



**Platte River**  
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

# 2024

## Integrated Resource Plan

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Estes Park • Fort Collins • Longmont • Loveland

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# Glossary

Term or acronym	Definition
<b>ATB</b> .....	Annual Technology Book
<b>BE</b> .....	Beneficial building electrification
<b>CDPHE</b> .....	Colorado Department of Public Health and Environment
<b>CIG</b> .....	Colorado Interstate Gas
<b>CPI</b> .....	Consumer Price Index
<b>DER</b> .....	Distributed energy resources
<b>DG</b> .....	Distributed generation
<b>DR</b> .....	Demand response
<b>ELCC</b> .....	Effective Load Carrying Capability
<b>EPA</b> .....	U.S. Environmental Protection Agency
<b>EPRI</b> .....	Electric Power Research Institute
<b>ERCOT</b> .....	Electric Reliability Council of Texas
<b>EV</b> .....	Electric vehicle
<b>GW</b> .....	Gigawatt
<b>GWh</b> .....	Gigawatt-hour
<b>HVAC</b> .....	Heating, ventilation and air conditioning
<b>IRP</b> .....	Integrated resource plan or integrated resource planning process
<b>ITC</b> .....	Federal solar tax credit
<b>JDA</b> .....	Joint dispatch agreement

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<b>LOLE</b> .....	Loss of Load Expectation	<b>TOU</b> .....	Time of use
<b>LOLH</b> .....	Loss of Load Hours	<b>VPP</b> .....	Virtual power plant
<b>MISO</b> .....	Midcontinent Independent System Operator	<b>WAPA</b> .....	Western Area Power Administration
<b>MW</b> .....	Megawatt	<b>WECC</b> .....	Western Electricity Coordination Council
<b>MWh</b> .....	Megawatt-hours	<b>WEIS</b> .....	Western Energy Imbalance Service market
<b>NEM</b> .....	Net energy metering		
<b>NEVI</b> .....	National Electric Vehicle Infrastructure Formula Program, a federal grant program established under the Infrastructure Investment and Jobs act to provide states with funding to expand availability of EV fast charging infrastructure on transportation corridors		
<b>NREL</b> .....	National Renewable Energy Laboratory		
<b>ODTY</b> .....	One Day in Ten Years		
<b>PPA</b> .....	Power purchase agreement		
<b>PRM</b> .....	Planning reserve margin		
<b>RDP</b> .....	Resource Diversification Policy		
<b>RFP</b> .....	Request for proposals		
<b>RP22</b> .....	Platte River's Resource Plan 2022		
<b>RTO West</b> .....	Regional Transmission Organization West		
<b>SPP</b> .....	Southwest Power Pool		

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# 01

## Executive summary

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Platte River Power Authority's 2024 Integrated Resource Plan (IRP) presents a comprehensive strategy to reduce carbon emissions for the communities we serve in Northern Colorado while upholding our foundational pillars of reliability, financial sustainability and environmental responsibility. Developed amidst unprecedented market changes, the IRP addresses the challenges of long-range planning by evaluating various decarbonization scenarios and incorporating feedback from our board of directors, customers and stakeholders.

The IRP explores a diverse range of resource options for continuing our work toward the Resource Diversification Policy (RDP) goal, including renewable energy, battery energy storage, distributed generation, energy efficiency and demand response. The plan also shows how we will maintain reliability with an energy portfolio composed primarily

of weather-dependent, renewable resources.

Given the inherent uncertainties in long-term planning, the IRP is based on projections of future electricity demand, costs of renewable resources, advancements in technology, and evolving market and regulatory environments. Acknowledging that these factors will change, the plan is intended to serve as a roadmap, allowing for adjustments and modifications to optimally reflect changing market conditions and continue the implementation of our decarbonization strategy.

This IRP informs Platte River's next steps toward achieving a low-carbon energy portfolio by illustrating how we will reduce carbon emissions by at least 80% below 2005 levels by 2030 to meet state goals, and by supporting our board-adopted RDP.



## Outreach and engagement

Building on what we learned from the last IRP, we expanded our outreach and engagement efforts considerably for the 2024 IRP.

We partnered with our owner communities to help educate customers about the relationship between Platte River and their cities. Over a six-month period, we presented our IRP process and updates to numerous community organizations,

stakeholder groups and city leadership. We coupled these presentations with two engagement sessions hosted by Platte River to share IRP milestones, and offered digital resources including a dedicated website, email address and robust database of frequently asked questions and answers.

The feedback we collected between June and November 2023 helped inform the development of the portfolios.



## Portfolios

The IRP is designed to align Platte River's future portfolio with our continued work toward the RDP, with a primary focus on reducing carbon while maintaining reliability. All portfolios will emit some carbon in 2030 because commercially viable noncarbon dispatchable options are not available. After 2030, we model no new thermal generation and plan for long-duration energy storage. Energy prices assumed embedded carbon taxes in the evaluation of each portfolio.

**No new carbon:** Focuses on wind, solar and energy storage, testing the viability of excluding new thermal generation to meet demand and reliability.

**Minimal new carbon:** Adds a modest amount of new thermal generation (80 megawatts) to support reliability and evaluates potential emerging technologies.

**Carbon-imposed cost:** Adds a carbon cost to discourage new carbon-emitting resource additions to the resource mix.

**Optimal new carbon:** Balances cost, reliability and carbon considerations between the additional new carbon and carbon-imposed cost portfolios.

**Additional new carbon:** Presents a least-cost portfolio without specific carbon constraints, prioritizing cost and reliability.



Because external risks to executing the clean energy transition have substantially increased, Platte River developed a risk-adjusted plan to address the challenges of integrating renewable resources as modeled. The primary risks are supply chain issues; engineering, procurement and construction delays; regulatory uncertainty on pricing; the mismatch in timing between customer demand and the availability of renewable generation; and market price volatility. This plan also allows for adjustments to market prices, emerging technologies and regulatory developments.

## Conclusion

We are pleased to present the third iteration of the resource plan since our board passed the RDP. While we have made significant progress diversifying our portfolio since 2018—adding renewable energy to serve about one third of the owner communities' energy needs on an annual basis—we will immediately begin work on the fourth iteration as factors continue to change and evolve around us.

As you review our latest plan, we hope you take away a greater understanding of the complexity and challenges of replacing coal with renewables, firming up the intermittency of renewables with dispatchable resources, and doing right by the owner communities and our employees while pursuing one of the most accelerated decarbonization goals in the country.

This clean energy transition is a journey that will continuously evolve with changing circumstances and advancements in technology. Platte River is committed to making the transition on behalf of the owner communities to create a diverse, low-carbon energy portfolio for a sustainable future.

# 02

## Introduction

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Platte River Power Authority's 2024 IRP is a living document that guides and informs our efforts to supply reliable, environmentally responsible and financially sustainable energy and services to our owner communities while we work toward a noncarbon energy future. Throughout this document, we highlight how Platte River will address high-level policy goals while incorporating staff recommendations and research, third-party studies, and legislative, regulatory, market and technology changes.

Platte River developed this IRP with involvement from our owner communities and their customers. The board of directors approved the previous IRP document in 2020. Platte River is required to update the IRP and file it with the Western Area Power Administration (WAPA) every five years.

The report is organized as follows:

- The remainder of this section provides a general overview, background and history of Platte River, illustrating the foundational pillars and board-adopted policy that guide our planning activities and decisions.
- While IRPs are common among electric utilities, Platte River's approach is unique. Chapter 3 describes our process and timeline, the progress we made since our last IRP, and the industry challenges we face, including persistent impacts from the COVID-19 pandemic. Chapter 4 further highlights the variables and challenges Platte River faces as we pursue a clean, reliable energy future.
- Most of the report provides technical background data, assumptions and methodology that influence and shape our IRP, including demand, impacts of distributed energy resources (DER) and electrification, supply-side assumptions, extreme weather events and more. Chapter 7 of this report details the IRP design, including the studies, portfolios and our modeling methodology.
- Chapter 8 shows our modeling results; Chapter 9 highlights the resulting action plan from this IRP.



## Public power utilities

Platte River is one of more than 2,000 community-owned electric utilities in the U.S. These utilities are operated by local governments and provide their owner communities with reliable, responsive, not-for-profit electric service. Public power utilities serve one in seven electricity customers across the U.S. – more than 54 million citizens – and operate in 49 states and in several U.S. territories.<sup>1</sup>

The American Public Power Association emphasizes the following characteristics of public power utilities:

- **Service-oriented:** We exist to serve and add value to our owner communities.
- **Community-owned:** We help advance the good of the community.
- **Local control and decision-making:** Decisions reflect our owner communities' needs and values.
- **Not-for-profit:** We focus on safely providing reliable, environmentally responsible and financially sustainable energy and services.
- **Responsive:** Because we are part of our communities, we react quickly to their needs.

<sup>1</sup> American Public Power Association website, [www.publicpower.org](http://www.publicpower.org)





## 2.1 Platte River overview

Until the mid-1960s, many Colorado municipal utilities separately received wholesale electric service from the Bureau of Reclamation's system of hydroelectric generating facilities throughout the Colorado and Missouri River basins. In late 1965, 31 municipal utilities created the Platte River Municipal Power Association to manage and protect their collective hydropower rights, particularly due to the Bureau's announcement that it could not meet growing energy needs beyond the mid-1970s and no new (hydroelectric) energy projects would be built.

In 1973, four of the original 31 municipal utilities—Estes Park, Fort Collins, Longmont and Loveland—collaborated to pass legislation to form the Platte River Power Authority, a not-for-profit entity that would provide its owner communities with long-term energy above their limited allotment of federal hydropower. Following voter approval of a constitutional

amendment, Platte River reformed in 1975 as a joint action agency, empowered to acquire assets to better serve its owner communities. These assets are discussed in greater detail throughout this document.

Also in 1975 (after the Colorado legislature passed enabling legislation), the four communities signed the organic contract establishing Platte River as a political subdivision of the state of Colorado. The organic contract is the agreement between the four owner communities that creates Platte River, establishing its purpose and governance structure.

Platte River is governed by an eight-person board of directors. The board includes the mayor (or a designee of the mayor) of each owner community and four other directors who are appointed to four-year staggered terms by the governing bodies of the owner communities. The board meets nine times per calendar year to establish and guide policy for the organization.

## 2.1.1 Foundational pillars

Platte River is guided by three pillars that drive its mission. Together with our vision and values, these pillars inform all activities and serve as the foundation for Platte River's decarbonization efforts.



### Reliability

Providing a highly reliable supply of power to our owner communities



### Environmental responsibility

Achieving noncarbon energy goals and protecting our natural resources



### Financial sustainability

Managing financial risks, providing stable, competitive wholesale rates that generate adequate cash flow and maintain access to low-cost capital

## 2.1.2 Vision, mission and values

### Our vision

To be a respected leader and responsible power provider improving the region's quality of life through a more efficient and sustainable energy future.

### Our mission

While driving utility innovation, Platte River will safely provide reliable, environmentally responsible and financially sustainable energy and services to the owner communities of Estes Park, Fort Collins, Longmont and Loveland.



## Our values

**Safety:** Without compromise, we will safeguard the public, our employees, contractors and assets we manage while fulfilling our mission.

**Integrity:** We will conduct business equitably, transparently and ethically while complying fully with all regulatory requirements.

**Service:** As a respected leader and responsible energy partner, we will empower our employees to provide energy and superior services to our owner communities.

**Respect:** We will embrace diversity and a culture of inclusion among employees, stakeholders and the public.

**Operational excellence:** We will strive for continuous improvement and superior performance in all we do.

**Sustainability:** We will help our owner communities thrive while working to protect the environment we all share.

**Innovation:** We will proactively deliver creative solutions to generate best-in-class products, services and practices.

## Environmental leadership

Platte River continually demonstrates a strong commitment to environmental responsibility while safely providing reliable and financially sustainable energy and services to the four owner communities. Below are examples of our environmental stewardship:

- Incorporated state-of-the-art emissions controls on the coal-fired Rawhide Unit 1, consistently positioned among the lowest SO<sub>2</sub>-emitting coal-fired plants in the country, according to data available from the U.S. Environmental Protection Agency (EPA).
- Became the first utility in Colorado to offer wind energy to the owner communities through the Medicine Bow Wind Project in 1998.
- Began commercial operation of 30 MW of solar at the Rawhide Energy Station in 2016. Platte River later added another 22 MW of solar to the area, with a 2 megawatt-hour (MWh) battery storage facility.
- Completed construction of a new headquarters campus in Fort Collins in 2020 that is designed to serve as an example of energy efficiency. The campus received Gold LEED Certification by the U.S. Green Building Council in 2023.
- Adopted the Resource Diversification Policy in 2018, becoming one of the first utilities in Colorado and the country to set a goal of a 100% noncarbon energy mix by 2030.

## 2.2 Resource Diversification Policy

In 2018, Platte River’s Board of Directors passed a landmark policy (Figure 1) that directs the general manager/CEO to proactively work toward the goal of reaching a 100% noncarbon energy resource mix by 2030 while maintaining the foundational pillars. The policy also lists several advancements (or caveats) that must occur for Platte River to meet this ambitious goal.

### Purpose

This policy is established to provide guidance for resource planning, portfolio diversification and carbon reduction.

### Policy

The board of directors (the board) directs the general manager/CEO to proactively work toward the goal of reaching a 100% noncarbon resource mix by 2030, while maintaining Platte River’s three pillars of providing reliable, environmentally responsible and financially sustainable electricity and services.

The board recognizes the following advancements must occur in the near term to achieve the 2030 goal and to successfully maintain Platte River’s three pillars:

- An organized regional market must exist with Platte River as an active participant
- Battery storage performance must mature and the costs must decline
- Utilization of storage solutions to include thermal, heat, water and end user available storage
- Transmission and distribution infrastructure investment must be increased
- Transmission and distribution delivery systems must be more fully integrated
- Improved distributed generation resource performance



- Technology and capabilities of grid management systems must advance and improve
- Advanced capabilities and use of active end user management systems
- Generation, transmission and distribution rate structures must facilitate systems integration

Resource planning is an ongoing process and Platte River continuously evaluates opportunities to add noncarbon resources. Platte River reviews its generation portfolio annually as part of the budgeting and planning process. This process sets the foundation for developing an IRP submitted to the Western Area Power Administration every five years as required. The resource planning process includes evaluating the progress of energy storage, distributed power sources and new technologies. As a leader in the utility industry in Colorado for many years, Platte River will continue to move forward to meet the resource needs and wants of the four owner communities. The board recognizes the integration of noncarbon resources and new technologies will shape the future of Platte River's and the four owner communities' energy supply.

**Figure 1.** *Resource Diversification Policy*

# 03

## IRP process overview



## 3.1 What is an IRP?

A utility IRP<sup>2</sup> compares the supply-side resources (generated or purchased by the utility) and demand-side resources (contributed by customers, including DER) with projected energy needs (load) and selects an optimal set of resources to meet future needs while meeting the regulatory requirements and policy goals at the highest level of reliability.

Key components of an IRP include:

- Customers' future electricity needs (or load forecast)
- Future costs and availability of supply and demand side resources
- Regulatory and policy requirements including environmental considerations
- Community engagement to hear stakeholder feedback and questions
- An assessment of future technologies

These components and other inputs are used in a complex planning and optimization model to develop a 10-to-20-year roadmap of investments to provide reliable supplies during the planning horizon. An IRP model optimally selects from demand- and supply-side resources while meeting the planning reserve margin (PRM<sup>3</sup>) or other reliability criteria, to ensure adequate electricity supply under all reasonably expected variations of weather, customer demand and resource availability.

A key component of an IRP is an action plan that outlines the specific activities the utility plans to conduct in the next three to five years while developing the next IRP. An IRP is a snapshot in time; planning is an ongoing and dynamic process. An IRP acts as a roadmap or guide, while the actual investment decisions are made based on the best information available at the time of the decision.

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<sup>2</sup> In this document the acronym IRP is used in two different ways—an integrated resource plan and as an integrated resource planning process.

<sup>3</sup> PRM is defined as the additional generating capacity available to meet a future year peak demand. It is expressed as a percentage of peak demand. Historically, Platte River has maintained a 15% PRM which means if the load forecast expects a peak demand of 100 MW in a future year, Platte River would build or acquire 115 MW of generation or DER capacity to reliably meet that peak demand.

## 3.2 Why do an IRP now?

In 2020, Platte River developed an IRP that outlined several paths to work toward the RDP goal. The plan's recommendations were developed before the global COVID-19 pandemic, which put many things on hold for two years, including construction of renewable energy projects. The pandemic triggered widespread supply chain issues and contributed to increased costs for labor, capital, equipment and new resources, which resulted in multiple rounds of contract renegotiations for renewable projects. State and federal clean energy policies also created intense competition for renewable resource projects and related equipment and staffing.

Meanwhile, Winter Storm Uri in February 2021 was a wakeup call about the increased frequency of extreme weather events and

the need for a reliable power supply. While the emergence of new technologies and the passage of the Inflation Reduction Act are positive developments, the industry continues to face inflationary pressures and supply chain challenges.

This 2024 IRP captures these developments, re-affirms our commitment to the RDP and charts a path toward that goal. While Platte River is not required to file an IRP with WAPA before 2025, we expedited this IRP to support the accelerated integration of renewable resources. We finalized our assumptions underlying this IRP in summer 2023, so this IRP provides portfolios or snapshots of the future viewed from 2023. This IRP will need updating as technology and circumstances evolve. Platte River will prepare the next IRP in 2028.

### 3.2.1 IRP timeline

The 2024 IRP process started in 2022 by commissioning pre-IRP studies from external consultants and continued through early 2024. Figure 2 illustrates a high-level timeline and list of major activities. Community engagement is an important part of the IRP process and is highlighted in yellow.

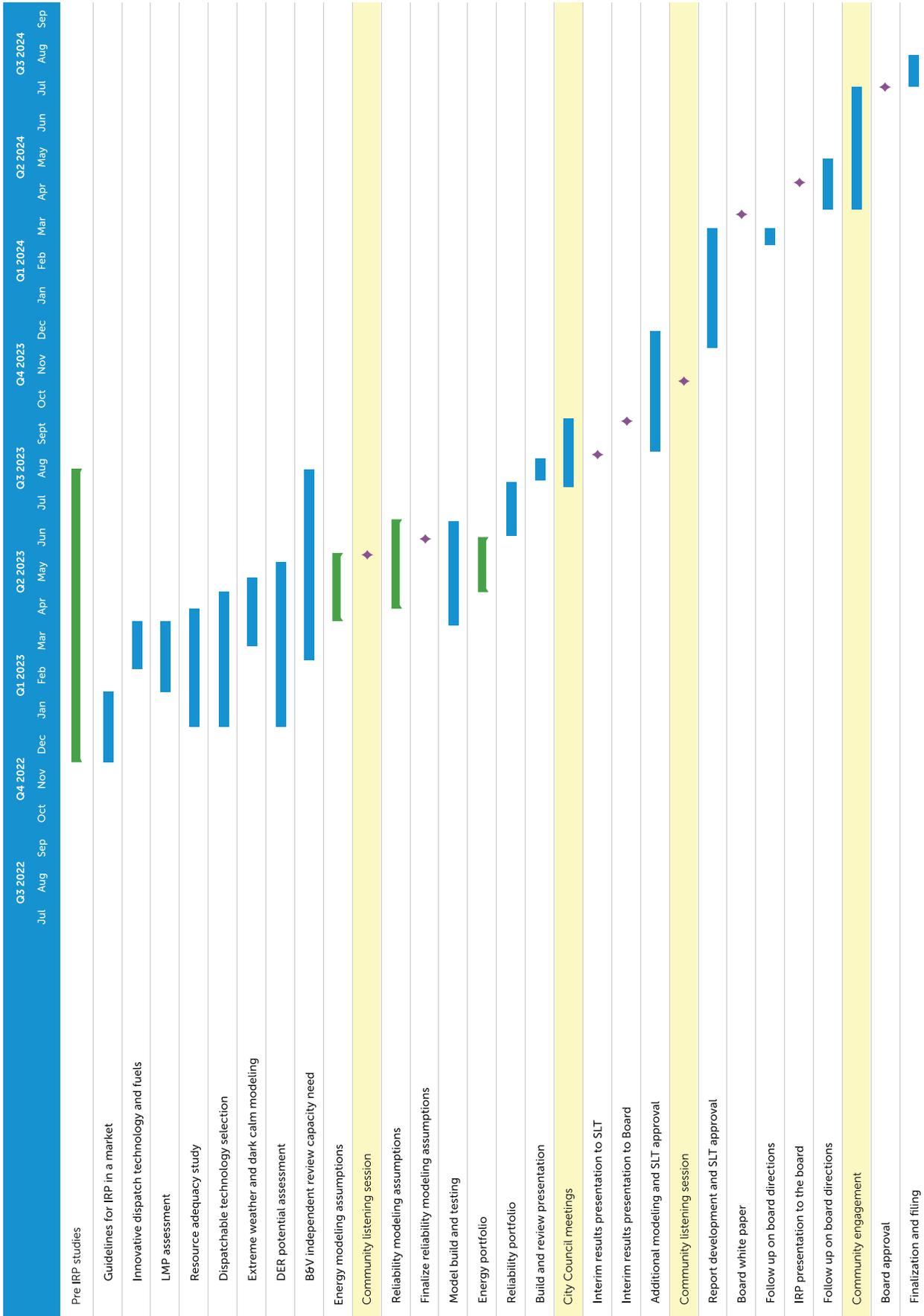


Figure 2. Timeline of 2024 Integrated Resource Plan activities and milestones

### 3.3 Progress since the last IRP

Platte River continued to work toward achieving the RDP after submitting our last IRP, acquiring more renewable generation, expanding efforts to join a regional market and working with the owner communities to expand DERs. Specific annual achievements are summarized below.

#### 2020

- Began receiving energy from the Roundhouse Wind Energy Center, a 225-megawatt (MW), 80-turbine wind farm. Additionally, Platte River purchased the 230-kilovolt generator outlet line from the project, securing energy delivery to the owner communities throughout the 22-year power purchase agreement (PPA).
- Launched the DER strategy committee with staff members from Platte River and the owner communities. The DER strategy committee explores how to integrate systems that will better balance supply and demand as we transition our energy portfolio.
- Finalized closure dates for remaining coal units in Platte River's portfolio. Rawhide Unit 1 will close by the end of 2029, 16 years before its planned retirement. Craig Unit 2 will close by September 2028. (The 2025 closure date for Craig Unit 1 was announced in 2016.)
- Signed a PPA to build Platte River's largest solar project, which, when operational, will provide up to 150 MW of power.

#### 2021

- Commissioned the 22 MW Rawhide Prairie Solar project, including a 2 megawatt-hour battery.
- Created the transition and integration division, combining DER and energy solutions with resource planning and information and operations technology departments to foster the innovation needed to achieve a noncarbon electric system that includes integrated DERs.
- Together with the owner communities, developed a comprehensive DER strategy providing a path forward to jointly attain the full value of DERs to the benefit of customers and the grid.
- The Efficiency Works Business team launched the Community Efficiency Grant to provide additional financial support for energy upgrades in businesses and multifamily properties serving the income-qualified community.
- Issued a request for proposals (RFP) to competitively procure up to 250 MW of solar generation and co-located battery resources connected at the distribution or transmission level.

## 2022

- Accelerated the timeline for new noncarbon energy resources to maintain the reliability and financial sustainability of the resource portfolio ahead of retiring coal-fired generation resources.
- Confirmed the purchase of 150 MW of solar energy from the vendor for the Black Hollow Solar project, restating an agreement originally signed in 2020. Logistical challenges delayed the project, now scheduled to begin commercial operation in 2025.
- Analyzed and evaluated large-scale four-hour storage and longer duration energy storage and evaluated adding an additional wind project to Platte River's portfolio. Developed a revised portfolio (RP22) that added about 105 MW more capacity by 2030 than the 2020 IRP. RP22 called for 450 MW of solar, 300 MW of wind, 200 MW of four-hour storage and 166 MW dispatchable thermal generation.
- Together with the joint dispatch agreement (JDA) partners, Platte River announced plans to join the existing Western Energy Imbalance Service (WEIS) operated by the Southwest Power Pool (SPP). The WEIS replaces the JDA and allows Platte River to gain experience operating in a larger imbalance market. Investments began in 2022 to prepare for entry into the WEIS.
- Launched an interactive electric vehicle (EV) shopper guide website with information on currently available EVs, including cost, performance specifications and available incentives, as well as a calculator that allows visitors to compare the total cost of ownership of EVs in comparison with each other and compared with conventional vehicles.



## 2023

- Issued an RFP to competitively procure 150-250 MW of wind generation. Responses to the RFP were received in late 2023, with evaluation of the responses continuing in 2024.
- Began operating in the SPP WEIS market.
- Selected a vendor for battery storage facilities located in the owner communities. The projects' expected capacity will range from 20-25 MW, consisting of four-hour duration lithium-ion batteries.
- Expanded the EV website to offer EV Fleet Planning as a calculator tool for local fleet operators to develop plans to calculate the costs of fleet transitions.
- Enhanced program offerings through the partnership between Efficiency Works and Energy Outreach Colorado to actively engage with participants on more significant home upgrades including energy efficiency and building electrification, resulting in nearly \$1 million of investments to support the income-qualified residential upgrades in Platte River's owner communities.
- Expanded Efficiency Works programs to include multiple building electrification measures, supporting 359 heat pump installations with over \$1 million in incentives to help customers to overcome financial hurdles and investing nearly \$10,000 training local contractors on building electrification.
- Actively supported over 100 income-qualified customers to upgrade their homes, with plans to support over 250 customers annually in future years.
- Signed a commitment agreement to join the SPP Regional Transmission Organization West (RTO West) on April 1, 2026.
- Committed to advancing EV infrastructure by launching one of the highest incentives in the state, of \$5,000 per public charging port, to promote public charger hosting by local business and multifamily properties by offsetting some of the installation cost.

## 3.4 External developments since the 2020 IRP

### 3.4.1 Pandemic

The COVID-19 pandemic brought unprecedented challenges worldwide and the power sector was no exception. Immediately after the pandemic started, the economic slowdown resulted in electricity demand reduction and changing demand patterns. As economic activity slowly resumed, the electricity demand started coming back with residential demand increasing (compared to pre-

<sup>4</sup> <https://www.iea.org/reports/renewable-energy-market-update-june-2023/executive-summary>

pandemic levels) due to a significant increase in citizens working from home.

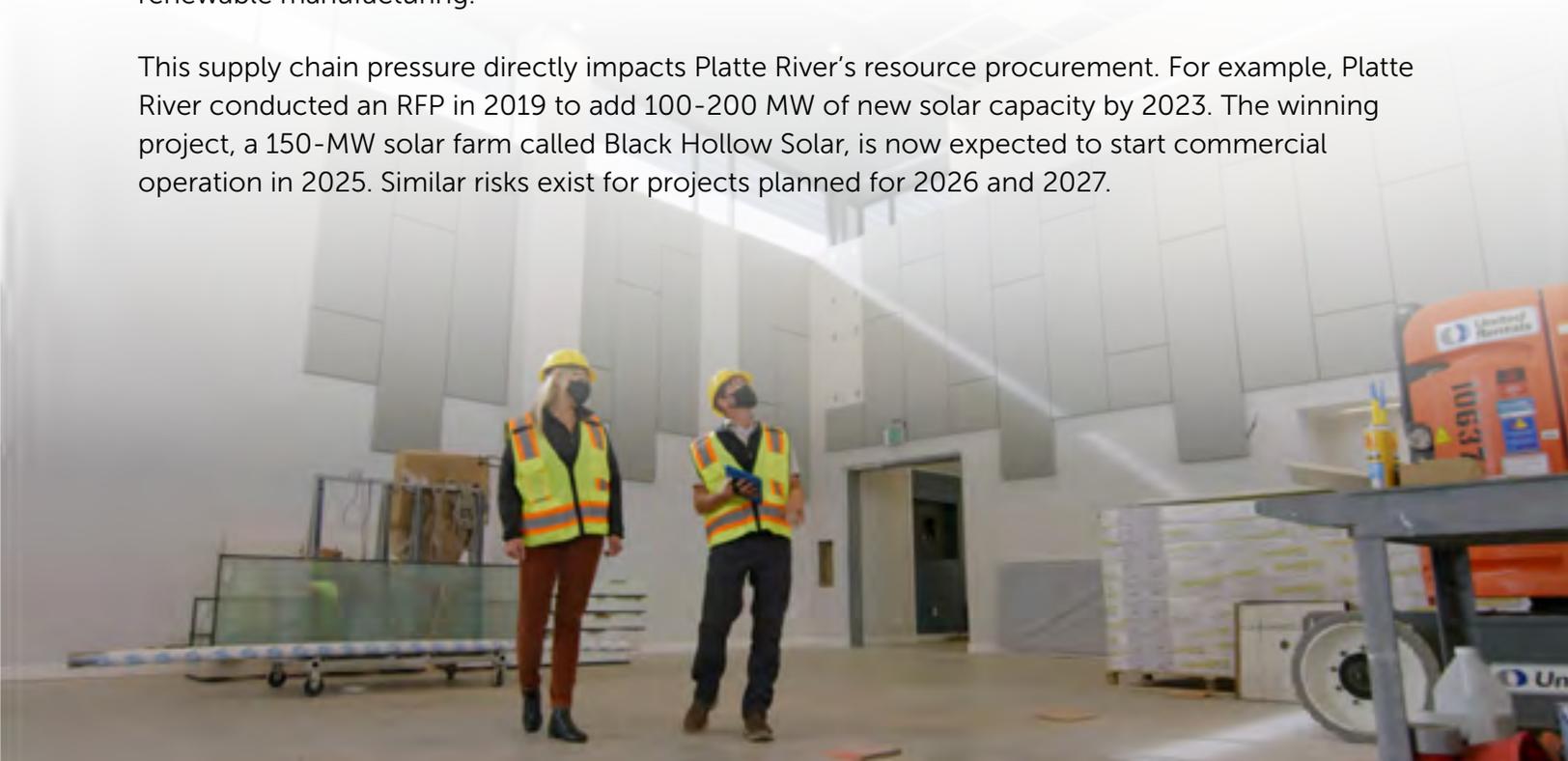
Supply chain slowdowns are among the pandemic's biggest impacts and are detailed in the next section. The pandemic also slowed down construction and new renewable project development due to reluctance of investors to commit capital amid market volatility and uncertainty about future energy demand.

As the world began adapting and recovering after the first few months of the pandemic, it prompted many governments to reevaluate energy policies and regulatory frameworks to address emerging challenges and support economic recovery efforts. The pandemic also highlighted the importance of resilient and sustainable energy systems. Significantly higher demand and sustained challenges with supply chains contributed to the cost of renewable resources and energy storage projects nearly doubling post pandemic.

### 3.4.2 Supply chain issues

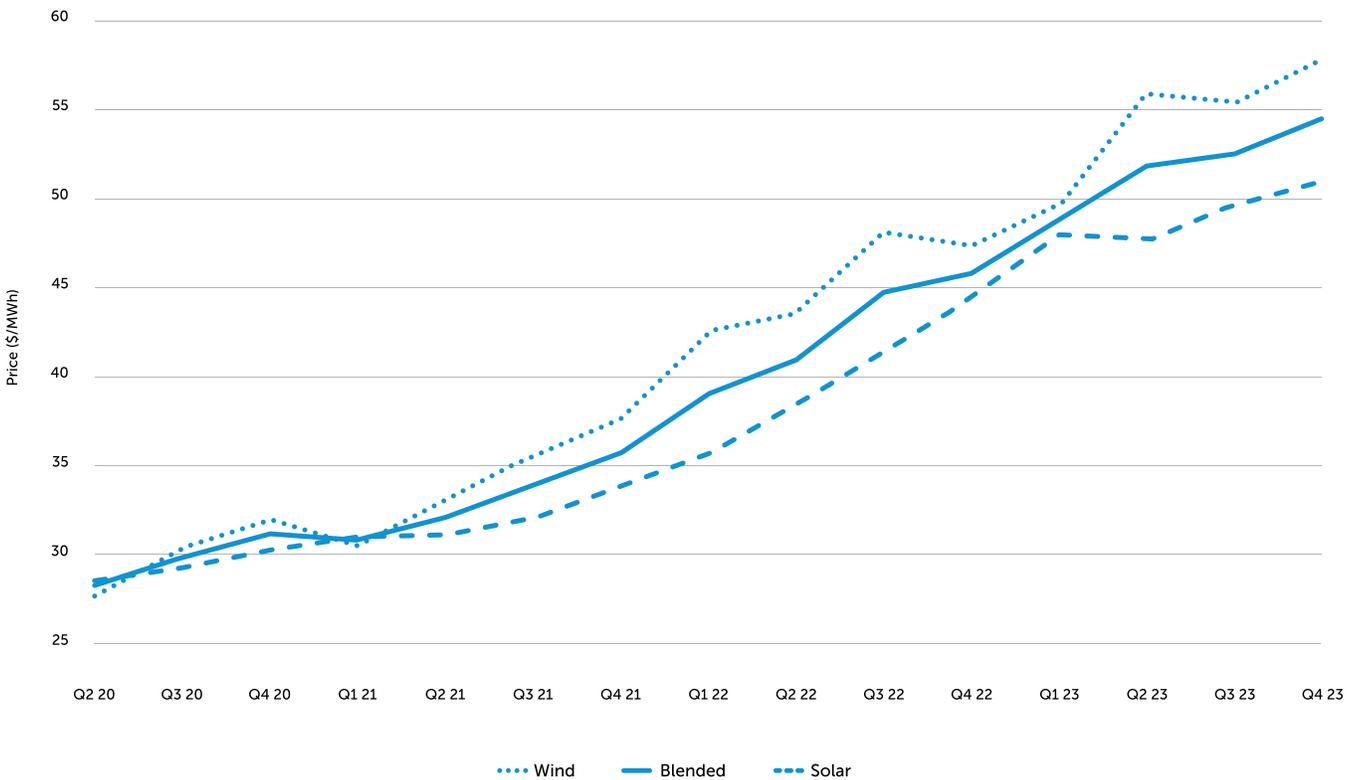
Supply chains were impaired by factory shutdowns, component shortages, labor shortages and financial, economic, demand and policy uncertainty during the pandemic. While this slowed down the supply side of electricity, the demand side recovered quickly and in fact, significantly increased. Renewable energy project supply chains are global and reflect worldwide demand. According to the International Energy Agency, the world added less than 200 gigawatts (GW) of new renewable resources in 2019 and more than 440 GW in 2023.<sup>4</sup> Although renewable supply chains are recovering from pandemic-related stress, the surge in demand is increasing pressure. In the U.S., the Inflation Reduction Act has significantly increased incentives to expand the domestic supply chain of renewable generation. But this further strains the supply chain as companies rush to develop U.S. renewable manufacturing.

This supply chain pressure directly impacts Platte River's resource procurement. For example, Platte River conducted an RFP in 2019 to add 100-200 MW of new solar capacity by 2023. The winning project, a 150-MW solar farm called Black Hollow Solar, is now expected to start commercial operation in 2025. Similar risks exist for projects planned for 2026 and 2027.



### 3.4.3 Renewable resource pricing

Due to supply chain issues and increased demand, the prices for renewables have significantly increased since the last IRP. As shown in Figure 3 from Level Ten Energy<sup>5</sup>, PPA prices in the U.S. doubled by the end of 2023 compared to 2020 levels.



**Figure 3.** PPA prices in the U.S. between 2020 and 2023

Major drivers for this price increase are higher demand, higher cost of capital, higher inflation rates, higher transmission costs, higher risk premiums and trade policy changes. These drivers are detailed below.



**Higher demand:** Consistent with the global increase in demand for renewable generation, demand in the U.S. has also increased, especially after the passage of the Inflation Reduction Act, as illustrated in Table 1. According to the U.S. Energy Information Administration (EIA), the U.S. is expected to add 62.8 GW<sup>6</sup> of new capacity in 2024, 55% more than the 40.4 GW added in 2023. This represents the most capacity added annually since 2003.

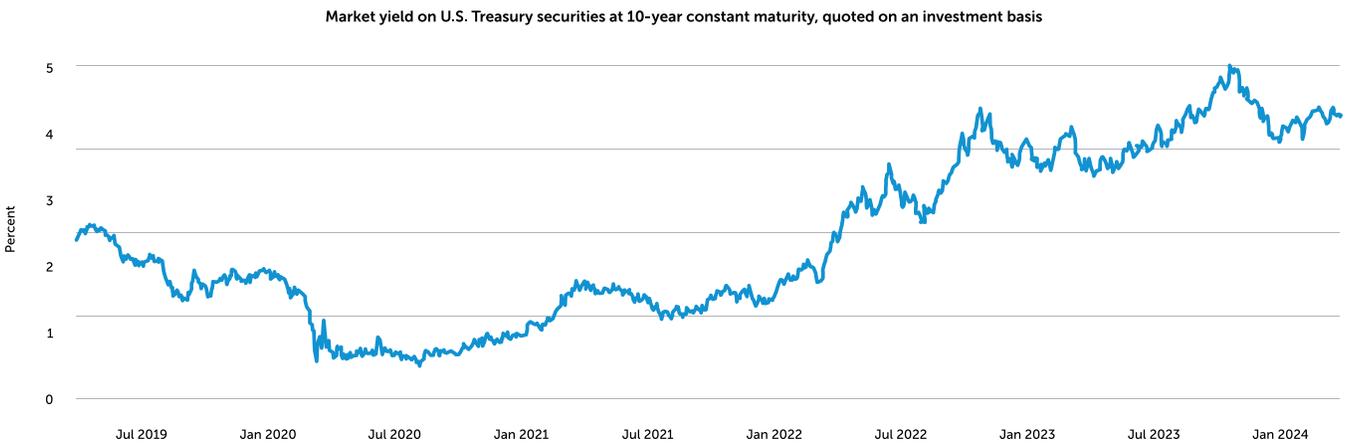
Of this new capacity, the 36.4 GW of added solar is double the 18.4 GW added in 2023. Expected 2024 battery storage additions of 14.3 GW will be more than double the 6.3 GW added in 2023. The significant increase in demand for renewable energy, both domestically and globally, puts upward pressure on prices.

	2023	2024
New capacity	40.4 GW	62.8 GW
Solar	18.4 GW	36.4 GW
Battery	6.3 GW	14.3 GW

**Table 1.** U.S. demand for renewable generation



**Higher cost of capital:** Most of the renewable projects built by third-party developers and sold under long term PPAs are financed with up to 80% debt. Therefore, interest rates (especially long-term debt rates) affect PPA prices. U.S. long-term interest rates, as measured by the yield on 10-year U.S. Treasury Securities, have more than doubled in the past few years as shown by Figure 4 from the Federal Reserve’s Economic Data.<sup>7</sup>



**Figure 4.** Market yield on U.S. Treasury securities at 10-year constant maturity, quoted on an investment basis

<sup>5</sup> <https://www.leveltenenergy.com/ppa>

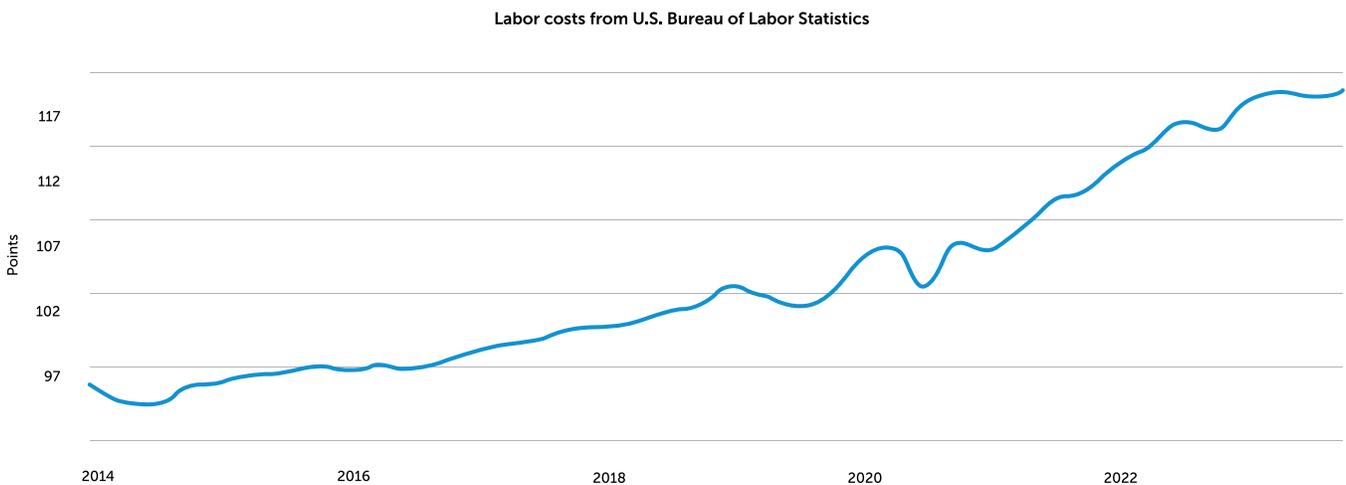
<sup>6</sup> <https://www.eia.gov/todayinenergy/detail.php?id=61424>

<sup>7</sup> <https://fred.stlouisfed.org/series/DGS10>

Corresponding to the 10-year Treasury Securities yield increases, the developer's cost of capital for financing a project has approximately doubled over the last few years from 3-4% to over 7%. This increased cost of debt has significantly increased the carrying cost of projects, raising PPA prices for utilities.



**Higher inflation:** According to the U.S. Bureau of Labor Statistics, the Consumer Price Index (CPI), which is a general measure of inflation, increased 17% in the past three years (January 2021 to January 2024), almost three times the prior three-year period (January 2018 to January 2021), when it increased 6%. This increase in CPI has affected all sectors of the economy, including the price of renewable generation. More specifically, labor costs have seen significant increases in the past few years as shown in Figure 5.



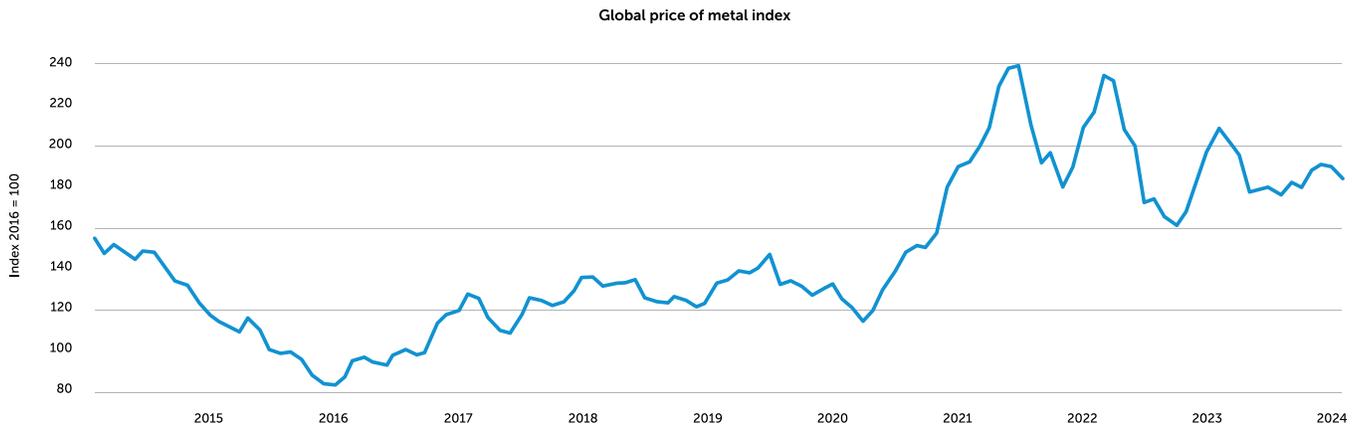
**Figure 5.** Labor costs from U.S. Bureau of Labor Statistics

Similarly, metal costs have seen more volatility and net increase over the past few years, as shown in Figure 6.<sup>8</sup>



**Higher transmission costs:** Transmission costs to interconnect renewables are increasing at two levels. First, inflation increases transmission interconnection equipment costs. Second, as more and more renewable resources are added to the grid, the cost to interconnect the next renewable project is often higher due to the need to upgrade the existing transmission infrastructure.

<sup>8</sup> <https://fred.stlouisfed.org/series/PMETAINDEXM>



**Figure 6.** *Global price of metal index*



**Higher risk premiums:** Recent inflation and uncertainty about future inflation mean that developers assume the recent increase in equipment and labor prices will continue in the future. For example, developers have experienced a significant increase in engineering, construction, and procurement costs and assume these annual cost increases will continue. Recently, Platte River agreed to higher pricing on previously signed PPAs to enable project construction.

Additionally, Anti-Dumping and Countervailing Duties and Uyghur Forced Labor Prevention Act policies created uncertainty for imports from certain countries. These policies, coupled with other factors mentioned earlier, has pushed the price of renewable generation higher. The Inflation Reduction Act and other policies will expand domestic manufacturing, but it may take years before we see any downward pressure on prices.



## 3.5 Resource planning refresh in 2022

Following the pandemic and associated impacts on cost, Platte River staff updated the recommended portfolio from the 2020 IRP in 2022. The revised plan is called RP22 and includes the following:

### 3.5.1 Acceleration of renewable integration

The 2020 IRP had assumed all new generation and storage would come online on Jan. 1, 2030, after Platte River's last coal plant closed. RP22 adds renewables, storage and dispatchable resources while considering project development timelines and supply chain issues. Platte River seeks to have most, if not all, new resources ready by 2028 to give at least one full year of operating experience to Platte River staff before retiring Rawhide Unit 1. This accelerated timeline shows a gradual increase in renewable generation after 2025.

### 3.5.2 Extreme weather modeling

While Platte River's 2020 IRP simulated average weather and load conditions, the impact of Winter Storm Uri in February 2021 on power supply across the midsection of the continental U.S. provided a valuable lesson for enhancing future power supply reliability. During Uri, northern Colorado experienced extremely cold weather and saw little to no renewable generation for three days. We refer to this event of no renewable generation as a "dark calm" and simulated these events in future planning.

To enhance the reliability of the future power supply, RP22 simulates 24 years of hourly historical weather (with its unique hourly load, wind and solar profiles) and

dark calm events. To meet this enhanced reliability requirement, RP22 added 62 MW of additional dispatchable capacity and reduced reliance on four-hour storage relative to the 2020 IRP recommended portfolio.

### 3.5.3 Expanded DER impact

Working closely with our owner communities, Platte River completed its DER strategy in July 2021. The strategy brought an expanded focus on DERs. Since the completion of 2020 IRP, customers have rapidly adopted EVs and distributed solar. Similarly, there is increased interest in heating electrification to replace natural gas-fueled heating. As a result, RP22 models rapid growth in DERs, including EVs, heating electrification and demand response.

### 3.5.4 Renewable supply chain impact

As discussed above, the renewable generation costs and project lead times increased after the pandemic. RP22 considers these increased costs and longer development times for the future portfolio.

## 3.6 Regulatory environment

This section outlines the legislative, regulatory and policy environment in which Platte River developed this IRP. It covers current legislative requirements with which Platte River must comply (both state and federal) as well as political assumptions that influenced the resource plan. This IRP addresses applicable state and federal laws, including those highlighted below.

Platte River is accountable to its board, to the Colorado Department of Public Health and Environment (CDPHE) through commitments made in its voluntarily filed Clean Energy Plan, and to the EPA through its contributions to Colorado's regional haze state implementation plan. The Colorado Public Utilities Commission does not regulate Colorado municipal utilities.

### 3.6.1 Colorado policy review

Since the passage of Platte River's RDP in 2018, Colorado's legislature has increased its attention to energy and environmental policies. Many recent bills impact utilities' resource planning and operations. The following bills are relevant to Platte River's resource planning and this IRP:

**HB19-1261:** The Climate Action Plan to Reduce Pollution set aggregated and sector-specific targets for reducing statewide greenhouse gas pollution. The bill set aggregate reduction targets at 26% by 2025, 50% by 2030 and 90% by 2050 compared to 2005 levels. The General Assembly encouraged consumer-owned electric utilities to file Clean Energy Plans demonstrating at least an 80% reduction in emissions by 2030 compared to 2005 levels. Platte River subsequently filed a voluntary Clean Energy Plan in line with the standards of HB19-1261. In addition to rulemakings for utilities, HB19-1261 also ushered in sweeping changes for

other sectors, such as transportation and buildings, that have a direct impact on future electric load and utilities' resource planning.

**SB19-096:** This bill directed CDPHE's Air Quality Control Commission to collect greenhouse gas emissions data from emitting entities and report on the data to support the state in meeting its greenhouse gas emission reduction goals.

**HB22-1244:** This bill created a new program within CDPHE's Air Pollution Control Division to regulate toxic air contaminants. It also gave the Air Quality

Control Commission permission to create air toxics rules more restrictive than those of the federal Clean Air Act. Starting in 2024, regulated organizations must submit annual toxic emissions reports that the Air Pollution Control Division will make available to the public.

**SB23-198:** Expressing legislative concern that utilities are on track to meet the greenhouse gas reduction goals set out in HB19-1261, this bill requires any utility that submitted a Clean Energy Plan before Jan. 1, 2024, to model

at least one portfolio that achieves a 46% emissions reductions by 2027 (as compared to 2005 levels) and at least one portfolio that achieves greater emissions reductions than the Clean Energy Plan submitted. The Air Pollution Control Division must subsequently confirm that utilities have adequate resources to achieve the 2030 clean energy target. As part of this IRP process, Platte River’s board will consider portfolios that meet the requirements of SB23-198.

Table 2 illustrates how these Colorado policies are either considered in Platte River’s RDP, modeled in this IRP or apply only to reporting functions.

Colorado policy	Reporting	Considered by RDP	Modeled by 2024 IRP
<b>HB19-1261:</b> The Climate Action Plan to Reduce Pollution			
<b>SB19-096:</b> Collect Long-term Climate Change Data			
<b>HB22-1244:</b> Public Protections from Toxic Air Contaminants			
<b>SB23-198:</b> Clean Energy Plans			

**Table 2.** How Colorado policies are considered, modeled or reported by Platte River

In 2018, Colorado Governor Jared Polis ran on a platform of achieving 100% renewable energy by 2040 and continues to direct his staff to achieve this goal. To drive and monitor Colorado's adherence to the greenhouse gas emissions reductions goals set out in HB19-1261, the state released its first Greenhouse Gas Pollution Reduction Roadmap in January 2021.

Concurrent with this IRP process, the Polis administration published its Greenhouse Gas Pollution Reduction Roadmap 2.0 in February 2024, which will accelerate Colorado's clean energy goals.

### 3.6.2 Federal policy overview

As a hydropower customer of WAPA, Platte River must file an IRP with WAPA every five years. This IRP document complies with WAPA requirements as detailed in Appendix A.

On June 16, 2020, Platte River announced its plans to retire Rawhide Unit 1 no later than Dec. 31, 2029. Colorado incorporated Unit 1's planned retirement into its state implementation plan for the regional haze program, making the retirement federally enforceable.

The U.S. Congress passed the Infrastructure Investment and Jobs Act, also known as the Bipartisan Infrastructure Law, in 2021 and the Inflation Reduction Act in 2022. Together these bills resulted in unprecedented federal investments in the clean energy transition through tax credits (including for not-for-profits that have historically not paid taxes and therefore have not been eligible for tax credits)

and competitive grant programs. In response, Platte River has dedicated resources to submitting grant applications and to exploring tax credits for new renewable energy assets. To date, Platte River has mainly captured these benefits through PPAs with renewable developers, whose prices reflect federal subsidies. In partnership with trade associations such as the American Public Power Association and Large Public Power Council, Platte River is continuing to explore opportunities.

Platte River is carefully monitoring the EPA's new regulations on power plants with coal- or new natural gas-fired generating units. In May 2024, the EPA finalized rules to reduce greenhouse gas emissions from power plants. Platte River will continue to closely follow these and other federal developments.



## 3.7 Stakeholder engagement process

### 3.7.1 Outreach strategy

Platte River's communications, marketing and external affairs team worked closely with the transition and integration team to develop a robust community engagement strategy for the 2024 IRP. We collaborated with the four owner communities' distribution utility communications and community relations staff. Owner communities' staff recommended which neighborhood groups, community and nonprofit organizations and customer accounts to engage and helped coordinate presentations for city councils and council-appointed boards. This allowed for a more targeted approach on engaging with stakeholders across Platte River's service region, responding to questions and addressing concerns surrounding the reliability, environmental responsibility and affordability of future energy portfolios.

#### 3.7.1.1 Community meetings

While some owner community stakeholder groups knew Platte River as a wholesale power provider, many constituents were unaware who generates their power and how. An added value of the IRP community meetings was the opportunity for citizens to engage with their community-owned generation and transmission utility.

Mindful of equity and access, Platte River either visited every group we presented to or provided a virtual option, provided information in Spanish and equipped meetings with translators and listening assistance options.

While the audiences were widespread across Platte River's service region with diverse backgrounds, there were general themes that surfaced. Those themes include:



Discussions around customer behavior changes and impacts to resource planning



The increasing trend of beneficial electrification and growth in demand and load



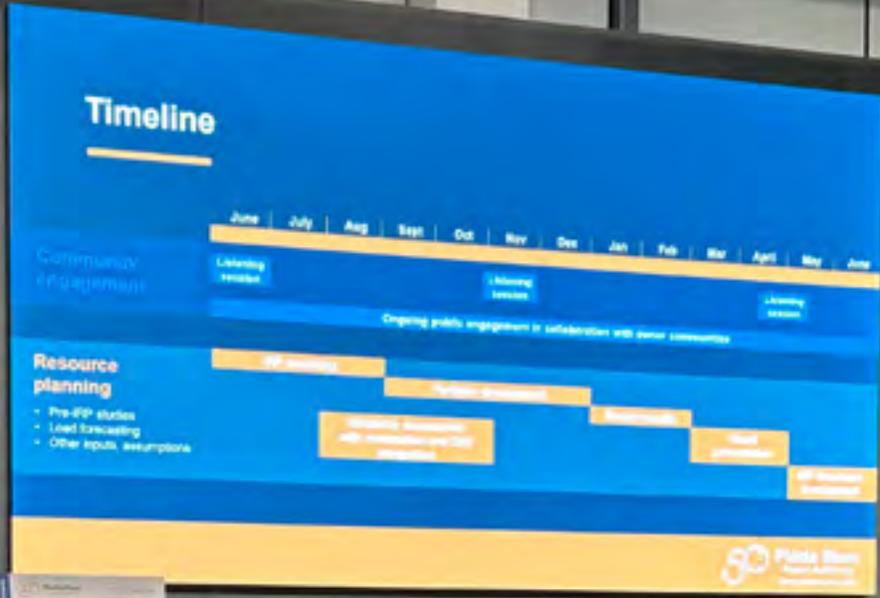
Impacts of climate change and extreme weather modeling



Clarity on what is a dispatchable resource



Equity and affordability



Each presentation gave the audience an opportunity to ask questions. The Platte River team continues to receive questions via email, social media and in-person. To date, we have logged and answered over 150 questions.

Presentations per owner community:

- Estes Park: 2
- Fort Collins: 8
- Longmont: 5
- Loveland: 4

Presentations per community group type:

- Neighborhood group: 2
- Community organization: 6
- Nonprofit: 5
- Customer account: 1
- Council-appointed board: 3
- City/town councils: 4

### 3.7.1.2 Business community engagement

Platte River engaged the business community primarily through downtown development authorities and local chambers of commerce: the Estes Park Chamber of Commerce, the Fort Collins Area Chamber of Commerce, the Longmont Chamber of Commerce and the Loveland Chamber of Commerce. We presented to chamber staff, committee appointees and members, sharing information about Platte River, the RDP, the IRP process and forecasts of our shared energy future. We captured questions and feedback from the business community, who are integral drivers of economic and workforce development in the region.



### 3.7.1.3 Consulting with industry experts

Platte River's resource planning staff actively consulted with national institutes and public power councils, including the Electric Power Research Institute (EPRI), National Renewable Energy Laboratory (NREL) and the Large Public Power Council.

### 3.7.2 Campaigns and resources

Platte River's first brand awareness and public education campaign launched soon after the start of our 2024 IRP community engagement. The parallel run of these two efforts aimed to educate the utility's service region about who Platte River is while driving users to Platte River's digital platforms to learn more about our aggressive decarbonization efforts.

Platte River used both organic and paid media to support community engagement activities for the 2024 IRP, including:

- Digital technologies like social media, email distribution and websites
- Cross-functional organic outreach through support from platforms across each owner community and distribution utility
- Paid media with advertisements placed in traditional and digital platforms with high visibility across each owner community
- Engagement with local media, including hosting an editorial meeting with local media partners



In addition, Platte River developed and maintains the following resources for continued engagement with the public.

### **3.7.2.1 Microsite**

Staff developed a detailed and interactive IRP microsite ([prpa.org/2024irp](http://prpa.org/2024irp)) that is updated as information evolves and additional details are available. Members of the public are encouraged to visit this site to learn more about Platte River's plans and to access more in-depth information including the studies conducted as part of the IRP.

Our staff captured and answered all questions asked during the community engagement phase. These answers are provided in an appendix to this IRP. A subset of high frequency questions was extracted from the full list to develop a 'frequently asked questions' page published to the IRP microsite.

### **3.7.2.2 Dedicated email**

Platte River created a dedicated email for IRP specific questions and comments at [2024IRP@prpa.org](mailto:2024IRP@prpa.org). This approach allows for direct communication with engaged citizens and allows staff to track their contributions.

## **3.7.3 Results**

The 2024 IRP reflects extensive collaboration among Platte River teams and gathering input from key stakeholders and the communities we serve. This process was designed to provide an open and transparent view of Platte River's resource planning strategy, accountability to our owner communities and the state of Colorado's clean energy goals and to underscore the value of equally maintaining our three foundational pillars.

One of the major takeaway messages we identified across each outreach effort: Platte River must continue to safely provide affordable and reliable power to its owner communities and their customers while addressing the evolving landscape in which we operate. Each owner community served by Platte River has set, or is in the process of setting, its own clean future initiative and is challenging Platte River to match these efforts to provide northern Colorado with electric service in an increasingly sustainable manner.

# 04

## Platte River's path to a clean, reliable energy future



## 4.1 Key variables and strategic considerations

Platte River considered whether the advancements identified in the RDP have been met while working toward the RDP goal. Other variables in this IRP include:

### 4.1.1 Load forecast

Load forecast refers to how load, or aggregate electricity demand, is changing and the impacts of those changes to the energy mix.

### 4.1.2 Energy and capacity planning

**Energy planning** involves managing the production and purchase of megawatt-hours (MWh) of electricity to meet customer demand efficiently and sustainably. Effective energy planning can decrease emissions by integrating renewable energy sources while maintaining reliability.

**Capacity planning** is crucial for utilities to have sufficient generation resources to meet peak load demands plus a reserve margin, known as the PRM. The PRM supports reliability and accommodates unexpected demand surges or generation outages.

#### Capacity vs. energy value

Resources may be developed primarily for their capacity value rather than their energy output. These resources may run infrequently but are critical during peak demand periods or emergencies. Their primary function is to be available when the system needs them the most, supporting grid stability and reliability.



### 4.1.3 Customer programs

Customer programs is the term to describe how existing energy efficiency programs are performing today, how they will evolve tomorrow, and how the behaviors that result from program adoption will impact load forecast.

Most of Platte River's existing customer programs are geared toward energy efficiency, access to renewable energy, support for low-income residents or electrification. Our IRP accounts for these programs' impact on total demand and peak demand for electricity.

The IRP also anticipates an increased focus on energy efficiency, battery storage and electrification. These needs will draw on existing customer programs and will be enhanced by new or expanded programs over the next several years.

### 4.1.4 Emerging technologies

Resource planning staff engaged with an engineering consulting team to evaluate the viability, long-term scalability and technological performance of emerging technologies. Platte River must balance the adoption of these technologies with the impacts they may have on the three foundational pillars.

### 4.1.5 Power markets

Participation in an organized market is needed for Platte River to achieve the clean energy transition. Over the years, Platte River has participated in numerous forums related to organized markets. Platte River, along with Xcel

Energy, Black Hills Energy and later Colorado Springs Utilities, participated in the JDA for several years. The JDA was a small-scale, regionally focused market operated by Xcel Energy that allowed for more efficient use of generating resources and balancing renewable resources.

Although the JDA benefited Platte River, the opportunity to join an energy imbalance market was the next step in the path toward full energy market participation. This led to three of the JDA participants joining the SPP WEIS market in April 2023. While it functions like the JDA, the WEIS has a larger footprint and SPP serves as the independent market operator.

In September 2023, Platte River announced plans to join the SPP RTO West. Platte River, along with other utilities, expects to transition into this market on April 1, 2026. When the RTO West market is functioning, Platte River will sell all its generation into the market and purchase all its load obligations from the market.

### 4.1.6 Resource adequacy

Resource adequacy refers to the ability of Platte River to have sufficient resources to constantly deliver electricity to all consumers, even under challenging conditions. Resource adequacy is a critical aspect of resource planning and operation, to maintain enough generation capacity to meet the peak demand plus a reserve margin for unforeseen events, such as generator failures, weather events, sudden spikes in demand or other system disruptions.

### 4.1.7 Transmission and distribution infrastructure

As Platte River's energy portfolio continues to diversify, new resources will be interconnected to the transmission network. In a regional transmission network owned by more than one entity, the new resources may be interconnected directly to Platte River's transmission lines or to transmission lines owned by others.

Each transmission line owner manages a generator interconnection process to require the new generation resources to be interconnected in a way that does not adversely impact the reliability of the transmission network. New generation resources will require new interconnection infrastructure and if necessary, transmission network upgrades. The transmission network upgrades will be identified

during the interconnect study process. The upgrades may include new transmission lines or modifying existing transmission lines.

As new resource projects are established, network upgrades or modifications will be evaluated and identified. Platte River has included the costs to fund future transmission projects in our long-term capital budget. Current budget estimates will be refined as the details of the new resources are identified.

### 4.1.8 DER adoption and integration

Traditionally, customer electricity needs consisted solely of aggregate electricity demand. With the growth of DERs, today's customer demand must also include a seamless and economic integration of distributed resources.





## 4.2 Navigating challenges and maintaining the foundational pillars

The foundational pillars serve as guideposts for all Platte River activities, including the resource planning and modeling activities documented in this IRP.

### 4.2.1 Reliability – dispatchable capacity

Dispatchable capacity refers to any resource that can start, stop, and change output level quickly to produce more or less power when needed. The reliability challenges during extreme weather events and dark calms (characterized by the absence of solar and wind energy due to adverse weather conditions for multiple days) highlight the vulnerability of serving load with weather-dependent energy sources. These events underscore the critical role of dispatchable capacity in maintaining power supply.

Platte River commissioned a study with ACES to analyze different weather patterns from the past five decades across a broad region to understand the frequency and impact of extreme weather and dark calm events. The findings emphasize the need for a diversified energy portfolio and supply strategies that can withstand varying weather conditions, including rare and extreme events.

The future of energy reliability hinges on supporting renewable resources with dispatchable resources (including innovative energy storage solutions) to provide continuous power supply during all weather scenarios.

### 4.2.2 Environmental responsibility – cost of carbon

The portfolios modeled in this IRP assume that future electricity prices will also include carbon taxes.

The carbon-imposed cost portfolio imposes additional costs disincentivizing dispatch of high-carbon energy sources unless needed to maintain reliability of the system even after accounting for their environmental impact. This factors environmental ramifications of carbon emissions into decision-making, steering energy strategies toward more sustainable pathways.

The evaluation process for including technologies in a carbon-imposed cost portfolio prioritizes renewable energy sources like wind and solar due to their minimal carbon footprint. Dispatchable capacity resources are also considered for their potential to balance reliability with reduced emissions, aligning the portfolio with environmentally responsible objectives.



### 4.2.3 Financial sustainability – rates and affordability

As a not-for-profit utility, Platte River's revenues from its wholesale power rates fund ongoing operations and are reinvested into the system for the benefit of the owner communities. The owner communities' distribution utilities integrate Platte River's wholesale rates into their retail and commercial electric rates.

Platte River's rate-setting policy calls for established service offerings and supporting rate structures that complement the strategic objectives and values of the organization. Platte River's rate structure strives to meet the following objectives:

- Align wholesale pricing signals with cost of service
- Adapt to cost structure changes
- Integrate noncarbon resource additions

In support of Platte River's foundational pillars of providing reliable, environmentally responsible and financially sustainable energy and services, and Platte River's mission, vision and values and strategic initiatives, the strategic financial plan provides direction to preserve long-term financial sustainability and manage financial risk. The objectives of the strategic financial plan are:

- Generate adequate earnings margins and cash flows



- Maintain sufficient liquidity for operational stability
- Maintain access to low-cost capital
- Provide wholesale rate stability
- Maximize cost savings through pricing signals that provide system benefits and revenue stability
- Navigate resource acquisition costs increases and delays

Platte River is also subject to financial and rate requirements in the Power Supply Agreements and the General Power Bond Resolution. Platte River's Board of Directors

has the exclusive authority to establish electric rates and must review rates at least once each calendar year.

To meet these objectives and requirements, staff established financial metrics and rate stability strategies, taking into consideration rating agency guidelines. Following its strategic financial plan, Platte River will maintain long-term financial sustainability by implementing appropriate rates and strategies that:

- Reduce significant single-year rate hikes
- Provide greater rate predictability to support owner communities with more accurate, long-term planning
- Maintain a strong financial position and AA credit rating

Competitive wholesale rates give the owner communities economic benefits for their customers. Platte River strives to maintain services and rates offered at competitive prices compared to similar services and products provided by other wholesale electric utilities in the region. Platte River's fiscal responsibility and rate stability strategies help reduce long-term rate pressure and give the owner communities greater rate predictability.

Platte River's long-term rate forecast is prepared and presented to the board of directors in the spring of each year. The IRP results, along with the most current assumptions, will be included in the rate forecast prepared in spring 2024.

# 05

## Electricity demand



## 5.1 Load forecast methodology and data

The future load forecast is a key input for the 2024 IRP. It serves as the foundation for decision-making around resource allocation, capacity planning and infrastructure development. Accuracy of future load forecasts is critical for new resource development and investment in new technologies.

Historically, utility load forecasts were driven by weather, economic activity and efficiency improvements. While these are still the primary drivers, DERs are rapidly becoming a significant contributor to future electricity demand. While all DERs are important, energy efficiency, distributed solar, EVs and beneficial electrification are the primary contributors to the future load forecast. These DERs impact the load forecast in different ways. For example, energy efficiency reduces load, distributed solar reduces net load during the day, EVs add load across the day (especially in the evenings), and

beneficial electrification increases load in colder months. This complex combination of opposing impacts increases the uncertainty in expected future load. Consequently, it increases the need for flexible plans and frequent plan updates, to provide reliable power supply under wide-ranging future load scenarios.

Load forecasting models rely on historical data to develop future forecasts. Most DERs are in early stages of development and there is very little historical data available for them. Therefore, Platte River developed a load forecast based on history without considering DERs. A separate forecast for DERs was developed based on expected adoption rates. The two forecasts were then merged to develop a composite or net load forecast. This composite load forecast was used in the Plexos model to build the supply side resource mix.

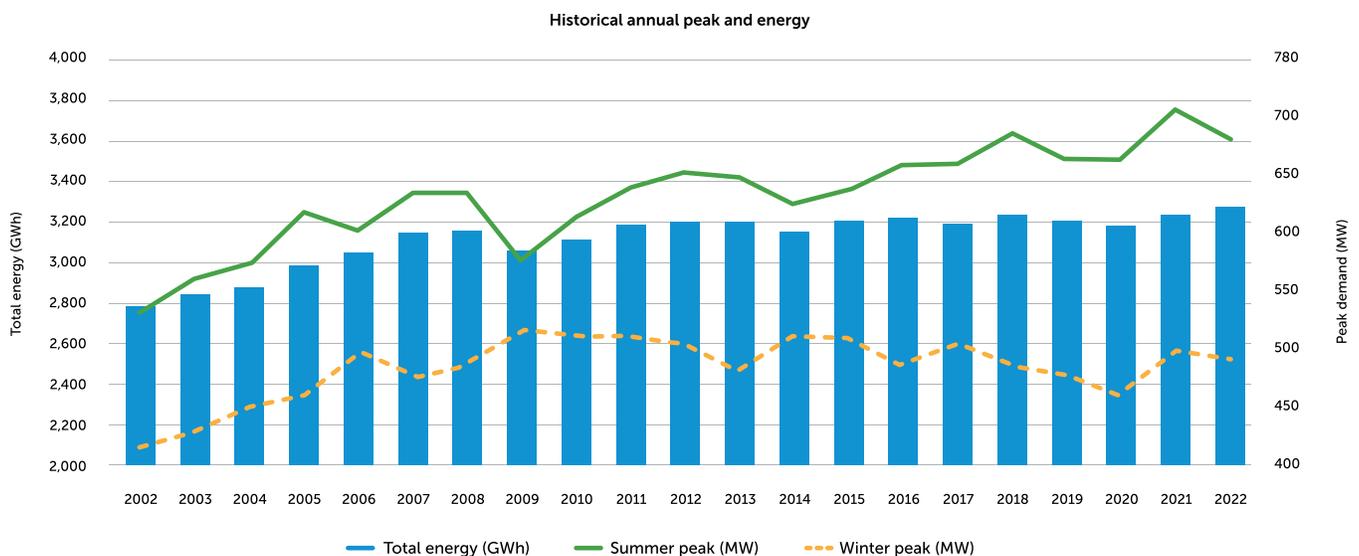
## 5.2 Load forecast without DER

Platte River hired The Energy Authority (TEA), a third-party consultant, to develop a 20-year load forecast for the planning period of 2024-2043. TEA developed a load forecast without considering DERs, referred to as the base load forecast. TEA developed a forecast of monthly energy consumption and monthly peak demand as well as hourly load shapes.

### 5.2.1 Methodology

The monthly load forecast used a “least squares linear regression” model, using historical data to derive a linear relationship between a dependent variable and one or more independent variables. The dependent variable was forecasted using linear relationships and projections for each independent variable as discussed below.

Forty years of historical weather data, along with 20 years of load and economic data, were used to train three linear regression models. The first model considered total monthly energy as the regression’s dependent variable. The remaining two models considered peak load as the dependent variable, with a model specifically for June through September and another for all remaining months in the year. This split was due to the contrast in peak load history between summer, which has grown consistently, and winter, which has seen a slight decrease since the late 2000s. Figure 7 illustrates the total and peak load history for Platte River, aggregated by year.



**Figure 7.** Historical annual peak and energy

Once the regression model was trained using historical data, a projection for each of the forecast drivers was input into the three models, creating monthly forecasts for total energy and peak load.

### 5.2.2 Forecast drivers

Future load growth can be driven by weather trends, economic factors or specific changes in customer usage patterns. To project future load patterns, Platte River’s linear regression model used temperature, number of households and changes in air conditioning use.



**Weather and seasonal impacts.** One of the fundamental metrics to quantify the severity of weather is degree days. This metric takes the difference between the average daily temperature and a set point. In this case, the set point was 65 degrees Fahrenheit (°F). Heating degree days take the sum of this calculation for temperatures below 65°F, while cooling degree days use this calculation for temperatures above 65°F. The distinction between heating and cooling degree days was made because hot and cold weather have different impacts on customer energy usage.

Based on the past 40 years of historical temperature data, a weather-normal forecast was developed for both heating and cooling degree days. Forty years of data were used to better capture the slight warming trend that has been observed in temperature history. This warming trend was incorporated into the weather-normalized forecast, resulting in a slight decrease in annual heating degree days and a slight increase in annual cooling degree days over time, as illustrated in Figure 8.

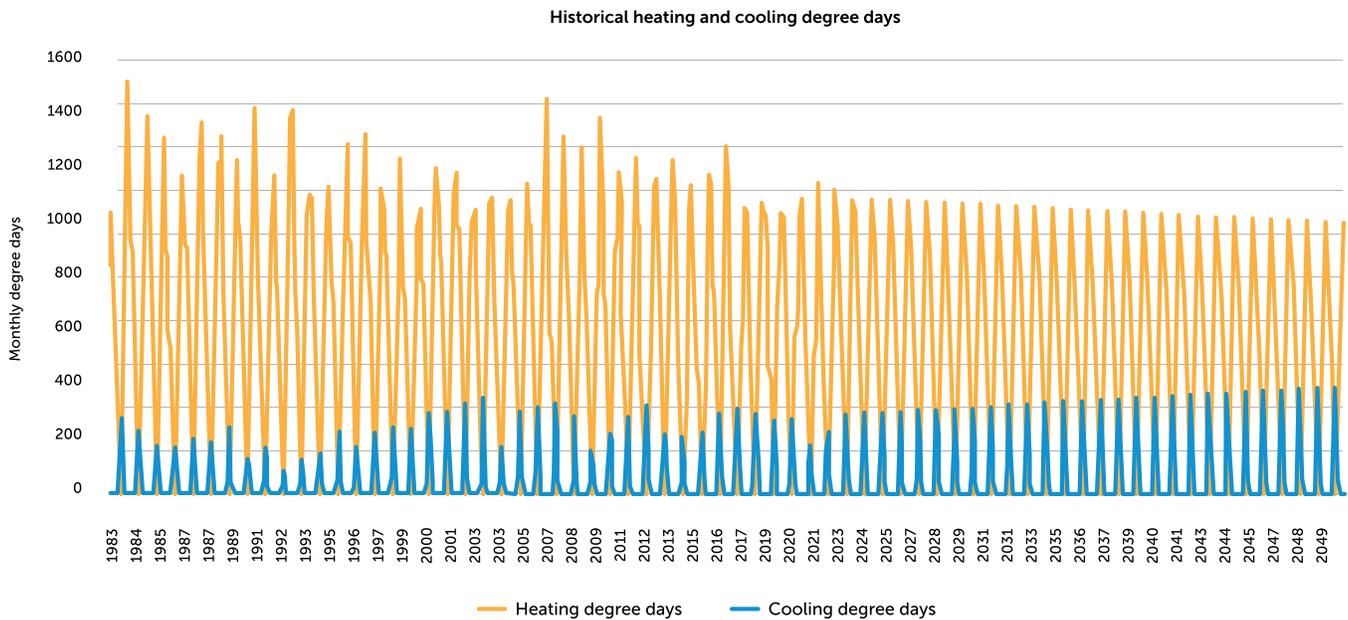
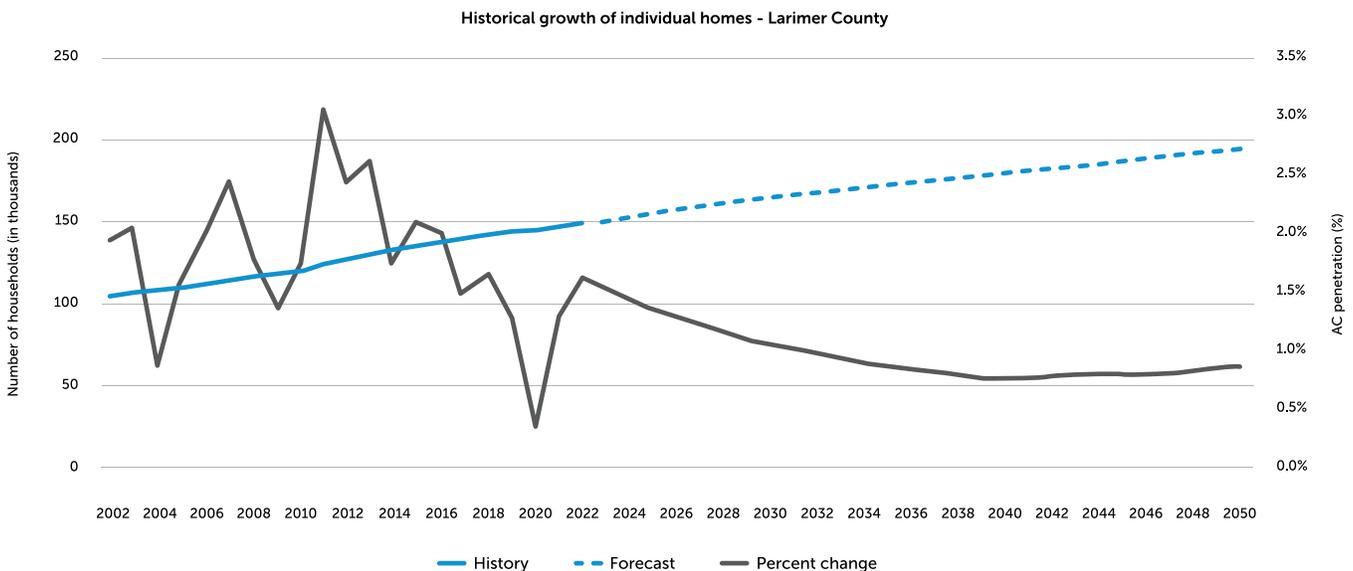


Figure 8. Historical heating and cooling degree days

Another factor incorporated into the load forecast model was the month of the year. This was used both to smooth the monthly forecast and to better consider seasonal impacts that may not be captured solely using heating or cooling degree days.



**Number of households.** Number of households was used to project economic growth within Platte River's service territory. These projections were obtained for Larimer County from Woods and Poole, an economic forecasting firm. While sections of Platte River's service territory exist in surrounding counties, the model assumes that economic growth in Larimer County reflects the growth of nearby areas as well. Growth in number of households is expected to continue to soften through the 2030s, following the trend observed since 2011. From 2040 onward, growth in number of households slightly flattens as illustrated in Figure 9.



**Figure 9.** Historical growth of individual homes



**Air conditioning use.** A large driver for load growth over the past 20 years is an increase in the percentage of single-family homes with central air conditioning. This has increased both total energy consumption and peak demand during the summer months. Growth in air conditioner use is expected to slightly decrease in the future, with an average of 0.6% year-over-year increase through 2050, as illustrated in Figure 10.

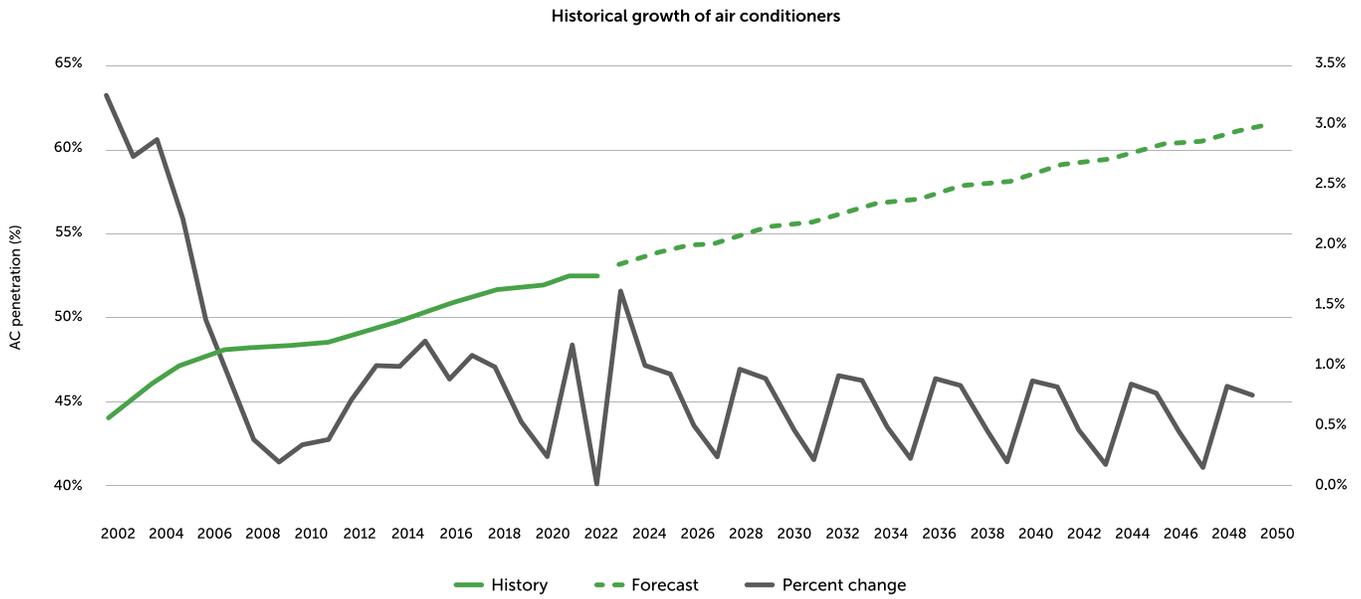


Figure 10. Historical growth of air conditioners

### 5.2.3 Forecast results

Figure 11 displays the annual total energy forecast, summer peak demand and winter peak demand through 2050. The growth in summer peak demand is expected to outpace growth in total energy, reflecting the trend observed since the early 2010s. While winter peak demand is projected to increase, it is at a lower rate than both summer peak and total energy forecasts. Average summer peak and total energy growth rates for the first 10 years of the plan are shown in Table 3.

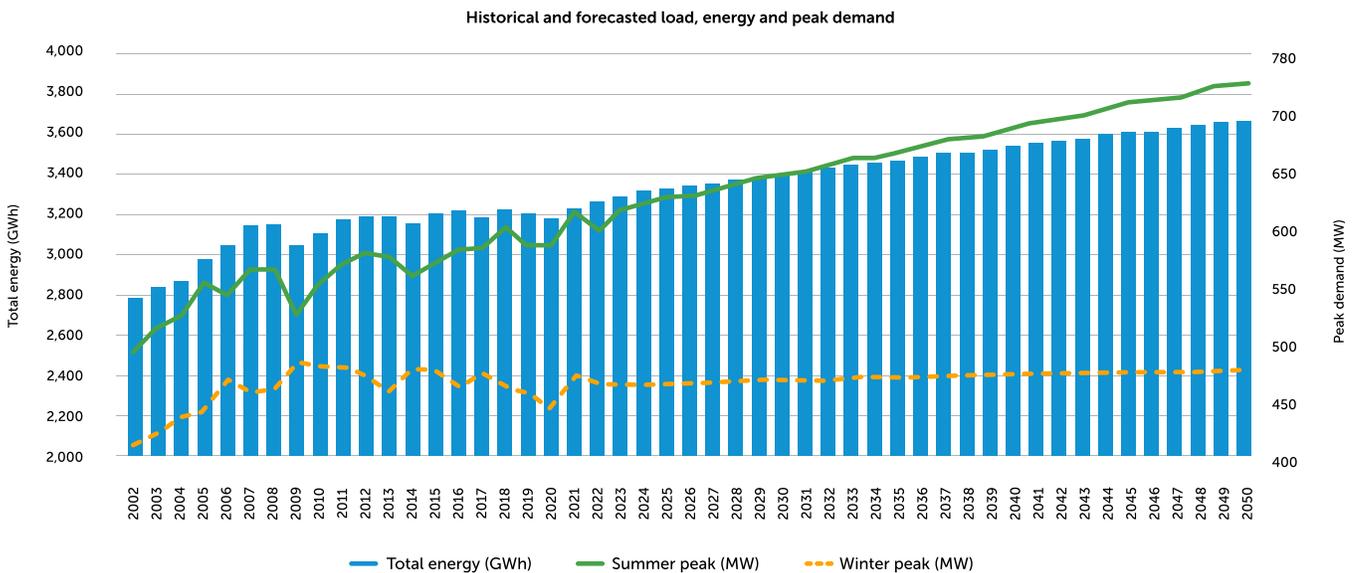


Figure 11. Historical and forecasted load, energy and peak demand (base forecast without DERs)

2024 – 2033 year-over-year average growth – base load forecast	
Total energy	0.5%
Summer peak load	0.8%

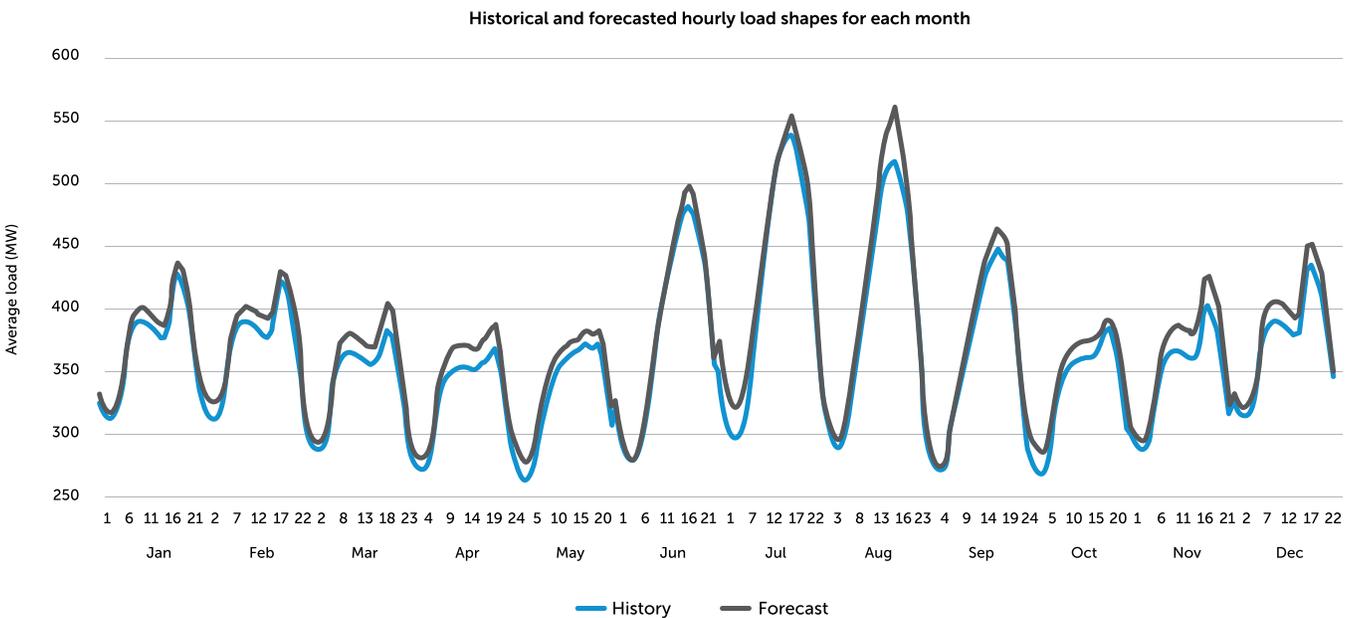
**Table 3.** Average annual load growth, energy and peak demand

### 5.2.4 Hourly load shape

In addition to monthly forecasts, an hourly load shape forecast was developed for hourly dispatch modeling purposes. Rather than using a linear regression tool, a more robust model was chosen to develop the hourly shape due to the many nuances observed between hourly load and temperature changes over time. Hourly load data for 2013-2022 and temperature

data for 2002-2022 was input into the model. The model created an hourly weather normal temperature forecast using the rank and average method. After the hourly load forecast for 2023 was developed, the total energy and peak load shape for each month was then normalized to the monthly projections for 2023. While there were not large discrepancies between the hourly and monthly model projections prior to normalization, this was done to ensure consistency between the two forecasts.

Figure 12 compares the average hourly shape, by month, for the 10 years of historical hourly data and the 2023 projections. There are increases in average hourly load between the load history and forecast, but these reflect load growth observed during 2013-2022. The forecasted load shape is commensurate with historical load shapes.



**Figure 12.** Historical and forecasted hourly load shapes for each month

## 5.3 DER integration, flexible DERs and the virtual power plant

The term “DER” encompasses a range of technologies installed and used at a customer’s premises or within the distribution system. DER can be either on the customer or utility side of the meter. These assets potentially provide advantages to both the electric system and customers alike. These resources include energy efficiency, building electrification, transportation electrification, distributed generation, distributed energy storage and demand response.

DERs are, as stated in the name, resources. For resources to provide value, they must be put to effective use. Effectively using DERs to provide system-wide benefits is often referred to as “integrating” DERs. Integrating DERs means they have been made a functioning part of the electric system. This includes some or all of the following:



**Visibility and forecasting.** DERs must be “visible” to and predictable by electric system planners and operators for their effects to be taken into consideration. To support system planning, DER impacts must be forecast years in advance. To support system operations, DER forecasts must look seconds, minutes, or days into the future.



**Dispatchability or control.** Flexible DERs can be controlled or dispatched by utility system operators to maintain reliability or to achieve system-wide financial benefits.



**Customer awareness, engagement and participation.** The customer is provided support and services to help them understand their opportunities, benefits and responsibilities as participants in the electric system.

When flexible DERs are integrated in this manner and aggregated into coordinated operational programs, they are considered a virtual power plant (VPP). A VPP is a network of aggregated flexible DERs that can be controlled by Platte River and the owner community distribution utilities through advanced software to support grid reliability and financial sustainability.

Modeled in forecast



### Energy efficiency

Save energy and save money by using energy more efficiently



### Electrification

Reduce greenhouse gases by replacing fossil fuel use with increasingly decarbonized electricity



### Distributed generation

On site noncarbon generation  
*Solar generation*



### Demand response

Shift energy to align electric use to renewable availability and to decarbonize the electric system in a cost effective and reliable manner

*EVs, batteries and traditional demand response*



### Distributed energy storage

Flexible DER as part of a VPP

### 5.3.1 DER forecast studies

Platte River commissioned two DER forecast studies to support DER and resource planning. The first, Platte River Power Authority Beneficial Building Electrification Forecast, Mar. 12, 2022, was completed by Apex Analytics, LLC (“Building Electrification Study”). The second, Distributed Energy Resources Forecast and Potential Study, Aug. 28, 2023, was completed by Dunsky Energy+Climate Advisors (“DER Study”).<sup>9</sup> A summary of the studies and their results is included below, and the full studies are available in the appendices of this report.

The Building Electrification Study scope included the following:

- Study period: 24 years (2023 through 2046)
- Building electrification categories: space heating, water heating and cooking
- Sectors/segments: residential and commercial
- Scenarios: three market potential scenarios that consider market, policy, and technology factors and inputs (for example, technology cost and performance; federal, state and local codes, standards, or incentives) and program or utility factors and inputs (like incentives or rates)
- Outputs: annual energy impacts, hourly and peak demand impacts

The DER Study scope included the following:

- Study period: 20 years (2024 through 2043)



- DER categories: energy efficiency, transportation electrification, distributed generation + storage, and demand response (or flexible DER, including EV charge management, battery storage management and traditional demand response)
- Sectors/segments: residential single family, residential multi-family, small commercial, large commercial
- Scenarios: three market potential scenarios that consider market, policy, and technology factors and inputs (for example, technology cost and performance; federal, state, and local codes, standards, or incentives) and program or utility factors and inputs (like incentives, rates, or avoided costs)

<sup>9</sup> Platte River did not consider cogeneration and district heating/cooling in these studies because of the lack of interest by our customers and the future trend of electrifying heating and cooling to reduce gas burning.



- Outputs: technology adoption (number of units), annual energy impacts, hourly and peak demand impacts, program metrics (budgets)

The results of these studies inform load forecasts and DER program plans as discussed below.

### 5.3.2 Energy efficiency

Energy efficiency programs help customers reduce their energy consumption through a variety of interventions, including outreach, education, contractor engagement and incentives. Platte River and the owner communities deliver energy efficiency programs under the Efficiency Works™ brand, jointly funded and administered by

Platte River and its owner communities. These programs give communities a cost-effective way to manage load growth, reduce carbon emissions and help customers reduce electricity costs, and provide a cost-effective option when compared to the cost of supply-side resources otherwise needed.

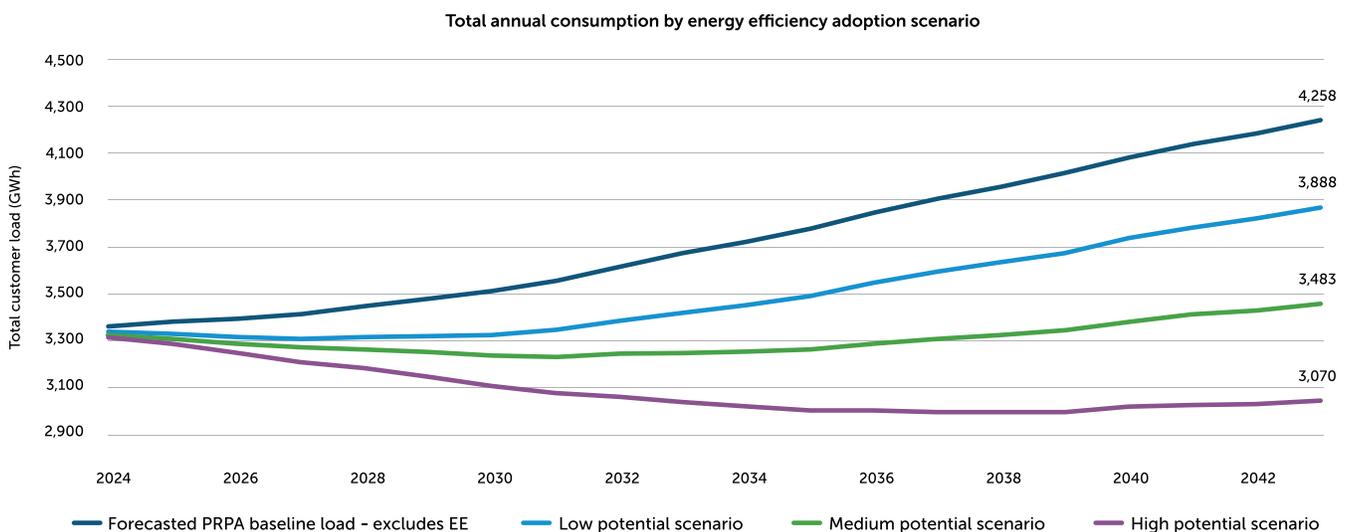
#### 5.3.2.1 Energy efficiency forecast study results

The DER Study evaluated the energy efficiency potential, identifying three adoption scenarios: low, medium and high. The adoption scenarios were evaluated based on three other utility potential studies, taking into consideration local factors, such as the owner communities' customer segmentation, historical participation

data for existing Platte River energy efficiency programs and the building electrification forecast study identifying heat pump adoption rates. Two of the key takeaways from the study include:

- Platte River could achieve an average incremental savings rate of almost 0.78% of annual load each year between 2024 and 2030 in the low scenario, 1.15% in the medium scenario, 1.71% in the high scenario. This would come at a cumulative cost (2024-2030) of about \$105 million, \$200 million and \$460 million, respectively.
- Energy efficiency savings for lighting, heating, ventilation and air conditioning (HVAC) pumps and fans and plug load (energy used by equipment that is plugged into an outlet) make up over 60% of total forecasted savings by 2043 for the commercial sector. For the residential sector, heating provides almost 60% of the energy efficiency savings, due in part to growing residential heating electrification, followed by plug load and domestic hot water.

The study applied the energy efficiency potential scenarios to the estimated customer baseload forecast. Figure 13 shows the effect of energy efficiency on load forecast and Figure 14 shows energy savings by market segment.



Note: The baseline load includes expected customer load growth and electrification growth (PRPA baseline load + building electrification Low projection). Transportation electrification and distributed solar are not included in the baseline load.

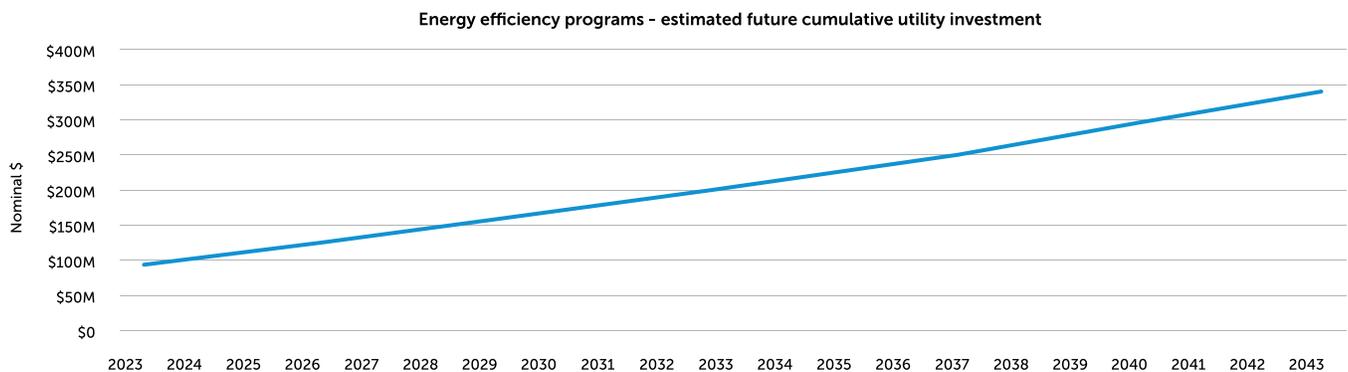
**Figure 13.** Total annual consumption by energy efficiency adoption scenario

Platte River continues to invest significant resources in a portfolio of energy efficiency programs, which include some of the highest incentives in the region. These investments are intended to help avoid the need for new generation resources due to customers using energy more effectively.

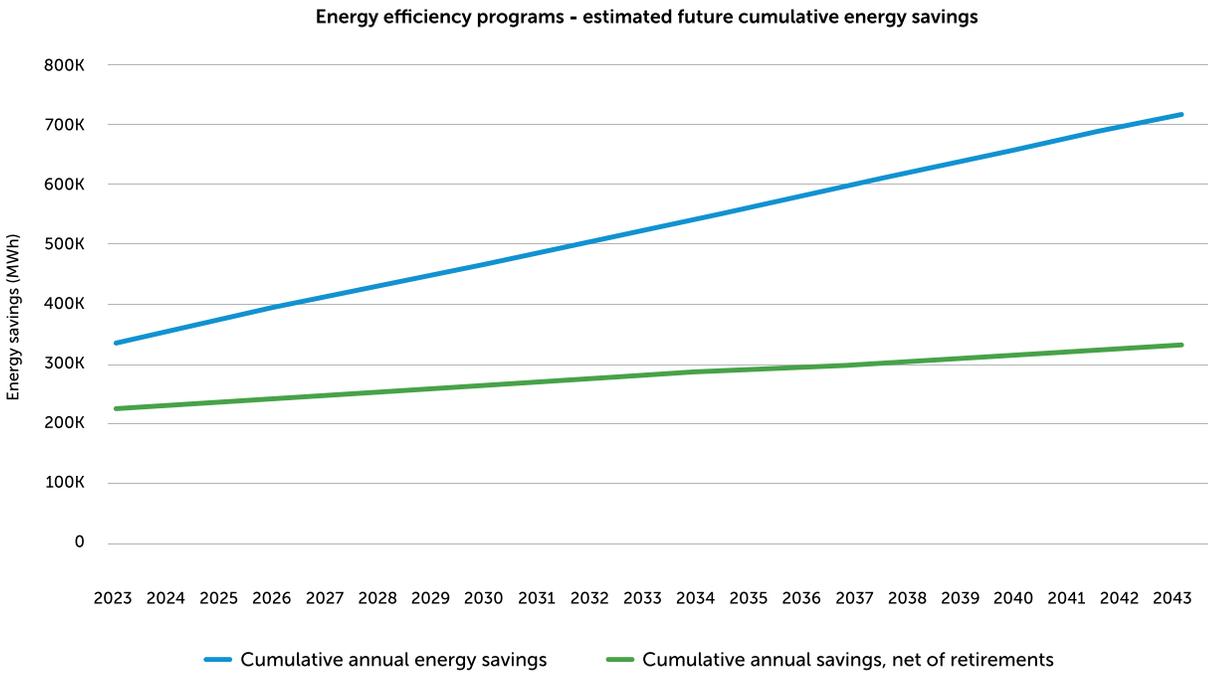


**Figure 14.** Cumulative potential savings (GWh)

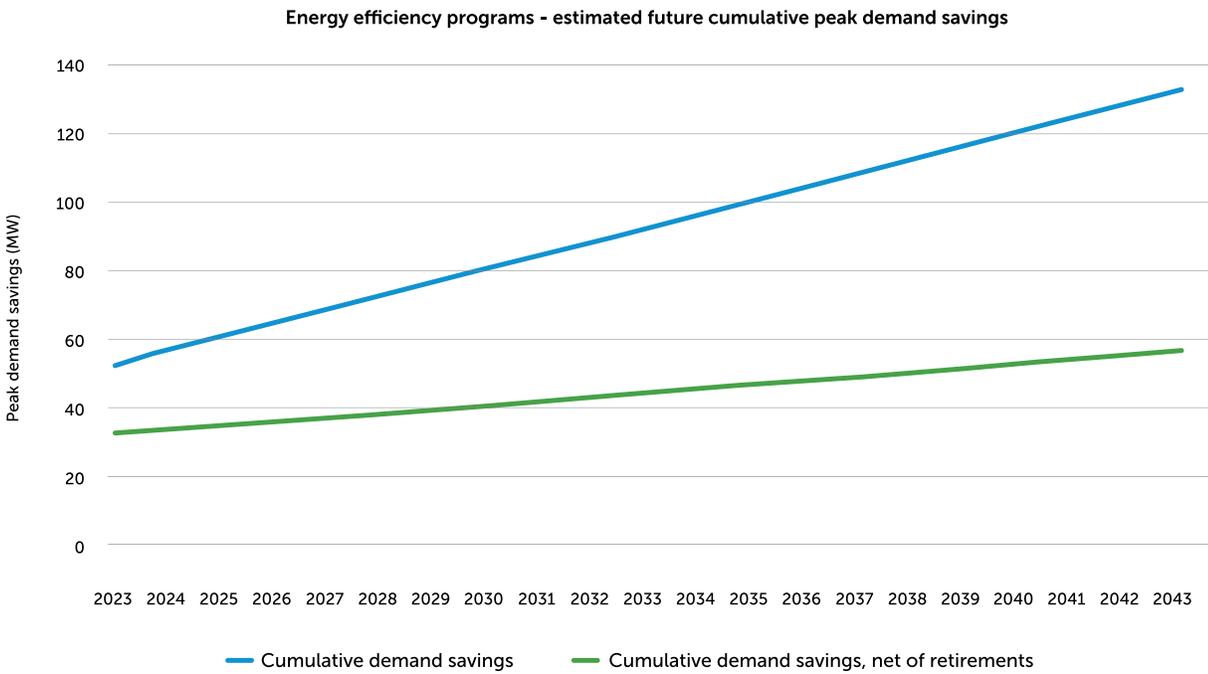
However, current participation rates are consistent with the low forecast contained in the DER study. Platte River plans to continue investment in energy efficiency at current levels through 2030 and beyond with adjustment for inflation, as long as the investment provides value through customer participation and energy-saving benefits. See figures 15, 16 and 17 for estimated future investments and associated savings within the owner communities for energy efficiency services. These ongoing investments in energy efficiency services will continue to evolve and provide a strong foundation of programming for other DER technologies to build upon in future years.



**Figure 15.** Energy efficiency programs - estimated future cumulative utility investment



**Figure 16.** Energy efficiency programs - estimated future cumulative energy savings



**Figure 17.** Energy efficiency programs - estimated future cumulative peak demand savings

## 5.3.3 Electrification

### 5.3.3.1 Buildings

Building electrification refers to new uses for electricity that replace other sources of energy used in buildings. When building electrification provides additional economic benefits, grid benefits and environmental benefits, it is referred to as beneficial building electrification. Typically, building electrification involves the replacement of natural gas or propane appliances in residential and commercial properties with more carbon-efficient appliances that consume electricity.

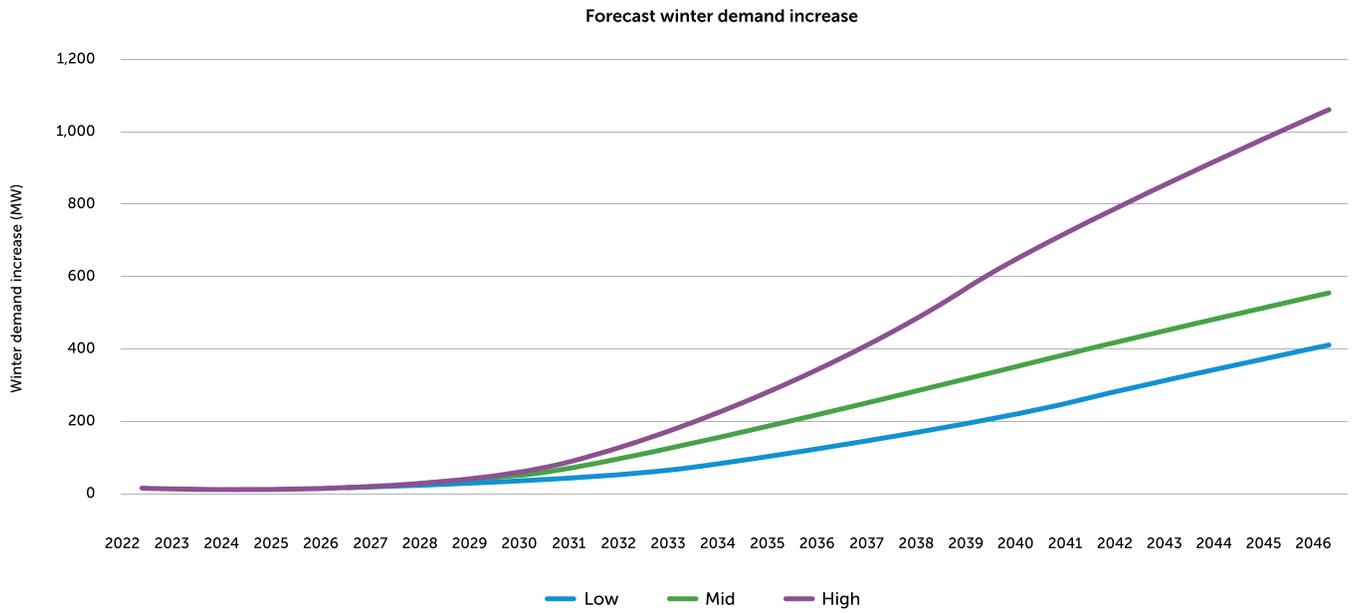
As Platte River’s owner communities pursue carbon emission reduction and as Platte River decarbonizes its generation, building electrification becomes an attractive alternative that can be incorporated into existing Efficiency Works customer programs.



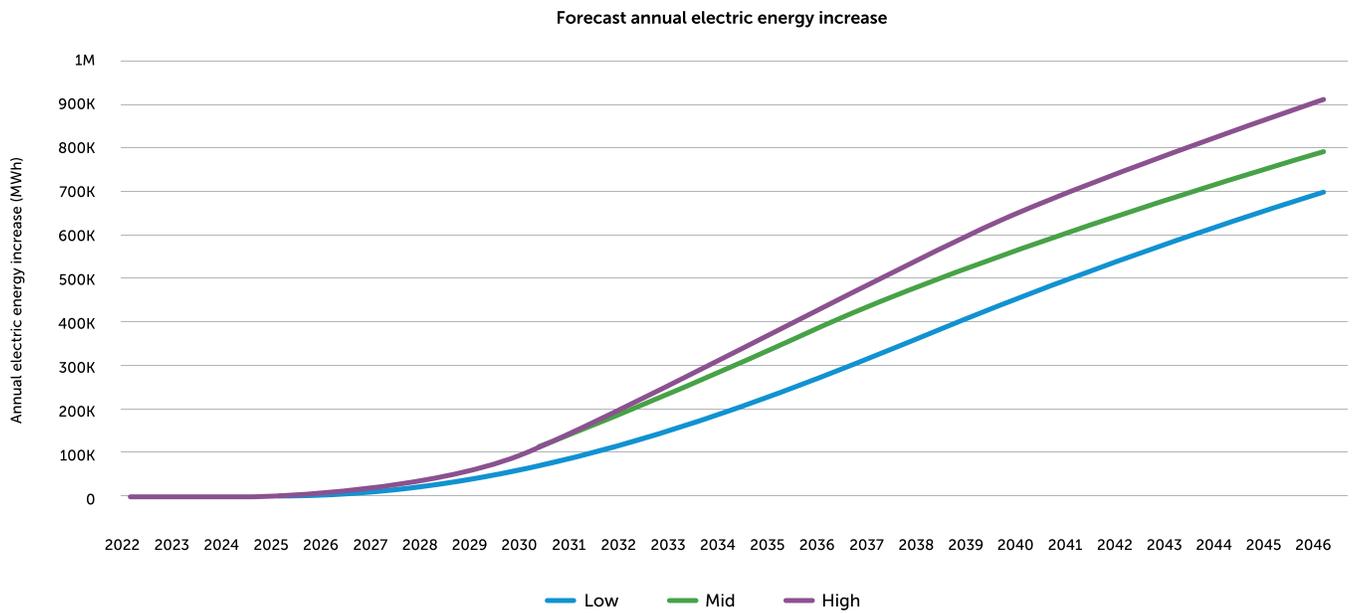
**Building electrification forecast study results.** In 2022, Platte River completed a Building Electrification Study to provide a range of forecasts for building electrification adoption and effects on electric consumption. The study evaluated the adoption electrification of end uses with a focus on those with the most significant potential: space heating, water heating and cooking. Three growth scenarios were considered—low, medium and high—based on varying levels of policy interventions and technology types. Medium utility incentives were assumed for all three scenarios. Some key findings from the study include:

- Only minor impacts on overall electricity consumption are expected through 2030. However, starting in the 2030s, building electrification impacts become larger.
- Most of the energy and demand growth occurs in the winter; summer impacts are minimal.
- Full electrification of heating during extreme cold will cause Platte River to become a winter peaking utility sometime after 2035.
- Policies requiring all-electric new homes or businesses could push impacts sooner – winter peaking will occur within five to 10 years of requiring all-electric new homes.
- Electrifying residential space heating with heat pumps is the highest impact building electrification technology and supports ongoing energy efficiency options.
- Full electrification of heating causes significant cost and reliability challenges.
- Without program or policy support, or significant changes to heat pump technology, efficiency and economics, cost and accessibility challenges will limit adoption of building electrification.

Results of the study are shown in Figures 18 and 19. Additional details on building electrification impacts can be found in the APEX Analytics study at [prpa.org/2024irp/information](http://prpa.org/2024irp/information).



**Figure 18.** Forecasted winter demand increase



**Figure 19.** Forecasted annual electric energy increase

Platte River initially adopted the low forecast for its load forecast in 2022. However, it now appears the medium forecast best reflects recent changes observed in the market. These include increasing availability of federal and state tax incentives, along with the increasing acceptance of heat pump technology by local HVAC contractors.

### 5.3.3.2 Transportation

Transportation electrification refers to the shift from vehicles with internal combustion engines powered predominantly by fossil fuels (gasoline and diesel) to vehicles powered by batteries charged from the electric grid. Transportation electrification reduces dependence on fossil fuels and reduces emissions from burning fossil fuels, including greenhouse gases. Transportation electrification is driving challenges and opportunities for vehicle owners and operators; businesses involved in the sales, service and fueling of vehicles; and for electric utilities.



**Transportation electrification forecast study results.** The DER Study evaluated the adoption of EVs in the following categories: light-duty vehicles (including personal vehicles and commercial fleets), medium-duty-vehicles, heavy-duty vehicles and buses. Three growth scenarios were considered—low, medium and high—based on varying levels of policy interventions; technology availability and cost declines; and market factors (for example, electric rates, fuel prices). Utility rebates were not evaluated. Table 4 summarizes the driving factors for each scenario considered in the study.



Parameter	Low scenario	Medium scenario	High scenario
<b>Policy/program interventions</b>			
Public charging infrastructure expansion	Limited Planned investments + current growth trajectory	Moderate Planned investments + accelerated growth trajectory aligned with Colorado National EV Infrastructure Formula Program (NEVI <sup>10</sup> )	Significant Expanded infrastructure to ensure adoption is not constrained
Vehicle incentives	Current federal and state EV incentives, phase out prematurely in 2028 and 2026, respectively	Current federal and state EV incentives, phased out as currently planned in 2032 and 2028, respectively	Increased incentives and extended beyond currently planned in 2035 and 2030, respectively
Existing building charging infrastructure retrofits	Limited 15% of multi-unit buildings with access to charging by 2035	Moderate 40% of multi-unit buildings with access to charging by 2035	Significant 90% of multi-unit buildings with access to charging by 2035
Zero-emission vehicle mandates	None	None	Stringent 100% by 2035
<b>Technology factors</b>			
Battery costs	Limited cost declines	Moderate cost declines	Aggressive cost declines
EV model availability	Limited availability	Moderate availability	High availability
<b>Market factors</b>			
Vehicle sale	Maintain historical trends		
Fuel prices	Limited escalation	Moderate escalation	Rapid escalation

**Table 4.** Primary drivers for transportation electrification

Figures 20, 21 and 22 depict the anticipated adoption for the three scenarios in terms of number of vehicles, annual energy and summer peak demand.

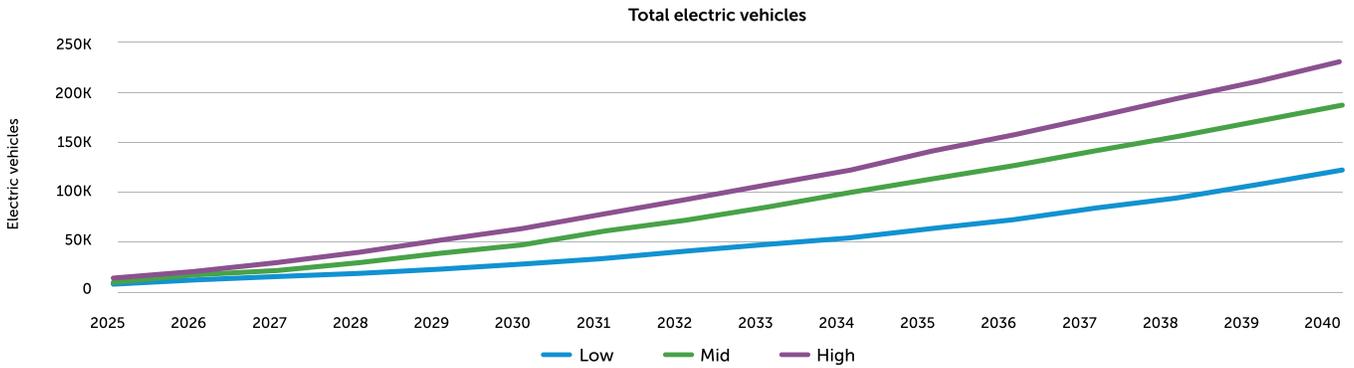


Figure 20. Total electric vehicles

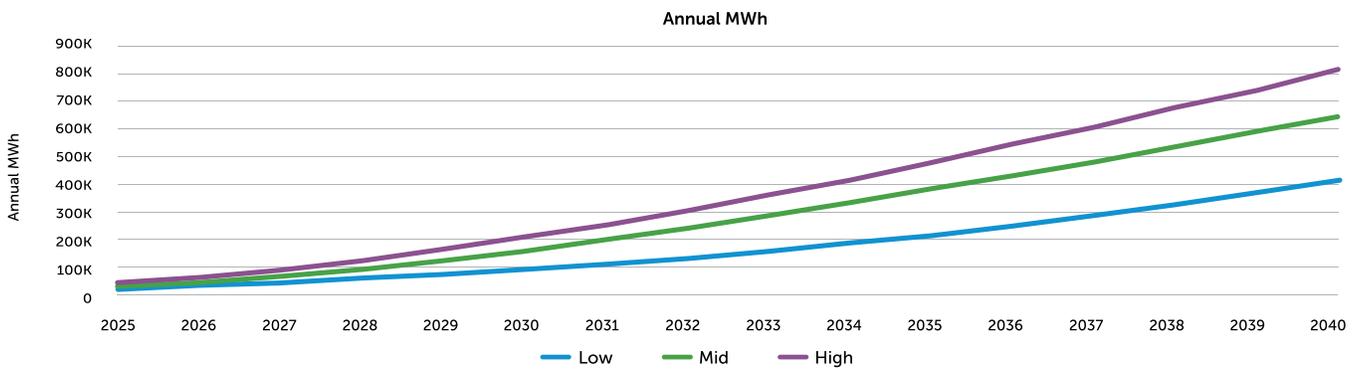


Figure 21. Annual MWh

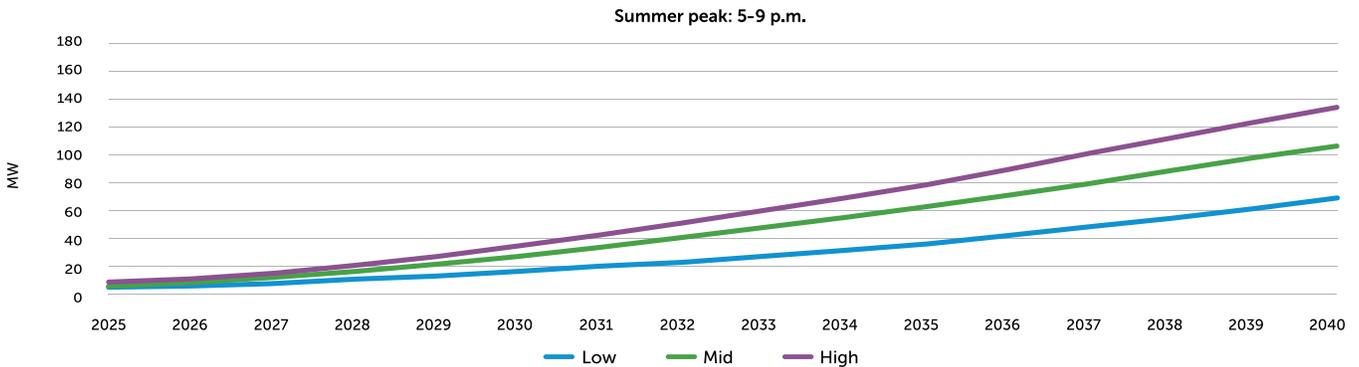


Figure 22. Summer peak: 5-9 p.m.

<sup>10</sup> National Electric Vehicle Infrastructure Formula Program (NEVI) is a federal grant program established under the Infrastructure Investment and Jobs act to provide states with funding to expand availability of EV fast charging infrastructure on transportation corridors.



Note that the summer peak demands are based on a diverse set of EV charging profiles (home charging, workplace charging, public charging, commercial fleet charging). These profiles assume some customers will respond to time-of-use pricing, where available. Winter peak demand effects are expected to be about 70% higher than summer peak due to the additional use of electricity in EVs to provide heat in the occupant compartment and to the batteries.

In all three growth scenarios the forecasted growth in EV adoption is poised to escalate significantly during the study period of 2023-2043.



**Monitoring and forecasting EV adoption.** As of the end of 2022, Platte River's owner communities witnessed a notable surge in the adoption of EVs. The number of estimated registered EVs within the communities at the end of 2022 was around 2,900. Throughout 2023 EV adoption has seen a steady increase, with an estimated 4,000 EVs by the end of the year, slightly under the previous forecast of 4,500. This growth within the owner communities follows closely with the Colorado state trend of a 3% growth each month, or 43% annually, in new EV registration.

The DER Study evaluated a range of adoption scenarios to inform the load forecast used for resource planning. Platte River has chosen the medium forecast, approximately 48,000 EVs by the end of 2030, which represents 42% compound annual growth from current levels. Adoption will continue to be monitored and adjustments will be made to the forecast as more data becomes available.

### 5.3.4 Transitioning Efficiency Works programs to distributed energy solutions

The Efficiency Works program offerings through Platte River's distributed energy solutions department are shifting focus to meet the customer needs through additional product education,

energy advisory services and repurposing incentives to business and home upgrades that support future load flexibility. A few examples of this transition include:

- Supporting building electrification upgrades that can provide future flexibility or load control throughout the year (not just a summer peak reduction of air conditioner loads).
- Incentivizing public EV charger infrastructure to provide more charging locations for EV drivers throughout the day to accommodate different charge control program models.
- Optimizing commercial HVAC equipment through the Building Tune-up program that will provide an eventual path for advanced system automation control installations and ongoing system performance visibility.

A variety of new customer program offerings have been developed and launched in recent years to support this transition as described in sections below.

### 5.3.5 New customer programs to address future electrification requirements

#### 5.3.5.1 Building electrification activities

In 2023, the Efficiency Works programs continued to support owner community initiatives and began shifting to include multiple building electrification measures. These measures mostly focused on heating and cooling equipment within residential properties

while leveraging the existing energy efficiency contractor networks. The initial building electrification programming is focused on the following areas to support customers as they decarbonize their homes and business:

- Retrofitting existing residential properties
- Educating residential and commercial customers on effective ways to use their energy with building electrification upgrades
- Providing incentives to the income qualified community sector to support building electrification initiatives
- Developing programs to support distributors selling building electrification equipment in the commercial HVAC sector
- Engaging and training local contractors about the benefits of building electrification upgrades

The shift in building electrification programming also aligns with possible incentives offered through the Inflation Reduction Act and state tax credits. As interest in building electrification continues to grow, customer programs will encourage energy efficiency upgrades like building envelope improvements. In combination with the building electrification upgrades, these improvements will allow for the potential to call on demand response activities for longer durations in the future.

## Including income-qualified communities in the energy transition

For several years, Platte River has offered various programs to support income-qualified customers. In 2021, the Efficiency Works Business team launched the **Community Efficiency Grant** to provide additional financial support for energy upgrades in businesses and multifamily properties serving the income-qualified community. This effort has increased the number of participating entities **eight-fold** on an annual basis, resulting in 103 upgrades, saving an estimated \$385,000 annually on the businesses' electric costs through the investment of nearly \$2.1 million of the Efficiency Work Business programs. The Community Efficiency Grant is expanding eligibility in 2024 to more entities that serve the community.

In addition, Efficiency Works has partnered with Energy Outreach Colorado (EOC) since 2016 to provide free energy advising and upgrades to eligible participants. In 2023, Efficiency Works revamped the partnership structure and services available, resulting in significant positive impacts for the residential income-qualified segment. The offerings have shifted focus to actively engage with participants on more significant home upgrades including energy efficiency and building electrification. According to the EOC, this partnership has grown to be one of the most well-funded income-qualified programs and has the strongest participation impact goals in the state of Colorado. In 2023, investments of nearly \$1 million have been made to support the income-qualified residential upgrades in our communities and this level of annual investment is expected to continue.





### 5.3.5.2 Transportation electrification activities

Platte River supports customers on their transportation electrification journey as they evaluate options and consider adopting EVs. This support starts with information. Platte River and the owner communities offer information on EVs through Efficiency Works.

In 2022, Platte River launched an interactive EV shopper guide website. The website includes information on currently available EVs, including cost, performance specifications and available incentives. It also includes a calculator that allows visitors to compare the total cost of ownership of EVs in comparison with each other and compared with conventional vehicles. In 2023, the website was expanded to offer EV Fleet Planning as a calculator tool for local fleet operators to develop plans to calculate the costs of fleet transitions. In 2024, expansion in the EV space will continue to support

commercial customers with additional technical services to plan for EV fleet transitions and work closely with the distribution utilities on potential service upgrades and interconnection requirements.

Platte River's commitment to advancing EV infrastructure is exemplified by the 2023 initiative offering one of the highest incentives in Colorado - \$5,000 per public charging port. This incentive aims to encourage local businesses and multifamily properties to host public chargers by offsetting some of the installation cost. Promoting more public charging options and making EV charging more available and visible are intended to reduce "range anxiety" among EV drivers and potential EV drivers.

### 5.3.5.3 Commercial HVAC system optimization activities

In 2021, Efficiency Works relaunched an improved Building Tune-up program focusing on supporting commercial customers to optimize more complex systems. The program is one of the few in the nation that focuses on upgrades and services ranging from enhanced maintenance practices to complex retrocommissioning. In its current form, the programming engages with large commercial and industrial customers to optimize complex building automation systems and local HVAC contractors performing ongoing maintenance services, and engages many small and medium commercial properties in the owner communities.

Since the relaunch, the program has increased energy savings at commercial properties from an annual average of four participants to over 50. The program has also increased the number of properties participating through increased engagement of local contractors in the HVAC industry. Program staff are currently evaluating options to expand services into monitoring-based commissioning and installing advanced rooftop unit controls during routine maintenance visits. Both expansion options will provide pathways for commercial customers to participate in a future VPP, providing additional energy consumption flexibility within the system.

### 5.3.6 Distributed generation and distributed energy storage

Distributed generation refers to electric generation sources, typically solar facilities, located near the point of use, within customer

premises or on the distribution system. Similarly, distributed storage refers to energy storage, typically battery storage, located near the point of use, within customer premises or on the distribution system. Distributed generation and distributed storage are considered together in this section due to the synergy between them.

From Platte River's perspective, storage is essential to achieving a noncarbon electric system because it helps align variable renewable generation, like wind and solar, with load. It does this by storing surplus energy when wind and solar generation exceed load and by discharging storage when wind and solar output drop below load. Similarly, from a customer's perspective, distributed storage paired with distributed solar generation helps the customer make use of more of their on-site generation to serve their own load. This reduces the energy they would otherwise export to the grid and later repurchase from the grid when solar production does not align with their use.

#### 5.3.6.1 Distributed generation solar and distributed storage forecast study results

The DER Study evaluated the adoption of distributed generation solar and distributed storage. The solar adoption forecast model considered historical rates of adoption and evaluated future adoption based on several parameters that varied across four scenarios. Some solar was assumed to be adopted alone, some was assumed to be adopted with distributed storage and some distributed storage was assumed to be adopted alone. Table 5 summarizes the driving factors for each scenario considered in the study.

Parameter	Low scenario	Medium scenario	Medium export-rate scenario	High scenario
<b>Policy/program interventions</b>				
Solar and storage incentives	Federal ITC (solar tax credit) benefits phased out early (2028).  No owner community incentives.	Federal ITC, phased out on schedule (2035)  Current Fort Collins incentives, phased out 2028		Federal ITC extended to 2040.  Fort Collins incentives adopted by all owner communities.
Codes and standards	No mandates	All new buildings must have solar beginning 2030. A gradual increase is assumed 2024 – 2030.		All newly constructed buildings must have solar beginning in 2024 (commercial) and 2027 (residential)
Retail net energy metering (NEM) and export compensation	Current NEM and export compensation (Fort Collins time of use and other owner communities' flat rates)	New NEM:  All communities adopt time of use (TOU) rates and export compensation, summer on-peak 5 – 9 p.m. Non-TOU (commercial) has export rates 5% less than retail	New NEM with exports valued at forecasted wholesale energy market rates	New NEM:  All communities adopt TOU rates and export compensation, summer on-peak 5 – 9 p.m. Non-TOU (commercial) has export rates 5% less than retail
Incentive for storage participation in VPP	None	\$150/kW-yr.		\$216/kW-yr.
Storage adoption relative to solar	10% of solar includes storage	30% of solar includes storage	50% of solar includes storage	30% of solar includes storage
<b>Technology factors</b>				
Distributed solar cost	Limited cost decline (historical regional cost + future NREL solar cost decline)	Moderate cost decline (historical regional cost + future NREL solar cost decline)		Aggressive cost declines (historical regional cost + future NREL solar cost decline)
Distributed storage cost	Limited NREL storage cost decline	Moderate NREL storage cost decline		Aggressive NREL storage cost decline

**Table 5.** Adoption of distributed generation – solar and storage

The DER Study considered a range of assumptions. First, the DER Study assessed the impact of federal investment tax credits, with the assumption ranging from early phaseout, in 2028, compared to scheduled phaseout, in 2035, and extended phaseout in 2040. Owner community incentives were also considered, ranging from none to Fort Collins's current incentives, to adoption of Fort Collins' incentives by the other three owner communities. In all cases, the incentives were assumed to phase out in 2028, coinciding with the significant increase in Platte River's noncarbon portfolio. The study evaluated new building standards ranging from no solar requirement to increasingly stringent requirements for new construction to include solar.

The study also considered the effect of retail rates, and specifically net energy metering (NEM), on distributed generation solar and distributed storage adoption. NEM refers to the financial compensation customers with solar (and increasingly customers with solar and distributed storage) can receive due to both reduced purchases of electricity from their retail electricity provider and due to exporting excess solar and distributed storage output to the grid whenever solar and storage produce more energy than the customer consumes.

The study evaluated a range of possible NEM rates. The **low scenario** assumed existing NEM rates apply. This includes Fort Collins's existing time-of-use rate, which charges higher rates during on-peak periods (weekdays, 2 to 7 p.m. during summer months and 5 to 9 p.m. in other months) and lower rates all other hours. Exported energy is credited on the same schedule, but at rates that are 10 to 20% lower. The other owner communities largely have time-invariant rates and compensate exports at

or close to the retail rate.

The **medium and high scenarios** assumed all owner communities adopt a rate structure like Fort Collins and that the summer on-peak period shifts later in the day, to 5 to 9 p.m., for all communities. This is due to anticipated high adoption of solar by customers and by Platte River. This results in reduced demand for energy and ample supply when solar energy is available, followed by higher demand and reduced supply as the sun sets and solar output diminishes and then stops. This will lead to higher energy costs as the sun sets and after the sun is down.

The **medium export-rate scenario** assumed the financial value of solar will erode due to higher solar adoption by customers, Platte River and other utilities in the region; low energy prices when solar is plentiful, followed by high prices when solar is absent. Achieving greater value from the solar energy will require that it be shifted in time, from peak solar hours to hours just after the sun sets, which can be achieved through increased deployment and use of energy storage (whether distributed or utility-scale). Modifying the retail rate to compensate exported solar at the wholesale rate will better reflect the value solar alone brings to the system, and at the same time provide value to customers who adopt and use distributed storage to reduce exports and use more solar energy at the home or business.

The study also assessed the adoption of distributed storage. This is projected to be driven by rates and the rate structure as well as on incentives that could be paid to customers to adopt distributed storage and to enroll distributed storage in a VPP for Platte River to dispatch. The combined impact of changes to net energy metering, export compensation and

VPP incentives, coupled with declines in storage costs, are projected to drive higher adoption of storage with solar – increasing from the low scenario (in which 10% of solar was assumed to include storage) to 50% for the medium-export scenario.

Platte River also constructed a fifth scenario, which starts with the medium scenario and then shifts over a period of about 10 years to the medium export-rate scenario.

Figures 23 and 24 illustrate the forecasted adoption of distributed solar and storage, respectively.

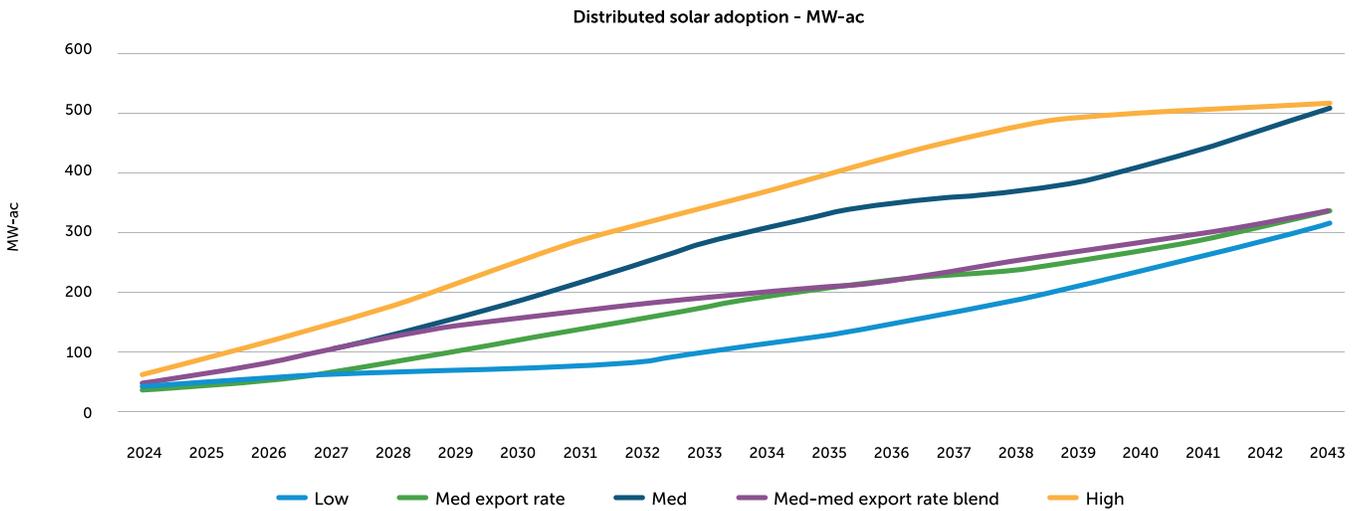


Figure 23. Distributed solar adoption - MW-ac

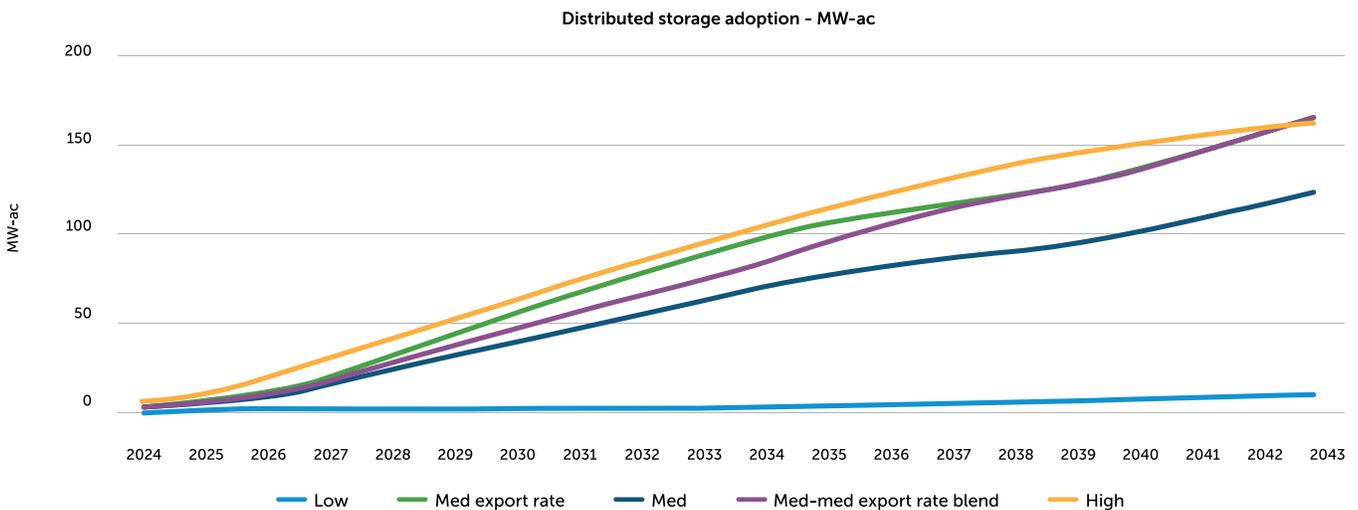
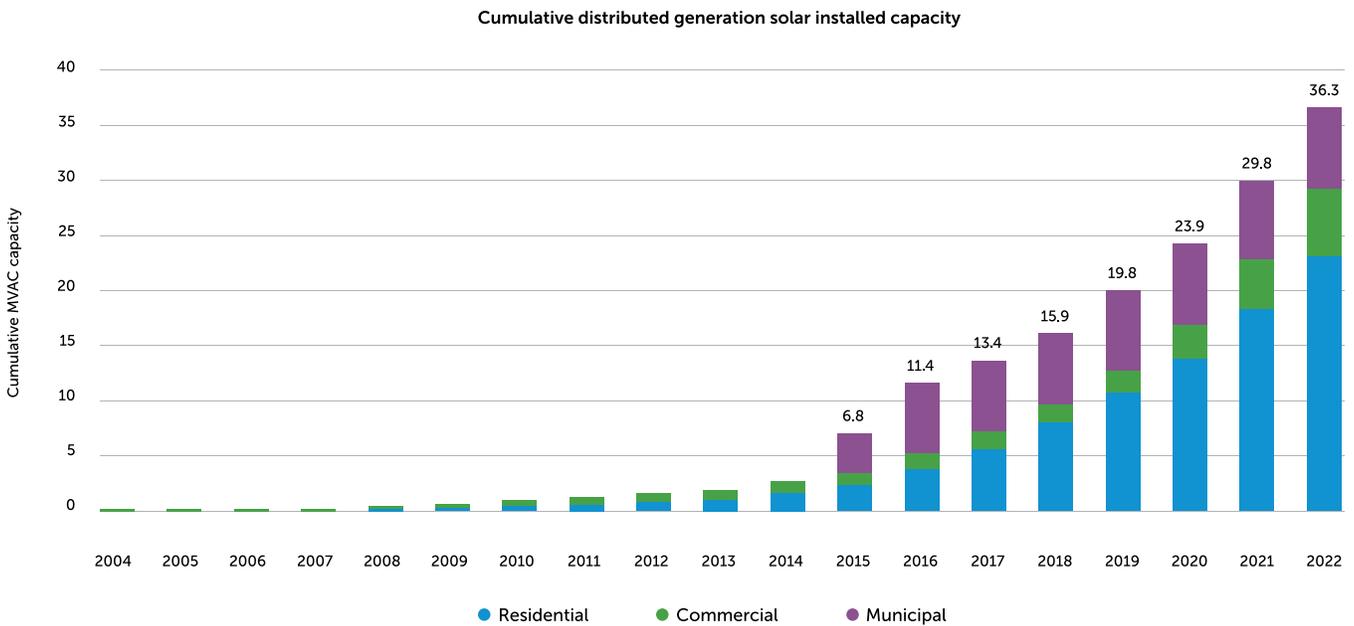


Figure 24. Distributed storage adoption - MW-ac

### Monitoring and forecasting distributed generation solar and distributed storage adoption.

The rise of distributed generation within the owner communities has primarily been driven by individual customers adopting rooftop solar power. Solar energy constitutes around 94% of the existing distributed generation capacity. The remaining capacity is divided among wind (0.02%), cogeneration (4.1%) and hydropower (1%).

Figure 25 illustrates the growth of distributed solar capacity within Platte River's network, fueled by available federal and local incentives, coupled with customers' economics and drive to reduce carbon emissions from electricity generation. As of the end of 2022, estimated distributed solar within Platte River's owner communities totaled 36.3 MW (AC), with 63% from residential solar, 17% from commercial solar, and 20% owned or procured by Platte River or the owner communities.



**Figure 25.** Cumulative distributed generation solar installed capacity

Between 2017 and 2022, there has been a notable increase in distributed storage deployment, raising the total capacity to about 1.2 MW in the owner communities. This comprises about 175 systems, averaging a discharge rate of about 7 kW per system. Each year since 2017, there has been an increase in distributed storage system interconnections, with the highest number of installations in 2022. This significant rise highlights the widespread adoption of storage solutions, particularly battery storage, as a versatile tool for providing backup energy and enhancing the operational efficiency of distributed solar systems.

The DER Study evaluated a range of distributed generation solar and distributed storage adoption scenarios to inform the load forecast used for resource planning and to inform DER planning.

Platte River has chosen the blend of the medium and medium-export-rate forecasts. This combination of scenarios represents a gradual change in NEM rates that improves the financial benefit of adopting distributed storage with distributed generation solar. This forecast indicates approximately 155 MW distributed generation solar and 47 MW distributed storage by the end of 2030. This represents 20% annual growth in installed solar capacity and 48% annual growth in storage capacity from current levels. Adoption will continue to be monitored and adjustments will be made to the forecast as more data becomes available.

### 5.3.7 Flexible DERs and the virtual power plant

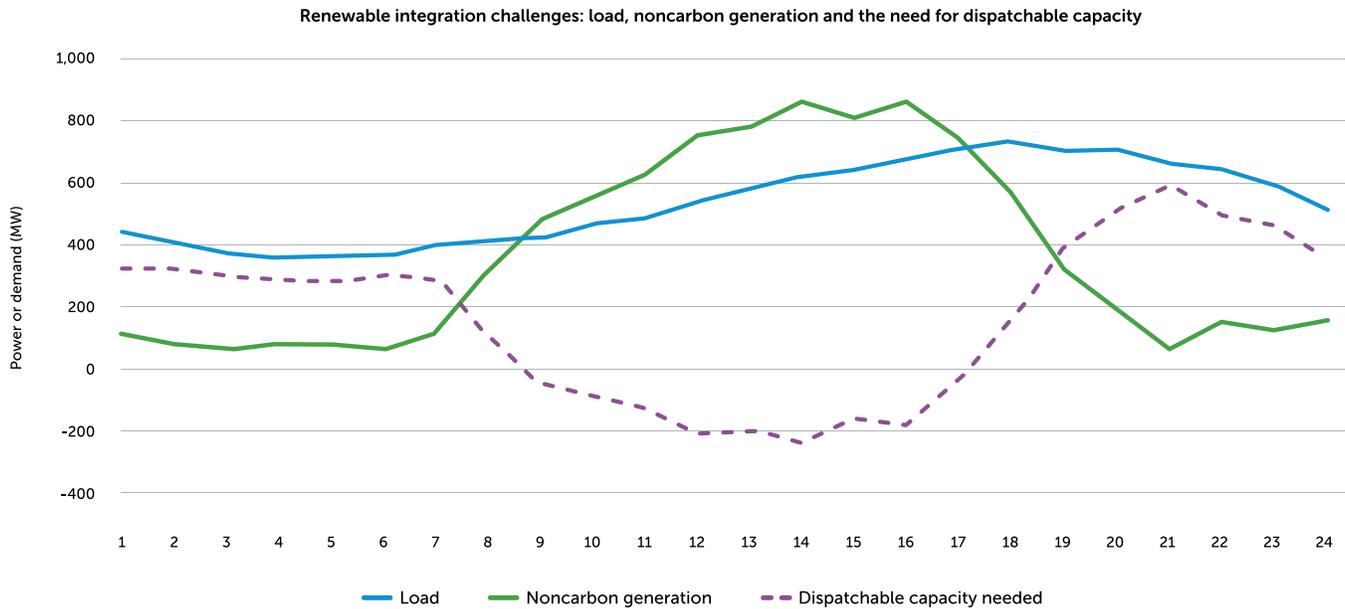
As described in previous sections, a VPP is an aggregation of flexible DERs that can be dispatched to support electric system reliability, financial benefits and individual customer benefits. As the name suggests, the VPP can act like a power plant, but it is different in that it is created by thousands of DER devices operating across the electric system. They act in concert, enabled by communication, data collection and management, control and optimization technology.

#### 5.3.7.1 Flexible DER and VPP forecast study results

The DER Study included an assessment of flexible DER that could provide VPP capacity. VPP capacity was evaluated using a multi-step approach that considered the technical, economic and achievable potential of flexible DER technology combined with utility program approaches:

- Technical potential assesses the quantity of flexible DER capacity that theoretically exists in the owner community service territory and how it is expected to grow over time.
- Economic potential considers how much of the technical potential is economic compared to other utility resource options. The study relied on the total resource cost test framework, which compares the marginal costs of a VPP resource for Platte River, the owner communities and their customers to the marginal cost of utility resources.
  - o The cost of utility resources included hourly energy costs based on forecasted market energy prices, carbon tax, capacity costs based on four-hour storage and distribution capacity costs based on owner community estimates.
  - o The cost of achieving VPP potential included utility program administration costs (excluding incentives) and customer DER technology costs.
  - o The cost of achieving VPP potential did not include the cost to the utility of VPP-enabling technology and systems. The need for enabling technology and systems is unaffected by which flexible DER programs Platte River and the owner communities offer.
- Achievable potential considers how much of the economic potential can be realized as a dispatchable VPP capacity at the time of system need and considering customer enrollment rates in VPP program.

The potential study assessed achievable capacity at times of high “net load.” This was defined as the load that remains after deducting wind, solar and hydropower. Figure 26 illustrates what this might look like in 2030. Note that while only one day is shown, there are multiple days each summer that would have a similar, though slightly smaller, peak net load. As a result, flexible DER capacity is required many hours throughout the summer. As electrification increases winter loads at a more rapid rate than summer loads, the need for winter dispatchable capacity will grow as well.



**Figure 26.** *Renewable integration challenges: load, noncarbon generation and the need for dispatchable capacity*

The DER Study assessed a variety of factors that could drive varying levels of achievable VPP capacity. These were combined in four scenarios as shown in Table 6.



Parameter	Low scenario	Medium scenario	Medium export-rate scenario	High scenario
Time-varying rates	Existing residential TOU rates in Fort Collins only (summer on-peak 2 – 7 p.m.)	New residential TOU rates in all owner communities (summer on-peak 5-9 p.m., aligning with net system peak)	New residential TOU with solar exports valued at forecasted wholesale energy market rates	New residential TOU rates in all owner communities (summer on-peak 5-9 p.m., aligning with net system peak)
Program marketing and incentives	Industry-standard marketing and incentives	Industry-standard marketing and incentives	Industry-standard marketing and incentives	Maximum cost-effective marketing and incentives
Efficiency scenario	Low	Low	Low	High
Electric vehicle scenario	Low	Medium	Medium	High
DS solar and storage scenario	Low	Medium	Medium export-rate	High

**Table 6.** Primary drivers of achievable VPP capacity

Within each scenario, various flexible DER approaches were evaluated in an interactive model to determine how they could be combined to provide a sustained reduction in the system net peak, considering the impact of time-varying rates, direct-control programs and each DER’s operating characteristics, as summarized in Table 7.



Measure group	Measure sub-group	Characteristics						
		Curtailment potential	Event duration (hours)	Pre-charge time	Pre-charge sizing	Rebound time	Rebound sizing (per hour)	Event frequency (per year)
<b>HVAC controls</b>	Smart thermostats	[75%, 33%]	Up to 2 h	1 h	40%	2 h	30%	20
<b>EV charging</b>	EV smart chargers	100%	4 h +	N/A	N/A	6 h	17%	300+
	Vehicle-to-grid	100%	4 h +	N/A	N/A	6 h	17%	300+
<b>Water heating</b>	Electric water heaters	100%	Up to 4 h	2 h	17%	4 h	17%	15
<b>Other loading flexibility</b>	Large C&I curtailment	25%	Up to 4 h	N/A	N/A	N/A	N/A	15

**Table 7.** Flexible DER operating characteristics – load

Measure group	Measure sub-group	Characteristics					
		Size (kW)	Curtailment potential	Round trip efficiency	Typical event duration (hours)	Typical rebound / pre-charge time	Typical event frequency (per year)
<b>Storage</b>	Battery storage - residential	3.3	33%	85%	4 h	4 h	300+
	Battery storage – small commercial	5	100%	85%	4 h	4 h	300+
	Battery storage – large commercial	50	100%	85%	4 h	4 h	300+

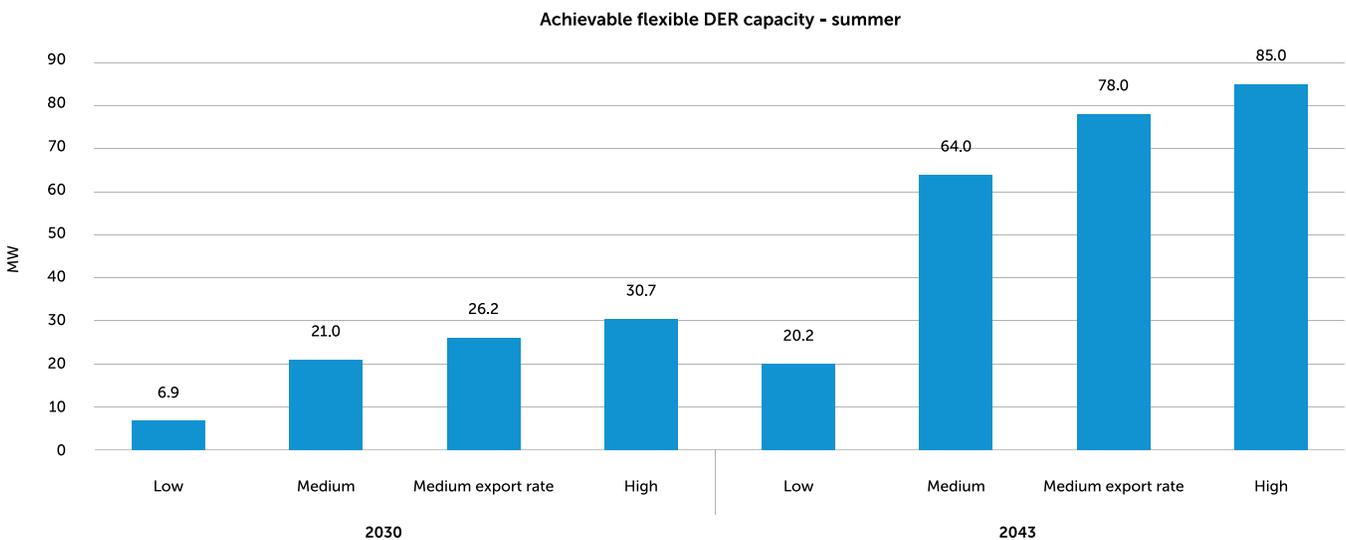
**Table 8.** Flexible DER operating characteristics – storage

- For residential, it is assumed 33% of the battery is available for flexible DER program, with the remainder used for customer resiliency.
- For commercial batteries, 100% is assumed available for flexible DER, as batteries are typically used for peak load management, and backup generators are used for resiliency.

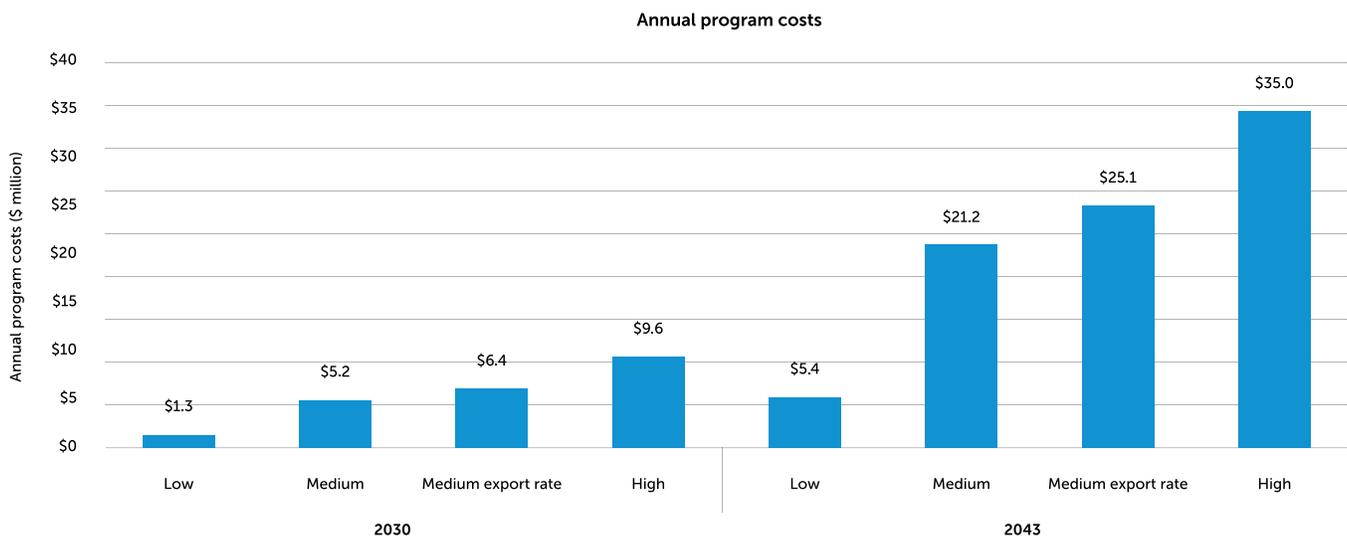


As illustrated in tables 7 and 8, the flexibility of EVs and battery storage is apparent, with both having the ability to be dispatched on a near-daily basis, 300 times annually. This provides potential for a highly flexible, available resource that can be used to balance variable noncarbon generation. Flexibility of other DERs, such as HVAC control, large commercial and industrial curtailment and water heater control will be limited due to impacts on comfort and productivity.

Figures 27 and 28 summarize the resulting achievable capacity for each of the cases, as well as the annual costs in 2030 and 2040. Program costs are strictly incentives and program administration. They do not include VPP system costs. Growth from 2030 to 2040 was driven largely by increasing adoption of battery storage and EVs.



**Figure 27.** Achievable flexible DER capacity - summer



**Figure 28.** Annual program costs

Key takeaways from the DER Study include:

- Summer peak load reductions range from 6.9 MW to 30.7 MW across the different scenarios in 2030.
- The commercial sector is forecasted to have the greatest potential for the low scenario while the residential sector overtakes commercial in the medium and high cases, due to increasing adoption of EVs and distributed storage.
- For the residential sector, battery storage is expected to be by far the most prominent measure in all scenarios except the low one, followed by smart EV chargers and AC smart thermostats in the summer and electric resistance smart thermostats in the winter.
- The commercial demand response potential is primarily driven by large commercial and industrial opportunities, followed by battery storage and water heating.

#### **Develop and implement VPP customer programs.**

Customers who have flexible DERs and are willing to enroll them in the VPP provide the engine for the VPP's operation. Therefore, a major focus of Platte River and the owner communities is to develop customer programs that support customer enrollment and ongoing participation.

Customer programs must support Platte River's pillars of providing reliable, environmentally responsible and financially sustainable energy, while also providing benefits to participating customers. The DER Study has identified the following opportunities for flexible DERs that can participate in the VPP:

- **Distributed storage management.** Distributed storage is expected to grow significantly, often paired with distributed generation solar.
- **EV charge management (including vehicle-to-grid when available).** EV

adoption is expected to grow significantly, providing a large and highly flexible load for the VPP. Vehicle-to-grid is also anticipated to grow, with the potential of providing additional storage to the grid.

- Large commercial and industrial customer custom demand response.** These customers are likely to have large and sometimes unique DER opportunities. Platte River anticipates developing custom approaches to support these projects similar to the custom, pay-for-performance incentives currently offered for efficiency improvements.
- HVAC demand response.** HVAC demand response programs manipulate electric load for heating and cooling buildings for short periods of time, either through direct control of the heating or cooling system components (for example, compressor load-control switches) or increasingly, through wi-fi enabled thermostats ("smart thermostats").
- Electric water heater demand response and storage.** Electric water heater demand response takes advantage of the storage that is typically integral to

the water heat to allow active heating to be curtailed for brief periods.

Taken together, these customer resources are anticipated to provide a VPP capable of dispatching 32 MW of capacity by 2030 and 93 MW by 2040. To improve the availability of this capacity, Platte River anticipates enrolling more DER capacity than these values indicate. This is to account for limitations on the flexibility of DERs to consistently provide capacity during the evening peak while respecting customer restrictions on Platte River's and the owner communities' use of their flexible DERs. As a result, the enrolled capacity of customer resources may reach an estimated 71 MW by 2030 and 204 MW by 2040. As experience is gained operating the VPP, it is possible that other uses for the enrolled capacity may emerge.

In addition to the customer resources, the VPP is anticipated to include other flexible DERs developed by Platte River and the owner communities. Platte River is in developing plans for 20 MW of distribution-scale storage to be located within the owner communities. This is expected to bring the total achievable VPP capacity to about 52 MW by 2030 and 113 MW by 2040.

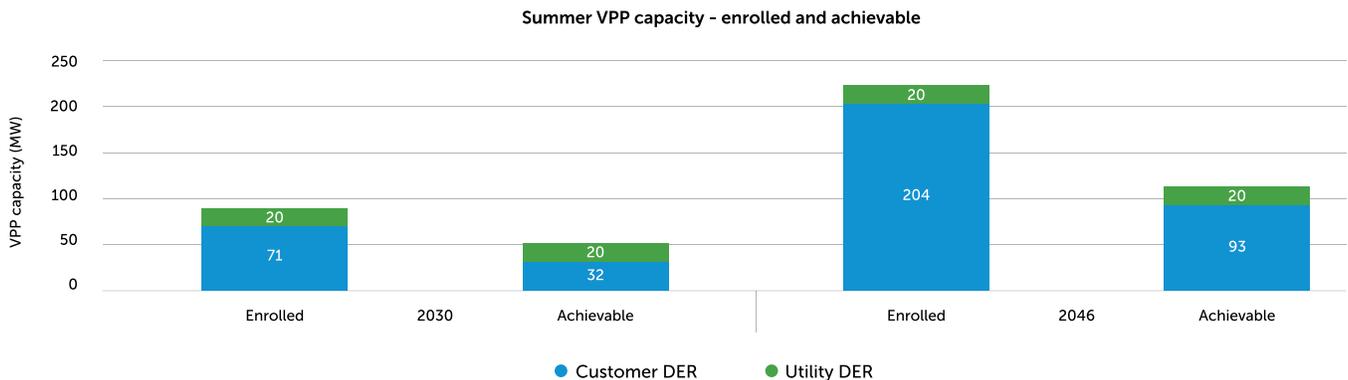


Figure 29. Summer VPP capacity - enrolled and achievable



Achieving a VPP of this magnitude requires a high level of customer participation. The enrolled capacity is projected to include 50,000 DER devices by 2030 and close to 100,000 devices by 2040, drawn from the owner communities' customer base of about 172,000 customers. To achieve this high level of participation, Platte River will collaborate with the owner communities to support customers on their DER journeys. This includes engaging customers as they evaluate their DER options and consider enrollment in the VPP. It is also expected to include providing incentives for enrollment and ongoing participation based on the system benefits their DERs can provide. In addition, Platte River and the owner communities will need to engage with the local, regional and some national market actors in the manufacturing, distribution, sales, installation, and operation of DERs.

Platte River issued an RFP in May 2024 to identify firms experienced in providing VPP customer program deployment to provide a rapid, cost-effective, and customer-focused portfolio of VPP programs.

### **5.3.8 Summary of selected scenarios for DER and VPP potential**

Platte River evaluated a range of DER potential scenarios, ranging from low to high. Table 9 summarizes the scenarios selected for each type of DER and describes the reason the scenario was selected.

DER type	Selected scenario	Description
Energy efficiency	Low	Low scenario is most consistent with current participation levels, even as Efficiency Works offers some of the highest efficiency incentives in the state.
Building electrification	Medium	Medium scenario is most consistent with observed adoption rates and with increasing local, regional and national support for electrification.
Transportation electrification	Medium	Medium scenario is most consistent with observed adoption rates and with increasing local, regional and national support for electrification.
Distributed generation and storage	Medium-medium export rate	A hybrid scenario starting with medium and shifting to medium export rate was used to reflect current adoption trends and anticipated shifts in net metering policy to favor storing excess solar rather than exporting it.
Virtual power plant / flexible DERs	Hybrid – see description	A hybrid scenario was defined in part by the DER adoption scenarios described above. In addition, EVs that the study assumed would respond to time-varying rates were instead reclassified as being under direct load management to provide greater responsiveness to varying system conditions. The result is that the selected VPP potential is close in magnitude to the high scenario.

**Table 9.** Summary and logic for selected scenarios

## 5.4 Load forecast with DER (final) 2024-2043

Section 5.2 of this chapter covered load forecast before considering the impact of DERs. In section 5.3, we covered different DERs and saw how much energy and peak demand they contribute (like distributed solar or demand response) and require from the system (like EVs and building electrification). This section discusses the energy and peak demand contribution of each DER and the composite load forecast including the contributions from all the DERs. The composite load forecast, including energy and peak demand, was used in the Plexos model to develop a supply-side portfolio.

## 5.4.1 Energy contributions of DER

### 5.4.1.1 Distributed generation

Figure 30 shows the energy contribution from distributed generation, primarily distributed solar. This is shown as negative because it represents the reduction in customer energy needs from Platte River’s supply. The bars show energy in gigawatt-hours (GWh) and the solid line shows percent reduction in total Platte River energy. By 2030, distributed generation energy is expected to reduce base energy by 6% and by the end of planning horizon in 2043, it is expected to reduce the predicted base energy by about 13%. Distributed solar produces more energy in summer and less energy in winter but these are annualized values.

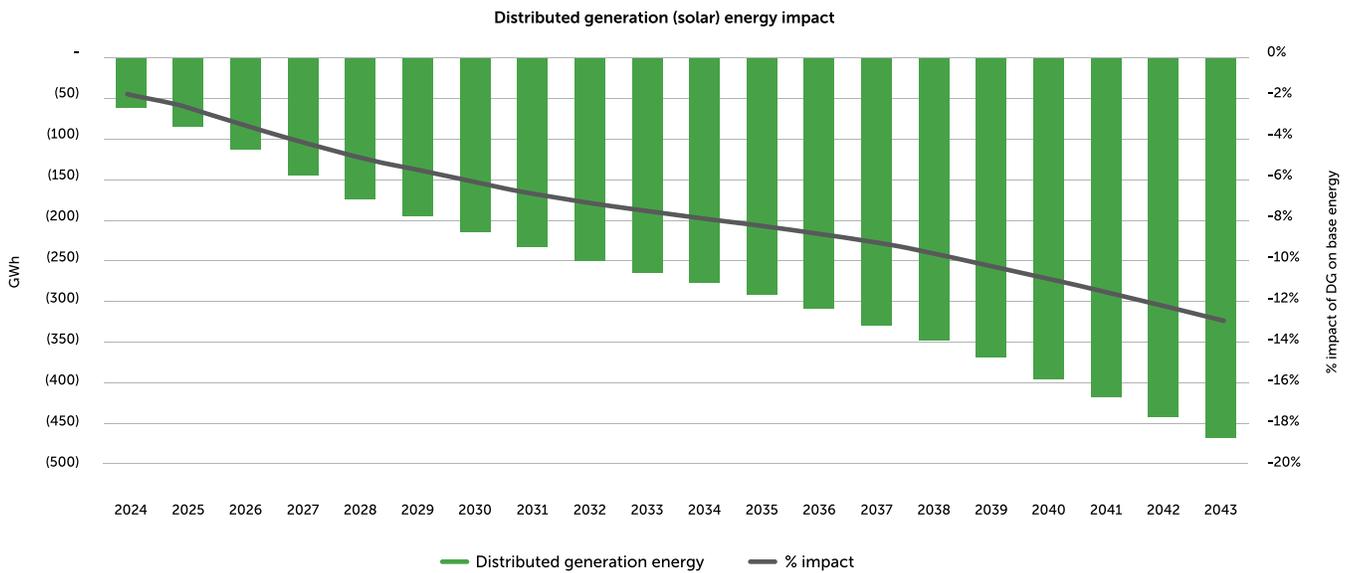


Figure 30. Distributed generation (solar) energy impact

### 5.4.1.2 Building electrification

As illustrated in Figure 31, building electrification (mostly consisting of heating load) starts from a very small level but is expected to grow rapidly in the next decade. The bars show energy in GWh and the solid line shows the percent increase in the base energy forecast. By 2030, building electrification is expected to increase base energy by 3% and by the end of the planning horizon in 2043, it is expected to add about 19% to the predicted base energy. Because it is heating load, most of the building electrification energy requirements will be in winter, but we show annual values in the chart.

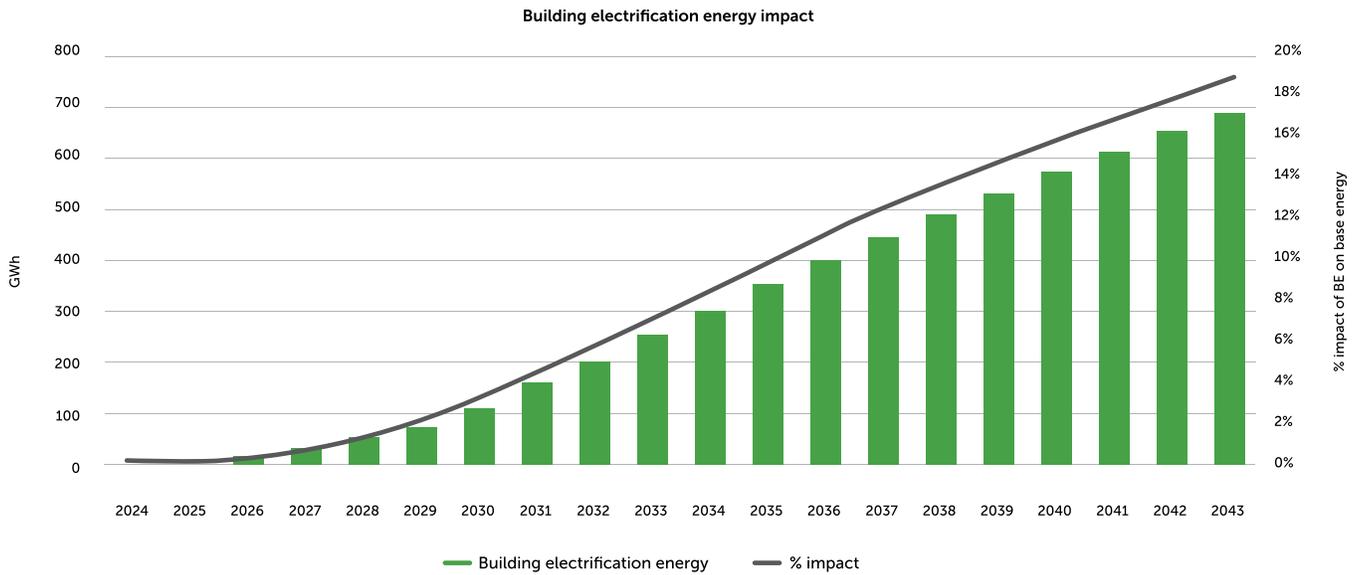


Figure 31. Building electrification energy impact

### 5.4.1.3 Electric vehicles

As illustrated in Figure 32, EV load starts from a very low level but is expected to grow rapidly in the next decade. The bars show energy in GWh and the solid line shows percent increase in the base energy forecast. By 2030, EV is expected to increase base energy by 5% and by the end of the planning horizon in 2043, it is expected to add about 23% to the predicted base energy. These are annual values. EV load is evenly distributed across the year. A portion of the EV load is flexible and exact charging time can be managed by the utility to more opportune times.

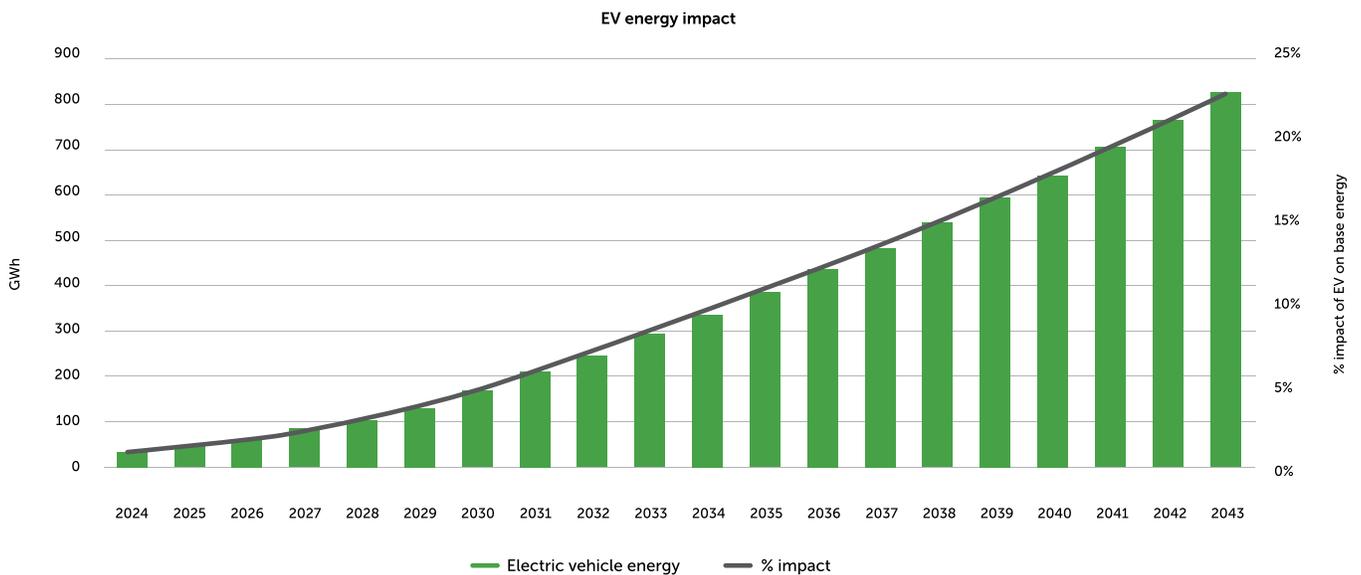


Figure 32. EV energy impact

## 5.4.2 Capacity contribution of DER

### 5.4.2.1 Distributed generation

Figure 33 shows the summer peak capacity contribution from distributed generation. This is shown as negative because this is the reduction in customer peak demand due to the rooftop solar. The bars show summer peak capacity in megawatts and the solid line shows percent reduction in total Platte River annual summer peak demand. By 2030, distributed generation is expected to reduce summer peak by 2% and by the end of planning horizon in 2043, it reduces the predicted summer peak by about 3.4%. Although the absolute megawatt addition of rooftop solar is large, its impact on the summer peak is small due to low Effective Load Carrying Capability (ELCC) value of distributed solar (like utility scale solar). Basically, the incremental contribution of solar to reduce summer peak becomes negligible to zero as more solar is added and the peak hour moves closer to the sunset.

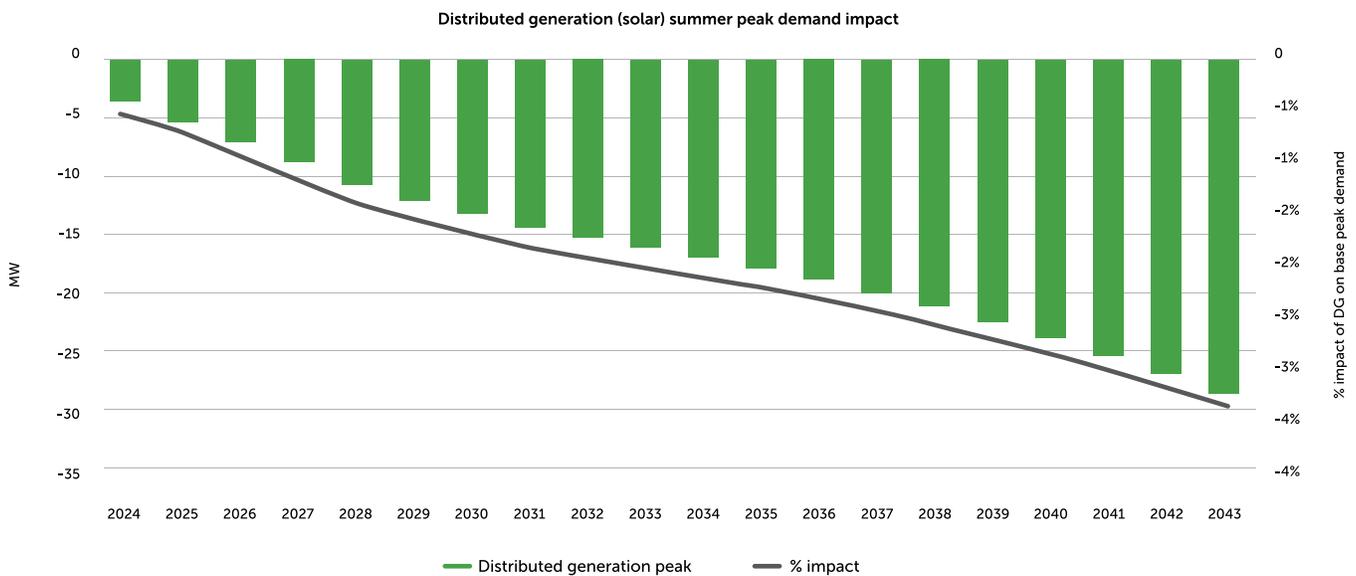


Figure 33. Distributed generation (solar) summer peak demand impact

### 5.4.2.2 Demand response

Figure 34 shows the summer peak capacity contribution from demand response or flexible resources such as home battery storage and EV charging load. This is shown as negative because it represents the reduction in overall customer peak demand. The bars show summer peak capacity in megawatts and the solid line shows percent reduction in total Platte River annual summer peak demand. By 2030, demand response is expected to reduce summer peak by 5% and by the end of planning horizon in 2043, it reduces the predicted summer peak by about 9%.

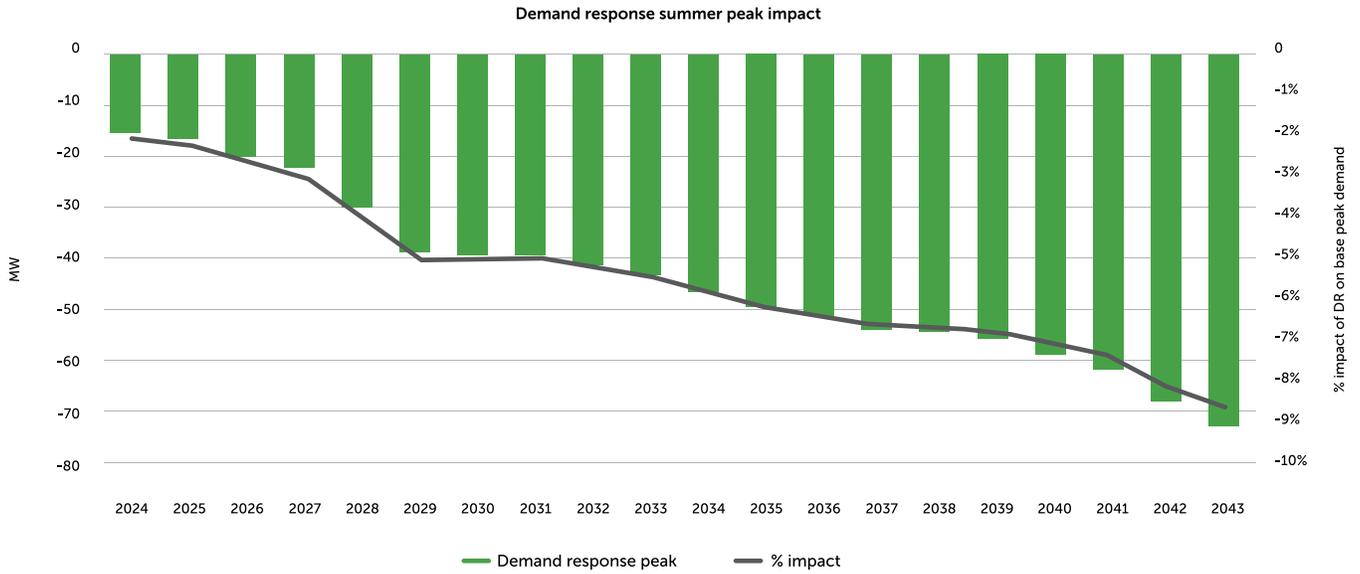


Figure 34. Demand response summer peak impact

### 5.4.2.3 Building electrification

As illustrated in Figure 35, building electrification starts from a very low level but is expected to grow rapidly in the next decade. Most building electrification contribution is from heating systems in colder months, so the impact on summer peak demand is fairly small, mainly coming from electric cooking and water heating. The bars show summer peak hour building electrification load in megawatts and the solid line shows percent increase in the base peak demand. By 2030, building electrification is expected to increase summer base peak by about 1% and by the end of the planning horizon in 2043, it adds about 3% to the predicted base summer peak demand.

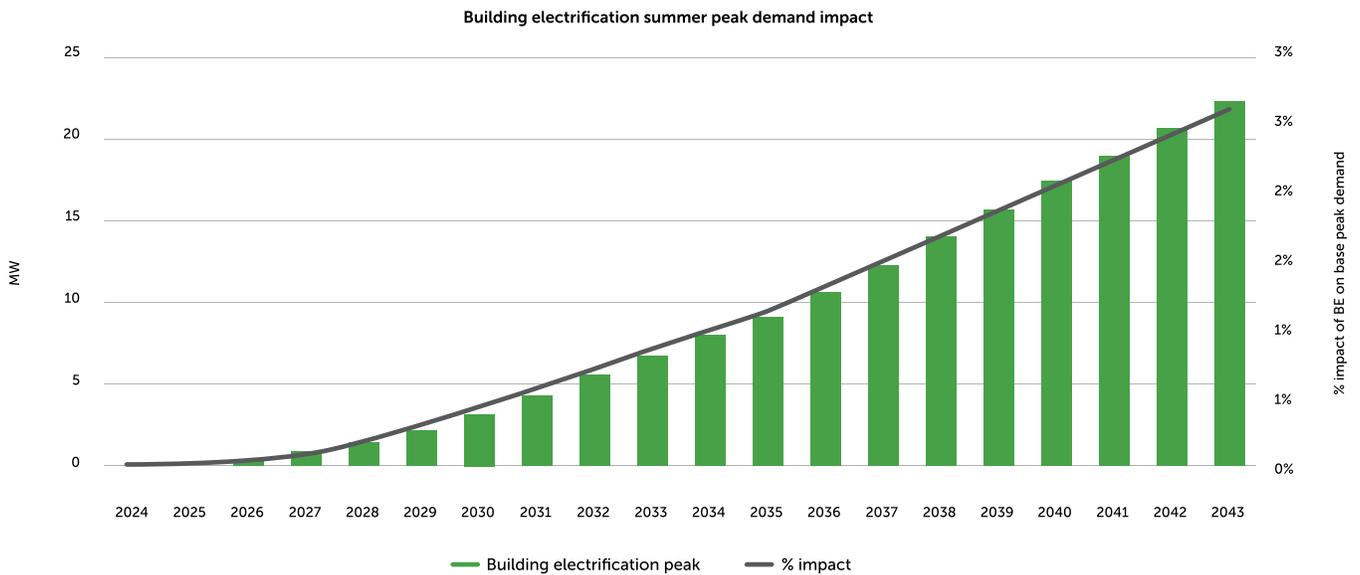


Figure 35. Building electrification summer peak demand impact

### 5.4.2.4 Electric vehicles

As illustrated in Figure 36, electric vehicle load starts from a very low level but is expected to grow rapidly in the next decade. This figure shows the portion of the EV load that is inflexible and cannot be managed or moved away from the summer peak hour. The bars show summer peak capacity in megawatts and the solid line shows percent increase in the summer base peak demand forecast. By 2030, EV is expected to increase summer base peak demand by 3% and by the end of the planning horizon in 2043, it adds about 15% to the predicted base summer peak demand. It is important to note that most EV load is flexible, and its exact charging time can be managed by the utility to lower summer peak demand. Contribution from the flexible EV charging load is not included in the chart below because we assume it will be controlled at the time of summer peak hour and moved to a later, lower-demand hour.

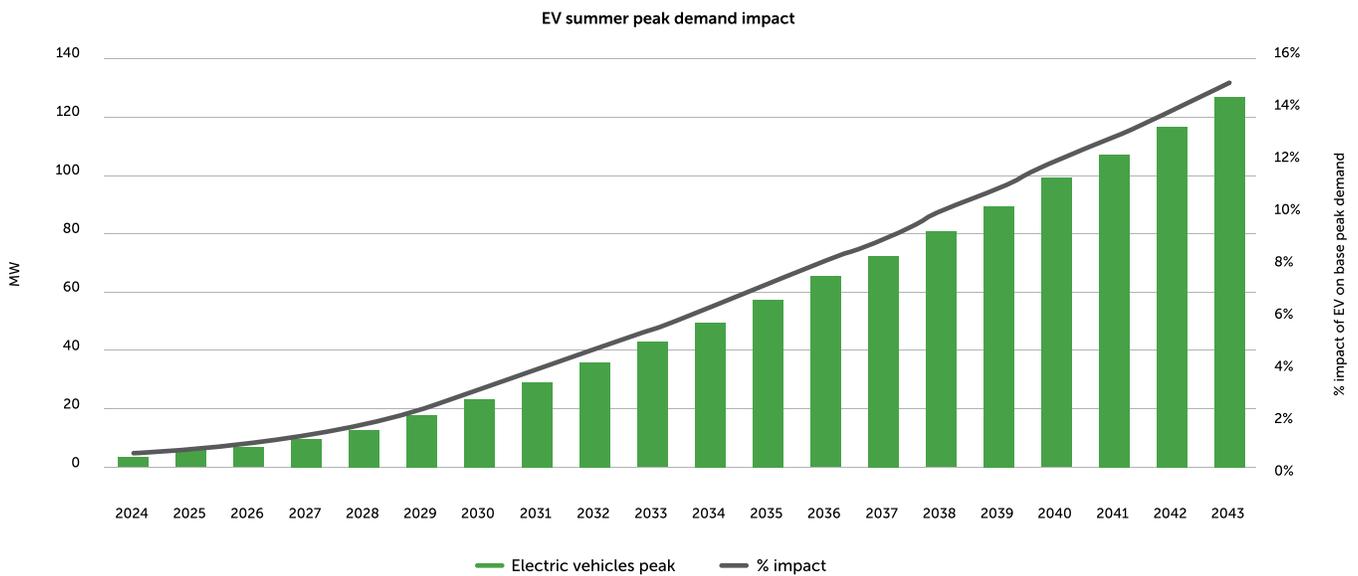
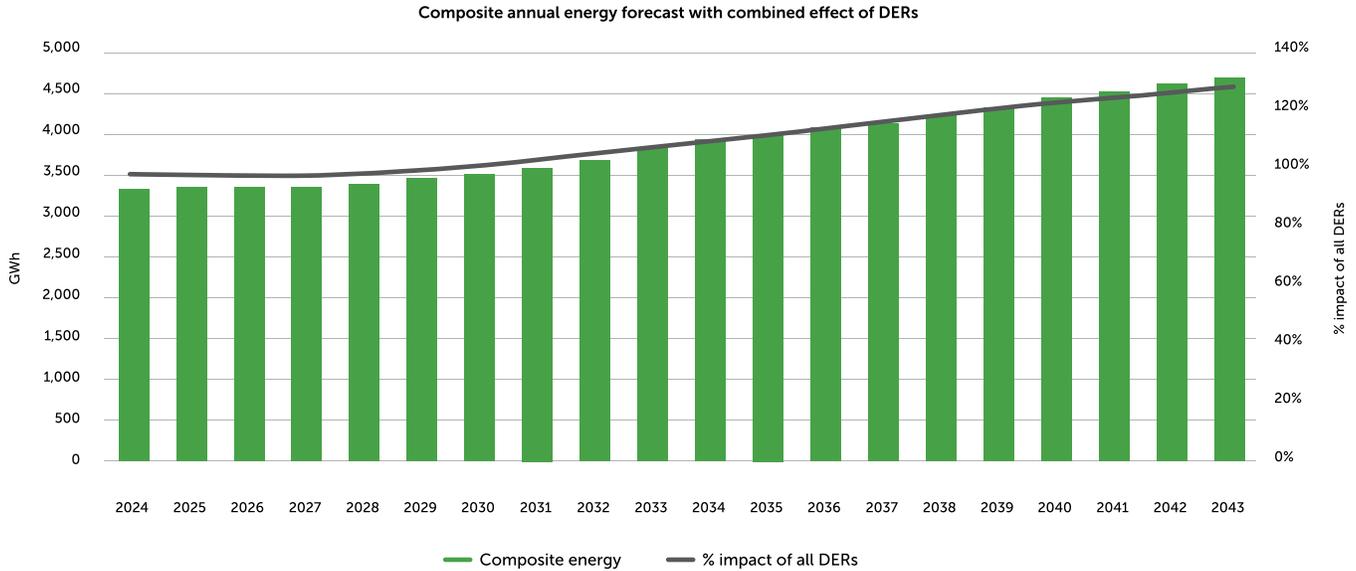


Figure 36. EV summer peak demand impact

### 5.4.3 Composite load with all DER contributions

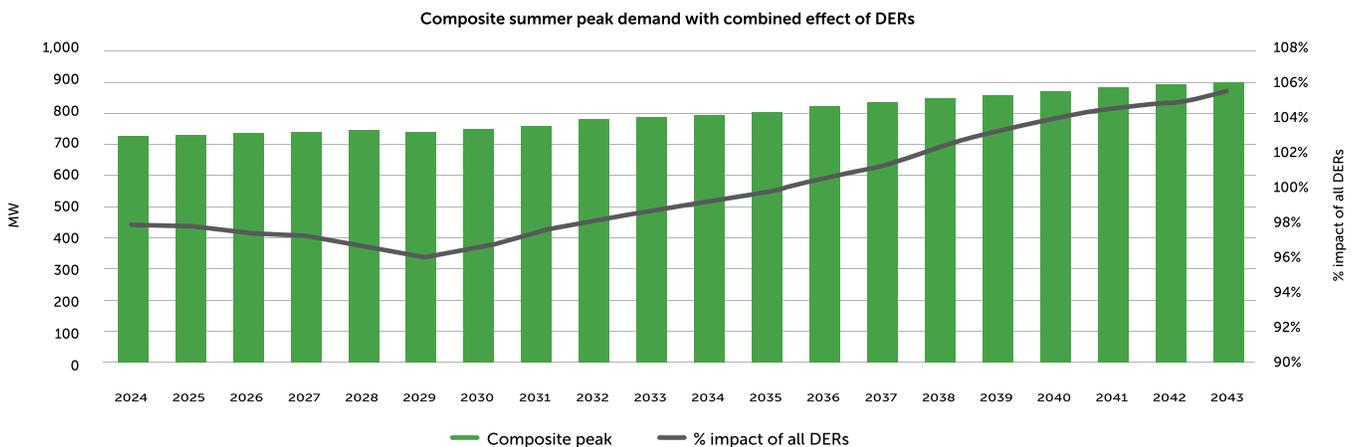
Collectively, DERs decrease electric consumption and load growth in early years, due to the presence of distributed generation resources like rooftop solar and demand response programs, offsetting additional load created by electric vehicles and building electrification. However, as adoption of electric vehicles and building electrification increase, the additional load outpaces growth in distributed generation, resulting in higher load growth. The combined DER impact trend is similar for annual energy and summer peak demand but the percent impact varies. Figure 37 shows composite annual energy requirements and the combined percent impact of DERs.



**Figure 37.** Composite annual energy forecast with combined effect of DERs

The green bars in Figure 37 show composite annual energy in gigawatt hours that Platte River’s supply system must produce, and the solid black line shows the combined impact of all DERs as a percent. The combined effect of DERs reduces the annual energy need through 2029 and increases it afterwards, due to rapid increase in building electrification and EV load, reaching an almost 29% increase by 2043.

Figure 38 shows composite summer peak requirement and the combined percent impact of DERs. The green bars show composite summer peak demand in megawatts that Platte River’s supply system must provide, and the solid black line shows the combined impact of all DERs. The combined effect of DERs reduces the summer peak demand through 2035 and increases it after, due to rapid increase in building electrification and EV load, reaching an almost 6% increase by 2043. The combined percent impact of DERs on summer peak demand is much lower than the percent impact on annual energy consumption because the two major DERs, EV and building electrification, do not increase the summer peak load as much as they increase annual energy consumption.



**Figure 38.** Composite summer peak demand with combined effect of DERs



# 06

## Supply-side assumptions

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This section reviews assumed supply-side resources available to serve projected demand. These assumptions include commodity fuel prices, resource costs and their future trajectory, as well as assumptions about how Platte River interacts with other power suppliers in our region. The study period spans 20 years starting Jan. 1, 2021, largely because the typical life of investments for new generating capacity is 20-30 years.

## 6.1 Commodity price projections

Commodity price projections are a key input to resource planning. Platte River engaged Siemens Energy Business Advisory (previously Pace Advisory or Siemens) to provide regional natural gas, power, carbon dioxide (CO<sub>2</sub>), nitrogen oxides, sulfur dioxide (SO<sub>2</sub>), and mercury cost projections. Platte River projected coal prices based on unique coal supply plans for its coal-fired generation fleet. The following subsections discuss these commodity price projections in more detail.





### 6.1.1 Natural gas prices

Siemens provided a monthly natural gas price forecast for the Colorado Interstate Gas (CIG) trading hub, extending through the planning horizon. In addition to the base case pricing, Siemens also provided high and low gas price projections the planning team used to develop sensitivity cases. The high- and low-price projections reflect changes to the underlying fundamentals of the gas market, such as production volumes, export volumes or changes in consumption. All three gas price projections are shown in Figure 39.

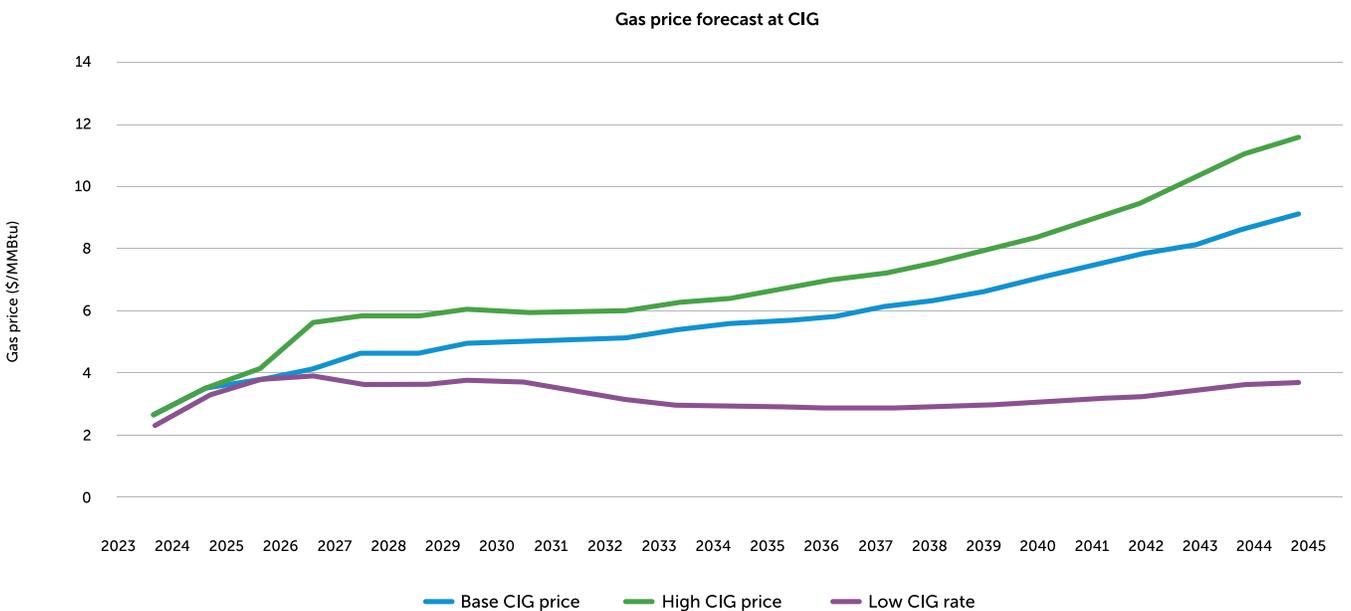


Figure 39. Gas price forecast at CIG

In addition to the above gas commodity prices, Platte River also pays transportation for natural gas delivered to the Rawhide site. Charges begin at \$1.05/MMBtu for 2024, based on actual expenses, and increase at the assumed inflation rate.

Analysis assumes additional gas-related cost for gas pipeline reservation to improve the reliability of gas supplies after coal retirements. Actual gas supply cost varies depending on consumption levels, but an average cost to firm gas supply ranges from \$35/kw-yr to \$50/kw-yr for different gas units. These costs begin in 2030 and end in 2040, when the models assume the units switch to 100% green hydrogen. To improve fuel supply reliability, we will analyze options for firming up gas supplies, such as on-site storage or constructing an additional pipeline to the Rawhide plant site.

### 6.1.2 Green hydrogen prices

Green hydrogen as a noncarbon-emitting fuel for traditional gas turbines has potential in the future, as technological and economical barriers for storing and transporting hydrogen diminish. Based on the recommendations from Black & Veatch, Platte River assumed a 50% blend of hydrogen with natural gas in 2035 and use of 100% hydrogen in 2040. Future hydrogen pricing is uncertain; IRP modeling assumed 2035 hydrogen prices five times the prices of natural gas by 2035, decreasing to three times of natural gas by 2045. Hydrogen prices can be expressed in \$/MMBtu or \$/kg units. Price projections are shown in Figure 40.

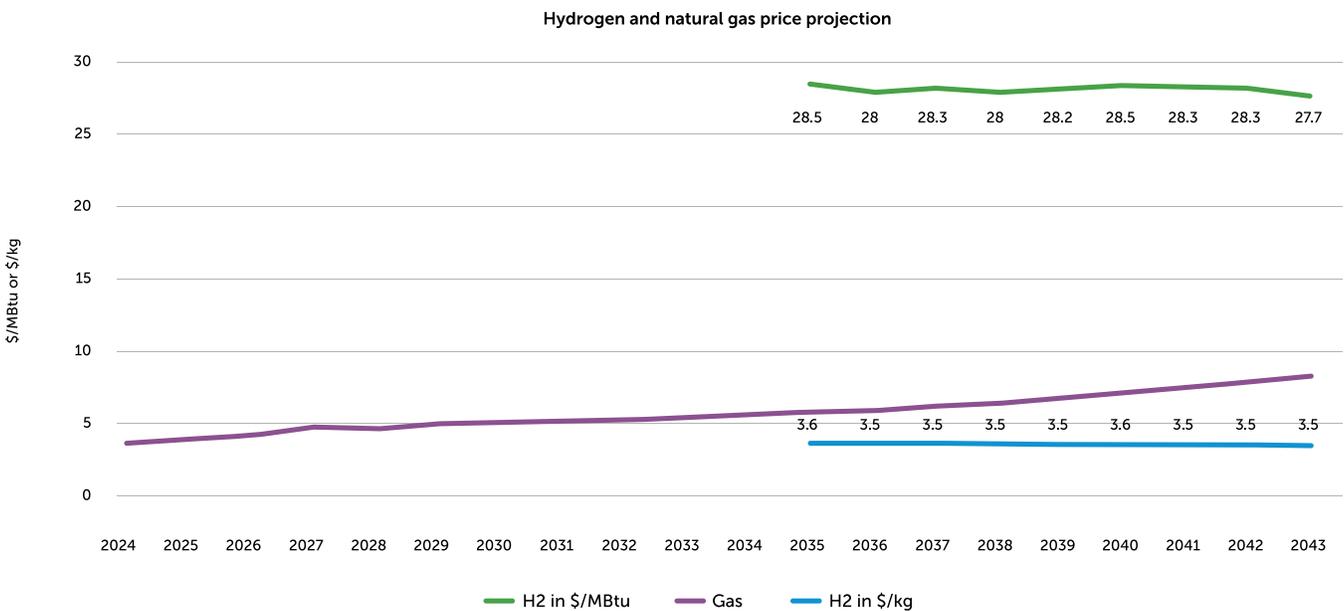


Figure 40. Hydrogen and natural gas price projection

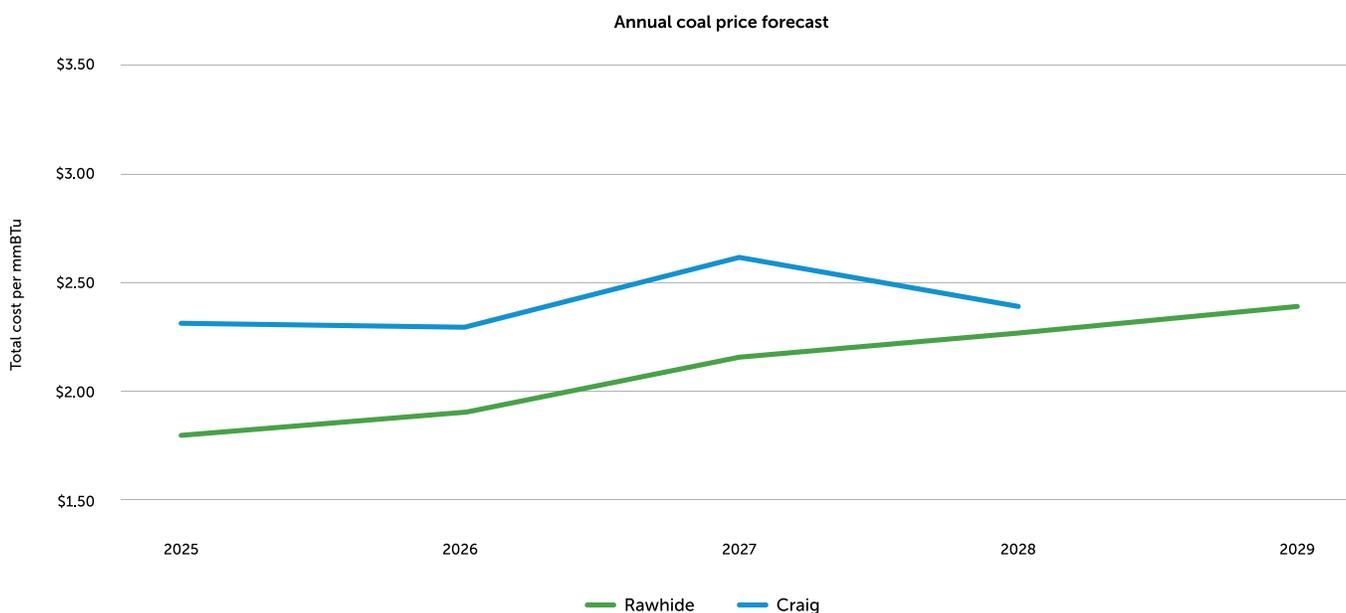
### 6.1.3 Coal prices

Each coal plant in Platte River’s portfolio operates with a unique coal supply arrangement. This means that price forecasts for Rawhide Unit 1 and the two Craig units are developed separately, as discussed below.

Rawhide receives coal from the Powder River Basin by rail and its price forecast is largely based on broader market prices. Near-term prices reflect existing contracts and prices that have been locked in with the supplier and near-term coal market assessments and indices. As locked-in quantities with prices tied to market indices decrease over time, the remaining coal is priced at Siemens’s forecast for Powder River Basin coal. By 2027, the price forecast is based entirely on the forecasted commodity price

from Siemens. The commodity price is adjusted to reflect mine-specific pricing. It includes additional costs for required dust suppressants and taxes passed through by the mine. Transportation expenses, based on the current rail rates projections, are also added to forecast delivered coal price.

The overall Craig coal price forecast is based on price forecasts provided by Trapper Mine, which is adjacent to the Craig plant. Platte River has a partial ownership interest in Trapper Mine and coal costs are determined on a “cash cost” basis, with no transportation costs incurred. Figure 41 illustrates the delivered coal prices for Platte River coal plants.



**Figure 41.** Annual coal price forecast

### 6.1.4 Regional power prices

Platte River’s resources are dispatched in real time with resources from other utilities in the WEIS market to maximize economic exchange of power across the market. In addition to the real-time market, Platte River transacts with neighboring utilities bilaterally, selling excess power and buying power when needed. To simulate these bilateral transactions with neighboring utilities, resource planning models a regional market where Platte River can buy or sell when economical. Siemens has provided hourly future prices for Colorado area and these hourly prices are used in our simulations. During portfolio simulations, the Platte River system was allowed to buy power when the regional market price is lower than Platte River’s marginal cost of production and allowed Platte River to sell excess power when the market prices are higher than its marginal cost. Net revenues from market transactions reduce the overall cost of providing power to Platte River’s owner communities.

With more renewable resources on the regional grid, renewable energy becomes a bigger driver of power prices. Siemens predicts that average annual power prices will remain relatively stable over the 20-year planning horizon. However, daytime prices (labeled as “on-peak solar” prices in Figure 42) will decline as more solar generation is added.

Figure 42 shows our current forecast for on-peak and off-peak power prices, including solar and non-solar hours. The model defines on-peak hours as Monday-Saturday from 6 a.m. to 10 p.m., with on-peak solar 8 a.m. to 5 p.m. every day and on-peak non-solar 5 p.m. to 10 p.m. Monday-Saturday. Off peak hours are 11 p.m. to 5 a.m. Monday-Saturday and all day Sunday. As shown in Figure 42, on-peak non-solar prices (representing the evening hours) stay the highest and on-peak solar, which reflect the day and time when solar is plentiful, are the lowest prices.

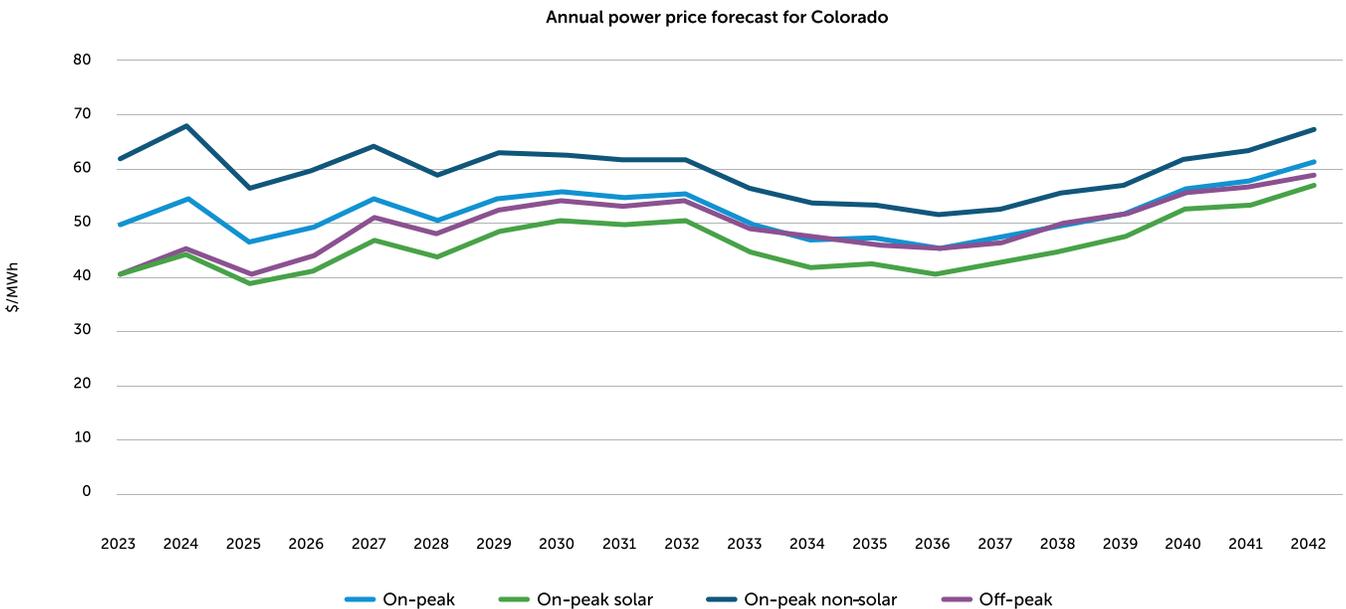


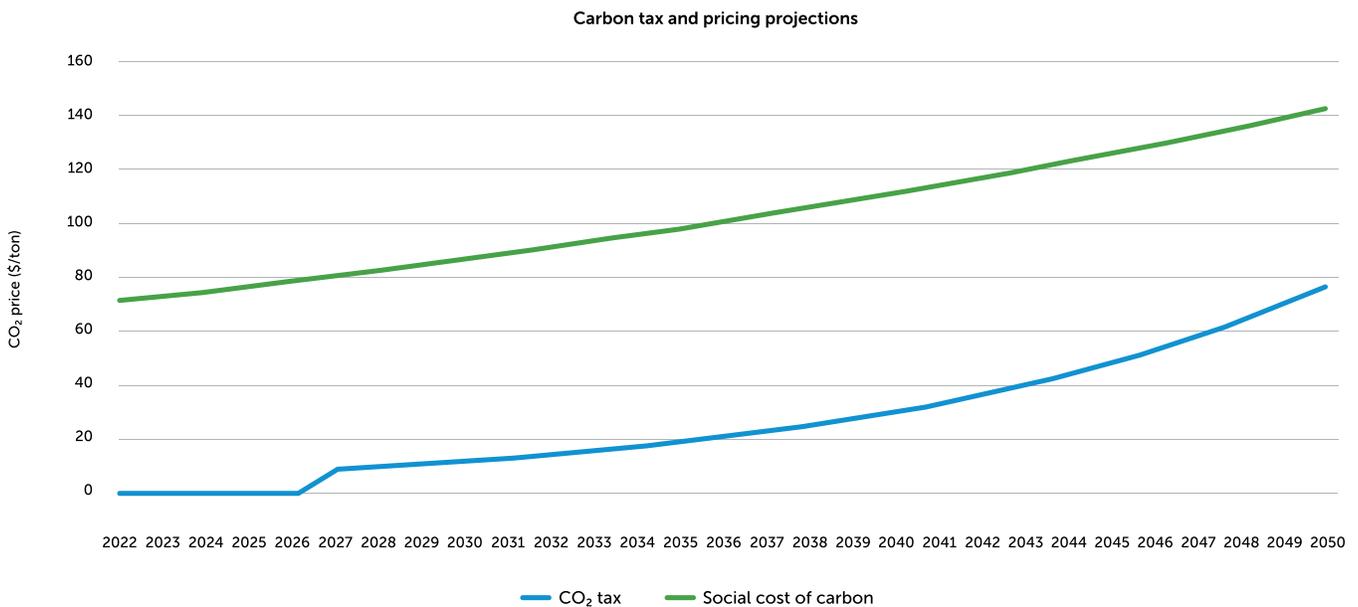
Figure 42. Annual power price forecast for Colorado

For the 2024 IRP, Siemens provided an hourly price forecast and the renewable energy patterns used in their price forecasting models, which helped correlate relationships between market prices and energy production from the intermittent wind and solar resources. Siemens also provided the natural gas and emission prices forecasts, which were appropriately correlated to an hourly level in the IRP assumptions to ensure internal consistency among various projections.

### 6.1.5 Carbon taxes embedded in projected energy prices

Siemens supplied a carbon price (tax) forecast based on its expectations concerning public policy discussions and potential legislation. A carbon tax will discourage carbon emissions.

Platte River also evaluated portfolio outcomes using a social cost of carbon. The social cost of carbon simulates total direct and indirect (such as healthcare or extreme weather events) cost to the society from continued CO<sub>2</sub> emissions. The social cost of carbon projection was based on the guidance of the Colorado Air Quality Control Commission, which valued the social cost of carbon at \$68 per short ton in 2020 with an escalation rate of 2.5%, as shown in Figure 43.



**Figure 43.** Carbon tax and pricing projections

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## 6.2 Regional import/export limits

Platte River joined the WEIS market in April 2023, where Platte River's generation resources are jointly dispatched along with generation resources of other market participants to minimize dispatch costs for all market participants. When it joins SPP RTO West, Platte River will serve its load with a combination of owned resources and lower-cost resources from other market participants, implying real-time power sales and purchases with other RTO members. In addition, Platte River will continue bilateral transactions with regional entities, marketing excess energy through short- and long-term transactions. For IRP modeling, analysts assumed purchases or sales up to 150 MW in any hour. The 150 MW import/export limit means that market transaction volume remains realistic and that Platte River builds enough reliable energy generation to meet customers' needs and planning reserve margin requirements.

## 6.3 Supply-side generation resources

This section discusses all power generation resources Platte River considered to meet its customers' future electricity needs, beginning with our existing resources followed by committed resources. We then discuss additional future resources and the screening process to select candidate resources. A detailed discussion follows concerning the resources (both renewable and traditional) that Platte River is evaluating for future investment.

### 6.3.1 Platte River's existing resources

Platte River's existing supply-side resources consist of power plants, PPAs and community solar generation facilities. Distributed and community-owned solar were modeled as supply-side resources even though they may have unique contracts with retail load or with an owner community's distribution utility. For modeling purposes, they function as resources that serve community load. Tables 10-15 list Platte River's existing resources.

Coal generation facilities	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation	Nominal retirement / contract expiration
Rawhide Unit 1	280	280	1984	2029
Craig Unit 1	77	77	1980	2025
Craig Unit 2	74	74	1979	2028

**Table 10.** *Platte River's existing coal resources*

Natural gas (simple-cycle CTs) generation facilities	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation
Rawhide Unit A	65	65	2002
Rawhide Unit B	65	65	2002
Rawhide Unit C	65	65	2002
Rawhide Unit D	65	65	2004
Rawhide Unit F	128	128	2008

**Table 11.** *Platte River's existing natural gas resources*

Contracted wind resources	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation
Medicine Bow	6	1	1998
Silver Sage <sup>11</sup>	12	2	2009
Spring Canyon I <sup>12</sup>	32	5	2014
Spring Canyon II	28	6	2014
Roundhouse	225	39	2020

**Table 12.** *Platte River's contracted wind resources*

Contracted hydropower <sup>13</sup> resources	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation
Loveland Area Project	30	30	1973
Colorado River Storage Project	60	48	1973

**Table 13.** *Platte River's contracted hydropower resources*

Contracted solar resources	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation
Commercial solar power purchase program	4	2	Approved 2013
Fort Collins community solar	1	0.4	2015
Foothills Solar (Platte River share)	0.5	0.2	2016
Rawhide Flats	30	17	2016
Rawhide Prairie	22	12	2020

**Table 14.** *Platte River's contracted solar resources*

Contracted storage resources	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation
Rawhide Prairie Battery	1 MW x 2 hours	1	2020

**Table 15.** *Platte River's contracted storage resources*

<sup>11</sup> Silver Sage wind has been sold through 2029, when its PPA with Platte River expires. It does not return as a resource.

<sup>12</sup> Both Spring Canyon resources were sold in 2020 through 2030. They will return to Platte River in June 2030 and serve Platte River customers for the remaining term of their contract (through 2039).

<sup>13</sup> Estimated effective capacity due to persistent drought conditions throughout the West.

## 6.3.2 Committed or expected resources

This category includes resources for which either a final contract has been signed or negotiations are ongoing. These resources are treated like existing resources. These resources are included in modeling as assumed available and not subject to change through the optimization and resource selection process. These resources are shown in Table 16.

Committed resources	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation	Current status
<b>Solar</b>				
Black Hollow	150	31	2025	PPA signed
New solar	150	24	2026	Negotiations ongoing
<b>Storage</b>				
Community battery	25 MW x 4 hours	18	2026	Negotiations ongoing

**Table 16.** *Committed resources*

## 6.3.3 Future candidate resources

Platte River selected future candidate generation resources by reviewing data from credible public sources, its consultants and its own market intelligence as detailed below. This section provides an overview of data sources, selection process and details of the selected resources.

### 6.3.3.1 U.S. Energy Information Administration

The EIA publishes cost and performance of new generation every year in its annual energy outlook report. The EIA report<sup>14</sup> is comprehensive and covers state of the art in traditional, low-carbon and renewable power

generation technologies. We selected the following technologies from this report for further evaluation:

- Onshore wind
- Solar photovoltaic
- Battery storage
- Aero-derivative combustion turbine
- Reciprocating internal combustion engine
- Carbon sequestration
- Modular nuclear
- Geothermal

Planning staff screened out the following technologies from this report, as they are not suitable for Platte River's future power supply portfolio.



- Coal with or without carbon sequestration
- Combined cycle with or without carbon sequestration
- Large nuclear
- Offshore wind
- Biomass
- Solar thermal
- Conventional hydro
- Fuel cells

### 6.3.3.2 Black & Veatch consulting support

In addition to the resources considered from the EIA report, Platte River engaged Black & Veatch<sup>15</sup> to assess the landscape of low- and no-carbon fuels, energy storage and dispatchable power generation technologies. The Black & Veatch report assessed the availability of these technologies for 2028 commercial operation. For technologies not available for 2028, they estimated their future costs and

commercial availability in the next decade. Black & Veatch reviewed the following options:

- **Biofuels.** The study concluded biofuels for power generation are not a viable option at Rawhide due to limited fuel availability and significant modifications required in the equipment to burn this fuel. Biofuels are better suited for transportation applications, rather than large power generation.
- **Hydrogen** – both green and blue. Green hydrogen is produced by an electrolyzer using renewable electricity, while blue hydrogen is produced from natural gas and the CO<sub>2</sub> produced in the process is sequestered and stored in the ground. Hydrogen can be used as fuel in traditional power generation machines like CTs with some modifications. But there are significant techno-economic challenges to store and transport hydrogen. The study concluded that green hydrogen could be a viable option for Platte River starting in the middle of the next decade.

<sup>14</sup> [https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec\\_cost\\_perf.pdf](https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf)

<sup>15</sup> Results from the generation technology screening by Black & Veatch are accessible on Platte River's IRP microsite at [prpa.org/2024irp/information](http://prpa.org/2024irp/information).

- **Renewable natural gas.** Renewable natural gas is produced mostly at landfill or biowaste locations. The study concluded that renewable natural gas for power generation at the Rawhide site is not a viable option due to limited fuel availability. This fuel is better suited for small power generation at or near locations where the fuel is produced, such as landfill or wastewater treatment sites. Another possible use of renewable natural gas is for transportation, like the City of Longmont using renewable natural gas from its wastewater facility in the waste services truck fleet, displacing the use of diesel fuel. In some cases, renewable natural gas can be refined enough to meet the pipeline quality natural gas standard and can be pumped back into the gas network.
- **Ammonia.** Since transporting hydrogen over long distances is technologically and economically challenging (because hydrogen is a very light-weight molecule), industry is considering converting hydrogen into ammonia and then transporting it. At the destination, ammonia can be used directly in power generation or converted back to hydrogen and then used. The study concluded ammonia for power generation is not a viable option. It is better suited for transportation applications, rather than large-scale power generation.
- **Carbon capture and sequestration.** Carbon capture and sequestration technology was considered for removing CO<sub>2</sub> from the existing combustion turbine units at the Rawhide site. The study concluded carbon capture and sequestration is not a viable option at Rawhide due to high cost of CO<sub>2</sub> removal in peaking units (like those at Platte River, where combustion turbines are expected to run less than 20% of the time), and lack of known places to sequester CO<sub>2</sub>. Carbon capture and sequestration technology is a better option for baseload applications, where the generation source is running continuously and where the large capital cost can be spread over numerous tons of removed CO<sub>2</sub>. Additionally, carbon capture and sequestration technology is in the early commercial stages of development, with few proven and successful applications for power generation.
- **Long duration energy storage.** The study concluded that long-duration energy storage is an emerging technology, but not ready for commercial operation in 2028. This technology has potential and may become commercially available by the middle of the next decade. Platte River decided to plan for a 10 MW pilot long-duration energy storage project by 2030 and assume the technology would be available for commercial applications by 2035.
- **Flexible and low CO<sub>2</sub> emitting thermal power generation.** In addition to the low- or no carbon emitting power generation options discussed above, the study reviewed various traditional combustion turbine and reciprocating internal combustion engine technologies that are flexible, reliable, efficient and hydrogen-capable. Three key future dispatchable technology requirements will be reliability, flexibility, and the ability to provide power for at least one week during dark calms. Because low or no-carbon options were not commercially available, the study recommended using gas-fired combustion turbines or reciprocating

internal combustion engines for commercial operation in 2028 and progressively converting to green hydrogen when it is economically available in large quantities. Combustion turbine and reciprocating internal combustion engine vendors claim that these machines will be capable of burning about 30% hydrogen by 2028.

### 6.3.3.3 Platte River’s own market intelligence

Platte River’s portfolio integration team monitors markets and collects information informally and formally through requests for information and requests for proposals. This engagement informs Platte River of the latest technology and pricing trends in the area. EIA, Annual Technology Book (ATB) or consultants can provide market trends and average prices, but the real prices for our area are available only through engagement with developers and vendors. Platte River conducted a solar and storage RFP in 2022 and started a wind RFP in 2023. These market interactions were valuable for collecting information about the projects being developed in our region—their costs, locations, schedules and technologies. This information was used to input costs of renewable and storage technologies in IRP modeling.

### 6.3.3.4 NREL’s Annual Technology Book

NREL provides cost, efficiency and technology improvement trends of renewable and storage technologies in the ATB every year. We used the data in the 2022 ATB for this IRP, as it was the latest available in the spring of 2023 when staff

finalized assumptions.

After a detailed review of all the sources mentioned above and internal deliberations, Platte River decided the following:

- For wind, solar and four-hour storage costs, we used our own market intelligence data for early year prices where data was available from multiple vendors.
- After the first three years, we used cost escalation and efficiency improvement rates proposed by the ATB.
- Actual cost data used for each technology is shown in the following sections.

For dispatchable resources, Platte River relied on the recommendations of Black & Veatch. Platte River decided the best option is to use highly flexible, state-of-the-art, hydrogen-capable aeroderivative combustion turbine technology. These machines will initially use natural gas fuel and by 2035 may start using 50% green hydrogen blend and by 2040 may use 100% green hydrogen. The process of selecting aeroderivative technology is discussed in section 6.3.7.

## 6.3.4 New wind resources

While wind resource availability within Platte River’s service territory is limited, wind is abundant to the north and the southeast. Most likely, our future wind will come from southeast Wyoming or eastern Colorado. We have assumed that the southeast Wyoming wind will be delivered to Platte River through existing transmission capacity that will become available after retirement of Craig coal generation.



Eastern Colorado wind would be delivered through a neighboring transmission system at a cost of \$6/MWh in 2023 and escalating with inflation. Because the existing transmission infrastructure in southeast Wyoming is limited, only 200 MW of wind is expected to be procured without incremental transmission cost. Any future wind will include a transmission charge or new transmission infrastructure at an assumed cost of \$6/MWh.

New wind resources are assumed to be procured under PPAs for 100 to 200 MW blocks. PPA payments compensate the developer or the owner for capital costs (depreciation and returns), financing costs, interest during construction, taxes (sales, property, and income) and ongoing operating and maintenance costs. PPA prices for wind are based on recent quotes from project developers in the region. We assumed future wind prices will escalate based on the 2022 ATB future wind cost curves.

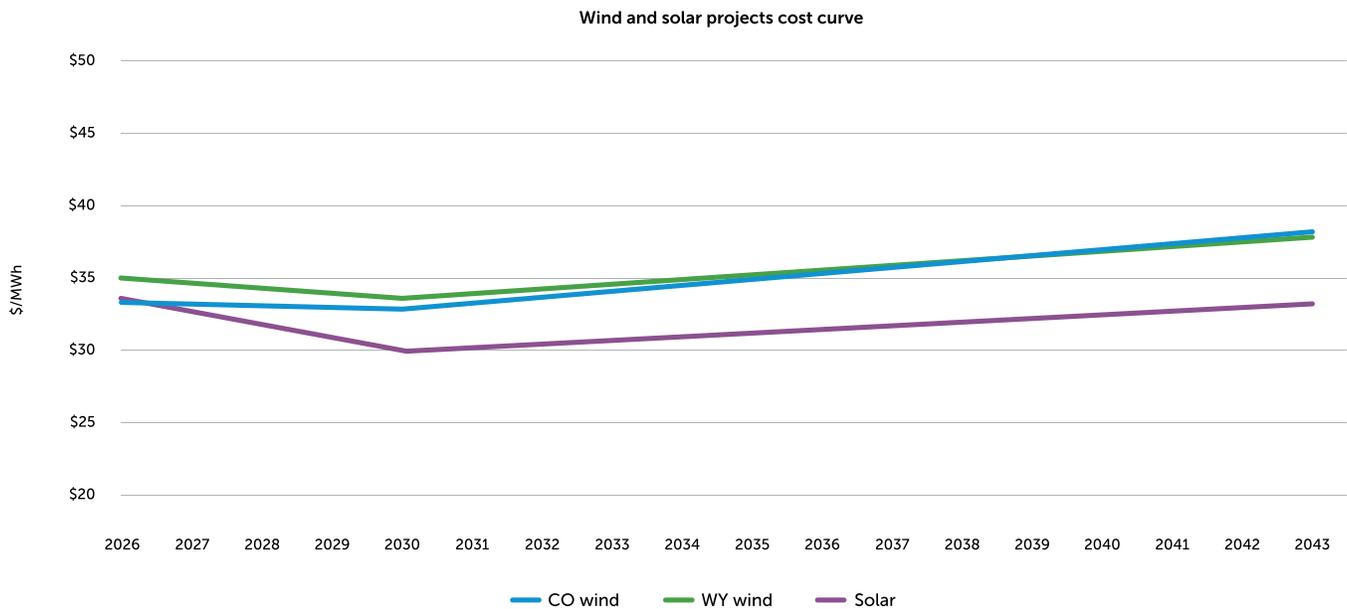
Southeast Wyoming wind is assumed to have an average annual capacity factor of 42.5%, while the eastern Colorado wind was modeled with a 45% capacity factor.

Wind projects (existing or new) carry ancillary service charges through 2025. Beyond 2025, we assume those costs cease with entry into a regional market. The combined cost of wind ancillary services in 2024 were modeled at \$1.24/kw-mo.

Figure 44 shows wind costs for the two locations along with solar costs. As mentioned earlier, PPA prices are generally fixed for their terms (typically 20-30 years). Figure 44 assumes that for 2026, the southeast Wyoming wind PPA price will be fixed at \$35/MWh for the PPA term, while for the wind PPA signed in 2030, it will cost \$33.65/MWh for the life of the project.

### 6.3.5 New solar resources

New solar resources were considered as 50 MW block sizes priced at a 30-year levelized PPA payment, including transmission interconnection costs. Solar generation is assumed to have an annual capacity factor of 28%. Platte River received solar price data based on recent RFPs and negotiations with developers. These prices were escalated with NREL's 2022 ATB solar cost projections.



**Figure 44.** Wind and solar projects cost curve

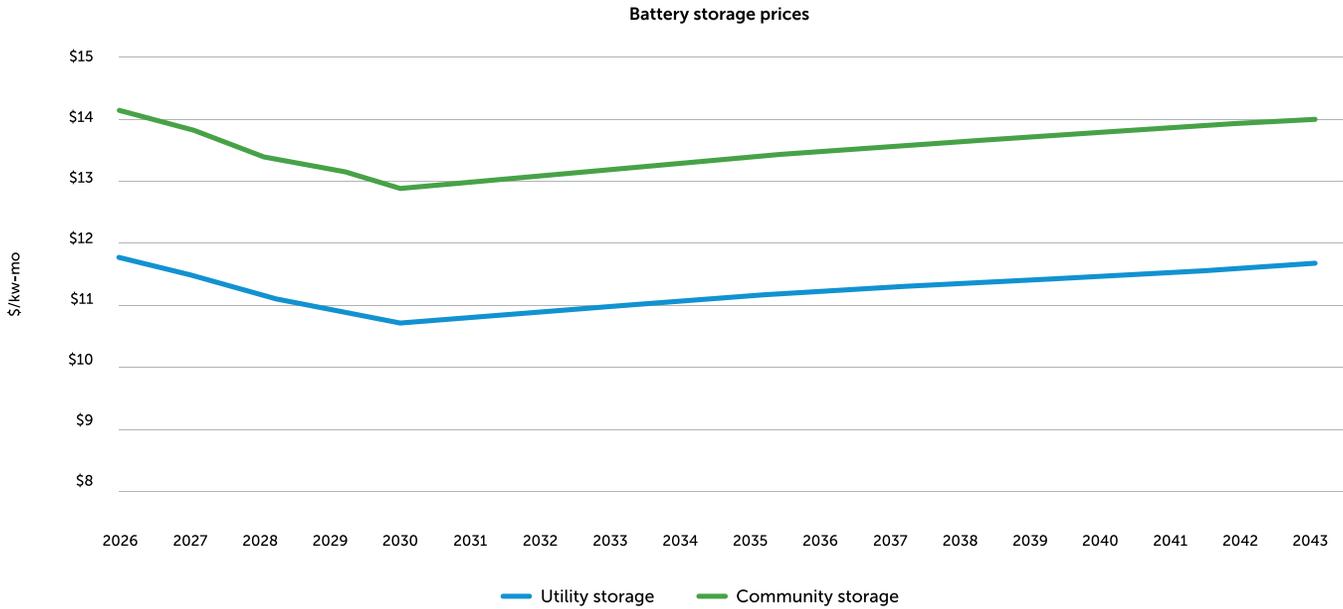
Platte River assumed that new solar projects will be built within the existing Platte River transmission footprint. Consequently, no new transmission capital costs or third-party wheeling costs were assumed for solar generation. Solar ancillary service costs in 2024 were assumed at \$0.09/kw-mo.

### 6.3.6 New storage resources

Energy storage is the keystone in a deeply decarbonized power supply portfolio. A 100% renewable power supply portfolio using wind and solar as the main source of energy will need energy storage from a few seconds to several days to complement supply intermittency. Platte River considered a variety of different commercially available battery storage technology options, including lithium-ion batteries for four-hour storage duration, flow batteries for 10-hour storage duration and

long-duration energy storage batteries for 100-hour storage duration. These battery types will provide different services to support the grid while complementing renewable intermittency.

Four-hour lithium-ion battery technology is mature and commercially available. We assumed 200 MWh of storage per 50-MW four-hour battery, which would provide up to four hours of discharge capacity at a rate of 50 MW per hour. Four-hour batteries were assumed to have an 85% round trip storage efficiency. The economic life of a four-hour battery was modeled to be 20 years. Like wind and solar, 2024 prices for four-hour battery storage were based on the recent RFP and vendor negotiations. Future prices escalate based on the 2022 ATB. See the cost projections in Figure 45.



**Figure 45.** Battery storage prices

Ten-hour flow batteries are an emerging technology with no existing commercial installations as of 2023. We worked with a vendor to get cost, efficiency, and performance details. Based on the data provided by the vendor, this technology was not found to be economical during our early technology screening and minimal cost portfolio development process. Therefore, this technology was not considered as a resource in the IRP. However, this technology has potential to become part of the future power supply portfolio. As the technology matures, Platte River will consider it.

Long-duration energy storage is critical for supplying power during extended dark calm periods. Like flow batteries, this technology is also under development with no existing commercial installations as of 2023. Platte River analyzed the cost, efficiency, and performance details of long-duration energy storage. When fully developed and commercialized, long-duration energy storage will reduce the need for fossil generation to provide backup power

and reliability in a renewable portfolio. Platte River plans to integrate a 10 MW pilot unit before 2030. For IRP modeling, we assumed that the technology will be commercially available by 2035. The current capital cost of this technology is high, and the round-trip efficiency is low. We assumed cost reduction and performance improvements over time as the technology matures and finds commercial applications.

### 6.3.7 New dispatchable thermal generation resources

As mentioned earlier, after a thorough review of all the options for no- or low-carbon fuels, and for dispatchable generation technologies, Black & Veatch recommended Platte River use natural gas-fired generation for 2028 commercial operation and then convert to green hydrogen fuel when it is commercially available. Platte River and Black & Veatch looked at 50+ options and screened down to the seven listed in Table 17 for detailed assessment.

Characteristic	Unit	LM2500	LM600	LMS100	RICE	7F CC conversion	LM600 CC	SGT800
Unit size	MW	28	40	90	17	17-116	31-44	55
Heart rate	btu/kWh	9,875	9,649	8,820	8,510	6,646	7,087	9,707
Cost per MW	\$/MW	\$1.8	\$1.7	\$1.2	\$1.7	\$2.2	\$2.3	\$1.4

**Table 17.** Screened dispatchable technologies

LM2500, LM6000 and LMS100 are aeroderivative CTs manufactured by General Electric. RICE is reciprocating internal combustion engine. The next two were combined cycle options; converting the existing 7F CT at Rawhide station or install 4 LM6000 CTs with combined cycles. Finally, SGT800 is a combination of frame and aeroderivative technologies manufactured by Siemens.

After analyzing the levelized cost of energy and reviewing operational characteristics of the seven technologies, a smaller group of four featured in Table 18 was selected

for more detailed assessment. These four technologies were further analyzed in detail for characteristics like reliability, emissions, economic value, operational flexibility, fuel versatility, constructability and market performance. During this detailed evaluation, higher weights were assigned to the factors aligned with Platte River's three pillars of reliability, environmental responsibility and financial sustainability. This analysis concluded that aeroderivative technology was the best option for Platte River. The LM6000 technology was selected as the presumed technology for inclusion in the supply portfolio.

Qualification	Weight	Option 1	Option 2	Option 3	Option 4
Reliability	30%	1.52	2.52	2.7	1.51
Emissions	25%	0.7	2.41	2.34	1.69
Costs	20%	1.55	1.47	1.55	2
Operational flexibility	10%	0.9	0.91	0.88	0.8
Fuel versatility	5%	0.05	0.36	0.36	0.42
Constructability	5%	0.45	0.45	0.45	0.35
Market performance	5%	0.4	0.5	0.45	0.45
<b>Total weighted score</b>	<b>100%</b>	<b>5.57</b>	<b>8.62</b>	<b>8.72</b>	<b>7.21</b>

**Table 18.** Results of detailed screening of four selected technologies

# 07

## IRP design

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## 7.1 Studies

The following studies support this IRP. All studies are available on the IRP microsite.

- PRM and ELCC study by Astrape Consulting
- Beneficial electrification forecast by Apex Analytics
- Distributed energy resources forecast and potential study by Dunsky
- Extreme weather events and dark calm analysis by ACES
- Independent review of dispatchable capacity needs by Black & Veatch
- Generation technology screening by Black & Veatch

Additionally, this IRP uses fundamental market analysis of supply and demand in the region provided by Siemens, and a locational marginal pricing assessment by ACES.

## 7.2 Objectives

The objective of this IRP is to continue Platte River's journey toward achieving the goals of the RDP by developing a roadmap

to meet the owner communities' needs for reliable, environmentally responsible and financially sustainable energy and services using a diverse power supply portfolio.

## 7.3 Planning for a reliable future power supply

Power supply reliability is a key responsibility of a utility. It is a foundational pillar for Platte River's planning and operations. Platte River plans to join a full organized energy market in 2026, which will take over transmission planning and some operational responsibilities. In a market, a load-serving entity like Platte River is required to bring enough resources to reliably serve its load according to the reliability criteria enacted by the market operator. Markets allow a wider access to improve economics and reliability under varying weather and operating conditions, but they do so by relying on the resources contributed by each market participant. This chapter covers reliability modeling in the IRP and the development of different power supply portfolios to cover a wide range of future possibilities.





### 7.3.1 Power supply reliability

As society's dependence on electricity increases, power supply reliability is becoming more critical. Electric reliability is not only the foundation for commerce; our security and safety depend on it. This critical dependence became tragically clear when Texas power outages during Winter Storm Uri caused 246<sup>16</sup> deaths and billions of dollars in economic losses.

Power supply reliability is the ability of a power system to keep the lights on under changing supply and demand conditions. Electric utilities

must plan, design, construct and operate an electric supply system for reliability of supply.

There are a few terms used under the broad umbrella of reliability:

- Adequacy is a measure of the ability of a power system to meet the electric power and energy requirements of its customers within acceptable technical limits, considering scheduled and unscheduled outages of system components.
- Security is the ability of the power system to withstand disturbances.

<sup>16</sup> Texas winter storm: 246 Texans' deaths classified as winter-storm related (kxan.com).

<sup>17</sup> <https://www.energy.gov/articles/economic-benefits-increasing-electric-grid-resilience-weather-outages>



- Resilience is the ability to quickly adapt and recover from a disruption, with minimal impact.

Historically, threats to power supply reliability included equipment failure (at the distribution, transmission, or generation level) or extreme weather like hurricanes, floods, snowstorms and heat storms. More than 90% of the power supply interruptions or reliability events can be attributed to breakdowns in the distribution system.<sup>17</sup>

Distribution system interruptions are typically localized and affect a small number of customers. Reliability events that stem from interruptions on the generation or transmission system, or lack of generation, are broader reaching and potentially more

consequential. With increased reliance on wind and solar generation in the future, an additional threat to reliability will be low or no production from these intermittent resources for extended periods.

In our IRP process, Platte River focuses on reliable, environmentally responsible and lowest reasonable cost power supply portfolios. Some of the major variables that drive power supply reliability in our planning process are:

- Occasional generation equipment failures
- Load forecast uncertainty
- Variability of hourly wind and solar generation patterns
- Occasional extreme weather (such as heat or cold waves)
- Extended periods of low or no renewable generation

After an extensive review of hourly generation profiles of solar and wind, we found that there are certain times when there is very little or no renewable generation for extended periods. We call these incidents dark calms. We have found that dark calm events occur frequently and can last from a day to as long as seven days.

While our definitions of reliability and related concepts are general, over the years the power industry has developed specific metrics and methods to plan for a reliable supply portfolio as discussed in the next section. A starting point for developing a reliable power supply is a resource adequacy study. This study simulates a future power supply portfolio under varying conditions of power supply and power demand to assess its reliability.

## 7.3.2 Planning for a reliable future portfolio

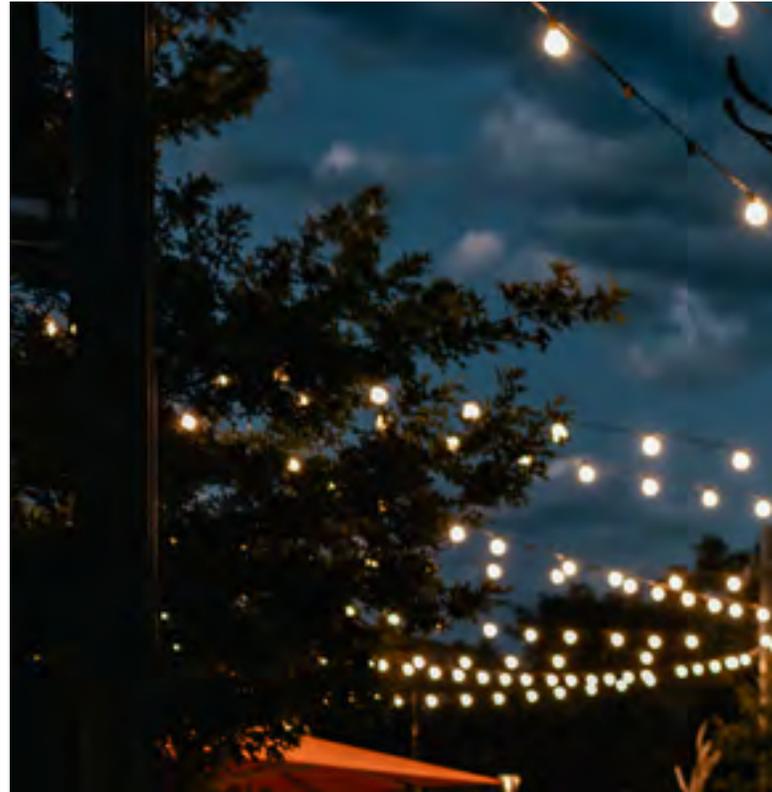
### 7.3.2.1 Reliability metrics for planning

The North American Electric Reliability Corporation, the regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid, defines requirements for resource adequacy in Standard BAL-502-RFC-02.<sup>18</sup> This standard requires utilities to “calculate a planning reserve margin that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year analyzed being equal to 0.1.” This metric is also referred to as Loss of Load Expectation (LOLE) of 0.1 per year or LOLE of one day in 10 years, or sometimes, as “One Day in Ten Years” (ODTY). This metric has been widely used in planning studies since the early days of modern power systems.<sup>19</sup>

This metric has traditionally guided investment in generation to provide reliability accepted as the optimal target. Historically, ODTY or 0.1 day LOLE per year has required utilities to maintain a 10-15% PRM. PRM is defined as the percent additional firm capacity relative to the peak demand in a future year. Specifically,

$$\text{PRM} = \frac{\text{Firm capacity} - \text{peak demand}}{\text{Peak demand}}$$

Historically, PRM covered planned or unplanned outages (equipment breakdowns) and load forecast error due to weather and economic growth uncertainty. Following the retirement of dispatchable coal generation (which provides



firm capacity) over the past decade, and with the introduction of intermittent renewable generation resources, the structure of power supply portfolios is rapidly changing.

LOLE of 0.1 day per year is still the dominant metric in the power industry, but some alternatives are being proposed and debated.<sup>20</sup> The main criticism of 0.1 day LOLE per year metric is that this probabilistic calculation does not adequately measure the depth (how much power was lost, or how many customers lost power), breadth (how long power was lost) and the frequency (how often power was lost).

In a recent report,<sup>21</sup> EPRI summarized the existing and proposed metrics, arguing that a single metric such as ODTY may conceal some risks and may not be able to sufficiently capture



the future challenges to the power grid from:

- Rapid decarbonization of power supply with the retirement of dispatchable resources and adoption of intermittent renewables.
- Adoption of electrification in transportation and heating.
- Adoption of DERs with wider customer involvement.

- Climate change and extreme weather events.

With the introduction of renewable generation, the concept of planning for the “Peak Hour” of the year is giving way to planning for every hour in the year. The hour when the system experiences peak demand is less important than the load net of renewables. For example, Figure 46 from New York ISO<sup>22</sup> shows that typically they experience peak demand between 3-4 p.m. in July, but, due to solar generation, the net peak demand is lower and shifts to 5-6 p.m.

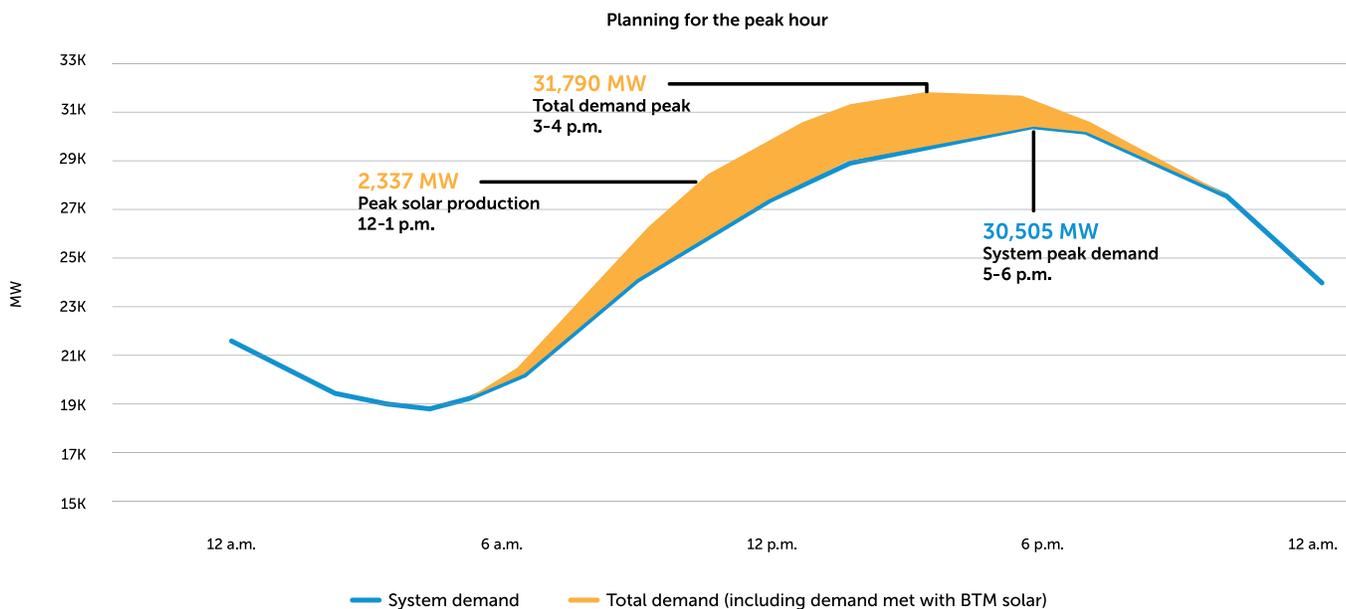
<sup>18</sup> <https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RFC-02.pdf>

<sup>19</sup> [https://www.astrape.com/wp-content/uploads/2024/01/EISPC\\_The\\_Economic\\_Ramifications\\_of\\_Resource\\_Adequacy\\_White\\_Paper.pdf](https://www.astrape.com/wp-content/uploads/2024/01/EISPC_The_Economic_Ramifications_of_Resource_Adequacy_White_Paper.pdf)

<sup>20</sup> [https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/ra\\_t3b2\\_workshop-1\\_presentation-telos-and-gridlab.pdf](https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/ra_t3b2_workshop-1_presentation-telos-and-gridlab.pdf)

<sup>21</sup> <https://www.epri.com/research/products/000000003002023230>

<sup>22</sup> <https://www.nyiso.com/-/shaving-peaks-with-the-sun>



**Figure 46.** *Planning for the peak hour*

Other parts of the country experience similar phenomena. Wind generation may shift the net peak demand to different hours. In fact, the Western Electricity Coordination Council (WECC), the entity responsible for reliability of the electric grid in 13 western states (including Colorado), is proposing to estimate resource adequacy for every hour, targeting an hourly LOLE of 0.002%.<sup>23</sup>

### 7.3.2.2 Platte River PRM for future planning

For the 2020 IRP, Platte River used a 15% PRM as its reliability metric. With the changing portfolio mix in the region<sup>24</sup> and with the backdrop of ongoing discussions in the industry, we engaged Astrape Consulting to perform a resource adequacy<sup>25</sup> study for this 2024 IRP. This study computed PRM and ELCC<sup>26</sup> of intermittent renewable resources, small amounts of energy battery storage and DERs. The study focused on the year 2030 and modeled the Platte River supply portfolio, along with other utilities in Colorado. The study assumed these utilities will develop the power supply portfolios projected in their respective IRPs and will be part of a functioning market. The study concluded that all Colorado utilities, including Platte River, would need a PRM of 19.9%. This value, though higher

<sup>23</sup> [https://www.wecc.org/\\_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/2022%20Western%20Assessment%20of%20Resource%20Adequacy.pdf&action=default](https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/2022%20Western%20Assessment%20of%20Resource%20Adequacy.pdf&action=default)

<sup>24</sup> Platte River has filed a voluntary clean energy plan committing to reduce its 2030 CO<sub>2</sub> emissions by at least 80% from 2005 levels.

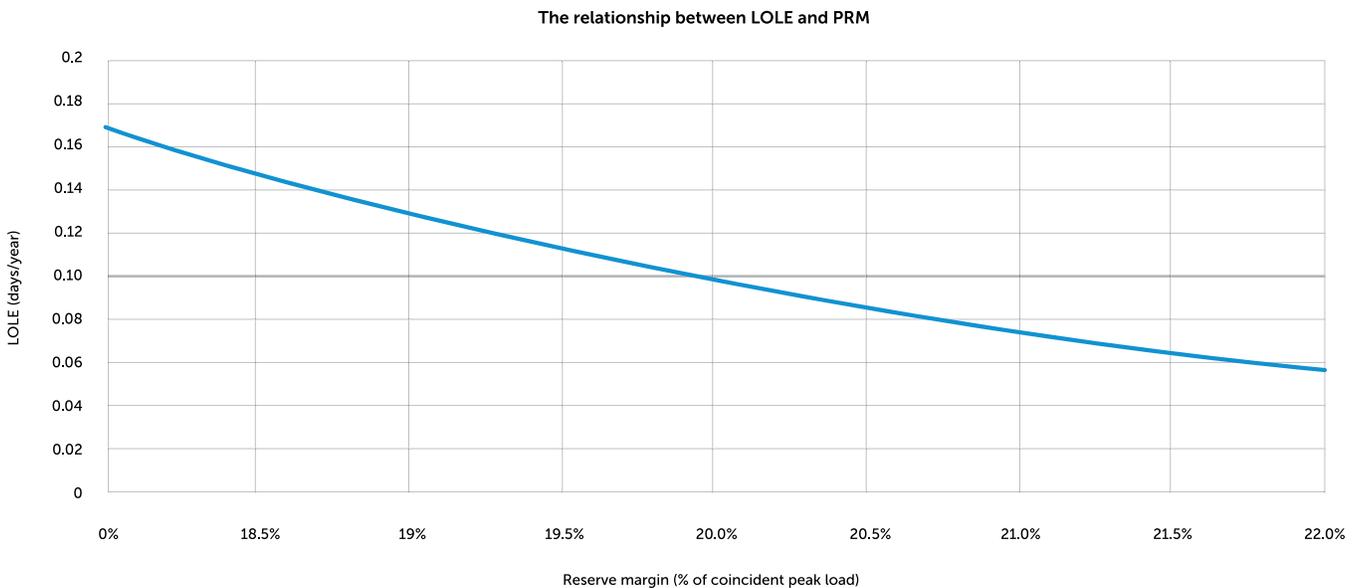
<sup>25</sup> <https://www.prpa.org/wp-content/uploads/2023/11/2024IRP-PRM-and-ELCC-study-by-Astrape.pdf>

<sup>26</sup> ELCC of a resource is the measurement of that resource's ability to produce energy at the time of peak demand.

<sup>27</sup> <https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf>

than the 2020 IRP PRM of 15%, aligns with the WECC-recommended Planning Reserve Margin Index or Variability Margin Index in its 2023 Western Assessment of Resource Adequacy<sup>27</sup> report. Power markets like the Midcontinent Independent System Operator (MISO) and SPP are also looking at higher PRMs than previously recommended due to coal retirements and more intermittent energy integration.

Astrape's proposed PRM of 19.9% for 2030 incorporates its analysis of Colorado, utilities including Xcel Colorado, Colorado Spring Utilities and Black Hills Colorado, using their modeling platform Strategic Energy & Valuation Model, which is also used by major U.S. utilities and several regional power pools. Astrape modeled major uncertainties like weather by using 42 years of historical data for hourly wind, solar and load shapes, three to five days of dark calms, five scenarios of future load forecast error and 300 scenarios of generation availability, for a total of 63,000 simulation scenarios for each hour of the year 2030. This comprehensive analysis produced the relationship between LOLE and PRM as shown in Figure 47.



**Figure 47.** *The relationship between LOLE and PRM*

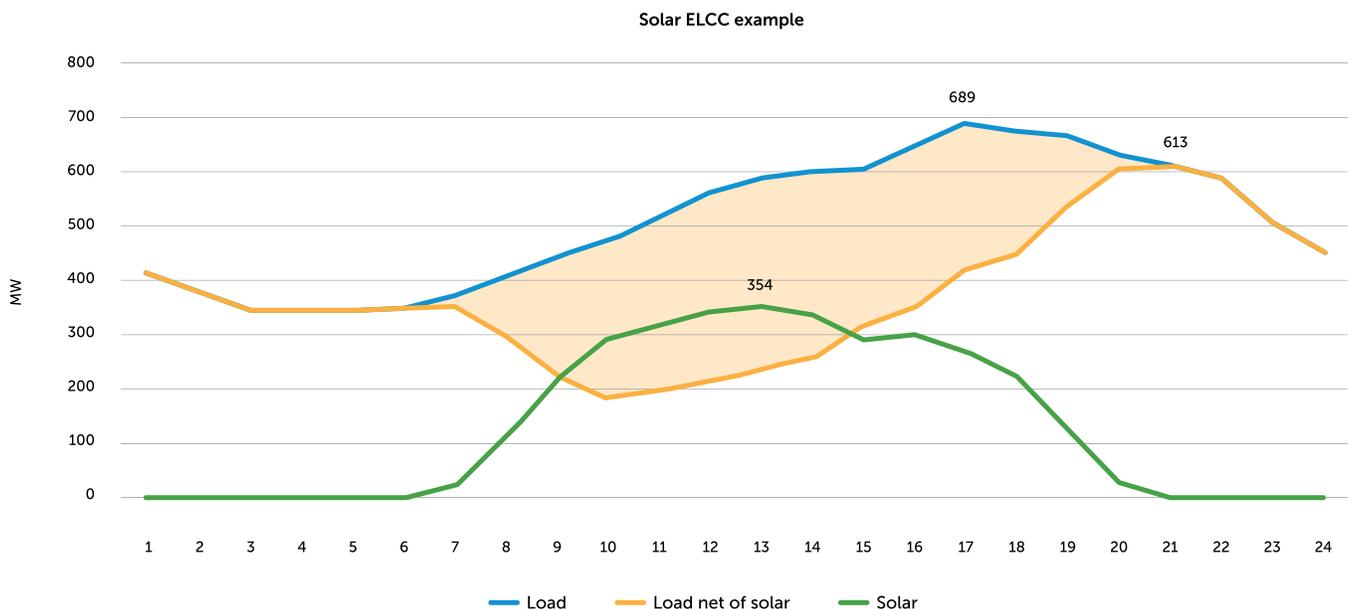
At 0.1 day LOLE per year, the PRM is 19.9%. If we were to build a more reliable system with a LOLE of 0.06, or one outage every 16 years, we will need a PRM of 21.8%. On the other hand, a LOLE of 0.16, with an expected outage every six years, would require a PRM of 18.4%. Essentially, the more spare capacity we have, the less likely we are to face a supply shortage or LOLE.

As mentioned earlier, EPRI recommends not relying on one metric. Utilities and other entities are considering many metrics. In addition to the PRM, we used Loss of Load Hours (LOLH) in our IRP modeling. LOLH measures the average duration of outages. We used LOLH 0.2 during reliability testing of our portfolios.

### 7.3.2.3 ELCC values for renewables and limited energy resources

The ELCC of a renewable or energy-limited resource measures its expected contribution to peak demand. For example, 100 MW from a coal or gas fired plant can provide 100 MW at the time of peak. When running at full load, it will reduce the peak load by 100 MW. The ELCC of this resource is 100 MW or 100%.

But 100 MW of wind, solar or four-hour storage may or may not be able to provide 100 MW at system peak. This means its ELCC will be lower than the nameplate capacity. This can be seen for solar generation in the example shown in Figure 48. It shows hypothetical hourly load and solar generation forecast for a summer day in 2030 for Platte River's system.

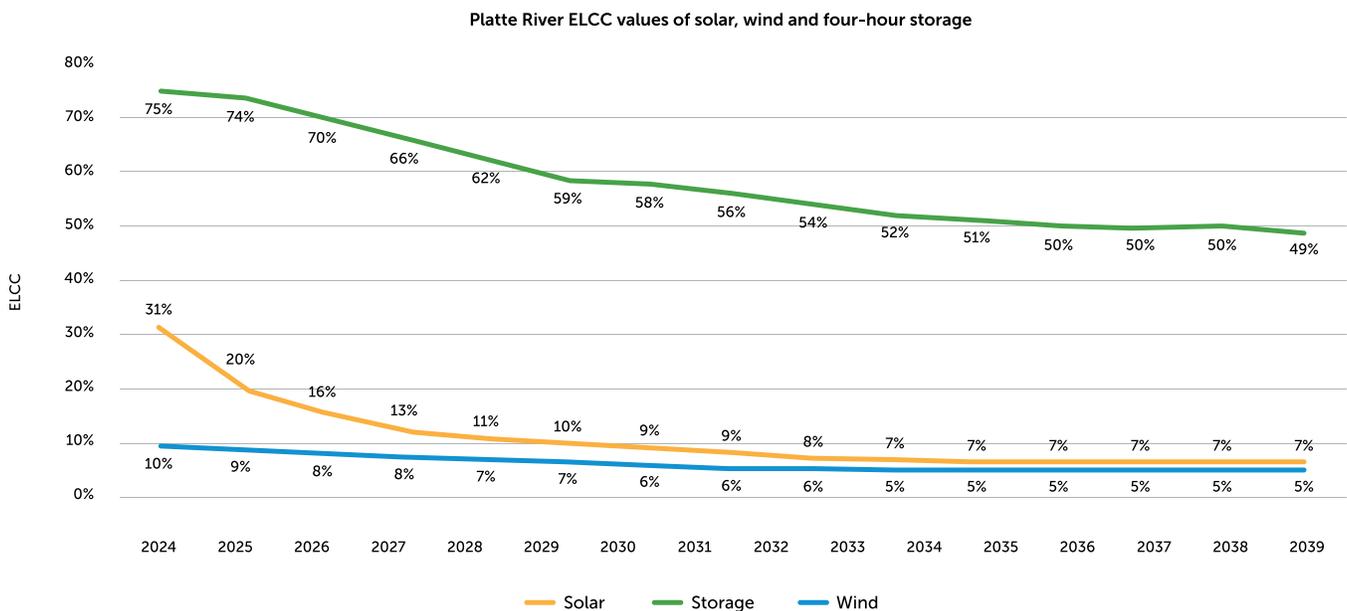


**Figure 48.** Solar ELCC example

The blue line shows hourly load for 24 hours across the day. The peak load during the day is 689 MW at hour 17 or 5 p.m. The green line shows solar generation. It starts around 6 a.m., peaks at 354 MW at 1 p.m. and drops to zero by 9 p.m. The orange line shows hourly load net of solar generation. Solar generation reduces the load by the shaded area. The orange line shows that the peak hour of the load has shifted from 5 p.m. to 9 p.m. and is 613 MW. So, the solar generation has reduced the peak demand by 76 MW (689 minus 613). While the maximum solar generation is 354, the nameplate of installed capacity of solar is 507 MW in this example. For this day, solar ELCC is  $76/507=15\%$ . In other words, installed capacity of 507 MW reduces the peak demand by 76 MW. Put another way, the effect solar had on the peak is that it reduced peak by 76 MW.

As we install more solar, its impact on reducing peak will be zero, because the peak demand hour has already moved to 9 p.m., after sunset when solar stops producing. In that case, the incremental ELCC of solar after 507 MW is zero. This example shows just one hypothetical day. In reality, ELCC calculations are computed after thousands of simulations under different load and weather conditions.

ELCC of wind and other resources follows the same declining pattern with more resource additions. As more wind is added, the incremental contribution of the next wind project to reduce peak demand continues to decline. Figure 49 shows the ELCC values of solar, wind and four-hour storage through time as computed by Astrape, which we used for this IRP. As utilities in Colorado add more of these resources over time, their ELCC contributions diminish.



**Figure 49.** *Platte River ELCC values of solar, wind and four-hour storage*

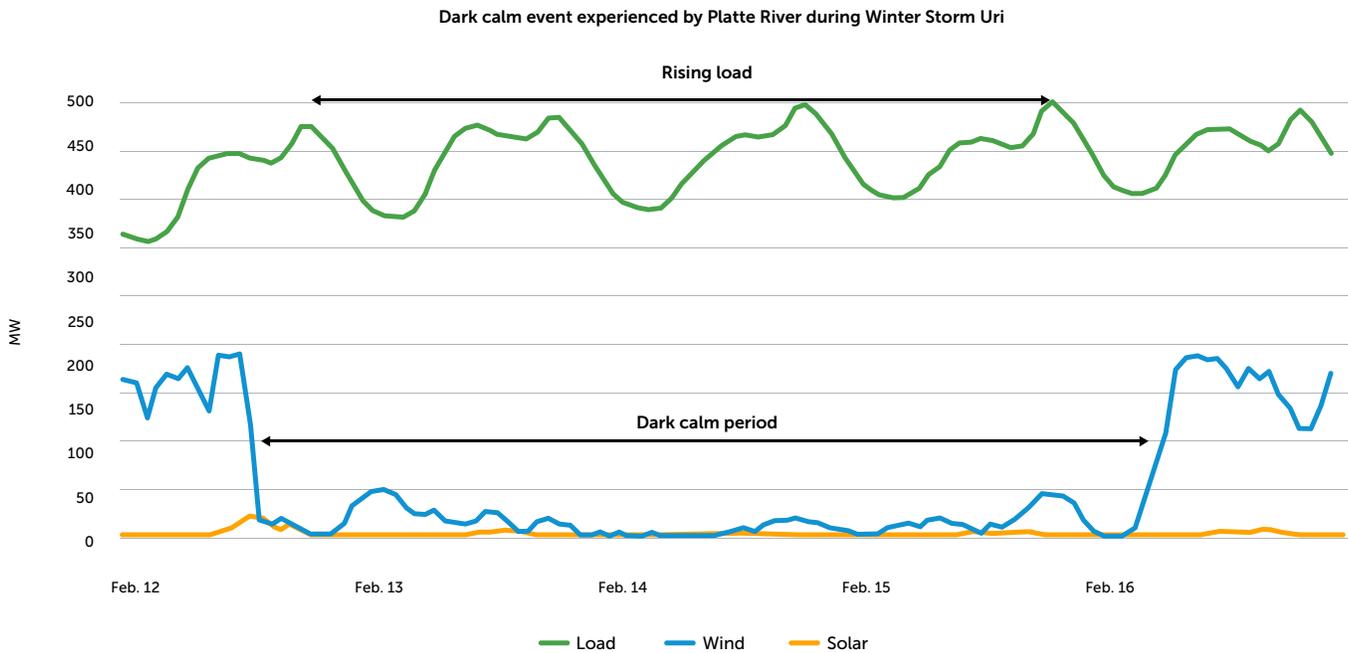
Table 19 shows ELCC values of longer duration battery storage and some DER technologies, as computed by Astrape and used by Platte River in this IRP. The installation of more resources of the same type reduces that resource type’s ELCC. For example, the ELCC of distributed solar is 8.5% if Colorado utilities install 500 MW. It drops to 5.8% with 4,000 MW installed.

Technology	Penetration (MW)	Average ELCC (%)	Marginal ELCC (%)
8-hour batteries	500	92.7%	91.6%
8-hour batteries	1,000	90.5%	84.4%
8-hour batteries	1,500	87.0%	75.6%
100-hour batteries	500	92.7%	91.6%
100-hour batteries	1,000	91.9%	90.8%
100-hour batteries	1,500	91.4%	90.0%
Distributed generation solar	500	8.5%	7.9%
Distributed generation solar	1,000	8.0%	7.2%
Distributed generation solar	2,000	7.2%	5.8%
Distributed generation solar	4,000	5.8%	2.9%
Beneficial electrification	100	6.9%	7.4%
Beneficial electrification	200	7.3%	8.2%
Beneficial electrification	300	7.8%	9.0%
Electric vehicles	100	32.0%	33.6%
Electric vehicles	200	33.8%	37.3%
Electric vehicles	300	35.7%	41.0%
Demand response	100	92.3%	87.3%
Demand response	200	87.1%	77.8%
Demand response	300	82.6%	70.4%

**Table 19.** *ELCC values of long-duration energy storage and DERs*

### 7.3.2.4 Extreme weather and dark calm modeling

Winter Storm Uri, which brought blackouts to Texas and stressed power supply across a much wider area, also impacted power supply in our area. Due to extremely cold weather for many days, demand for electricity continued to rise. Additionally, there was very little renewable generation for almost 80 hours during Feb. 12-16, 2021, as shown in Figure 50.



**Figure 50.** Dark calm event experienced by Platte River during Winter Storm Uri

During this 2021 dark calm, Platte River was able to serve its customers' load reliably because dispatchable coal resources were available. But after coal units retire in 2030, we may experience similar or even more severe dark calms. A fundamental requirement of an IRP is to develop supply portfolios that will be reliable under varying conditions of weather, previously experienced or not. This led us to hire ACES to conduct a study on extreme weather and dark calm events.<sup>28</sup>

ACES reviewed hourly weather profiles for 70 locations west of Mississippi for the past five decades (1973-2019) to estimate the frequency, duration and depth of extreme weather and dark calm events. Since these events are uncommon, ACES reviewed weather data across a wide region and over a long period of time to enhance confidence in the findings. Figure 51 shows locations of the airports where data was collected.

<sup>28</sup> <https://www.prpa.org/wp-content/uploads/2023/04/2024IRP-Extreme-weather-events-and-Dark-Calm-Analysis-by-ACES.pdf> In 2022, Platte River filed a voluntary CEP with the state of Colorado, laying out a plan to reduce its greenhouse gas emissions by at least 80% by 2030 (compared to a 2005 base line).



**Figure 51.** Locations of extreme weather events

### 7.3.2.5 Extreme weather events

The study found the following durations and frequencies of heat and cold waves:

Heat wave summary – west region						
Number of hours	48	72	96	120	144	168
Events per year	0.47	0.02	0.09	0.04	0.021	0.043

**Table 20.** Heat wave summary - west region

This means every other year, there is a heat wave lasting two days and every 11th year, there is a heat wave lasting four days.

Cold wave summary – west region													
Number of hours	48	72	96	120	144	168	192	216	240	264	288	312	336
Events per year	4.9	1.7	0.9	0.4	0.17	0.08	0	0	0	0	0	0	0

**Table 21.** Cold wave summary - west region

This data shows cold waves are more common with five two-day events every year and a weeklong event almost every 12th year.

The study also found that load, power and gas prices rise during these extreme events and noted these increases during winter storms Uri and Elliot and the 2020 summer heat wave in the Pacific Northwest. Because our focus with extreme weather modeling is on reliability, we assessed how extreme weather impacts load only. The study found that during these events, on average, the load could increase by about 10% relative to the normal load for that time of year. So, for reliability assessments during extreme weather, we increased the hourly load by 10%.

### 7.3.2.6 Dark calm events

Frequency and duration of dark calm events was assessed for the MISO North , covering parts of Illinois, Indiana, Wisconsin and Michigan; MISO Central, covering parts of Minnesota, Iowa and North Dakota; and the Northwest portion of the Electric Reliability Council of Texas (ERCOT). Table 22 shows the frequency and duration of different levels of dark calm events.



Dark calm events by location				
% of full output	48 hours	72 hours	96 hours	120 hours
<b>MISO Central</b>				
5%	3.0	1.25	0.5	0.25
10%	11.2	5.6	2.4	2.0
15%	6.2	11.4	3.8	4.8
<b>MISO North</b>				
5%	1.0	1.0	0.67	0.0
10%	5.0	1.75	0.5	1.0
15%	2.2	3.0	1.2	2.0
<b>Northwest ERCOT</b>				
10%	3.8	1.0	0.2	0.2
15%	3.2	3.4	3.0	1.2

**Table 22.** *Dark calm events by location*

As shown in Table 22, a dark calm event in MISO Central, where the output of renewable drops to 5% of total generation occurs:

- Three times during the year for two days every year
- Once per year for three consecutive days
- Every other year for four consecutive days
- Every four years for five consecutive days

Dark calm events where output of renewables drops to 10% of total generation are more frequent than events where renewable

generation is only 5% of total generation. Dark calm events are less intense and less frequent in MISO North and Northwest ERCOT.

In the Plexos model, we averaged the two 5% rows for MISO Central and MISO North. Multiplying the probability of an event's occurrence with its duration yields the expected outage hours in a given year for that event. For example, as illustrated in Table 23, an average of two events with a duration of 48 hours means any given year would expect a total of 96 dark calm hours because the events last two days.

Since the events are non-additive, we sum all the expected hours to find the total expected dark calm hours in a year. In this case, an average year would see a total of 248 hours of dark calm spread across events of different durations.

Dark calm duration (hours)	48	72	96	120	Total dark calm hours
Average # of dark calm events across all regions (5% of full output)	2.000	1.125	0.585	0.125	
Expected dark calm hours per year	96	81	56.16	15	<b>248.16</b>

**Table 23.** *Dark calm event duration and frequency*

### 7.3.2.7 Transmission planning

Platte River conducts annual transmission assessment studies to plan for a system that adequately supports both short and long-term load obligations to the owner communities. The studies use transmission network modeling software and integrate forecasted owner community loads, existing and planned generation, and loads and generation from neighboring utilities.

Short-term studies evaluate system needs under the current transmission network configuration, integrating projected short-term load and generation forecasts. Evaluating long-term transmission needs includes forecasting long-term load and generation forecasts with both the current transmission system and planned transmission additions.

The study objectives are for the transmission system to perform reliably during extreme contingency situations, heavy or light load conditions and fault events. If a study identifies network deficiencies, further analysis follows to determine network expansion options to mitigate those deficiencies. Transmission studies are conducted during annual internal assessment activities, along with collaborative studies with regional transmission planning committees.

### 7.3.3 Need for new resources

As explained in chapter 5, we forecast our future energy needs as annual peak demand (maximum demand in any hour) and total annual energy for every hour of the year. For supply-side planning, we adjust these values with DER contribution from our customers. The net peak demand and energy demand are what Platte River needs to plan for through this IRP process. As discussed earlier in this chapter, Platte River plans to meet its future peak demand with 19.9% PRM to protect supply reliability. We also discussed that renewable and energy limited resources contribute less ELCC capacity toward the peak demand than their maximum or nameplate capacity.

Figure 52 shows the capacity requirements and capacity contributions from the existing and committed resources.

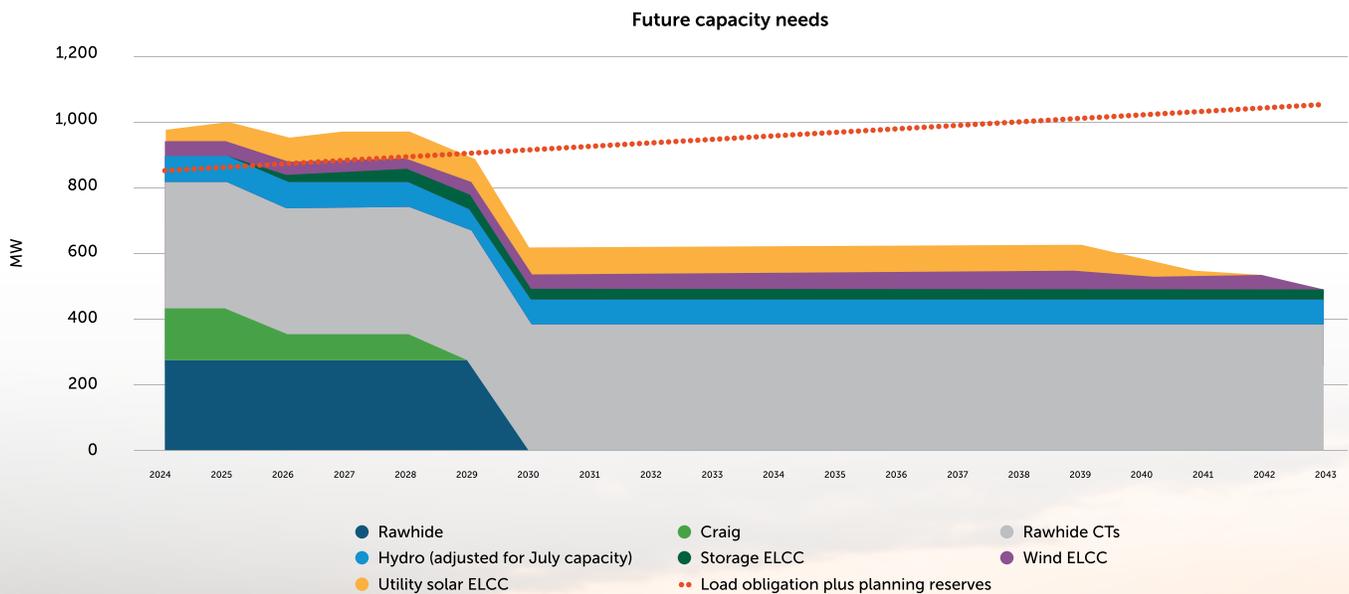
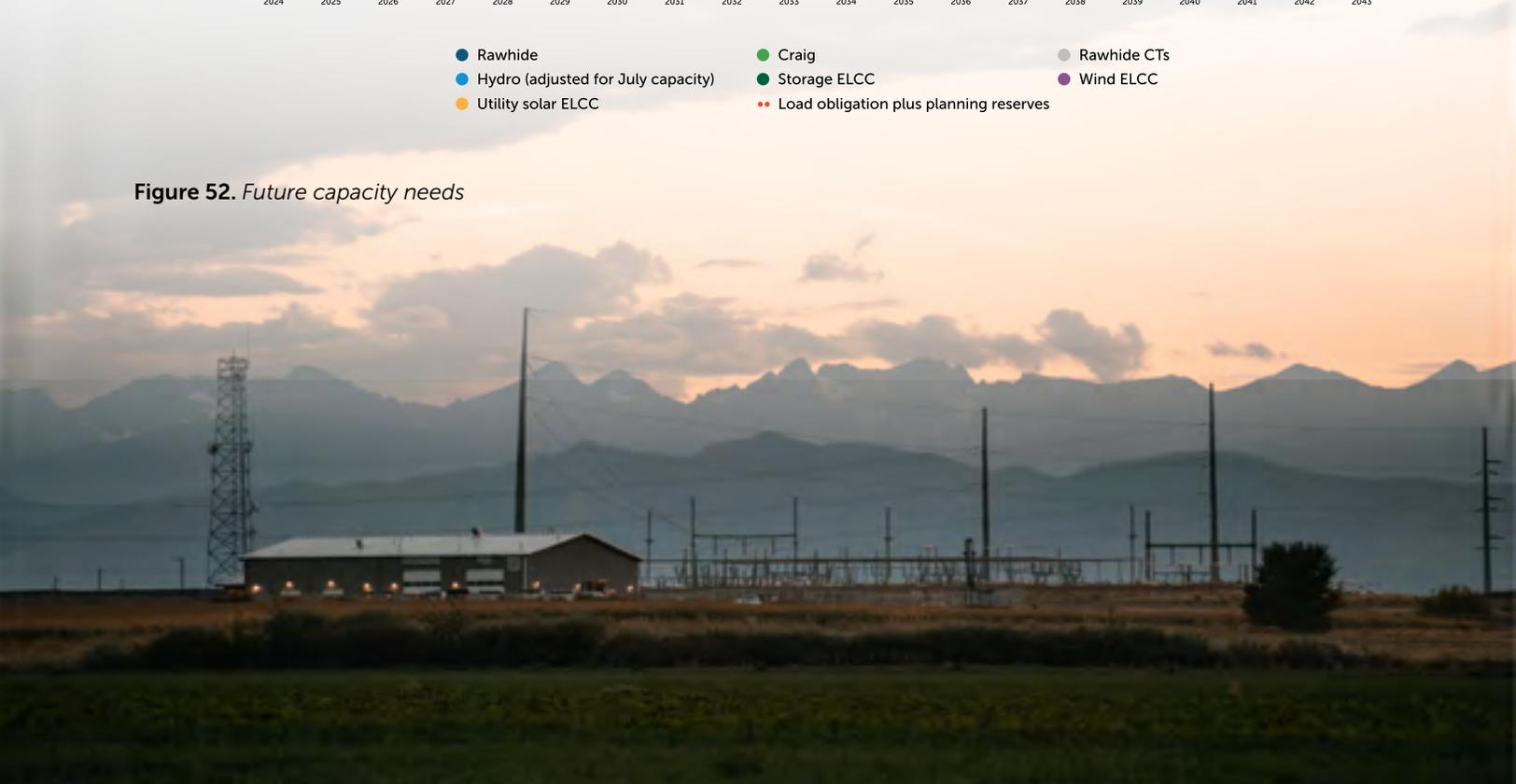
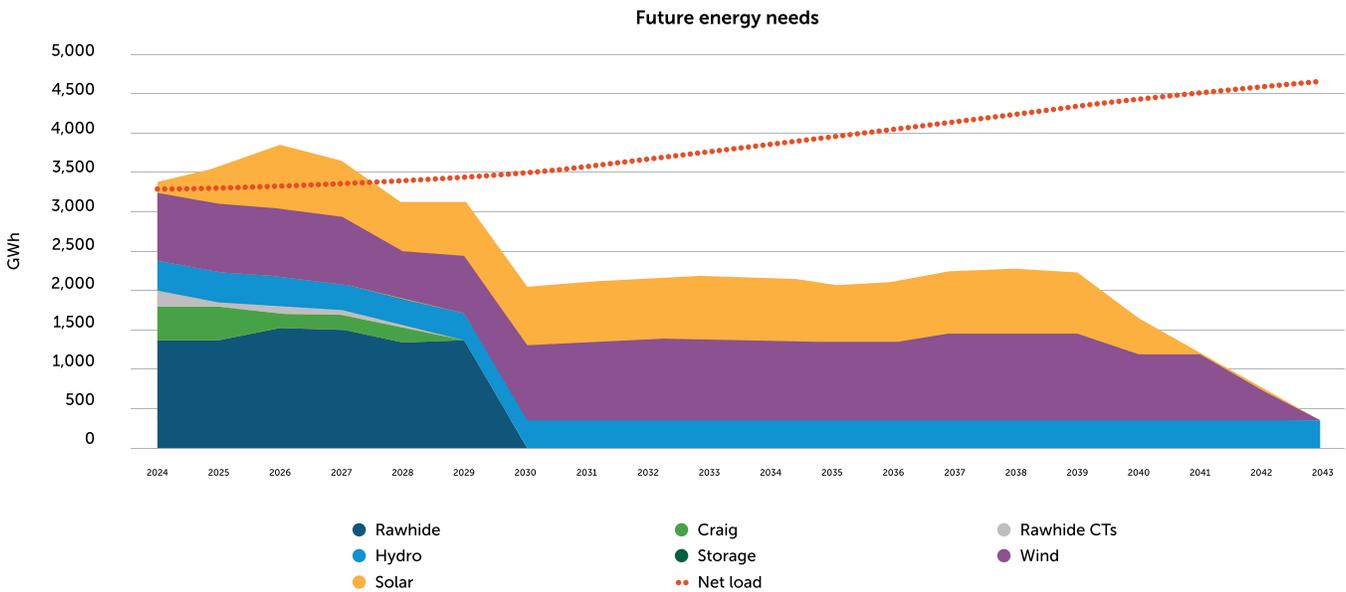


Figure 52. Future capacity needs



The dotted red line shows capacity requirements, while the area chart shows the capacity available. By 2029, following the retirements of Craig coal units, Platte River would need to build some new capacity, and by 2030, with the retirement of Rawhide coal plant, the additional capacity requirement rises to about 200 MW. The gap continues to expand as our load continues to increase and when our existing wind and solar PPAs reach their maturation dates. The IRP process offers recommendations to fill this gap with the lowest cost, least-emitting reliable resources.

Figure 53 shows similar chart depicting the energy deficit that will need to be filled in this IRP. Note small changes in renewable energy from year to year are due to projected changes in excess or “dumped” renewable generation.



**Figure 53.** Future energy needs

Although capacity and energy gaps appear in 2030, Platte River plans to bring new resources online before 2030. This would give us time to test the availability and reliability of our new portfolio before retiring the last coal plant by the end of 2029.

## 7.4 Future portfolios

The portfolios selected for this IRP are designed to capture the range of potential paths available to Platte River as it transforms its generation portfolio and strives to meet the RDP goal. Reliability is the only firm constraint common to all portfolios. Other financial, operational and environmental metrics are optimized within the unique constraints of each portfolio.

Due to PRM requirements and to support reliability during dark calm events, Platte River keeps its existing combustion turbines in all portfolios. All portfolios emit some CO<sub>2</sub> in 2030 because dispatchable noncarbon options will not be available by 2030, so thermal units are dispatched to balance the system during shortages. Portfolios that build new dispatchable thermal generation assume a blend 50% green hydrogen fuel by 2035 to reduce CO<sub>2</sub> emissions. All dispatchable thermal generation is assumed to switch to 100% green hydrogen by 2040 and reach zero CO<sub>2</sub> emissions. No new dispatchable thermal generation is allowed after 2030 and the IRP assumes long-duration energy storage becomes available in 2035. All portfolios assumed that future electricity prices would also include carbon taxes. Below is a brief description of all the portfolios.

### 7.4.1 No new carbon

In this portfolio, Platte River cannot add new thermal generation. Wind, solar and four-hour storage are the only new resource additions available until 2035, when long-duration energy storage is assumed to also become available. This portfolio is designed to test the feasibility of relying on the existing combustion turbines to maintain reliability, without adding new thermal generation.

### 7.4.2 Minimal new carbon

This portfolio is built to add minimal amount of new thermal generation. It adds only 80 MW of new dispatchable thermal generation.

### 7.4.3 Carbon-imposed cost

This portfolio is built with the cost of carbon assigned to the dispatch cost of all thermal units. This additional cost, assigning a dollar value to the externalities associated with emitting CO<sub>2</sub>, disincentivizes the construction and use of carbon-emitting resources unless it is more cost effective than other options after accounting for the social cost of carbon. Specifically, this is a least-cost portfolio where the assumed cost carbon emissions have been internalized into the optimization process.

## 7.4.4 Optimal new carbon

This portfolio is a balance between the additional new carbon and carbon-imposed cost portfolios in terms of reliability and cost, building 200 MW of new thermal generation. This portfolio is optimal to support reliability in all conditions, as dark calm and extreme weather events continue to become more severe, as they have in the recent past.

## 7.4.5 Additional new carbon

This portfolio is the result of a least-cost optimization. The model builds the lowest-cost portfolio that meets reliability standards, but adds no additional constraints to guide resource selection or operation.

## 7.5 Methodology

Developing future power supply portfolios is a multi-step, iterative process. Figure 54 illustrates the initial steps and the subsequent iteration through the remaining steps.

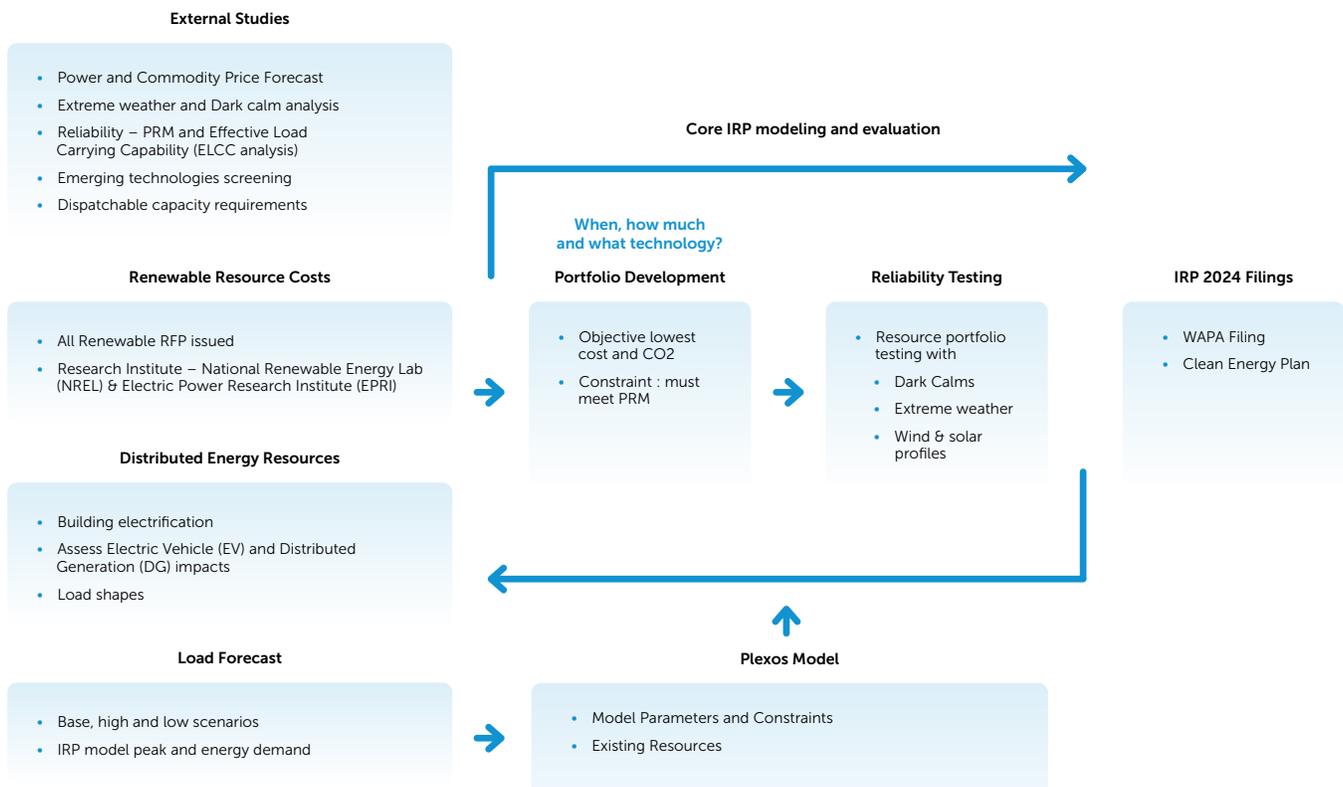


Figure 54. IRP process



### 7.5.1 Multi-step portfolio selection methodology

**Data collection and review:** Gather data on existing resources, including their performance and their expected operational lives; develop power and fuel price forecasts; review existing and potential future environmental regulations. These results provide a first step in understanding the planning landscape for the IRP.

**Demand forecasting:** Estimate future electricity demand, considering factors such as population growth, economic trends and technological advancements to project the energy needs over the planning horizon.

**DER forecasting:** Forecast new sources of demand, such as beneficial electrification and electric vehicles as well as additional demand-side resources, including customer-sited storage, rooftop solar, demand response and other programs.

**Technology assessment:** Evaluate the performance, costs, and environmental impacts of various energy technologies, including renewable energy sources, dispatchable thermal resources and energy storage. Based on the results of this high-level evaluation, Platte River can eliminate some technologies from consideration.

**Stakeholder engagement:** Collect feedback from a broad range of stakeholders. Community members, local businesses and advocacy



organizations are invited to offer their ideas and raise any concerns they have with the IRP process. This collaborative approach helps portfolios reflect the range of interests and priorities in the communities we serve.

## 7.5.2 Portfolio iterations

**Optimization modeling:** Use Plexos to develop and evaluate different portfolios of energy resources. Each portfolio is the result of a unique mix of inputs and constraints designed to test different aspects of the planning criteria, such as financial sustainability or environmental responsibility.

**Reliability testing:** Conduct reliability testing to identify uncertainties and potential challenges associated with different resource options. With high penetration of variable generation, the most critical risk tests quantify the system's exposure to dark calms or extreme weather. Platte River also reviews potential challenges associated with excessive energy length (too much energy produced compared to load) in a region expected to add substantial amounts of renewable energy in the future.

**Sensitivity analysis:** Explore how different external factors, such as fuel and market prices or emissions, might influence the performance of the portfolios. This helps develop plans that should be resilient under a range of future outcomes.

## 7.6 Reliability testing of portfolios

Because reliability is a foundational pillar, we first make sure each candidate portfolio is sufficiently reliable. As a starting point, a least-cost portfolio is developed to fill the capacity and energy gaps identified above while meeting the PRM requirement for every year of the planning horizon. Meeting the annual PRM requirement while applying the ELCC to energy-limited resources is useful, but does not test or guarantee reliability during extreme weather events or dark calms. So we conducted additional reliability testing through the Monte Carlo functionality in Plexos to understand how the portfolios might behave under stress conditions. Using the data from the extreme weather report supplied by ACES and historical weather data from Vaisala, we modeled different system conditions with the following variables:

1. **Weather:** Wind and solar profiles reflecting conditions from 1997-2019 (hourly profiles for 24 years), drawn with equal probability across the suite of simulations. In our runs, with 504 iterations, each weather year was experienced 21 times.
2. **Thermal unit outages:** The software randomly draws the timing of thermal unit outages. The duration of outages is also hypothetical, but the software does align the random outages with the known long-term forced outage rate over the course of many draws.
3. **Load forecast error:** Each iteration simulated a potential deviation from the near-term load forecast. This represents a shift in load drivers, such as population changes or economic indicators, over the one-to-four-year horizon, which is too short for the utility to respond to. The system, as built, would need to cover these near-term divergences before new resources could be brought online in response. For this IRP, Table 24 summarizes the potential load forecast error outcomes.

LFE	Probability
-4%	7.26%
-2%	24.10%
0%	37.28%
2%	24.10%
4%	7.26%

**Table 24.** Potential load forecast error outcomes

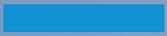
- 
4. **Dark calm events:** Based on observed historical events, the model simulated weather events with impacts on both load and weather-dependent generation. These events could last between one and five days, with a two-day event being the most common. Often, dark calm events occur with extreme weather events. In any year, the system would expect to experience a total of 248 hours of extreme weather conditions distributed across several events. As with thermal outages, specific years could experience higher or lower than average dark calm outages with the long-term average converging to the expected value over many iterations. Across all 504 iterations of our reliability modeling, the dark calm hours in a year varied from a low of 119 hours to a high of 458 hours. Specific details on the impact to wind, solar and load are described below.
- a. **Load:** Load is modeled to increase by 10% during the event, which is consistent with data seen in other regions during extreme weather events. This is primarily driven by increased heating load during winter storms while cooling load is expected to increase during heat dome events in the summer. This increase captures the load already embedded in the load forecast.
  - b. **Building heating:** During extreme winter storms, some new load from heat pumps is expected to shift to much less efficient electrical resistance heating as temperatures drop below their operating ranges. This increase in load is captured individually and is quantified by the consultant who supplied the beneficial electrification forecast.
  - c. **Solar:** During the winter months, solar generation during a dark calm averages 5% of its nameplate. These generators can experience a variety of issues including snow cover or icing, overcast skies or debris or dust buildup due to high winds. In the summer months, solar output during a dark calm event averages 10% because summer outages are often caused by extended overcast weather.
  - d. **Wind:** During the winter months, wind generation during a dark calm averages 5% of its nameplate. This reduced production is primarily due to blade icing, but overspeed (wind too strong to safely operate turbines) also drives some outages. In the summer months, output during a dark calm event also averages 5%, as summer wind droughts, especially during heat dome events, are common.

## 7.7 Modeling tool

Platte River used the Plexos simulation and modeling tool for the 2024 IRP. Plexos is an economic dispatch and capacity expansion model developed by Energy Exemplar ([www.energyexemplar.com](http://www.energyexemplar.com)).

# 08

## IRP study results



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This chapter presents the modeling results for each portfolio, with comparisons of their most important metrics including cost, CO<sub>2</sub> emission reductions and renewable energy penetration—metrics that align with Platte River’s foundational pillars of financial sustainability and environmental responsibility. As noted previously, every portfolio considered in this IRP meets our reliability criteria (another foundational pillar).

## 8.1 Summary of five portfolios

Every portfolio assumed a common starting point of existing resources plus new, near-term resource additions from recently signed agreements and solicitations under development. These are considered “committed” resources and the IRP process considers them “given,” just like existing resources. These near-term additions represent Platte River’s best estimate of solicitation results. In the current environment, project timelines, pricing and size are uncertain and subject to change. Platte River remains flexible and will adjust future capacity acquisitions to compensate for changes to current acquisitions.

### 8.1.1 Load forecast with DER assumptions

Customer load and DER projections for all the portfolios are similar. Therefore, the various portfolios primarily represent different supply-side options. Load forecast and DER projections are discussed in detail in chapter 5. Figures 37 and 38 in Chapter 5 show annual peak and energy forecasts and DER impact through the planning period. Figures 55 and 56 illustrate annual peak and energy forecasts for quick reference.

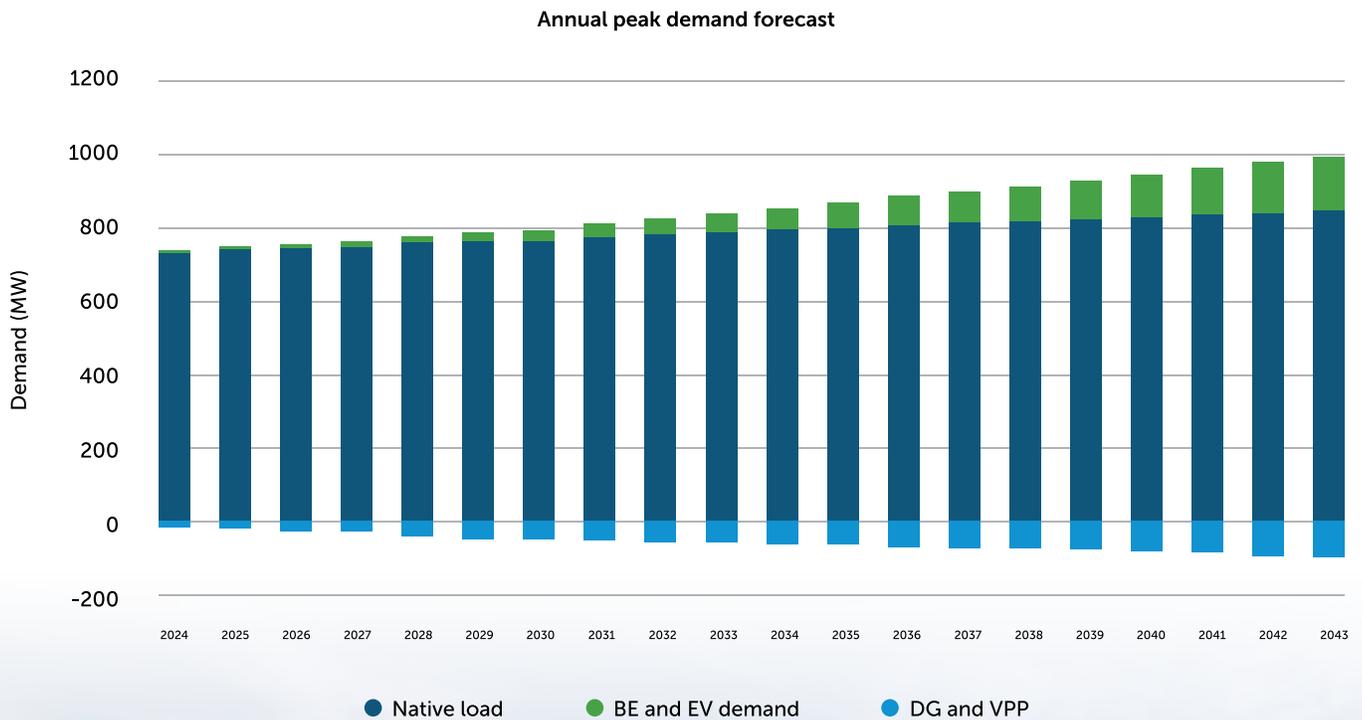
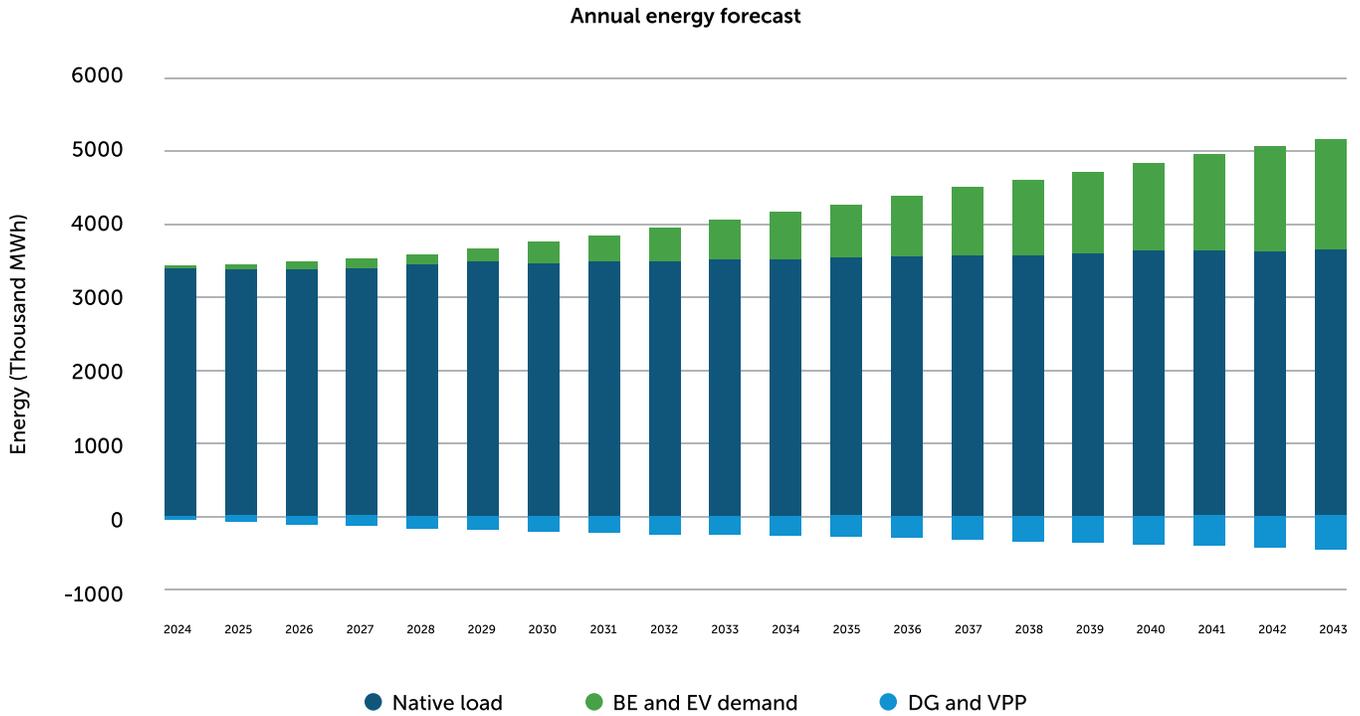


Figure 55. Annual peak demand forecast





**Figure 56.** Annual energy forecast

Figures 55 and 56 illustrate that DERs are projected to grow much faster than the base load. Distributed generation, which is largely rooftop solar, reduces base peak load by 7% in 2030 and 10% by 2040. The growth of building beneficial electrification and EVs is even faster. Together, these add about 8% to the annual energy demand by 2030 and 34% by 2040.

Table 25 summarizes the utility-scale resources common to all portfolios before Platte River developed and optimized its expansion plans. As described in earlier sections, there are also DER resources embedded in every portfolio that are not subject to optimization during the modeling process.

	Existing resources MWs	Near-term solicitation MWs	Total MWs
Wind	231	250	481
Solar	52	300	352
Battery energy storage systems	1	50	51
Long-duration storage	0	10	10

**Table 25.** Existing and committed resources



Additionally, the following assumptions are common to all the portfolios:

- No new thermal generation is constructed after 2030 and all subsequent resource additions will be noncarbon-emitting resources.
- Long-duration energy storage technology is available from 2035 onwards.
- New thermal generation uses a fuel blend containing 50% green hydrogen from 2035 onwards.
- All thermal generation uses 100% green hydrogen fuel from 2040 onwards, eliminating CO<sub>2</sub> emissions.

The portfolios developed in this IRP cover a broad range of potential pathways Platte River might consider as it decarbonizes its power supply portfolio. We are committed to completely retire coal generation by the end of 2029 so the expansion plans include aggressively adding renewable energy. Each portfolio adds 600-800 MW of new renewable energy capacity, although the mix

between wind and solar may be different in each portfolio as the optimization seeks to minimize cost while meeting reliability metrics.

Platte River also models additional thermal units and storage to complement its renewable energy acquisitions and comply with reliability criteria. The main differences between the portfolios are the choices about adding thermal resources and storage.

Table 26 summarizes the resources added during the resource acquisition period, as well as the final buildout at the end of the planning horizon in 2043. Note the solar and wind energy additions closely converge by 2043, with only a 100 MW capacity spread between the highest and lowest additions. This is because all portfolios depend heavily on renewable energy, with thermal energy largely acting as a reliability backstop.

	No new carbon	Minimal new carbon	Carbon-imposed cost	Optimal new carbon	Additional new carbon (lowest cost)
<b>2024-2029 incremental additions (MWs)</b>					
Wind	300	300	400	400	300
Solar	450	500	350	300	300
Four-hour storage	2,850	1,050	275	175	100
Long-duration storage	10	10	10	10	10
Dispatchable thermal	0	80	160	200	240
<b>Final 2043 Portfolio (MWs)</b>					
Wind	885	885	985	885	985
Solar	600	600	550	600	450
Four-hour storage	2,850	1,100	400	275	175
Long-duration storage	10	160	10	160	110
Dispatchable thermal	0	80	160	200	280

**Table 26.** Summary of five portfolios

Additional detailed tables are provided in the following section for each portfolio, showing annual capacity additions by each category, further divided into new and existing resources.

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## 8.2 Individual portfolio details

In this section we describe notable features of each portfolio and show the 20-year projections for each by year and by resource type.

### 8.2.1 No new carbon portfolio

This portfolio does not add any new thermal generation but continues to operate the existing natural gas CTs at Rawhide. To serve its future energy and reliability needs, Platte River adds an incremental 300 MW of wind and 450 MW of solar. To maintain reliability, the portfolio relies on four-hour battery storage with a total addition of 2,850 MW by 2029.

The substantial buildout of four-hour storage in the early years eliminates the need for additional storage during the planning period. Table 27 shows annual resource additions over the planning horizon for this portfolio.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	
Coal	431	431	354	354	354	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	81	78	75	72	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Frame units (existing)	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Aeroderivative units (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	30	0	0	0
Solar (new)	0	150	300	300	450	450	450	450	500	500	500	500	500	550	600	700	550	450	550	600	600
Wind	231	231	231	231	231	231	231	291	291	291	285	285	285	285	285	285	225	225	225	225	0
Wind (new)	0	0	0	200	300	300	360	300	300	300	400	400	400	400	400	400	560	660	660	885	885
Storage 4-hr	2	2	27	52	1452	2852	2852	2852	2852	2852	2852	2852	2852	2852	2852	2852	2850	2850	2850	2850	2850
Storage LT	0	0	0	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Solar DER	46	62	83	105	126	141	155	169	180	190	200	210	223	236	251	266	282	299	318	337	337
Storage DER	3	6	10	17	24	32	39	47	54	63	70	76	82	86	90	94	101	108	115	123	123
<b>Total</b>	<b>1234</b>	<b>1399</b>	<b>1520</b>	<b>1772</b>	<b>3457</b>	<b>4806</b>	<b>4607</b>	<b>4628</b>	<b>4698</b>	<b>4716</b>	<b>4827</b>	<b>4843</b>	<b>4861</b>	<b>4929</b>	<b>4997</b>	<b>5117</b>	<b>5088</b>	<b>5090</b>	<b>5186</b>	<b>5263</b>	<b>5263</b>

**Table 27.** No new carbon portfolio annual resource additions (in MW)

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## 8.2.2 Minimal new carbon portfolio

This portfolio allows only 80 MW of new thermal generation. Due to this constraint, this portfolio requires a substantial amount of four-hour storage by 2030, as much as 1,050 MW. This portfolio also adds 300 MW of wind and 500 MW of solar by 2030. This is the most additional solar among all the portfolios, complementing the four-hour storage needed to cover daily peaks. After 2030, more wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 28 shows annual resource additions over the planning horizon for this portfolio.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	
Coal	431	431	354	354	354	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	81	78	75	72	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Frame units (existing)	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Aeroderivative units (new)	0	0	0	0	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Solar	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	30	0	0	0
Solar (new)	0	150	300	300	450	500	500	500	500	500	550	550	600	700	700	750	600	500	600	600	600
Wind	231	231	231	231	231	231	231	291	291	291	285	285	285	285	285	285	225	225	225	225	0
Wind (new)	0	0	0	200	300	300	360	300	300	300	300	400	400	400	400	400	560	660	660	660	885
Storage 4-hr	2	2	27	52	552	1052	1052	1052	1052	1052	1052	1052	1052	1052	1052	1052	1050	1050	1075	1100	1100
Storage LT	0	0	0	0	10	10	10	10	10	10	10	10	10	10	10	60	60	110	110	110	110
Solar DER	46	62	83	105	126	141	155	169	180	190	200	210	223	236	251	266	282	299	318	318	337
Storage DER	3	6	10	17	24	32	39	47	54	63	70	76	82	86	90	94	101	108	115	115	123
<b>Total</b>	<b>1234</b>	<b>1399</b>	<b>1520</b>	<b>1772</b>	<b>2637</b>	<b>3136</b>	<b>2937</b>	<b>2958</b>	<b>2978</b>	<b>2996</b>	<b>3057</b>	<b>3173</b>	<b>3241</b>	<b>3359</b>	<b>3427</b>	<b>3497</b>	<b>3468</b>	<b>3520</b>	<b>3641</b>	<b>3693</b>	<b>3693</b>

**Table 28.** Minimal new carbon portfolio annual resource additions (in MW)

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### 8.2.3 Carbon-imposed cost portfolio

The carbon-imposed cost attempts to measure the economic and environmental cost of CO<sub>2</sub> for society. Due to the increased cost for CO<sub>2</sub> emissions, this portfolio limits the addition of new dispatchable thermal units to 160 MW and favors four-hour battery storage, with 275 MW of new capacity. As with other plans, wind and solar are the primary energy sources, with 400 MW of new wind and 350 MW of new solar by 2030. After 2030, additional wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 29 shows annual resource additions over the planning horizon for this portfolio.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Coal	431	431	354	354	354	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	81	78	75	72	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Frame units (existing)	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Aeroderivative units (new)	0	0	0	0	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160
Solar	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	30	0	0
Solar (new)	0	150	300	300	300	350	350	350	400	450	450	450	450	450	450	500	450	450	500	550
Wind	231	231	231	231	231	231	231	291	291	291	285	285	285	285	285	285	225	225	225	0
Wind (new)	0	0	0	200	400	400	460	400	400	400	400	500	500	500	600	600	660	760	760	985
Storage 4-hr	2	2	27	52	127	277	277	302	327	352	377	377	377	377	377	377	375	375	375	400
Storage LT	0	0	0	0	10	10	10	10	10	10	10	60	60	60	60	60	110	160	160	160
Solar DER	46	62	83	105	126	141	155	169	180	190	200	210	223	236	251	266	282	299	318	337
Storage DER	3	6	10	17	24	32	39	47	54	63	70	76	82	86	90	94	101	108	115	123
<b>Total</b>	<b>1234</b>	<b>1399</b>	<b>1520</b>	<b>1772</b>	<b>2242</b>	<b>2391</b>	<b>2192</b>	<b>2238</b>	<b>2333</b>	<b>2426</b>	<b>2462</b>	<b>2628</b>	<b>2646</b>	<b>2664</b>	<b>2782</b>	<b>2852</b>	<b>2873</b>	<b>3025</b>	<b>3071</b>	<b>3173</b>

**Table 29.** Carbon-imposed cost portfolio annual resource additions (in MW)

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## 8.2.4 Optimal new carbon portfolio

This portfolio adds 200 MW of new dispatchable thermal resources and 175 MW of new battery storage as it balances capacity support across both thermal and batteries. Like the carbon-imposed cost portfolio, this portfolio adds 400 MW of wind but slightly less solar, with 300 MW of new capacity by 2030. After 2030, additional wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 30 shows annual resource additions over the planning horizon for this portfolio.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Coal	431	431	354	354	354	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	81	78	75	72	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Frame units (existing)	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Aeroderivative units (new)	0	0	0	0	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Solar	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	30	0	0
Solar (new)	0	150	300	300	300	300	300	300	300	300	400	400	400	400	400	450	450	450	550	600
Wind	231	231	231	231	231	231	231	291	291	291	285	285	285	285	285	285	225	225	225	0
Wind (new)	0	0	0	200	400	400	460	400	400	400	400	500	500	500	600	600	660	660	660	885
Storage 4-hr	2	2	27	52	102	177	177	202	227	252	252	252	252	252	252	252	250	250	250	275
Storage LT	0	0	0	0	10	10	10	10	10	10	10	60	60	60	60	60	110	160	160	160
Solar DER	46	62	83	105	126	141	155	169	180	190	200	210	223	236	251	266	282	299	318	337
Storage DER	3	6	10	17	24	32	39	47	54	63	70	76	82	86	90	94	101	108	115	123
<b>Total</b>	<b>1234</b>	<b>1399</b>	<b>1520</b>	<b>1772</b>	<b>2257</b>	<b>2281</b>	<b>2082</b>	<b>2128</b>	<b>2173</b>	<b>2216</b>	<b>2327</b>	<b>2493</b>	<b>2511</b>	<b>2529</b>	<b>2647</b>	<b>2717</b>	<b>2788</b>	<b>2840</b>	<b>2936</b>	<b>3038</b>

**Table 30.** Optimal new carbon portfolio annual resource additions (in MW)

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### 8.2.5 Additional new carbon portfolio

The primary objective of this portfolio is to minimize costs. To do so, this portfolio relies on 240 MW of new dispatchable thermal resources to provide firm capacity. Renewables still supply most of the energy, with 300 MW of new wind and 300 MW of new solar by 2030. To help manage the renewable energy, this portfolio adds 100 MW of storage. After 2030, additional wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 31 shows annual resource additions over the planning horizon for this portfolio.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Coal	431	431	354	354	354	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	81	78	75	72	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Frame units (existing)	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Aeroderivative units (new)	0	0	0	0	240	240	240	240	240	240	240	240	240	240	240	240	240	280	280	280
Solar	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	30	0	0
Solar (new)	0	150	300	300	300	300	300	300	300	300	300	350	350	350	350	400	400	350	400	450
Wind	231	231	231	231	231	231	231	291	291	291	285	285	285	285	285	285	225	225	225	0
Wind (new)	0	0	0	200	300	300	360	300	300	300	500	500	500	600	600	600	660	760	760	985
Storage 4-hr	2	2	27	52	52	102	102	102	127	152	152	152	152	152	152	152	150	150	150	175
Storage LT	0	0	0	0	10	10	10	10	10	10	10	60	60	60	60	60	110	110	110	110
Solar DER	46	62	83	105	126	141	155	169	180	190	200	210	223	236	251	266	282	299	318	337
Storage DER	3	6	10	17	24	32	39	47	54	63	70	76	82	86	90	94	101	108	115	123
<b>Total</b>	<b>1234</b>	<b>1399</b>	<b>1520</b>	<b>1772</b>	<b>2147</b>	<b>2146</b>	<b>1947</b>	<b>1968</b>	<b>2013</b>	<b>2056</b>	<b>2267</b>	<b>2383</b>	<b>2401</b>	<b>2519</b>	<b>2537</b>	<b>2607</b>	<b>2678</b>	<b>2770</b>	<b>2816</b>	<b>2918</b>

**Table 31.** Additional new carbon portfolio annual resource additions (in MW)

## 8.3 Comparative analysis of portfolios

### 8.3.1 Portfolio costs

As part of “least-cost” resource planning and optimization, the Plexos model captured relevant incremental costs associated with building, acquiring and operating the power supply portfolios over the 20-year planning horizon. Platte River excluded other costs from the model, like depreciation of existing transmission and generation infrastructure, cost of DERs and administrative and general costs. While these additional costs are important, they are not relevant to the capacity expansion planning process. The cost comparison presented here is not a rate forecast because it does not capture the full revenue requirement needed to set rates. Figure 57 compares the annual cost of all five portfolios.

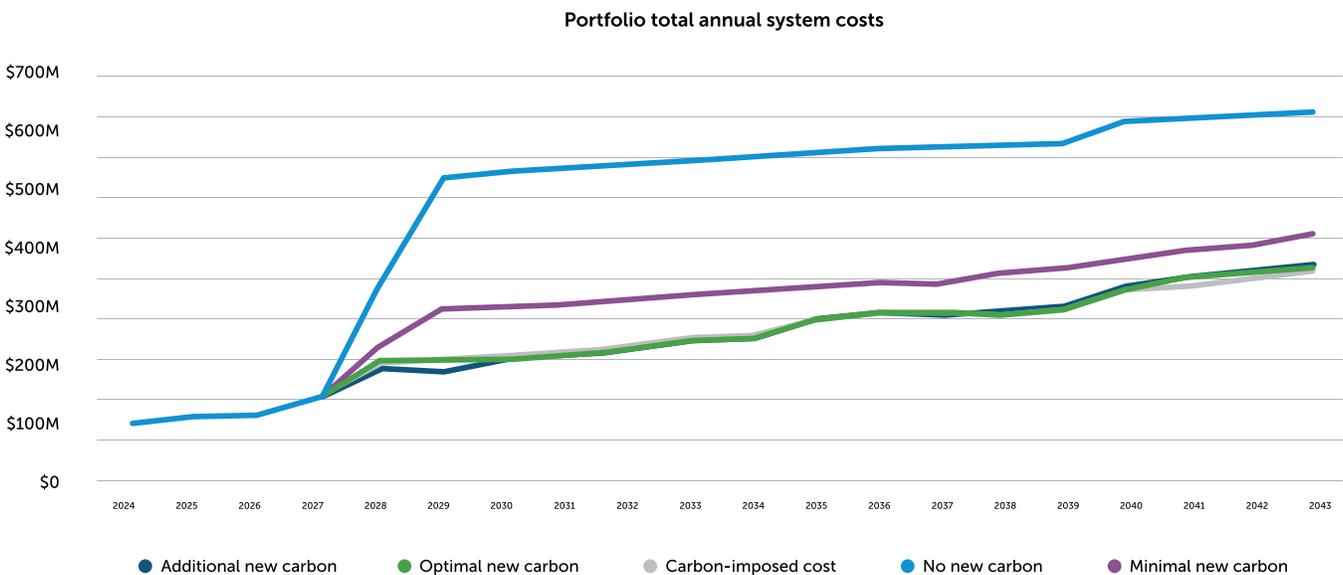


Figure 57. Portfolio total annual system costs

The no new carbon portfolio stands out as significantly more expensive, with the large buildout of four-hour storage starting in 2027. Annual costs exceed \$500 million per year by 2028 and continue an upward trend. The minimal new carbon portfolio is also noticeably more expensive than others, again due to the large battery buildout, with annual costs exceeding \$300 million by 2029. The remaining portfolios’ costs are similar, with some annual deviations due to small changes in resource size and timing. Looking at the present value of the total portfolio cost in Table 32, costs for the carbon-imposed cost, optimal new carbon and additional new carbon portfolios are within 1%

of each other. But the minimal new carbon portfolio is about 20% more expensive than the three lower-cost portfolios (on a net present value basis), while the no new carbon portfolio is almost twice as expensive, costing an extra \$2.6 billion over the planning horizon.

20-year net present value (\$000)	
No new carbon	\$5,344,991
Minimal new carbon	\$3,372,202
Carbon-imposed cost	\$2,779,024
Optimal new carbon	\$2,772,407
Additional new carbon	\$2,761,036

**Table 32.** Portfolio net present value cost comparison

As noted previously in this report, the portfolios rely on different technologies to supply differing services. Cost, energy and capacity breakouts in Table 33 highlight the complementary roles of renewable energy and thermal units in the optimal new carbon portfolio. In this case, when looking at the net present value of costs from 2030 through 2043, thermal units account for about 29% of the total cost while supplying almost 58% of the firm capacity and only about 7% of the energy. In contrast, noncarbon resources account for nearly 49%

of the cost while contributing just over 91% of the energy but only about 23% of the firm capacity. The thermal resources are more cost-efficient at contributing capacity while noncarbon resources are more cost-efficient at contributing energy. A reliable and low-cost portfolio needs an optimal combination of both capacity and energy. While battery storage does not generate energy, it shifts the renewable production to omitted renewable production hours, thereby contributing to capacity needs and supporting renewable energy integration.



	% of cost	% of generation	% of capacity
Thermal	29.2%	6.9%	57.9%
Noncarbon	48.8%	91.5%	23.1%
Battery storage	15.1%	0.0%	19.0%
Purchases	6.9%	1.6%	0.0%
<b>Total</b>	<b>100.0%</b>	<b>100.0%</b>	<b>100.0%</b>

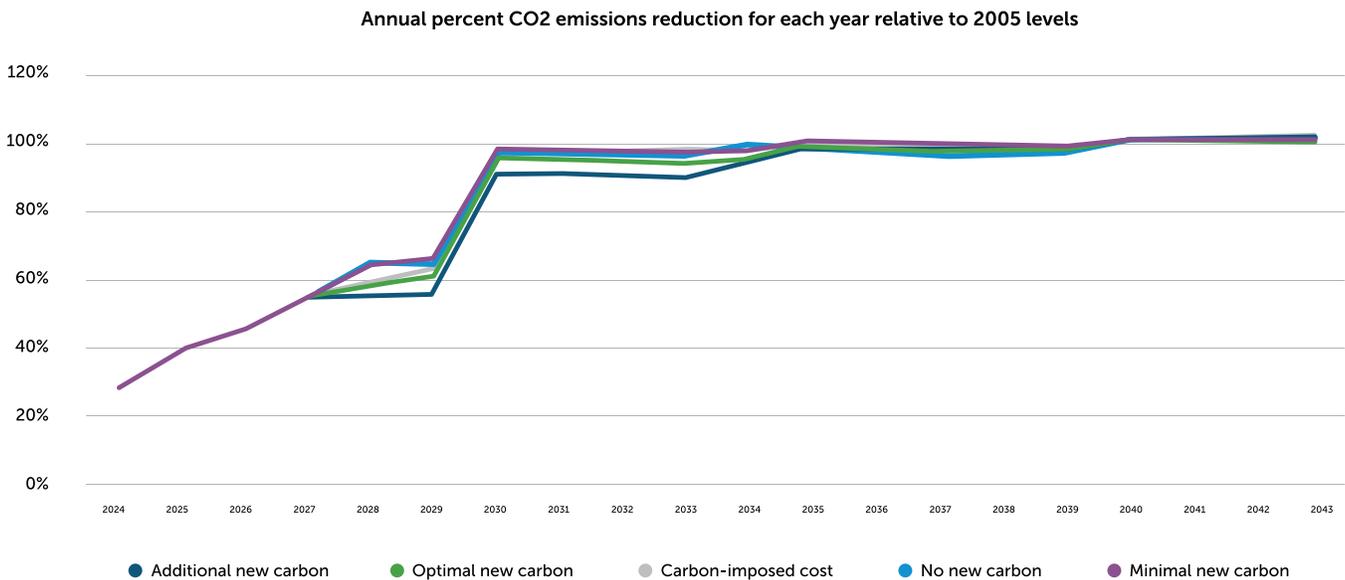
**Table 33.** Optimal new carbon portfolio: cost, energy and capacity contribution breakout

### 8.3.2 Portfolio CO2 emissions

Lowering CO2 emissions is a primary metric driving portfolio development and selection. While there are many ways to quantify a portfolio's emissions, this IRP uses the methodology developed in conjunction with Colorado's Clean Energy Plan (CEP)<sup>29</sup> rules.

Under this methodology, stack emissions from the portfolio are adjusted to reflect additional emissions associated with energy purchases while energy sales assign the associated CO2 to the counterparty buying energy. This netting prevents companies from avoiding emissions by outsourcing generation to an outside counterparty and helps Colorado measure total CO2 emissions due to electricity production and consumption within the state. This methodology also avoids penalizing companies for supplying energy to other utilities. This methodology is a good match for a future market where energy is entirely sold into and purchased from the market without regard to how individual companies balance load and generation. Figure 58 shows annual percent reduction of CO2 emissions for each portfolio relative to Platte River's 2005 baseline emissions.

<sup>29</sup> In 2022, Platte River filed a voluntary CEP with the state of Colorado, laying out a plan to reduce its greenhouse gas emissions by at least 80% by 2030 (compared to a 2005 base line).



**Figure 58.** Annual percent CO2 emissions reduction for each year relative to 2005 levels

Starting in 2025, Platte River makes substantial progress to reduce CO2 emissions due to the renewable energy additions and phased coal retirements. By 2027, we expect all five portfolios to achieve a 55% CO2 reduction. By 2030, the additional new carbon portfolio achieves a 91% reduction, while the remaining portfolios have reductions greater than 95%. After 2035, when the remaining thermal units should begin partially burning green hydrogen, the average carbon reduction for all five portfolios is 99%. This rises to 100% when we assume that all thermal units will transition to 100% hydrogen fuels in 2040, eliminating CO2 emissions.

All portfolios comply with:

- The framework in SB23-198 requiring Platte River to model at least one plan that can demonstrate 46% CO2 reduction (from 2005 levels) by 2027 and one plan that reduces carbon further than its filed CEP; and
- Platte River's voluntary CEP showing its plan to achieve at least 80% CO2 reduction (from 2005 levels) by 2030.

In addition to CO2 emissions reductions, emissions from other pollutants, including volatile organic compounds, carbon monoxide and nitrogen oxides, will also decrease with the coal plant retirements. We assume the new dispatchable generation will use the best available control technologies to maintain compliance with state laws and minimize environmental impact on water resources and air quality.

## 8.4 Recommendation

### 8.4.1 Optimal new carbon portfolio

Planning is a dynamic process, and the IRP is snapshot in time. The 2024 IRP presents a possible future based on the best information available in the summer of 2023. The five portfolios presented in this chapter cover a wide range of future paths. All five portfolios provide reliable electricity supplies during the planning horizon under our assumed set of conditions and variables. But our assumed conditions will probably change. In fact, they will almost certainly change in the long run because we are living amid rapid transition. While all five portfolios provide hypothetical options to meet load requirements and reduce carbon emissions, we must select one that:

- Presents a path towards meeting our RDP and state goals.
- Meets Platte River’s three pillars of reliability, financial sustainability and environmental responsibility.
- Presents a path where the actions taken in early years will not unnecessarily limit future options or intensify risks.

The following section highlights the key merits of each portfolio and provides a recommendation.

The **no new carbon portfolio** does not add any new CO<sub>2</sub> emitting sources, but it is the most expensive due to heavy reliance on four-hour storage batteries. It builds 2,850 MW of new batteries, almost three times our expected peak demand in 2030. Consequently, it costs about twice as much as some other portfolios. As



a not-for-profit entity, Platte River must pass these higher costs to the owner communities, causing significant rate shock.

The no new carbon portfolio does not offer the least CO<sub>2</sub>-emitting path, as it relies heavily on existing dispatchable generation to complement renewable generation. This portfolio fails the financial sustainability test and is not as effective in reducing CO<sub>2</sub> emissions post-2030 as other portfolios. Due to heavy reliance on four-hour battery storage, this portfolio may be unreliable in a dark calm event that spans more days than we have modeled. This portfolio does not present a plausible future path.

The **minimal new carbon portfolio** builds 80 MW of new thermal generation and 1,050 MW of new storage batteries, almost 50% more than



the expected peak demand in 2030. This portfolio emits the least CO<sub>2</sub> but is more than 20% more costly than the optimal new carbon portfolio. Just like the no new carbon portfolio, due to heavy reliance on four-hour storage batteries, this portfolio may be unreliable in a dark calm that spans multiple days. Because it does not meet Platte River's requirements for reliability or financial sustainability, this portfolio does not present a workable future path.

The **carbon-imposed cost portfolio** builds 160 MW of new thermal generation and presents a workable path. While this portfolio is reliable for the historically experienced weather uncertainties, it may not be reliable if weather events continue to become more extreme as they have in the

recent past.

The **optimal new carbon portfolio** builds 200 MW of new efficient thermal generation and presents a viable path. This portfolio presents a balance between the additional new carbon and carbon-imposed cost portfolios in both cost and the amount of new thermal generation. This portfolio better supports reliability if weather events continue to become more extreme, as they have in the recent past. This is our recommended portfolio.

The **additional new carbon portfolio** builds 240 MW of new efficient and flexible thermal generation. It is the lowest-cost portfolio but emits more CO<sub>2</sub> than some other portfolios that also meet reliability and financial sustainability pillars. This portfolio presents a workable future path.

The carbon-imposed cost, optimal new carbon and additional new carbon portfolios are potentially workable options. There are important differences among the three. After careful consideration, Platte River recommends the optimal new carbon portfolio because it optimally balances the organization's three foundational pillars, offers more flexible and lower-risk early decisions, has the robustness to withstand changes in assumptions and helps advance the 100% noncarbon energy goal of the RDP.

The recommended portfolio is a possible path for the future and not a firm plan. Platte River will further refine this path during implementation, incorporating market conditions, technology evolution, availability, and cost and timing of new resources. This plan will evolve as needed to align with our board's direction and our owner communities' wishes. Staff will continue to refine this portfolio with new data, assumptions, and market conditions. With these refinements and improvements, Platte River will continue to advance toward a 100% noncarbon supply mix while maintaining its three pillars of safely providing reliable, environmentally responsible and financially sustainable energy and services.

## 8.5 Risk assessment and sensitivity analysis

Platte River developed all five portfolios using several assumptions, assessments and forecasts about commodity prices, customer load growth, costs of renewables, DER adoption rates, market evolution, technology evolution, and other inputs. But these inputs are unlikely to occur

exactly as assumed, requiring us to adapt. In this section, we outline the risks our plan faces, summarize our sensitivity analyses and provide options to adjust the plans for key risks. As time passes and newer information is available, we will modify our plans.

### 8.5.1 IRP risks and barriers

As Platte River moves forward with this IRP implementation, we must consider two types of risks. First, there are execution risks that complicate portfolio implementation. These risks tend to be very specific to the composition of the portfolio, driven by large, complex external factors (such as global supply chains) and are difficult to hedge because they are unique and difficult to forecast. We discuss these risks in detail below.

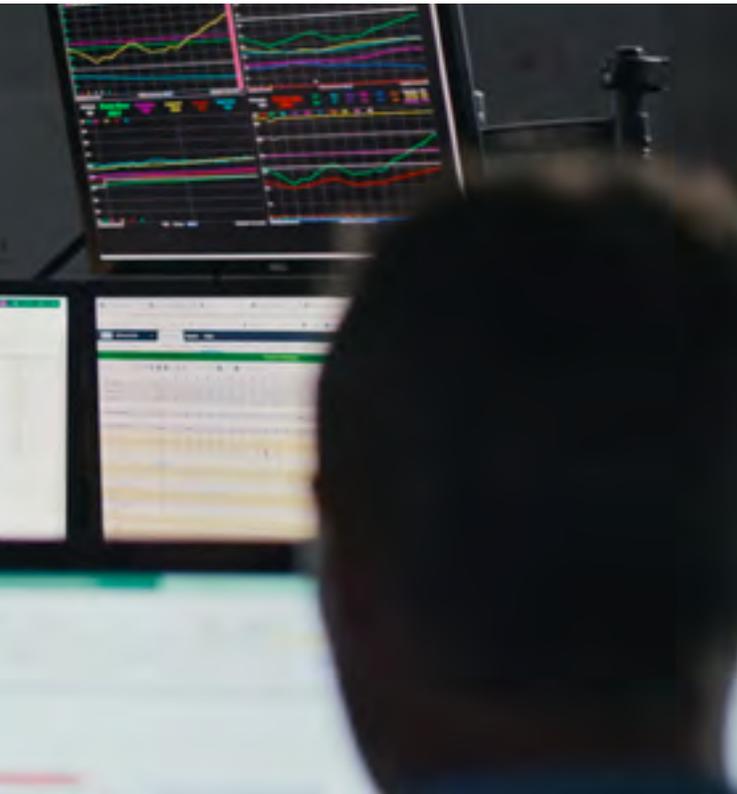
#### 8.5.1.1 Execution risks

- **Cost escalation** – As discussed in section 3.4.3, renewable costs continue to escalate dramatically. Platte River uses the latest market data to develop plans, but costs continue to rise, and new generation may be more expensive than anticipated. Renewable energy seems to carry the highest exposure due to both high market demand and complex, immature supply chains. Thermal generation has seen moderate escalation and other resource additions could be impacted by trade policies. Platte River must be prepared to adjust to the best portfolio mix to reflect evolving cost considerations.





- **Siting complications** – Individual projects have unique siting challenges. Platte River must address community concerns about the impact of a project itself or its transmission connections. Local regulation can also shift rapidly and require project modifications that often add costs. Projects may also encounter unexpected geological, hydrological or environmental conditions.
- **Technology evolution** – Our proposed portfolios assume a specific timeline of technology readiness. This forecast is based on our best estimates, but technology development is beyond Platte River’s control. If specific storage technologies fail to mature or hydrogen is not available at the required volumes, the portfolio would need to be reoptimized to accommodate this new reality. More specifically, we assumed long-duration energy storage and green hydrogen will be available and economically viable for commercial deployment in 2035 to help continue to decarbonize Platte River’s resource mix . If these technologies are not available at the projected dates or are available sooner, our decarbonization schedule will change accordingly.
- **DER adoption rates** – Platte River is proactively working with its owner communities to forecast and incentivize customer-sited resources. Like other technology forecasts, the exact trajectory of deployment of many new and emerging technologies is uncertain. Rooftop solar, electric vehicles, beneficial building electrification and battery storage systems



all impact both the energy mix and flexibility of the system. If there are unforeseen breakthroughs or complications, Platte River will need to adjust its resource mix in response.

### 8.5.1.2 Operational risks

There are operational risks that can occur in each plan once they are executed. It is easier to understand and quantify these operational risks with specific model runs. Their impact on portfolio viability is still significant and uncertain, but it is easier to evaluate the quantifiable tradeoffs.

- **Fuel and market price risk** – Portfolios are developed using the best estimates

of future fuel and energy market prices. Past volatility suggests the potential for future volatility. Sensitivity runs modeling gas and power prices help establish each portfolio's susceptibility to this input and the consequences of future deviations from the expected value.

- **Regulatory risk on carbon accounting and emissions** – There continues to be a range of opinions on how carbon emissions will be regulated. The presence or absence of a carbon tax can impact the economics of a portfolio. Again, a sensitivity analysis can help quantify the financial impacts of a carbon tax.
- **Market evolution** – The implementation of a western energy market will impact different resources in different ways. Transmission congestion may erode the economics of remotely sited resources, while a robust energy market may impact price levels and volatility. If multiple utilities add renewable resources and transmission constraints emerge in moving power out of our region, there is a risk that excess renewable generation will depress market prices. This risk is more difficult to quantify than other operational risks, but Platte River continues to explore the potential range of impacts as the market develops.

The risks described above can impact a portfolio in different ways. One way to analyze their impacts is to conduct sensitivity analyses, where we change a driver or variable and measure the resulting impact on the portfolio. Section 8.5.2 discusses these analyses.

Because these risks and assumptions can change simultaneously, the combined effect can be large and drive us to change the portfolio mix. In section 8.5.3, we assess the combined risk of renewable cost increases and market price changes and review potential portfolio modifications to reduce this risk.

## 8.5.2 Sensitivity analyses

To understand the robustness of the modeled portfolios, the IRP process tests the portfolios under assumptions different from the base assumptions. In a sensitivity analysis, a single assumption or input is changed (gas prices, for example) and the portfolio is re-evaluated. Portfolios with stronger responses to the new assumption or input show greater risk. This analysis provides a deeper understanding of the tradeoff between cost and risk. For this IRP, Platte River performed sensitivity analyses on two main inputs: natural gas prices and renewable energy prices.

### 8.5.2.1 Natural gas prices

Natural gas prices can impact a portfolio in two ways. First, the price of this fuel directly influences regional market prices, which impacts the volume and cost or revenue of imports and exports to and from the Platte

River system. Second, the portfolios continue to consume modest amounts of natural gas in the future, so changes in price directly impact the economics of the thermal generation. In this analysis, gas prices were tested at both higher and lower levels than the base assumption used in the portfolio development. Siemens, the supplier of the base gas price forecast, also supplied the high and low gas price trajectories, seen in Figure 39 earlier in this document, as well as associated market prices for each sensitivity.

### 8.5.2.2 High gas prices

Under this sensitivity, gas prices are 20% higher on average from 2030 to 2040. On a net present value basis, the portfolios' costs change very little, indicating the relatively small role of gas in future portfolios. On the low side, there is a 0.3% savings for the minimal new carbon portfolio while the additional new carbon portfolio has a cost increase of 1.4%. In general, higher gas prices increase the system operating cost due to higher fuel expenditures, but these increases are partially offset by higher sale revenues from higher market prices. Portfolios with more gas generation will see a net increase in cost, while portfolios with more must-sell renewable energy will benefit from the attractive market prices and see a slight savings.



### 8.5.2.3 Low gas prices

For this sensitivity, gas prices remain relatively flat starting in 2026. While the base case and high-price sensitivity show average escalation rates of 4.45% and 5.71% respectively through 2043, the low-price curve has a net gain of 0.2% by 2043, with a small decline during the 2030s. As expected, the results are the opposite of the high gas price sensitivity. Since this sensitivity sees a larger change to gas prices, with an average decrease of 54% relative to the base assumption, the change in net present value is more noticeable than in the high gas price sensitivity. The additional new carbon portfolio sees a cost savings of 5.1% and the optimal new carbon portfolio sees a savings of 3.6%. The minimal new carbon and no new carbon portfolios see modest savings of 0.6% and 0.8%, respectively.

### 8.5.2.4 Renewable energy prices

As discussed in section 3.4.3, renewable energy projects have seen significant cost increases in recent years.

In addition to the cost drivers of the projects themselves (including supply chain issues and competition for renewable resources), a second source of uncertainty around the cost

of new renewable energy comes from Platte River's expected market participation. There is some possibility that the market will fail to launch as planned, or will launch with a different mix of participants, which would leave some projects exposed to higher transmission costs than might otherwise be expected in a market. Assuming the market does move forward as planned, there is still substantial uncertainty around the additional costs of transmission congestion, both under the existing portfolio and as regional portfolios evolve with more renewable energy concentrated at the optimal sites. Without a market, or with a market that is more congested than expected, the delivered cost of our renewable energy would rise.

For these reasons, Platte River ran a sensitivity analysis on renewable energy prices. We evaluated price increases for new wind and solar projects under each portfolio. Table 34 compares the base assumption to the higher price sensitivity for selected years. We did not test prices for energy storage and thermal generation because Platte River has not seen similar price volatility in those markets and their transmission congestion risk is much lower.



	Wind cost (including transmission costs)		Solar cost	
	Base	High sensitivity	Base	High sensitivity
2030	32.85 \$/MWh	40.99 \$/MWh	30.01 \$/MWh	40.37 \$/MWh
2035	34.82 \$/MWh	43.75 \$/MWh	31.22 \$/MWh	41.99 \$/MWh
2040	36.87 \$/MWh	46.67 \$/MWh	32.43 \$/MWh	43.62 \$/MWh

**Table 34.** Renewable PPA prices

Because each portfolio adds a similar amount of renewable energy, the results across the portfolios are reasonably close. On a net present value basis, the smallest change is a \$181 million increase for the additional new carbon portfolio, while the largest increase is \$198 million for the carbon-imposed cost portfolio. The optimal new carbon portfolio has a cost increase of \$190 million, which is about a 7% increase if renewable energy prices reach the level projected in the sensitivity.

The last two columns of Table 35 illustrate how the relative difference among portfolio costs changes from the base case to the sensitivity case. These intra portfolio cost comparisons are shown relative to the lowest cost portfolio referred to as the additional new carbon portfolio (labeled as "ANC" in the table below). For the base case runs, the cost of the no new carbon portfolio is 93.6% higher relative to the additional new carbon portfolio, while the sensitivity case is 88.0% higher. There is very little change in the relative cost differences for the remaining portfolios.

Portfolio	Base and sensitivity comparison			Intra portfolio cost comparison	
	Base case	Sensitivity: high RE	% change	Base case: % diff vs. ANC	Sensitivity: % diff vs. ANC
No new carbon	\$5,344,991	5,531,559	3.5%	93.6%	88.0%
Minimal new carbon	\$3,372,202	3,559,856	5.6%	22.1%	21.0%
Carbon-imposed cost	\$2,779,024	2,976,911	7.1%	0.7%	1.2%
Optimal new carbon	\$2,772,407	2,962,228	6.8%	0.4%	0.7%
Additional new carbon	\$2,761,036	2,941,920	6.6%	0.0%	0.0%

**Table 35.** Renewable PPA prices

### 8.5.2.5 Sensitivity analysis summary

While uncertainty about some model inputs is unavoidable, quantifying the impacts of those uncertainties can help manage the risks associated with them. Table 36 compares the net present value costs across the base case assumptions and the sensitivities described above.

Net present values	Base	High gas and power	Low gas and power	High renewable energy prices
No new carbon	\$5,344,991	\$5,343,332	\$5,304,721	\$5,531,559
Minimal new carbon	\$3,372,202	\$3,363,500	\$3,352,897	\$3,559,856
Carbon-imposed cost	\$2,779,024	\$2,783,634	\$2,724,507	\$2,976,911
Optimal new carbon	\$2,772,407	\$2,794,671	\$2,672,710	\$2,962,228
Additional new carbon	\$2,761,036	\$2,800,210	\$2,620,375	\$2,941,920

**Table 36.** Net present value cost comparison with gas prices and renewable prices

At a high level, the no new carbon portfolio and the minimal new carbon portfolio are uncompetitive in every case. Table 37 converts the net present value costs into rankings for the base case and each sensitivity, with the result that the no new carbon portfolio is last under every assumption tested and the minimal new carbon portfolio is fourth under every assumption tested.

Net present value rankings	Base	High gas and power	Low gas and power	High renewable energy prices	Average
No new carbon	5	5	5	5	5.0
Minimal new carbon	4	4	4	4	4.0
Carbon-imposed cost	3	1	3	3	2.5
Optimal new carbon	2	2	2	2	2.0
Additional new carbon	1	3	1	1	1.5

**Table 37.** Portfolio ranking with sensitivity analysis

The top three portfolios are more competitive, and their relative value depends on the future trajectory of prices and the impacts of CO<sub>2</sub> emissions. The optimal new carbon portfolio proves to be robust, with a second-place ranking in every run. This portfolio is, on average, only 0.9% more expensive than the best portfolio in any given sensitivity (including the base case). While some portfolios may perform better in a specific set of circumstances, the optimal new carbon portfolio performs well across the range of outcomes and proves to be a cost-effective and robust solution.

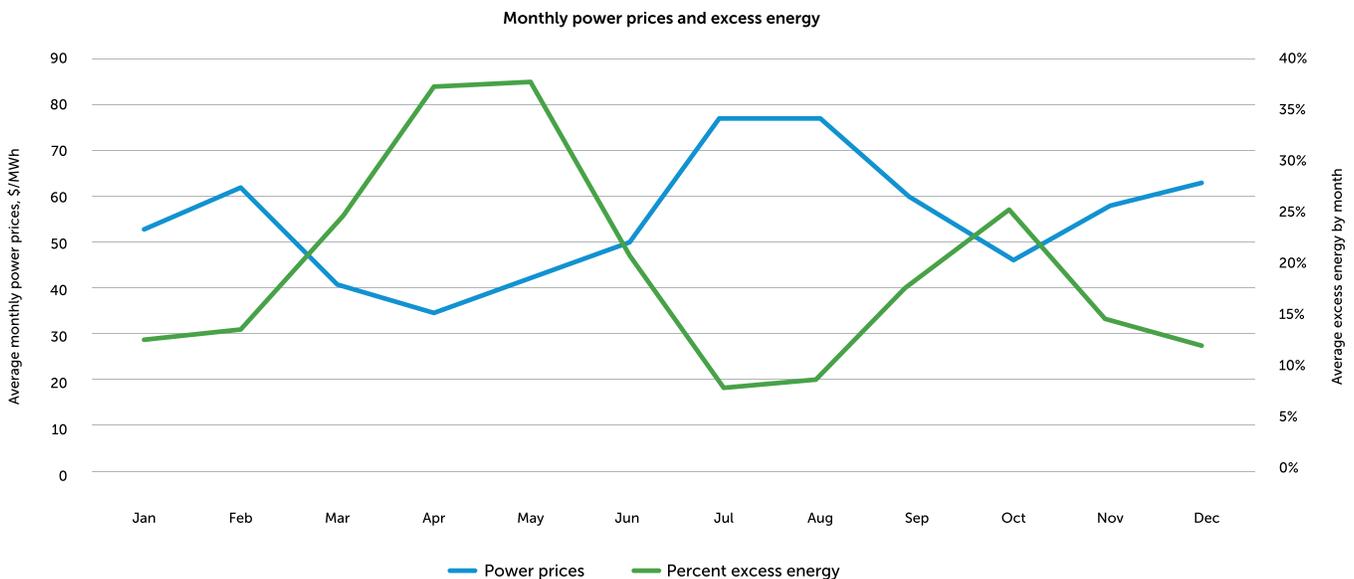
### 8.5.3 Excess renewable and market participation risk

With a substantial increase in intermittent renewable resources, Platte River faces an increasing risk from the mismatch in timing between customer demand and when renewable generation is available. Some of the mismatch can be managed with energy storage, but it would be impractical to balance the entire renewable energy portfolio using current battery storage technology. When there is insufficient renewable energy, Platte River can purchase energy from the market, withdraw stored energy, or rely on thermal generation to fill the gap. When there is too much energy, Platte River will store the excess (after meeting its load) and must sell any additional renewable energy into the market or curtail the resource.

Starting in 2030, Platte River anticipates having about 10% to 35% surplus energy on an annual basis. Of that excess, about 75% is expected to be sold, while the remainder will be curtailed due to limited energy demand and constrained transmission systems.

Because renewable energy contracts are structured as take-or-pay, Platte River must pay the full price of the PPA whether we take delivery of the energy or not. In this context, Platte River will sell excess renewable energy into the market if the market price is greater than \$0 but will incur a loss if the market price is below the PPA price. Therefore, the economic value of the surplus renewable energy depends on the cost of the PPA relative to the market price of the energy at the time of the excess energy.

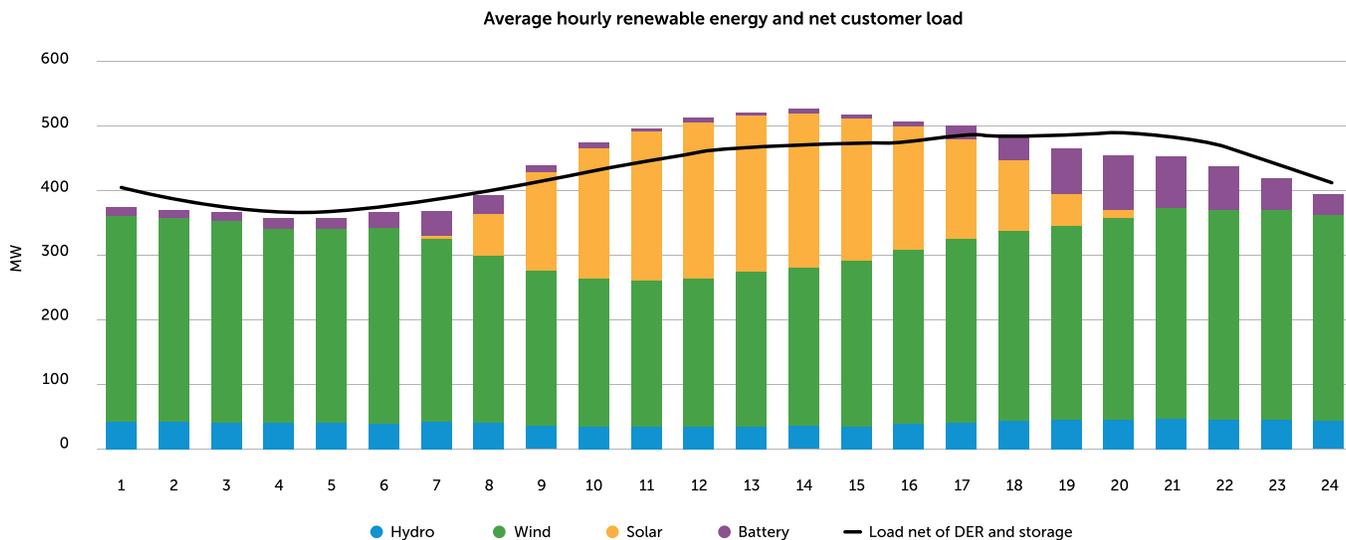
Given that the entire region is adding wind and solar resources, we anticipate market prices to be lowest when we have surplus renewable energy. Figure 59 illustrates the average expected monthly power prices in 2031 and monthly excess renewable energy as a percentage of the total monthly energy required by Platte River customers.



**Figure 59.** *Monthly power prices and excess energy*

The blue line shows average monthly prices, while the green line shows excess energy as a percent. The average prices are lowest in April and May, when the excess energy is above 35% of Platte River's needs. Excess energy is relatively low in higher-priced months of summer and winter.

To better understand the supply-demand balance and assess energy risk, Platte River staff analyzed expected hourly operations during the year 2031 using 24 historical hourly weather patterns for the recommended portfolio, which called for adding 400 MW of new wind by 2030. The diversity of weather data allows a broader quantification of the risk across multiple weather years, rather than relying on a single representative year.



**Figure 60.** Average hourly renewable energy and net customer load

Figure 60 summarizes the average excess megawatts by hour of day and month of the year. During the day, we have excess energy in midday when solar output is high. However, during the morning and evening hours, when the load is ramping up, the Platte River system needs dispatchable capacity and market access.

Balancing this excess renewable energy with the need for sufficient energy during high demand is one of the primary tasks of this IRP. Platte River developed the recommended portfolio with 400 MW of new wind, with the wind power purchase price around \$32/MWh, and market prices in the 2030s around \$50/MWh, making excess energy revenue positive. However, if market prices continue to drop with the addition of renewable resources in the region and

demand for renewable energy continuing to rise, the cost of renewable energy will increase. In this scenario, the risk is not only the limited value from excess renewable energy but also market price volatility.

Platte River will need to consider these risks before fully implementing the recommended plan. This exposure to factors outside Platte River's control makes managing the portfolio's risk a critical part of the execution phase. Platte River will continue to monitor commodity prices (like gas), market power price forecasts, and the cost of renewable energy to refine and rebalance the plan as necessary to meet our financial sustainability pillar. If necessary, we can adjust the renewable mix or storage capacity to mitigate risk if it is cost-effective.



# 09

## Action plan

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Platte River will continue to work toward the RDP goal over the next five years. Platte River plans to retire coal generation, add more renewable generation, add energy storage, add a VPP, join a full organized energy market and add efficient dispatchable thermal generation to complement renewable intermittency. We expect to carry out the following specific activities.





## 9.1 2024-2028: Execution phase

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Renewable energy acquisition	Contract for new 107 MW solar from the 2022 solar RFP	2024	Execution risks (section 7.5.1.1) <ul style="list-style-type: none"> <li>• Cost escalation</li> <li>• Siting complications</li> <li>• Technology evolution</li> </ul>
	Contract for new 250 MW wind from the 2023 wind RFP	2024	
	Begin commercial operation of 150 MW Black Hollow Solar project	2025	Operational risks (section 7.5.1.2) <ul style="list-style-type: none"> <li>• Market evolution</li> </ul>
	Begin commercial operation of a 130 MW solar project	2027	
Dispatchable capacity (reliability)	Contract to add up to 20 MW of distributed energy storage from 2021 solar and storage RFP	2024	Execution risks (section 7.5.1.1) <ul style="list-style-type: none"> <li>• Cost escalation</li> <li>• Siting complications</li> <li>• Technology evolution</li> <li>• DER adoption rates</li> </ul> Operational risks (section 7.5.1.2) <ul style="list-style-type: none"> <li>• Fuel and market price risk</li> <li>• Regulatory risk on carbon accounting and emissions</li> <li>• Market evolution</li> </ul>
	Issue RFP for four-hour battery energy storage system	2024	
	Review results from all-dispatchable-resource RFP	2024	
	Begin adding up to 200 MW of dispatchable thermal generation resources. Major activities include: <ul style="list-style-type: none"> <li>• Apply for air and land use permits</li> <li>• Identify actions related to ordering some long lead time equipment, especially related to power transmission</li> <li>• Develop initial project design and enlist engineering, procurement and construction contractor</li> </ul>	2024	

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Dispatchable capacity (reliability)	Issue RFP for systems and services to support development of a VPP that can provide dispatchable capacity for Platte River and the owner communities	2024	<p>Execution risks (section 7.5.1.1)</p> <ul style="list-style-type: none"> <li>• Cost escalation</li> <li>• Siting complications</li> <li>• Technology evolution</li> <li>• DER adoption rates</li> </ul> <p>Operational risks (section 7.5.1.2)</p> <ul style="list-style-type: none"> <li>• Fuel and market price risk</li> <li>• Regulatory risk on carbon accounting and emissions</li> <li>• Market evolution</li> </ul>
	Issue RFP for dispatchable thermal resource development if the 2024 all dispatchable resource RFP does not result in an acceptable project	2025	
	With our owner's engineer and contractor, complete plant design for new resource and balance of plant services	2025	
	Complete battery energy storage system agreements	2025	
	Issue RFP for additional energy storage system	2025	
	Plan VPP systems design and architecture	2025	
	Start work on a demonstration project for long-duration energy storage system	2025	
	Build VPP systems, system integrations and develop key functionality	2026	
	Begin commercial operation of up to 25 MW of distributed energy storage from 2021 solar RFP	2026	
	Launch VPP with 7 MW dispatchable capacity	2027	

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Customer programs	Plan and develop VPP customer programs	2025	Execution risks (section 7.5.1.1) <ul style="list-style-type: none"> <li>• Technology evolution</li> <li>• DER adoption rates</li> </ul>
	Launch VPP customer programs	2026	Operational risks (section 7.5.1.2) <ul style="list-style-type: none"> <li>• Market evolution</li> </ul> VPP system integration Third-party DER device aggregators
Community engagement	Continue public education campaign to engage communities, customers in the energy transition	2024-2028	
	Support renewable energy project acquisitions and engage communities through groundbreaking events, ribbon-cutting ceremonies	2025-2028	
Transmission	Complete construction and energize the 230-kV interconnection switching station (Severance substation) to interconnect new renewable resources	2025	Execution risks (section 7.5.1.1) <ul style="list-style-type: none"> <li>• Cost escalation</li> <li>• Siting complications</li> </ul> Operational risks (section 7.5.1.2) <ul style="list-style-type: none"> <li>• Market evolution</li> </ul>
Markets	Begin training staff to prepare for SPP RTO West market entry	2024	Operational risks (section 7.5.1.2) <ul style="list-style-type: none"> <li>• Market evolution</li> </ul> System integration Market tariff and resource adequacy
	Screen and select market interface software	2024	
	Begin testing operations in SPP RTO West	2025	
	Join SPP RTO West market operations on April 1	2026	

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Other enabling activities	Finalize and file a just transition plan with the state of Colorado for workers affected by Rawhide Unit 1's closure	2024	Interest rates
	Working alongside other owners, retire Craig Unit 1 (of which Platte River owns a 77 MW share)	2025	
	Initiate 2028 IRP process	2026	
	Issue bonds to fund capital investments	2025-2026	
	Continue 2028 IRP process including: <ul style="list-style-type: none"> <li>• Receive studies from external consultants</li> <li>• Execute community engagement activities to educate public, collect stakeholder feedback</li> <li>• Conduct modeling and analyze portfolios</li> <li>• Compile draft report</li> </ul>	2027	

## 9.1 2024-2028: Execution phase

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Renewable energy acquisition	Begin commercial operation of new wind generation	2028	<p>Execution risks (section 7.5.1.1)</p> <ul style="list-style-type: none"> <li>• Cost escalation</li> <li>• Siting complications</li> <li>• Technology evolution</li> </ul> <p>Operational risks (section 7.5.1.2)</p> <ul style="list-style-type: none"> <li>• Market evolution</li> </ul>
	Testing, commissioning, and operation of new dispatchable thermal resource	2028	<p>Execution risks (section 7.5.1.1)</p> <ul style="list-style-type: none"> <li>• Cost escalation</li> <li>• Siting complications</li> <li>• Technology evolution</li> <li>• DER adoption rates</li> </ul> <p>Operational risks (section 7.5.1.2)</p> <ul style="list-style-type: none"> <li>• Fuel and market price risk</li> <li>• Regulatory risk on carbon accounting and emissions</li> <li>• Market evolution</li> </ul>
Dispatchable capacity (reliability)	Begin commercial operation of energy storage systems (for which RFP was issued in 2025)	2028	
	Grow VPP dispatchable capacity to 15 MW and develop market dispatch capabilities	2029	
	Grow VPP dispatchable capacity to 24 MW and develop distribution dispatch capabilities	2029	
	Develop a mobile app to help customers and distribution utilities connect with Platte River's system	2028-2030	
Community engagement	Support mobile app deployment with communications and community activations	2028-2030	
	Continue public education campaign to engage communities, customers in the energy transition	2028-2030	

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Other enabling activities	Implement the Just Transition Plan	2024-2030	
	Working alongside other owners, retire Craig Unit 2 (of which Platte River owns a 74 MW share)	2028	
	Seek approval from Platte River Board for 2028 IRP; file with WAPA	2028	
	Retire Rawhide Unit 1 by December 31	2029	

# 10 Appendices

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## Appendix A: IRP checklist for WAPA

Document section	Requirement	Included in this IRP	Section number
<p>IRP design, IRP study results</p> <p>Power markets</p> <p>Energy efficiency</p> <p>DER integration, flexible DERs and the virtual power plant</p> <p>IRP portfolios</p>	<p>Does the IRP evaluate the full range of alternatives for new energy resources, including:</p> <ul style="list-style-type: none"> <li>• new generating capacity?</li> <li>• power purchases?</li> <li>• energy conservation and efficiency?</li> <li>• cogeneration and district heating/cooling applications?</li> <li>• renewable energy resources?</li> </ul>		6.3.3, 6.3.4, 6.3.5, 6.3.6, 6.3.7 7.1, 7.4, 8.2, 8.3 4.1.5, 6.3.4, 6.3.5, 5.3.2 5.3.1 7.4, 8.2, 8.3
Planning for a reliable future power supply	Does the IRP provide adequate and reliable service to the customer's electric consumers?		7.3
IRP design, IRP study results	Does the IRP take into account the necessary features for system operation?		4.2.1, 7.3, 8.5
DER integration, flexible DERs and the virtual power plant	Does the IRP take into account the ability to verify energy savings achieved through energy efficiency?		5.3
DER integration, flexible DERs and the virtual power plant	Does the IRP take into account the projected durability of such savings measured over time?		5.3
Load forecast methodology and data	Does the IRP treat demand and supply resources on a consistent and integrated basis?		5.3, 5.4.1, 5.4.2
Planning for a reliable future power supply	Does the IRP consider electrical energy resource needs?		7.3
Energy and capacity planning, DER integration, flexible DERs and the virtual power plant, supply side generation resources, IRP portfolios	Does the IRP identify and compare resource options?		4.1.2, 5.3, 6.3, 7.4, 7.5

Document section	Requirement	Included in this IRP	Section number
Comparative analysis of portfolios, portfolio recommendation, risk assessment and sensitivity analysis	Does the IRP clearly demonstrate that decisions were based on a reasonable analysis of the options?		8.3, 8.4, 8.5
Action plan	Does the IRP include an action plan describing specific actions the customer will take to implement the IRP?		9
Action plan	Does the IRP list the time period that the action plan covers?		9
Action plan	Does the IRP include an action plan summary consisting of: <ul style="list-style-type: none"> <li>• Actions the customer expects to take in accomplishing the goals identified in the IRP?</li> <li>• Milestones to evaluate accomplishment of those actions during implementation?</li> <li>• Estimated energy and capacity benefits for each action planned?</li> </ul>		9
Portfolio CO2 emissions	Does the IRP, to the extent practicable, minimize adverse environmental effects of new resource acquisitions and document these efforts?		8.3.2 with additional text from environmental
Portfolio CO2 emissions	Does the IRP include a qualitative analysis of environmental effects in a summary format?		8.3.2
Stakeholder engagement process	Does the IRP provide ample opportunity for full public participation in preparing and developing the IRP?		3.7

Document section	Requirement	Included in this IRP	Section number
Stakeholder engagement process	Does the IRP include a brief description of public involvement activities?		3.7
Board resolution to approve the 2024 IRP	Does the IRP document that each MBA member approved the IRP, confirming that all requirements have been met?		Appendix C
Board resolution to approve the 2024 IRP	Does the IRP contain the signature of each MBA member's responsible official, or document passage of an approval resolution by the appropriate governing body?		Appendix C
Electricity demand	Does the IRP contain a statement that the customer conducted load forecasting, including specific data?		5.1-5.4
Planning for a reliable future power supply, portfolio CO2 emissions, DER integration, flexible DERs and the virtual power plant, IRP portfolios	Does the IRP contain a brief description of measurement strategies for identified options to determine whether the IRP's objectives are being met?		7.3.2.2, 8.3.2, 5.3
Planning for a reliable future power supply, portfolio CO2 emissions, DER integration, flexible DERs and the virtual power plant, IRP portfolios	Does the IRP identify a baseline from which the customer will measure the benefits of IRP implementation?		7.3.2.2, 8.3, 5.3
	Does the IRP specify the responsibilities and participation levels of individual members of the MBA and the MBA?	N/A	



## Appendix B: 2024 Just Transition Plan



**Platte River**  
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

# 2024 JUST TRANSITION PLAN



# BACKGROUND

Platte River Power Authority (Platte River) is a not-for-profit, community-owned public power generation and transmission utility that provides safe, reliable, environmentally responsible and financially sustainable energy and services to the communities of Estes Park, Fort Collins, Longmont and Loveland, Colorado, for delivery to their distribution utility customers. Platte River owns and operates Rawhide Energy Station (Rawhide), located roughly ten miles north of Wellington, Colorado. Rawhide consists of one 280 megawatt (MW) capacity coal fired boiler (Unit 1) and five natural gas-fired combustion turbines with a combined 388 MW capacity (Units A, B, C, D and F) that support peak power demand. Additionally, Rawhide also has 52 MW of solar and a 2 MW-hour battery storage system.

Platte River, like other Colorado utilities, is transforming how it generates and delivers energy. In 2018, Platte River's board of directors (the board) approved the Resource Diversification Policy (RDP), which directed Platte River to proactively work toward achieving a 100% noncarbon energy mix by 2030 while maintaining Platte River's three foundational pillars of providing reliable, environmentally responsible and financially sustainable electricity and services. A significant milestone on the journey to 100% noncarbon energy is its commitment to retire Unit 1 by the end of 2029. This commitment is reflected in its current Integrated Resource Plan (2024 IRP) and in its Clean Energy Plan, which was submitted to the state of Colorado in 2022. This commitment is also included in Resolution 08-24 which formally announces Unit 1's accelerated retirement as part of the 2024 IRP. With Platte River's commitment to retiring Unit 1, the utility will submit this document – Platte River's Just Transition Plan – to the Colorado Office of Just Transition within 30 days of Platte River's board of directors approving Resolution 08-24 and the 2024 IRP.

Platte River is not just transforming its energy mix. Embracing the future will require Platte River to change and adapt as an organization. Platte River entered the Southwest Power Pool (SPP) Western Energy Imbalance Service market in 2023 and will enter SPP's Regional Transmission Organization –West (RTO–West) in April 2026, which is one of the key advancements identified to further the RDP. To support entering RTO–West, Platte River is initiating a strategic workforce analysis to identify the necessary changes to its people, processes, and technologies.

Platte River's board passed Resolution 08-2020 (Workforce Resolution) in 2020, when Platte River announced Unit 1's retirement. The Workforce Resolution planned six principles that Platte River is committed to follow when implementing its transition plan. These principles are:

- Transparency
- Workforce Planning
- Workforce Opportunities
- Workforce Training
- Retention Strategies
- Transition Support

Platte River, through its Workforce Resolution and Just Transition Plan, will continue to demonstrate its unwavering commitment to support and retain employees who wish to remain with the organization through Unit 1's retirement and its transition to a clean energy future.

# PLATTE RIVER AT A GLANCE

Platte River Power Authority is a not-for-profit, community-owned public power utility that generates and delivers safe, reliable, environmentally responsible and financially sustainable energy and services to Estes Park, Fort Collins, Longmont and Loveland, Colorado, for delivery to their utility customers.

<b>Headquarters</b>	<b>2023 peak demand of owner communities</b>
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Fort Collins, Colorado	680 MW
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<b>General manager/CEO</b>	<b>2023 deliveries of energy</b>
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Jason Frisbie	4,506,208 MWh
---------------	---------------

<b>Began operations</b>	<b>2023 deliveries of energy to owner communities</b>
-------------------------	-------------------------------------------------------

1973	3,161,533 MWh
------	---------------

<b>Staff</b>	<b>Transmission system</b>
--------------	----------------------------

268	Platte River has equipment in 27 substations, 263 miles of wholly owned and operated high-voltage lines, and 522 miles of high-voltage lines jointly owned with other utilities.
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# PLATTE RIVER POWER AUTHORITY'S 2024 JUST TRANSITION PLAN

As required by House Bill 19-1314 and to further its commitment to Unit 1's retirement and the 100% noncarbon goal of its RDP, Platte River submits this Just Transition Plan to the Colorado Office of Just Transition. Platte River views this Just Transition Plan as a living document and anticipates that it will revise both the Just Transition Plan and its IRP as Unit 1's Dec. 31, 2029 retirement date nears. Platte River's Just Transition Plan follows the six principles of its Workforce Resolution and supports its ongoing commitment to retain employees through the energy transition and to avoid involuntary separations (layoffs) due to Unit 1's retirement.





# PRINCIPLE 1: TRANSPARENCY

Platte River management will make every effort to communicate impacts proactively and transparently to employees as decisions are made, including the timelines of planned events.

To implement this principle, Platte River consistently updates both Rawhide and Headquarters staff on the transition plan, including at plant and business meetings and through updates to Platte River's board. Platte River also discusses the upcoming transition, including its commitment to retain employees after Unit 1's retirement, with external candidates as part of the interview and hiring process. Platte River offers RTO–West training to the whole organization and will provide the results of its upcoming gap analysis to internal stakeholders so that each department can evaluate the changes to people, processes, and technology that will be needed in 2026 and beyond. Platte River also plans to provide this Just Transition Plan and the 2024 IRP to all employees through multiple channels and opportunities for employee to submit questions, concerns, and feedback on Platte River's transition.

Platte River's Just Transition Plan is led by a cross-functional team including representatives from power generation, operations, human resources, communications, and legal affairs and is sponsored by Platte River's Chief Operating Officer – Generation, Transmission and Markets. This cross-functional team currently plans additional outreach and communication to staff on workforce planning and workforce transition to accompany the Just Transition Plan and 2024 IRP. The cross-functional team is guided by the RDP, the Workforce Resolution and Platte River's Strategic Plan as it deploys Platte River's strategic workforce planning tools to further those goals and establish ongoing dialogue on how to best meet them in a just and transparent way.

# PRINCIPLE 2: WORKFORCE PLANNING

Platte River management will continue to evaluate and identify workforce needs and to communicate its needs to staff.

To implement this principle, Platte River's leadership, partnering with its human resources department, is currently using strategic planning, data modeling, and other workforce planning tools to anticipate Platte River's future workforce needs. While this modeling is an imperfect science, Platte River is committed to using the best tools and data available, and to continually updating its models as Unit 1's retirement nears and Platte River's future needs become clearer.

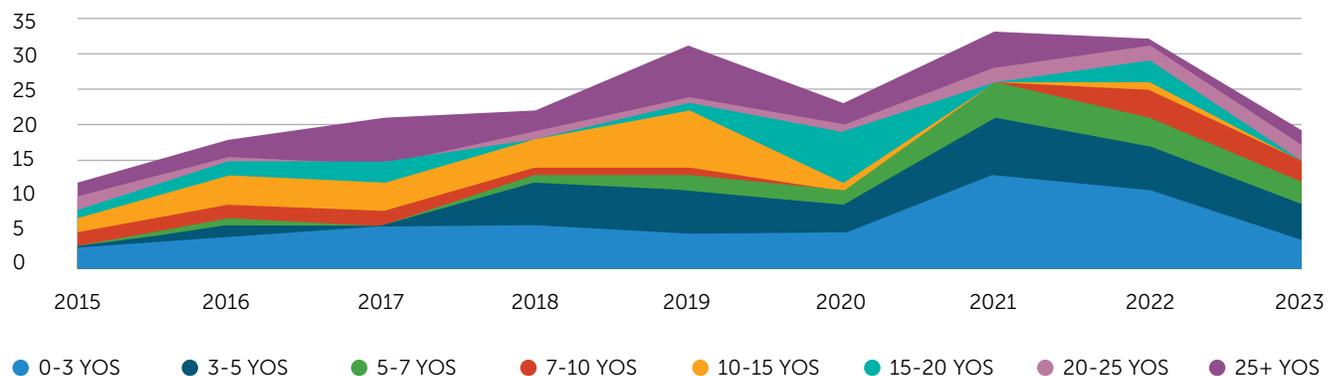
It is important to note that Platte River is growing as an organization, even as Unit 1 retires. It will need additional staff in many functional areas to meet the RDP and the Strategic Plan, including in power marketing, power delivery, compliance, information technology, and substation maintenance. Platte River has determined how future vacancies will

provide opportunities to transition Rawhide employees to other positions in the organization.

Platte River's internal modeling also shows that its workforce transition will largely be driven by natural attrition and retirement, not through layoffs. Many current Platte River employees have more than 25 years of service. Historically, Platte River attrition has been low amongst its longest-tenured employees, a trend that it anticipates may change as more staff members reach retirement age. Platte River, like other employers, has experienced increased attrition and volatility amongst its newer employees, a trend that it anticipates will not change between now and 2029.

Figure 1 and Figure 2 show the general trends that Platte River has modeled and observed in attrition by years of service, both for the organization as a whole and for Rawhide.

**Figure 1: Platte River Attrition by Years of Service**



**Figure 2: Rawhide Attrition by Years of Service**

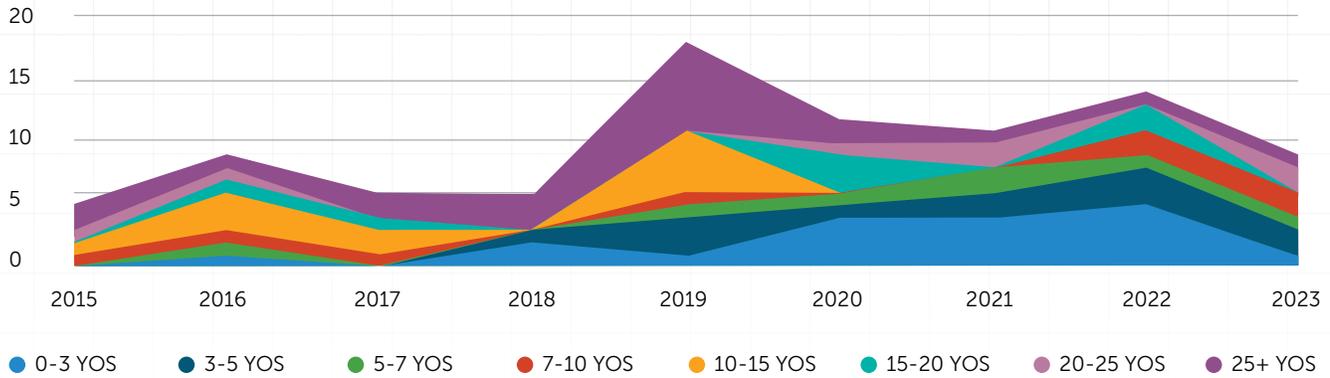
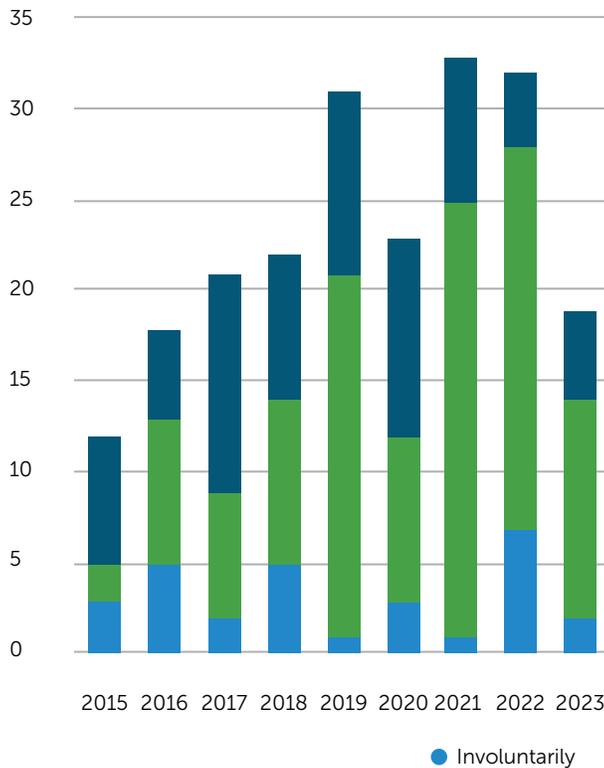
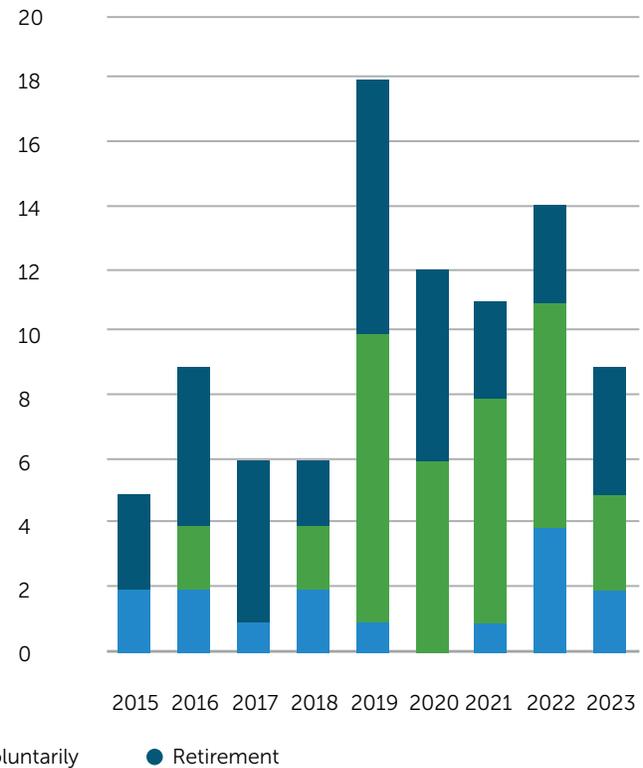


Figure 3 and Figure 4 show the historical reasons for attrition, both for Platte River as a whole and specifically for Rawhide. Retirement drives greater attrition at Rawhide than at Platte River as a whole, another trend that it anticipates will be stable through 2029. Platte River’s projections for natural attrition show that it will be understaffed at Rawhide in the latter part of the decade (for example, from 2027 to 2029).

**Figure 3: Platte River Attrition by Reason**



**Figure 4: Rawhide Attrition by Reason**



Platte River projects that it will need to transition approximately 25-30 Rawhide employees at Unit 1’s retirement if it backfills vacancies that arise due to retirements or other natural attrition. See Table 1. But Platte River may also fill in for natural attrition with contract labor as Unit 1’s retirement date nears. Platte River will be able to better estimate the exact number of employees to transition in future years, as it clarifies the number of employees needed to support the remaining generation at Rawhide and its other departments.

**Table 1. Projected headcount and the number of employees to transition to Rawhide**

Department	Current headcount <small>As of Jan. 1, 2024</small>	Target headcount <small>At retirement Dec. 2029</small>	Target headcount <small>Post 2030</small>	Employees to transition
Plant operations	31	22	10-15	7-12
Mechanical maintenance	14	8	6	2
Instrumentation and electrical	12	12	4	8
Fuel handling / facilities	12	5	4	1
Engineering	10	7	2	5
Lab	2	2	2	0
CAD	1	1	0	1

**Current headcount**

This is the number of employees at Rawhide to support Unit 1 as of May 2022. It does not include contract workers, which are managed by the vendors who employ them.

**Target headcount (at retirement)**

This is the estimated number of employees needed to safely operate Rawhide Unit 1 and the existing combustion turbines.

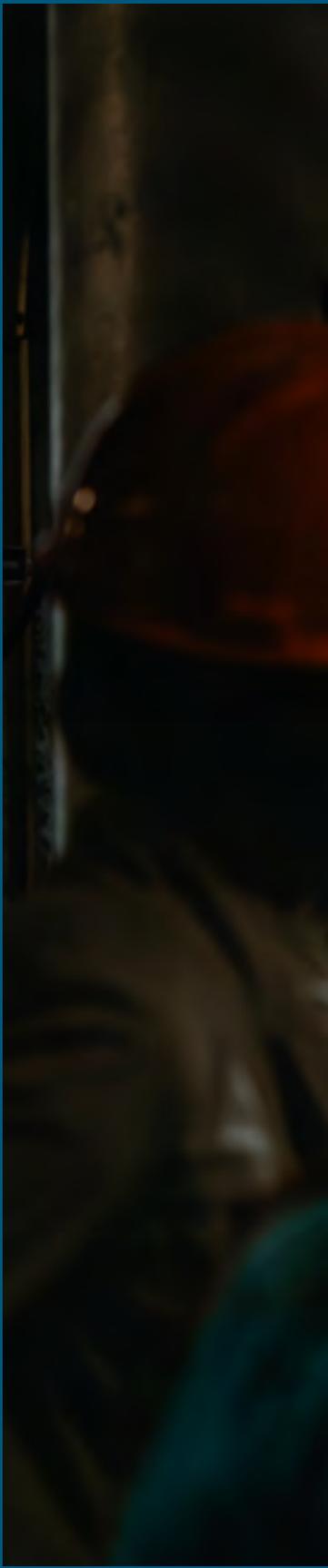
**Target headcount (post-2030)**

This represents the number of employees that it estimates are needed to run the existing gas combustion turbines at Rawhide after Unit 1 retires. These estimates may be updated in future filings.

**Employees to transition**

This number represents employees whose existing jobs may be eliminated due to Unit 1’s retirement. Therefore, this is the number of employees to retrain, transfer within other business areas, or otherwise transition as part of the Just Transition Plan.

Platte River is committed to finding opportunities for each of these employees to remain with the organization, if desired. Platte River intends to honor its promise that no employees will be laid off or involuntarily separated solely due to Unit 1’s retirement and the energy transition. How Platte River intends to meet this commitment is discussed further in the principles below.





# PRINCIPLE 3: WORKFORCE OPPORTUNITIES





Platte River management will prioritize internal staff for workforce opportunities where Rawhide employees have relevant qualifications and experience.

To implement this principle, Platte River is identifying growth opportunities and projected work for existing employees to transition at Rawhide and at Headquarters. The main areas where Platte River sees these opportunities are:

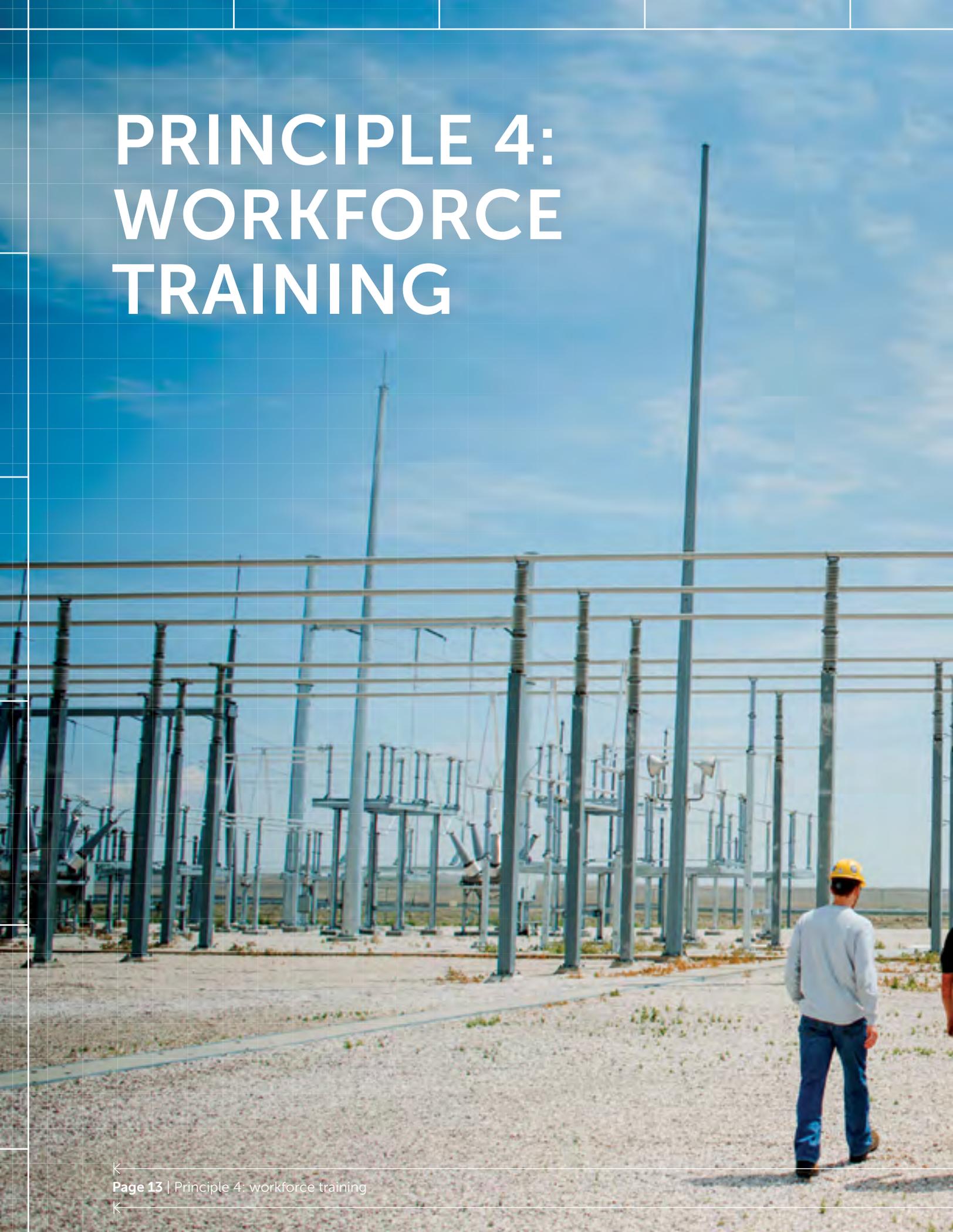
- Power markets and marketing desks (both transmission and generation)
- Compliance
- Information Technology
- Facilities
- Substations

Each of these areas is anticipated to grow between now and 2029 due to the energy transition and Platte River's entry into RTO–West. Platte River encourages high-performing employees to reach out to their supervisors (either as part of a scheduled performance discussion or at other times) to discuss potential transition plans and opportunities. Platte River advertises all vacancies to internal employees and seeks to prioritize internal applicants for many of its open positions.

Platte River plans additional formal efforts in the upcoming years to highlight potential growth opportunities within the organization and support employee advancement and retention. These efforts include an internal "career fair" (expected in 2026) to showcase potential opportunities within the organization and to further the dialogue between departments that may lose staff and departments that need additional employees. Platte River also plans a "shadowing" program between Rawhide and headquarters so that Rawhide employees may learn more about headquarters positions that may be available, and the knowledge, skills, or abilities needed for those roles.

No later than year end 2028, Platte River plans to start formal interviews with employees to have more in-depth discussions about their goals and determine how they may align with future roles. These formal interviews will also help Platte River determine what training, education, or other support might be needed to successfully transition employees into future growth roles.

# PRINCIPLE 4: WORKFORCE TRAINING





Platte River management will provide workforce training for Rawhide employees when appropriate to allow them to successfully transition into new roles.

To implement this principle, Platte River will use the career fair, shadowing, and interview programs described above to engage with employees on how Platte River can best help employees meet their career goals. Platte River intends to capture and analyze information learned through annual employee evaluation processes and other discussions to identify employment trends and skill gaps and to formalize training programs that are specific to the identified skill needs post-2029.

Platte River understands that training and education may be a large component of the workforce transition, particularly for employees contemplating career changes. Platte River currently has a tuition reimbursement program for employees who want to increase skills. This program is already in use with a current Rawhide employee taking courses in information technology. Platte River anticipates this program will grow significantly as it identifies skill gaps and helps employees chart career paths. Platte River is working with its staff to increase transferable skills (like computer literacy) in its current workforce. Platte River will also explore partnerships with local educational institutions in northern Colorado and southern Wyoming. These partnerships may include formal training programs tailored to the Rawhide transition or a continuation of the current tuition reimbursement program, depending on employee and Platte River needs.





# PRINCIPLE 5: RETENTION STRATEGIES

Platte River management will evaluate, design, and implement employee retention strategies to ensure Rawhide Unit 1 continues to provide safe, reliable and financially responsible energy to its owner communities until its closure date.

Platte River is committed to implementing this principle for transitioning Rawhide employees. But employee retention is not just a concern as part of the energy transition or the Just Transition Plan. Platte River seeks to be a leading employer to drive retention for all employees, at both Rawhide and headquarters, and has made many recent changes to its compensation and total employee rewards programs to support employee retention. These changes include industry-leading total rewards and compensation packages, such as:

- Platte River family leave program (providing 12 weeks fully paid family leave),
- Platte River's compensation philosophy is inclusive of a compensation study which uses a market-leading pay above the 50th percentile in 2024,
- Platte River's employee-focused benefits program, and
- Hybrid and remote work available for certain roles.

Platte River is exploring other options for retention at Rawhide up to transition, including retention bonus programs and incentives for advance retirement planning in the years leading up to Unit 1's closure. Platte River will work with its employees to evaluate and carefully implement these strategies in a way that supports the goals of continued operational excellence at Rawhide, an orderly and well planned closure, and employee transition to new roles.



# PRINCIPLE 6: TRANSITION SUPPORT



For those employees whose paths lead away from Platte River, Platte River management will seek to ease their transitions with placement support and incentives, where appropriate.

When discussing this principle, it is important to reiterate that current projections show few, if any, non-voluntary transitions due to the retirement of Rawhide Unit 1. As discussed in the first five principles, above, Platte River is committed to retaining its workforce and anticipates finding roles for Rawhide employees who want to transition to new roles after 2029. Platte River does not anticipate layoffs or other mass transitions. Platte River's Just Transition Plan supports an individualized and career-focused approach for each employee affected by Unit 1's closure.

Should any non-voluntary transitions be needed in the future due to Unit 1's retirement, Platte River is committed to supporting those employees as it supports those who transition voluntarily. Efforts will be deployed through career path discussions and ongoing training and education opportunities like those provided to employees transitioning to internal Platte River roles. Platte River also provides an employee assistance program, which is available to current employees contemplating career changes and transitions. This program may include counseling support as well as legal or financial advice to assist employees in making life changes.

# CONCLUSION

Platte River is committed to a just transition and to retaining its staff and culture of operational excellence. This document will be updated as its workforce plans evolve. Platte River will remain committed to the principles outlined by its board and management to demonstrate their unwavering support to the Platte River employees that safely and reliably operate Unit 1, its highest-performing and most cost-effective resource. Platte River looks forward to working with its staff, management, and the Office of Just Transition to responsibly move toward its energy future.





## Appendix C: Board resolution for 2024 IRP approval

## RESOLUTION NO. 07-24

### Background

- A. Platte River Power Authority (Platte River) was formed to provide electric generation and transmission services to its owner communities.
- B. Platte River is obligated by contract to serve the owner communities' wholesale electrical capacity and energy needs through 2060.
- C. Platte River and its owner communities collaborate to conduct supply-side and demand-side planning.
- D. Platte River uses integrated resource planning to support its development of a resource portfolio consistent with its three foundational pillars of reliability, environmental responsibility and financial sustainability.
- E. In 2018, the board of directors (board) adopted the Resource Diversification Policy, which directs Platte River's general manager/CEO to proactively work toward the goal of reaching a 100% non-carbon resource mix by 2030, while maintaining Platte River's three pillars of providing reliable, environmentally responsible and financially sustainable electricity and services.
- F. By law and to remain eligible for federal hydropower allocations, Platte River must submit a formal integrated resource plan (IRP) to the Western Area Power Administration every five years. Given the challenges of quickly advancing the board's Resource Diversification Policy goals, compounded by rapid evolution of utility technology, the board encouraged staff to accelerate its formal IRP development process. Platte River staff completed and submitted its most recent IRP in 2020, and shared with the board an informal update to the IRP inputs and assumptions in 2022.
- G. Platte River staff, collaborating with industry experts, has worked over the past 18 months to develop the 2024 IRP with updated studies, assumptions, technology advancements, and modeling inputs. Platte River supported community engagement through numerous in-person and virtual meetings, cataloguing and responding to stakeholder questions, and a dedicated internet microsite. Staff shared background information for the 2024 IRP with the board in April 2024 and presented a full draft of the 2024 IRP at the May 2024 board meeting.

**RESOLUTION NO. 07-24**

H. The 2024 IRP reflects existing and potential future resources based on current information, technology and system capabilities and recognizes these and other factors will continue to evolve.

I. Staff recommends selection of the 2024 IRP's optimal new carbon portfolio to establish a new baseline for planning, budgetary and ratemaking purposes.

J. The optimal carbon portfolio in the 2024 IRP provides a path for Platte River to reduce its carbon emissions by more than 90% from 2005 levels while maintaining reliability and financial sustainability, and is therefore consistent with the Resource Diversification Policy and surpasses Colorado legislative goals for greenhouse gas reductions.

K. Staff expects to prepare an updated IRP by 2028, while continuing to communicate transparently and foster public engagement in Platte River's long-term resource planning activities.

L. The board intends that when it approves the Just Transition Plan (Resolution 08-24) for the closure of Rawhide Unit 1, the Just Transition Plan will become part of the 2024 IRP.

Resolution

The board of directors of Platte River Power Authority therefore resolves that:

1. The 2024 IRP, as contained in the July 2024 meeting packet, is approved, and
2. Staff's recommendation to select the optimal new carbon portfolio as Platte River's new baseline for planning, budgetary and ratemaking purposes is accepted, and
3. When the board approves Platte River's Just Transition Plan for Rawhide Unit 1, the Just Transition Plan becomes part of the 2024 IRP.

AS WITNESS, I have signed my name as Secretary and have affixed the corporate seal of the Platte River Power Authority this 25 day of July 2024.

Angela  
Secretary

Adopted: July 25, 2024

Vote: 6-0





# Platte River

Power Authority

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