Based on analysis of a rolling five-year history of actual forced outage data.

Operational Mitigations: Imports anticipated from **neighbors** during emergencies



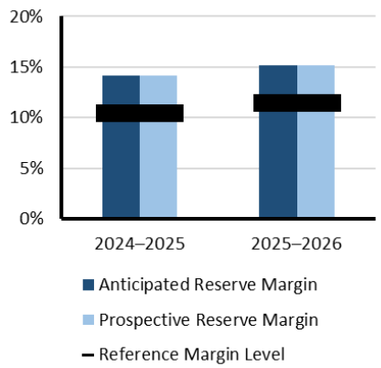
NPCC-Québec

NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominately hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

Highlights

- NPCC-Québec projects adequate capacity margins above its reference reserve requirements and that system resource adequacy will be maintained for the province for the 2025–26 Winter assessment period.
- No hydropower performance issues are expected during extreme cold because of design criteria for cold weather.
- No fuel supply or transportation issues are anticipated for the upcoming winter season.
- While a slight decrease in net firm transfers has occurred since last winter (-89 MW), significant increases in demand-side management programs (+450 MW year-over-year) have been realized over the same period and are expected to compensate for this winter's modest expected load growth.

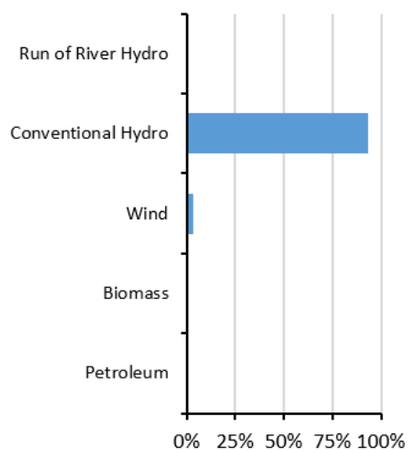
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 8:00 a.m.

Demand Scenarios: Demand forecasts include demand-side resources. The demand side resources are the same for the 50/50 and extreme demand scenarios. The extreme load forecast is determined at two standard deviations higher than the mean, which has a 6.06% probability of occurrence.

Extreme Derates: Maintenance outages and other deratings are already included in existing-certain capacity calculation. Wind capacity is 64% derated

Typical Forced Outages: Unplanned outages are 1,500 MW.

Operational Mitigations: Operational mitigations include imports from neighboring areas and reduction of reserves



PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM's footprint covers approximately 369,054 square miles and with an approximate population of 67 million people. PJM is the area's BA, Transmission and Resource Planner, interchange authority, TOP, transmission service provider, and RC. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

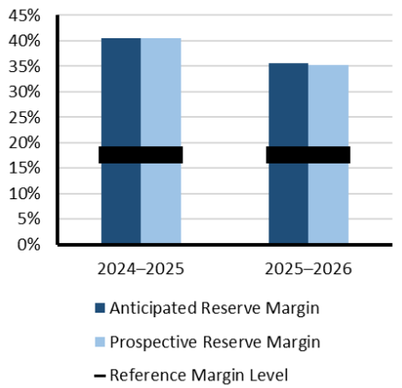
Highlights

- Due to the low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with highest loss-of-load risk remains the hour with highest forecasted demand.
- PJM is expecting little capacity adequacy risk during Winter 2025–2026 and expects around 35% installed reserves, which is above the target IRM of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- Last winter, PJM hit a new all-time winter peak, but generator preparations anticipating congestion and tight capacity projections led to sufficient reserves throughout the demand event and PJM's transmission system performed well.
- The decrease in reserves from Winter 2024–2025 is due to load increases and retirement of generation without like (non-solar dispatchable) replacement generation.

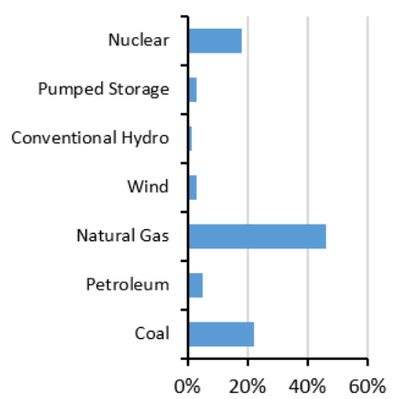
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

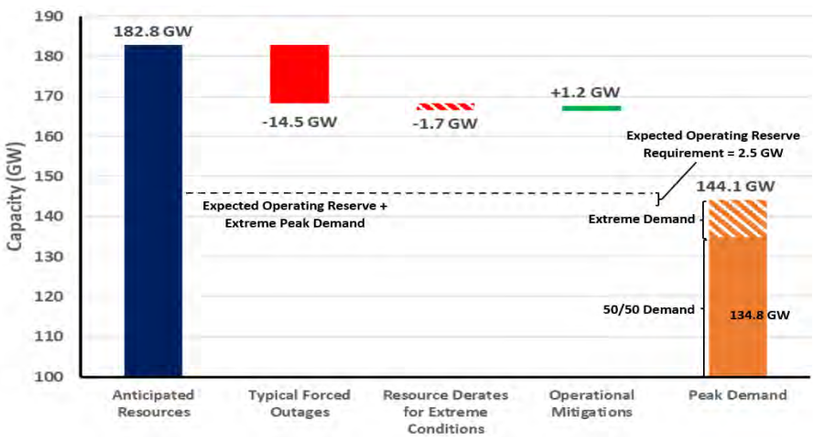
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Based on historical data and trending

Resource Derates for Extreme Conditions: Reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: accounts for an estimated value based on operational / emergency procedures



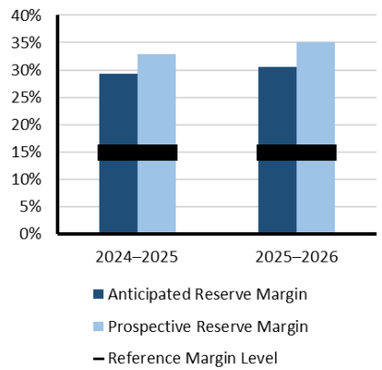
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-Central is transitioning from a summer-peaking area to a dual-peaking system.
- For the 2025–2026 Winter, SERC-Central projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Most entities across SERC-Central report that fuel security is strong since it is supported by firm natural gas contracts, storage resources, and reliable pipeline capacity. Coal inventories are projected to remain within operational ranges necessary to meet winter demand.
- Following lessons from Winter Storm Elliott, one SERC-Central entity raised its winter Planning Reserve Margin target to 26% and updated preparedness programs with improved heat trace capabilities.

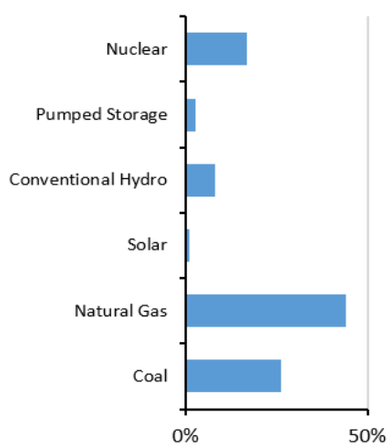
On-Peak Reserve Margin



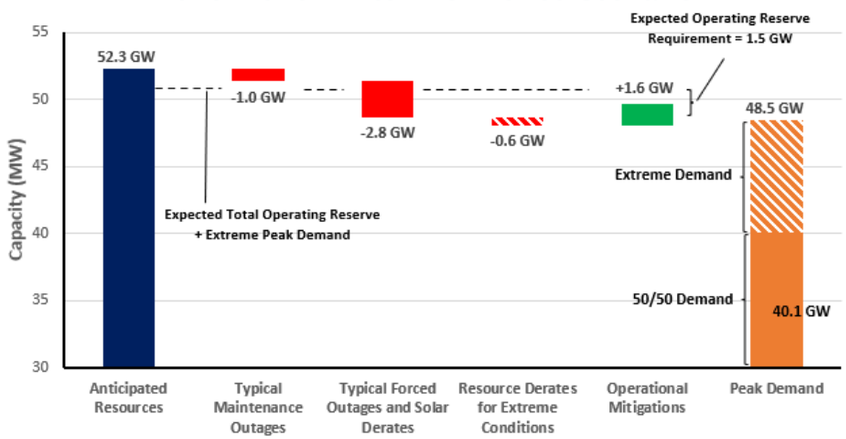
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand. A severe cold weather event that extends to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for expected outages during December through February

Typical Forced Outages and Solar Derate: Includes any weighted average forced-outage rates on-peak that are not factored into the anticipated resources calculation . Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions

Operational Mitigations: A total of over 1.6 GW based on operational/emergency procedures



SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six Regional Entities across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

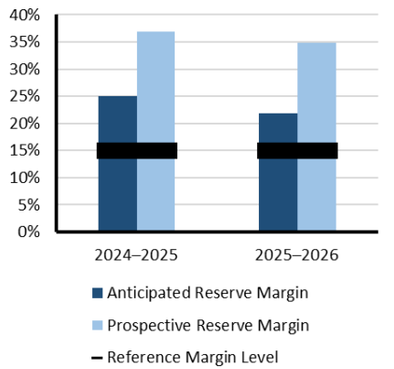
Highlights

- SERC-East is transitioning from a summer-peaking area to potentially peaking during both summer and winter. This shift is attributed to the continued addition of solar PV generation, which reduces summer peak demand, and a trend toward electrification of heating, which drives up winter peak demand.
- For the 2025–2026 Winter, the SERC-East region projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Fuel supplies and transportation remain stable, and entities anticipate maintaining adequate coal and oil inventories with no reported changes to fuel procurement or operator plans for the upcoming winter.
- Probabilistic Base Case Results (Median Weather): EUE is 61.95 MWh and LOLH is 0.06 hours/year. EUE values are likely due to higher winter peaks and/or lower supply of capacity that can meet early winter morning demand.
- Mitigation measures for extreme conditions include voltage reduction (25–50 MW) and load-shedding programs that cover up to 30% of system load.

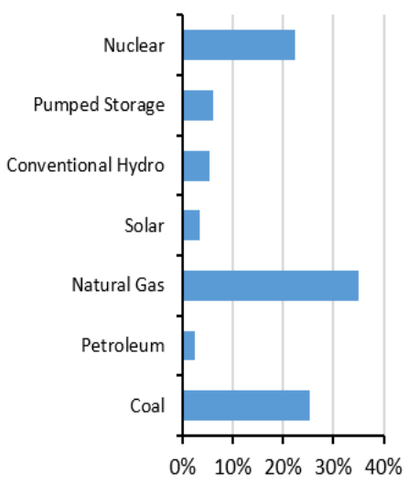
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal demand scenarios. A severe cold weather event extending to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

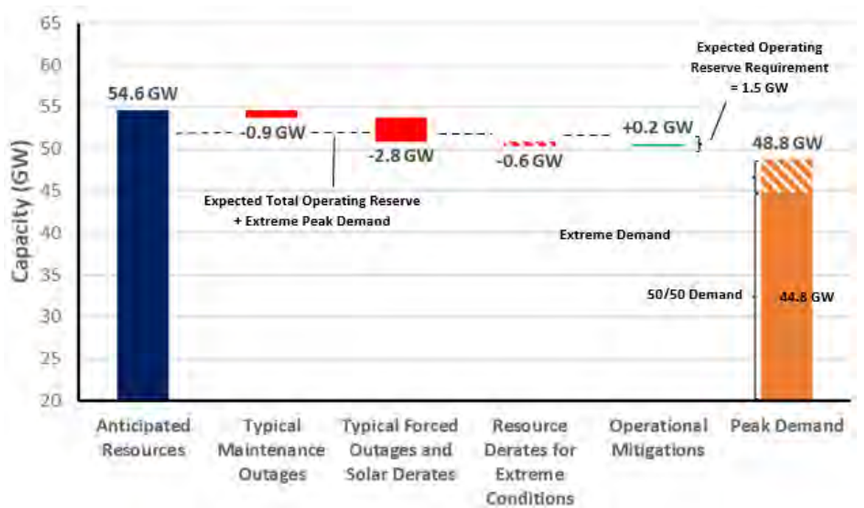
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages (excluding 2022–2025)

Operational Mitigations: A total of 0.2 GW based on operational/emergency procedures



SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

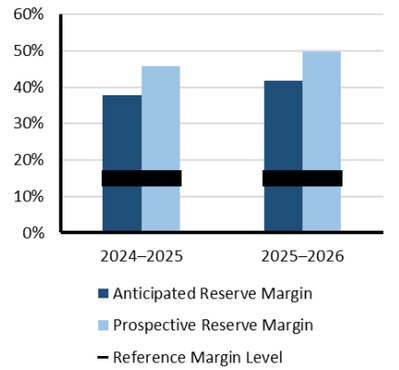
Highlights

- SERC-Florida Peninsula is a summer-peaking assessment area.
- Florida Peninsula entities have not identified any emerging reliability issues for the upcoming 2025–26 Winter season with an ARM projected at 39%, well above the RML, while the 2024 NERC ProbA base-case results project a sufficient level of resources to serve the expected load under median weather and typical system operating conditions (EUE is 1.09 MWh and LOLH is 0.00 hours/year).
- Many entities report strong fuel security, supported by firm natural gas contracts, storage resources, reliable pipeline capacity, and actively managed coal and oil inventories, which are projected to remain within operational ranges to meet winter demand.
- Florida Peninsula entities do not assume non-firm external assistance from neighboring areas during extreme conditions.

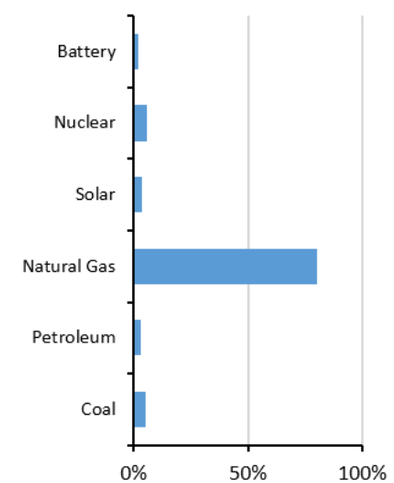
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

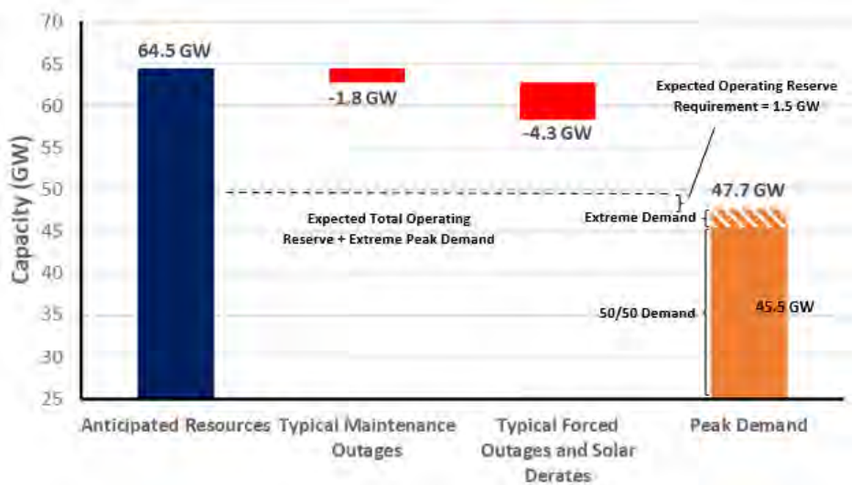
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions



SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

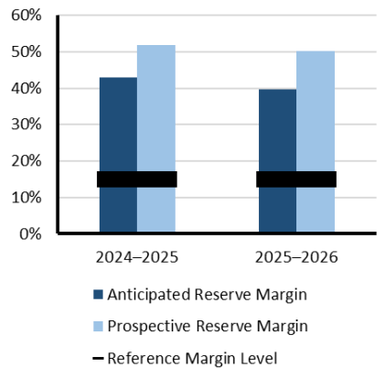
Highlights

- SERC-Southeast is trending towards becoming slightly winter-peaking.
- For the 2025–2026 Winter, SERC-Southeast entities report no emerging reliability concerns and expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories to serve the expected load under typical system operating conditions. The 2024 NERC ProbA base-case results in EUE and LOLH are both 0.00.
- While most SERC-Southeast BAs expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories, one BA highlights potential risks related to natural gas transportation capacity, citing high pipeline utilization, competition for delivered gas, and ratable flow requirements. Mitigation strategies include securing third-party gas supply, adding dual-fuel capability, and implementing coal inventory management.
- Entities have made refinements such as replacing specific 230 kV circuit breakers and increasing monitoring frequencies for critical plant systems after January 2025 winter events.

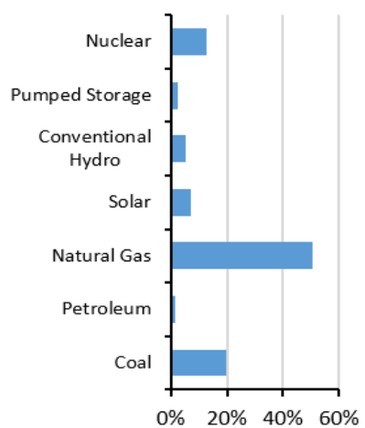
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

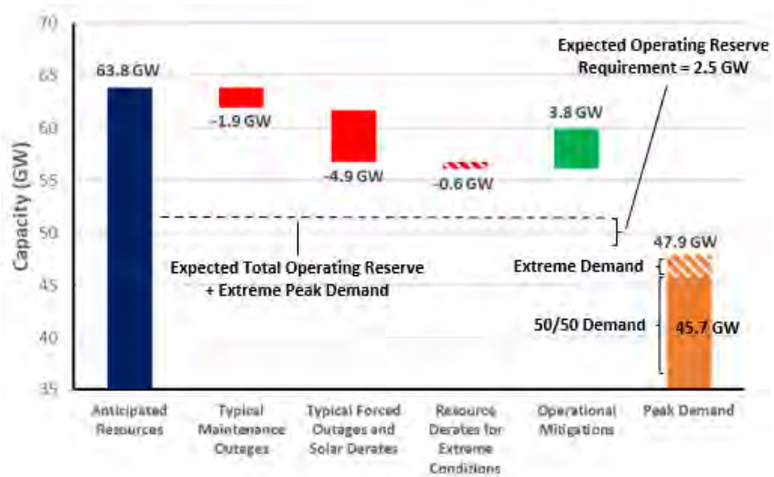
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages

Operational Mitigations: A total of 3.8 GW based on operational/emergency procedures



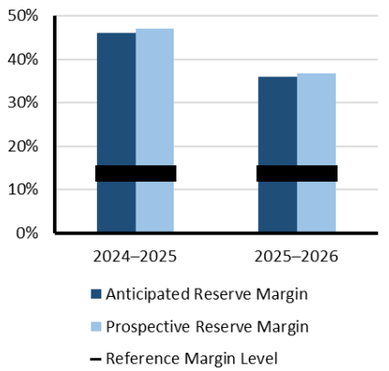
Texas RE-ERCOT

ERCOT is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas power grid.

Highlights

- Given expected system conditions, an ARM of 36% and RML of 13.75%, ERCOT expects to have sufficient operating reserves for the peak hour ending 8:00 a.m.
- ERCOT does not expect any significant fuel supply issues for the winter.
- ERCOT has conducted 2,028 generation resource and transmission service provider (TSP) winter weatherization inspections since Winter 2021–2022.
- Winter peak demands typically occur before sunrise and after sunset when solar generation is not available. Significant battery storage mitigates these risks.
- ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
- Increased load growth in west Texas combined with "no solar" and low wind conditions can cause transmission lines into this area to become heavily loaded. ERCOT has introduced improved dynamic line ratings that allow for greater transfers at colder temperatures and periods of low irradiance.

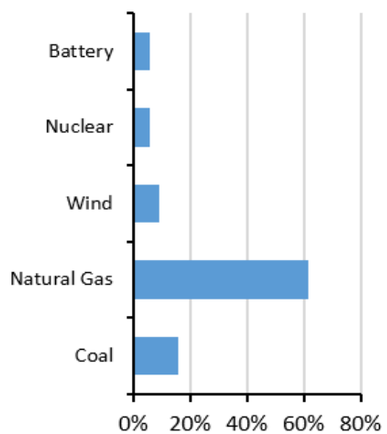
On-Peak Reserve Margin



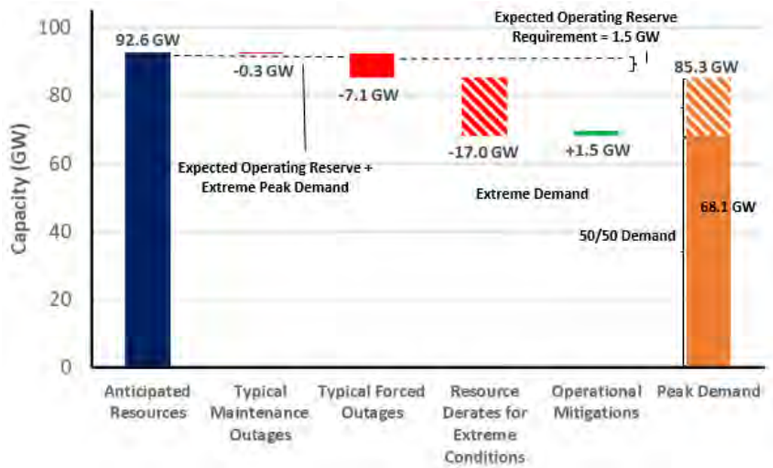
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Presumes weather conditions comparable to Winter Storm Uri. The adjustment is calculated as the difference between the 100th percentile and 50th percentile values from ERCOT's Probabilistic Reserve Risk Model (PRRM) simulated load outcome distribution for hour ending 8:00 a.m.

Typical Maintenance Outages: Based on historical winter data and consideration of ERCOT's allowed maximum system daily planned outage capacity

Typical Forced Outages: Based on a probability distribution created using historical ERCOT Outage Scheduler data for the last three Januarys.

Resource Derates for Extreme Conditions: Weather-related thermal and wind outages based on Winter Storm Uri levels, adjusted for reductions due to weatherization standards. Also includes high non-weather-related outages.

Operational Mitigations: Additional potential capacity from switchable generation and imports



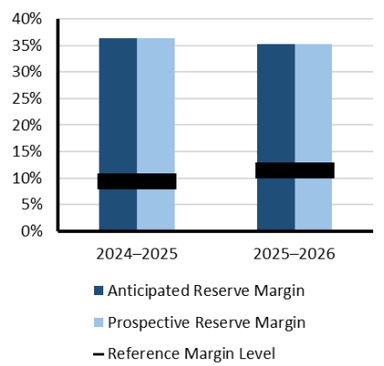
WECC-Alberta

WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's Planning Entity and RC responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta's transmission system has three interties with neighboring areas: Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

Highlights

- At an extreme winter peak of 12,982 MW, with extreme forced outages at 530 MW and derates for extreme conditions bringing wind energy availability down by 1,800 MW and hydroelectricity by 88 MW, the required reserves are 759 MW and are sufficiently met, even with low availability.
- Demand is expected to increase 1.1% from last winter with the existing-certain installed capacity having increased 23%.
- Solar availability is down because 1,000 MW of PV moved from originally expecting to come on-line in 2024 as Tier 1 resources to Tier 2s mostly anticipated to come on-line in 2025, but with less certainty.

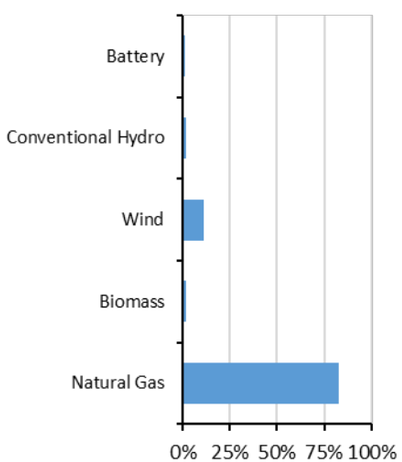
On-Peak Reserve Margin



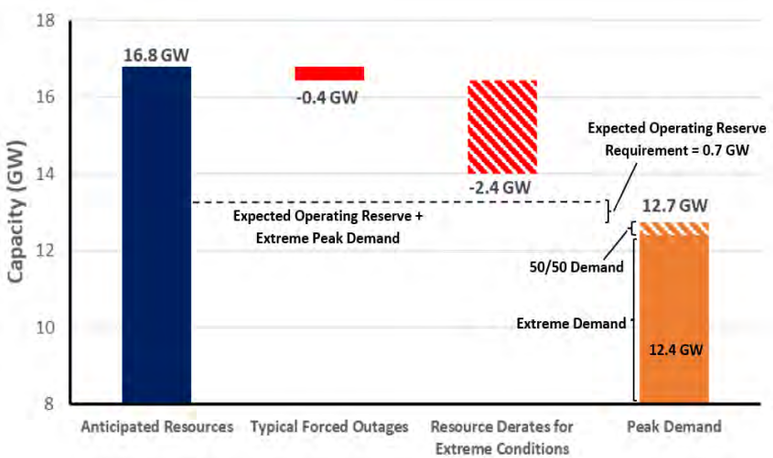
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS data

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern BA area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025-26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA*.

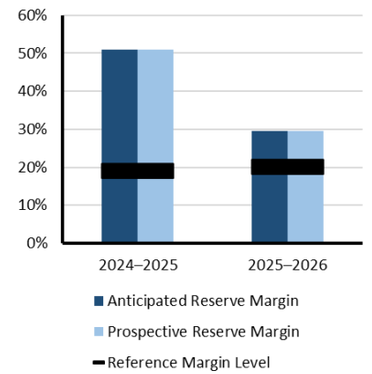
Highlights

- At an extreme winter peak of 11.1 GW under an extreme combination of derates and outages, the region could be short 1.0 GW before imports and is expected to need to rely on transfers.
- Net internal demand is expected to increase 1% since last year, with total internal demand up 1.8% being offset by a doubling of controllable and dispatchable demand response.
- Tier 1 resources have declined and do not appear to be offset by increases in existing-certain generation resource capacity. Nameplate wind has increased by almost 18% and solar by almost 30%. Hydro is also up over 7% in total installed capacity.
- Reliance on imports is expected to be required to maintain resource adequacy during extreme peak demand and extreme derate conditions.

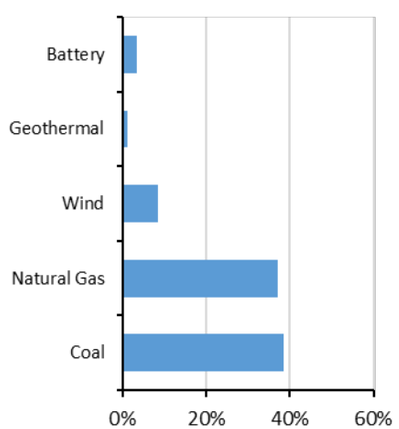
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

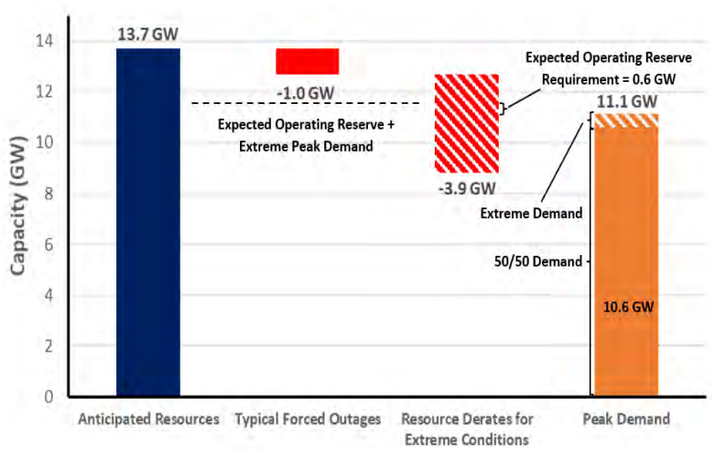
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Extreme Derates: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



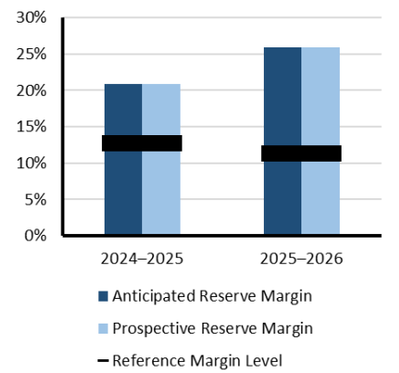
WECC-British Columbia

WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and RC for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia BES and its interconnections. BC Hydro operates an integrated system supported by 30 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro's transmission system has two interties with neighboring areas: the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during winter.

Highlights

- Peak demand is expected to remain about the same as last winter.
- There are about 200 MW more (47%) planned Tier 1 resources for this winter than last.
- Solar nameplate capacity has increased from 2 MW to 17 MW since last winter and hydroelectric nameplate capacity is up more than 5%, or 1,366 MW.

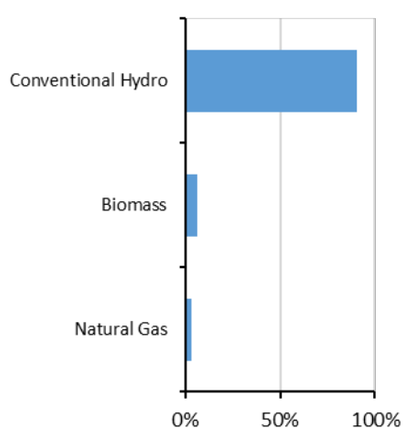
On-Peak Reserve Margin



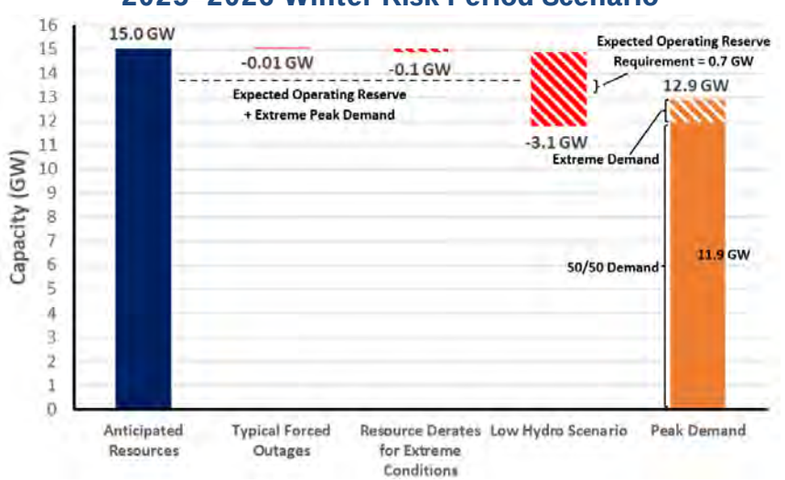
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme demand scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

Low Hydro Scenario: Estimated derate for lower hydro output



WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, the Los Angeles Department of Water and Power, the Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

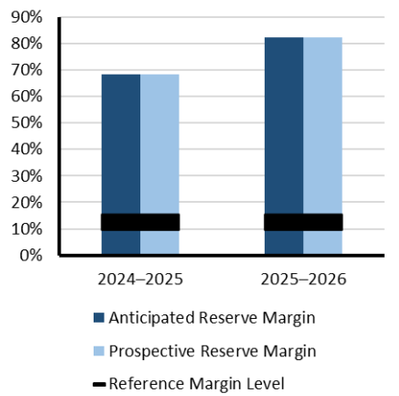
Highlights

- Operating reserve margins are met before imports in all winter resource availability scenarios.
- On-peak demand is expected to remain about the same as last winter. Demand-side management is down about 10%.
- Existing-certain capacity is up almost 5%, while planned Tier 1 resources are up more than 2 GW. The total wind nameplate capacity is up almost 27% and solar almost 13%. Hydro is down 4%.
- No reliance on imports is expected to be required to maintain resource adequacy for Winter 2025–2026.

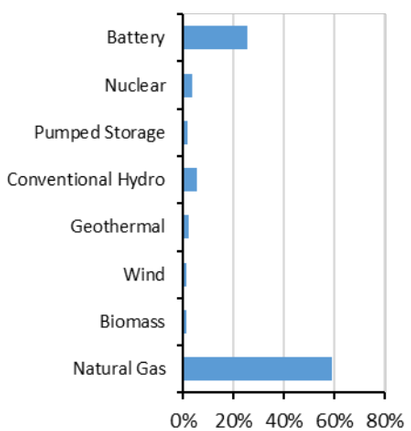
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

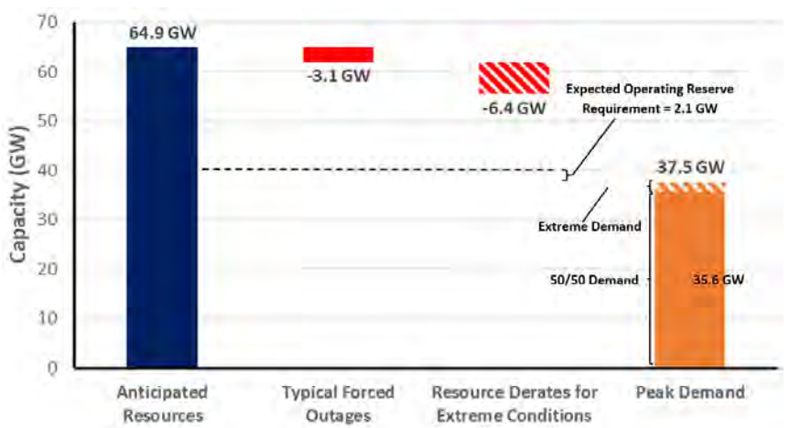
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



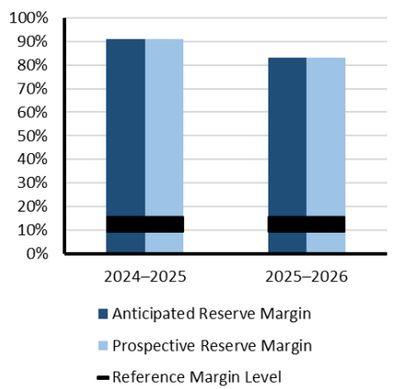
WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

Highlights

- As a summer-peaking region, operating reserve margins are met before imports in all scenarios.
- Planned Tier 1 resources are down 100% to zero as expected resources have either been brought on-line to move into existing or, in the case of some natural gas, have been delayed until 2026 and moved into Tier 2.
- The existing-certain on peak reserve margin is down by 5.2%, and the anticipated and prospective reserve margins are down by 7.8%; however, since Mexico is heavily summer-peaking, the 83% reserve margin still exceeds the RML of 12.5%, which remains unchanged.

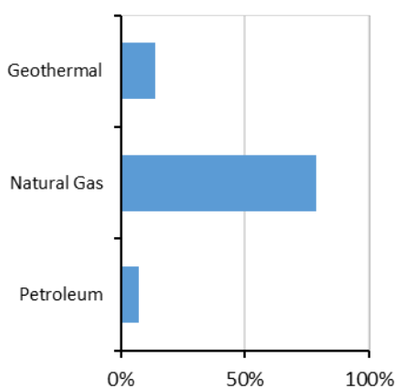
On-Peak Reserve Margin



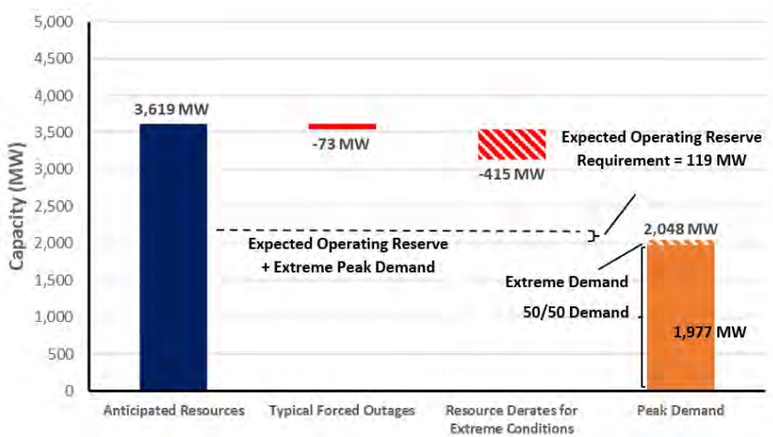
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

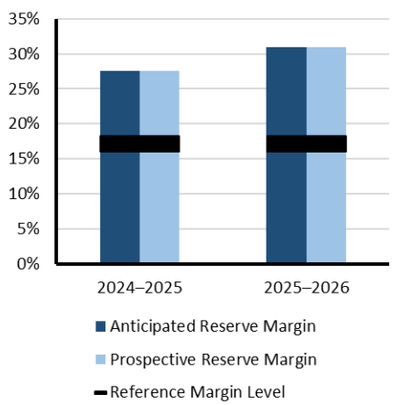
Highlights

- The Northwest has historically been a mixed season-peaking region.
- Operating reserve margins are expected to be met after imports in all winter scenarios.
- Total and net internal demand are up 9.3% with the primary drivers being data centers, residential electrification, transportation electrification, and semiconductor manufacturing.
- Large coal unit retirements and conventional hydro unit retirements are attributable to the reduction in existing certain capacity of 10.5%; however, planned Tier 1 resources have soared over 580%, from 463 MW to over 3 GW.
- Nameplate wind capacity is up over 3 GW (26%) and solar nameplate capacity is up nearly 2,690 MW (134%), which has also increased the solar availability on the peak hour.
- An increase in firm imports is seen in the model, 6.1 GW, absorbing the reduction in existing certain capacity of 4 GW.

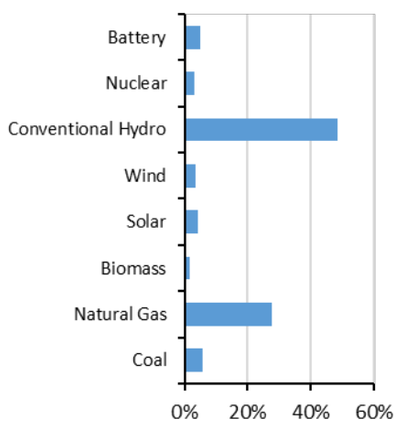
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

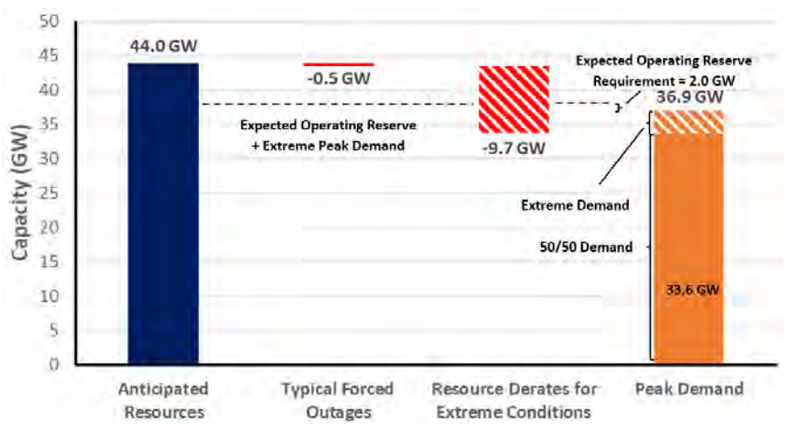
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period. This value includes 6.8 GW of hydro derates.



WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

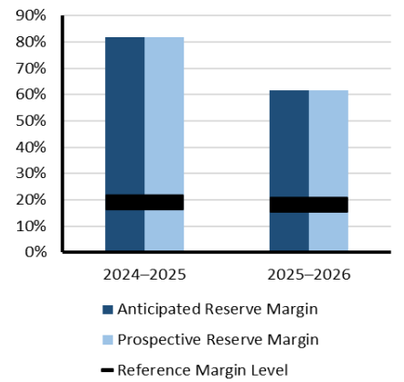
Highlights

- In Rocky Mountain, operating reserve margins are expected to be met before imports in all winter scenarios.
- Total and net internal demand are up almost 1%. The primary drivers are data centers and commercial and industrial customer growth.
- Planned Tier 1 resources are up over 84%, from almost 200 MW to over 365 MW. Solar nameplate capacity is up 27%; however, on-peak solar energy availability is down 100% due to the shift to after sunset. Expected hydro on peak energy availability is also down by around a quarter on the peak hour. Existing-Certain, Anticipated, and Prospective Reserve Margins are all down by over 20% on the peak hour; however, the region still maintains resource adequacy with margins hovering around 60% compared to the RML of 18%.
- No reliance on imports is expected to be required to maintain resource adequacy under combined extreme peak and extreme derated conditions.

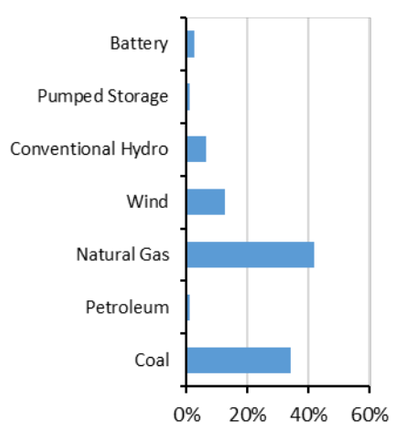
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

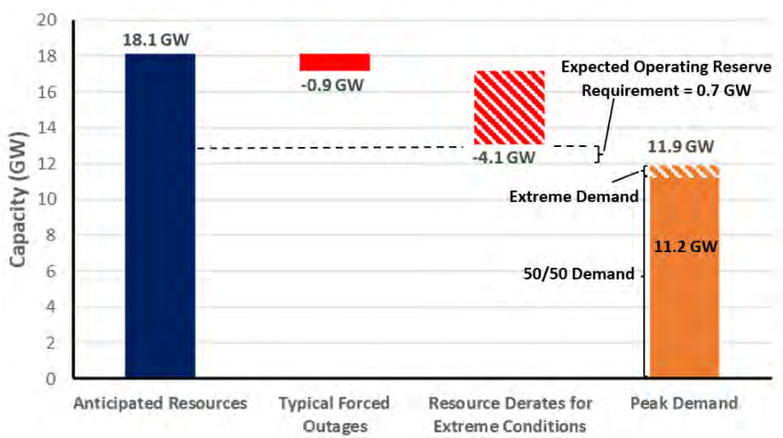
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

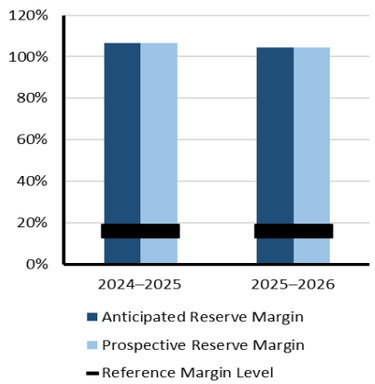
Highlights

- The Southwest is anticipated to be resource adequate under all winter expected and extreme energy availability and demand scenarios before imports.
- Total internal demand is expected to be up 1.5% and net internal demand up 2.3% since last winter. The primary drivers for load growth are data centers and industrial and residential electrification. Controllable and dispatchable demand response is down nearly half, by 163 MW.
- Planned Tier 1 resources are down over 19% as some have moved into existing certain, which is up almost 3%, over 1 GW, and other projects have experienced delays.
- Wind nameplate is up 12%, 470 MW, correlating to on-peak energy availability from wind increasing almost 11%, by 114 MW, while solar nameplate is up 27% or over 2.5 GW.

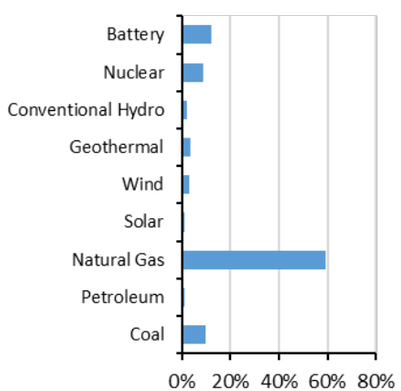
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

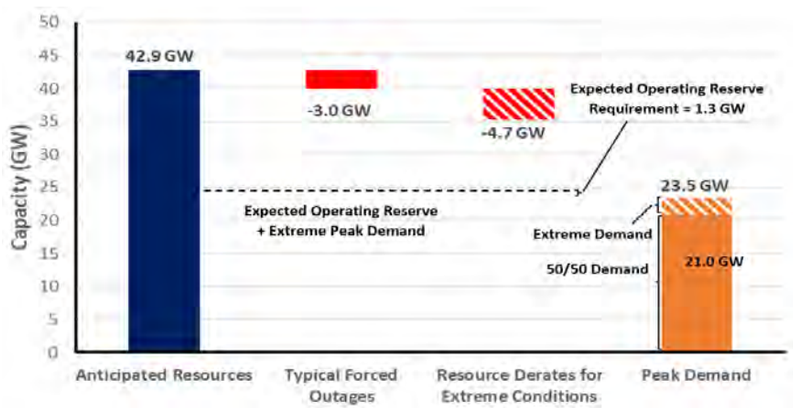
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[11] or total internal demand for the summer and winter of each year.[12]
• Total internal demand projections are based on normal weather (50/50 distribution)[13] and are provided on a coincident[14] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (VER) (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

[11] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[12] The summer season represents June–September and the winter season represents December–February.

[13] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[14] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The ARM, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[15] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. NPCC-Maritimes marginally does not meet its RML for the upcoming winter. Other than NPCC-Maritimes, all assessment areas have sufficient ARMs to meet or exceed their RML for the 2025 winter as shown in **Figure 4**.

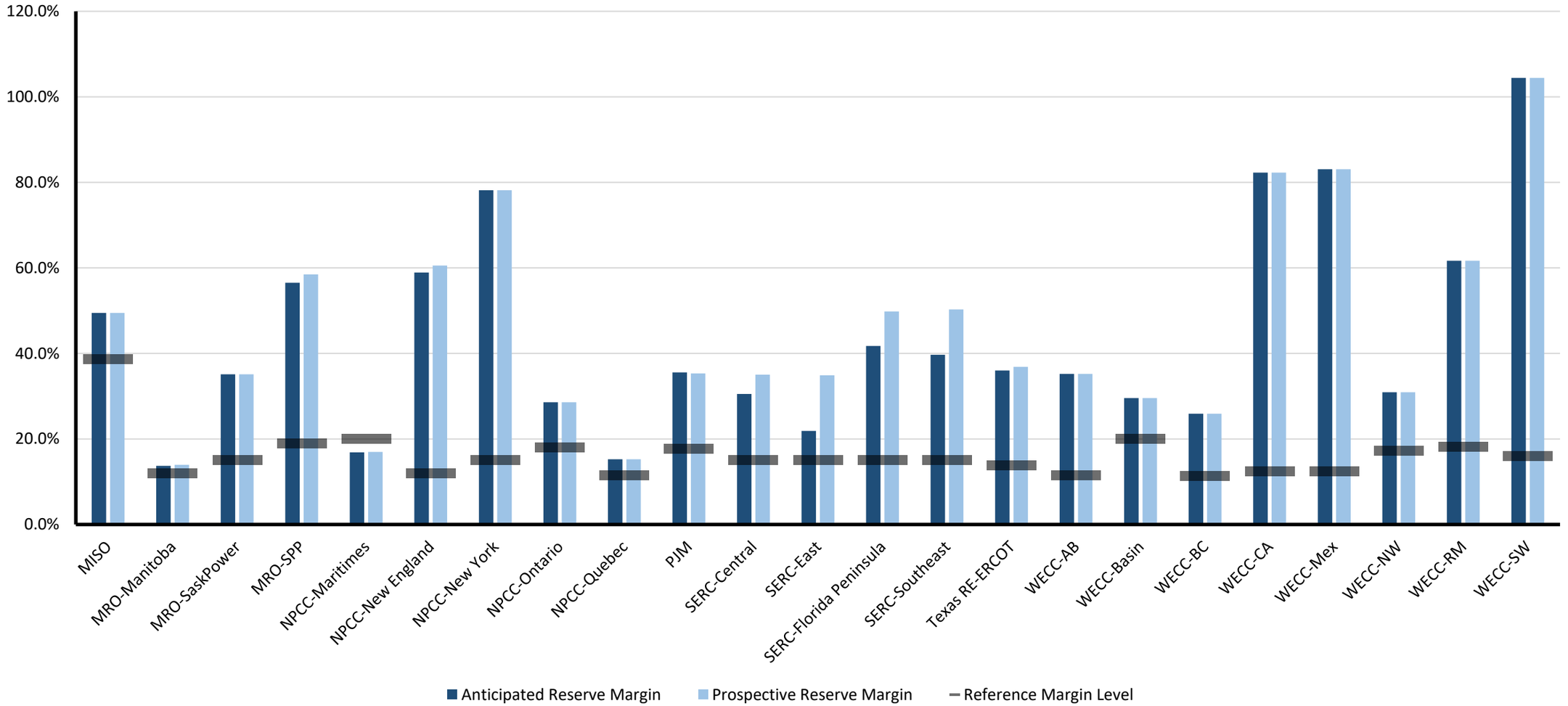


Figure 4: Winter 2025–2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[15] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast ARMs from the 2024–2025 Winter to the 2025–2026 Winter. All areas except NPCC-Maritimes remain above their RMLs for 2025–2026 Winter. The Canadian winter-peaking systems, which include MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, WECC-Alberta, and WECC-British Columbia, may have reserve margins that are near RMLs but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the Data Concepts and Assumptions section.

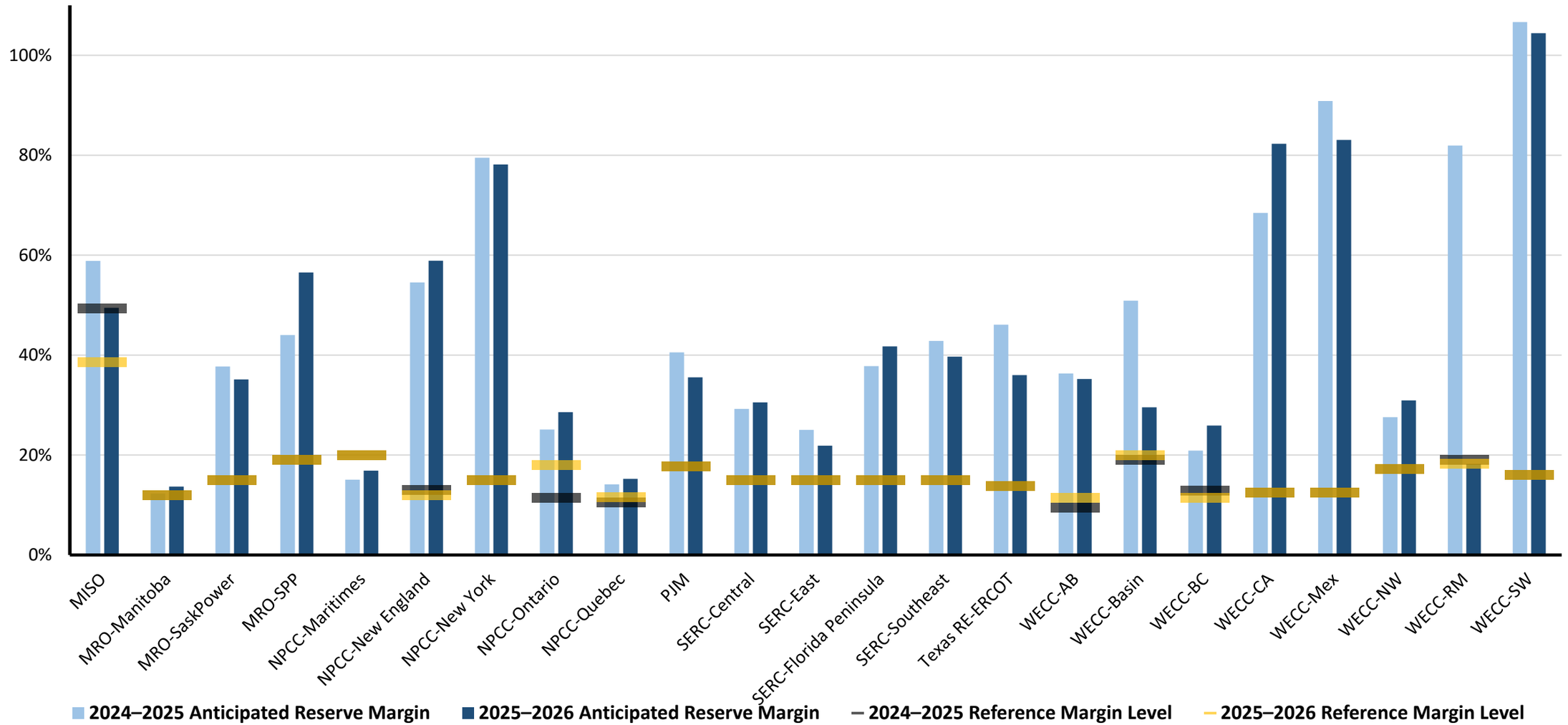


Figure 5: Winter 2024–2025 and Winter 2025–2026 Anticipated Reserve Margins Year-to-Year Change

Demand and Resource Tables

Peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area are as follows in each table.

MISO			
Demand, Resource, and Reserve Margins	**2024–2025 WRA[16]**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	102,353	105,249	2.8%
Demand Response: Available	6,219	8,250	32.7%
Net Internal Demand	96,134	96,999	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	150,407	142,880	-5.0%
Tier 1 Planned Capacity	122	0	0.0%
Net Firm Capacity Transfers	2,310	2,113	-8.5%
Anticipated Resources	152,717	144,993	-5.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	152,839	144,993	-5.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	58.9%	49.5%	-9.4
Prospective Reserve Margin	59.0%	49.5%	-9.5
Reference Margin Level	49.4%	38.6%	-10.8

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,788	47,168	3.0%
Demand Response: Available	1,128	1,091	-3.3%
Net Internal Demand	45,926	46,077	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	67,252	71,074	5.7%
Tier 1 Planned Capacity	0	1087	0.0%
Net Firm Capacity Transfers	-1,116	-32	-97.1%
Anticipated Resources	66,136	72,129	9.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	66,090	73,029	10.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.0%	56.5%	12.5
Prospective Reserve Margin	43.9%	58.5%	14.6
Reference Margin Level	19.0%	19.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,852	3,944	2.4%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,802	3,894	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,946	4,972	0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	5,236	5,262	0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,236	5,262	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.7%	35.1%	-2.6
Prospective Reserve Margin	37.7%	35.1%	-2.6
Reference Margin Level	15.0%	15.0%	0.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,814	4,903	1.8%
Demand Response: Available	0	0	0.0%
Net Internal Demand	4,814	4,903	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,924	5,688	-4.0%
Tier 1 Planned Capacity	10	0	-100.0%
Net Firm Capacity Transfers	-527	-113	-78.5%
Anticipated Resources	5,407	5,575	3.1%
Existing-Other Capacity	18	13	-26.8%
Prospective Resources	5,425	5,588	3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.3%	13.7%	1.4
Prospective Reserve Margin	12.7%	14.0%	1.3
Reference Margin Level	12.0%	12.0%	0.0

[16] MISO-provided updated data post 2024-25 WRA publication.

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	6,167	6,061	-1.7%
Demand Response: Available	259	248	-4.4%
Net Internal Demand	5,907	5,813	-1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,647	6,704	0.9%
Tier 1 Planned Capacity	6	88	0.0%
Net Firm Capacity Transfers	145	1	-99.0%
Anticipated Resources	6,798	6,794	-0.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	6,798	6,800	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.1%	16.9%	1.8
Prospective Reserve Margin	15.1%	17.0%	1.9
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,651	20,056	-2.9%
Demand Response: Available	343	440	28.2%
Net Internal Demand	20,308	19,616	-3.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	30,030	29,935	-0.3%
Tier 1 Planned Capacity	194	0	-100.0%
Net Firm Capacity Transfers	1,161	1,235	6.4%
Anticipated Resources	31,385	31,170	-0.7%
Existing-Other Capacity	306	322	5.2%
Prospective Resources	31,691	31,492	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	54.5%	58.9%	4.4
Prospective Reserve Margin	56.1%	60.5%	4.5
Reference Margin Level	13.0%	12.0%	-1.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,800	24,200	1.7%
Demand Response: Available	802	1,027	28.1%
Net Internal Demand	22,998	23,173	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,522	40,080	-1.1%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	759	1,203	58.5%
Anticipated Resources	41,281	41,283	0.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	41,281	41,283	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	79.5%	78.2%	-1.3
Prospective Reserve Margin	79.5%	78.2%	-1.3
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,898	22,013	0.7%
Demand Response: Available	915	868	-5.2%
Net Internal Demand	20,982	21,146	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,652	27,319	2.5%
Tier 1 Planned Capacity	0	294	#DIV/0!
Net Firm Capacity Transfers	-450	-420	-6.7%
Anticipated Resources	26,202	27,193	3.8%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	26,202	27,193	3.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.1%	28.6%	3.5
Prospective Reserve Margin	25.1%	28.6%	3.5
Reference Margin Level	11.5%	18.0%	6.5

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,512	40,799	0.8%
Demand Response: Available	4,451	4,902	10.9%
Net Internal Demand	36,061	35,897	-0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	41,560	41,698	0.3%
Tier 1 Planned Capacity	73	61	0.0%
Net Firm Capacity Transfers	-479	-390	-18.6%
Anticipated Resources	41,154	41,368	0.5%
Existing-Other Capacity	-479	0	0.0%
Prospective Resources	41,154	41,368	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	15.2%	1.1
Prospective Reserve Margin	14.1%	15.2%	1.1
Reference Margin Level	10.5%	11.5%	1.0

PJM			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	136,328	140,827	3.3%
Demand Response: Available	5,616	5,998	6.8%
Net Internal Demand	130,712	134,829	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	179,216	178,335	-0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	4,502	4,448	-1.2%
Anticipated Resources	183,718	182,783	-0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	183,718	182,452	-0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	40.6%	35.6%	-5.0
Prospective Reserve Margin	40.6%	35.3%	-5.2
Reference Margin Level	17.7%	17.7%	-12.3

SERC-Central			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,895	42,875	0.0%
Demand Response: Available	1,497	2,809	87.6%
Net Internal Demand	41,397	40,067	-3.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,578	50,454	-2.2%
Tier 1 Planned Capacity	0	0	0%
Net Firm Capacity Transfers	1,922	1,847	-3.9%
Anticipated Resources	53,500	52,301	-2.2%
Existing-Other Capacity	1,498	1,810	20.8%
Prospective Resources	54,998	54,111	-1.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.2%	30.5%	1.3
Prospective Reserve Margin	32.9%	35.1%	2.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,005	45,703	1.6%
Demand Response: Available	982	888	-9.6%
Net Internal Demand	44,023	44,815	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	54,379	54,460	0.1%
Tier 1 Planned Capacity	72	11	-84.3%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	55,045	54,622	-0.8%
Existing-Other Capacity	5,209	5,832	12.0%
Prospective Resources	60,254	60,453	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.0%	21.9%	-3.2
Prospective Reserve Margin	36.9%	34.9%	-2.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,494	48,628	0.3%
Demand Response: Available	2,780	3,127	12.5%
Net Internal Demand	45,714	45,501	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,579	63,502	1.5%
Tier 1 Planned Capacity	15	692	4510.0%
Net Firm Capacity Transfers	400	300	-25.0%
Anticipated Resources	62,994	64,494	2.4%
Existing-Other Capacity	3,673	3,671	0.0%
Prospective Resources	66,667	68,165	2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.8%	41.7%	3.9
Prospective Reserve Margin	45.8%	49.8%	4.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,308	47,056	3.9%
Demand Response: Available	1,638	1,365	-16.7%
Net Internal Demand	43,670	45,691	4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,805	63,339	0.9%
Tier 1 Planned Capacity	765	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	62,378	63,828	2.3%
Existing-Other Capacity	3,920	4,847	23.7%
Prospective Resources	66,298	68,675	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.8%	39.7%	-3.1
Prospective Reserve Margin	51.8%	50.3%	-1.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	73,193	77,387	5.7%
Demand Response: Available	5,447	9,330	71.3%
Net Internal Demand	67,746	68,057	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	98,712	89,977	-8.8%
Tier 1 Planned Capacity	239	1351	464.9%
Net Firm Capacity Transfers	20	1,235	6075.0%
Anticipated Resources	98,971	92,562	-6.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	99,691	93,137	-6.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	46.1%	36.0%	-10.1
Prospective Reserve Margin	47.2%	36.9%	-10.3
Reference Margin Level	13.75%	13.8%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,280	12,411	1.1%
Demand Response: Available	0	0	0.0%
Net Internal Demand	12,280	12,411	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,535	16,658	23.1%
Tier 1 Planned Capacity	3206	124	-96.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	16,740	16,782	0.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	16,740	16,782	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.3%	35.2%	-1.1
Prospective Reserve Margin	36.3%	35.2%	-1.1
Reference Margin Level	9.5%	11.5%	2.0

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,568	10,758	1.8%
Demand Response: Available	85	170	100.0%
Net Internal Demand	10,483	10,588	1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,213	13,183	-0.2%
Tier 1 Planned Capacity	2,605	533	-79.5%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	15,817	13,717	-13.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	15,817	13,717	-13.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	50.9%	29.6%	-21.3
Prospective Reserve Margin	50.9%	29.6%	-21.3
Reference Margin Level	19.0%	20.0%	1.0

WECC-CA			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	36,441	36,281	-0.4%
Demand Response: Available	743	666	-10.4%
Net Internal Demand	35,698	35,615	-0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,380	57,923	4.6%
Tier 1 Planned Capacity	4,757	6,997	47.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	60,138	64,920	8.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	60,138	65,920	8.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	68.5%	82.3%	13.8
Prospective Reserve Margin	68.5%	82.3%	13.8
Reference Margin Level	12.5%	12.5%	0.0

WECC-BC			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,966	11,936	-0.3%
Demand Response: Available	0	0	0.0%
Net Internal Demand	11,966	11,936	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,870	14,389	3.7%
Tier 1 Planned Capacity	433	637	47.0%
Net Firm Capacity Transfers	164	0	-100.0%
Anticipated Resources	14,467	15,026	3.9%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	14,467	15,026	3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.9%	25.9%	5.0
Prospective Reserve Margin	20.9%	25.9%	5.0
Reference Margin Level	12.8%	11.4%	-1.5

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	1,983	1,977	-0.3%
Demand Response: Available	0	0	0%
Net Internal Demand	1,983	1,977	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,733	3,619	-3.0%
Tier 1 Planned Capacity	52	0	-100.0%
Net Firm Capacity Transfers	0	0	0%!
Anticipated Resources	3,784	3,619	-4.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	3,784	3,619	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	90.8%	83.1%	-7.8
Prospective Reserve Margin	90.8%	83.1%	-7.8
Reference Margin Level	12.5%	12.5%	0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	30,748	33,604	9.3%
Demand Response: Available	30	30	0.0%
Net Internal Demand	30,718	33,574	9.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,729	34,671	-10.5%
Tier 1 Planned Capacity	463	3,152	581.5%
Net Firm Capacity Transfers	0	6,136	100%!
Anticipated Resources	39,192	43,959	12.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	39,192	43,959	12.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	30.9%	3.3
Prospective Reserve Margin	27.6%	30.9%	3.3
Reference Margin Level	17.2%	17.2%	0.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,481	11,501	9.7%
Demand Response: Available	282	285	1.1%
Net Internal Demand	10,199	11,216	10.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	18,356	17,768	-3.2%
Tier 1 Planned Capacity	199	366	84.3%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	18,555	18,134	-2.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	18,555	18,134	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	81.9%	61.7%	-20.3
Prospective Reserve Margin	81.9%	61.7%	-20.3
Reference Margin Level	19.0%	18.2%	-0.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,844	21,147	1.5%
Demand Response: Available	340	177	-47.9%
Net Internal Demand	20,504	20,970	2.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,991	40,135	2.9%
Tier 1 Planned Capacity	3,381	2,733	-19.2%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	42,372	42,868	1.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	42,372	42,868	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	106.6%	104.4%	-2.2
Prospective Reserve Margin	106.6%	104.4%	-2.2
Reference Margin Level	16.0%	16.0%	0.0

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity and may vary widely year to year based on the identified risk hour. In many areas, winter demand peaks in the early morning hours or early evening resulting in little or no electrical resource output from solar PV resources and wide variability in wind availability. The following table shows the capacity contribution of existing wind and solar PV resources at the identified risk hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS.

BPS Variable Energy Resources On-Peak Capacity Contributions by Assessment Area

	Wind			Solar			Run of River Hydro		
Assessment Area/Interconnection (* - includes all hydro)	Nameplate Wind (MW)	Expected Wind (MW)	Expected Share of Nameplate (%)	Nameplate Solar PV (MW)	Expected Solar (MW)	Expected Share of Nameplate (%)	Nameplate Hydro (MW)	Expected Hydro (MW)	Expected Share of Nameplate (%)
MISO	30,247	8,772	29%	13,726	686	5%	2,351	1,404	60%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	202	0	0%
MRO-SaskPower	816	433	53%	30	0	13%	884	703	80%
MRO-SPP	35,714	7,198	20%	1,197	457	38%	114	72	63%
NPCC-Maritimes	1,635	241	15%	155	10	6%	1,357	1,283	95%
NPCC-New England	2,675	455	17%	3,620	0	0%	3,742	1,453	39%
NPCC-New York	2,586	737	29%	627	0	0%	974	596	61%
NPCC-Ontario	4,943	1,971	40%	478	0	0%	0	0	0%
NPCC-Québec	4,024	1,426	35%	10	0	0%	445	445	100%
PJM*	13,318	5,463	41%	15,732	1	0%	8,134	7,900	97%
SERC-Central	1,324	370	28%	1,576	455	29%	4,991	4,027	81%
SERC-East	0	0	0%	7,068	1,792	25%	3,010	2,951	98%
SERC-Florida Peninsula	0	0	0%	12,058	2,151	18%	0	0	0%
SERC-Southeast	0	0	0%	8,670	4,461	51%	3,258	3,258	100%
Texas RE-ERCOT	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC-AB*	5,712	1,919	34%	2,206	0	0%	894	285	32%
WECC-Basin*	5,932	1,148	19%	3,853	62	2%	2,667	1,473	55%
WECC-BC*	747	85	11%	17	0	0%	17,752	13,560	76%
WECC-CA*	9,382	682	7%	28,328	0	0%	15,740	4,572	29%
WECC-Mex	40	4	11%	350	0	0%	0	0	0%
WECC-NW*	14,744	1,319	9%	4,695	1,556	33%	32,915	18,502	56%
WECC-RM*	5,681	2,265	40%	3,521	0	0%	3,251	1,327	41%
WECC-SW*	4,303	1,182	27%	12,139	391	3%	3,117	948	30%
EASTERN INTERCONNECTION	93,517	25,692	27%	64,937	10,013	15%	29,017	23,647	81%
QUÉBEC INTERCONNECTION	4,024	1,426	35%	10	0	0%	445	445	100%
TEXAS INTERCONNECTION	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC INTERCONNECTION	46,541	8,605	19%	55,108	2,008	4%	76336	40667	53%
INTERCONNECTION TOTAL:	184,711	43,556	23%	155,664	12,685	8%	106,377	65,325	61%

Review of Winter 2024–2025 Capacity and Energy Performance

The meteorological winter across the contiguous United States had an average temperature of 34.1 degrees F—1.9 degrees above average—ranking in the warmest third of NOAA's historical record. Total winter precipitation in the US was 5.87 inches, 0.92 of an inch below average, ranking in the driest third of the December–February climate record.[17] Most of Canada experienced temperatures at least 2°C above the baseline average with the Maritime provinces, southern Ontario, and the Canadian west coast recording temperature departures nearer the baseline average while a small region in southern Saskatchewan recorded temperatures just slightly below the baseline average.[18]

In February 2025, FERC and NERC and its Regional Entities launched a joint review of the BPS' performance during the January 2025 arctic events, which comprised Winter Storms Blair, Cora, Demi, and Enzo.[19] The week of January 19–25, 2025 was the third coldest winter week (spanning Sunday through Saturday) across the United States since 2000. Between January 21 and 22, 2025, natural gas demand peaked at 150 Bcf/day, electric demand peaked at 683 GW, and unplanned outages peaked at 71,022 MW. Nevertheless, during the January 2025 arctic events, manual load shed was not required. The January 2025 arctic events had lower observed hourly wind chill temperatures in pockets of the Northeast, the Louisiana Gulf, California, and the Southwest compared to Winter Storms Uri, Elliott, Gerri, and Heather. During the January 2025 arctic events, the most extreme storm relative to typical weather was Winter Storm Enzo—a Gulf and Southern storm. On January 20, 2025, a burst of snow, sleet, and freezing rain developed across Texas and Louisiana late in the day. A mixture of sleet and freezing rain fell from Austin to San Antonio and to the southernmost point of Texas. By the early morning hours of January 21, 2025, for the first time in history, a blizzard warning was issued for southwest Louisiana and the southeastern-most point of Texas. Snow fell in Gulf cities in Texas, southern Mississippi, southern Alabama, and western Florida. On January 21, 2025, Baton Rouge recorded 7.6 inches of snowfall, making it the city's snowiest day since recordkeeping began in 1892, while New Orleans saw its snowiest day on record, with a total of 8.0 inches. Temperatures plunged to single digits in Louisiana. Temperatures in some parts of the state fell to levels not seen in more than 125 years.

The review team engaged with 10 electric entities across the Eastern and Texas Interconnections to gather the information necessary to provide a high-level overview of the BPS' performance during the cold weather events. Based on the data and interviews that the team reviewed, electric generators appear to have performed better during the January 2025 arctic events because of additional generator commitments, improved preparedness, increased situational awareness, and the implementation of lessons learned from previous extreme cold weather events and prior report recommendations. The natural gas system also performed better overall, serving record levels of natural gas demand and experiencing only minor production declines and short-duration force majeure events.

On October 1, 2025, NERC submitted to the Federal Energy Regulatory Commission its first *Cold Weather Data Annual Report*. This report includes a review of forced outage data from GADS for the winter 2024–2025 period indicating performance consistent with historical performance as reported in NERC's annual *State of Reliability* report. This is within the normal range of capacity that occurs across the fleet. During the Winter 2024–2025 period, the highest amount of capacity in a forced outage state for all reasons occurred on January 20, 2025, with 68,519 MW across all regions. The outages occurring over January 20, 2025, were analyzed as part of the joint FERC, NERC, and Regional Entity *2025 System Performance Review*. The joint FERC, NERC, and Regional Entity *2025 System Performance Review* found a reduction in peak coincident unplanned generator outages for the four 2025 winter storms reviewed compared to past winter storms; however, this review also noted that it was not an exact comparison due to prior winter storms having different characteristics.

Eastern Interconnection–Canada and Québec Interconnection

No EEAs were needed during the previous winter season. One entity plans to make a slight increase to the demand-response program based on last winter's operations.

[17] Despite Arctic air outbreaks, U.S. had warm, dry winter on average | National Oceanic and Atmospheric Administration
[18] Climate Trends and Variations Bulletin – Winter 2024/2025 - Canada.ca
[19] https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional

Eastern Interconnection–United States

Several entities indicated that generators performed better during the January 2025 arctic events than in previous winter storms. For example, TVA stated that generator performance within its footprint was stable, with minimal natural gas delivery issues. Southeastern RC detailed that no major fuel-related outages occurred. FRCC noted that generator performance was strong during this period. The significant characteristics of Winter Storm Enzo in the Southern and Gulf states were freezing precipitation and snow accumulation, especially in regions where those conditions rarely occur. In FRCC, only the northern portion of Florida experienced severe arctic weather including freezing precipitation and snowfall (record-setting, in some cities) that were abnormal for the region even though certain northern cities have faced cold temperatures in the past. In Florida, entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events. ISO-NE, NYISO, and PJM all generally described the January 2025 arctic events as having cold temperatures but overall weather conditions that were similar to a winter without a major storm.

MISO emerged from Winter 2024–2025 without turning to emergency procedures despite the wide-ranging winter storms from January 6 to 9 and again from January 20 to 22. Generators continue to prioritize scheduling planned or maintenance outages to the shoulder seasons of fall and spring to maximize unit availability for the winter season. Also, extreme cold weather outage adders were added to the LOLE model to make sure that winter storm risks are included in planning. In PJM, demand reached a new all-time winter peak on January 22, 2025, of 143,714 MW with sufficient reserves. PJM did call an EEA1 on January 22, 2025, however reserves remained adequate. PJM had less than 3% load forecast error over the peak days of the January cold weather events. Reliability cases were conducted, and units with extended start times were evaluated and started early to ensure units were on-line before extreme cold weather settled in. PJM had a 9.24% forced outage rate on the peak day, a relatively low forced outage rate for the weather experienced. There were also very few gas production problems; however, market issues prevented proper scheduling because of the four-day holiday weekend.

In SERC-Central, entities reported only limited impacts from Winter 2024–2025 coldest weather and made minor adjustments. One entity declared conservative operations ahead of peak conditions but experienced no emergencies. One entity raised its winter Planning Reserve Margin target to 26% following lessons learned from Winter Storm Elliott. Corrective actions were implemented due to isolated equipment issues, including improved heat trace capabilities and adding heat trace equipment to the cold weather critical component list. During the previous winter season, some SERC-Florida Peninsula entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Despite these challenges, entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events.

Texas Interconnection–ERCOT

There were no energy emergencies for the Texas RE-ERCOT region last winter and no conditions that prompted changes in operating procedures. Winter Storm Kingston, which occurred in February 2025, was the only storm where ERCOT utilized firm fuel supply service resources (FFSS), a firm-fuel product that provides additional grid reliability and resiliency during extreme cold weather and compensates generation resources that meet a higher resiliency standard. A maximum FFSS deployment of 470 MW occurred on February 19 between the hours 13:10 and 17:02. Two other storms, Enzo and Cora, impacted ERCOT in January 2025, but these storms did not cause any system reliability issues.

Western Interconnection

Between January 11 and 17, 2024, a prolonged Arctic outbreak impacted British Columbia, Alberta, and the U.S. Pacific Northwest, driving record electricity demand and widespread reliability challenges. Four U.S. Northwest BAs and one Canadian BA declared energy emergencies, underscoring two core vulnerabilities: Inadequate capacity during evening peak hours (4 to 8 p.m.) and Insufficient fuel supply (limited hydro availability) across multiple days.

Although temperatures were comparable to the December 2022 cold snap, WECC-Northwest peak demand rose two percentage points to 6% over then, with BC Hydro and AESO both setting new all-time records. The U.S. Northwest relied heavily on imports—averaging 4,745 MW during peaks and 5,241 MW across all hours, mostly from the Southwest and Rockies. California remained a net importer, providing little relief. Market prices in the Northwest reached or neared caps across most hours, indicating persistent scarcity rather than short-term peaks. Overall, the January 2024 event illustrated capacity alone does not ensure resilience. Sustained energy availability with interregional flexibility (both physical and market-based) will be key to maintaining reliability through the 2025–2026 and future winter seasons.

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
MISO	Jan. 21	18:00	108,888*	96,134 100,395	101,655	-977	18,468	16,761	0	519	17,010
MRO-Manitoba Hydro	Jan. 20	08:00	5,132	4,814 5,060	5,292	-277	142	52	N/A	0	146
MRO-SaskPower	Dec. 18	18:00	3,785	3,802 3,897	3,641	-231	664	368	0	3	0
MRO-SPP	Feb. 20	08:00	47,981	45,926 47,054	40,898	-1,424	4,886	4,783	255	36	9,272
NPCC-Maritimes	Jan. 22	07:00	5,810	5,907 6,498	4,266	-1,174	368	261	3	5	*
NPCC-New England	Jan. 21	18:00	19,607	20,308 21,814	17,686	-1,896	285	329	4	23	624
NPCC-New York	Jan. 22	19:00	23,521	22,998 24,023	18,932	-4,589	654	728	0	0	4,835

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
NPCC-Ontario	Jan. 22	18:00	21,940	20,951 22,179	24,250	2,990	3,693	1,914	0	0	*
NPCC-Québec	Jan. 22	08:00	37,178	36,061 39,545	39,514	-766	1,463	1,449	0	0	*
PJM	Jan. 22	09:00	144,420	130,712 144,939	152,142	7,731	3,704	3,620	3,076	1	8,663
SERC-C	Jan. 22	08:00	47,815	41,397 47,062	40,898	-6,921	563	176	214	455	1,538
SERC-E	Jan. 23	08:00	47,130	44,023 47,662	41,810	-5,323	0	0	145	2,526	1,830
SERC-FP	Jan. 25	08:00	43,974	45,714 54,239	41,702	-557	0	0	362	1,684	2,824
SERC-SE	Jan. 22	08:00	46,490	43,670 45,116	48,227	1,741	0	0	592	3,861	2,210

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
TRE-ERCOT	Feb. 20	08:00	80,560	73,193[5] 90,405[5]	79,960	-191	9,397	15,697	1,586	15	5,742
WECC-AB	Dec. 18	17:00	12,241	12,280 12,635	12,711	-470	3,175	1,867	4	0	*
WECC-BC	Feb 3	18:00	11,359	11,996 12,749	11,415	44	70	279	0	0	839
WECC-CA/MX	Dec. 12	15:00	35,555	35,359 36,823	31,925	-4,669	4,021	569	11,547	0	1,627
WECC-NW	Feb. 12	08:00	54,278	58,001 62,230	48,437	-920	2,607	7,876	1,494	2,198	3,281
WECC-SW	Feb. 13	16:00	22,969	16,177 17,777	25,087	2,117	2,741	1,065	1,599	182	1,496
Highlighting Notes:			Actual peak demand in the highlighted areas met or exceeded extreme scenario levels				Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
Table Notes: [1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities. [2] See NERC *2024–2025* WRA demand scenarios for each assessment area. Values are the normal winter peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand. [3] Expected values of wind and solar resources from the *2024–2025 WRA*. [4] Values from NERC Generator Availability Data System for the 2024–2025 winter hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024–2025 winter risk period scenarios in the *2024–2025 WRA*. [5] Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (5.4 GW for winter 2024-2025) to the demand scenarios found on p. 29 of the 2024-2025 WRA. *Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.										

Errata

December 2025

- Corrections made to the VER Table (page 50): Hydro values for WECC NW, Western Interconnection Total, and Total

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-21

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit LL: Division, *Technical Review Document for Operating Permit 96OPMF155* (Jan. 2005)

TECHNICAL REVIEW DOCUMENT
for
OPERATING PERMIT 96OPMF155

to be issued to:

Tri-State Generation & Transmission Association
Craig Station
Moffat County
Source ID 0810018

Cathy Rhodes
May, 2002
Revised January, 2005

I. PURPOSE:

This document will establish the basis for decisions made regarding the applicable requirements, emissions factors, monitoring plan and compliance status of emission units covered by the operating permit proposed for this site. It is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. This narrative is intended only as an adjunct for the reviewer and has no legal standing. The conclusions made in this report are based on information provided in the original application submittal of February 23, 1996 and the revised application submittal of January 4, 1999, and additional information received on October 21, 1999 and August 31, 2001.

Any revisions made to the underlying construction permits associated with this facility in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or an additional or revised Construction Permit.

II. SOURCE DESCRIPTION:

This facility is located in Craig, Moffat County, Colorado. The area is classified as an attainment area for all pollutants. Wyoming is an affected state within 50 miles of the facility. There are two Federal Class I areas within 100 kilometers of the facility: Mount Zirkel National Wilderness Area and Flattops National Wilderness Area. Dinosaur National Monument, although not a Class I area, is within 100 kilometers of the facility, and has been designated by the State to have the same sulfur dioxide increment as Federal Class I areas.

The entire plant is categorized as a major stationary source for the Prevention of Significant Deterioration (PSD) provisions. The EPA issued a PSD permit for Unit 3 on March 26,

1980. Future modifications at this facility resulting in a significant net emissions increase (see Colorado Regulation No. 3, Part A, Section I.B.37 and 58) for any pollutant listed in Colorado Regulation No. 3, Part A, Section I.B.58 or a modification which is major by itself may result in the application of the PSD review requirements.

The Craig Station consists of three coal fired steam driven electric generating units (Units 1, 2, and 3). Total net electric generating capacity is 1264 MW. Natural gas, propane and fuel oil are used as secondary fuels for flame stabilization, startup and shutdown. All three units are subject to the provisions of Title IV, the Acid Rain Program, of the Clean Air Act. Units 1 & 2 PM emissions were controlled by ESPs and wet limestone scrubbers control SO_2 emissions. Under a January 10, 2001 Consent Order, the ESPs have been replaced with baghouses and the wet scrubbers were upgraded. A baghouse controls PM emissions, and a spray dry scrubber controls SO_2 emissions from Unit 3. All three units have low-NO_x burners to control NO_x emissions. Overfire air and related NO_x control upgrades are now in place for Unit 1 and Unit 2. This permit currently only covers Units 1 and 2 and associated equipment. This permit does not currently cover Unit 3 or its associated equipment (except for coal handling, which may at times also serve Units 1 and 2). Associated activities covered by the permit include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area, as well as numerous insignificant activities.

Unit 3 is currently operating under the provisions of an EPA-issued PSD permit (issued on March 26, 1980, revised January 12, 1981, and August 14, 1992) and State-issued Construction permits 12MF322(1-4) and 98MF0141. The draft version of this permit that went to Public Comment on May 17, 2001 as well as the Proposed version of the permit that went to EPA on September 13, 2004 covered all three boilers. Prior to the Public Comment period, EPA, the Division, and Tri-State had discussions regarding the interpretation of several conditions of the EPA PSD permit. Following Public Comment, discussions continued on two issues: Range Z and the applicability of the BACT limits during periods of startup, shutdown, and malfunction (s/s/m). The root of the issues lies with imprecise and confusing language that was put into the PSD permit when it was issued some 25 years ago. Some of the issues were not resolved, and EPA sent a formal objection letter to the Division on October 22, 2004, citing the remaining unresolved issues. Under the provisions of Regulation No. 3, Part C, § VI.H, the Division has 90 days in which to submit a revised permit to EPA after a formal objection letter is received. During the 90 day period, Tri-State indicated that they were planning on submitting an application to the Division for a major PSD modification to Unit 3 sometime in April 2005. State statutes and Federal regulations provide for the Air Pollution Control Division ("APCD") to issue PSD permits for major modifications made after September 2, 1986. Section 25-7-210 C.R.S. states:

> Sections 25-7-201 and 25-7-203 to 25-7-206 shall apply only to applications for proposed new major stationary sources and major modifications which are submitted on or after the date of approval by the United States

environmental protection agency of the program for prevention of significant deterioration embodied in the state implementation plan.

Thus the March application will result in a new PSD Construction permit for Unit 3 and associated activities. The new permit will replace the existing PSD permit, and will address the provisions upon which the EPA's objection was based.

Since a new PSD permit will be issued in the near future, the Division and the EPA have agreed that the Division will at this time issue a revised Operating Permit which contains only the requirements for Units 1 and 2. The Unit 3 requirements will be added to this operating permit once the new PSD permit is issued. The EPA and the Division believe that this is the best and most expedient method to resolve the existing PSD permit concerns and the EPA objections regarding the initially proposed operating permit. The new PSD permit will be issued using the appropriate procedures in Regulation No. 3, including public notice and participation requirements. Under Regulation No. 3, Part C provisions, the applicant must apply for a modification to incorporate the new PSD permit requirements into their operating permit within twelve months of startup of the modified Unit 3. The revised Operating Permit will be issued using the Significant Modification procedures of Regulation No. 3, Part C, including public notice and participation requirements and EPA review.

The following Potential-to-Emit and actual 1997 emissions data are based on information supplied in the Title V application (rounded figures – includes all three units and all associated activities).

	POTENTIAL TO EMIT, TONS PER YEAR					
	PM	PM_{10}	SO_2	NO_X	VOC	CO
B001 - Unit 1	1891	435	22695	13239	60	498
B002 - Unit 2	1891	435	22695	13239	60	498
B003 - Unit 3	566	130	3770	9426	58	484
P101 - Coal Handling Units 1 & 2	41	18				
P102 - Coal Handling Unit 3	2	1				
P201 - Limestone Handling Units 1 & 2	14	3				
P202 - Lime Handling Unit 3	23	6				

P203 - Ash Handling Units 1 & 2	neg	Neg				
P204 - Ash Handling and Ash Haul Roads Unit 3	115	30				
P205 – Landfill	4	1				
P401 - Unit 1 CT	14	14			5	
P402 - Unit 2 CT	14	14			5	
P403 - Unit 3 CT	14	14			5	
Total	4588	1101	49160	35904	194	1479
FACILITY 1997 ACTUAL EMISSIONS TPY	772	250	10094	15750	133	1110

CT = Cooling Tower

III. EMISSION SOURCES

The following sources are specifically regulated under terms and conditions of the Operating Permit for this site:

B001 - Unit #1 - Babcock & Wilcox Boiler
B002 – Unit #2- Babcock & Wilcox Boiler

Applicable Requirements - Final Approval Construction Permit 10MF579 was issued for Units 1 and 2. Applicable requirements are as follows.

Construction Permit 10MF579

- This source is subject to the requirements of the New Source Performance Standards for Fossil Fuel Fired Steam Generators, as in effect May 1, 1973.

  Construction Permit 10MF579 indicates that the Units are subject to the NSPS as it existed on May 1, 1973. This is because the units were permitted when Subpart D was in the proposal process, and had not been finalized by the EPA. Subsequently, the EPA finalized the rule, and it applies to all sources constructed, reconstructed, or modified after August 17, 1971. The rule does not provide for any exceptions for sources constructed prior to final promulgation, therefore, Units 1

and 2 are subject to the most current version of Subpart D. This revision to the Construction Permit is incorporated directly into this operating permit through a combined Construction Permit/Operating Permit procedure. Note: The EPA did not promulgate startup, shutdown, and malfunction provisions until October 15, 1973.

- Emissions of sulfur dioxide shall not exceed 1.2 pounds per million Btu heat input, maximum 3 hour average.

- Visible emissions shall not exceed 20 percent opacity.

- Emissions of particulate matter shall not exceed 0.1 pounds per million Btu heat input, maximum 2 hour average. *On June 14, 1974, the EPA revised Subpart D to change the sampling time requirements for PM from a minimum of 2 hours to a minimum of 60 minutes per run, to make the provision consistent with 60.8(f). The sampling interval specified in 60.46 was shortened to be consistent with the 60-minute-per-run requirement. The preamble to this revision states that these actions are intended for clarification and for maintaining consistency throughout the regulations. They are not intended to alter the substantive content of the regulations. Thus, the 2 hour averaging time no longer applies to Units 1 and 2.*

- Emissions of nitrogen oxides shall not exceed 0.7 pounds per million Btu heat input, maximum 3 hour average.

- This source shall comply with all applicable monitoring, notification, and record keeping requirements of the New Source Performance Standards (Regulation 6) and Regulation 1. IV.

- This source is subject to the requirements of Regulation 6. Section I., including Section I.4 which states: At all times, including periods of start-up, shutdown, and malfunction, the facility and control equipment shall, to the extent practicable, be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

- A Revised Air Pollutant Emission Notice shall be filed when a significant change in emissions occurs, as required by Regulation No.3.II.B.

Colorado Regulation No. 1

- Except as provided in Section II.A.4, opacity shall not exceed 20% (Section II.A.1)
- Opacity shall not exceed 30%, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or cleaning of control equipment (Section II.A.4)
- Particulate emissions shall not exceed 0.1 lbs/mmBtu heat input (Section III. A.1.c)
- Continuous emission monitoring (Section IV)
- Continuous Opacity Monitor (COM) requirements (Section IV.B.1)
- Continuous Emission Monitor (CEM) for SO_2 or fuel sampling (Section IV.B.2)
- If CEM for SO_2 then CEM for either O_2 or CO_2 (Section IV.B.3)
- Calibration of CEMs (Section IV.F)
- Notification and Recordkeeping (Section IV.G)
- Recordkeeping duration (Section IV.H)
- Reporting requirements - if fuel sampling (Section IV.I)
- Sulfur dioxide emissions shall not exceed 1.2 lbs/mmBtu heat input (Section VI.A.3.a.(ii)), based on a 3 hour rolling average

Colorado Regulation No. 8, Part C

- Lead (Pb) emissions shall not be such that emissions result in an ambient lead concentration exceeding 1.5 μg/scm averaged over a one-month period (Reg 8, Part C) - This is a **State-only** requirement

NSPS Subpart D Requirements (40 CFR, Part 60, Subpart D as adopted by reference in Colorado Regulation No. 6, Part A)

- Emissions of Particulate Matter shall not exceed 0.1 lbs/mmBtu heat input
- Opacity shall not exceed 20%, except for one six-minute period of not more than 27% - does not apply during start-up, shutdown and malfunction
- SO_2 emissions shall not exceed 1.2 lbs/mmBtu heat input when burning coal, 3 hour average
- NO_X emissions shall not exceed 0.70 lbs/mmBtu heat input when burning coal, 3 hour average

- Source shall install, calibrate, maintain and operate continuous monitoring systems for measuring opacity, SO_2 and NO_X emissions and either O_2 or CO_2

PM, SO_2, and NO_x emission limits do not apply during startup, shutdown, or malfunction. (See October 15, 1973 Federal Register)

Acid Rain (Title IV) Requirements

- The Code of Federal Regulations lists 8153 (Unit 1) and 7785 (Unit 2) SO_2 allowances (as listed in 40 CFR 73.10(b)) for these sources. Note that additional allowances can be obtained as needed per 40 CFR Part 75. The units will be allocated 8153 and 7785 allowances per year from 2000 to 2009 (as listed in the EPA's "Allowances Held Report," January 4, 1999).
- NO_x emissions of 0.50 lbs/mmBtu heat input, on an annual average basis (source opted to comply with Phase I limits (§76.5(a)(2) by early election (§ 76.8), which went into effect January 1, 1997).
- Acid rain permitting requirements per 40 CFR Part 72.
- Continuous emission monitoring requirements per 40 CFR Part 75.
- The source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emissions (40 CFR Part 77).

January 10, 2001 Consent Decree Requirements

- Requires replacement of ESPs at Units 1 and 2 with baghouses, FGD upgrades, and installation of NO_x emission control upgrades by certain dates
- PM emissions from Units 1 and 2 shall not exceed 0.03 lb/mmBtu heat input by certain dates
- SO_2 emissions from Units 1 and 2 shall not exceed 0.160 lb/mmBtu heat input, on a 30 day rolling average and 0.130 lb/mmBtu heat input on a 90 day rolling average, by certain dates
- SO_2 emissions from Units 1 and 2 shall be controlled by either 86% on a 30 day rolling average, or 90% on a 90 day rolling average, by certain dates, unless a "showing" is made
- NO_x emissions from Units 1 and 2 shall not exceed 0.30 lb/mmBtu heat input on an annual average basis, by certain dates
- Limits opacity as follows: (1) 20% averaged over each separate 6-minute period at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, opacity shall not exceed 30% for more than 6 minutes in any 60 consecutive minutes; (2) 30% for more than 6 minutes during any 60 consecutive minutes during any startup; (3) 20% during any

shutdown, unless excused by an upset condition; (4) 20% except for one six minute period per hour of not more than 27% opacity as averaged over each separate 6-minute period with an hour, beginning each hour on the hour. Emissions during startup, shutdown and malfunction are excused under this opacity limit.

- Requires stack testing for PM
- Requires installation and operation of continuous opacity monitors and continuous monitors for SO_2 emissions, NO_x emissions, CO_2, and flow
- Requires permittee to operate Units 1 and 2 using good operating practices

Note: Since this permit went to public notice, the milestones for various Consent Decree requirements have passed. The permit is therefore revised to delete those due dates and obsolete requirements related to the ESPs.

Consent Decree Requirements as a Pollution Control Project

Typically, the Division does not consider the addition of a control device to be a modification for purposes of permitting. The installation of the baghouses and the FGD upgrades do not result in an increase in emissions. The NO_X emission control upgrades may decrease NO_X emissions substantially but increase CO emissions slightly. In the case of Craig Units 1 and 2, the addition of control equipment is required by the consent decree and qualifies as an environmentally beneficial pollution control project. No additional permitting or testing requirements were included in the consent decree for the potential increase in CO emissions from the low NOx emission control upgrades. Therefore, the Division does not believe it is appropriate to include any other permitting requirements or emission limitations for a possible increase of CO emissions due to the NO_X emission control upgrades.

Effect of Incorporation of Consent Decree into the Operating Permit

The Consent Decree requirements were approved by the EPA as part of the Colorado State implementation Plan and are applicable requirements which must be included in the operating permit. Under terms of the Consent Decree, upon issuance of this operating permit, the Division assumes certain compliance/enforcement provisions of the Decree. As for any applicable requirement incorporated into an operating permit, nothing in the permit is intended to have the effect of relaxing any requirement in the Consent Decree or to change or modify any rights of the parties to that decree.

Voluntary Emission Reduction Agreement (VERA)

In 2001, a VERA was completed for Units 1 and 2, to reduce emissions which affect visibility and air quality related values. VERA's normally include specific emission limits and related requirements, and are included as applicable requirements in operating permits. In this case, the VERA states that the Division finds and determines that the provisions of the Consent Decree meet the requirements for a VERA for Units 1 and 2. Therfore, this VERA

is not incorporated into the operating permit, since the Consent Decree requirements are incorporated.

Emission Factors - The combustion of coal in the boilers results in emissions of NO_x, SO_2, PM, PM_{10}, CO, VOC, and Pb. CEMs are used to determine compliance with emission standards and to estimate annual emissions of NO_x, and SO_2. For PM and PM_{10}, stack test results and monitored heat content of the fuel are used to determine compliance and estimate annual emissions. Standard factors from the AP-42 manual, or other emission factors/procedures acceptable to the Division (see Regulation No. 3, Part A, II.B.1 for acceptable alternative methods) along with appropriate removal efficiencies for control equipment, are used to estimate CO, VOC, HAP and Pb emissions.

Monitoring Plan - CEMs are used to demonstrate compliance with the NO_x and SO_2 lb/mmBtu limits. Stack testing and a baghouse and wet scrubber maintenance plan are used to demonstrate compliance with the PM limits. The required frequency for PM stack testing will be reduced, if the source meets criteria based on the test results in relation to the emission standard, as set forth in the permit. The heat content of the fuel is needed for these determinations. The heat input can be calculated from the carbon dioxide CEM required under the Acid Rain Program, or measured through a coal sampling plan, or vendor information.

Compliance with opacity limits is demonstrated using a COM.

Scales are used to measure the amount of coal combusted in the boiler. These data are used to estimate PM, PM_{10}, CO, VOC, and HAP emissions.

The permittee performed a one-time modeling exercise which demonstrated compliance with the Regulation No. 8 lead requirements.

Compliance Status - The Division accepts these Units were in compliance at the time the Title V application was submitted. In addition, the most recent inspection report indicates the Units were in compliance at the time of inspection.

B001 - Unit #1 - Babcock & Wilcox Boiler - Natural Gas, Propane, and Fuel Oil
B002 - Unit #2 - Babcock & Wilcox Boiler - Natural Gas, Propane, and Fuel Oil

Coal is the primary fuel for these boilers. Secondary fuels (natural gas, propane, or fuel oil) are used during non-routine periods such as startup and shutdown, adding to or removing coal pulverizers from service, or other flame stability efforts.

Applicable Requirements - The Construction Permit did not address secondary fuels. The NSPS, Subpart D sets forth emission limits when fuels are combined for combustion. The

permittee submitted information which indicates that, for the past five years, “alternative” fuel use has comprised less than 1% of total heat input. By calculation, the Subpart D emission limits for this amount of natural gas, propane or fuel oil remain essentially unchanged from the coal emission limit. The Division therefore assumes the source is in compliance with Subpart D emission limits whenever alternate fuel use comprises less than 5% of total heat input. If alternate fuel use comprises more than 5% of total heat input on an annual basis, the permit must be reopened to include Subpart D requirements for combined fuel combustion. In addition, this source is subject to Regulation No. 1 emission limits, which are equal to or less stringent than Subpart D provisions. The Division therefore also assumes the source is in compliance with Regulation No. 1 requirements whenever alternate fuel use comprises less than 1% of total heat input.

Alternate Operating Scenarios

The permittee requested the ability to dispose of spent boiler tube cleaning waste as an alternate operating scenario. Circulation of water through the boiler tubes results in an accumulation of mineral deposits over time. The mineral deposition decreases the efficiency of the heat transfer from the boiler tube to the circulating water. Periodically, the tubes are cleaned to recover the heat transfer efficiency. The cleaning is accomplished by circulating cleaning solutions, generally acid and detergent mixtures, through the tubing. Commonly, the accumulated spent materials are slowly injected into an operating boiler for disposal. The permittee had previously requested to dispose of cleaning waste in the boiler, in March of 1993. At that time the Division agreed to the proposal, and determined a modification to the Construction Permit was not necessary. The permittee provided information regarding studies performed by the Electric Power Research Institute which indicates that disposal of cleaning wastes does not have a significant effect on operations or emissions. This has been an on-going practice for boilers operated by utilities, and has not been cited by the Division as a compliance issue.

In addition, the permittee indicates that on a sporadic basis, they wish to combust non-hazardous petroleum contaminated soils and materials in the boiler. These materials are generated on occasions at the Craig Station when accidental spills of petroleum liquids (lube oils and fuel) occur. Because of the expected small quantity of non-hazardous petroleum contaminated soils and materials generated, it is expected that introduction of such materials into the boiler for combustion will not cause the exceedance of any applicable emission limit or emission of pollutants not generated by routine operation of these boilers.

Provisions for these two alternate operating scenarios are provided for in the Operating Permit.

P101 – Coal Handling – Units 1 & 2

The Unit 1 and 2 coal handling system transfers coal delivered by trucks on unpaved haul roads to Craig Station to the Unit 1, 2, and 3 coal storage piles and silos. On occasion, coal is deposited in a coal surge pile prior to being transferred to the crusher. The coal is

crushed and conveyed to the coal transfer building, where it is sent either to the stockpiles or coal silos. Coal destined for the storage pile is conveyed to the stackout tower and then to telescoping chutes for loadout to the storage pile. Coal is reclaimed underground from storage and is transferred to generation building coal silos. Bagfilters and enclosed conveyors control PM emissions from all sources except coal delivery unloading, the coal pile stackout and the storage piles. Telescopic chutes are used to control PM emissions from the coal pile stackout. Coal unloading and stackout is controlled with water spray containing a surfactant, on an as-needed basis. Note that water sprays may not be operable during cold weather. The coal haul road is treated with a resinous adhesive, or equivalent, as often as necessary.

Applicable Requirements - Final Construction Permit 11MF276 was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF276

- Limits process throughput to 3,900,000 tons per year
- Limits opacity to 20%
- Sets forth measures for minimizing fugitive particulate matter emissions

  Requested revisions:

  "The coal being loaded to live storage will be sprayed with water with a surfactant added," is revised to read: "The coal being loaded to live storage will be sprayed with water with a surfactant added, on an as-needed basis." This is consistent with other Tri-State construction permits.

  "The haul road used by coal trucks on the Craig Station property shall be treated with a resinous adhesive (or equivalent) to control dust. The treatment material shall be bladed into the soil according to the manufacturer's specification and shall be reapplied as often as necessary to remain viable as a control measure." Is revised to read: "The haul road used by coal trucks on the Craig Station property shall be treated with magnesium chloride (or equivalent) to control dust. The treatment material shall be applied according to the manufacturer's specification and shall be reapplied as often as necessary to remain viable as a control measure."

  The requirement for water spray bars at the unloading station is revised to indicate that the spray bars will be used *as needed*.

Regulation No.1.II.A.1 & 4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes

(Note: These limits do not apply to fugitive particulate emissions (Colorado Regulation No. 1, II.8(iii)) - Colorado Regulation No. 3 defines "fugitive emissions" as "those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening." The Division has determined that the emissions from the coal pile stackout telescopic chute are fugitive.) Other fugitive sources include the storage piles, unloading to the grizzly, unloading to the coal surge pile, and the haul road.

40 CFR Part 60 Subpart Y, NSPS for Coal Preparation Plants

- Opacity not to meet or exceed 20% for all sources except the storage piles, unloading to coal surge pile, coal pile stackout and coal stackout building, coal reclaim A & B, coal tripper deck and silos, common coal drive house, and haul roads - Not applicable during startup, shutdown, or malfunction

Emission Factors - AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM_{10} emissions.

Monitoring Plan - As-fired and as-received belt scales continuously weigh the coal as it moves from the truck unloading hoppers to the units or stockpile, and from the stockpile to the coal silos. These monitoring records can be used to identify compliance with the coal handling limits. The emissions are calculated based on the amount of coal being processed.

For those sources subject to an opacity standard, a U.S. EPA Reference Method 9 opacity observation is performed by a certified observer at least semi-annually. An operation and maintenance plan shall be implemented for the baghouses.

A quarterly inspection is performed to ensure PM Emission Control Plan measures are in place.

Compliance Status - The Division accepts this process was in compliance at the time the Title V application was submitted.

P102 – Coal Handling – Unit 3

The Unit 3 coal handling system transfers coal delivered by rail car to the Unit 1,2, and 3 coal piles and silos. Coal drops from the railcars into underground hoppers and is conveyed to the crusher building. After crushing, coal is conveyed to the stackout building, where it is either sent to the stockpile or to the transfer building. Coal in the transfer building is conveyed to the coal silos in the generation building. Bagfilters control PM emissions from all sources except coal delivery unloading, the coal pile stackout and the storage piles.

Telescopic chutes are used to control PM emissions from the coal pile stackout. Water is sprayed at the coal train unloading to control PM emissions. Note that water sprays may not be operable during cold weather. Water, compaction or chemicals are used, as necessary, to control PM emissions at the coal storage piles. Since the Unit 3 system handles coal which may be delivered to Units 1 and 2, the system is included in the Operating Permit at this time.

Applicable Requirements - Final Construction Permit 12MF322(2) was issued for these sources. Applicable requirements are as follows.

Construction Permit 12MF322(2)

- Limits opacity to 20%
- Sets forth measures for minimizing fugitive PM emissions
- Requires emissions from crushing, transferring, and coal reclaiming to be controlled by fabric filter baghouses

Colorado Regulation No.1.II.A.1&4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes *(Note: These limits do not apply to fugitive particulate emissions (Colorado Regulation No. 1, II.8(iii)) - Colorado Regulation No. 3 defines "fugitive emissions" as "those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening." Fugitive sources include coal train unloading, coal stackout, and storage piles.)*

40 CFR Part 60 Subpart Y, NSPS for Coal Preparation Plants

- Opacity not to meet or exceed 20% - Not applicable during startup, shutdown, or malfunction - Does not apply to coal stackout, common coal transfer building extension, common coal drive house, coal tripper deck and silos, to the storage pile, or to the open coal storage pile

Other

The Construction Permit does not contain a specific processing limit, however, records of the amount of coal processed are necessary for estimating emissions.

Emission Factors - AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM_{10} emissions.

Monitoring Plan - As-fired and as-received belt scales continuously weigh the coal as it moves from the rail cars unloading hoppers to the Units or stockpile, and from the stockpile to the coal silos. The emissions are calculated based on the amount of coal being processed. A U.S. EPA Reference Method 9 opacity observation is performed by a certified observer every six months and a baghouse operating and maintenance plan is required.

A quarterly inspection is performed to ensure PM Emission Control Plan measures are in place.

Compliance Status - The Division accepts the process was in compliance at the time the Title V application was submitted.

P201 – Limestone Handling and Storage Facility – Units 1 & 2

The Unit 1 & 2 limestone handling system provides for receiving, transferring, storage, and preparation of limestone before it is introduced to the Units 1 & 2 wet limestone scrubbers. Limestone is delivered by trucks, and unloaded to a receiving hopper. Limestone is then transferred to the silos. Bagfilters are used to control PM emissions at the silo and unloading.

Applicable Requirements - Final Construction Permit 11MF415 was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF415

- Limits opacity to 20%
- Requires unloading facilities emissions to be controlled by baghouse

Construction Permit requirement is revised from: “All process equipment shall be maintained and operated so that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system.” To: “All process equipment shall be maintained and operated so as to minimize leakage of air contaminents to the atmosphere prior to their treatment in the pollution control system.”

Colorado Regulation No. 1, II.A.1 & 4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes

Does not apply to fugitive emission sources: limestone hauling.

Other

The Construction Permit does not specifically limit the amount of limestone delivered, however, the amount is needed to calculate emissions estimates

Emission Factors - AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM_{10} emissions

Monitoring Plan -Semi-annual U.S. EPA Reference Method 9 opacity observations will be performed on the baghouses and a baghouse operation and maintenance plan is required.

Compliance Status - The Division accepts the units were in compliance at the time the Title V application was submitted.

P203 – Ash Handling System – Units 1 & 2

The Unit 1 and 2 ash handling and processing system provides for transferring ash from the boilers and ESPs to ash silos for temporary storage before it is transported for off-site disposal or commercial sale. The Unit 1 and 2 boilers generate both bottom ash and fly ash. The bottom ash handling system transfers all materials using water, thus there are no particulate emission sources associated with bottom ash handling. Fly ash is pneumatically transported to the silos. Bagfilters are used to control PM emissions for the silos and the dry ash unloading for commercial sale. Water and dustless unloaders are used to control PM for truck loading operations for ash disposal.

Applicable Requirements - Final Construction Permit 11MF332 was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF332

- Limits opacity to 20%
- Requires bagfilter control of ash silos
- Sets forth measures for minimizing fugitive dust emissions

Construction Permit requirement is revised from: “All process equipment shall be maintained and operated so that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system.” To: “All process equipment shall be maintained and operated so as to minimize leakage of air contaminents to the atmosphere prior to their treatment in the pollution control system.”

Colorado Regulation No. 1, II.A.1&4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control

equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes
Does not apply to fugitive emission sources: truck loading for disposal

Other

The Construction Permit does not specifically limit the amount of ash processed, however, the amount is needed to calculate emissions estimates.

Emission Factors - Standard AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM_{10} emissions.

Monitoring Plan - For those sources subject to an opacity standard, semi-annual U.S. EPA Reference Method 9 opacity observations will be performed and a baghouse operation and maintenance plan is required. The dry ash unloader on silo A dischargers directly into silo A. Therefore, there is not a separate source of emissions. The dry ash unloading on silo B discharges to a bagfilter which discharges inside the silo B building adjacent to a piperack, therefore, a Method 9 reading is not required, and absent credible evidence to the contrary, the Division assumes the opacity standard is being met. The word “credible” as it is used in the term “credible evidence” shall be applied under the provisions of the permit as defined by Colorado and Federal Rules of Evidence. Quarterly inspections will be performed to ensure the bagfilters and PM emission minimization measures are in place.

Compliance Status - The Division accepts the process was in compliance at the time the Title V application was submitted.

P204 – Ash Handling System and Ash Haul Road Ash Haul Road for Units 1, 2 and 3 (Ash and Scrubber Sludge Hauling)

The Unit 3 ash handling and processing system provides for transferring of ash from the Unit 3 boiler, baghouse hoppers, and ash collection locations in the scrubber building to an ash silo or the recycle ash tank for temporary storage before it is transported offsite for disposal or commercial sale. The boiler generates both bottom ash and fly ash. The bottom ash handling system transfers all materials using water, thus there are no particulate emission sources associated with bottom ash handling. Flyash is pneumatically conveyed to the silo. Baghouses control PM emissions for the silo, day tank and dry ash unloading for commercial sale. Water and dustless unloaders control PM for the ash unloading operations for disposal. Magnesium chloride is applied to the unpaved portion of the ash haul road, as necessary, to control PM emissions.

Applicable Requirements - Final Construction Permit 12MF322(3) was issued for these activities. Applicable requirements are as follows.

Construction Permit 12MF322(3)

- Limits opacity to 20%

- Sets forth measures for minimizing fugitive dust emissions
  (*Note: Construction Permit Condition 3. States "Ash deposited in trucks for transport to disposal areas shall be sufficiently wet to maintain a moisture content greater than 12% and/or a control of visible emissions equal to that of an enclosed cargo box originally permitted." The Division believes requiring a specific moisture content is not practical. In addition, it is not practical to attempt to compare current visible emissions to the now removed cargo box. This condition is therefore revised as follows: "Ash deposited in trucks for transport to disposal areas shall be sufficiently moist to minimize fugitive emissions." This is consistent with minimization measures set forth in the Construction Permit 11MF332 for Units 1 & 2 ash handling.*

PSD Permit

- Requires magnesium chloride to be used on the ash haul road according to manufacturer's specifications

Colorado Regulation No. 1, II.A.1 & 4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes
  Not applicable to fugitive emission sources: truck loading for disposal and haul roads.

Other

The Construction Permit does not specifically limit the amount of ash processed, however, the amount is needed to calculate emissions estimates.

Emission Factors - Standard AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM_{10} emissions

Monitoring Plan - For those sources subject to an opacity standard, semi-annual U.S. EPA Reference Method 9 opacity observations will be performed and a baghouse operation and maintenance plan is required. The dry ash unloading baghouse is located inside a building, therefore a Method 9 reading is not required, and absent credible evidence to the contrary, the Division assumes the opacity standard is being met. A quarterly inspection will be performed to ensure the bagfilters and PM emission minimization measures are in place.

Compliance Status - The Division accepts the process was in compliance at the time the Title V application was submitted.

P205 – Staging/Landfilling

Wet and dry waste products are hauled to the staging/landfilling area, where they are unloaded. The staged wastes are then subsequently loaded in a truck for final disposal at Trapper Mine. The staging/landfilling activities are considered to have negligible emissions.

Applicable Requirements - Final Construction Permit 11MF994(F) was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF994(F)

- Sets forth a Particulate Emissions Control Plan
  (Note: The Construction Permit indicates that Mining activities are subject to the 20% opacity guideline, under Regulation No. 1. This activity is not "mining," but consists of construction (land clearing and leveling) and storage and handling of materials, which are also subject to the 20% opacity guideline. The permit language is revised to delete the reference to mining activities. The 20% is a guideline, as stated in Regulation No. 1 and its Statement of Basis and Purpose. The regulation shifted the use of opacity observations from an enforceable standard for area sources to a guideline in determining when the adequacy of applied control methods should be reviewed. U.S. EPA Method 9 readings are not required for these sources.)

Other

The Construction Permit does not specifically limit the amount of waste processed, however, the amount is needed to calculate emissions estimates.

Emission Factors - Standard AP-42 equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM_{10} emissions.

Monitoring Plan - A quarterly inspection will be performed to ensure PM emission minimization measures are in place.

Compliance Status - The Division accepts the process was in compliance at the time the Title V application was submitted.

P206 - Soda Ash Addition System

This system was for addition of soda ash to coal for Boiler Units #1 and #2. Due to the Consent Decree changes to the scrubber system, the soda ash addition system has been dismantled and is not longer included in this operating permit.

P401 – Unit 1 Cooling Tower
P402 – Unit 2 Cooling Tower

The cooling towers are used to dissipate waste heat from the boilers circulating water system. Pollutants expected to be emitted include PM and small quantities of chloroform produced by the introduction of chlorine in the recirculating cooling tower water to control biological growth. The cooling towers were not permitted at the time of the initial Operating Permit application submittal. The application documents for a construction permit were submitted and Initial construction permits were subsequently issued.

Applicable Requirements - Initial Construction Permits 98MF0141 and 96MF195 were issued for these sources. The source has demonstrated compliance under the provisions of Regulation No. 3, Part B, Section IV.H for initial approval construction permit 98MF0141 but not yet received a final approval construction permit. Under the provisions of Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect. The appropriate provisions of the initial approval construction permit have been directly incorporated into this operating permit.

Construction Permits 98MF0141 and 96MF195

- Limit the design and maximum circulating water rates.
- Limit the total dissolved solids content of the water.
- Limit the drift loss and set forth schedules for retrofitting drift eliminators (at the time of Construction Permit issuance, the cooling towers equipped with older style drift eliminators. New, more efficient drift eliminators are considered to represent “BACT” for cooling towers, and the schedule was developed to implement the new style drift eliminators.) The Construction Permits require progress reports by March 31 of the following year. The Operating Permit requires reports by April 30, to be consistent with APEN reporting requirements. (*Note: Construction of the new drift eliminators is completed, therefore the schedule is not included in this operating permit.*)
- Limits PM, PM_{10}, and VOC emissions

Colorado Regulation No. 1, II.A.1&4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes

Emission Factors - PM emissions are estimated using EPA factors. VOC emissions are estimated using factors from a report by Michelletti. A copy of the report is included in the Operating Permit application.

Monitoring Plan - Measurements of TDS will be made and recorded monthly.

Compliance Status - The applicant has submitted the documents needed to obtain a construction permit and permits were issued. The Division accepts the cooling towers are now in compliance.

Miscellaneous

Emission Factors - From time to time published emission factors and/or other emission estimating methods are changed based on new or improved data. A logical concern is what happens if the use of the new factors/methods in a calculation results in a source being out of compliance with a permit limit. For this operating permit, the emission factors, equations, and/or other emission estimating methods included in the permit are considered to be fixed until changed by the permit. Obviously, emission factors dependent on the fuel sulfur content or heat content of the fuel can not be fixed and will vary with the test results. The method for determining the emissions is, however, fixed. It is the responsibility of the permittee to be aware of changes in the factors, etc. and to notify the Division in writing of impacts on the permit requirements when there is a change. Upon notification, the Division will work with the permittee to address the situation. In addition, the Division will review the factors, etc. as appropriate during permit modifications and renewals.

APEN Reporting for Insignificant Activities - Some sources permitted under the issued Construction Permits are insignificant sources because the uncontrolled actual emissions for recent years are below APEN de minimis levels. (Note: Those sources with emissions below de minimis levels, but which are subject to an NSPS requirement are still subject to APEN reporting requirements.) These sources are listed in the Operating Permit as permitted sources, in the event emissions should increase above the de minimis level in the future.

Accidental Release Program – 112(r)

Section 112(r) of the Clean Air Act mandates a new federal focus on the prevention of chemical accidents. Sources subject to these provisions must develop and implement risk management programs that include hazard assessment, a prevention program, and an emergency response program. They must prepare and implement a Risk Management Plant (RMP) as specified in the Rule.

Based on the information provided by the applicant, this facility is subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act).

Compliance Assurance Monitoring (CAM)

The following emission points at this facility use a control device to achieve compliance with an emission limitation or standard to which they are subject and have pre-controlled emissions that exceed or are equivalent to the major source threshold. They are therefore subject to the provisions of the CAM program as set foth in 40 CFR Part 64 as adopted by reference into Colorado Regulation No. 3, Part C, Section XIV:

None.

(The Title V application was deemed administratively complete prior to April 20, 1998.)

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-21

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit M: Department, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (July 2025)

U.S. DEPARTMENT of ENERGY



Resource Adequacy Report

Evaluating the Reliability and Security of the United States Electric Grid

July 2025

Acknowledgments

This report and associated analysis were prepared for DOE purposes to evaluate both the current state of resource adequacy as well as future pressures resulting from the combination of announced retirements and large load growth.

It was developed in collaboration with and with assistance from the Pacific Northwest National Laboratory (PNNL) and National Renewable Energy Laboratory (NREL). We thank the North American Electric Reliability Corporation (NERC) for providing data used in this study, the Telos Corporation for their assistance in interpreting this data, and the U.S Energy Information Administration (EIA) for their dissemination of historical datasets. In addition, thank you to NREL for providing synthetic weather data created by Evolved Energy Research for the Regional Energy Deployment System (ReEDS) model.

DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience.

Historically, the nation's power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued. Thus, one of the key takeaways from this study process is the underscored "call to action" for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security.

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List of Acronyms

AI	Artificial Intelligence
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EO	Executive Order
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITCS	Interregional Transfer Capability Study
LBNL	Lawrence Berkeley National Laboratory
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LTRA	Long-Term Reliability Assessment
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PNNL	Pacific Northwest National Laboratory
ReEDS	Regional Energy Deployment System
RTO	Regional Transmission Organization
SERC	SERC Reliability Corporation
TPR	Transmission Planning Region
USE	Unserved Energy

Background to this Report

On April 8, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid." EO 14262 builds on EO 14156, "Declaring a National Emergency (Jan. 20, 2025)," which declared that the previous administration had driven the Nation into a national energy emergency where a precariously inadequate and intermittent energy supply and increasingly unreliable grid require swift action. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation's electrical grid.

EO 14262 mandates the development of a uniform methodology for analyzing current and anticipated reserve margins across regions of the bulk power system regulated by the Federal Energy Regulatory Commission (FERC). Among other things, EO 14262 requires that such methodology accredit generation resources based on the historical performance of each generation resource type. This report serves as DOE's response to Section 3(b) of EO 14262 by delivering the required uniform methodology to identify at-risk region(s) and guide reliability interventions. The methodology described herein and any analysis it produces will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.

Executive Summary

Our Nation possesses abundant energy resources and capabilities such as oil and gas, coal, and nuclear. The current administration has made great strides—such as deregulation, permitting reform, and other measures—to enable addition of more energy infrastructure crucial to the utilization of these resources. However, even with these foundational strengths, the accelerated retirement of existing generation capacity and the insufficient pace of firm, dispatchable generation additions (partly due to a recent focus on intermittent rather than dispatchable sources of energy) undermine this energy outlook.

Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation. A failure to power the data centers needed to win the AI arms race or to build the grid infrastructure that ensures our energy independence could result in adversary nations shaping digital norms and controlling digital infrastructure, thereby jeopardizing U.S. economic and national security.

Despite current advancements in the U.S. energy mix, this analysis underscores the urgent necessity of robust and rapid reforms. Such reforms are crucial to powering enough data centers while safeguarding grid reliability and a low cost of living for all Americans.

Key Takeaways

- **Status Quo is Unsustainable**. The status quo of more generation retirements and less dependable replacement generation is neither consistent with winning the AI race and ensuring affordable energy for all Americans, nor with continued grid reliability (ensuring "resource adequacy"). Absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens.
- **Grid Growth Must Match Pace of AI Innovation**. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. The situation necessitates a radical change to unleash the transformative potential of innovation.
- **Retirements Plus Load Growth Increase Risk of Power Outages by 100x in 2030**. The retirement of firm power capacity is exacerbating the resource adequacy problem. 104 GW of firm capacity are set for retirement by 2030. This capacity is not being replaced on a one-to-one basis and losing this generation could lead to significant outages when weather conditions do not accommodate wind and solar generation. In the "plant closures" scenario of this analysis, annual loss of load hours (LOLH) increased by a factor of a hundred.
- **Planned Supply Falls Short, Reliability is at Risk**. The 104 GW of retirements are projected to be replaced by 209 GW of new generation by 2030; however, only 22 GW would come from firm baseload generation sources. Even assuming no retirements, the model found increased risk of outages in 2030 by a factor of 34.

- **Old Tools Won't Solve New Problems.** Antiquated approaches to evaluating resource adequacy do not sufficiently account for the realities of planning and operating modern power grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages; move beyond exclusively analyzing peak load time periods; and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

This report clearly demonstrates the need for rapid and robust reform to address resource adequacy issues across the Nation. Inadequate resource adequacy will hinder the development of new manufacturing in America, slow the re-industrialization of the U.S. economy, drive up the cost of living for all Americans, and eliminate the potential to sustain enough data centers to win the AI arms race.

Developing a Uniform Methodology

DOE's resource adequacy methodology assesses the U.S. electric grid's ability to meet future demand through 2030. It provides a forward-looking snapshot of resource adequacy that is tied to electricity supply and new load growth, systematically exploring a range of dimensions that can be compared across regions. As detailed in the methodology section of this report, the model is derived from the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (ITCS) which leverages time-correlated generation and outages based on actual historic data.[1] A deterministic approach[2] simulates system stress in all hours of the year and incorporates varied grid conditions and operating scenarios based on historical events:

- **Demand for Electricity – Assumed Load Growth:** The methodology accounts for the significant impact of data centers, particularly those supporting AI workloads, on electricity demand. Various organizations' projections for incremental data center electricity use by 2030 range widely (35 GW to 108 GW). DOE adopted a national midpoint assumption of 50 GW by 2030, aligning with central projections from Electric Power Research Institute (EPRI)[3] and Lawrence Berkeley National Laboratory (LBNL).[4] This 50 GW was allocated regionally using state-level growth ratios from S&P's forecast,[5] reflecting infrastructure characteristics, siting trends, and market activity; and, mapped to NERC Transmission Planning Regions (TPRs).

1. This model differs from traditional peak hour reliability assessments in that it explicitly simulates grid performance hour-by-hour across multiple weather years with finer geographic detail and optimized inter-regional transfers, and explores various retirement and build-out scenarios. Furthermore, the DOE approach integrates weather-synchronized outage data.
2. Deterministic approaches evaluate resource adequacy using relatively stable or fixed assumptions about the representation of the power system. Probabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty that require more computing power. Deterministic was chosen for this analysis for transparency and to model detailed historic system conditions.
3. EPRI, "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," March 2024, https://www.epri.com/research/products/3002028905.
4. Shehabi, A., et al., "2024 United States Data Center Energy Usage Report," https://escholarship.org/uc/item/32d6m0d1.
5. S&P Global – Market Intelligence, "US Datacenters and Energy Report," 2024.

An additional 51 GW of non-data center load was modeled using NERC data, historical loads (2019-2023), and simulated weather years (2007-2013), adjusted by the Energy Information Administration's (EIA) 2022 energy forecast, with interpolation between 2024 and 2033 to estimate 2030 demand.

- **Supply of Electricity – Assumed Generation Retirements and Additions:** Between the current system and the projected 2030 system, the model considers three scenarios for generator retirements and additions. These scenarios were selected to describe the metrics of interest and how they change during certain assumptions of generation growth and retirements.

The resource adequacy standard (or criterion) is the measure that defines the desired level of adequacy needed for a given system. Conceptually, a resource adequacy criterion has two components—metrics and target levels—that determine whether a system is considered adequate. Comprehensive resource adequacy metrics[6] are incorporated in this analysis to capture the magnitude and duration of system stress events:

- **Magnitude of Outages – Normalized Unserved Energy (NUSE):** Measures the amount of unmet electrical energy demand because of insufficient generation or transmission, typically measured in megawatt hours (MWh).

  While USE describes the absolute amount of energy not delivered, it is less useful when comparing systems of different size or across different periods. Normalizing, by dividing by total load over a whole period (for example, a year) allows comparison of these metrics across different system sizes, demand levels, and periods of analysis. For example, 100 MWh of USE in a small, isolated microgrid can be more impactful than 100 MWh of USE in a larger regional grid that serves millions of people. USE is normalized by dividing by total load:

$$\frac{100\ MWh\ (of\ unserved\ energy)}{10{,}000{,}000\ MWh\ (of\ total\ energy\ delivered\ in\ a\ year)} x100 = 0.001\ percent$$

Although the use of NUSE is not standardized in the U.S. today,[7] several system operators domestically and across the world have begun using NUSE as a useful metric.

- **Duration of Outages – Loss of Load Hours (LOLH):** Measures the expected duration of power outages when a system's load exceeds its available generation capacity. At the core, LOLH helps assess how frequently and for how long the power system is likely to experience insufficient supply, providing a picture of reliability in terms of time. LOLH is calculated as both a total and average value per year, in addition to the maximum percentage of load lost in any given hour per year.

6. In the interest of technical accuracy, and separate from their contextualization in the main text, NUSE is more precisely a measure of volume that is expressed as a percentage. Similarly, 2.4 hours of LOLH represents the cumulative sum of distinct periods of load loss, not a singular, continuous duration.
7. There is no common planning criterion for this metric in North America. NERC's Long-Term Reliability Assessment employs a normalized expected unserved energy (NEUE) metric to define target risk levels for each region. Grid operators, such as ISO-NE, have also considered NUSE in energy adequacy studies. For example, see ISO-NE, "Regional Energy Shortfall Threshold (REST): ISO's Current Thinking Regarding Tail Selection," April 2025, https://www.iso-ne.com/static-assets/documents/100022/a09_rest_april_2025.pdf.

Reliability Standard

DOE's methodology recognizes that the traditional 1-in-10 loss of load expectation (LOLE) criterion is insufficient for a complete assessment of resource adequacy and risk profile. This antiquated criterion is not calculated uniformly and fails to adequately account for crucial factors such as the duration and magnitude of potential outages.[8] To provide a comprehensive understanding of system reliability and, specifically, to complement current resource adequacy standards while informing the creation of new criteria, the methodology uses the following reliability standard:

- **Duration of Outages:** No more than 2.4 hours of lost load in an individual year.[9] This translates into one day of lost load in ten years to meet the 1-in-10 criteria.

- **Magnitude of Outages:** No more than an NUSE of 0.002%.[10] This means that the total amount of energy that cannot be supplied to customers is 0.002% of the total energy demanded in a given year.

Achieving Reliability Standard

- **Perfect Capacity Surplus/Deficit:** Defined as the amount of generation capacity (in MW) a region would need to achieve specified threshold conditions. Based on these thresholds, this standard helps answer the hypothetical question of how much more (or less) power plant capacity is needed for a power system to be considered "perfectly reliable" according to pre-defined standards. This methodology employs this perfect capacity metric to identify the amount of capacity needed to remedy potential shortfalls (or excesses) in generation.

Key Results Summary

This analysis developed three separate cases for 2030. The "**Plant Closures"** case assumes all announced retirements occur plus mature generation additions based on NERC's Tier 1 resources category,[11] which encompasses completed and under-construction power generation projects, as well as those with firm-signed and approved interconnection service or power purchase agreements. The "**No Plant Closures"** case assumes no retirements plus mature additions. A "**Required Build**" case further compares the impacts of retirements on perfect capacity additions needed to return 2030 to the current system level of reliability.

8. While 1-in-10 analyses have evolved, industry experts have raised concerns about its effectiveness to address future system risks. Concerns include energy constraints that arise from intermittent resources, increasing battery storage, limited fuel supplies, and the shifting away of peak load periods from times of supply shortfalls.
9. The "1-in-10 year" reliability standard for electricity grids means that, on average, there should be no more than one day (24 hours) of lost load over a ten-year period. This translates to a maximum of 2.4 hours of lost load per year.
10. This analysis targets NUSE below 0.002% for each region because this is the target NERC uses to represent high risk in resource adequacy analyses. Estimates used in industry and analyzed recently range from 0.0001% to 0.003%.
10. Mature generation additions are based on NERC's 2024 LTRA Tier 1 resources, which assume that only projects considered very mature in the development pipeline will be built. For example, Tier 1 additions are those with signed interconnection agreements or power purchase agreements, or included in an integrated resource plan, indicating a high degree of certainty in their addition to the grid. Full details of the retirement and addition assumptions can be found in the methodology section of this report.

DOE ran simulations using 12 different years of historical weather. Every hour was based on actual data for wind, solar, load, and thermal availability to stress test the grid under a range of realistic weather conditions. The benefit of this approach is that it allows for transparent review of how actual conditions manifest themselves in capacity shortfalls. For all scenarios, LOLH and NUSE are calculated and used to compare how they change based on generation growth, retirements, and potential weather conditions.

- **Current System:** Supply of power (generation) and demand for power (load) consistent with 2024 NERC Long-Term Reliability Assessment (LTRA), including 2023 actual generation plus Tier 1 additions for 2024.

- **Plant Closures:** This case assumes 104 GW of announced retirements based on NERC estimates including approximately 71 GW of coal and 25 GW of natural gas, which closely align with retirement numbers in EIA's 2025 Annual Energy Outlook. In addition, this case assumes 100% of 2024 NERC LTRA Tier 1 additions totaling 209 GW are constructed by 2030. This includes 20 GW of new natural gas, 31 GW of additional 4-hour batteries, 124 GW of new solar and 32 GW of incremental wind. Details of the breakdown can be found in Appendix A.

- **No Plant Closures:** This case adds all the Tier 1 NERC additions but assumes no retirements.

- **Required Build:** To understand how much capacity may need to be added to reach reliability targets, the analysis adds hypothetical perfect capacity (which is idealized capacity that has no outages or profile) until a NUSE target of 0.002% is realized in each region. This scenario includes the same assumptions about retirements as our Plant Closures scenario described above.

As shown in the figures and tables below, the model shows a significant decline in all reliability metrics between the current system scenario and the 2030 Plant Closures scenario. Most notably, there is a hundredfold increase in annual LOLH from 8.1 hours per year in the current case to 817 hours per year in the 2030 Plant Closures. In the worst weather year assessed, the total lost load hours increase from 50 hours to 1,316 hours.

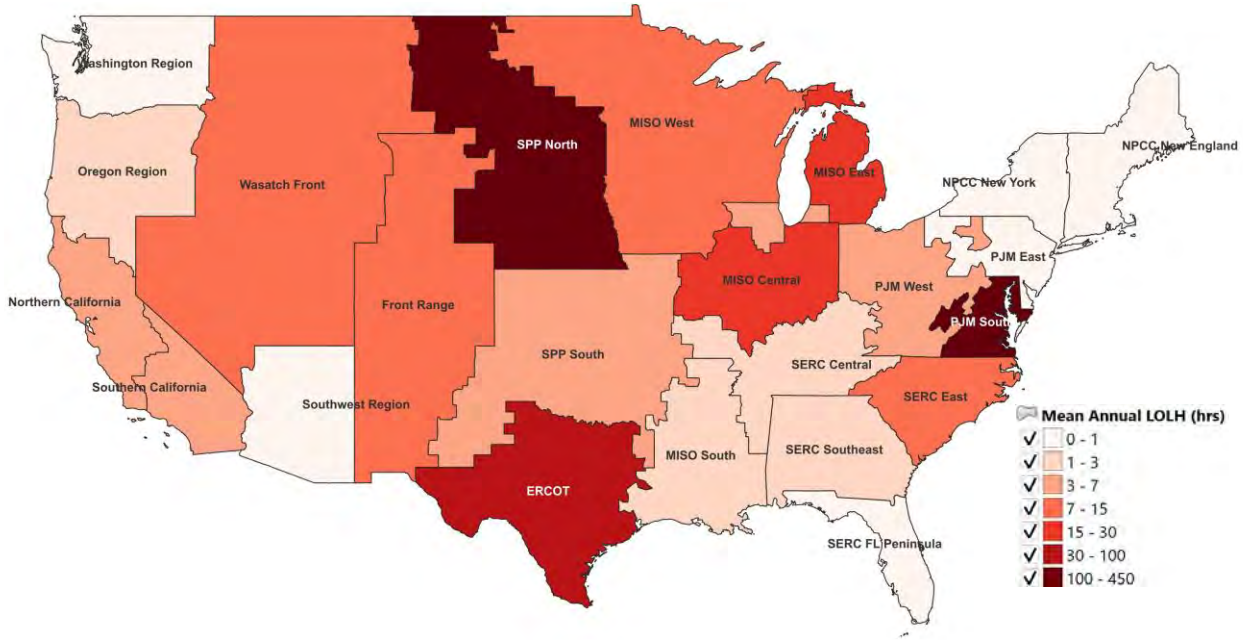


Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

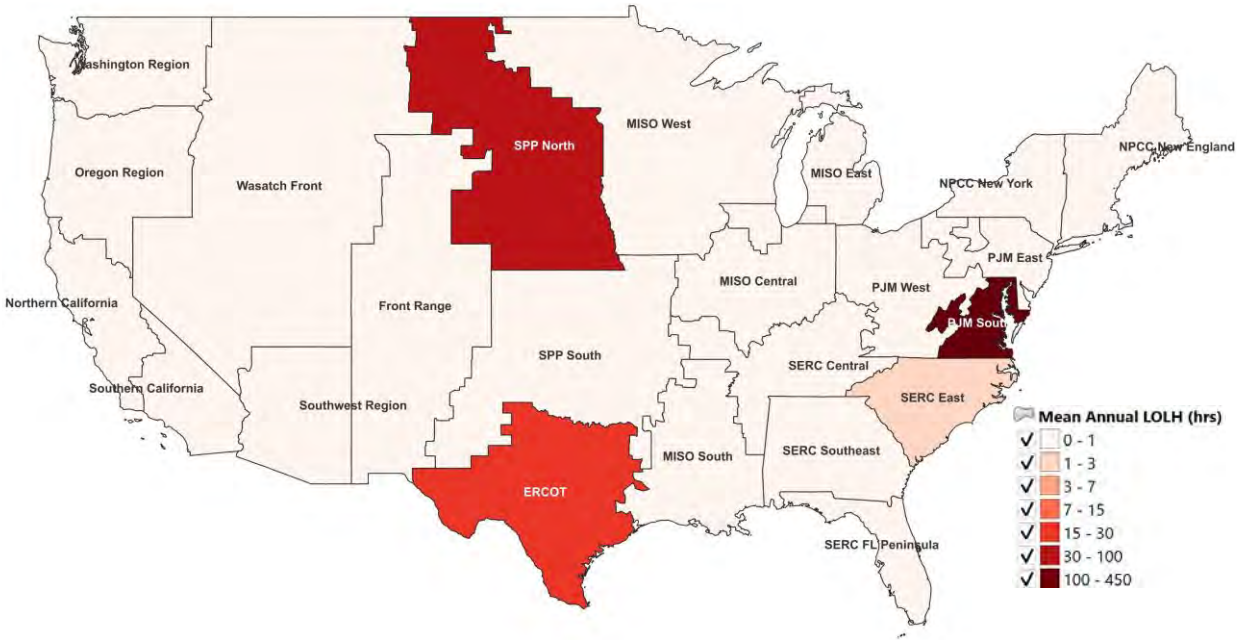


Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

Table 1. Summary Metrics Across Cases

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	8.1	817.7	269.9	13.3
Normalized Unserved Energy (%)	0.0005	0.0465	0.0164	0.00048
WORST WEATHER YEAR				
Annual Loss of Load Hours	50	1316	658	53
Normalized Unserved Load (%)	0.0033	0.1119	0.0552	0.002

Current System Analysis

Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study. In the current system case, ERCOT would be expected to experience on average 3.8 LOLH annually going forward and a NUSE of 0.0032%. When looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour.

However, PJM, ERCOT,[12] and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load. This results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load. It is worth noting that in the case of PJM and SPP, the current system model shortfalls occurred within subregions rather than for the entire ISO footprint.

12. ERCOT has since winterized its generation fleet and did not suffer any outages during Winter Storm Elliot.

2030 Model Results

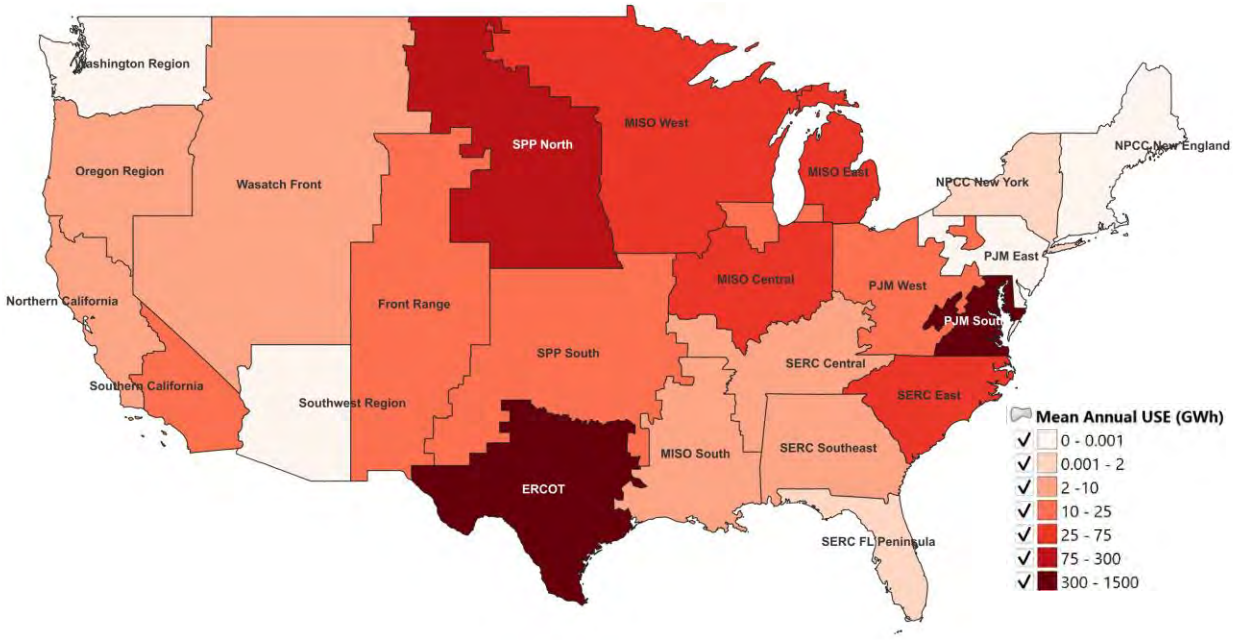


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Key Findings – Plant Closures Case:

- **Systemwide Failures**: All regions except ISO-NE and NYISO failed reliability thresholds. These two regions did not have additional AI/data center (AI/DC) load growth modeled.
- **Loss of Load Hours (LOLH)**: Ranged from 7 hours/year in CAISO to 430 hours/year in PJM.
- **Load Shortfall Severity**: Max shortfall reached as high as 43% of hourly load in PJM; 31% in CAISO.
- **Normalized Unserved Energy**: Normalized values ranged from 0.0032% (non-CAISO West) to 0.1473% (PJM), far exceeding thresholds of 0.002%.
- **Extreme Events**: Most regions experienced ≥3 hours of unserved load in at least one year. PJM had 1,052 hours in its worst year.
- **Spatial Takeaways**: Subregions in PJM, MISO, and SERC met thresholds—indicating possible benefits from transmission—but SPP and CAISO failed in all subregions.

Key Findings – No Plant Closures Case:

- **Improved System Performance**: Most regions avoided loss of load events. PJM, SPP, and SERC still experienced shortfalls.
- **Regional Failures**:

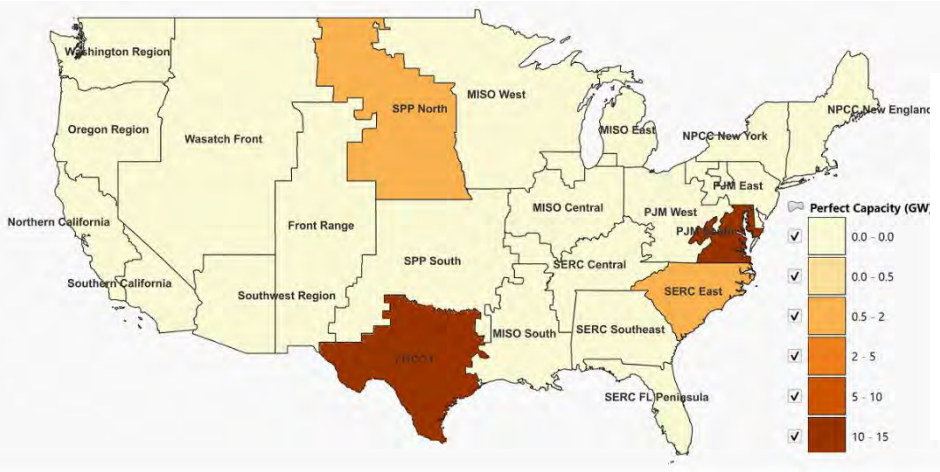
- **PJM**: 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.
- **SPP**: 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.
- **ERCOT**: 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall of 27%.
- **SERC-East**: Generally adequate (avg. 1 hour/year, 0.0003% NUSE), but Elliot storm in 2022 caused 42 hours of shortfall.

The overall takeaway is that avoiding announced retirements improves grid reliability, but shortfalls persist in PJM, SPP, ERCOT, and SERC, particularly in winter.

Required Build

This required build analysis quantifies "hypothetical capacity," defined as power that is 100% reliable and available that is needed to resolve the shortfalls. Known in industry as “perfect capacity,” this metric is utilized to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations. Nevertheless, it serves as a valuable indicator, illustrating either the magnitude of a resource gap or the scale of large load that will be unable to interconnect. For the Required Build case, this hypothetical capacity was calculated by adding new generating resources to each region until a target of 0.002% of NUSE is reached.

The table below shows the tuned perfect capacity results. For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year. By 2030, without considering any generation retirements, an additional 12.5 GW of generating capacity is needed across PJM, SPP, and SERC to reduce shortfalls.



	2024-Current System (MW)	2030-No Plant Closures (MW)
PJM	2400	10,500
SERC-E		500
SPP-N		1,500
ERCOT	1600	10500
Total	4000	23000

Perfect Capacity/Additions

Figure 4. Tuned Perfect Capacity (MW) By Region

1 Modeling Methodology

The methodology uses a zonal PLEXOS[13] model with hourly time-synchronous datasets for load, generation, and interregional transfer for the 23 U.S. subregions (referred to as TPRs in this study)[14] including ERCOT (see Figure 5 below). While ERCOT operates outside of FERC's general jurisdiction,[15] it provides a valuable case for understanding broader reliability and resource adequacy challenges in the U.S. electric grid, and FPA Section 202(c) allows DOE to issue emergency orders to ERCOT.

We base this analysis on actual weather and power plant outage data from 2007 to 2023 using NERC's ITCS[16] base dataset. DOE specifically decided to start this analysis with the ITCS dataset since it is a complete representation of the interconnected electrical system for the lower 48 and it has been thoroughly reviewed by industry experts in a public and transparent process. DOE has in turn made modifications to the dataset to fit the needs of this study. The contents of this section focus on those modifications which DOE implemented for purposes of this study.

PLEXOS is an industry-trusted simulation tool used for energy optimization, resource adequacy, and production cost modeling. This study leverages PLEXOS' ability to exercise an hourly production cost model to determine the balance between loads, generation, and imports for each region. Modeling was carried out using a deterministic approach that evaluates whether a power system has sufficient resources to meet projected demand under a pre-defined set of conditions which correspond to the past few years of real-world events. The model ultimately determines the amount of unmet load if generation resources and imports are not sufficient for meeting the load in each discrete time period.

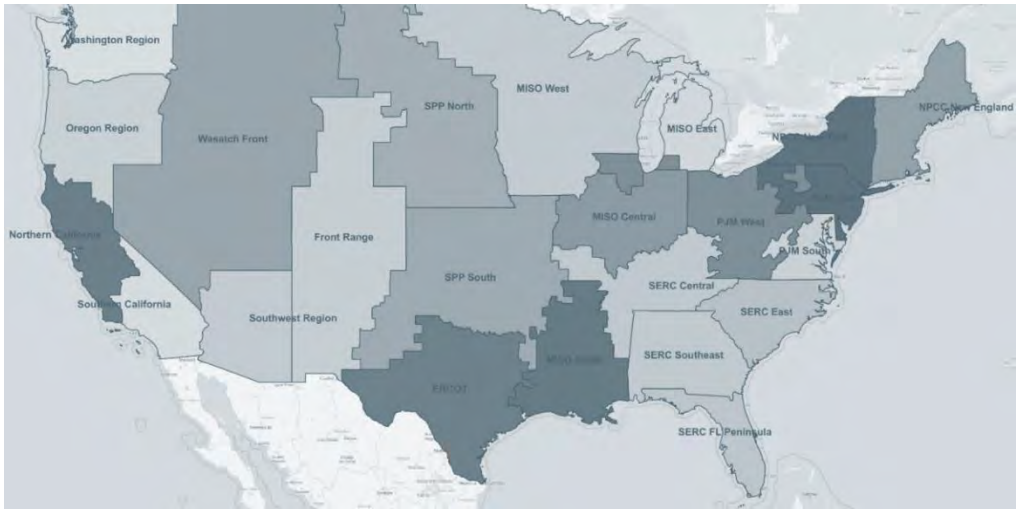


Figure 5. TPRs used in NERC ITCS

13. Energy Exemplar, "PLEXOS," https://www.energyexemplar.com/plexos.
14. The TPRs match the regional subdivisions in the NERC ITCS study, itself based on FERC's transmission planning regions.
15. Transmission within ERCOT is intrastate commerce. 16 U.S.C. § 824(b)(1) (provisions applying to "the transmission of electric energy in interstate commerce").
16. NERC "Integrated Transmission and Capacity System (ITCS)," accessed June 25, 2025, https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx.

This methodology developed a current model and series of scenarios to explore how different assumptions impact resource adequacy. This sensitivity analysis includes assumptions regarding load growth, generation build-outs and retirements, and transfer capabilities. By comparing the results of the current model with the scenario results, we can assess how generation retirements and load growth affect future generation needs.

The assessment uses data from 2007–2013 (synthetic weather data) and 2019–2023 (historical data). A brief summary of the methodological assumptions is provided here, with additional details available in the relevant appendixes.

- **Solar and Wind Availability** – Created from historical output from EIA 930 data, with bias correction of any nonhistorical data to match regional capacity factors, as calibrated to EIA 930 data.[17] Synthetic years used 2018 technology characteristics from NREL based on the Variable Energy Potential (reV) model, then mapped to synthetic weather year data. See Appendix A for more details.

- **Thermal Availability** – Calculated according to NERC LTRA capacity data, adjusted for historical outages and derates, primarily with GADS data. GADS data does not capture historical outages caused by fuel supply interruptions.[18]

- **Hydroelectric Availability** – Historical outputs are processed by NERC to establish monthly power rating limits and energy budgets, but energy budgets are not enforced in alignment with how they were treated in the ITCS. The team evaluated performance under different energy budget restrictions, but did not find significant differences during peak hours, justifying NERC ITCS assumptions that hydroelectric resources could generally be dispatched to peak load conditions. Later work may benefit from exploring drought scenarios or combinations of weather and hydrological years, where energy budgets may be significantly decreased.

- **Outages and Derates** – Data for the actual data period (2019–2023) are based on historical forced outage rates and deratings. Outage and deratings data for the synthetic period (2007–2013) are based on the historical relationships observed between temperature and outages (see Appendix G of the NERC ITCS Final Report for more information).

- **Load Projections and AI Growth** – Load growth through 2030 is assumed to match NERC 2024 ITCS projections, scaling the 12 weather years to meet 2030 projections. Additional AI and data center load is then added according to reports from EPRI and S&P regarding potential futures.

- **Transfer Capabilities and Imports/Exports -** Each subregion is treated as a “copper plate,” with the transfer capacity between each subregion defined by the availability of transmission pathways. It is an approximation that assumes all resources are connected to a single point, simplifying the transmission system within the model. Subregions are generally assumed to exhaust their own capacity before utilizing capacity available from their neighbors. Once the net remaining capacity is at or below 10 percent of load, the subregion begins to use capacity from a neighbor.

17. See ITCS Final Report, Appendix F, for the method that was implemented to scale synthetic weather years 2007–2013.
18. See ITCS Final Report, Appendix G, for outage and derate methods.

  - Imports are assumed to be available up to the minimum total transfer capacity and spare generation in the neighboring subregion.

  - To the extent the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario, the model projects an energy shortfall. See "Outputs" in the appendix for more details.

  - To ensure that transfers are dispatched only after local resources are exhausted, a wheeling charge of $1,000 is applied for every megawatt-hour of energy transferred between regions through transmission pathways.

- **Storage** – In alignment with the NERC ITCS methodology, storage was split into pumped hydro and battery storage. Pumped hydro was assumed to have 12 hours duration at rated capacity with 30% round-trip losses, while battery storage was assumed to have four hours and 13% round-trip losses. Storage is dispatched as an optimization to minimize USE and demand response usage under various constraints and is recharged during periods of surplus energy.
- **Demand Response –** Demand Response (DR) is treated as a supply-side resource and dynamically scheduled after all other regional resources and imports are exhausted. It is modeled with both capacity (MW) and energy (MWh) limitations and assumed to have three hours of availability at capacity but could be spread across more than three hours up to the energy limit. DR capacity was based on LTRA Form A data submissions for "Controllable and Dispatchable Demand Response – Available", or firm, controllable DR capacity.
- **Retirements** – Retirements as per the NERC LTRA 2024 model. To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant level data are used to tabulate generation retirement or addition capacity for each ITCS region and NERC assessment area. Disaggregation fractions are then calculated by technology based on planned retirements through 2030. See Appendix B for further information. Retirements are categorized into two categories:

  1. *Announced Retirements*: Includes both confirmed retirements and announced retirements. Confirmed retirements are generators formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date. To go from LTRA regions to ITCS regions, weighting factors are derived in the same way as in the generation set, based on EIA retirement data. In addition to confirmed retirements, announced retirements are generators that have publicly stated retirement plans that have not formally notified system operators and initiated the retirement process. This disaggregation method for announced retirements mirrors used for confirmed retirements.[19]
  2. *None*: Removes all retirements (after 2024) for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirement contributes to some of the adequacy challenges in some regions.

- **Additions** – Assumes only projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built. This data is based on projects

19. If announced retirements were less than or equal to confirmed retirements, the model adjusted the announced retirement to equal confirmed.

designated as Tier 1 in the NERC 2024 LTRA and are mapped to ITCS regions with EIA 860-derived weighting factors similar to those described for the retirements above. See Appendix A for further information.

- **Perfect Capacity Required** - Estimates perfect capacity (which is idealized capacity that has no outages or profile and is described in Section 2) until we reach a pre-defined reliability target. We used a metric of NUSE given the deterministic nature of the model, to be consistent with evolving metrics, and to be consistent with NERC's recent LTRAs. We targeted NUSE of below 0.002% for each region.

1.1 Modeling Resource Adequacy

This model calculates several reliability metrics to assess resource adequacy. These metrics were calculated using PLEXOS simulation outputs, which report the USE (in MWh) for all 8,760 hourly periods in each of the 12 weather years:

- **USE** refers to the amount of electricity demand that could not be met due to insufficient generation and/or transmission capacity. Several USE-derived indicators were considered:
    - *Normalized USE (percentage %):* The total amount of unserved load over 12 years of weather data, normalized by dividing by total load, and reported as a percentage.[20]
    - *Mean Annual USE (GWh)*: The 12-year average of each region's total USE in each weather year. This mean value represents the average annual USE across weather variability.
    - *Mean Max Unserved Power (GW)*: The 12-year average of each region's maximum USE value in each weather year. This mean value characterizes the typical non-coincident peak stress on system reliability.
    - *% Max Unserved Power*: The Mean Max Unserved Power expressed as a percentage of the average native load during those peak unserved hours for each region. This percentage value provides a normalized measure of the severity of peak unserved events relative to demand.
    - *Total number of customers without power*. The Mean Max Unserved Power expressed as the equivalent number of typical U.S. persons assuming a ratio of 17,625 persons/MW lost. This estimation contextualizes the effects of the outage on average Americans.
- **Loss of Load Hours (LOLH)** refers to the number of hours during which the system experiences USE (i.e., any hour with non-zero USE). Two LOLH-based indicators were considered:

20. NUSE can be reported as parts per million or as a percentage (or parts per hundred); though for power system reliability, this would include several zeros after the decimal point.

- *Mean Annual LOLH*: for each weather year and *TPR*, we count the total number of hours with USE across all 8,760 hours, and we then take the average of those 12 totals. *Annual LOLH Distribution* is represented in box and whisker plots for 12 samples, each sample corresponding to a unique weather year.

- *Max Consecutive LOLH (hours)*[21]: The longest continuous period with reported USE in each weather year.

It should be noted that USE is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system. Rather, it represents the unrealizable AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth. These numbers are used as indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need.

This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.

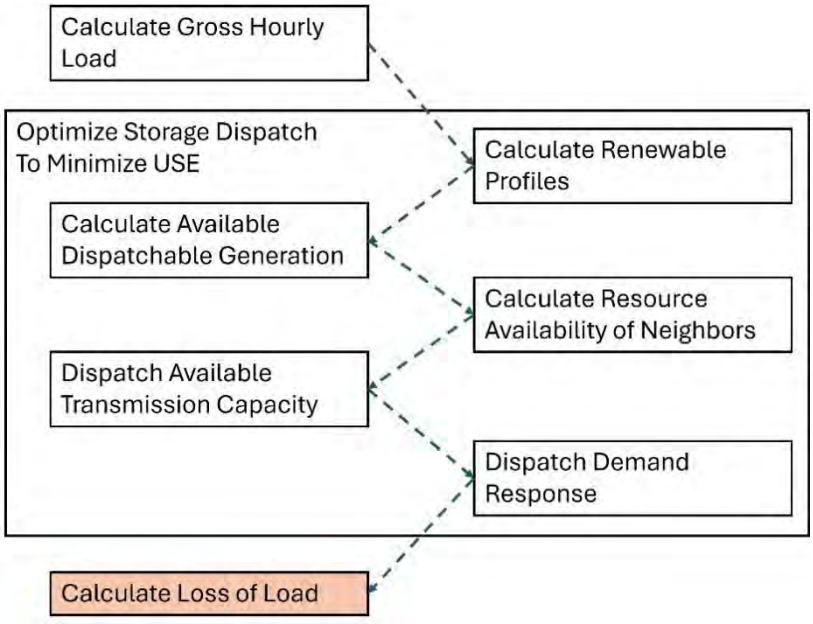


Figure 6. Simplified Overview of Model

21. One caveat on the maximum consecutive LOLH and max USE values is in how storage is dispatched in the model. Storage is dispatched to minimize the overall USE and is indifferent to the peak depth or the duration of the event. This may construe some of the max USE and max consecutive LOLH values to be higher than if storage was dispatched to minimize these values.

1.2 Planning Years and Weather Years

For the planning year (2030), historical weather year data are applied based on conditions between 2007 and 2024 to calculate load, wind and solar generation, and hydro generation. Dispatchable capacity (including dispatchable hydro capacity) is calculated through adjustment of the 2024 LTRA capacity data for historical outages from GADS data. Storage assets are scheduled to arbitrage hourly energy margins or else charge during periods of high energy margins (surplus resources) and discharge during periods of lower energy margins.

1.3 Load Modeling

Data Center Growth

Several utilities and financial and industry analysts identify data centers, particularly those supporting AI workloads, as a key driver of electricity demand growth. Multiple organizations have developed a wide range of projections for U.S. data center electricity use through 2030 and beyond, each using distinct methodologies tailored to their institutional expertise.

These datasets were used to explore reasonable boundaries for what different parts of the economy envision for the future state of AI and data center (AI/DC) load growth. For the purposes of this study, rather than focusing on any specific analysis, a more generic sweep was performed across AI/DC load growth and the various sensitivities that fit within those assumptions, as summarized below:

- McKinsey & Company projects ~10% annual growth in U.S. data center electricity demand, reaching 2,445 TWh by 2050. Their model blends internal scenarios with public signals, including announced projects, capital investment, server shipments, and chip-level power trends, supported by third-party market data.

- Lawrence Berkeley National Laboratory (LBNL) uses a bottom-up approach based on historical and projected IT equipment shipments, paired with assumptions on power draw, utilization, and infrastructure efficiency (PUE, WUE). Their projections through 2028 account for AI hardware adoption, operational shifts, and evolving cooling technologies.

- EPRI combines public data, expert input, and historical trends to define four national growth scenarios, low to higher, for 2023–2030, reflecting data processing demand, efficiency improvements, and AI-driven load impacts.

- S&P Global merges technology and power-sector models, evaluating grid readiness and facility growth under varying demand scenarios. Their forecasts consider AI adoption, efficiency trends, grid and permitting constraints, on-site generation, and offshoring risk, resulting in a wide range of outcomes.

These projections show wide variation, with 2030 electricity demand ranging from approximately 35 GW to 68 GW of average load. Given this uncertainty, including differences in hardware intensity, thermal management, siting assumptions, and behind-the-meter generation, the modeling team adopted a national midpoint assumption of approximately 50 GW by 2030.

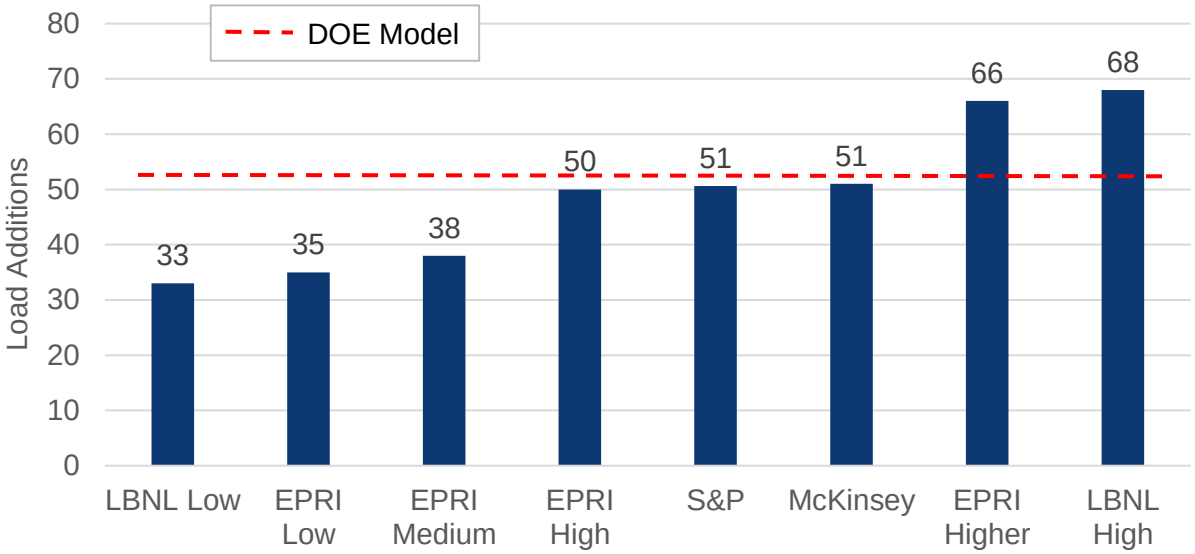


Figure 7. 2024 to 2030 Projected Data Center Load Additions

Figure 7 above displays a benchmark reflecting roughly the median across major studies and aligns with central projections from EPRI and LBNL. Using a single planning midpoint avoids double counting and enables consistent load allocation across national transmission and resource adequacy models. [Note: this figure was updated on October 27, 2025 to address a correction to the S&P projection.]

Data Center Allocation Method

To allocate the 50 GW midpoint regionally, the team used state-level growth ratios from S&P's forecast. These ratios reflect factors such as infrastructure, siting trends, and projected market activity. The modeling team mapped the state-level projections to NERC TPRs, ensuring transparent and repeatable regional allocation. While other methods exist, this approach ensured consistency with the broader modeling framework.

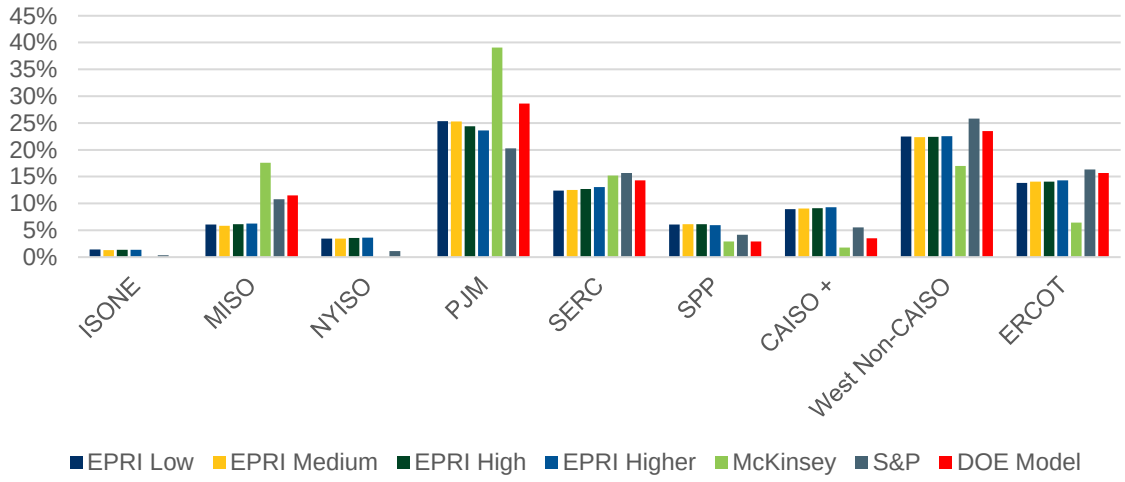


Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

Non-Data Center Load Modeling

The current electricity demand projections were built from NERC data, using historical load (2019–2023) and simulated weather years (2007–2013). These were adjusted based on the EIA's 2022 energy forecast. To estimate 2030 demand, the team interpolated between 2024 and 2033, scaling loads to reflect energy use and seasonal peaks. NERC provided datasets to address anomalies and include behind-the-meter and USE.

Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC LTRA forecast, for example, the 2024 LTRA saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.

Overall Impact on Projected Peak Load

As a result of the methods applied above, the average year co-incident peak load is projected to grow from a current average peak of 774 GW to 889 GW in 2030. This represents a 15% increase or 2.3% growth rate per year. Excluding the impact of data centers, this would amount to a 51GW increase from 774 GW to 826 GW which represents a 1.1% annual growth rate.

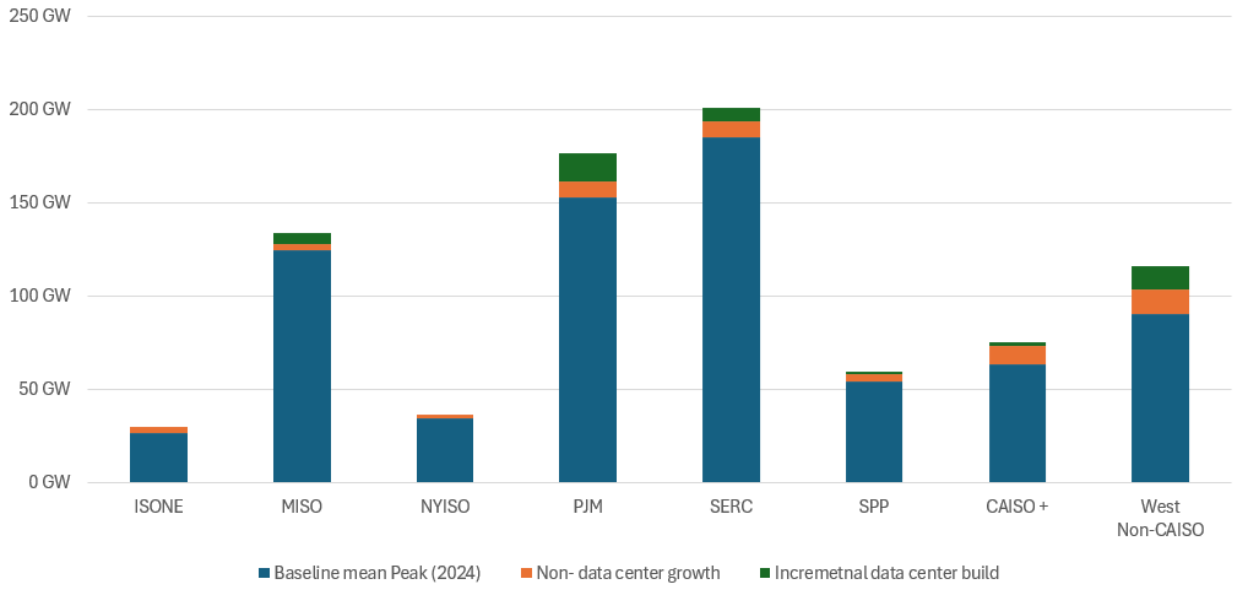


Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

1.4 Transfer Capabilities and Import Export Modeling

The methodology assumes electricity moves between subregions, when conditions start to tighten. Each region has a certain amount of capacity available, and the methodology determines if there is enough to meet the demand. When regions reach a “Tight Margin Level” of 10% of capacity, i.e., if a region’s available capacity is less than 110% of load, it will start transferring from other regions if capacity is available. A scarcity factor is used to determine which regions to transfer from and at what fraction – those with a greater amount of reserve capacity will transfer more. A region is only allowed to export above when it is above the Tight Margin Level.

Total Transfer Capability (TTC) was used and is the sum of the Base Transfer Level and the First Contingency Incremental Transfer Capability. These were derived from scheduled interchange tables or approximated from actual line flows. It should be noted that the TTC does not represent a single line, but rather multiple connections between regions. It is similar to path limits used by many entities but may have different values.

Due to data and privacy limitations, the Canadian power system was not modeled directly as a combination of generation capacity and demand. Instead, actual hourly imports were used from nearly 20 years of historical data, along with recent trends (generally less transfers available during peak hours), to develop daily limits on transfer capabilities. See Appendix B for more details on Canadian transfer limits.

1.5 Perfect Capacity Additions

To understand how much capacity may need to be added to reach approximate reliability targets, we tuned two scenarios by adding hypothetical perfect capacity to reach the reliability threshold based on NUSE.[22] Today, NERC uses a threshold of 0.002% to indicate regions are at high risk of resource adequacy shortfalls. In addition, several system operators, including the Australia Energy Market Operator and Alberta Electric System Operator, are using NUSE thresholds in the range of 0.001% to 0.003%. Several U.S. entities are considering lower thresholds for U.S. power systems in the range of 0.0001% to 0.0002%. [23]

For this analysis, we target NUSE below 0.002% for each region to align with NERC definitions. We iteratively ran the model, hand-tuning the "perfect capacity" to be as small as possible while reaching NUSE values below 0.002% in all regions.[24] As the work was done by hand with a limited number of iterations (15), this should not be considered the minimum possible capacity to accomplish these targets. Further, because the perfect capacity can be located in various places, there would be multiple potential solutions to the problem. These scenarios represent the approximate quantity of perfect capacity each region would require (beyond announced retirements and mature generation additions only) that would lead to Medium or Low risk based on the NERC metrics for USE.

Due to some regions with zero USE, the tuned cases do not reach the same level of adequacy, where the national average is 0.00045% vs. 0.00013%. Due to transmission and siting selection of perfect capacity, there could be many solutions.

22. We are not using the standard term "expected unserved energy" because we are not running a probabilistic model, so we do not have the full understanding of long-term expectations

23. MISO, "Resource Adequacy Metrics and Criteria Roadmap," December 2024. https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap667168.pdf.

24. NERC, "Evolving Criteria for a Sustainable Power Grid," July 2024. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Evolving_Planning_Criteria_for_a_Sustainable_Power_Grid.pdf.

2 Regional Analysis

This section presents more regional details on resource adequacy according to this analysis. For each of the nine Regional Transmission Organizations (RTOs) and sub-regions, comprehensive summaries are provided of reliability metrics, load assumptions, and composition of generation stacks.

2.1 MISO[25]

In the current system model and the No Plant Closures cases, MISO did not experience shortfall events. MISO's minimum spare capacity in the tightest year was negative, showing that adequacy was achieved by importing power from neighbors. In the Plant Closures case, MISO experienced significant shortfalls, with key reliability metrics exceeding each of the threshold criteria defined for the study.

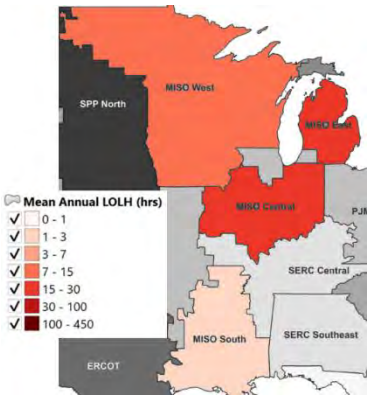


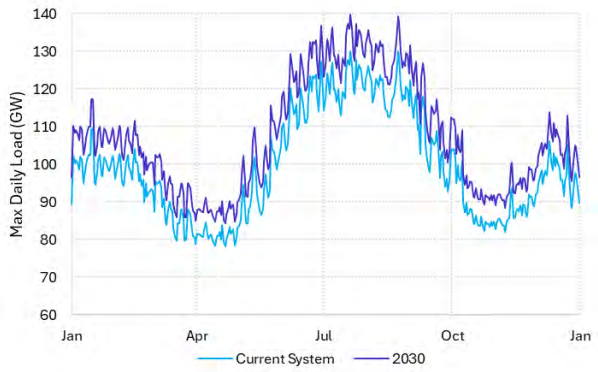
Table 2. Summary of MISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	37.8	-	-
Normalized Unserved Energy (%)	-	0.0211	-	-
Unserved Load (MWh)	-	157,599	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	124	-	-
Normalized Unserved Load (%)	-	0.0702	-	-
Unserved Load (MWh)	-	524,180	-	-

Load Assumptions

MISO's peak load was roughly 130 GW in the current model and projected to increase to roughly 140 GW by 2030. Approximately 6 GW of this relates to new data centers being installed (12% of U.S. total).

25. Following the initial data collection for this report, MISO issued its 2025 Summer Reliability Assessment. Based on that report, NERC revised evaluations from its 2024 LTRA and reclassified the MISO footprint from being an 'elevated risk' to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements. While DOE's analysis is based on the previously reported figures, DOE is committed to assessing the implications of updated data on overall resource adequacy and providing technical updates on findings, as appropriate.



Subregion	2024	2030
MISO-W	37,913	40,981
MISO-C	35,387	39,243
MISO-S	36,476	38,596
MISO-E	23,167	23,758
Total	**130,136**	**139,846**

Figure 10. MISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 207 GW.[26] In 2030, 21 GW of new capacity was added leading to 228 GW of capacity in the No Plant Closures case. In the Plant Closures case, 32 GW of capacity was retired such that net retirements in the Plant Closures case were -11 GW, or 196 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
MISO-W	71,612	67,453	77,605
MISO-C	51,982	47,735	58,823
MISO-S	54,511	52,756	59,710
MISO-E	29,213	28,105	32,255
Total	**207,319**	**196,049**	**228,393**

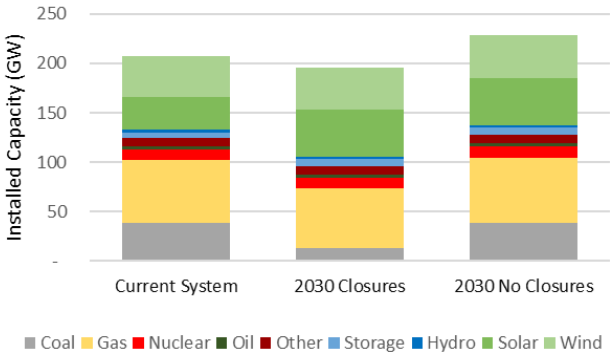


Figure 11. MISO Generation Capacity by Technology and Scenario

MISO's generation mix was comprised primarily of natural gas, coal, wind, and solar. In 2024, natural gas comprised 31% of nameplate, wind comprised 20%, coal 18%, and solar 14%. In 2030, most retirements come from coal and natural gas while additions occur for solar, batteries, and wind. In addition, the model assumed 3 GW of rooftop solar and 8 GW of demand response.

26. The total installed capacity numbers reported in this regional analysis section do not reflect the generating capability of all resources during stress conditions.

Table 3. Nameplate Capacity by MISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**37,914**	**64,194**	**11,127**	**2,867**	**8,717**	**5,427**	**2,533**	**32,826**	**41,715**	**207,319**
MISO-W	12,651	13,608	2,753	1,491	2,613	200	777	8,109	29,411	**71,612**
MISO-C	15,050	10,307	2,169	494	2,211	1,272	769	12,361	7,350	**51,982**
MISO-S	5,493	31,052	5,100	589	2,469	54	845	8,315	596	**54,511**
MISO-E	4,720	9,227	1,105	292	1,424	3,901	143	4,042	4,359	**29,213**
Additions	**0**	**2,535**	**0**	**330**	**0**	**1,929**	**0**	**14,354**	**1,926**	**21,074**
MISO-W	0	537	0	172	0	374	0	3,552	1,358	**5,993**
MISO-C	0	407	0	57	0	934	0	5,103	339	**6,841**
MISO-S	0	1,226	0	68	0	9	0	3,868	27	**5,199**
MISO-E	0	364	0	34	0	611	0	1,831	201	**3,042**
Closures	**(24,913)**	**(6,597)**	**0**	**(324)**	**(140)**	**(16)**	**(83)**	**0**	**(272)**	**(32,345)**
MISO-W	(8,313)	(1,398)	0	(168)	(56)	0	(25)	0	(192)	**(10,152)**
MISO-C	(9,889)	(1,059)	0	(56)	(7)	(3)	(25)	0	(48)	**(11,088)**
MISO-S	(3,609)	(3,191)	0	(67)	(55)	(0)	(28)	0	(4)	**(6,954)**
MISO-E	(3,102)	(948)	0	(33)	(21)	(13)	(5)	0	(28)	**(4,150)**

2.2 ISO-NE

In the current system model and the No Plant Closures case, ISO-NE did not experience shortfall events. The region maintained adequacy throughout the study period through reliance on imports. In the Plant Closures case, ISO-NE still did not exceed any key reliability thresholds, despite moderate retirements. This finding is partly due to the absence of additional AI or data center load growth modeled in the region. Accordingly, no additional perfect capacity was deemed necessary by 2030 to meet the study's reliability standards.

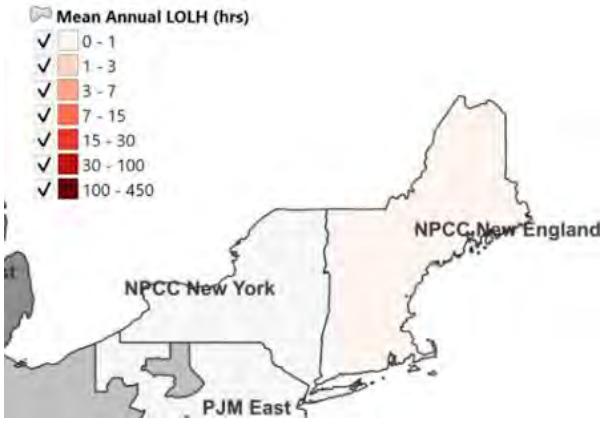
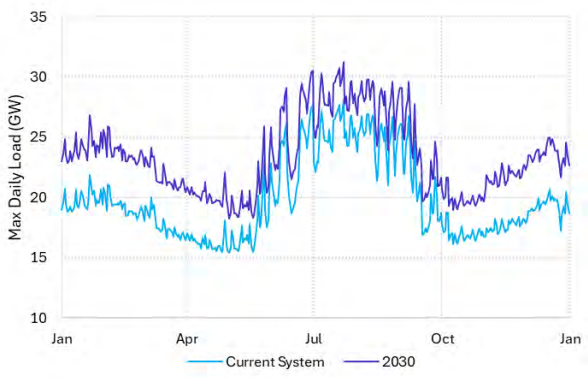


Table 4. Summary of ISO-NE Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	-	-	-
Normalized Unserved Energy (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	-	-	-
Normalized Unserved Load (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
Max Unserved Load (MW)	-	-	-	-

Load Assumptions

ISO-NE's peak load was roughly 28 GW in the current model and projected to increase to roughly 31 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
ISO-NE	28,128	31,261
Total	**28,128**	**31,261**

Figure 12. ISO-NE Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 40 GW. In 2030, 5.5 GW of new capacity was added leading to 45.5 GW of capacity in the No Plant Closures case. In the Plant Closures case, 2.7 GW of capacity was retired such that net generation change in the Plant Closures case was +11 GW, or 42.8 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ISO-NE	39,979	42,845	45,534
Total	**39,979**	**42,845**	**45,534**

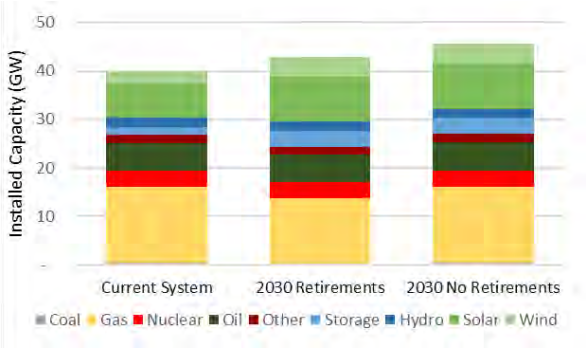


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

ISO-NE's generation mix was comprised primarily of natural gas, solar, oil, and nuclear. In 2024, natural gas comprised 39% of nameplate, solar comprised 17%, oil 14%, and nuclear 8%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed nearly 2 GW of rooftop solar and 1.6 GW of energy storage.

Table 5. Nameplate Capacity by ISO-NE Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**541**	**15,494**	**3,331**	**5,710**	**1,712**	**1,628**	**1,911**	**7,099**	**2,553**	**39,979**
ISONE	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	**39,979**
Additions	**0**	**90**	**0**	**181**	**0**	**1,607**	**0**	**2,183**	**1,495**	**5,555**
ISONE	0	90	0	181	0	1,607	0	2,183	1,495	**5,555**
Closures	**(534)**	**(1,875)**	**0**	**(203)**	**(77)**	**0**	**0**	**0**	**0**	**(2,690)**
ISONE	(534)	(1,875)	0	(203)	(77)	0	0	0	0	**(2,690)**

2.3 NYISO

In both the current system model and the No Plant Closures case, NYISO maintained reliability and did not exceed any shortfall thresholds. Adequacy was preserved through reliance on imports. In the Plant Closures case, NYISO experienced shortfalls but average annual LOLH remaining well below the 2.4-hour threshold and NUSE under the 0.002% standard. The worst weather year produced only 6 hours of lost load and a peak unserved load of 914 MW. Given the modest impact of retirements and no additional AI/data center load modeled, the study concluded that NYISO would not require additional perfect capacity to remain reliable through 2030.

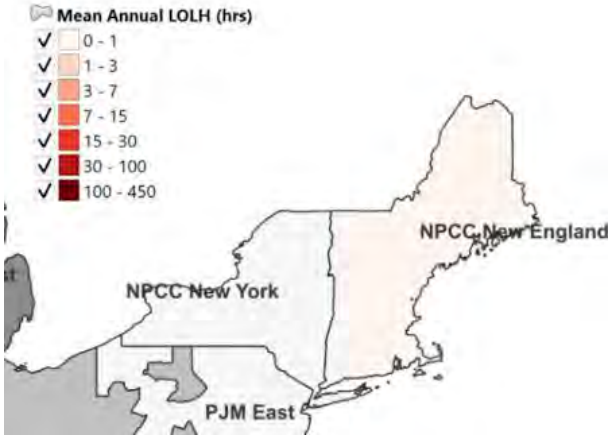
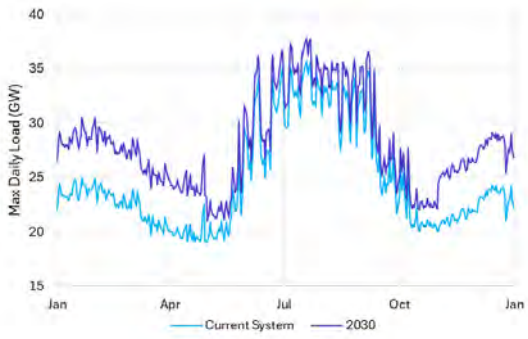


Table 6. Summary of NYISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.2	0.5	-	-
Normalized Unserved Energy (%)	0.00001	0.0001	-	-
Unserved Load (MWh)	18	209	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	2	6	-	-
Normalized Unserved Load (%)	0.0001	0.0013	-	-
Unserved Load (MWh)	216	2,505	-	-
Max Unserved Load (MW)	194	914	-	-

Load Assumptions

NYISO's peak load was roughly 36 GW in the current system model and projected to increase to roughly 38 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
NYISO	35,669	37,844
Total	**35,669**	**37,844**

Figure 14. NYISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 46 GW. In 2030, 5.5 GW of new capacity was added leading to 51 GW of capacity in the No Plant Closures case. In the Plant Closures case, 1 GW of capacity was retired such that net generation in the Plant Closures case was +4 GW, or 50 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
NYISO	45,924	50,396	51,444
Total	**45,924**	**50,396**	**51,444**

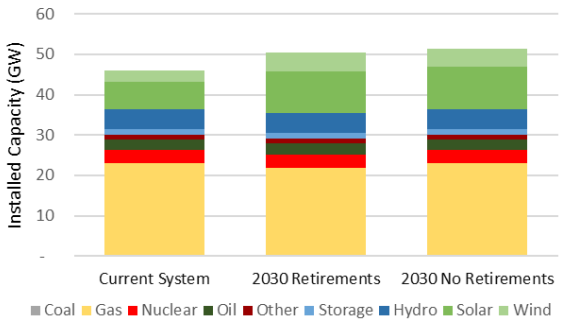


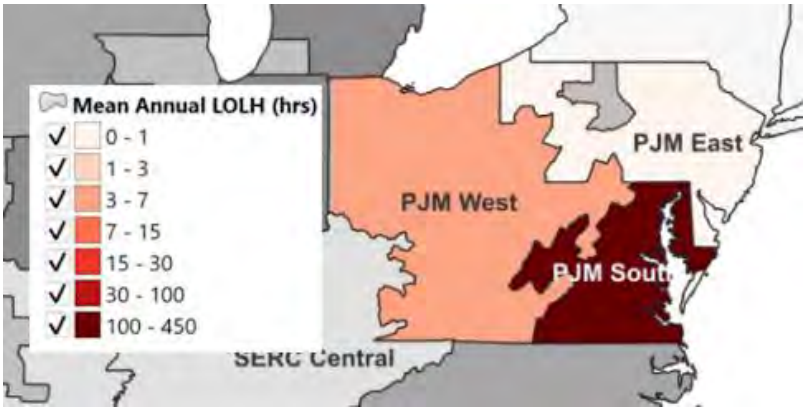
Figure 15. NYISO Generation Capacity by Technology and Scenario

NYISO's generation mix was comprised primarily of natural gas, solar, and hydro. In 2024, natural gas comprised 50% of total nameplate generation, solar comprised 14%, and hydro 11%. In 2030, most retirements come from natural gas while additions occur for solar and wind. The model assumed 6 GW of rooftop solar and nearly 1 GW of demand response.

Table 7. Nameplate Capacity by NYISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**0**	**22,937**	**3,330**	**2,631**	**1,194**	**1,460**	**4,915**	**6,749**	**2,706**	**45,924**
NYISO	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	**45,924**
Additions	**0**	**0**	**0**	**15**	**0**	**0**	**0**	**3,604**	**1,902**	**5,521**
NYISO	0	0	0	15	0	0	0	3,604	1,902	**5,521**
Closures	**0**	**(1,030)**	**0**	**(19)**	**0**	**0**	**0**	**0**	**0**	**(1,049)**
NYISO	0	(1,030)	0	(19)	0	0	0	0	0	**(1,049)**

2.4 PJM



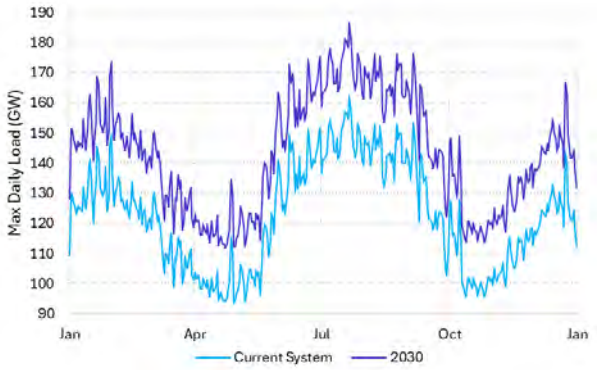
In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant Closures case, reliability metrics worsened significantly, with annual LOLH surging to over 430 hours per year and NUSE reaching 0.1473%—over 70 times the accepted threshold. During the worst weather year, 1,052 hours of load were shed. To restore reliability, the study found that PJM would require 10,500 MW of additional perfect capacity by 2030.

Table 8. Summary of PJM Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	2.4	430.3	213.7	1.4
Normalized Unserved Energy (%)	0.0008	0.1473	0.0657	0.0003
Unserved Load (MWh)	6,891	1,453,513	647,893	2,536
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	29	1,052	644	17
Normalized Unserved Load (%)	0.0100	0.4580	0.2703	0.0031
Unserved Load (MWh)	82,687	1,453,513	647,893	2,536
Max Unserved Load (MW)	4,975	21,335	17,620	4,162

Load Assumptions

PJM's peak load was roughly 162 GW in the current system model and projected to increase to roughly 187 GW by 2030. Approximately 15 GW of this relates to new AI/DC being installed (29% of U.S. total), primarily in PJM-S.



Subregion	2024	2030
PJM-W	81,541	92,378
PJM-S	39,904	51,151
PJM-E	41,003	43,118
Total	**162,269**	**186,627**

Figure 16. PJM Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 215 GW. In 2030, 39 GW of new capacity was added leading to 254 GW of capacity in the No Plant Closures case. In the Plant Closures case, 17 GW of capacity was retired such that net generation in the Plant Closures case was +22 GW, or 237 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
PJM-W	114,467	123,100	135,810
PJM-S	39,951	48,850	50,667
PJM-E	60,221	64,848	67,027
Total	**214,638**	**236,798**	**253,504**

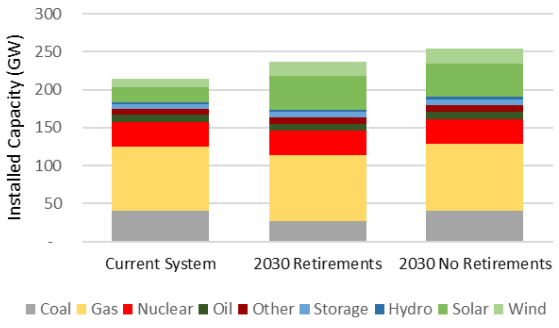


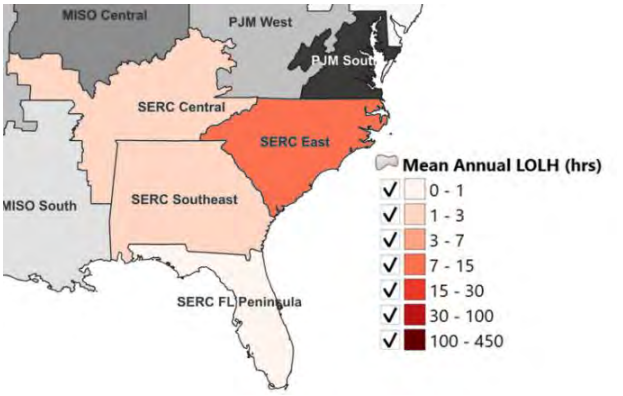
Figure 17. PJM Generation Capacity by Technology and Scenario

PJM's generation mix was comprised primarily of natural gas, coal, and nuclear. In 2024, natural gas comprised 39% of nameplate, coal comprised 19%, and nuclear 15%. In 2030, most retirements come from coal and some natural gas and oil while significant additions occur for solar plus lesser additions of wind, storage, and natural gas. The model assumed 9 GW of rooftop solar and 7 GW of demand response.

Table 9. Nameplate Capacity by PJM Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**39,915**	**84,381**	**32,535**	**9,875**	**8,248**	**5,400**	**3,071**	**19,495**	**11,718**	**214,638**
PJM-W	34,917	39,056	16,557	1,933	3,926	383	1,252	6,379	10,065	**114,467**
PJM-S	2,391	15,038	5,288	3,985	2,303	3,085	1,070	6,430	360	**39,951**
PJM-E	2,608	30,287	10,690	3,956	2,019	1,932	749	6,686	1,294	**60,221**
Additions	**0**	**4,499**	**0**	**32**	**317**	**1,938**	**0**	**24,991**	**7,089**	**38,866**
PJM-W	0	2,082	0	6	135	855	0	12,176	6,089	**21,343**
PJM-S	0	802	0	13	102	726	0	8,856	218	**10,717**
PJM-E	0	1,615	0	13	81	357	0	3,958	783	**6,806**
Closures	**(13,253)**	**(1,652)**	**0**	**(1,790)**	**(11)**	**0**	**0**	**0**	**0**	**(16,706)**
PJM-W	(11,593)	(765)	0	(350)	(1)	0	0	0	0	**(12,710)**
PJM-S	(794)	(294)	0	(722)	(6)	0	0	0	0	**(1,817)**
PJM-E	(866)	(593)	0	(717)	(3)	0	0	0	0	**(2,179)**

2.5 SERC



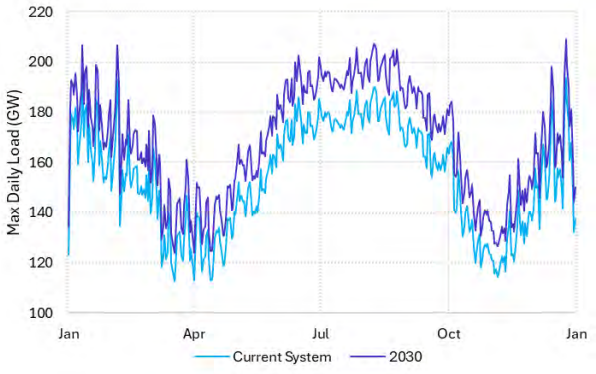
In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss of load hours during extreme cold events, including 42 hours of outages in a single winter storm. The analysis identified that planned retirements, combined with rising winter load from electrification, would stress the system. To restore reliability in SERC-East, the study found that 500 MW of additional perfect capacity would be needed by 2030. Other SERC subregions performed adequately, but continued monitoring is warranted due to shifting seasonal peaks and fuel supply vulnerabilities.

Table 10. Summary of SERC Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.3	8.1	1.2	0.8
Normalized Unserved Energy (%)	0.0001	0.0041	0.0004	0.0002
Unserved Load (MWh)	489	44,514	3,748	2,373
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	4	42	14	10
Normalized Unserved Load (%)	0.0006	0.0428	0.0042	0.0026
Unserved Load (MWh)	5,683	465,392	44,977	2,373
Max Unserved Load (MW)	2,373	19,381	6,359	5,859

Load Assumptions

SERC's peak load was roughly 193 GW in the current system model and projected to increase to roughly 209 GW by 2030. Approximately 7.5 GW of this relates to new AI/DCs being installed (14% of U.S. total).



Subregion	2024	2030
SERC-C	50,787	52,153
SERC-SE	48,235	54,174
SERC-FL	58,882	62,572
SERC-E	51,693	56,313
Total	**193,654**	**209,269**

Figure 18. SERC Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 254 GW. In 2030, 26 GW of new capacity was added leading to 279 GW of capacity in the No Plant Closures case. In the Plant Closures case, 19 GW of capacity was retired such that net generation change in the Plant Closures case was +7 GW, or 260 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SERC-C	53,978	54,014	59,660
SERC-SE	67,073	64,768	69,478
SERC-FL	72,714	83,127	86,173
SERC-E	59,914	58,513	63,973
Total	**253,680**	**260,423**	**279,285**

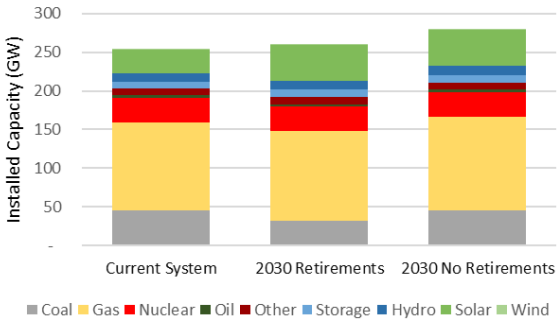


Figure 19. SERC Generation Capacity by Technology and Scenario

SERC's generation mix was comprised primarily of natural gas, coal, nuclear, and solar. In 2024, natural gas comprised 45% of nameplate, coal comprised 18%, nuclear 12%, and solar 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar and some storage. The model assumed 3 GW of rooftop solar and 8 GW of demand response.

Table 11. Nameplate Capacity by SERC Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**45,747**	**113,334**	**31,702**	**4,063**	**8,779**	**7,469**	**11,425**	**30,180**	**982**	**253,680**
SERC-C	13,348	20,127	8,280	148	1,887	1,884	4,995	2,328	982	**53,978**
SERC-SE	13,275	29,866	8,018	915	2,493	1,662	3,260	7,584	0	**67,073**
SERC-FL	4,346	47,002	3,502	1,957	3,198	538	0	12,172	0	**72,714**
SERC-E	14,777	16,340	11,902	1,044	1,202	3,384	3,170	8,096	0	**59,914**
Additions	**0**	**6,898**	**0**	**0**	**381**	**2,254**	**0**	**16,073**	**0**	**25,606**
SERC-C	0	4,831	0	0	0	80	0	771	0	**5,682**
SERC-SE	0	906	0	0	19	0	0	3,135	0	**4,059**
SERC-FL	0	1,161	0	0	218	1,670	0	10,410	0	**13,459**
SERC-E	0	0	0	0	144	504	0	1,757	0	**2,405**
Closures	**(14,075)**	**(4,115)**	**0**	**(672)**	**0**	**0**	**0**	**0**	**0**	**(18,862)**
SERC-C	(4,465)	(1,181)	0	0	0	0	0	0	0	**(5,646)**
SERC-SE	(5,160)	(124)	0	(176)	0	0	0	0	0	**(5,460)**
SERC-FL	(1,495)	(1,071)	0	(480)	0	0	0	0	0	**(3,046)**
SERC-E	(2,955)	(1,739)	0	(16)	0	0	0	0	0	**(4,710)**

2.6 SPP

In the current system model, SPP experienced shortfalls, but they were below the required threshold. Adequacy was preserved through reliance on imports. In the No Plant Closures case, SPP experienced persistent reliability challenges, with average annual LOLH reaching approximately 48 hours per year and peak hourly shortfalls affecting up to 19% of demand. In the Plant Closures case, system conditions deteriorated further, with unserved energy and outage hours increasing substantially. These shortfalls were concentrated in the northern subregion, which lacks the firm generation and import capacity needed to meet peak winter demand. The analysis determined that 1,500 MW of additional perfect capacity would be needed in SPP by 2030 to restore reliability.

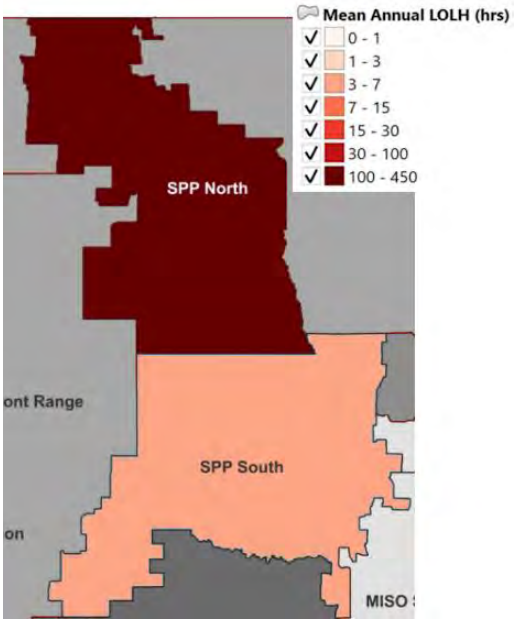
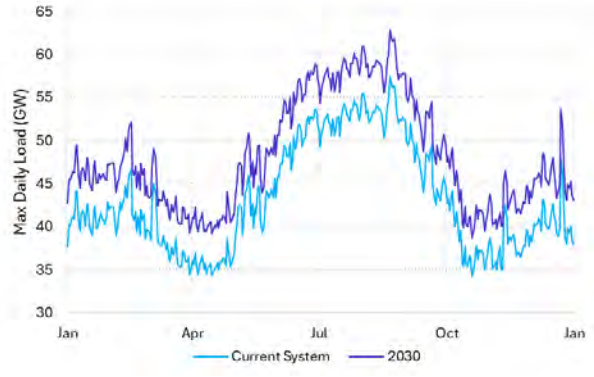


Table 12. Summary of SPP Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	1.7	379.6	47.8	2.4
Normalized Unserved Energy (%)	0.0002	0.0911	0.0081	0.0002
Unserved Load (MWh)	541	313,797	27,697	803
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	20	556	186	26
Normalized Unserved Load (%)	0.0022	0.2629	0.0475	0.0027
Unserved Load (MWh)	6,492	907,518	163,775	9,433
Max Unserved Load (MW)	606	13,263	2,432	762

Load Assumptions

SPP's peak load was roughly 57 GW in the current system model and projected to increase to roughly 63 GW by 2030. Approximately 1.5 GW of this relates to new AI/DCs being installed (3% of U.S. total).



Subregion	2024	2030
SPP-N	12,668	14,676
SPP-S	44,898	48,337
Total	**57,449**	**62,891**

Figure 20. SPP Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 95 GW. In 2030, 15 GW of new capacity was added leading to 110 GW of capacity in the No Plant Closures case. In the Plant Closures case, 7 GW of capacity was retired such that net generation change in the 2030 Plant Closures case was +8 GW, or 103 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SPP-N	20,065	20,679	22,385
SPP-S	75,078	82,451	88,064
Total	**95,142**	**103,130**	**110,449**

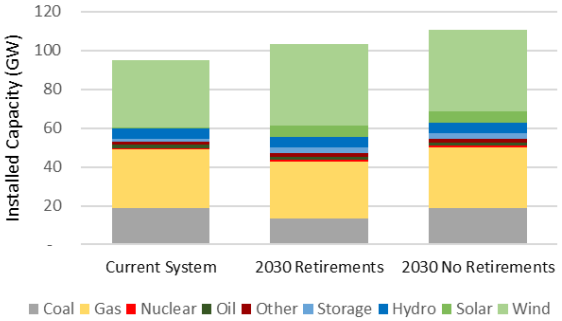


Figure 21. SPP Generation Capacity by Technology and Scenario

SPP's generation mix was comprised primarily of wind, natural gas, and coal. In 2024, wind comprised 36% of nameplate, natural gas comprised 32%, and coal 20%. In the 2030 case, most retirements come from coal and natural gas while additions occur for wind, solar, storage, and natural gas. The model assumed almost no rooftop solar and 1.3 GW of demand response.

Table 13. Nameplate Capacity by SPP Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**18,919**	**30,003**	**769**	**1,626**	**1,718**	**1,522**	**5,123**	**774**	**34,689**	**95,142**
SPP-N	5,089	3,467	304	504	519	8	3,041	91	7,041	**20,065**
SPP-S	13,829	26,536	465	1,121	1,199	1,514	2,082	683	27,649	**75,078**
Additions	**0**	**1,094**	**0**	**7**	**462**	**1,390**	**0**	**5,288**	**7,066**	**15,306**
SPP-N	0	126	0	2	114	11	0	633	1,434	**2,320**
SPP-S	0	968	0	5	348	1,379	0	4,655	5,632	**12,987**
Closures	**(5,530)**	**(1,732)**	**0**	**(56)**	**0**	**0**	**0**	**0**	**0**	**(7,318)**
SPP-N	(1,488)	(200)	0	(17)	0	0	0	0	0	**(1,705)**
SPP-S	(4,042)	(1,532)	0	(39)	0	0	0	0	0	**(5,613)**

2.7 CAISO+

In the current system and No Plant Closures cases, CAISO+ did not experience major reliability issues, though adequacy was often maintained through significant imports during tight conditions. In the Plant Closures case, however, the region faced substantial shortfalls, particularly during summer evening hours when solar output declines. Average LOLH reached 7 hours per year, and the worst-case year showed load shed events affecting up to 31% of demand. The NUSE exceeded reliability thresholds, signaling the system's vulnerability to high load and low renewable output periods.

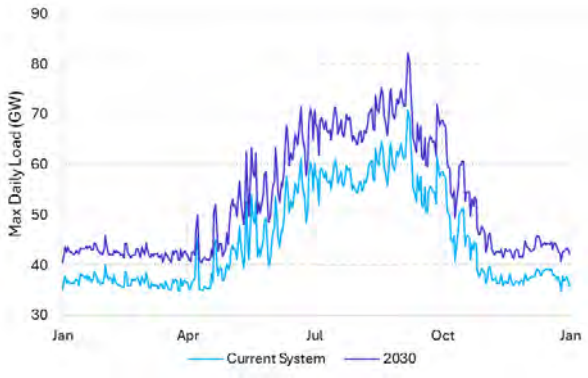


Table 14. Summary of CAISO+ Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	6.8	-	-
Normalized Unserved Energy (%)	-	0.0062	-	-
Unserved Load (MWh)	-	23,488	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	21	-	-
Normalized Unserved Load (%)	-	0.0195	-	-
Unserved Load (MWh)	-	73,462	-	-
Max Unserved Load (MW)	-	12,391	-	-

Load Assumptions

CAISO+'s peak load was roughly 79 GW in the current system model and projected to increase to roughly 82 GW by 2030. Approximately 2 GW of this relates to new AI/DCs being installed (4% of U.S. total).



Subregion	2024	2030
CALI-N	29,366	34,066
CALI-S	41,986	48,666
Total	**70,815**	**82,146**

Figure 22. CAISO+ Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 117 GW. In 2030, 14 GW of new capacity was added leading to 131 GW of capacity in the No Plant Closures case. In the Plant Closures case, 8 GW of capacity was retired such that net closures in the Plant Closures case were +6 GW, or 123 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
CALI-N	47,059	48,897	52,501
CALI-S	69,866	74,041	78,308
Total	**116,925**	**122,938**	**130,809**

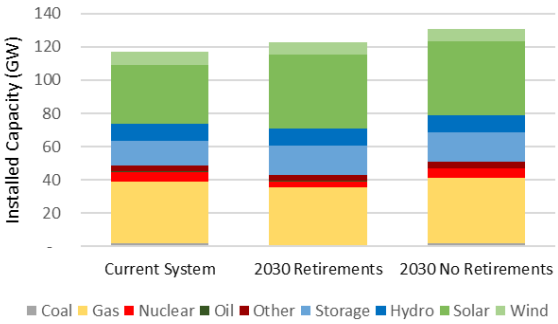


Figure 23. CAISO+ Generation Capacity by Technology and Scenario

CAISO+'s generation mix was comprised primarily of natural gas, solar, storage, and hydro. In 2024, natural gas comprised 32% of nameplate, solar comprised 31%, storage 13%, and hydro 9%. In 2030, most retirements come from coal, natural gas, and nuclear while additions occur for solar and storage. The model assumed 10 GW of rooftop solar and less than 1 GW of demand response.

Table 15. Nameplate Capacity by CAISO+ Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**1,816**	**37,434**	**5,582**	**185**	**3,594**	**14,670**	**10,211**	**35,661**	**7,773**	**116,925**
CALI-N	0	12,942	5,582	165	1,872	4,639	8,727	11,759	1,373	**47,059**
CALI-S	1,816	24,492	0	20	1,722	10,031	1,483	23,902	6,400	**69,866**
Additions	**0**	**2,126**	**0**	**0**	**92**	**3,161**	**0**	**8,507**	**0**	**13,885**
CALI-N	0	735	0	0	44	757	0	3,906	0	**5,442**
CALI-S	0	1,391	0	0	48	2,404	0	4,600	0	**8,442**
Closures	**(1,800)**	**(3,771)**	**(2,300)**	**0**	**0**	**0**	**0**	**0**	**0**	**(7,871)**
CALI-N	0	(1,304)	(2,300)	0	0	0	0	0	0	**(3,604)**
CALI-S	(1,800)	(2,467)	0	0	0	0	0	0	0	**(4,267)**

2.8 West Non-CAISO

In both the current system and No Plant Closures cases, the West Non-CAISO region maintained adequacy on average. In the Plant Closures case, the region's reliability declined, with annual LOLH increasing and peak shortfalls in the worst year affecting up to 20% of hourly load in some subregions. While overall NUSE normalized unserved energy remained just above the 0.002% threshold, specific areas, especially those with limited local resources and constrained transmission, exceeded acceptable risk levels. These reliability gaps were primarily driven by increasing reliance on variable energy resources without sufficient firm generation.

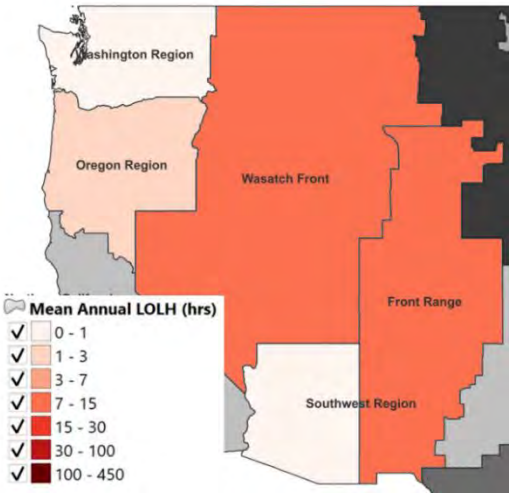
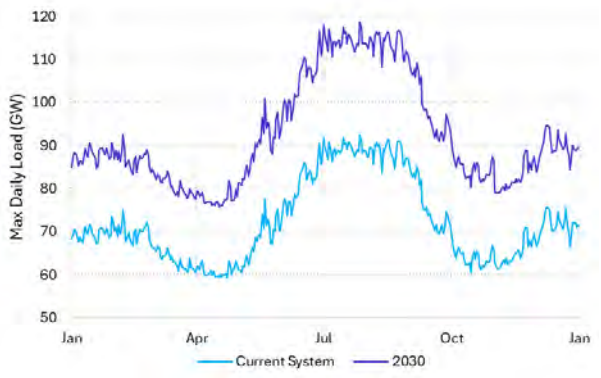


Table 16. Summary of West Non-CAISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	17.8	-	-
Normalized Unserved Energy (%)	-	0.0032	-	-
Unserved Load (MWh)	-	21,785	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	47	-	-
Normalized Unserved Load (%)	-	0.0098	-	-
Unserved Load (MWh)	-	66,248	-	-
Max Unserved Load (MW)	-	5,071	-	-

Load Assumptions

West Non-CAISO's peak load was roughly 92 GW in the current system model and projected to increase to roughly 119 GW by 2030. Approximately 12 GW of this relates to new AI/DCs being installed (24% of U.S. total).



Subregion	2024	2030
WASHINGTON	20,756	23,187
OREGON	11,337	16,080
SOUTHWEST	23,388	30,169
WASATCH	27,161	35,440
FRONT R	20,119	24,996
Total	**92,448**	**118,657**

Figure 24. West Non-CAISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 178 GW. In 2030, 29 GW of new capacity was added leading to 207 GW of capacity in the No Plant Closures case. In the Plant Closures case, 13 GW of capacity was retired such that net generation change in the Plant Closures case was 16 GW, or 193 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
WASHINGTON	35,207	36,588	37,573
OREGON	19,068	21,689	22,081
SOUTHWEST	42,335	47,022	49,158
WASATCH	42,746	45,175	50,251
FRONT R	38,572	43,011	47,844
Total	**177,929**	**193,485**	**206,908**

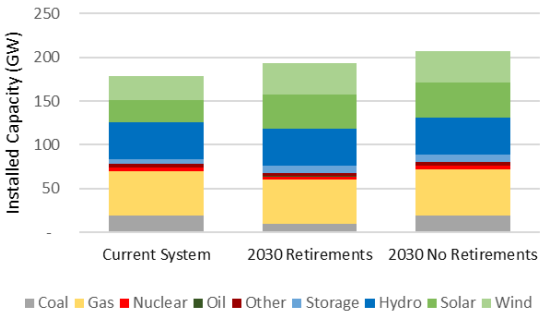


Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

West Non-CAISO's generation mix was comprised primarily of natural gas, hydro, wind, solar, and coal. In 2024, natural gas comprised 28% of nameplate, hydro comprised 24%, wind 15%, solar 13%, and coal 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar, wind, storage, and natural gas. The model assumed 6 GW of rooftop solar and over 1 GW of demand response.

Table 17. Nameplate Capacity by West Non-CAISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**19,850**	**49,969**	**3,820**	**644**	**4,114**	**5,104**	**42,476**	**24,652**	**27,298**	**177,929**
WASHINGTON	560	3,919	1,096	17	595	489	24,402	1,438	2,690	**35,207**
OREGON	0	3,915	0	6	456	482	8,253	2,517	3,440	**19,068**
SOUTHWEST	4,842	17,985	2,724	323	1,316	2,349	1,019	8,093	3,685	**42,335**
WASATCH	7,033	14,061	0	87	1,433	1,194	7,587	7,299	4,052	**42,746**
FRONT R	7,415	10,089	0	211	314	590	1,215	5,306	13,432	**38,572**
Additions	**0**	**2,320**	**0**	**1**	**8**	**2,932**	**0**	**14,759**	**8,959**	**28,979**
WASHINGTON	0	246	0	0	0	109	0	1,059	952	**2,366**
OREGON	0	246	0	0	0	150	0	1,399	1,218	**3,013**
SOUTHWEST	0	309	0	0	0	2,338	0	3,578	599	**6,823**
WASATCH	0	884	0	0	7	233	0	4,946	1,435	**7,505**
FRONT R	0	634	0	0	0	102	0	3,779	4,756	**9,271**
Closures	**(9,673)**	**(2,540)**	**0**	**(6)**	**(311)**	**(170)**	**(627)**	**0**	**(95)**	**(13,422)**
WASHINGTON	(317)	(195)	0	(0)	(66)	(28)	(369)	0	(11)	**(986)**
OREGON	0	(195)	0	(0)	(58)	0	(125)	0	(14)	**(392)**
SOUTHWEST	(1,185)	(951)	0	0	0	0	0	0	0	**(2,136)**
WASATCH	(3,978)	(699)	0	(2)	(178)	(89)	(115)	0	(16)	**(5,077)**
FRONT R	(4,194)	(501)	0	(4)	(8)	(53)	(18)	0	(54)	**(4,832)**

2.9 ERCOT

In the current system model, ERCOT exceeded reliability thresholds, with 3.8 annual Loss of Load Hours and a NUSE of 0.0032%, indicating stress even before future retirements and load growth. In the No Plant Closures case, conditions worsened as average LOLH rose to 20 hours per year and the worst-case year reached 101 hours, driven by data center growth and limited dispatchable additions. The Plant Closures case intensified these risks, with average annual LOLH rising to 45 hours per year and unserved load reaching 0.066%. Peak shortfalls reached 27% of demand, with outages concentrated in winter when generation is most vulnerable. To meet reliability targets, ERCOT would require 10,500 MW of additional perfect capacity by 2030.

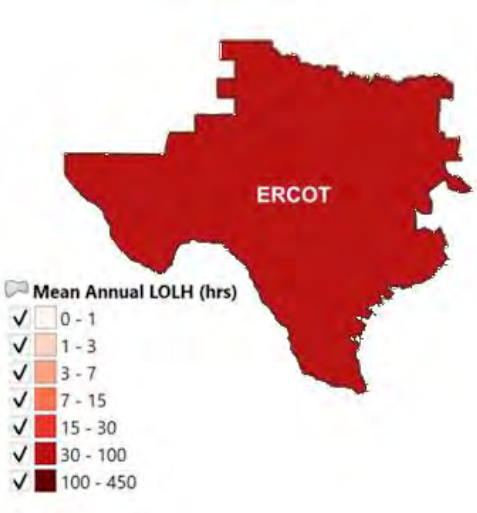
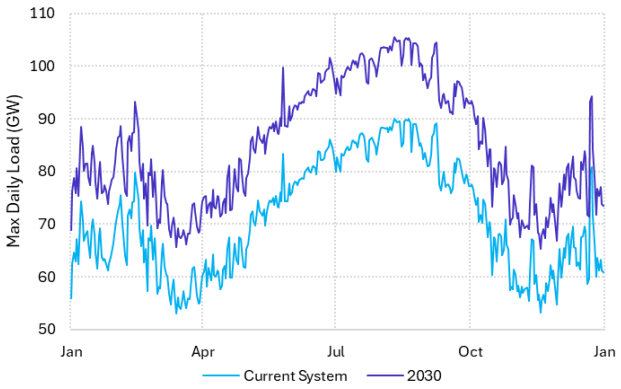


Table 18. Summary of ERCOT Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	3.8	45.0	20.3	1.0
Normalized Unserved Energy (%)	0.0032	0.0658	0.0284	0.0008
Unserved Load (MWh)	15,378	397,352	171,493	4,899
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	30	149	101	12
Normalized Unserved Load (%)	0.0286	0.02895	0.01820	0.0098
Unserved Load (MWh)	136,309	1,741,003	1,093,560	58,787
Max Unserved Load (MW)	10,115	27,156	23,105	8,202

Load Assumptions

ERCOT's peak load was roughly 90 GW in the current system model and projected to increase to roughly 105 GW by 2030. Approximately 8 GW of this relates to new data centers being installed (62% of U.S. total).



Subregion	2024	2030
ERCOT	90,075	105,485
Total	**90,075**	**105,485**

Figure 26. ERCOT Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 157 GW. In 2030, 55 GW of new capacity was added leading to 213 GW of capacity in the No Plant Closures case. In the Plant Closures case, 4 GW of capacity was retired such that net generation change in the Plant Closures case was +51 GW, or 208 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ERCOT	157,490	208,894	212,916
Total	**157,490**	**208,894**	**212,916**

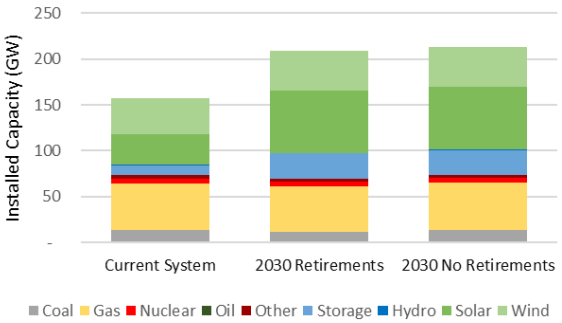


Figure 27. ERCOT Generation Capacity by Technology and Scenario

ERCOT's generation mix was comprised primarily of natural gas, wind, and solar. In 2024, natural gas comprised 32% of nameplate, wind comprised 25%, and solar 22%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed 2.5 GW of rooftop solar and 3.5 GW of demand response.

Table 19. Nameplate Capacity for ERCOT and by Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**13,568**	**50,889**	**4,973**	**10**	**3,627**	**10,720**	**583**	**33,589**	**39,532**	**157,490**
ERCOT	13,568	50,889	4,973	10	3,627	10,720	583	33,589	39,532	**157,490**
Additions	**0**	**569**	**0**	**0**	**0**	**16,538**	**0**	**34,681**	**3,638**	**55,426**
ERCOT	0	569	0	0	0	16,538	0	34,681	3,638	**55,426**
Closures	**(2,000)**	**(2,022)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(4,022)**
ERCOT	(2,000)	(2,022)	0	0	0	0	0	0	0	**(4,022)**

Appendix A - Generation Calibration and Forecast

The study team started with the grid model from the NERC ITCS, which was published in 2024 with reference to NERC 2023 LTRA capacity.[27] This zonal ITCS model serves as the starting point for the network topology (covering 23 U.S regions), transmission capacity between zones, and general modeling assumptions. The resource mix and retirements in the ITCS model were updated for this study to reflect the various 2030 scenarios discussed previously. Prior to developing the 2030 scenarios, the study team also updated the 2024 ITCS model to ensure consistency in the current model assumptions.

2024 Resource Mix

Because there were noted changes in assumed capacity additions between the 2023 and 2024 LTRAs[28], the ITCS model was updated with the 2024 LTRA data, provided directly by NERC to the study team. The 2024 LTRA dataset, reported at the NERC assessment area level—which is more aggregated in some areas than the ITCS regional structure (covering 13 U.S. regions; see Figure A.1)—includes both existing resource capacities[29] and Tier 1, 2, and 3 planned additions for each year from 2024 to 2033. As explained below, to incorporate this data into the ITCS model, a mapping process was developed to disaggregate generation capacities from the NERC assessment areas to the more granular ITCS regions by technology type. To preserve the daily or monthly adjustments to generator availability for certain categories (wind, solar, hybrid, hydropower, batteries, and other) by using the ITCS methods, the nameplate LTRA capacity was used. For all other categories (mostly thermal generators), summer and winter on-peak capacity contributions were used.

27. NERC, “Interregional Transfer Capability Study (ITCS).” https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.

28. NERC, “2024 Long-Term Reliability Assessment,” December, 2024, 24. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

29. Capacities are reported for both winter and summer seasonal ratings, along with nameplate values.

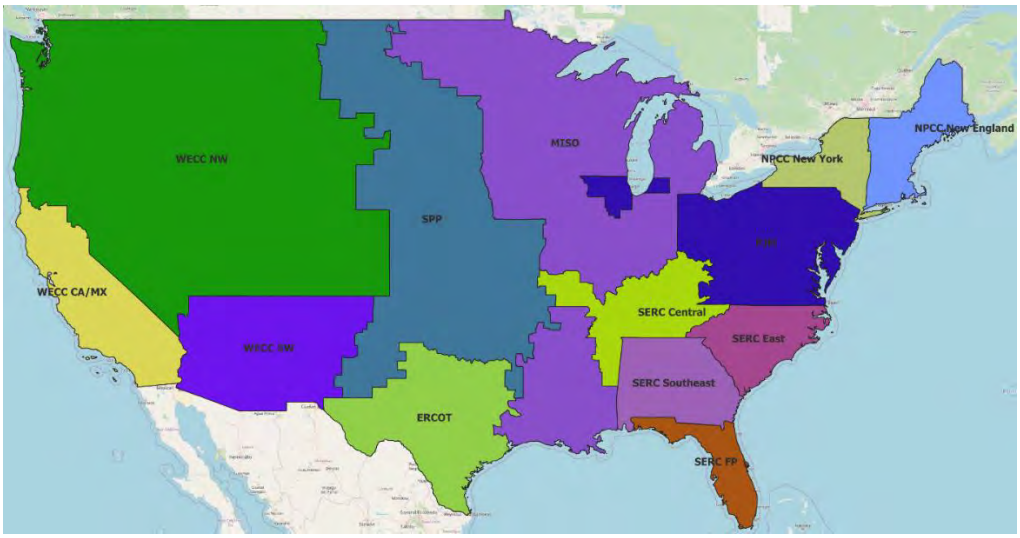


Figure A.1. NERC assessment areas.

To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant-level data were used to tabulate the generation capacity for each ITCS region and NERC assessment area. The geographical boundaries for the NERC assessment areas and the ITCS regions were constructed based on ReEDS zones.[30] Disaggregation fractions were then calculated by technology type using the combined existing capacity and planned additions through 2030 from EIA 860 data as of December 2024. Specifically, to compute each fraction, an ITCS region's total (existing plus planned) capacity was divided by the corresponding total capacity across all ITCS regions within the same mapped NERC assessment area and fuel type group:

$$Fraction_{rf} = \frac{Capacity_{rf}}{\sum_{r' \in ITCS(R)} Capacity_{r'f}} \qquad \textit{(Equation.1)}$$

Where $Capacity_{rf}$ is the capacity of fuel type f in ITCS region r and $ITCS(R)$ is the set of all ITCS regions mapped to the same NERC assessment area R. The denominator is the total capacity of that fuel type across all ITCS regions mapped to R.

Note that in cases where NERC assessment areas align one-to-one with ITCS regions, no mapping was required. Table A.1 summarizes which areas exhibited a direct one-to-one matching and which required disaggregation (1-to-many) or aggregation (many-to-one) to align with the ITCS regional structure.

An exception to this general approach is the case of the Front Range ITCS region, which geographically spans across two NERC assessment areas—WECC-NW and WECC-SW—resulting in two-to-one mapping. For this case, a separate allocation method was used: Plant-level data from EIA 860 were analyzed to determine the proportion of Front Range capacity located in each NERC area. These proportions were then used to derive custom weighting factors for allocating capacities from both WECC-NW and WECC-SW into the Front Range region.

30. NREL, "Regional Energy Development System," https://www.nrel.gov/analysis/reeds/.

Table A.1. Mapping of NERC assessment areas to ITCS regions.

NERC Area	ITCS Region	Match
ERCOT	ERCOT	1 to 1
NPCC-New England	NPCC-New England	1 to 1
NPCC-New York	NPCC-New York	1 to 1
SERC-C	SERC-C	1 to 1
SERC-E	SERC-E	1 to 1
SERC-FP	SERC-FP	1 to 1
SERC-SE	SERC-SE	1 to 1
WECC-SW	Southwest Region	1 to 1
MISO	MISO Central	1 to 4
MISO	MISO East	
MISO	MISO South	
MISO	MISO West	
SPP	SPP North	1 to 2
SPP	SPP South	
WECC-CAMX	Southern California	1 to 2
WECC-CAMX	Northern California	
WECC-NW	Oregon Region	1 to 3
WECC-NW	Washington Region	
WECC-NW	Wasatch Front	
WECC-NW	Front Range	2 to 1
WECC-SW	Front Range	

Table A.2 and Figure A.2 show the same combined capacities by ITCS region and NERC planning region, respectively.

Table A.2. Existing and Tier 1 capacities by NERC assessment area (in MW) in 2024.

2024 Exsting + Tier 1			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**330,342**	**82,793**	**26,771**	**3,624**	**-**	**991**	**19,607**	**3,298**	**28,980**	**72,757**	**94,364**	**25,753**	**24,367**	**856,682**
	ISONE	**Total**	541	15,494	3,331	5,710	818	-	233	1,571	57	1,911	3,386	2,553	661	3,713	39,979
	MISO	**Total**	**37,914**	**64,194**	**11,127**	**2,867**	**613**	**-**	**329**	**4,396**	**1,031**	**2,533**	**29,777**	**41,715**	**7,775**	**3,049**	**207,319**
		MISO-W	12,651	13,608	2,753	1,491	244	-	2	-	200	777	7,368	29,411	2,367	741	71,612
		MISO-C	15,050	10,307	2,169	494	32	-	152	773	499	769	10,587	7,350	2,026	1,774	51,982
		MISO-S	5,493	31,052	5,100	589	243	-	117	49	5	845	8,024	596	2,109	291	54,511
		MISO-E	4,720	9,227	1,105	292	94	-	57	3,574	327	143	3,799	4,359	1,273	243	29,213
	NYISO	**Total**	-	22,937	3,330	2,631	334	-	-	1,400	60	4,915	1,039	2,706	860	5,710	45,924
	PJM	**Total**	**39,915**	**84,381**	**32,535**	**9,875**	**851**	**-**	**-**	**5,062**	**338**	**3,071**	**10,892**	**11,718**	**7,397**	**8,603**	**214,638**
		PJM-W	34,917	39,056	16,557	1,933	112	-	-	234	149	1,252	5,780	10,065	3,814	599	114,467
		PJM-S	2,391	15,038	5,288	3,985	479	-	-	2,958	127	1,070	3,932	360	1,824	2,498	39,951
		PJM-E	2,608	30,287	10,690	3,956	260	-	-	1,870	62	749	1,180	1,294	1,759	5,506	60,221
	SERC	**Total**	**45,747**	**113,334**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**768**	**11,425**	**26,959**	**982**	**7,707**	**3,221**	**253,680**
		SERC-C	13,348	20,127	8,280	148	36	-	-	1,784	100	4,995	2,308	982	1,851	20	53,978
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	115	3,260	7,267	-	2,069	317	67,073
		SERC-FL	4,346	47,002	3,502	1,957	310	-	83	-	538	-	10,121	-	2,804	2,051	72,714
		SERC-E	14,777	16,340	11,902	1,044	219	-	-	3,369	15	3,170	7,263	-	983	833	59,914
	SPP	**Total**	**18,919**	**30,003**	**769**	**1,626**	**20**	**-**	**345**	**477**	**1,044**	**5,123**	**703**	**34,689**	**1,353**	**71**	**95,142**
		SPP-N	5,089	3,467	304	504	1	-	185	-	8	3,041	84	7,041	333	7	20,065
		SPP-S	13,829	26,536	465	1,121	19	-	160	477	1,037	2,082	619	27,649	1,020	64	75,078
ERCOT	**Total**		**13,568**	**50,889**	**4,973**	**10**	**163**	**-**	**-**	**-**	**10,720**	**583**	**31,058**	**39,532**	**3,464**	**2,531**	**157,490**
	ERCOT	**Total**	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490
WEST	**Total**		**21,666**	**87,403**	**9,403**	**829**	**1,565**	**4,093**	**106**	**4,536**	**15,238**	**52,687**	**44,042**	**35,071**	**1,944**	**16,271**	**294,854**
	CAISO+	**Total**	**1,816**	**37,434**	**5,582**	**185**	**726**	**2,004**	**35**	**3,514**	**11,156**	**10,211**	**25,614**	**7,773**	**829**	**10,047**	**116,925**
		CALI-N	-	12,942	5,582	165	465	1,049	9	1,967	2,672	8,727	6,723	1,373	349	5,036	47,059
		CALI-S	1,816	24,492	-	20	261	955	26	1,547	8,484	1,483	18,891	6,400	480	5,011	69,866
	Non-CA WECC	**Total**	**19,850**	**49,969**	**3,820**	**644**	**839**	**2,089**	**71**	**1,022**	**4,082**	**42,476**	**18,428**	**27,298**	**1,115**	**6,224**	**177,929**
		WA	560	3,919	1,096	17	352	-	-	140	350	24,402	1,052	2,690	243	386	35,207
		OR	-	3,915	-	6	293	21	-	-	482	8,253	2,145	3,440	141	372	19,068
		SOUTHWEST	4,842	17,985	2,724	323	102	1,047	-	176	2,173	1,019	5,641	3,685	168	2,452	42,335
		WASATCH	7,033	14,061	-	87	56	1,011	61	444	750	7,587	5,625	4,052	305	1,674	42,746
		FRONT R	7,415	10,089	-	211	36	10	10	262	328	1,215	3,966	13,432	258	1,340	38,572
		Total	**178,268**	**468,635**	**97,169**	**27,610**	**5,353**	**4,093**	**1,096**	**24,144**	**29,256**	**82,249**	**147,856**	**168,966**	**31,161**	**43,169**	**1,309,026**

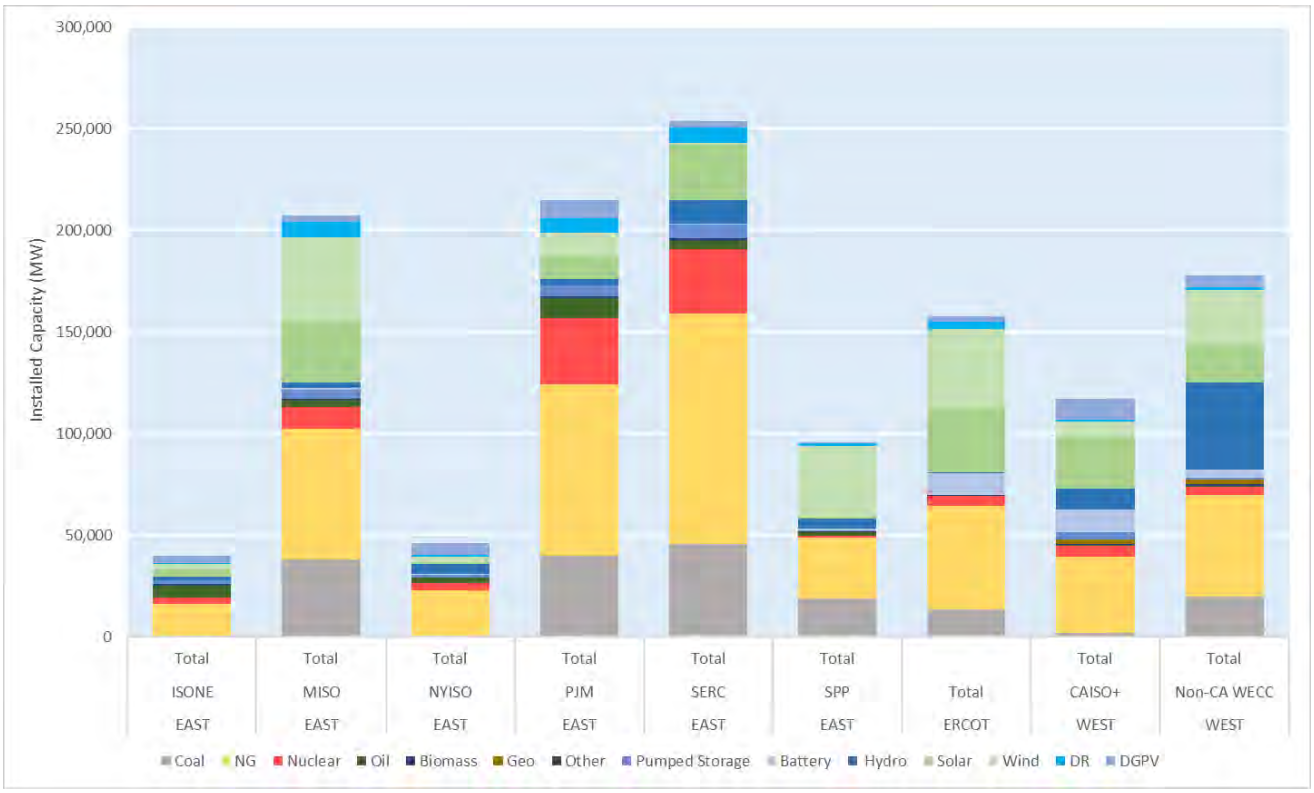


Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

Forecasting 2030 Resource Mixes

To develop the 2030 ITCS generation portfolio, the study team added new capacity builds and removed planned retirements.

(i) *Tier 1*: Assumes that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built. This results in minimal capacity additions beyond 2026. The data are based on projects designated as Tier 1 in the 2024 LTRA data for the year 2030.

Retirements

To project which units will retire by 2030, the study team primarily used the LTRA 2024 data and cross-checked it with EIA data. The assessment areas were disaggregated to ITCS zones based on the ratios of projected retirements in EIA 860 data. The three scenarios modeled are as follows:

(i) *Announced*: Assumes that in addition to confirmed retirements, generators that have publicly announced retirement plans but have not formally notified system operators have also begun the retirement process. This is based on data from the 2024 LTRA, which were collected by the NERC team from sources like news announcements, public disclosures, etc.

(ii) *None*: Assumes that there are no retirements between 2024 and 2030 for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirements contribute to resource adequacy challenges in regions where rapid AI and data center growth is expected.

Generation Stack for Each Scenario

Finally, when summing all potential future changes, the team arrived at a generation stack for each of the various scenarios to be studied. The first figure provides a visual comparison of all the cases, which vary from 1,309 GW to 1,519 GW total generation capacity for the entire continental United States, to enable the exploration of a range of potential generation futures. The tables below provide breakdowns by ITCS region and by resource type.

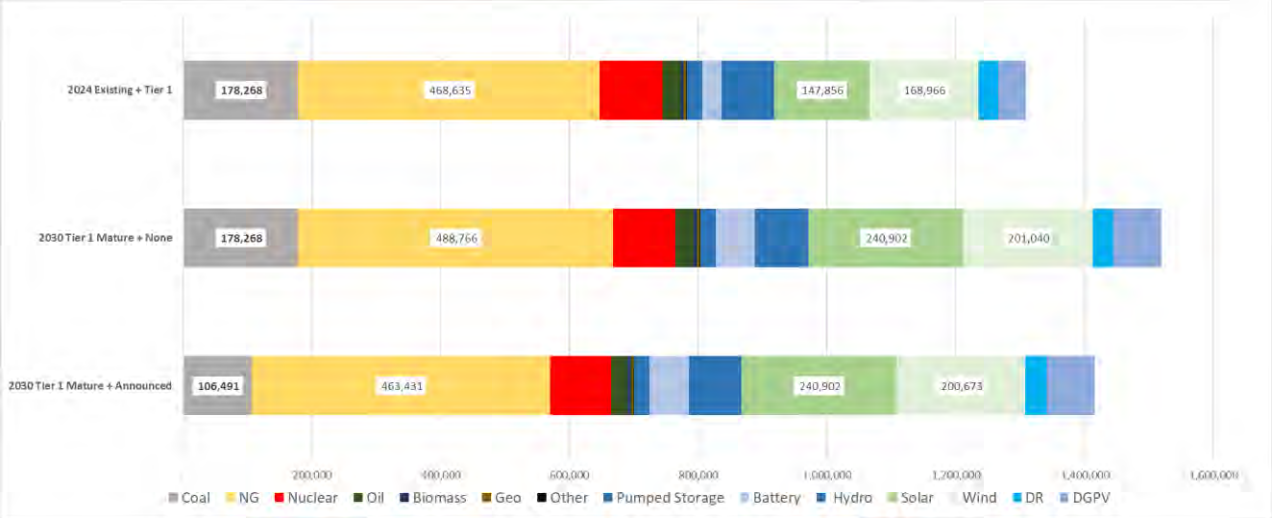


Figure A.9. Comparison of 2030 generation stacks for the various scenarios.

Table A.4. 2030 generation stack for Tier 1 mature + announced retirements.

2030 Tier 1 Mature + Announced			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**84,730**	**328,457**	**82,793**	**24,272**	**3,473**	**-**	**991**	**19,591**	**12,415**	**28,897**	**126,849**	**113,568**	**26,837**	**36,768**	**889,641**
	ISONE	**Total**	7	13,708	3,331	5,687	741	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	42,845
	MISO	**Total**	**13,001**	**60,132**	**11,127**	**2,873**	**473**	**-**	**329**	**4,380**	**2,960**	**2,450**	**44,132**	**43,369**	**7,775**	**3,049**	**196,049**
		MISO-W	4,338	12,747	2,753	1,494	188	-	2	-	574	751	10,920	30,577	2,367	741	67,453
		MISO-C	5,161	9,655	2,169	495	25	-	152	770	1,433	743	15,690	7,642	2,026	1,774	47,735
		MISO-S	1,883	29,087	5,100	591	187	-	117	49	14	817	11,892	619	2,109	291	52,756
		MISO-E	1,619	8,643	1,105	293	72	-	57	3,561	938	138	5,630	4,531	1,273	243	28,105
	NYISO	**Total**	-	21,907	3,330	2,628	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	50,396
	PJM	**Total**	**26,662**	**87,228**	**32,535**	**8,117**	**917**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**236,798**
		PJM-W	23,323	40,373	16,557	1,589	120	-	-	234	1,004	1,252	17,793	16,153	3,939	762	123,100
		PJM-S	1,597	15,546	5,288	3,276	516	-	-	2,958	853	1,070	12,105	577	1,883	3,181	48,850
		PJM-E	1,742	31,309	10,690	3,252	280	-	-	1,870	419	749	3,632	2,076	1,816	7,012	64,848
	SERC	**Total**	**31,672**	**116,117**	**31,702**	**3,391**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**260,423**
		SERC-C	8,883	23,777	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	54,014
		SERC-SE	10,321	28,127	8,018	899	424	-	-	1,548	618	3,260	9,024	-	2,213	317	64,768
		SERC-FL	2,851	47,092	3,502	1,477	310	-	83	-	2,208	-	16,717	-	3,022	5,865	83,127
		SERC-E	9,617	17,122	11,902	868	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	58,513
	SPP	**Total**	**13,389**	**29,365**	**769**	**1,576**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**103,130**
		SPP-N	3,602	3,394	304	489	1	-	185	-	18	3,041	717	8,475	447	7	20,679
		SPP-S	9,787	25,971	465	1,087	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	82,451
ERCOT	**Total**		**11,568**	**49,436**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**208,894**
	ERCOT	**Total**	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
WEST	**Total**		**10,193**	**85,538**	**7,103**	**823**	**1,427**	**3,983**	**106**	**4,366**	**21,330**	**52,060**	**51,648**	**43,935**	**1,981**	**31,931**	**316,424**
	CAISO+	**Total**	**16**	**35,789**	**3,282**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**122,938**
		CALI-N	-	12,373	3,282	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	48,897
		CALI-S	16	23,416	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	74,041
	Non-CA WECC	**Total**	**10,177**	**49,749**	**3,820**	**639**	**701**	**1,924**	**71**	**852**	**7,014**	**41,849**	**24,536**	**36,162**	**1,115**	**14,876**	**193,485**
		WA	243	3,971	1,096	16	286	-	-	111	459	24,033	1,404	3,631	243	1,092	36,588
		OR	-	3,967	-	6	238	18	-	-	632	8,128	2,865	4,644	141	1,051	21,689
		SOUTHWEST	3,657	17,343	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	47,022
		WASATCH	3,055	14,247	-	86	45	850	61	355	983	7,472	7,512	5,470	305	4,733	45,175
		FRONT R	3,221	10,222	-	208	30	8	10	209	430	1,197	5,296	18,133	258	3,789	43,011
		Total	**106,491**	**463,431**	**94,869**	**25,106**	**5,063**	**3,983**	**1,096**	**23,958**	**61,003**	**81,539**	**240,902**	**200,673**	**32,282**	**74,563**	**1,414,959**

Table A.5. 2030 generation stack for Tier 1 mature + no retirements.

2030 Tier 1 Mature + No Retirements			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**345,459**	**82,793**	**27,336**	**3,701**	**-**	**991**	**19,607**	**12,415**	**28,980**	**126,849**	**113,840**	**26,837**	**36,768**	**968,610**
	ISONE	**Total**	541	15,584	3,331	5,891	818	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	45,534
	MISO	**Total**	**37,914**	**66,729**	**11,127**	**3,197**	**613**	**-**	**329**	**4,396**	**2,960**	**2,533**	**44,132**	**43,641**	**7,775**	**3,049**	**228,393**
		MISO-W	12,651	14,145	2,753	1,662	244	-	2	-	574	777	10,920	30,768	2,367	741	77,605
		MISO-C	15,050	10,714	2,169	551	32	-	152	773	1,433	769	15,690	7,690	2,026	1,774	58,823
		MISO-S	5,493	32,278	5,100	657	243	-	117	49	14	845	11,892	623	2,109	291	59,710
		MISO-E	4,720	9,592	1,105	326	94	-	57	3,574	938	143	5,630	4,560	1,273	243	32,255
	NYISO	**Total**	-	22,937	3,330	2,646	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	51,444
	PJM	**Total**	**39,915**	**88,880**	**32,535**	**9,907**	**928**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**253,504**
		PJM-W	34,917	41,138	16,557	1,939	122	-	-	234	1,004	1,252	17,793	16,153	3,939	762	135,810
		PJM-S	2,391	15,840	5,288	3,998	522	-	-	2,958	853	1,070	12,105	577	1,883	3,181	50,667
		PJM-E	2,608	31,902	10,690	3,969	284	-	-	1,870	419	749	3,632	2,076	1,816	7,012	67,027
	SERC	**Total**	**45,747**	**120,232**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**279,285**
		SERC-C	13,348	24,958	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	59,660
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	618	3,260	9,024	-	2,213	317	69,478
		SERC-FL	4,346	48,163	3,502	1,957	310	-	83	-	2,208	-	16,717	-	3,022	5,865	86,173
		SERC-E	14,777	17,246	11,902	1,044	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	63,973
	SPP	**Total**	**18,919**	**31,098**	**769**	**1,632**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**110,449**
		SPP-N	5,089	3,594	304	506	1	-	185	-	18	3,041	717	8,475	447	7	22,385
		SPP-S	13,829	27,504	465	1,126	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	88,064
ERCOT	**Total**		**13,568**	**51,458**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**212,916**
	ERCOT	**Total**	13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
WEST	**Total**		**21,666**	**91,849**	**9,403**	**829**	**1,565**	**4,156**	**106**	**4,536**	**21,330**	**52,687**	**51,648**	**44,030**	**1,981**	**31,931**	**337,717**
	CAISO+	**Total**	**1,816**	**39,560**	**5,582**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**130,809**
		CALI-N	-	13,677	5,582	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	52,501
		CALI-S	1,816	25,883	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	78,308
	Non-CA WECC	**Total**	**19,850**	**52,289**	**3,820**	**645**	**839**	**2,097**	**71**	**1,022**	**7,014**	**42,476**	**24,536**	**36,257**	**1,115**	**14,876**	**206,908**
		WA	560	4,166	1,096	17	352	-	-	140	459	24,402	1,404	3,642	243	1,092	37,573
		OR	-	4,161	-	6	293	22	-	-	632	8,253	2,865	4,658	141	1,051	22,081
		SOUTHWEST	4,842	18,294	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	49,158
		WASATCH	7,033	14,945	-	88	56	1,018	61	444	983	7,587	7,512	5,486	305	4,733	50,251
		FRONT R	7,415	10,723	-	212	36	10	10	262	430	1,215	5,296	18,187	258	3,789	47,844
		Total	**178,268**	**488,766**	**97,169**	**28,175**	**5,429**	**4,156**	**1,096**	**24,144**	**61,003**	**82,249**	**240,902**	**201,040**	**32,282**	**74,563**	**1,519,243**

Appendix B - Representing Canadian Transfer Limits

Introduction

The reliability and stability of cross-border electricity interconnections between the United States and Canada are critical to ensuring continuous power delivery amid evolving demands and variable supply conditions. In recent years, increased integration of wind and solar generation, coupled with extreme weather events, has introduced significant uncertainties in regional power flows.

This report describes the development and implementation of a machine learning (ML)-based model designed to project the maximum daily energy transfer (MaxFlow) across major United States–Canada interfaces, such as BPA–BC Hydro and NYISO–Ontario. Leveraging 15 years of high-resolution load and generation data, summarizing it into key daily statistics, and training a robust eXtreme Gradient Boosting (XGBoost) regressor can allow data-driven predictions to be captured with quantified uncertainty.

The project team provided percentile-based forecasts—25, 50, and 75 percent—to support both conservative and strategic planning. The conservative methodology (25 percent) was used for this report to ensure availability when needed.

The subsequent sections detail the methodology used for data processing and feature engineering, the architecture and training of the predictive model, and the validation metrics and feature importance analyses used. Future enhancements could include incorporating weather patterns, neighboring-region dynamics, and fuel-specific generation profiles to further strengthen predictive performance and support grid resilience.

Methodology

This section describes the ML approach used to build the MaxFlow prediction model.

Dataset Collection and Preparation

Data were collected for hourly and derived daily load and generation over a 15-year period (2010–2024), comprising 8,760 hourly observations annually. Hourly interconnection flow rates were collected for the same years across all major United States–Canada interfaces.[1–17]

Underlying Hypothesis

The team hypothesized that the MaxFlow between interconnected regions is critically influenced by regional load and generation extrema (maximum and minimum) and their variability. These statistics reflect grid stress conditions, influencing interregional energy flow. Additionally, nonlinear interactions due to imbalances in adjacent regions further affect energy transfer dynamics.

Regression Model

The XGBoost regression model was chosen because of its ability to capture complex, nonlinear relationships, regularization capability to prevent overfitting, high speed and performance, fast convergence, built-in handling of missing data, and ease of confidence interval approximation.

XGBoost builds many small decision trees, one after another. Each new tree learns to correct the mistakes of the previous ensemble by focusing on which predictions had the greatest error. Instead of creating one large, complex tree, it combines many simpler trees—each making a modest adjustment—so that, together, they capture nonlinear patterns and interactions. Regularization (penalties for tree size and leaf adjustments) prevents overfitting, and a "learning rate" scales each tree's contribution so that improvements are made gradually. The final prediction is simply the sum of all those small corrections.

Model Training, Validation, and Assessment

Figure B.1 shows the data analysis and prediction process, which ties together seven stages—from raw CSV loading through outlier filtering, feature engineering, projecting to 2030, rebuilding 2030 features, training an XGBoost model, and finally making and evaluating the 2030 flow forecasts with quantiles. Each stage feeds into the next, ensuring that the features used for training mirror exactly those that will be available for future (2030) predictions.

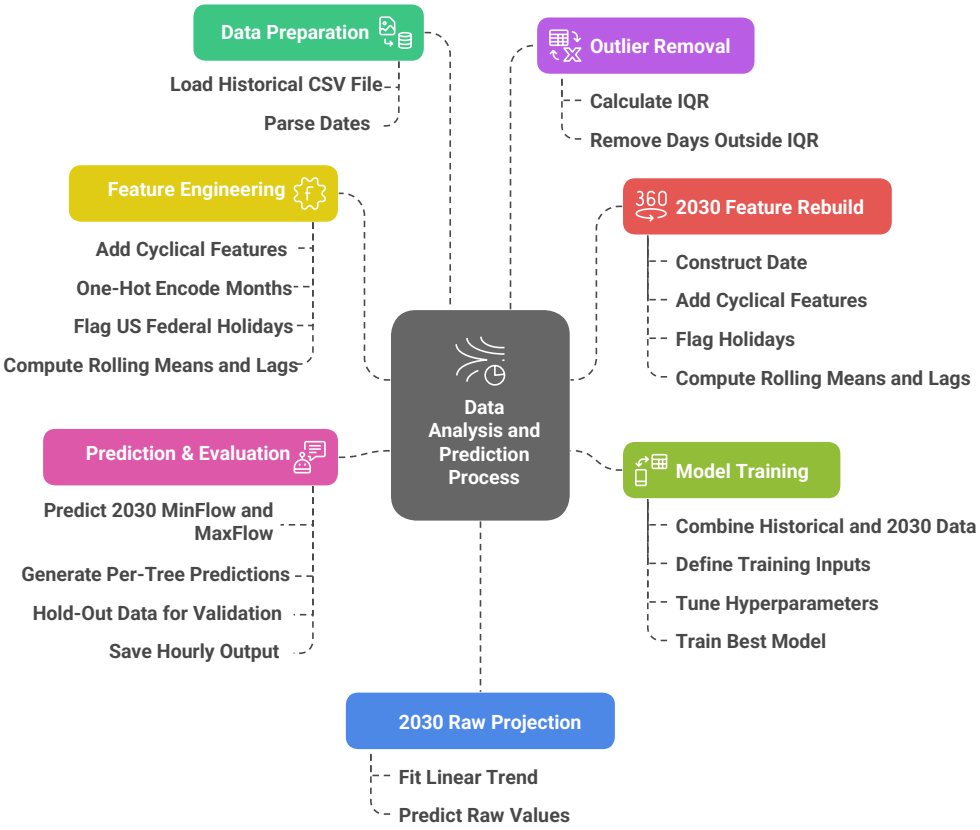


Figure B.1. Data analysis and prediction process.

Example Feature Importance for Predicting MaxFlow from Ontario to NYISO

The trained ML/XGBoost model can be used for predicting the desired year's MaxFlow. In addition, feature importance analysis can be added to assess the contribution of each variable.

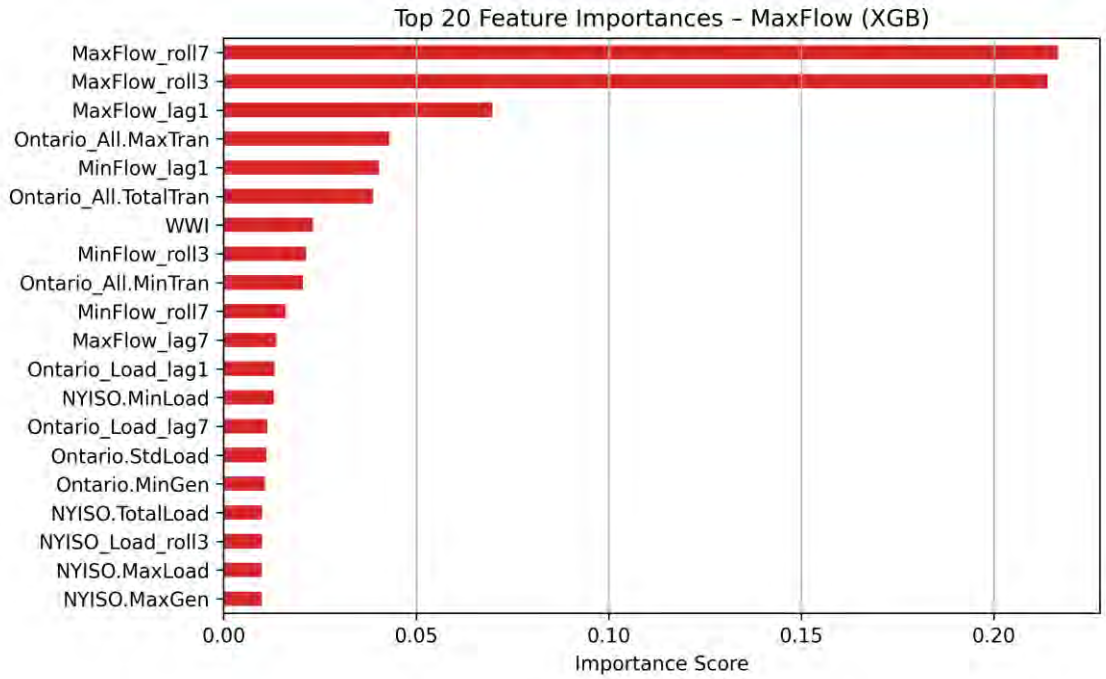


Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

The feature importance plot shows that MaxFlow rolling/lagging features and Ontario_All.MaxTran are the dominant predictors of MaxFlow, meaning temporal patterns and Ontario's peak transfer capacity strongly influence interregional flow limits. Weather-related variables (WWI, e.g., temperature, humidity, etc.) and Ontario_All.TotalTran also rank highly. The 2030 MaxFlow prediction plot shows seasonal fluctuations, with higher values early and late in the year. The red shaded area represents a 95 percent confidence interval for the predictions.

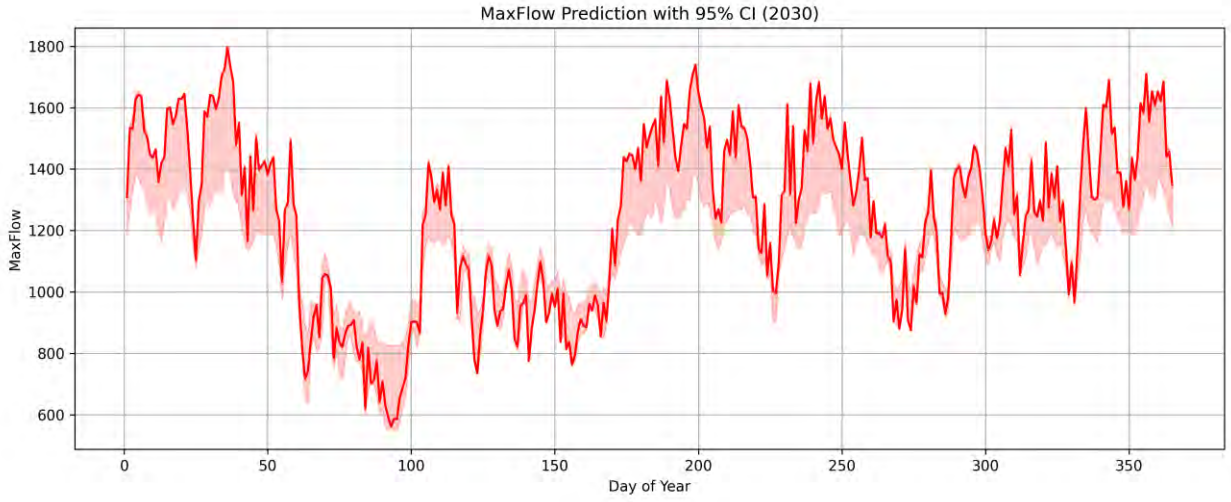


Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

Model Performance

Validating model performance on unseen data is essential to ensure the model's reliability and generalizability. The following evaluation examines how well the XGBoost model predicts minimum energy transfer (MinFlow) and MaxFlow on the validation split, highlighting strengths and areas for improvement.

Rigorous performance evaluation is a fundamental step in any ML workflow. From quantifying error metrics (root mean square error and mean absolute error) and goodness-of-fit (R^2) on both training and validation splits, it is possible to identify overfitting, assess generalization, and guide model refinement. Table B.1 shows XGBoost model performance for the Ontario–NYISO transfer limit.

Table B.1. eXtreme Gradient Boosting model performance for the Ontario–NYISO transfer limit.

Metric	Value	Explanation
MinFlow RMSE (Train)	69.2528	Root mean square error (RMSE) on training data for minimum energy transfer (MinFlow)
MinFlow R^2 (Train)	0.9651	R^2 on training data for MinFlow (higher → better fit)
MinFlow RMSE (Validation)	163.6642	RMSE on held-out data for MinFlow
MinFlow R^2 (Validation)	0.8073	R^2 on held-out data for MinFlow (higher → better generalization)
MaxFlow RMSE (Train)	114.4234	RMSE on training data for maximum energy transfer (MaxFlow)
MaxFlow R^2 (Train)	0.8838	R^2 on training data for MaxFlow (higher → better fit)
MaxFlow RMSE (Validation)	144.9614	RMSE on held-out data for MaxFlow
MaxFlow R^2 (Validation)	0.8178	R^2 on held-out data for MaxFlow (higher → better generalization)

Overall, the XGBoost model delivers excellent in-sample as well as out-of-sample accuracy. Similar outputs are available for each transfer limit.

Maximum flow predictions: Ontario to New York

Ontario and NYISO are connected through multiple high-voltage interconnections, which collectively provide a total transfer capability of up to 2,500 MW, subject to individual tie-line limits. Table B.2 outlines the data sources, preparation process, and assumptions used in creating datasets for the prediction models.

Table B.2. Ontario to New York transmission flow data and assumptions overview.

	Description
Data source	https://www.ieso.ca/power-data/data-directory
Data preparation	IESO public hourly inter-tie schedule flow data can be accessed for the years spanning from 2002 to 2023.
Assumptions	Positive flow indicates that Ontario is exporting to NY, and negative flow indicates that Ontario is importing from NY.

Figure B.4 illustrates the historical monthly MaxFlow for Ontario from 2007 through 2024, alongside 2030 projected quartile scenarios (Q1, Q2, and Q3). Analyzing these trends helps assess future reliability and facilitates capacity planning under varying conditions.

Historical monthly peaks (2007–2023) reveal a clear seasonal cycle for ONT–NYISO transfers: flows typically increase in late winter/early spring (February–April) and again in late fall/early winter (November–December). Over 16 years, the average spring peaks hovered around 1,700–1,900 MW, with occasional spikes above 2,200 MW. The 2030 forecast for Q1, Q2, and Q3 aligns with this pattern, predicting a springtime peak near 1,800 MW, a summer trough around 1,400 MW, and a modest late-summer uptick near 1,500 MW.

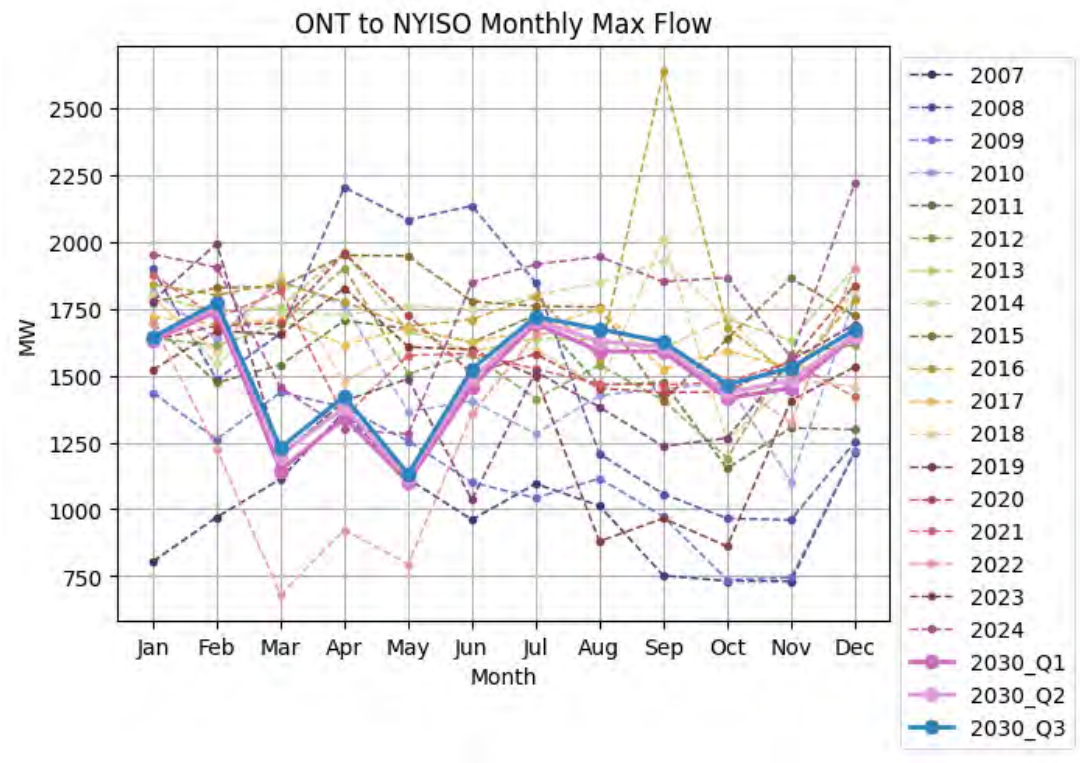


Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

The team used robust validation metrics to justify these results. When trained on daily data from the 2010–2024 period—incorporating projected 2030 loads, seasonal flags, and holiday effects—the XGBoost model achieved $R^2 > 0.80$ and a root mean square error below 150 MW on an unseen 20 percent hold-out dataset. Moreover, the 95 percent confidence intervals for monthly maxima were narrow (approximately ±150 MW), demonstrating low predictive uncertainty. A comparison of predicted maxima with historical extremes revealed that 2030 forecasts consistently fell within (or slightly above) the previous window of variability, implying realistic demand-driven behavior. In summary, the close alignment with historical peaks, strong cross-validated performance, and tight confidence bands collectively validate the results.

Discussion

The reason that the team used ML/XGBoost to approximate the 2030 transfer profiles was to ensure that there would be no violations or inconsistencies between transfer limits, load, and generation. The 15 years of data used were sufficient for having the models learn historical relationships and project them forward to 2030 to capture the underlying trends in load,

generation, and their interactions. The use of such an extensive dataset justifies using ML to establish consistent transfer profiles.

However, in some regions, like Ontario to NYISO, the available data encompassed a shorter time period, and the relationships were only partially captured because of a lack of neighboring-region data. In such cases, it was necessary to incorporate additional predictors, such as rolling and lag features from the transfer limits. Although the direct use of transfer limit data to project future transfer limits would typically be avoided, these engineered features help improve predictions when data coverage is sparse and the model's goodness-of-fit is low.

In all cases, the ML models ensured that these historical relationships were not violated, maintaining internal consistency among load, generation, and transfer limits. Overall, the team relied on ML when long-term data were available for training and projecting load and generation profiles. Rolling and lag features were used to reinforce the model when data availability was limited, but always with the goal of upholding consistent physical relationships in the 2030 projections.

Supplementary Plots for Additional Transfers

This section presents figures and tables showing results and source data information for each transfer listed below:

(iii) Pacific Northwest to British Columbia

(iv) Alberta to Montana

(v) Manitoba to MISO West

(vi) Ontario to MISO West

(vii) Ontario to MISO East

(viii) Ontario to New York

(ix) Hydro-Quebec to New York

(x) Hydro-Quebec to New England

(xi) New Brunswick to New England

The figures show the daily MaxFlow for each transfer that was considered in this analysis.

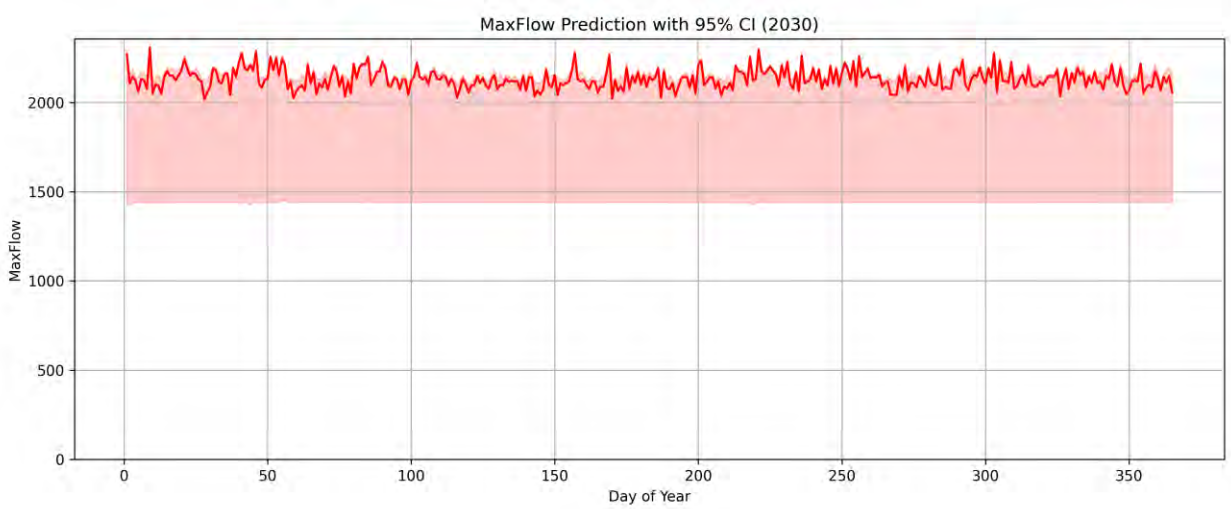


Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

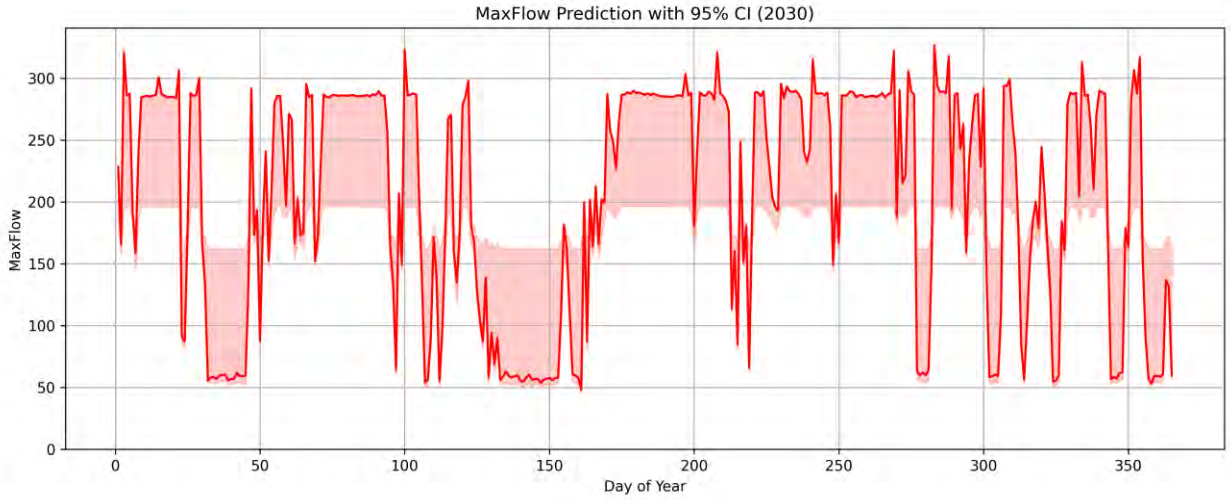


Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

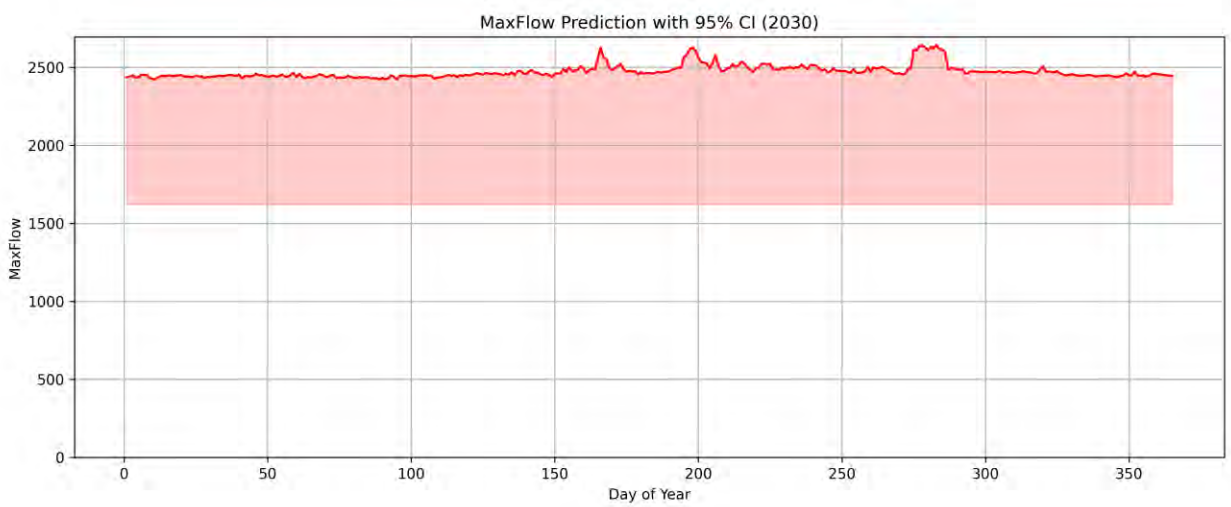


Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

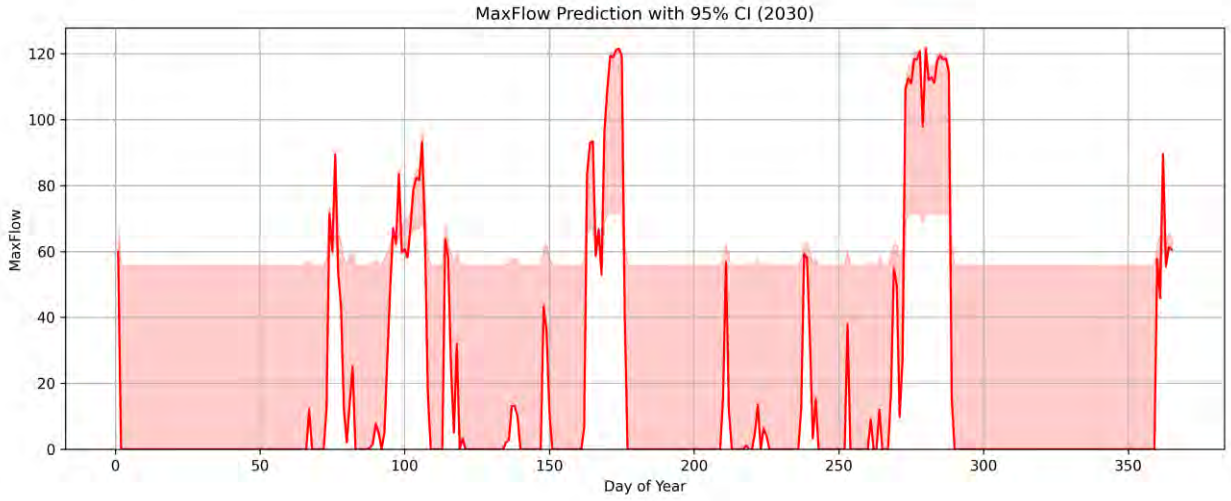


Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

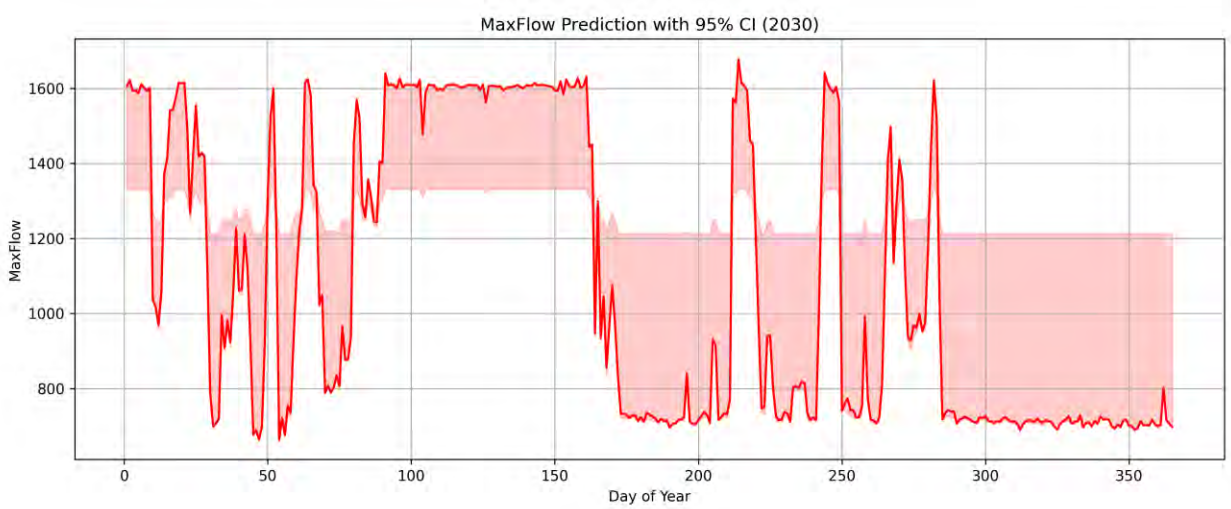


Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

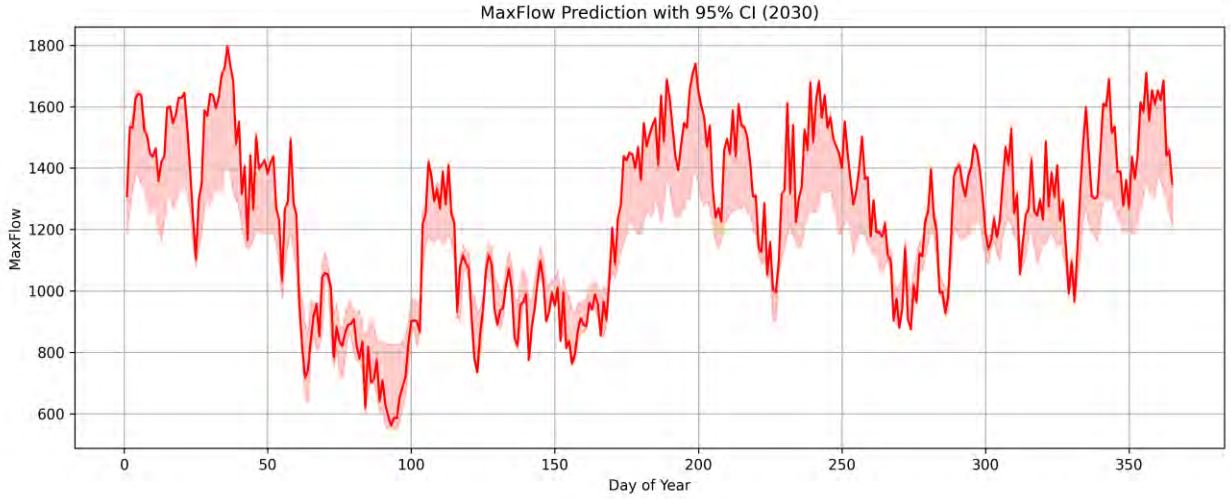


Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

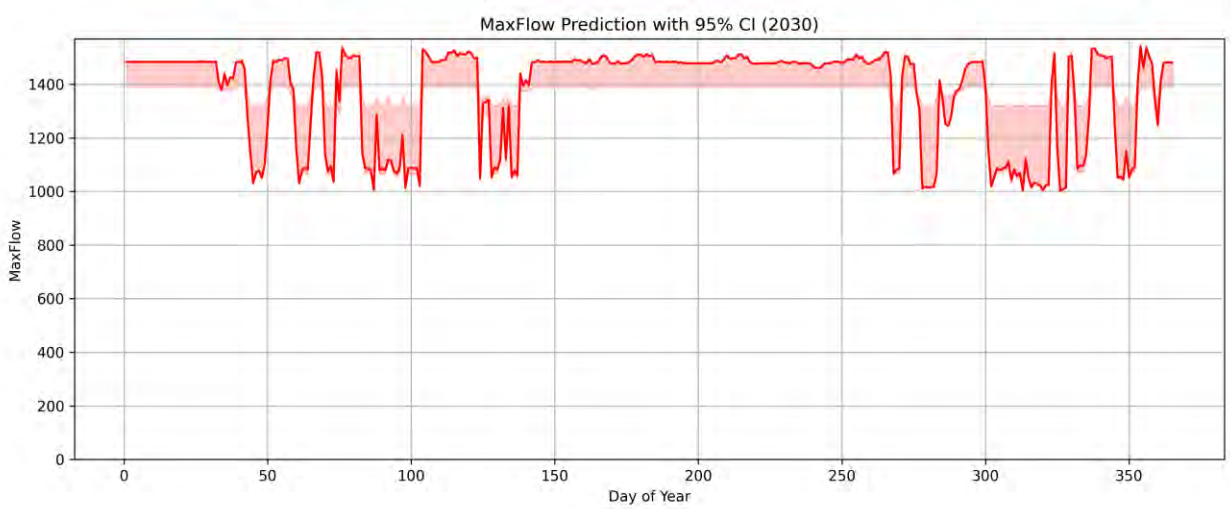


Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

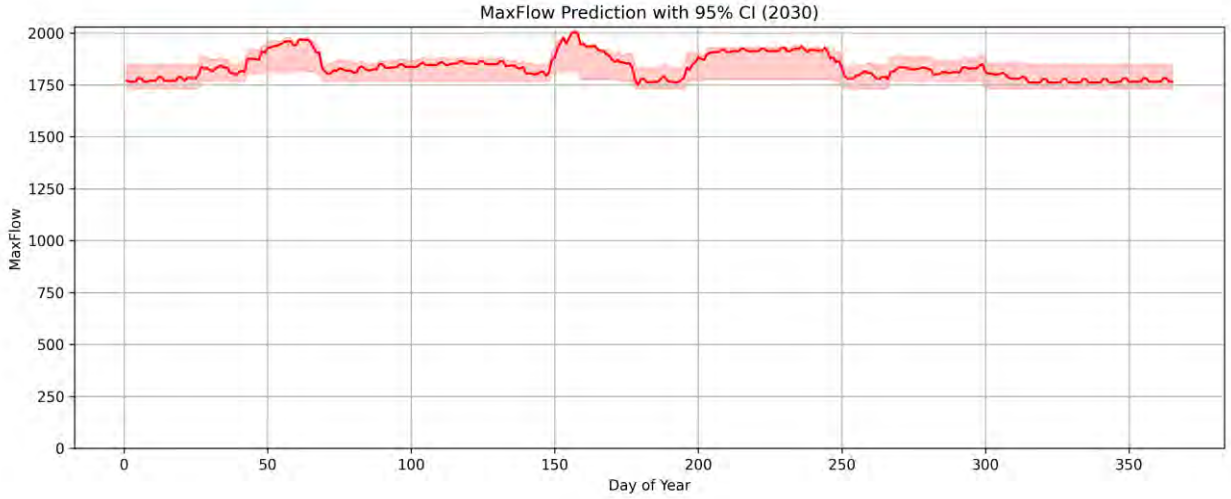


Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

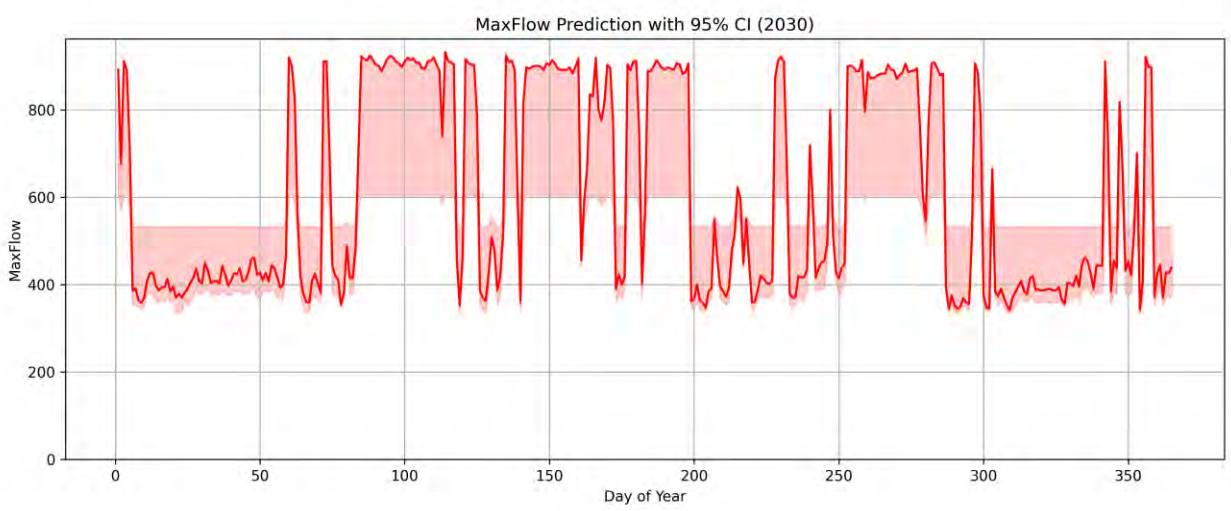


Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

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EO 14262

Federal Register / Vol. 90, No. 70 / Monday, April 14, 2025 / Presidential Documents 15521

Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. *Purpose*. The United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing. This increase in demand, coupled with existing capacity challenges, places a significant strain on our Nation's electric grid. Lack of reliability in the electric grid puts the national and economic security of the American people at risk. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy from all available electric generation sources and the integrity of our Nation's electric grid.

Sec. 2. *Policy*. It is the policy of the United States to ensure the reliability, resilience, and security of the electric power grid. It is further the policy of the United States that in order to ensure adequate and reliable electric generation in America, to meet growing electricity demand, and to address the national emergency declared pursuant to Executive Order 14156 of January 20, 2025 (Declaring a National Energy Emergency), our electric grid must utilize all available power generation resources, particularly those secure, redundant fuel supplies that are capable of extended operations.

Sec. 3. *Addressing Energy Reliability and Security with Emergency Authority*. (a) To safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure, the Secretary of Energy, in consultation with such executive department and agency heads as the Secretary of Energy deems appropriate, shall, to the maximum extent permitted by law, streamline, systemize, and expedite the Department of Energy's processes for issuing orders under section 202(c) of the Federal Power Act during the periods of grid operations described above, including the review and approval of applications by electric generation resources seeking to operate at maximum capacity.

(b) Within 30 days of the date of this order, the Secretary of Energy shall develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy. This methodology shall:

(i) analyze sufficiently varied grid conditions and operating scenarios based on historic events to adequately inform the methodology;

(ii) accredit generation resources in such conditions and scenarios based on historical performance of each specific generation resource type in the real time conditions and operating scenarios of each grid scenario; and

(iii) be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order.

(c) The Secretary of Energy shall establish a process by which the methodology described in subsection (b) of this section, and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability. This protocol shall additionally:

(i) include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region; and

(ii) prevent, as the Secretary of Energy deems appropriate and consistent with applicable law, including section 202 of the Federal Power Act, an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel of such generation resource if such conversion would result in a net reduction in accredited generating capacity, as determined by the reserve margin methodology developed under subsection (b) of this section.

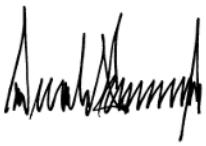
Sec. 4. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



THE WHITE HOUSE,
April 8, 2025.

[FR Doc. 2025–06381
Filed 4–11–25; 8:45 am]
Billing code 3395–F4–P

Available at (accessed on 5/27/2025):
https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid



U.S. DEPARTMENT of ENERGY

For more information, visit:
energy.gov/topics/reliability

DOE/Publication Number • July, 7 2025

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-21

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit MM: Tri-State, *General APEN- Form APCD-200* (Apr. 21, 2025)

Docusign Envelope ID: D6928A96-6020-4C46-BCC9-02DA7F27CD98

General APEN – Form APCD-200

Air Pollutant Emission Notice (APEN) and
Application for Construction Permit

All sections of this APEN form must be completed for both new and existing sources, including APEN updates. The Permit Application/Registration Checklist (Form APCD-100) must also be completed and submitted with this APEN form, unless specifically exempted. Incomplete applications will be rejected and will require re-submittal. *Your application will be rejected if it is filled out incorrectly, is missing information, or lacks payment for applicable fees. The re-submittal will require new payment for applicable fees.*

There may be a more specific APEN for your source (e.g. boiler, mining operations, engines, etc.). A list of all available APEN forms can be found on the Air Pollution Control Division (APCD) website.

This emission notice is valid for five (5) years. Submission of a revised APEN is required 30 days prior to expiration of the five-year term, or when a reportable change is made (significant emissions increase, increase production, new equipment, change in fuel type, etc.). See Regulation No. 3, Part A, II.C. for revised APEN requirements.

Permit Number: 96OPMF155 **AIRS ID Number:** 081 / 0018 / 001

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 1 - Administrative Information

Company Name[1]: Tri-State Generation and Transmission Association, Inc.

Site Name: Craig Station

Site Location: 2101 S. Ranney
Craig CO 81626

Site Location County: Moffat

NAICS or SIC Code: 4911

Mailing Address: *(Include Zip Code)* 1100 W. 116th Avenue
Westminster, CO

Contact Person: Brian Massengale

Phone Number: 303-254-3785

Portable Source Home Base: NA

E-Mail Address[2]: brian.massengale@tristategt.org

[1] Use the full, legal company name registered with the Colorado Secretary of State. This is the company name that will appear on all documents issued by the APCD. Any changes will require additional paperwork.
[2] Permits, exemption letters, and any processing invoices will be issued by the APCD via e-mail to the address provided.

517882

Docusign Envelope ID: D6928A96-6020-4C46-BCC9-02DA7F27CD98

Permit Number: 96OPMF155 **AIRS ID Number:** 081 / 0018 / 001

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 2 - Requested Action

☐ **NEW permit OR newly-reported emission source** *(check one below)*

☐ STATIONARY source ☐ PORTABLE source

- OR -

☐ **MODIFICATION to existing permit** *(check each box below that applies)*

☐ Change fuel or equipment ☐ Change company name[3] ☐ Add point to existing permit

☐ Change permit limit ☐ Transfer of ownership[4] ☐ Other *(describe below)*

- OR -

☑ **APEN submittal for update only (Note blank APENs will not be accepted)**

- ADDITIONAL PERMIT ACTIONS -

☐ **Limit Hazardous Air Pollutants (HAPs) with a federally-enforceable limit on Potential To Emit (PTE)**

☐ **APEN submittal for permit exempt/grandfathered source**

Additional Info & Notes: Craig Station Unit 1 Boiler

[3] For company name change, a completed Company Name Change Certification Form (Form APCD-106) must be submitted.
[4] For transfer of ownership, a completed Transfer of Ownership Certification Form (Form APCD-104) must be submitted.

Section 3 - General Information

General description of equipment and purpose: Electric Generation

Manufacturer: Babcock & Wilcox Model No.: NB24157 Serial No.: NA

Company equipment Identification No. *(optional)*: B001

For *existing* sources, operation began on: 1980

For *new or reconstructed* sources, the projected start-up date is: NA

☑ Check this box if operating hours are 8,760 hours per year; if fewer, fill out the fields below:

Normal Hours of Source Operation: _____ hours/day _____ days/week _____ weeks/year

Seasonal use percentage: Dec-Feb: _____ Mar-May: _____ Jun-Aug: _____ Sep-Nov: _____

Docusign Envelope ID: D6928A96-6020-4C46-BCC9-02DA7F27CD98

Permit Number: 96OPMF155 **AIRS ID Number:** 081 / 0018 / 001

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 4 - Processing/Manufacturing Information & Material Use

☑ Check box if this information is not applicable to source or process

From what year is the *actual annual amount*? _____

	Description	Design Process Rate *(Specify Units)*	Actual Annual Amount *(Specify Units)*	Requested Annual Permit Limit[5] *(Specify Units)*
Material Consumption:				
Finished Product(s):				

[5] Requested values will become permit limitations or will be evaluated for exempt status, as applicable, and should consider future process growth. Requested values are required on all APENs, including APEN updates.

Section 5 - Geographical/Stack Information

Geographical Coordinates *(Latitude/Longitude or UTM)*
13T 280,410 m E 4,482,335 m N

☐ Check box if the following information is not applicable to the source because emissions will not be emitted from a stack. If this is the case, the rest of this section may remain blank.

Operator Stack ID No.	Discharge Height Above Ground Level *(Feet)*	Temp. *(°F)*	Flow Rate *(ACFM)*	Velocity *(ft/sec)*
S001	600	117	1,838,406	62

Indicate the direction of the stack outlet: *(check one)*

☑ Upward ☐ Downward ☐ Upward with obstructing raincap

☐ Horizontal ☐ Other *(describe)*: _____

Indicate the stack opening and size: *(check one)*

☑ Circular Interior stack diameter *(inches)*: 300

☐ Square/rectangle Interior stack width *(inches)*: _____ Interior stack depth *(inches)*: _____

☐ Other *(describe)*: _____

Docusign Envelope ID: D6928A96-6020-4C46-BCC9-02DA7F27CD98

Permit Number: 96OPMF155 **AIRS ID Number:** 081 / 0018 / 001

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 6 - Combustion Equipment & Fuel Consumption Information

☐ Check box if this information is not applicable to the source (e.g. there is no fuel-burning equipment associated with this emission source)

Design Input Rate *(MMBTU/hr)*	Actual Annual Fuel Use *(Specify Units)*	Requested Annual Permit Limit[5] *(Specify Units)*
4,318	956,258 tpy	3,900,000 tpy

From what year is the *actual annual fuel use* data? 2024

Indicate the type of fuel used[6]:

☐ Pipeline Natural Gas *(assumed fuel heating value of 1,020 BTU/SCF)*

☐ Field Natural Gas Heating value: _____ BTU/SCF

☐ Ultra Low Sulfur Diesel *(assumed fuel heating value of 138,000 BTU/gallon)*

☐ Propane *(assumed fuel heating value of 2,300 BTU/SCF)*

☑ Coal Heating value: 9,763 BTU/lb Ash content: 9.3% Sulfur content: 0.4%

☐ Other *(describe)*: _____ Heating value *(give units)*: _____

[5] Requested values will become permit limitations or will be evaluated for exempt status, as applicable, and should consider future process growth. Requested values are required on all APENs, including APEN updates.

[6] If fuel heating value is different than the listed assumed value, provide this information in the "Other" field.

Section 7 - Criteria Pollutant Emissions Information

Attach all emission calculations and emission factor documentation to this APEN form.

Is any emission control equipment or practice used to reduce emissions? ☑ Yes ☐ No

If yes, describe the control equipment AND state the collection and control efficiencies:

Pollutant	Control Equipment Description	Collection Efficiency *(% of total emissions captured by control equipment)*	Control Efficiency *(% reduction of captured emissions)*
TSP (PM)	Baghouse		99.9
PM_{10}	Baghouse		99.9
$PM_{2.5}$	Baghouse		99.9
SO_x	Wet Scrubber		93.7
NO_x	Low NOx Burner/Overfire Air		45-60
CO	None		
VOC	None		
Other:			

Docusign Envelope ID: D6928A96-6020-4C46-BCC9-02DA7F27CD98

Permit Number: 96OPMF155 **AIRS ID Number:** 081 / 0018 / 001

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

From what year is the following reported *actual annual emissions* data? 2024

Use the following table to report the criteria pollutant emissions from source:
(Use the data reported in Sections 4 and 6 to calculate these emissions.)

Pollutant	Uncontrolled Emission Factor *(Specify Units)*	Emission Factor Source *(AP-42, Mfg., etc.)*	Actual Annual Emissions		Requested Annual Permit Emission Limit(s)[5]	
			Uncontrolled *(tons/year)*	Controlled[7] *(tons/year)*	Uncontrolled *(tons/year)*	Controlled *(tons/year)*
TSP (PM)	0.0100 lb/MMBtu	2024 Stack Test, AP-42		93		NA
PM_{10}	0.0092 lb/MMBtu	2024 Stack Test, AP-42		86		NA
$PM_{2.5}$	0.0053 lb/MMBtu	2024 Stack Test, AP-42		49		NA
SO_x	Measured	CEMS		335		NA
NO_x	Measured	CEMS		2,176.6		NA
CO	0.5 lb/ton	AP-42	239			NA
VOC	0.0002 lb/MMBtu	1999 Stack Test, AP-42	2			NA
Other:						

[5] Requested values will become permit limitations or will be evaluated for exempt status, as applicable, and should consider future process growth. Requested values are required on all APENs, including APEN updates.
[7] Annual emission fees will be based on actual controlled emissions reported. If source has not yet started operating, provide projected emissions.

Section 8 - Non-Criteria Pollutant Emissions Information

Does the emissions source have any uncontrolled actual emissions of non-criteria pollutants (e.g. HAP - hazardous air pollutant) equal to or greater than 250 lbs/year? ☑ Yes ☐ No

If yes, use the following table to report the non-criteria pollutant (HAP) emissions from source:
(Use the data reported in Sections 4 and 6 to calculate these emissions.)

CAS Number	Chemical Name	Overall Control Efficiency	Uncontrolled Emission Factor *(Specify Units)*	Emission Factor Source *(AP-42, Mfg., etc.)*	Uncontrolled Actual Emissions *(lbs/year)*	Controlled Actual Emissions[7] *(lbs/year)*
7782505 / 7440-02-0	Chlorine / Nickel		518 lb/TBtu / 1.4E-4 lb/MMBtu	2000 Stack Test / 2010 Test	10,168 / 2,748	
7440-47-3 / 75-09-2	Chromium / Methylene Chloride		2.08 E-4 lb/MMBtu / 18.9E-6 lb/TBtu	2010 Stack Test / EPRI	4,083 / 371	
57-12-5 / 7664-93-9	Cyanide / Sulfuric Acid		2.5 E-3 lb/ton / 7E-4 lb/MMBtu	AP-42 / 2009 Stack Test	2,391 / 13,070	
7647-01-0	Hydrogen Chloride		5.5 E-5 lb/MMBtu	2009 Stack Test	1,080	
7664-39-3	Hydrogen Fluoride		2.07 E-4 lb/MMBtu	2009 Stack Test	4,063	
7439-96-5	Manganese		3.67E-4 lb/MMBtu	2010 Stack Test	7,204	

[7] Annual emission fees will be based on actual controlled emissions reported. If source has not yet started operating, provide projected emissions.

Docusign Envelope ID: D6928A96-6020-4C46-BCC9-02DA7F27CD98

Permit Number: 96OPMF155 **AIRS ID Number:** 081 / 0018 / 001

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 9 - Applicant Certification

I hereby certify that all information contained herein and information submitted with this application is complete, true, and correct.

DocuSigned by:
Jerome Sturhahn
AFDDE2F9ABE741D...

4/21/2025

Signature of Legally Authorized Person (not a vendor or consultant) Date

Jerome H. Sturhahn Senior Vice President, General Counsel

Name (print) Title

Check the appropriate box to request a copy of the:

☐ Draft permit prior to issuance
☐ Draft permit prior to public notice

(Checking any of these boxes may result in an increased fee and/or processing time)

This emission notice is valid for five (5) years. Submission of a revised APEN is required 30 days prior to expiration of the five-year term, or when a reportable change is made (significant emissions increase, increase production, new equipment, change in fuel type, etc.). See Regulation No. 3, Part A, II.C. for revised APEN requirements.

Send this form along with $242.00 to:

Colorado Department of Public Health and Environment
Air Pollution Control Division
APCD-SS-B1
4300 Cherry Creek Drive South
Denver, CO 80246-1530

For more information or assistance, contact:

Small Business Assistance Program
cdphe_apcd_sbap@state.co.us

APCD Main Phone Number
(303) 692-3100

Make check payable to: **Colorado Department of Public Health and Environment**

Alternatively, payment can be provided online, by credit card or electronic check, via the APCD Payment Portal.