Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Board of directors regular meeting

2000 E. Horsetooth Road, Fort Collins, CO 80525
Thursday, July 25, 2024, 9 a.m.

Call to order

1. Consent agenda — *Motion to approve*
    a. Minutes of the regular meeting of May 30, 2024

Public comment

Committee reports

2. Defined Benefit Plan committee
    a. Defined Benefit Plan committee appointment — *Resolution 06-24*

Board action items

3. 2024 Integrated Resource Plan — *Resolution 07-24*
4. Rawhide Just Transition Plan — *Resolution 08-24*

Management presentations

5. Fiber management intergovernmental agreement amendment
6. One-year WEIS participation and SPP RTO West update
7. Flat Iron - Estes Park transmission line update
8. Legislative session recap

Monthly informational reports – May/June

9. Q2 performance dashboard
10. Legal, environmental and compliance report
11. Resource diversification report
12. Operating report
13. Financial report
14. General management report

Strategic discussions

Adjournment

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2024 board meeting planning calendar

Updated July 10, 2024

Aug. 29, 2024

Defined Benefit Plan committee meeting

Board action items	Management presentations	Management reports	Monthly informational reports
Fiber management intergovernmental agreement amendment	Battery energy storage update		Legal, environmental and compliance report
	Marketing update		Resource diversification report
			Operating report
			Financial report
			General management report

Sept. 26, 2024

Board action items	Management presentations	Management reports	Monthly informational reports
	2025 proposed strategic budget work session	Staffing update (memo only)	Legal, environmental and compliance report
	2025 rate tariff schedules		Resource diversification report
			Operating report
Committee report			Financial report
Defined Benefit committee report			General management report

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Oct. 31, 2024

Defined Benefit Plan committee meeting

Board action items	Management presentations	Management reports	Monthly informational reports
2024 FORVIS financial audit plan	2025 proposed strategic budget update – public hearing		Q3 performance dashboard
2025 rate tariff schedules	Long-term fuel supply strategy		Legal, environmental and compliance report
			Resource diversification report
			Operating report
			Financial report
			General management report

November 2024

No board of directors meeting

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Dec. 12, 2024

Board action items	Management presentations	Management reports	Monthly informational reports
2025 proposed board of directors regular meeting schedule	Transmission rate design changes	Benefits update (memo only)	Legal, environmental and compliance report
2025 Strategic Budget review and adoption			Resource diversification report
			Operating report
			Financial report
Committee report			General management report
Defined Benefit committee report			

Topics to be scheduled:

-

This calendar is for planning purposes only and may change at management's discretion.

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2024 board of directors

Owner communities	**Term expiration**
Town of Estes Park	
P.O. Box 1200, Estes Park, Colorado 80517	
Mayor Gary Hall	April 2028
Reuben Bergsten	December 2024
City of Fort Collins	
P.O. Box 580, Fort Collins, Colorado 80522	
Mayor Jeni Arndt—Vice Chair, Board of Directors	January 2026
Tyler Marr	December 2026
City of Longmont	
350 Kimbark Street, Longmont, Colorado 80501	
Mayor Joan Peck	November 2025
David Hornbacher	December 2026
City of Loveland	
500 East Third Street, Suite 330, Loveland, Colorado 80537	
Mayor Jacki Marsh	November 2025
Kevin Gertig—Chair, Board of Directors	December 2025

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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.

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Memorandum

Date: 7/17/2024

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Angela Walsh, executive director of board and administration

Subject: **Consent agenda – July**

Staff requests approval of the following item on the consent agenda. The supporting document is included for the item listed below. Approval of the consent agenda will approve the item unless a board member removes the item from consent for further discussion.

Attachment

- Minutes of the regular meeting of May 30, 2024

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Regular meeting minutes of the board of directors

2000 E. Horsetooth Road, Fort Collins, CO
Thursday, May 30, 2024

Attendance

Board members
Representing Estes Park: Mayor Gary Hall and Reuben Bergsten
Representing Fort Collins: Mayor Jeni Arndt and Tyler Marr
Representing Longmont: Mayor Joan Peck and David Hornbacher
Representing Loveland: Mayor Jacki Marsh and Kevin Gertig

Platte River staff
Jason Frisbie (general manager/CEO)
Sarah Leonard (general counsel)
Dave Smalley (chief financial officer and deputy general manager)
Melie Vincent (chief operating officer, generation, transmission and markets)
Raj Singam Setti (chief operating officer, innovation and resource strategy integration)
Eddie Gutiérrez (chief strategy officer)
Angela Walsh (executive director of board and administration, board secretary)
Kaitlyn McCarty (senior executive assistant)
Mitch Tomaier (IT systems administrator)
Shelley Nywall (director, finance)
Wade Hancock (senior manager, financial planning and rates)
Heather Banks (senior manager, fuels and water)
Javier Camacho (director, public/external affairs, strategic communications/social marketing)
Kendal Perez (manager, strategic communications and community relations)
Leigh Gibson (senior external affairs specialist)
Paul Davis (manager, distributed energy resources)
Bryce Brady (manager, distributed energy solutions)
Pat Connors (director, portfolio strategy and integration)
Erik Martin (financial analyst III)

Guests
none

Call to order

Chair Gertig called the meeting to order at 9:00 a.m. A quorum of board members was present via roll call. The meeting, having been duly convened, proceeded with the business on the agenda.

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Action items

1. Consent agenda

a. Approval of the regular meeting minutes of April 25, 2024
b. Resolution 04-24: Wholesale transmission service tariff (WT-25)

Director Bergsten moved to approve the consent agenda as presented. Director Marsh seconded. The motion carried 8-0.

Public comment

Chair Gertig opened the public comment section by reading instructions, noting that time to accommodate each speaker would be divided equitably by the number of in-person members of the public and callers wishing to speak at the start of public comment. Five members of the public addressed the board.

Board action items

2. Executive session

Chair Gertig noted the next item on the agenda was for the board of directors and senior leader staff to go into executive session for the purposes of determining positions relative to matters that may be subject to negotiations, developing strategy for negotiations, and instructing negotiators. Specifically, the board would confer with and provide guidance to staff about long-term power purchase agreements.

The general counsel advised that an executive session was authorized in this instance by Colorado Revised Statutes, Section 24-6-402(4)(e)(I); provided that no formal action would be taken during the executive session. Director Bergsten seconded, and the motion carried 8-0.

Reconvene regular session

The chair reconvened the regular session, confirming by roll call that all board members were present and asked if there was further discussion or action because of the executive session. No further discussion or action was taken.

3. Support for a virtual power plant (Raj Singam Setti)

Raj Singam Setti, chief operating officer, innovation and resource strategy integration, thanked the board for their feedback and support for the resolution. He stated the resolution will ensure collaboration will continue and the funding is stated clearly for the four owner communities and Platte River throughout the development of the virtual power plant (VPP). Director Bergsten commented on the cost-benefit ratio and community engagement throughout the process.

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Mr. Frisbie recommended taking a long-term view towards future benefits to the system for this portion of the portfolio. Director Marr supported starting the VPP early to keep the process moving forward. Discussion ensued among directors and staff regarding the four owner communities working together with Platte River to integrate systems of the five entities, choosing the technology that works well together and centralizing the system.

Director Bergsten moved to approve Resolution 05-24: Support for a virtual power plant. Director Hall seconded. The motion carried 8-0.

Management presentations

4. Draft 2024 Integrated Resource Plan (presenter: Raj Singam Setti)

Mr. Singam Setti provided an overview of the planning and assumptions used to develop the 2024 Integrated Resource Plan (IRP) and presented the results of the five portfolio options.

Director Arndt commented that the planning assumption for potential beneficial electrification and electric vehicle penetration forecast for load growth did not seem to match predictions from media reports on artificial intelligence (AI) power requirements. Mr. Singam Setti noted that AI growth is not expected to be as high in Northern Colorado as on the east coast.

Director Hornbacher asked if the wind capacity factors Platte River used are an industry standard set for planning purposes. Mr. Singam Setti explained that Platte River used third-party vendor evaluate Platte River's system and the western interconnection. Results showed capacity factors decreasing as more wind was added to the system. This is because wind's contribution to load service during peak demand is limited. Sarah Leonard, general counsel, explained the organized market sets the prescribed methodologies to assess load carrying capability to decide who meets resource adequacy requirements in the system. Melie Vincent, chief operating officer, generation, transmission and markets, added that transmission plays a role in obtaining a higher effective load carrying capability.

Director Hornbacher pointed out that after 2030 all coal is removed from the portfolio and the added dispatchable thermal resource will eventually change to green hydrogen when the technology catches up. Mr. Frisbie noted the chart does not include existing combustion turbines (CT) currently in the portfolio that will remain post 2030. He added that long-duration storage could replace the CTs in the future. Director Marr asked for a comparison of the three portfolios that are similar in cost. Mr. Singam Setti discussed the differences between the three portfolios in economic value, including the cost of each added resource, how much of the resource would be needed and how to manage the portfolio, referring to them as tools in the tool kit. He added that the differences are in portfolio reliability and associated costs.

Director Bergsten asked if the carbon-imposed cost was an internal addition or an external requirement for each portfolio. Mr. Singam Setti stated that a carbon tax may be imposed for thermal resources in the future and the variable was added to the cost comparison of each portfolio. Discussion ensued among directors and staff regarding carbon costs and the production of carbon-emitting resources.

5. Average wholesale rate projections and 2025 tariff schedule charges (presenters: Shelley Nywall and Wade Hancock)

Shelley Nywall, director of finance, discussed the Platte River financial governance framework, the historical average wholesale rates since 1978, the projected rate increases expected until 2034 and what is driving the rate increases.

Director Hornbacher recommended showing the value of reliability as an important factor included in the rate increase projections. Director Bergsten echoed the importance and value of reliability. Director Hornbacher commented on reliability and how that will impact the increased need for charging electric vehicles. Ms. Vincent noted that organized markets quantify the value of lost load. Director Hall commented on the variables included in rates forecasting. Discussion ensued among directors and staff regarding increasing costs, rate smoothing efforts and long-term outlooks for the variables that will change.

Wade Hancock, senior manager, financial planning and rates, presented the case comparisons for revenues and expenses, what is driving rate increases, rate stability strategies, rate modeling uncertainties, average wholesale rate ranges and the 2025 rate tariff schedule changes.

Director Arndt asked if customer price sensitivity is considered during the modeling process. Mr. Frisbie commented on household customer usage being minimal and that most of the energy consumption is commercial and industrial. Mr. Singam Setti and Mr. Hancock responded on customer behavior over the last six years has changed the load profiles affecting the load growth projections. Discussion ensued among directors and staff on customer behavior, cost considerations for businesses and automation of electricity saving devices.

Director Bergsten asked if the peaking units' usage in the winter compared to the summer months were being driven by the market. Mr. Hancock responded the CTs are being used more in the non-summer months than previous years; the summer use ratio changes when they are used in non-summer months. Ms. Vincent commented on the units being online to provide system reliability and to cover surplus sales contracts.

Management reports

6. Rawhide Just Transition Plan (presenter: Melie Vincent)

Ms. Vincent discussed the Rawhide Just Transition Plan that will be incorporated into the 2024 IRP and, upon approval, will be sent to the Colorado Office of Just Transition. Staff will present the plan during the July board meeting.

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7. Water Resources Reference Document update (presenter: Heather Banks)

Heather Banks, sr. manager, fuels and water, presented the eighth edition of the Water Resources Reference Document, noting the condensed version will be updated on a three-year cycle moving forward.

Monthly informational reports for April

8. Legal, environmental and compliance report (presenter: Sarah Leonard)

Ms. Leonard highlighted the Glen Canyon Dam ruling, Environmental Protection Agency's rules that will affect Platte River, and the Department of Energy's final ruling on coordinated interagency transmission authorizations and permits program.

9. Resource diversification report (presenter: Raj Singam Setti)

Mr. Singam Setti discussed ongoing negotiations with developers on two solar projects, working on term sheets for the wind projects and work being done to move the energy storage projects forward. He also mentioned Platte River staff continues to work with owner community staff on the distributed energy storage project with permitting and site locations.

10. Operating report (presenter: Melie Vincent)

Ms. Vincent highlighted operating results for a mild weather month in April, reflecting demand and energy below budget. Net variable cost to serve owner community energy was also below budget, driven by coal generation fuel savings and lower wind generation volume, offset by lower bilateral and market sales volume, higher coal generation fuel pricing and higher market purchase volume. Year-to-date, much like April, owner community demand and energy are below budget, resulting in lower coal generation, lower market sales volume and higher fuel pricing and purchase volume.

11. Financial report (presenter: Dave Smalley)

Mr. Smalley highlighted financial results for April, reflecting favorable change in net position compared to the budget. Below-budget revenues were more than offset by reduced operating expenses. Year to date, change in net position is $5 million above budget, however approximately $3 million of the variance is due to budget timing for work on the CT units. Year to date, below-budget operating expenses continue to offset below-budget revenues for the year.

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12. General management report (presenter: Jason Frisbie)

Mr. Frisbie highlighted the Fiber Optics Intergovernmental Agreement coming to the board as a presentation in July, with approval in August. He also noted the printed 2023 Annual Report handed out to the board. He thanked staff for working on the draft IRP document provided in the board packet.

Roundtable and strategic discussion topics

Directors provided updates from their individual communities.

Adjournment

With no further business, the meeting adjourned at 12:32 p.m. The next regular board meeting is scheduled for Thursday, July 25, 2024, at 9:00 a.m. either virtually or at Platte River Power Authority, 2000 E. Horsetooth Road, Fort Collins, Colorado.

AS WITNESS, I have executed my name as Secretary and have affixed the corporate seal of the Platte River Power Authority this ______ day of__________________, 2024.

____
Secretary

Adopted:
Vote:

Platte River Power Authority

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Memorandum

Date: 7/17/2024

To: Board of directors

From: David Hornbacher, board member, retirement committee chair
Jason Frisbie, general manager and chief executive officer

Subject: **Defined Benefit Plan committee report**

The retirement committee held its quarterly meeting on May 30, 2024. The minutes of the meeting are included in the board packet. At the board meeting, Dave Smalley will provide a summary of the May retirement committee meeting.

Attachment

- May 30, 2024 defined benefit plan committee minutes - DRAFT

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Regular meeting minutes of the defined benefit plan committee

2000 E. Horsetooth Road, Fort Collins, CO and virtually via Microsoft Teams
Thursday, May 30, 2024

Attendance

Committee members
Jeni Arndt
Reuben Bergsten
Jason Frisbie (plan administrator)
David Hornbacher, chair
Jacki Marsh
Dave Smalley

Platte River staff
Libby Clark (director, human resources and safety)
Jayna Curtis-Martin (total rewards administrator
Julie Depperman (director, treasury services)
Kaitlyn McCarty (senior executive assistant)
Shelley Nywall (director, finance)
Caroline Schmiedt (senior counsel)
Staci Sears (senior manager, human resources)
Peter Tatarko (compensation business partner)

Guests
Brian Arnell of Willis Towers Watson[1]
Anwiti Bahuguna of Northern Trust Asset Management (Northern Trust)[1]
Jim Hayes of Northern Trust[1]
Jason Palmer of Northern Trust[1]
Armand Yambao of Northern Trust[1]

Call to order

The meeting was called to order at 1:15 p.m. A quorum was present and the meeting, having been duly convened, was ready to proceed with business. Committee Chair Dave Hornbacher led the meeting.

Action items

(1) Review minutes of Feb. 29, 2024 and March 21, 2024 interim meetings. Chair David Hornbacher asked for a motion to approve the minutes from the Feb. 29, 2024, meeting. Reuben Bergsten moved to approve the minutes as submitted. Jacki Marsh seconded, and the motion carried 6-0. Chair Hornbacher asked for a motion to approve the minutes from the March 21, 2024, meeting. Jeni Arndt moved to approve the minutes as submitted. Reuben

[1]Left the meeting at 2:17 p.m. for investment consultant review follow-up

Bergsten seconded, Jacki Marsh abstained as she was absent from this meeting and the motion carried 5-0.

(2) Recommended Defined Benefit Plan (plan) contribution for 2025. Brian Arnell with Willis Towers Watson, the plan's actuary, reviewed the Dec. 31, 2023 actuarial valuation (2025 funding) memorandum, stating if assumptions are met going forward, the plan's actuary projects a steady decline in funding over the period from 2025 to 2045, with funding falling below $1 million beginning 2034. Mr. Arnell reviewed the defined benefit plan 20-year funding projections chart included in the memorandum and explained how the chart depicts the most recent funding projection compared to the funding expectations developed by the actuary in 2022 and 2023. The shift in the projections reflects the impact of market returns and plan experience (e.g., actual salary increases, terminations/ retirements, cost of living adjustments, etc.).

Mr. Arnell also reviewed the five-year historical funding and pension information table included in the memorandum, explaining how the total recommended contribution for the funding year is determined. Platte River's funding for the plan will decrease from $9.1 million in 2024 to $8.0 million in 2025. At the March 2023 board meeting, the board approved contributing $3.0 million of additional funding in 2023. This reduced the 2024 contribution from $9.1 million to $6.1 million. The 2025 funding includes a $3.8 million additional funding charge. The additional funding charge is implemented (amortized over five years) when the estimated present value of accrued benefits exceeds the estimated market value of assets. Mr. Arnell stated that the contribution for 2025 is in line with last year's estimate.

(3) First quarter investment performance. Anwiti Bahuguna of Northern Trust reviewed first quarter performance and highlighted plan performance relative to its benchmarks (included in the meeting materials). Northern Trust staff summarized key market developments, economic indicators and significant events that impacted the market.

Jason Palmer of Northern Trust provided a brief portfolio overview, highlighting that inception to date the portfolio returned 6.7%, slightly below the benchmark of 6.9%. For the quarter, the plan returned 3.9%, significantly below the benchmark return of 5.1%. The long-term return goal is 7.5%.

Mr. Palmer reviewed the plan's portfolio position for the first quarter and recapped his firm's asset allocation process. The portfolio consists of risk control and risk assets. During the quarter, Northern Trust repositioned the portfolio based on the revised Investment Policy Statement. The current portfolio is overweight equities, and underweight fixed income and real assets.

For the quarter, the plan assets increased from $112.9 million to $116.6 million, which accounts for contributions, income, appreciation, depreciation and benefit payments.

Mr. Palmer reviewed the plan's key performance drivers for the quarter. Global equities, fixed income and real assets all gained during the quarter. Tactical positioning with overweight cash and underweight global equities hurt performance. Tactical positioning detracted from results by 0.10% to 0.20%. Investment manager selection resulted in negative performance during the quarter. Two of the three QLV strategies underperformed (all three have been liquidated). Overall, investment manager selection hurt performance by 0.89% to 1.10%.

Page 16 of the quarterly investment report provides rationales for the portfolio's positioning in each asset class.

Mr. Palmer provided a portfolio transition update. In March 2024, Northern Trust implemented a revised investment portfolio structure based on the Investment Policy Statement approved in February 2024. The primary goal of the reallocation was to help enhance long-term expected returns with lower volatility than the prior investment portfolio. These changes included the following portfolio modifications:

- Transitioned into fundamentally driven investment strategies across global equity and high-yield strategies (eliminated quality, low-volatility equity strategies)
- Introduced distinct passive large cap and active small cap US equity strategies
- More balanced real asset portfolio structure
- Established long-duration fixed income strategy
- Slight increase to investment management fees (0.32% vs. 0.33% estimated)

(4) Asset and liability study. Armand Yambao of Northern Trust presented an asset liability study. Mr. Yambao noted the purpose of an asset liability study is to help a plan sponsor review the investment strategy and explore opportunities for improvement. The study models the financials of the pension plan over a ten-year forecasting period and across a full spectrum of economic scenarios. The last full asset liability study was completed in 2022.

The new strategic asset allocation is expected to provide a reasonable balance to manage the asset volatility while earning sufficient returns to improve the funded ratio over time. Platte River's disciplined contribution strategy continues to be key and contribution amounts could decline over time. The plan is 80% funded as of 12/31/2023. Four years ago (as of 12/31/2019), the funded ratio was 85% and previous stochastic projections in 2020 showed a 25% chance (i.e., 25th percentile) that the funded ratio would be 79% or less by 2024. Current projections show that funded ratio is expected to gradually improve to 90% by 2027 and expected to reach 100% within 10 years. Mr. Yambao indicated that Platte River may consider de-risking the asset allocation in 2027 if funded ratio is at least 95%. The rationale for potential de-risking in the future is that the plan becomes more mature as there are fewer active participants over time.

(5) OCIO fee survey results. Mr. Palmer reviewed the survey results from the outside chief investment officer (OCIO) fee survey. Historically, respondents to the survey noted lower OCIO/advisory fees, in basis points, as asset levels increased. While fees have trended lower historically, there is less downward pressure on fees than in the past. Distinct service models, services offered (e.g., bundled services, etc.) make fee comparisons somewhat challenging. For the second year in a row, OCIO providers cited fee comparisons as a top, major challenge. Platte River's annual OCIO fee is 15 basis points, which ranked in the second lowest fee tier (11-20 basis points) for plans with assets between $101M and $250M. At the end of 2023, 46% of respondents noted an annual OCIO fee in the 11-20 basis points range.

(6) Other business - follow-up: investment consultant review. Julie Depperman provided an investment consultant review following the March interim meeting. The committee members reiterated their disappointment in the portfolio's performance. The last investment consultant request for proposals (RFP) process was conducted in 2019. As part of the committee's fiduciary responsibility, the committee directed staff to move forward with an RFP for investment consulting services.

The next regular committee meeting is scheduled for Aug. 29, 2024, at 12:30 p.m. in the Platte River board room or virtually via Microsoft Teams.

The meeting adjourned at 2:54 p.m.

____
Chair David Hornbacher

RESOLUTION NO. 06-24

Background

A. The board of directors of Platte River Power Authority established a Defined Benefit Retirement Committee under the Platte River Defined Benefit Plan, consisting of four directors and two members of management to administer the Defined Benefit Plan.

B. Because Reuben Bergsten will no longer serve as a member of the Defined Benefit Plan Committee, there is now a vacancy.

C. Gary Hall has expressed a willingness to serve on the Defined Benefit Plan Committee.

Resolution

The board of directors of Platte River Power Authority therefore resolves that Gary Hall is elected to serve on the Defined Benefit Plan Committee until the next annual meeting of the board of directors.

AS WITNESS, I have signed my name as secretary and have affixed the corporate seal of the Platte River Power Authority this _________ day of _________________, 2024.

____
Secretary

Adopted:
Vote:

Platte River Power Authority

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Memorandum

Date: 7/17/2024

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Raj Singam Setti, chief operating officer, innovation and resource strategy integration

Subject: 2024 Integrated Resource Plan

The 2024 Integrated Resource Plan (IRP) represents the culmination of months of dedicated preparation, extensive public engagement, and our steadfast commitment to a sustainable and reliable energy future.

Platte River engaged nine top-tier industry consultants and invested thousands of hours in a comprehensive evaluation of scenarios to meet our clean energy challenges. The outcome is five strategic portfolio options and one recommended path forward. This plan proposes the addition of 760 megawatts of new renewable energy through wind and solar projects by 2030.

This is accompanied by a three-pronged approach to dispatchable capacity:

1. Developing a virtual power plant with our owner communities.
2. Implementing short- and long-duration energy storage solutions.
3. Using the most advanced, hydrogen-capable aeroderivative technology to support reliability and enable deeper decarbonization.

Staff will ask the board to approve the 2024 IRP at the July board meeting.

Attachments

- 2024 Integrated Resource Plan document
- Resolution 07-24: 2024 Integrated Resource Plan Approval

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2024 Integrated Resource Plan

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Glossary

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

LOLE .... Loss of Load Expectation

LOLH .... Loss of Load Hours

MISO .... Midcontinent Independent System Operator

MW .... Megawatt

MWh .... Megawatt-hours

NEM .... Net energy metering

NEVI .... 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

NREL .... National Renewable Energy Laboratory

ODTY .... One Day in Ten Years

PPA .... Power purchase agreement

PRM .... Planning reserve margin

RDP .... Resource Diversification Policy

RFP .... Request for proposals

RP22 .... Platte River's Resource Plan 2022

RTO West .... Regional Transmission Organization West

SPP .... Southwest Power Pool

TOU .... Time of use

VPP .... Virtual power plant

WAPA .... Western Area Power Administration

WECC .... Western Electricity Coordination Council

WEIS .... Western Energy Imbalance Service market

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01 Executive summary

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.

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.

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.

02 Introduction

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:

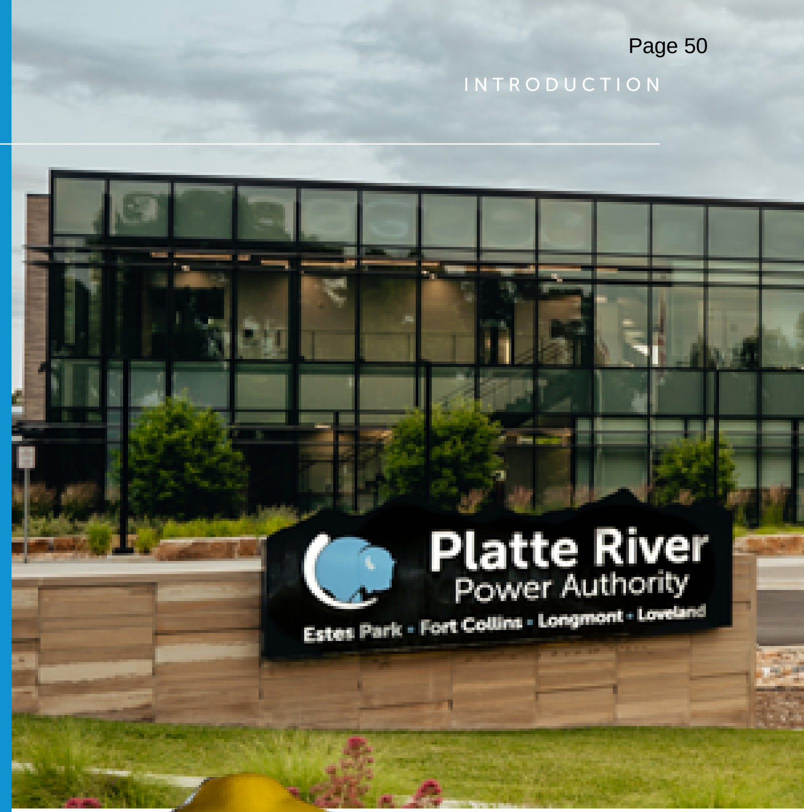
- The remainder of this section provides a general overview, background and history of Platte River, illustrating the foundational pillars and board-adopted policy that guide our planning activities and decisions.
- While IRPs are common among electric utilities, Platte River's approach is unique. Chapter 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.[1]

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.



[1] American Public Power Association website, 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 SO2-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[2] 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[3]) 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.

[2] In this document the acronym IRP is used in two different ways–an integrated resource plan and as an integrated resource planning process

[3] 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.

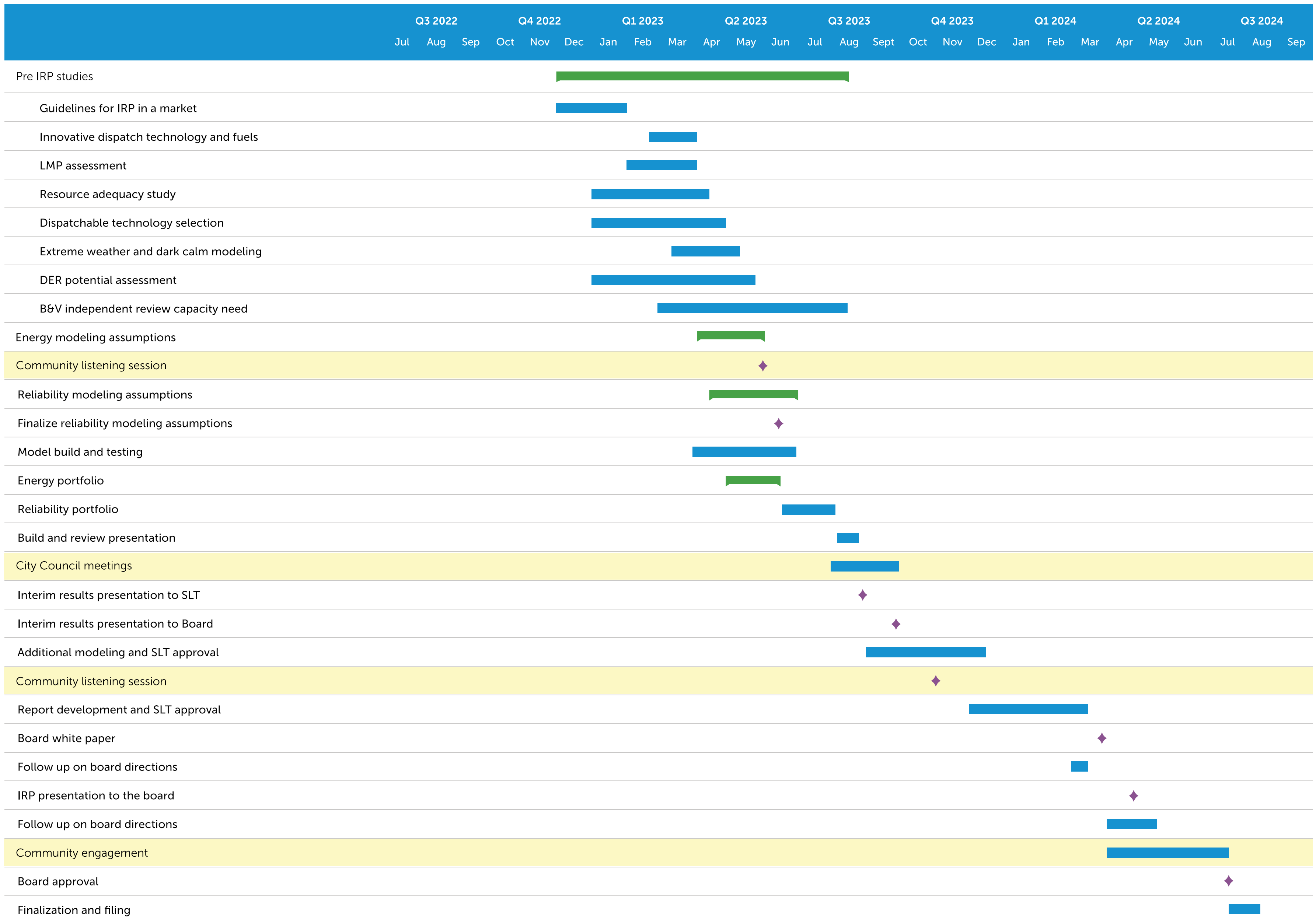


Figure 2. *Timeline of 2024 Integrated Resource Plan activities and milestones*

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-

[4] 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.[4] 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[5], PPA prices in the U.S. doubled by the end of 2023 compared to 2020 levels.

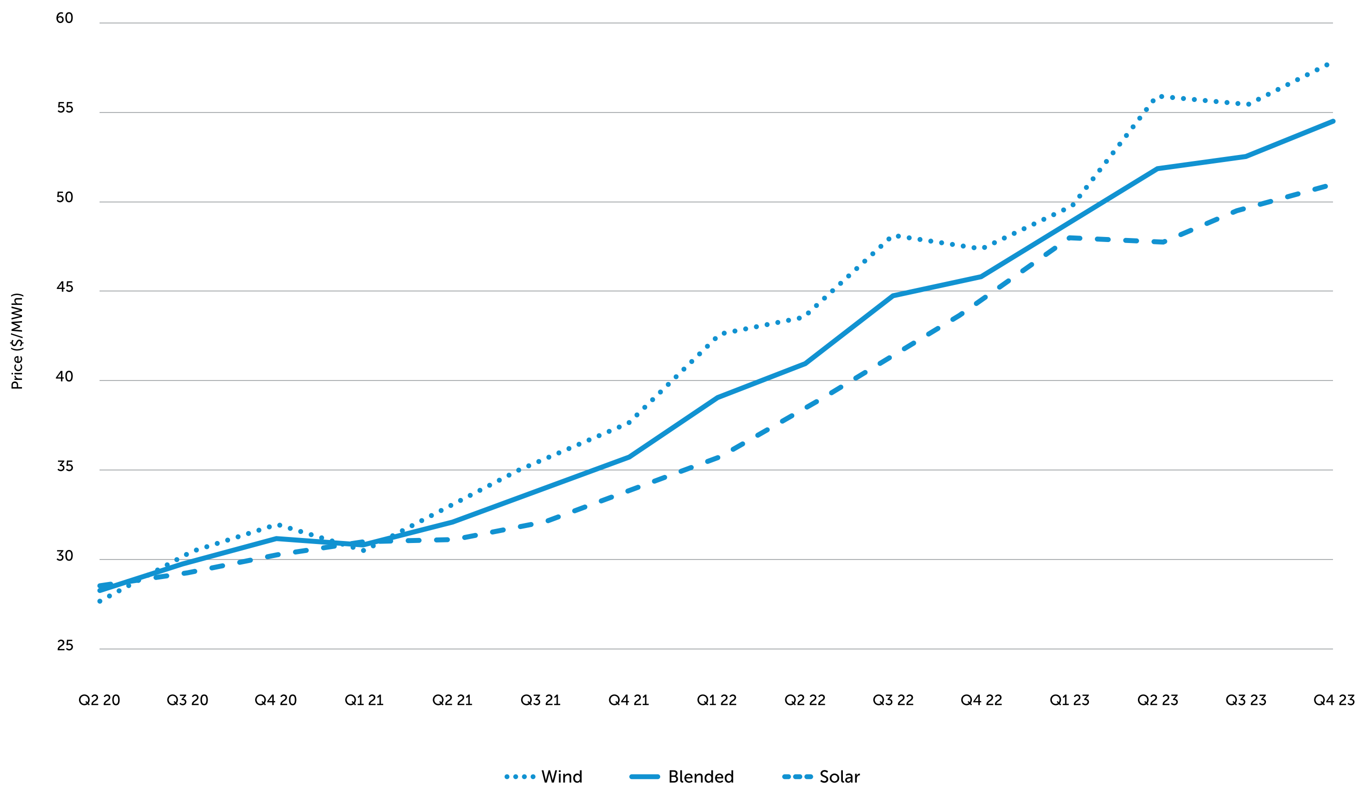


Figure 3. *PPA prices in the U.S. between 2020 and 2023*

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[6] 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.[7]

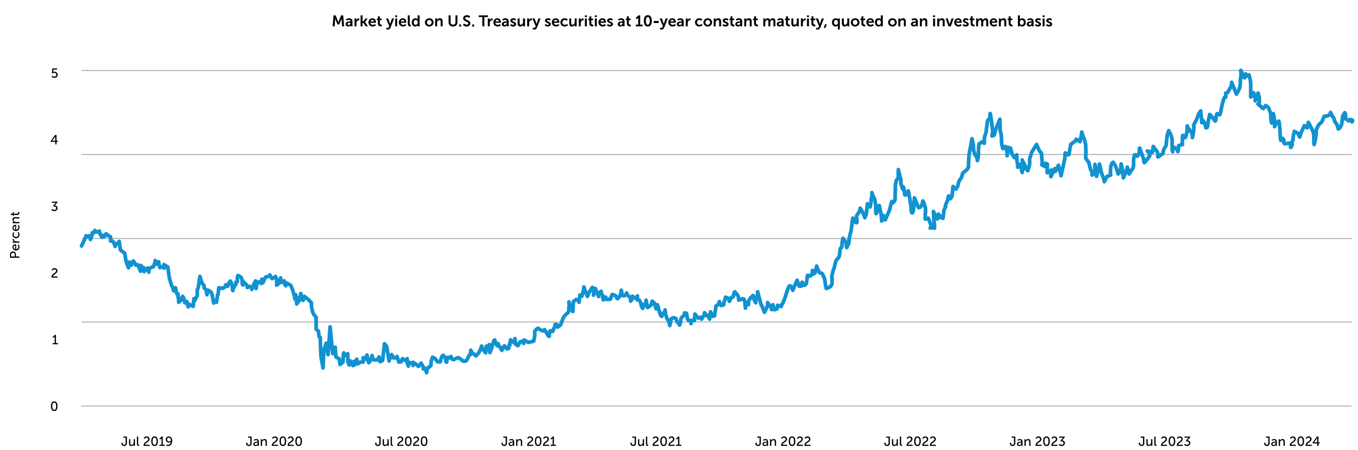


Figure 4. *Market yield on U.S. Treasury securities at 10-year constant maturity, quoted on an investment basis*

[5] https://www.leveltenenergy.com/ppa

[6] https://www.eia.gov/todayinenergy/detail.php?id=61424

[7] 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.

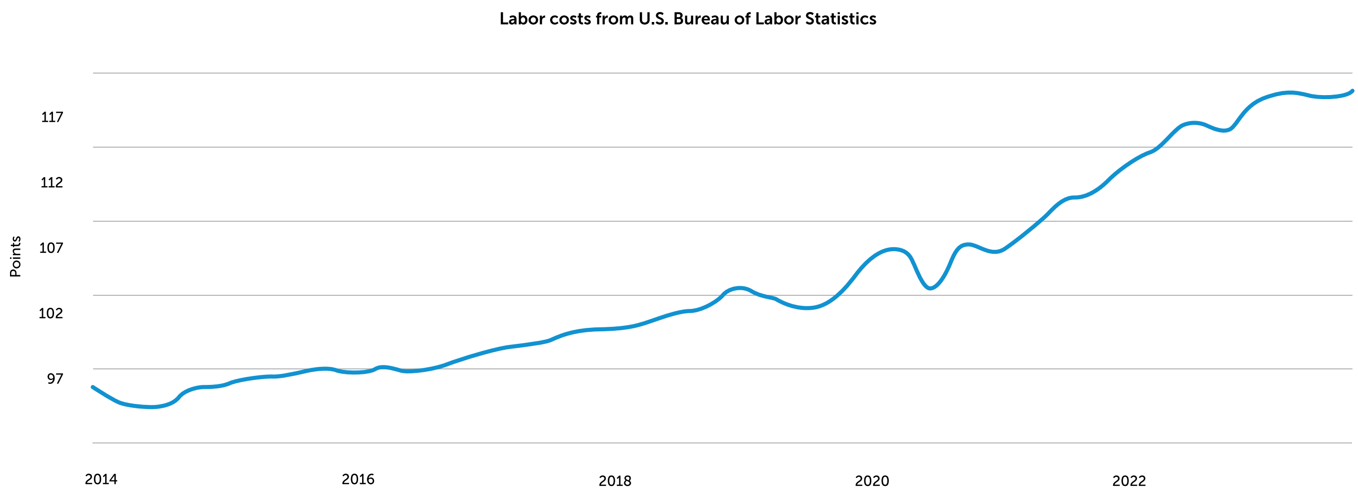


Figure 5. *Labor costs from U.S. Bureau of Labor Statistics*

Similarly, metal costs have seen more volatility and net increase over the past few years, as shown in Figure 6.[8]

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.

[8] https://fred.stlouisfed.org/series/PMETAINDEXM

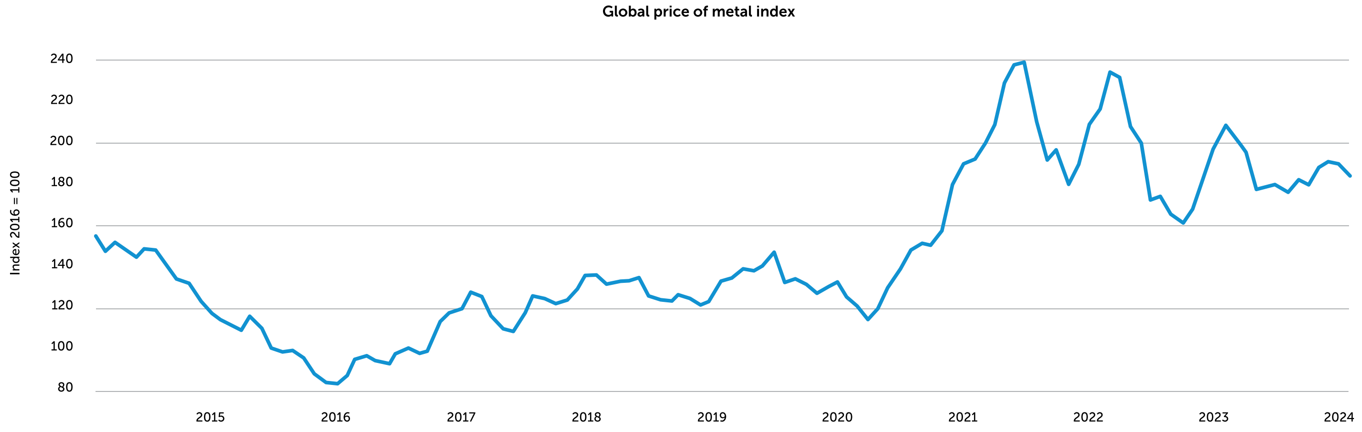


Figure 6. *Global price of metal index*

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
HB19-1261: The Climate Action Plan to Reduce Pollution		✓	
SB19-096: Collect Long-term Climate Change Data	✓		
HB22-1244: Public Protections from Toxic Air Contaminants	✓		
SB23-198: 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


Timeline
June
July
Aug
Sept
Oct
Nov
Dec
Jan
Feb
Mar
April
May
June
Community engagement
Resource planning
Load forecasting
Other inputs, assumptions
Platte River

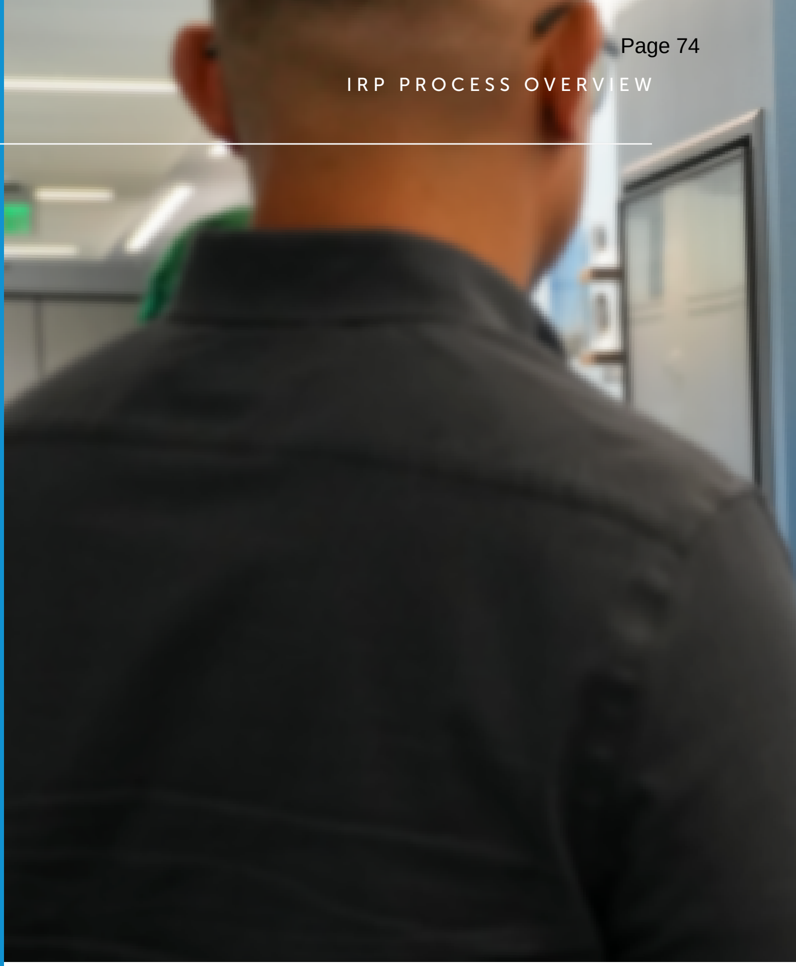
Each presentation gave the audience an opportunity to ask questions. The Platte River team continues to receive questions via email, social media and in-person. To date, we have logged and answered over 150 questions.

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) 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. 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.

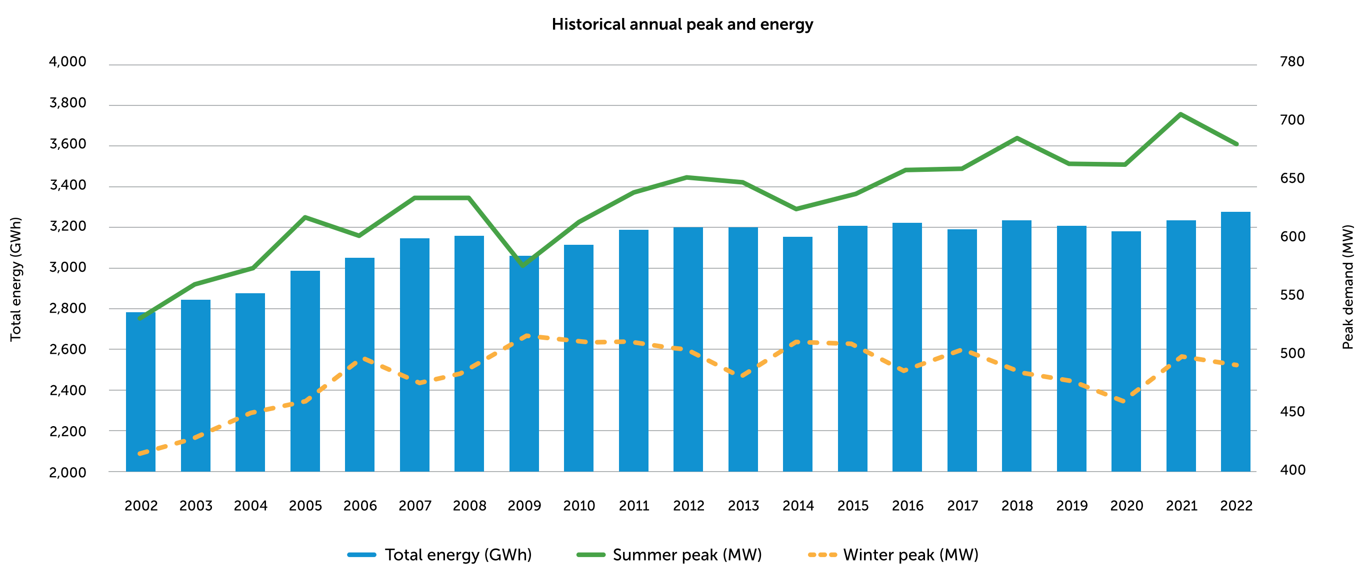


Figure 7. *Historical annual peak and energy*

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.

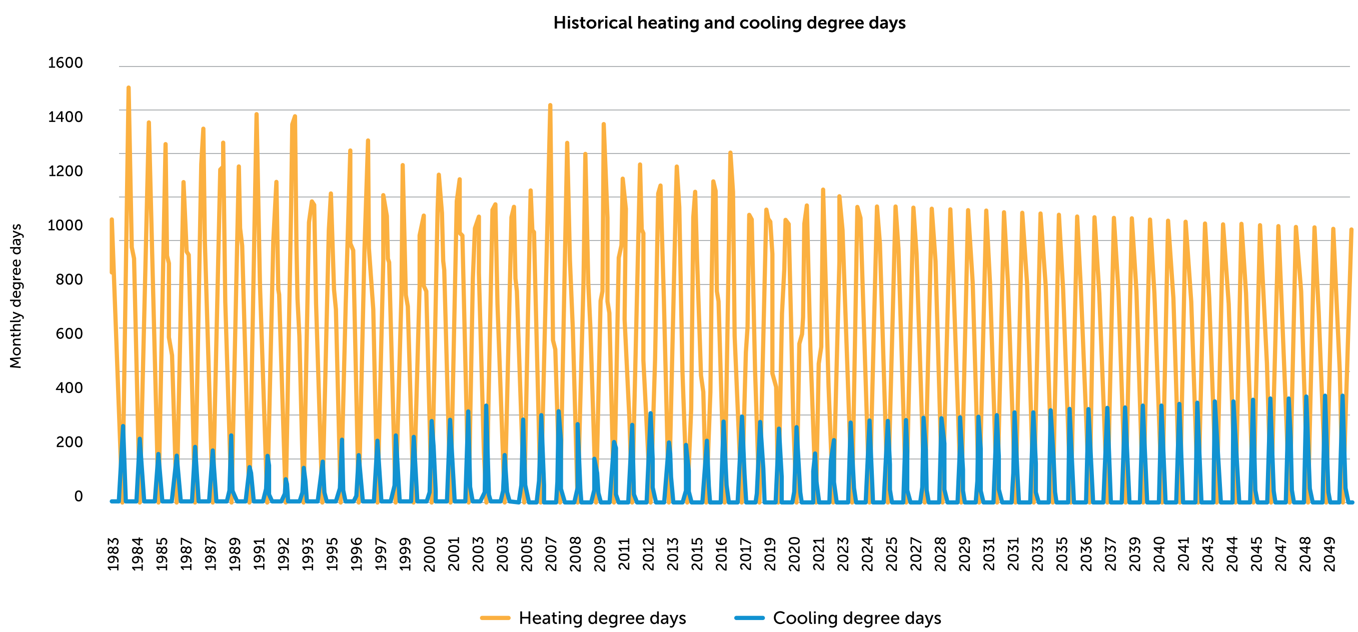


Figure 8. *Historical heating and cooling degree days*

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.

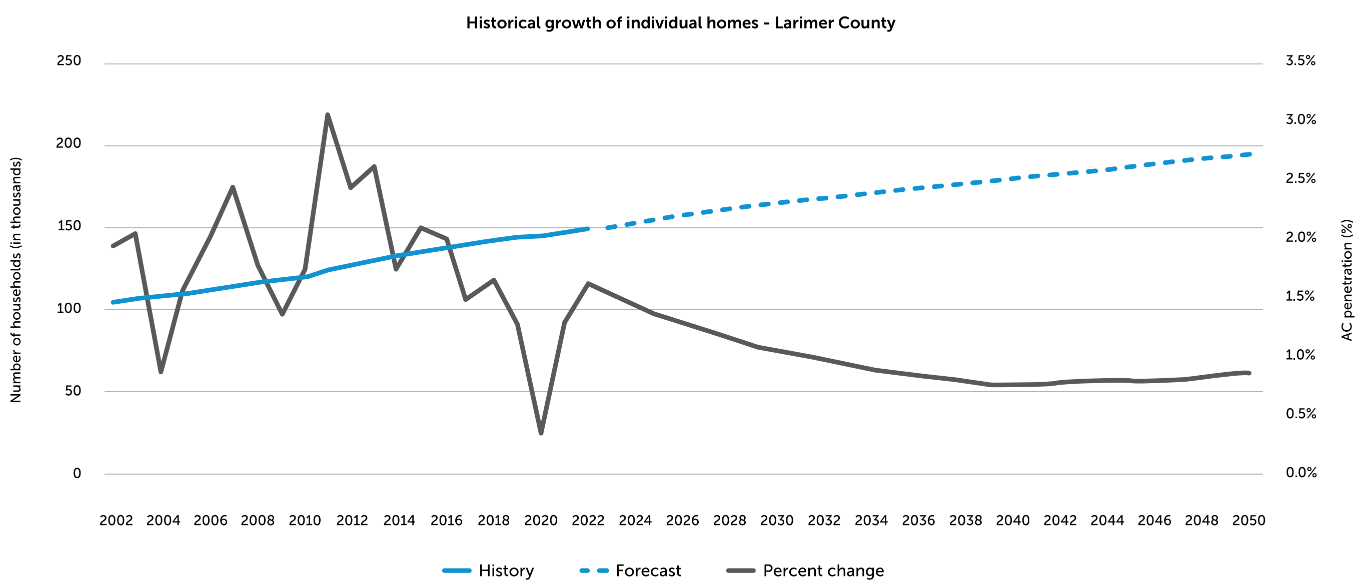


Figure 9. *Historical growth of individual homes*

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.

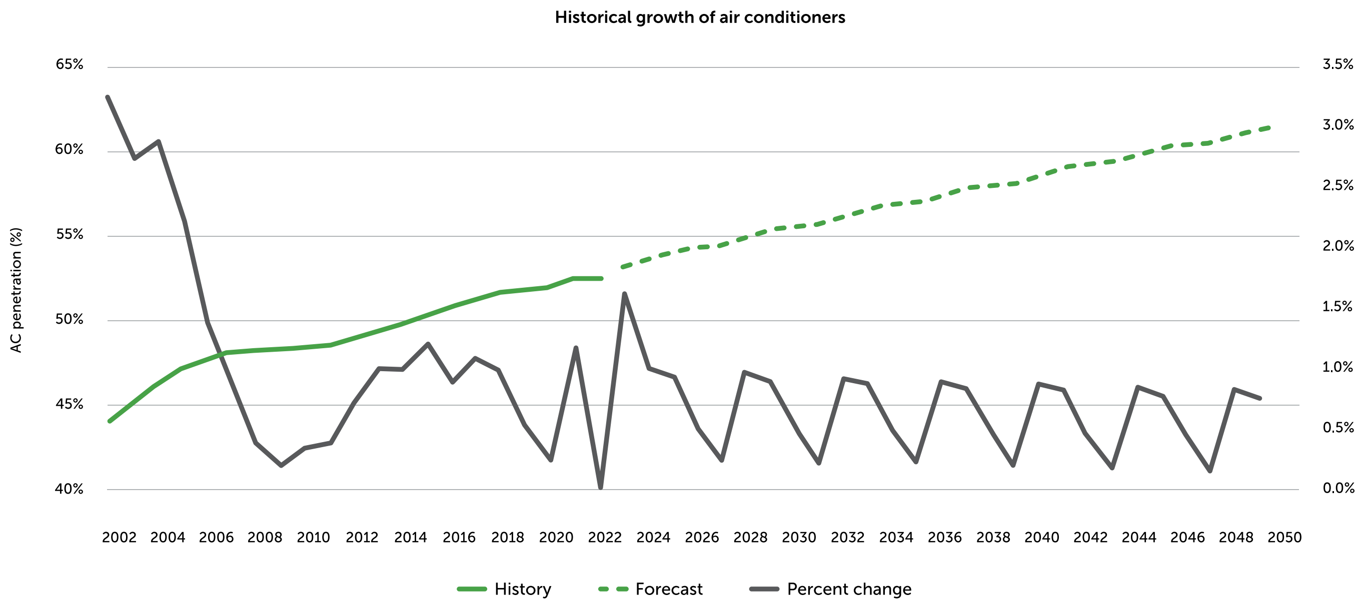


Figure 10. *Historical growth of air conditioners*

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.

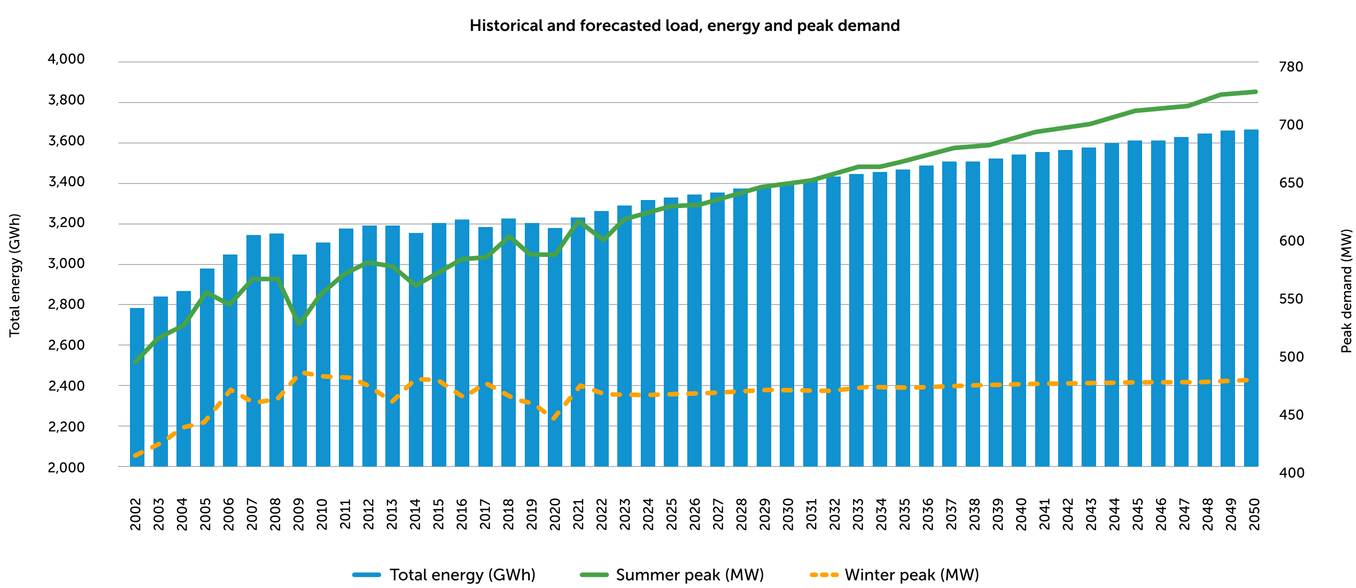


Figure 11. *Historical and forecasted load, energy and peak demand (base forecast without DERs)*

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.

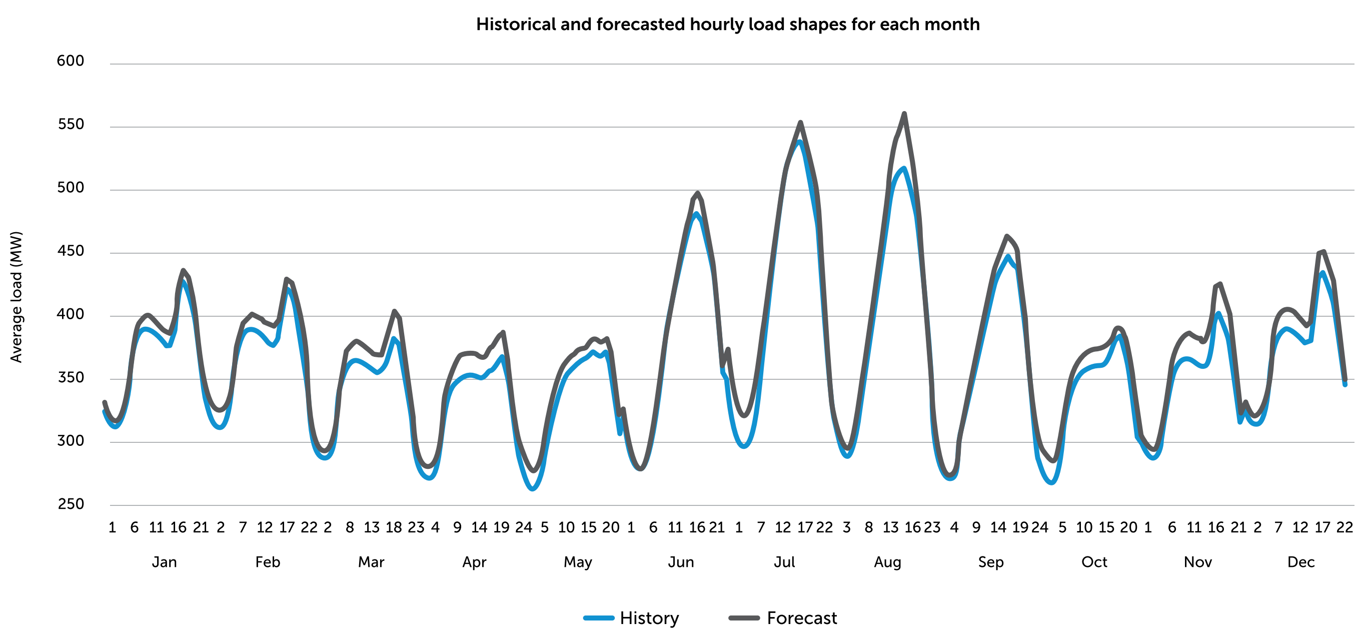


Figure 12. *Historical and forecasted hourly load shapes for each month*

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.

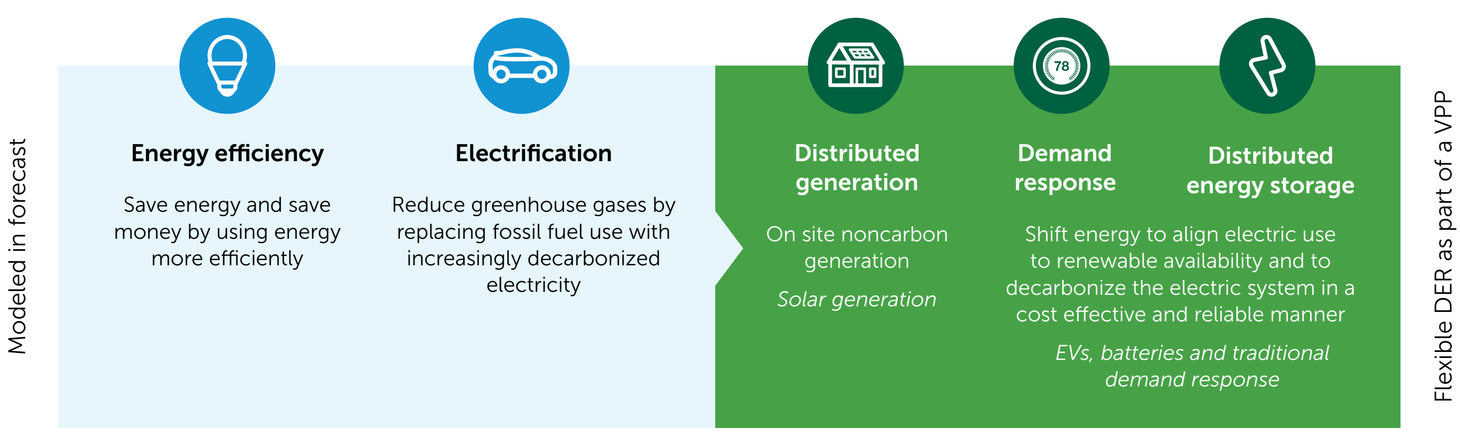
DERs are, as stated in the name, resources. For resources to provide value, they must be put to effective use. Effectively using DERs to provide system-wide benefits is often referred to as "integrating" DERs. Integrating DERs means they have been made a functioning part of the electric system. This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



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").[9] 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)

[9] 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.

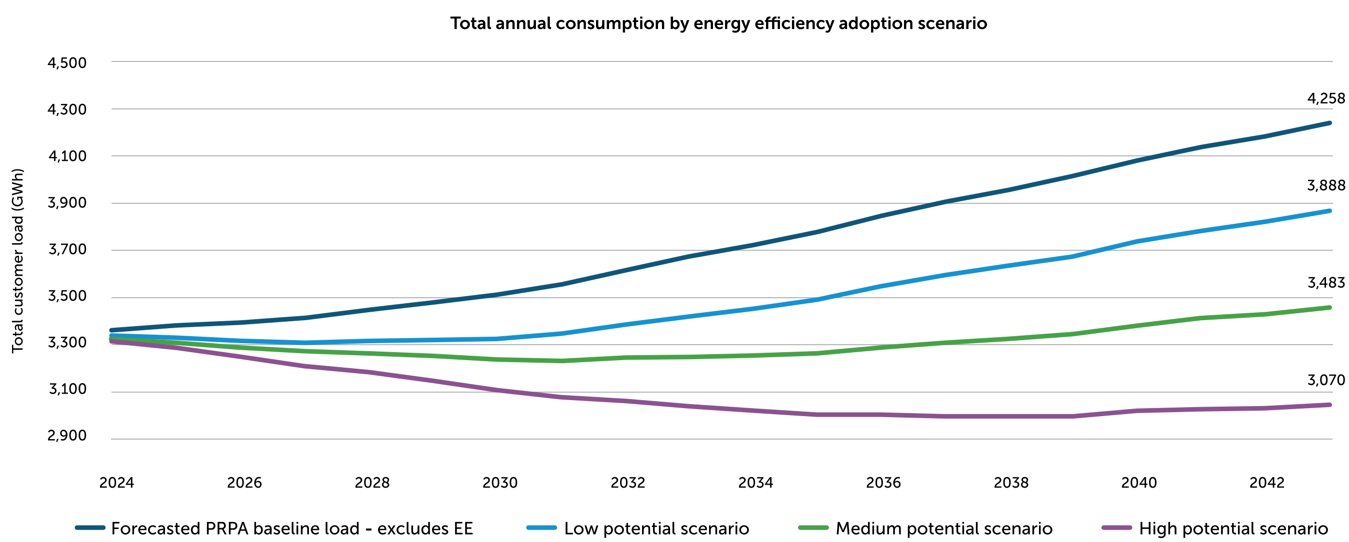
5.3.2.1 Energy efficiency forecast study results

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.

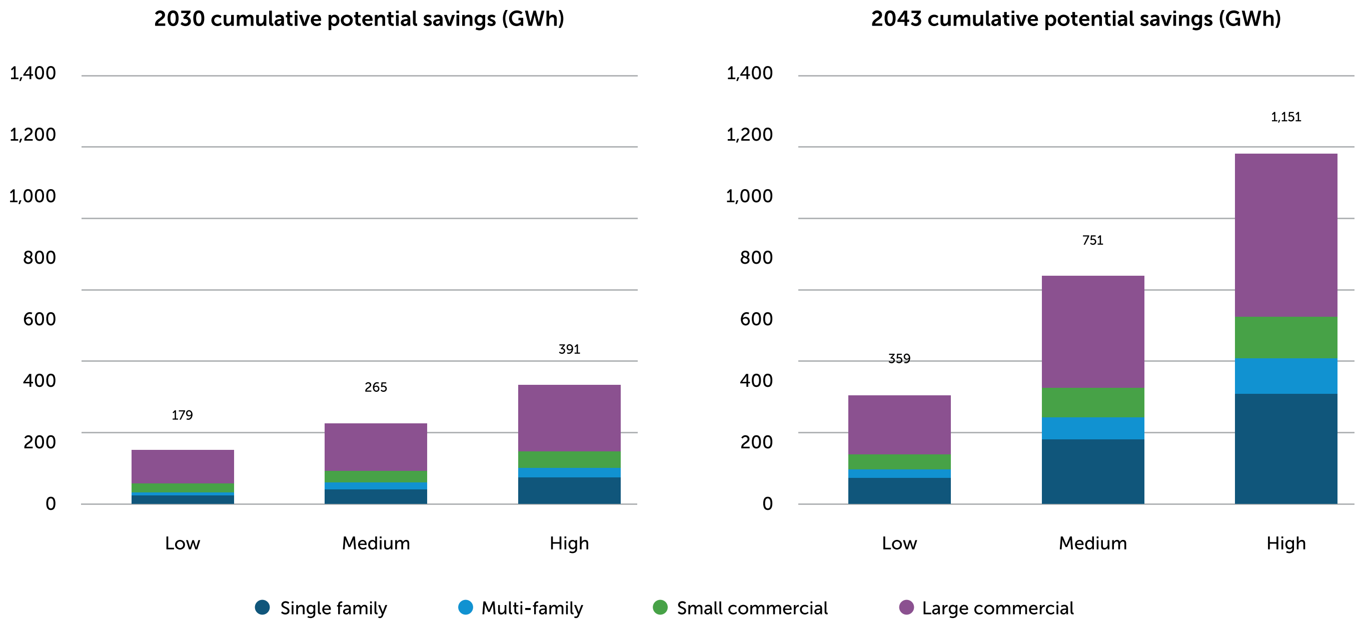


Figure 14. *Cumulative potential savings (GWh)*

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.

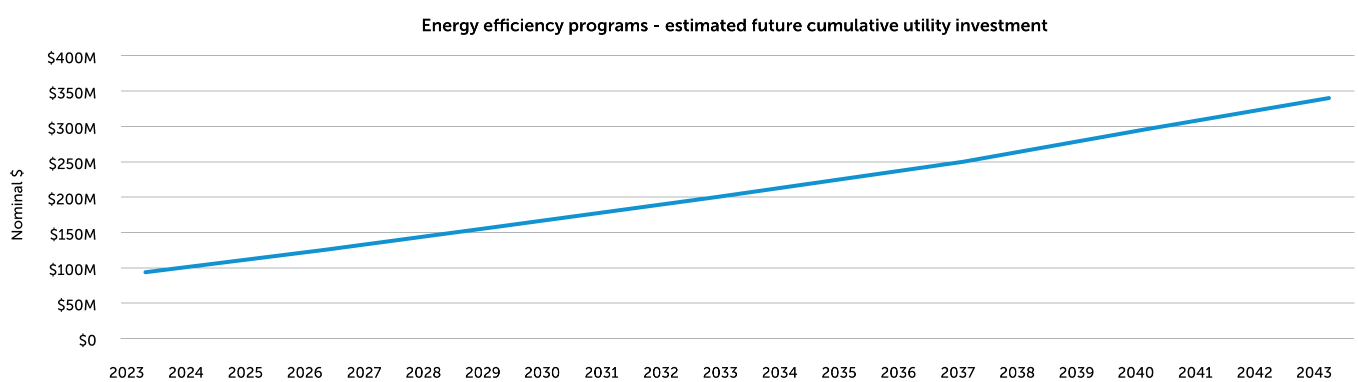


Figure 15. *Energy efficiency programs - estimated future cumulative utility investment*

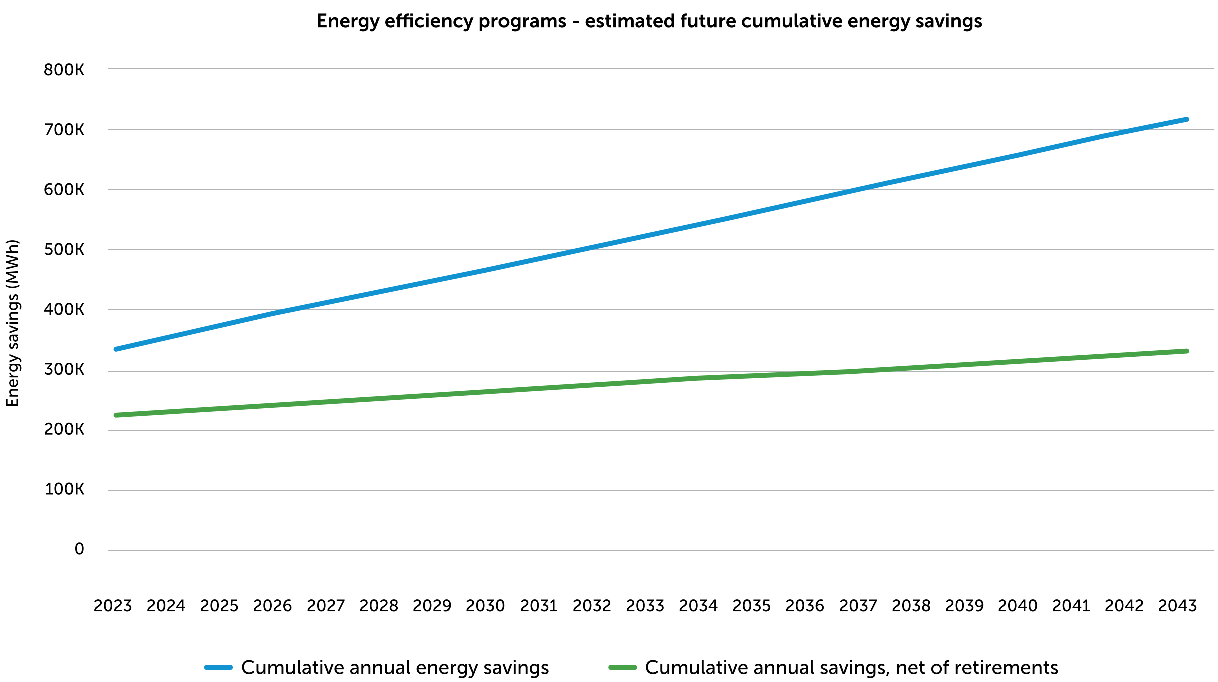


Figure 16. *Energy efficiency programs - estimated future cumulative energy savings*

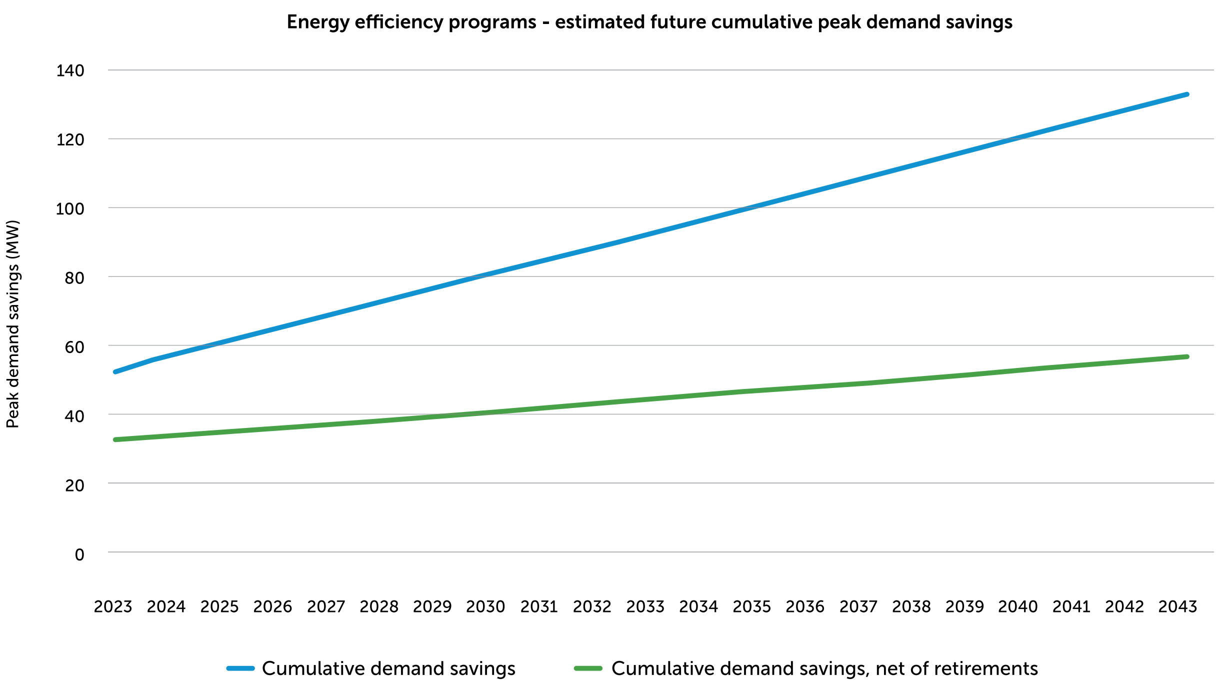


Figure 17. *Energy efficiency programs - estimated future cumulative peak demand savings*

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.

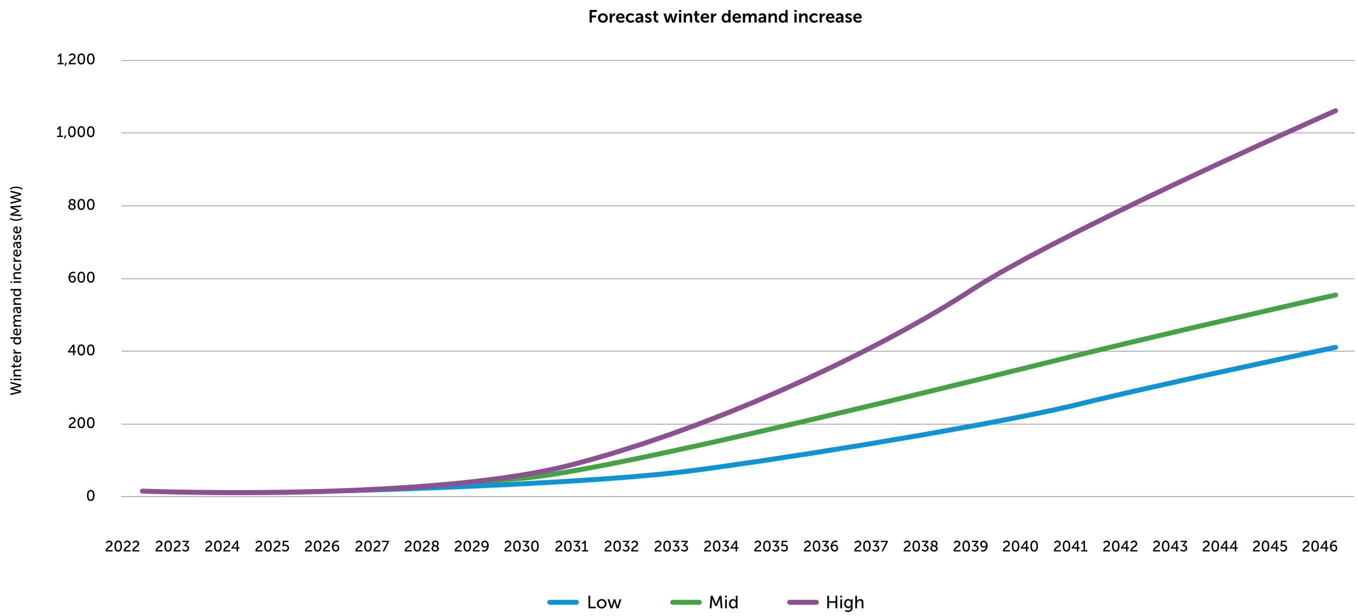


Figure 18. *Forecasted winter demand increase*

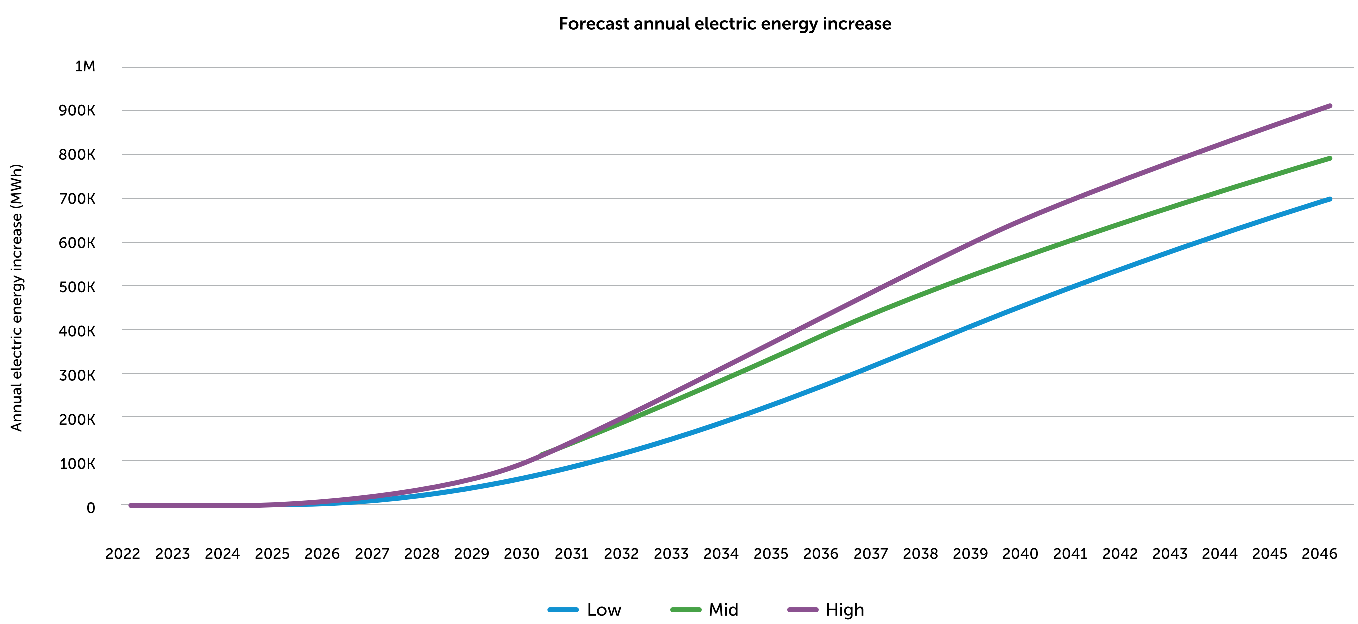


Figure 19. *Forecasted annual electric energy increase*

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
Policy/program interventions			
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[10])	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
Technology factors			
Battery costs	Limited cost declines	Moderate cost declines	Aggressive cost declines
EV model availability	Limited availability	Moderate availability	High availability
Market factors			
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.

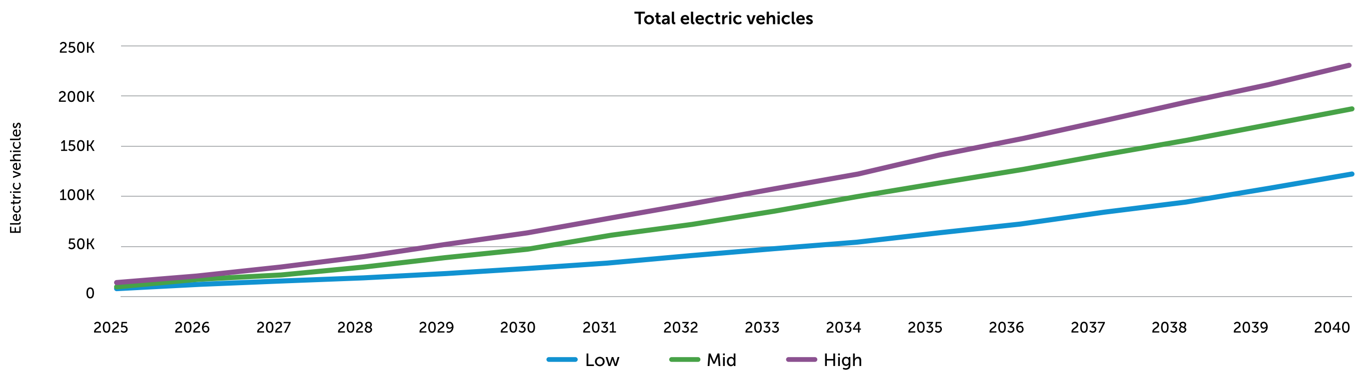


Figure 20. *Total electric vehicles*

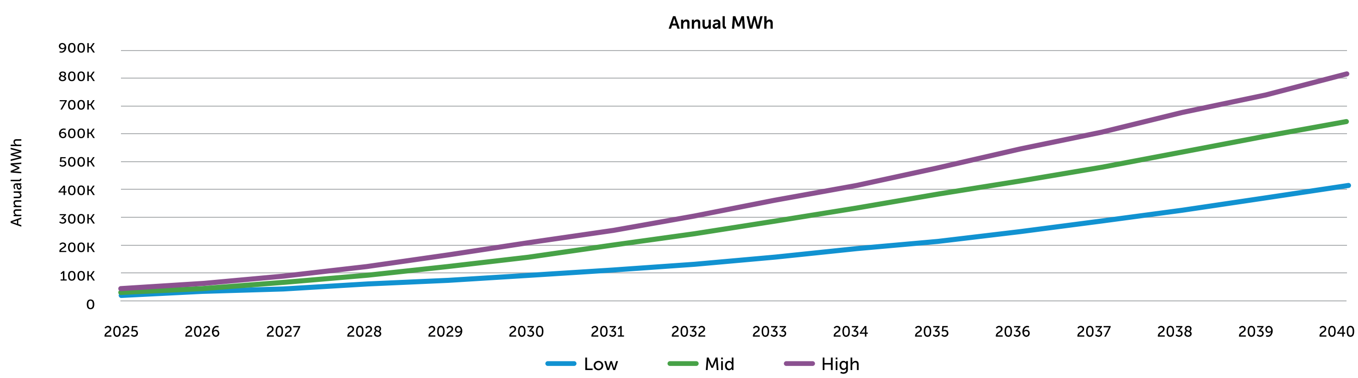


Figure 21. *Annual MWh*

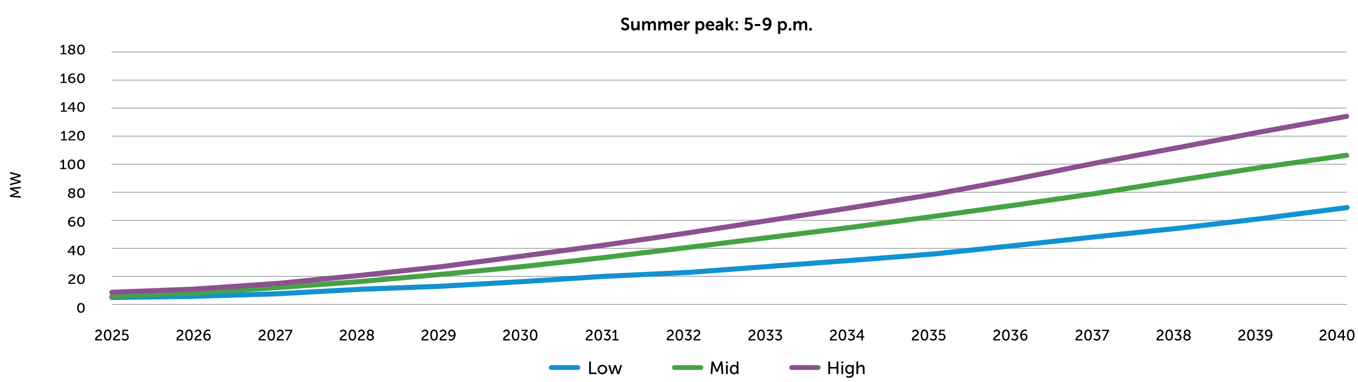


Figure 22. *Summer peak: 5-9 p.m.*

[10] 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 though 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
Policy/program interventions				
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
Technology factors				
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.

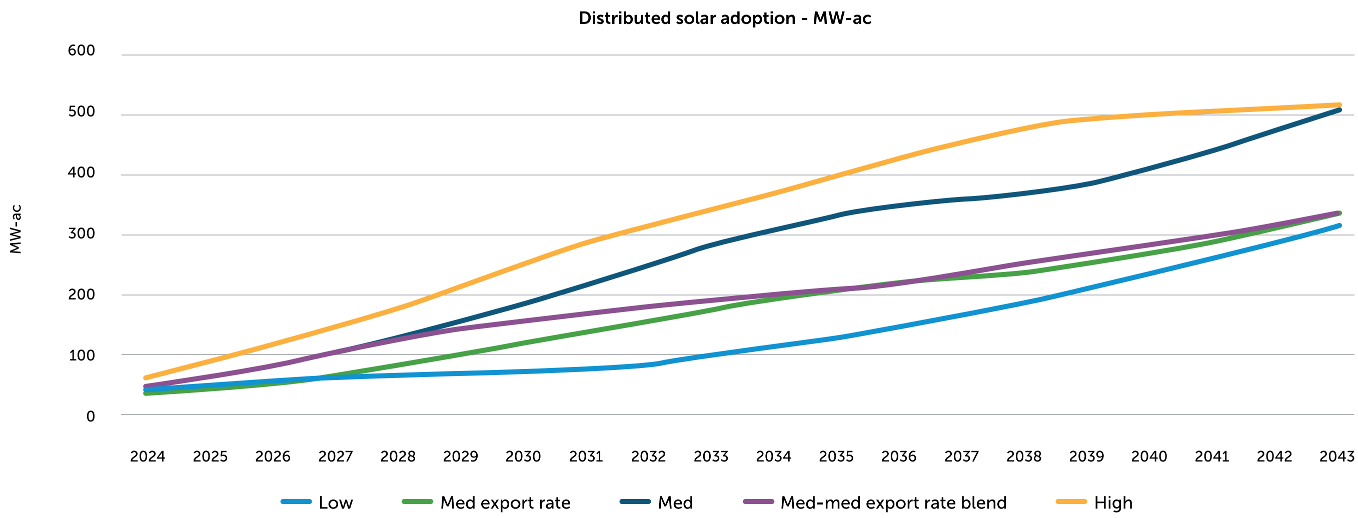


Figure 23. *Distributed solar adoption - MW-ac*

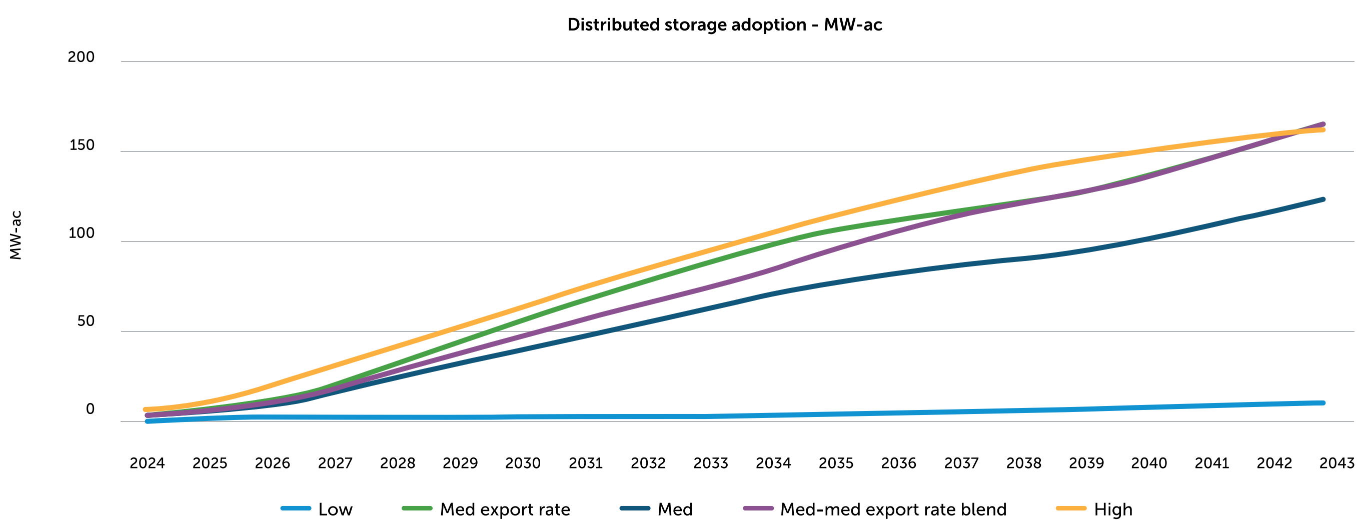


Figure 24. *Distributed storage adoption - MW-ac*

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.

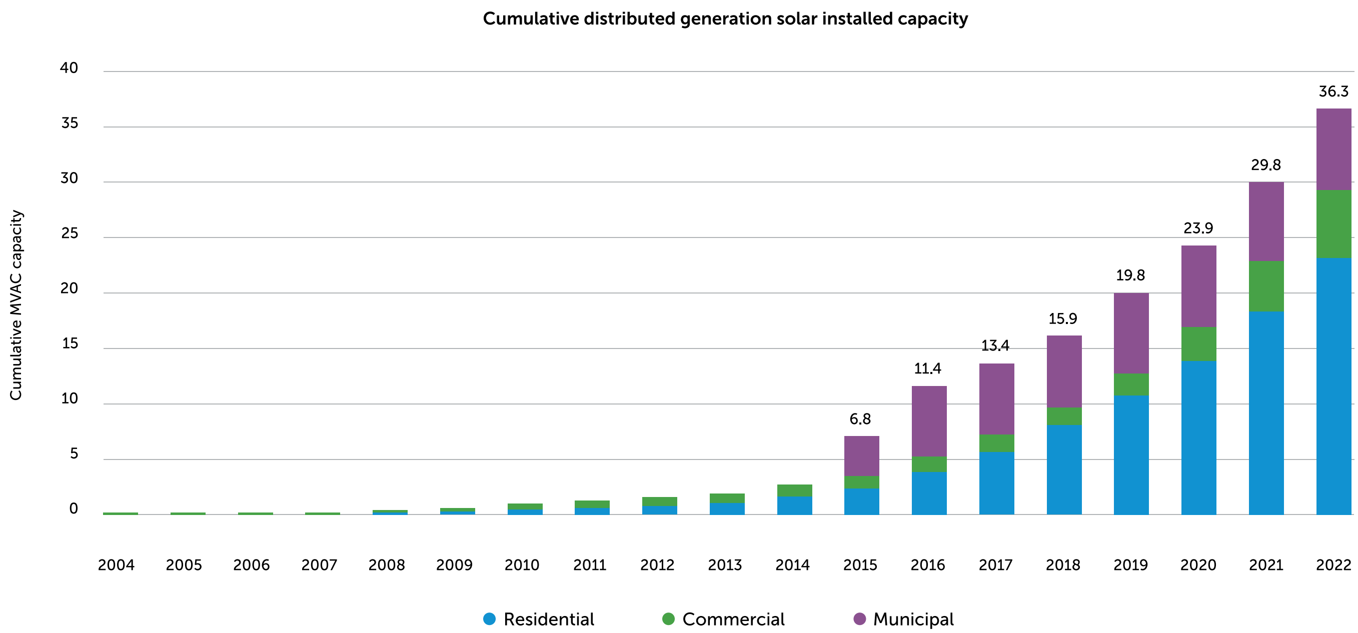


Figure 25. *Cumulative distributed generation solar installed capacity*

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.
    - 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.
    - The cost of achieving VPP potential included utility program administration costs (excluding incentives) and customer DER technology costs.
    - 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.

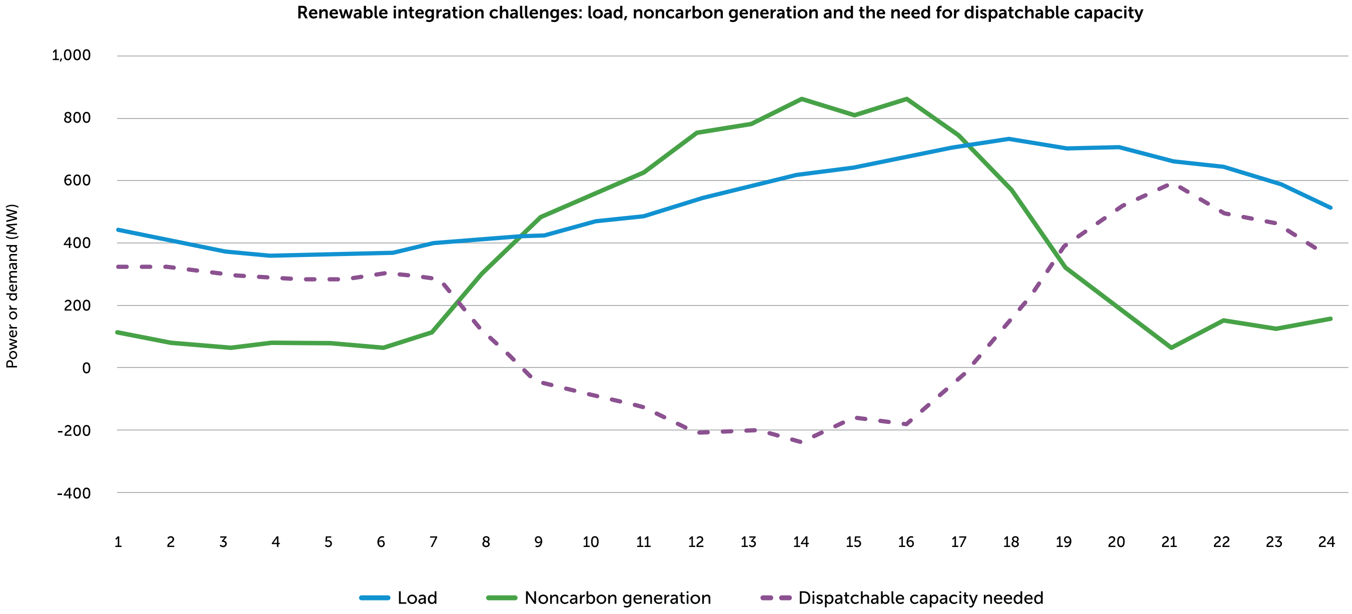


Figure 26. *Renewable integration challenges: load, noncarbon generation and the need for dispatchable capacity*

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						
		Curtail-ment potential	Event duration (hours)	Pre-charge time	Pre-charge sizing	Rebound time	Rebound sizing (per hour)	Event frequency (per year)
HVAC controls	Smart thermostats	[75%, 33%]	Up to 2 h	1 h	40%	2 h	30%	20
EV charging	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+
Water heating	Electric water heaters	100%	Up to 4 h	2 h	17%	4 h	17%	15
Other loading flexibility	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)	Curtail-ment potential	Round trip efficiency	Typical event duration (hours)	Typical rebound / pre-charge time	Typical event frequency (per year)
Storage	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.

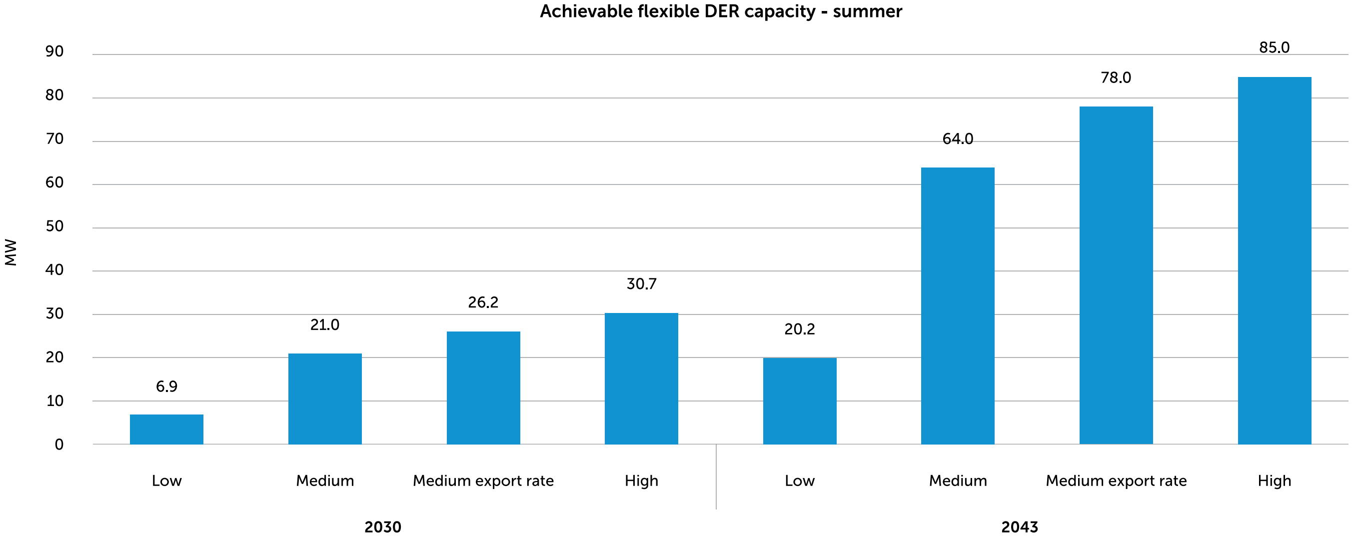


Figure 27. *Achievable flexible DER capacity - summer*

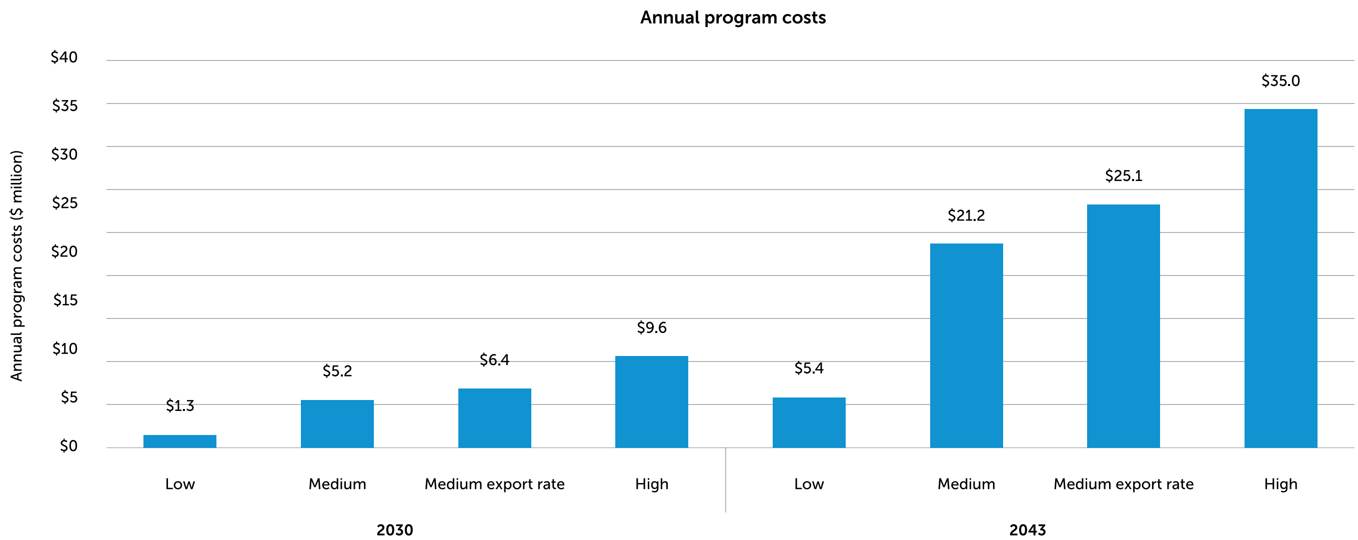


Figure 28. *Annual program costs*

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.

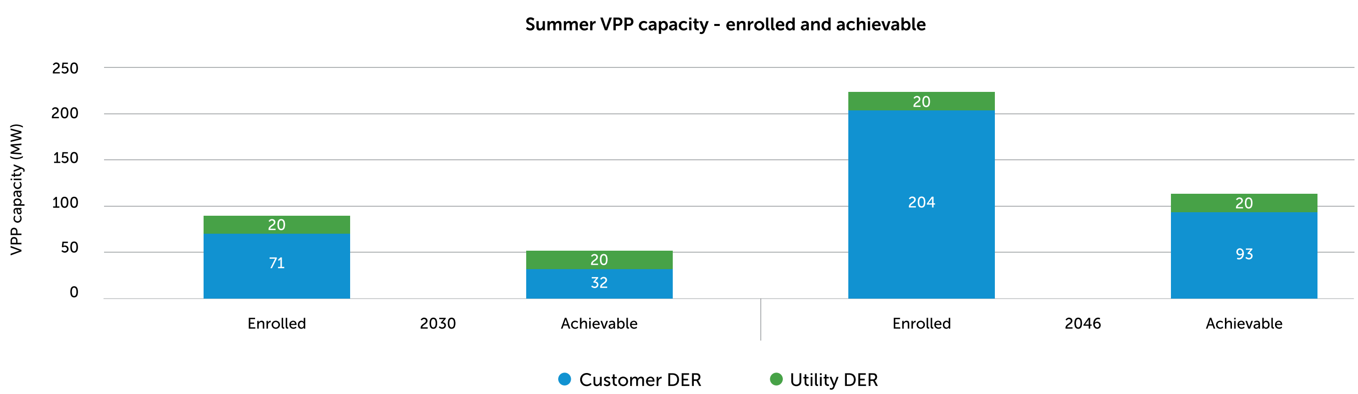


Figure 29. *Summer VPP capacity - enrolled and achievable*

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.

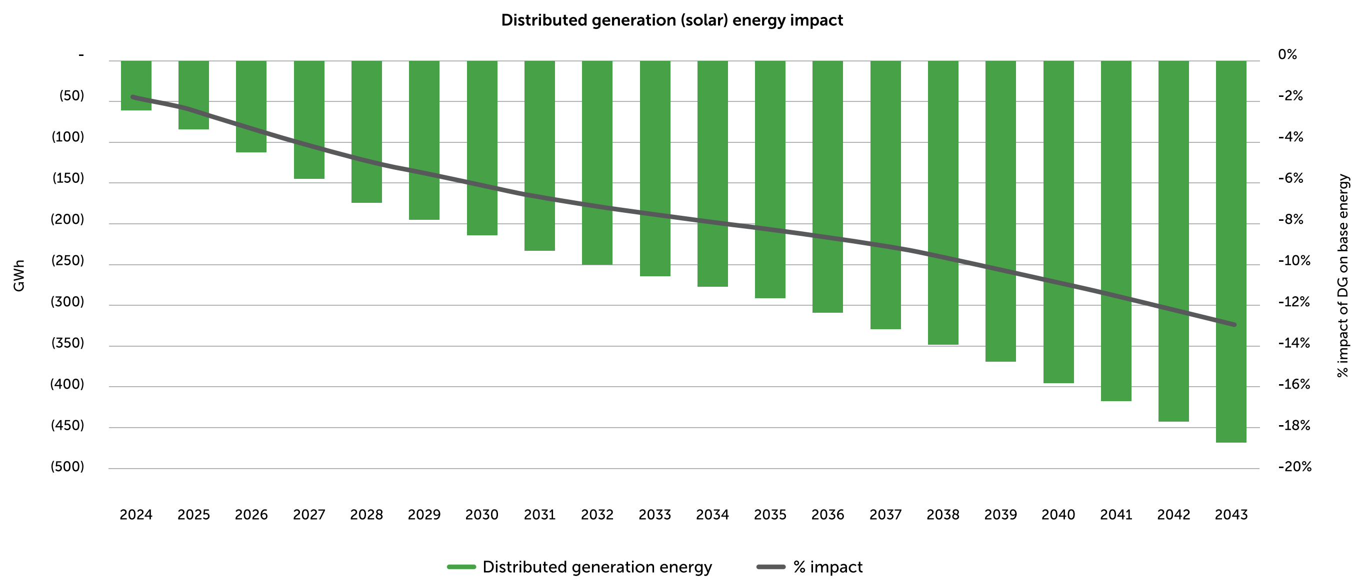


Figure 30. *Distributed generation (solar) energy impact*

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.

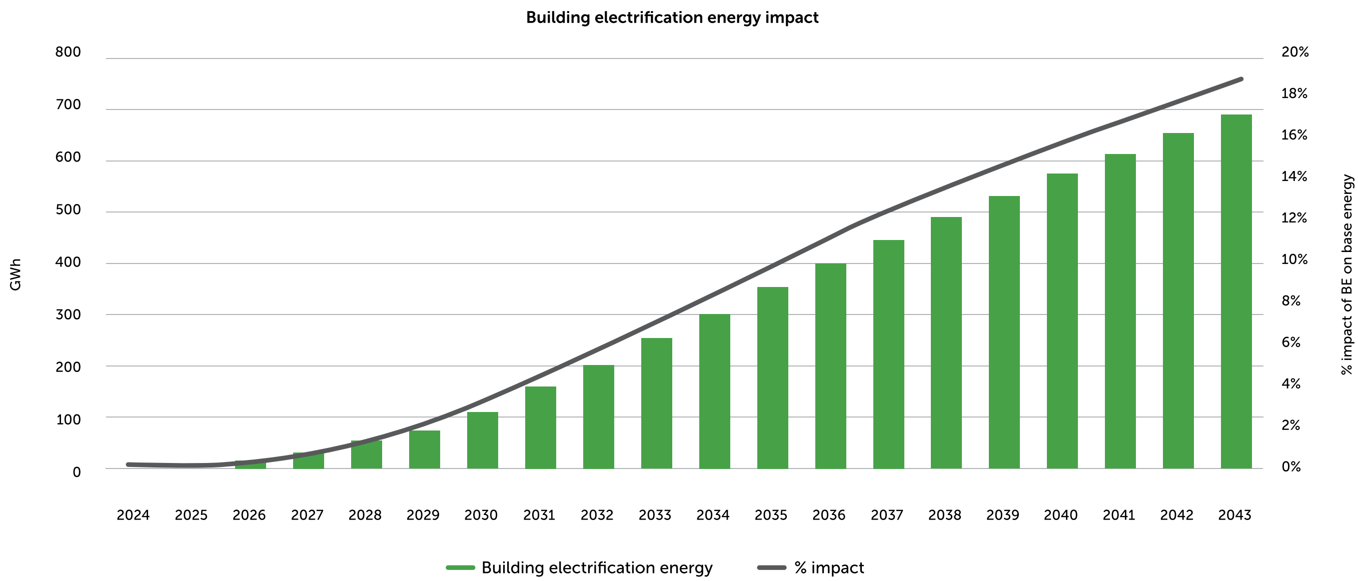


Figure 31. *Building electrification energy impact*

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.

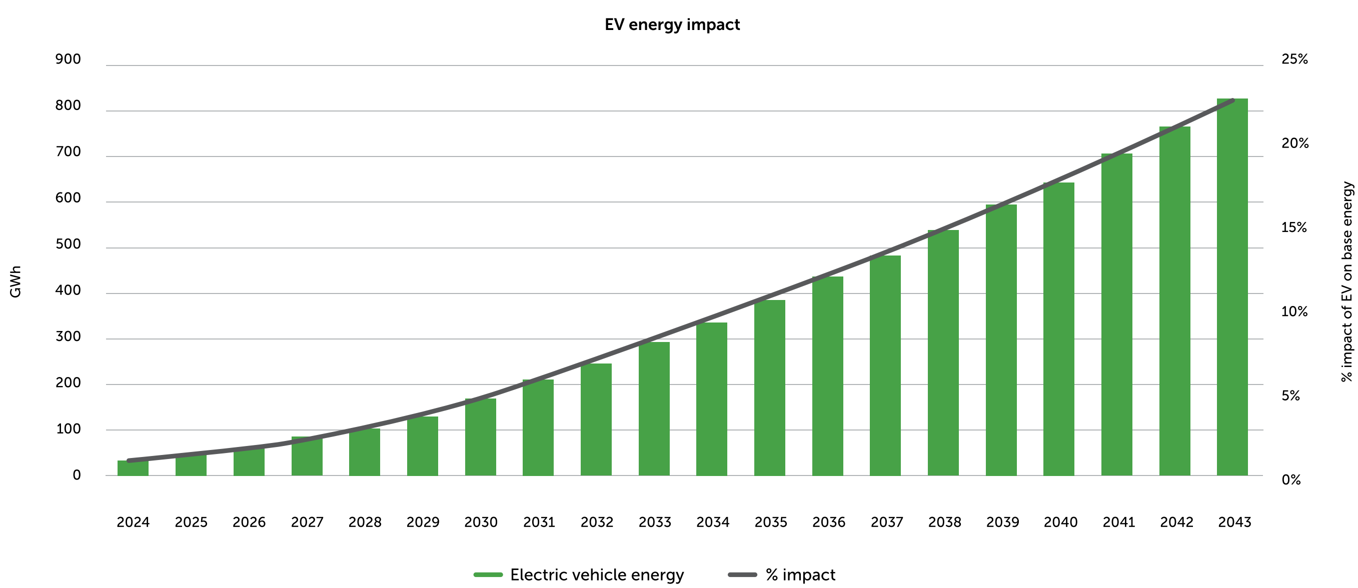


Figure 32. *EV energy impact*

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.

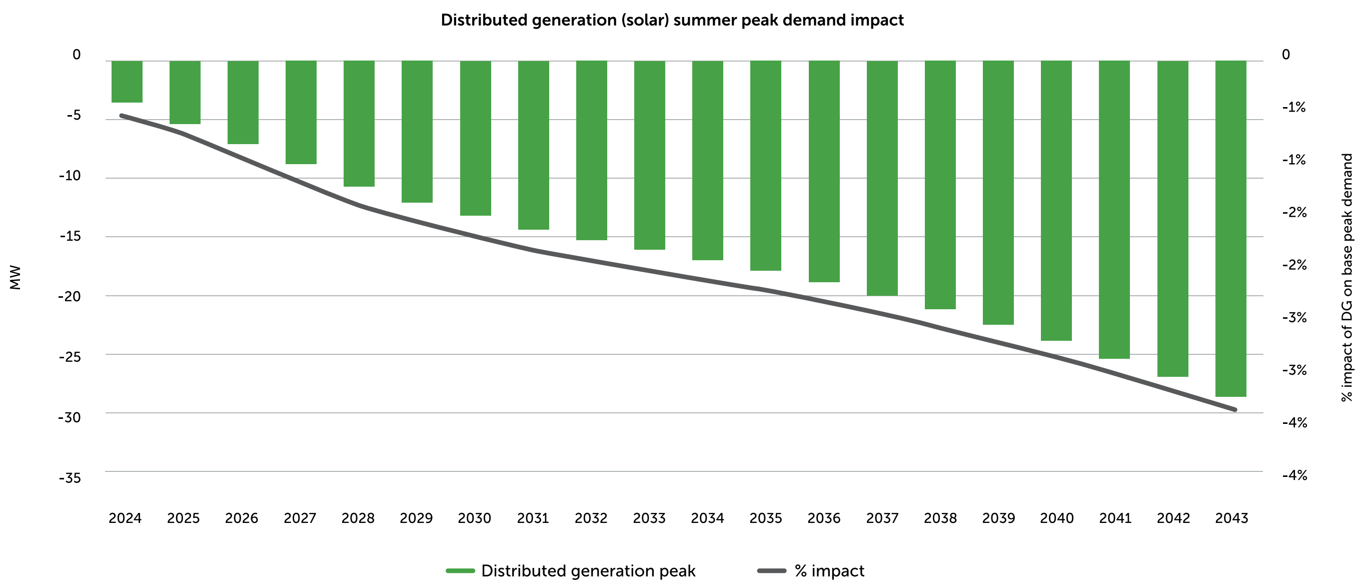


Figure 33. *Distributed generation (solar) summer peak demand impact*

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%.

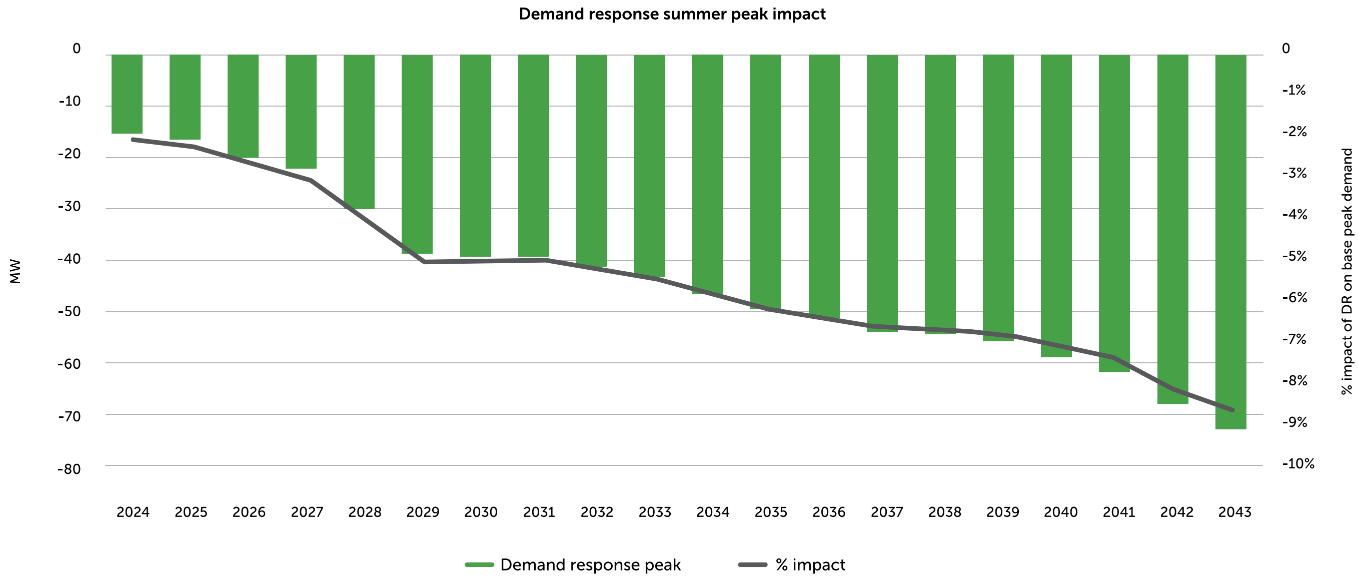


Figure 34. *Demand response summer peak impact*

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.

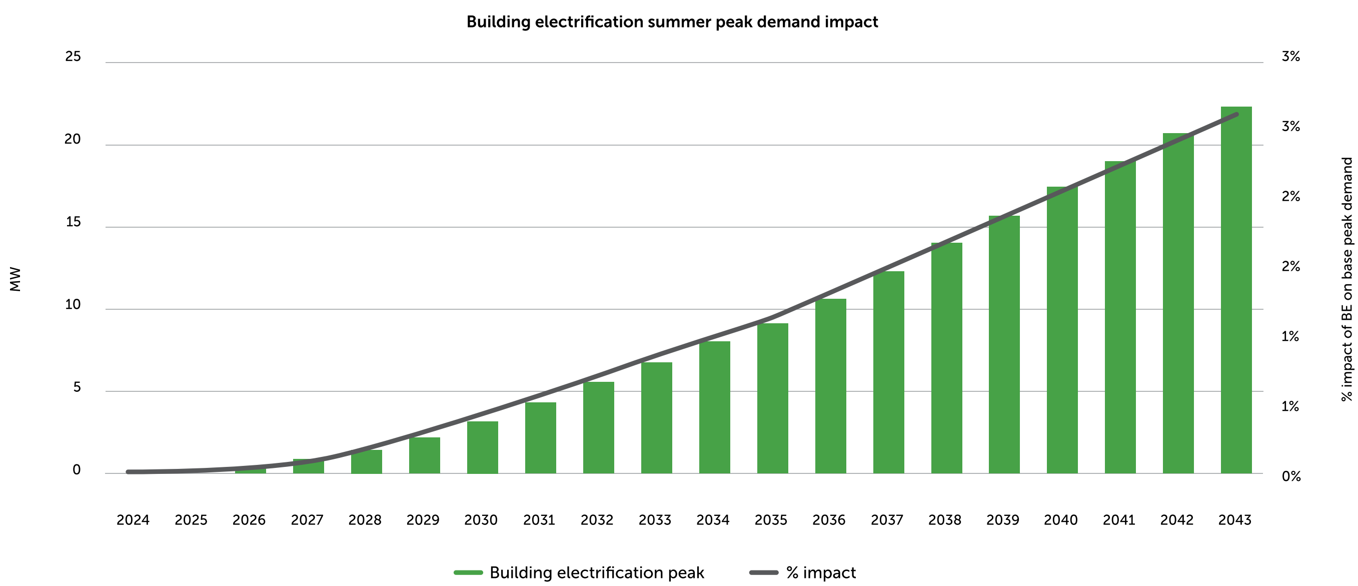


Figure 35. *Building electrification summer peak demand impact*

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.

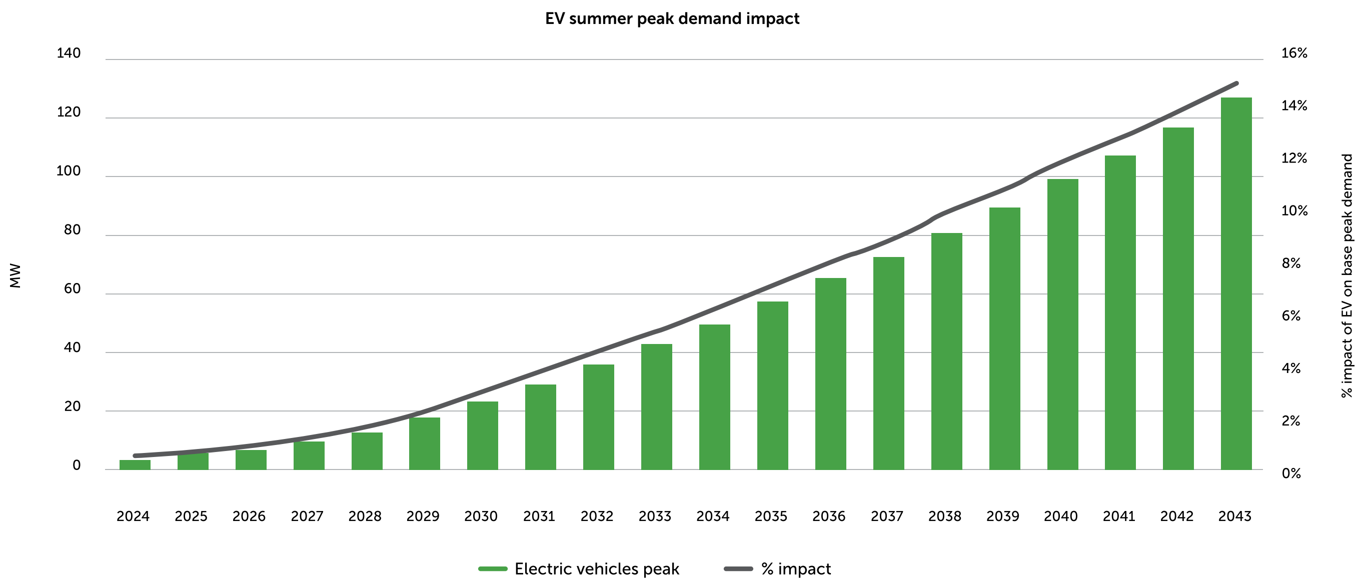


Figure 36. *EV summer peak demand impact*

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.

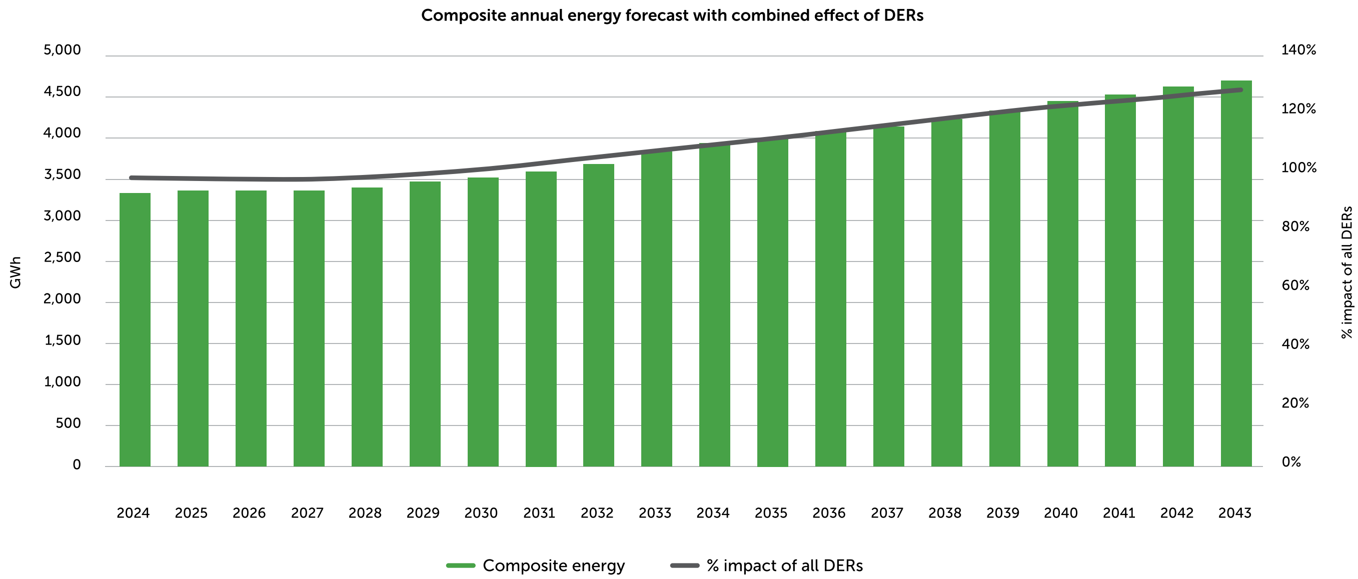


Figure 37. *Composite annual energy forecast with combined effect of DERs*

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.

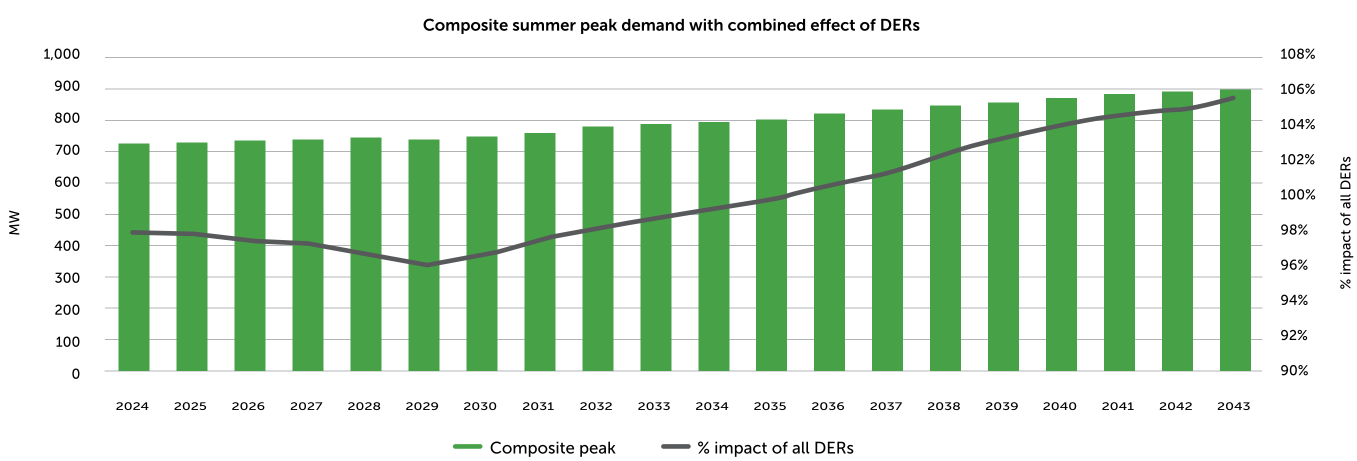


Figure 38. *Composite summer peak demand with combined effect of DERs*

06
Supply-side assumptions

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_2), nitrogen oxides, sulfur dioxide (SO_2), 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.

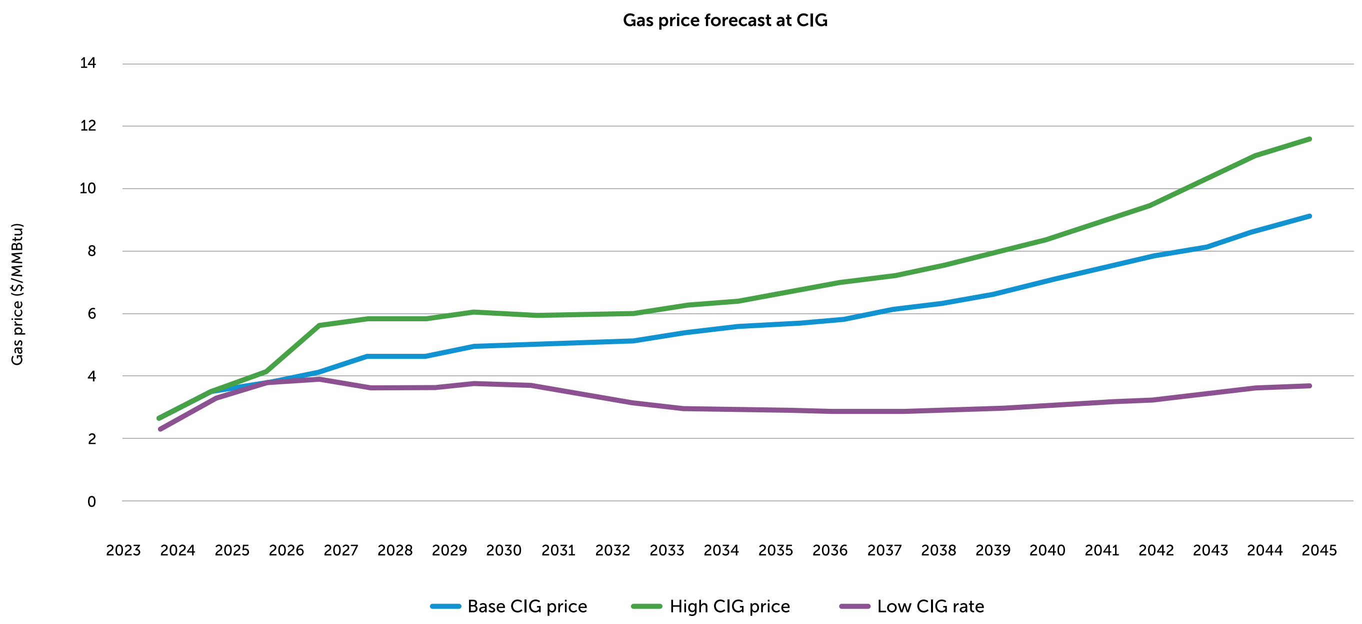


Figure 39. *Gas price forecast at CIG*

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.

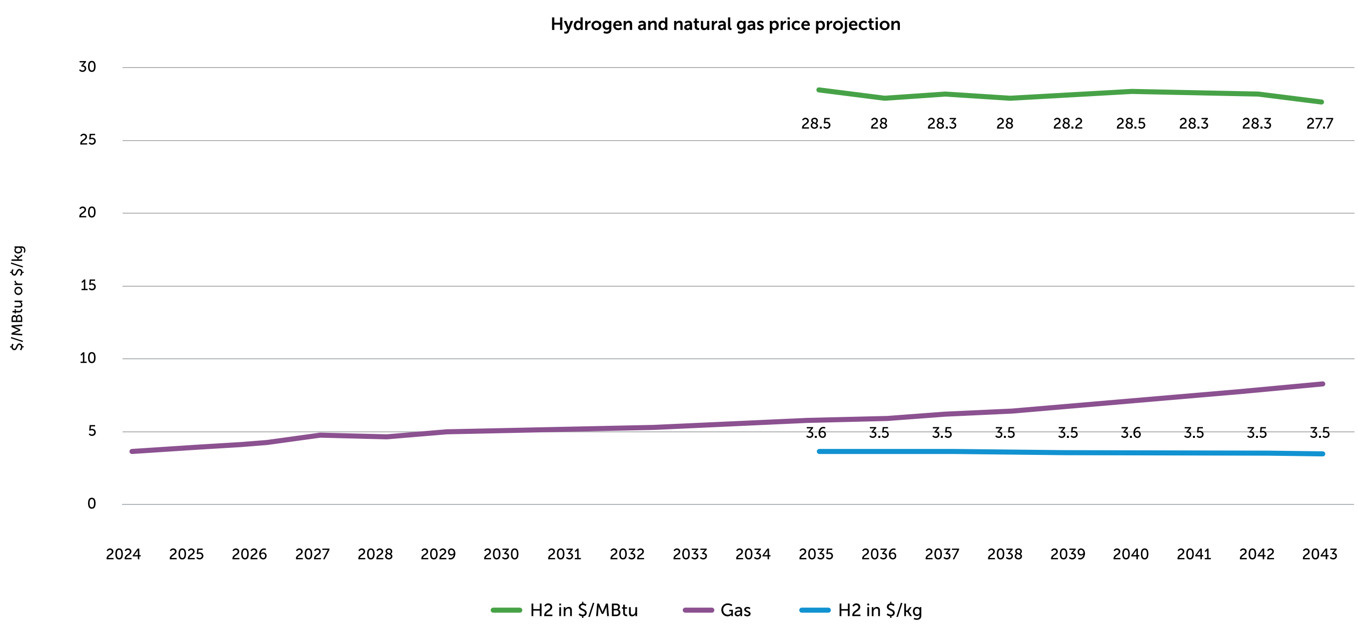


Figure 40. *Hydrogen and natural gas price projection*

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.

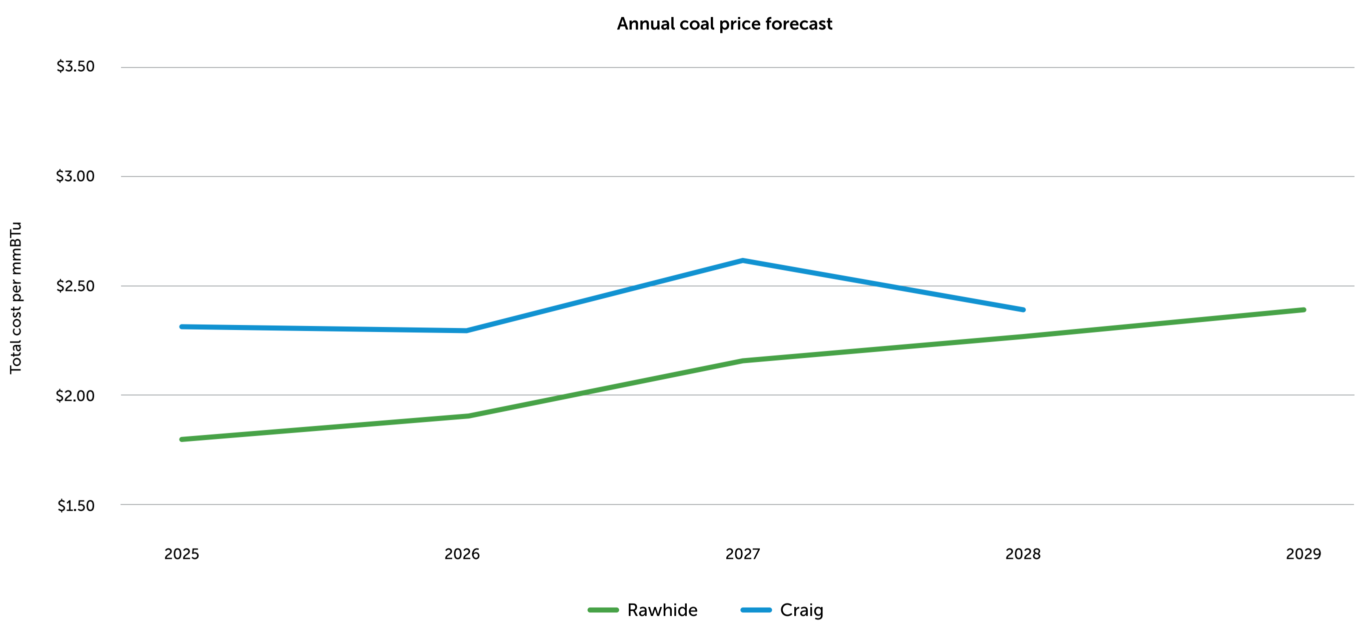


Figure 41. *Annual coal price forecast*

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.

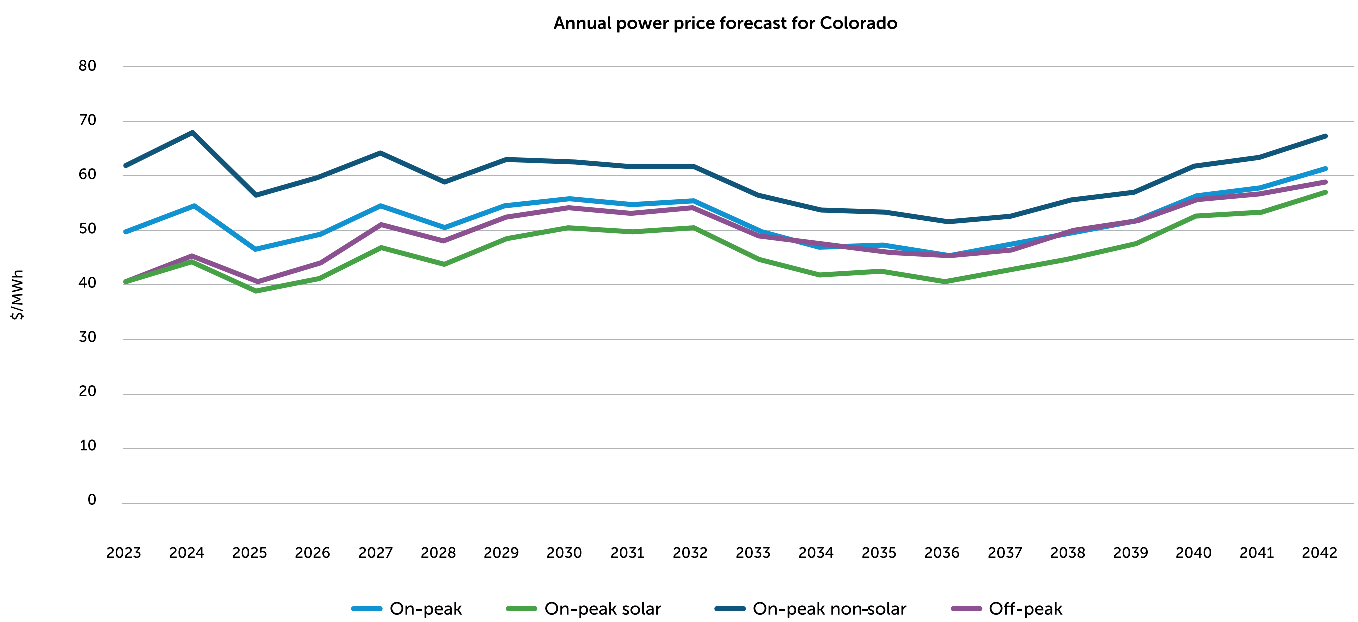


Figure 42. *Annual power price forecast for Colorado*

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 CO2 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.

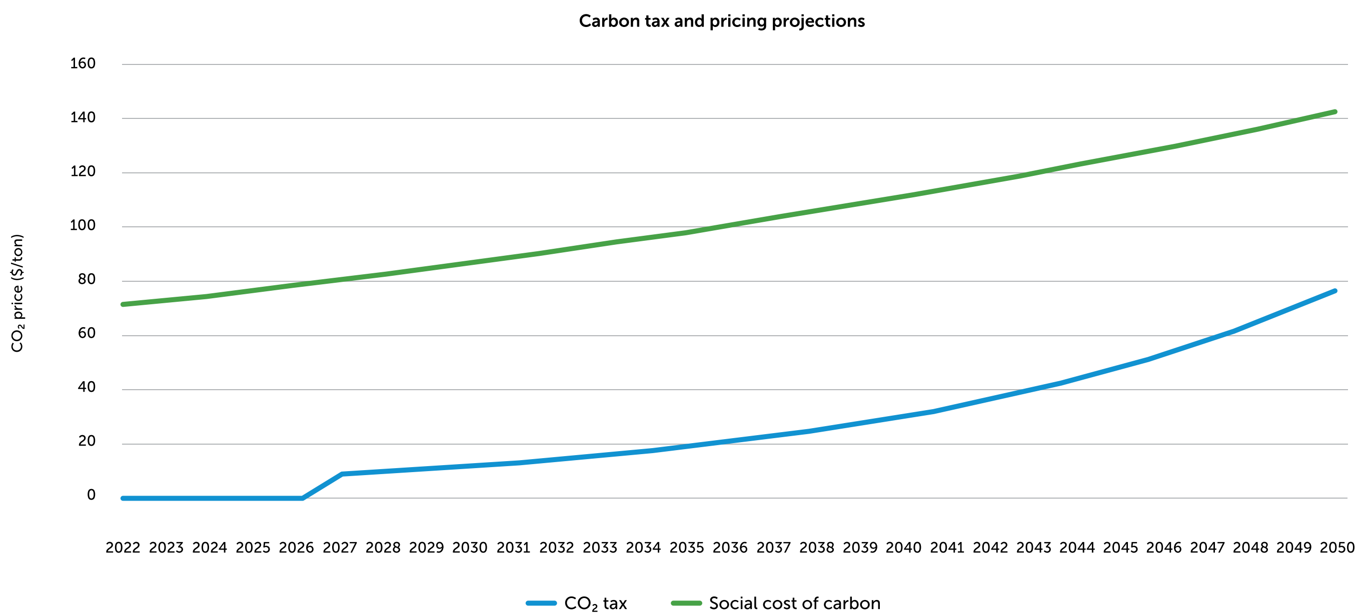


Figure 43. *Carbon tax and pricing projections*

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[11]	12	2	2009
Spring Canyon I[12]	32	5	2014
Spring Canyon II	28	6	2014
Roundhouse	225	39	2020

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

Contracted hydropower[13] 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*

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

[12] 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).

[13] 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
Solar				
Black Hollow	150	31	2025	PPA signed
New solar	150	24	2026	Negotiations ongoing
Storage				
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[14] 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
- Aeroderivative 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[15] 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 CO2 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 technoeconomic 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.

[14] https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf

[15] Results from the generation technology screening by Black & Veatch are accessible on Platte River's IRP microsite at 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 CO2 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 CO2 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 CO2. 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 CO2. 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 CO2 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

Plate 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.

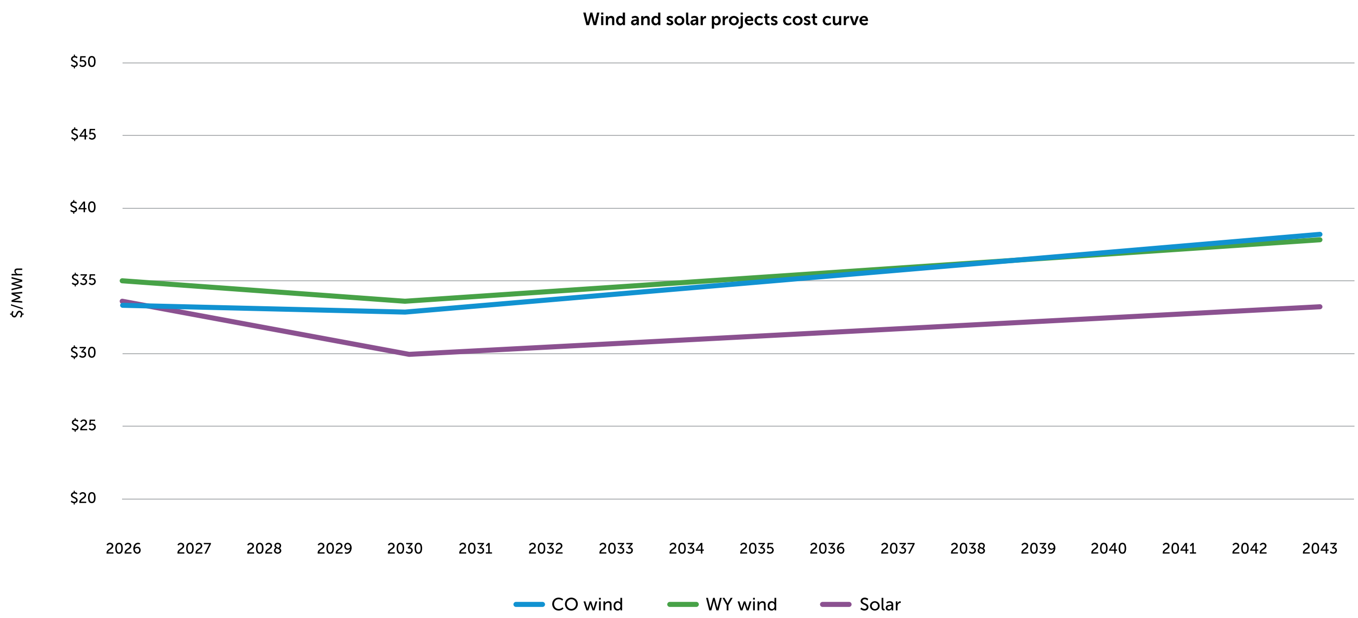


Figure 44. *Wind and solar projects cost curve*

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.

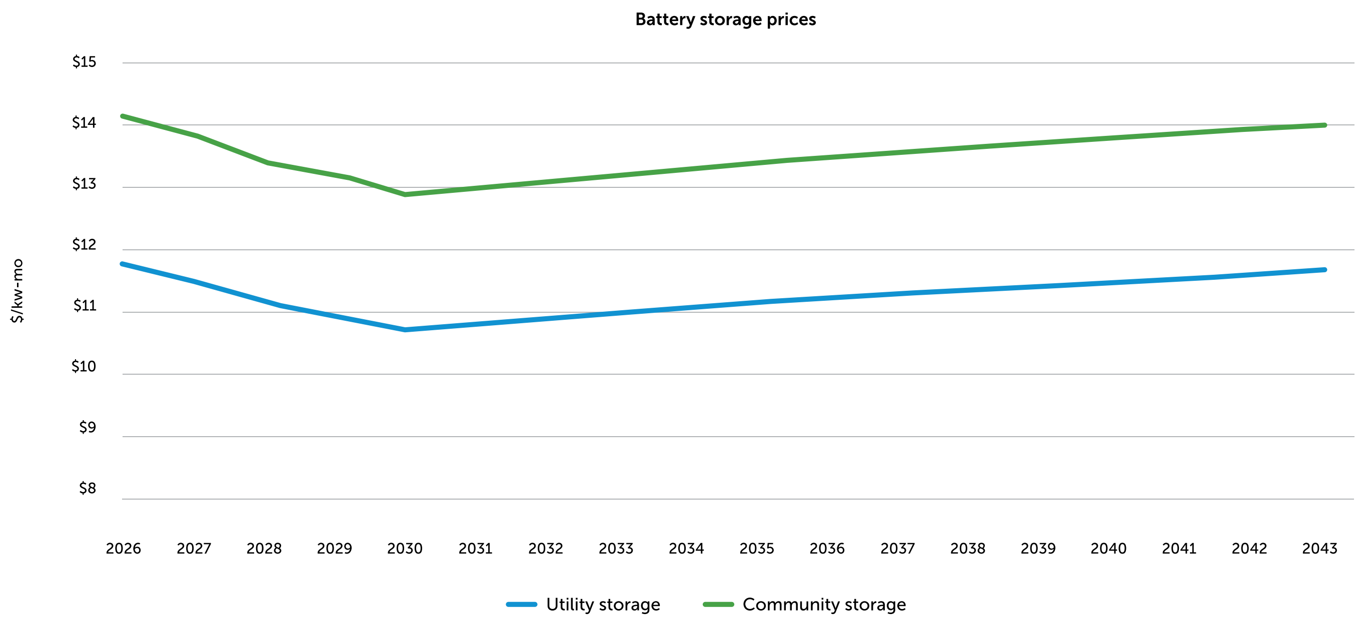


Figure 45. *Battery storage prices*

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 conver-sion	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	$M/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
Total weighted score	**100%**	**5.57**	**8.62**	**8.72**	**7.21**

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

07
IRP design

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[16] 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.

[16] Texas winter storm: 246 Texans' deaths classified as winter-storm related (kxan.com).

[17] 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.[17]

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.[18] 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.[19]

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,

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

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.[20] 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,[21] 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[22] 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.

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

[19] https://www.astrape.com/wp-content/uploads/2024/01/EISPC_The_Economic_Ramifications_of_Resource_Adequacy_White_Paper.pdf

[20] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/ra_t3b2_workshop-1_presentation-telos-and-gridlab.pdf

[21] https://www.epri.com/research/products/000000003002023230

[22] https://www.nyiso.com/-/shaving-peaks-with-the-sun

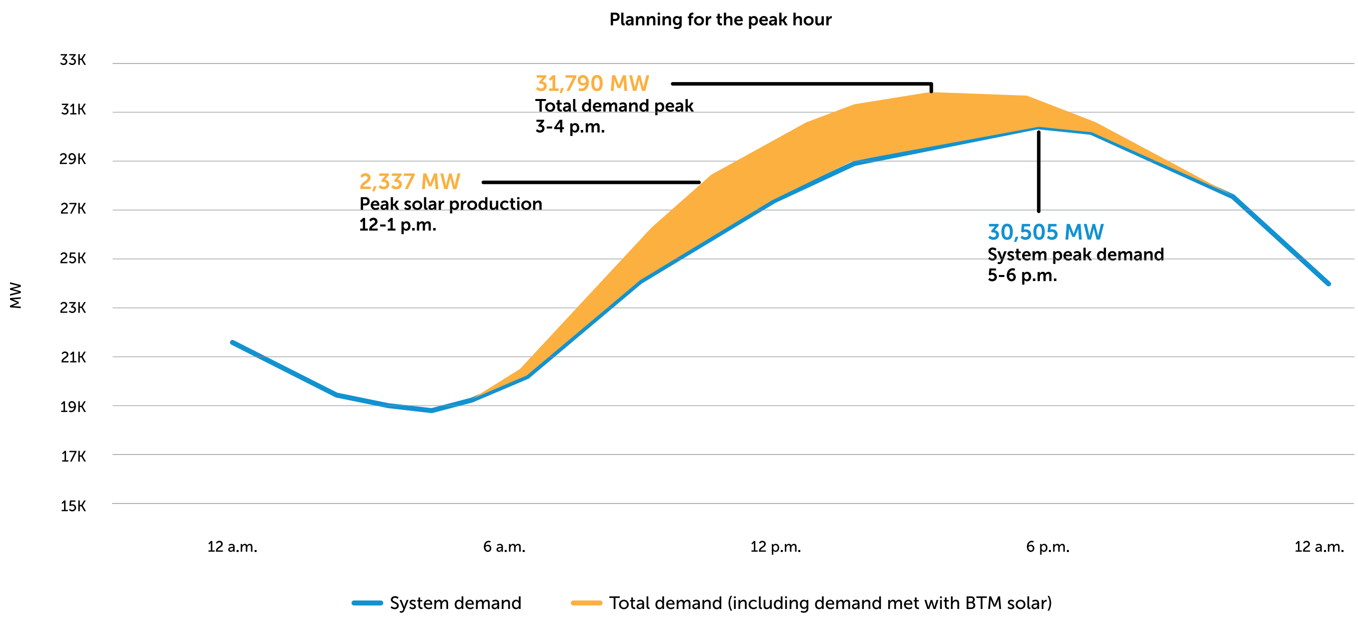


Figure 46. *Planning for the peak hour*

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%.[23]

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[24] and with the backdrop of ongoing discussions in the industry, we engaged Astrape Consulting to perform a resource adequacy[25] study for this 2024 IRP. This study computed PRM and ELCC[26] 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

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

[24] Platte River has filed a voluntary clean energy plan committing to reduce its 2030 CO2 emissions by at least 80% from 2005 levels.

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

[26] ELCC of a resource is the measurement of that resource's ability to produce energy at the time of peak demand.

[27] 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[27] 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.

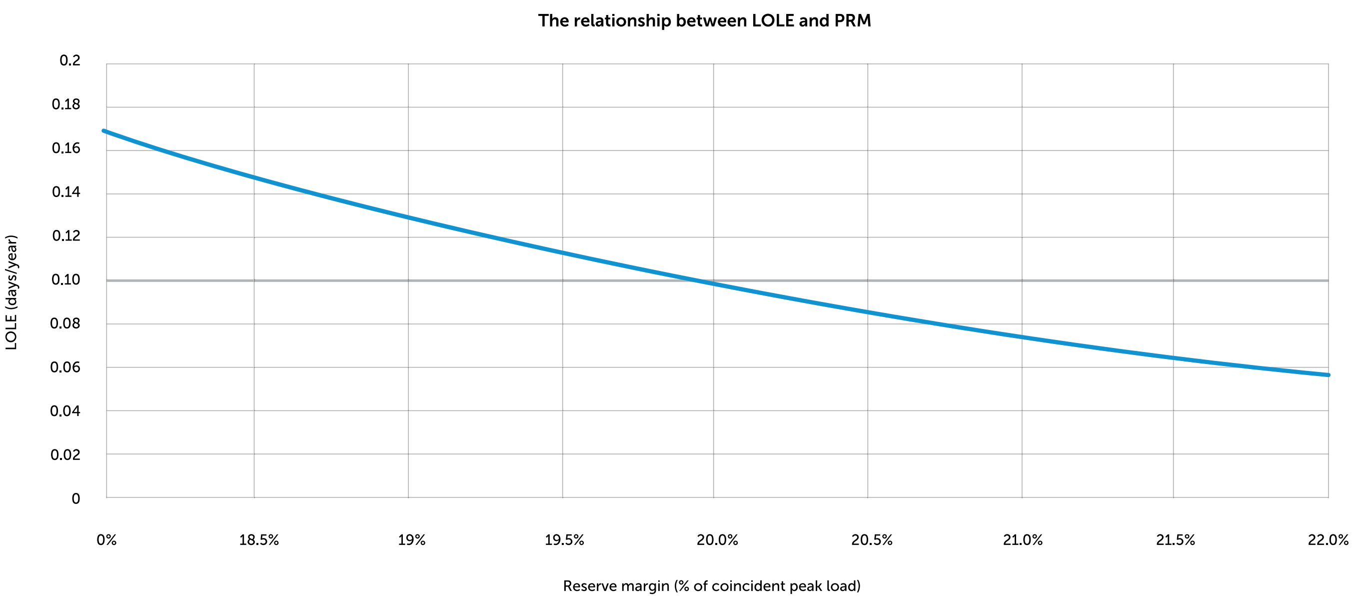


Figure 47. *The relationship between LOLE and PRM*

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.

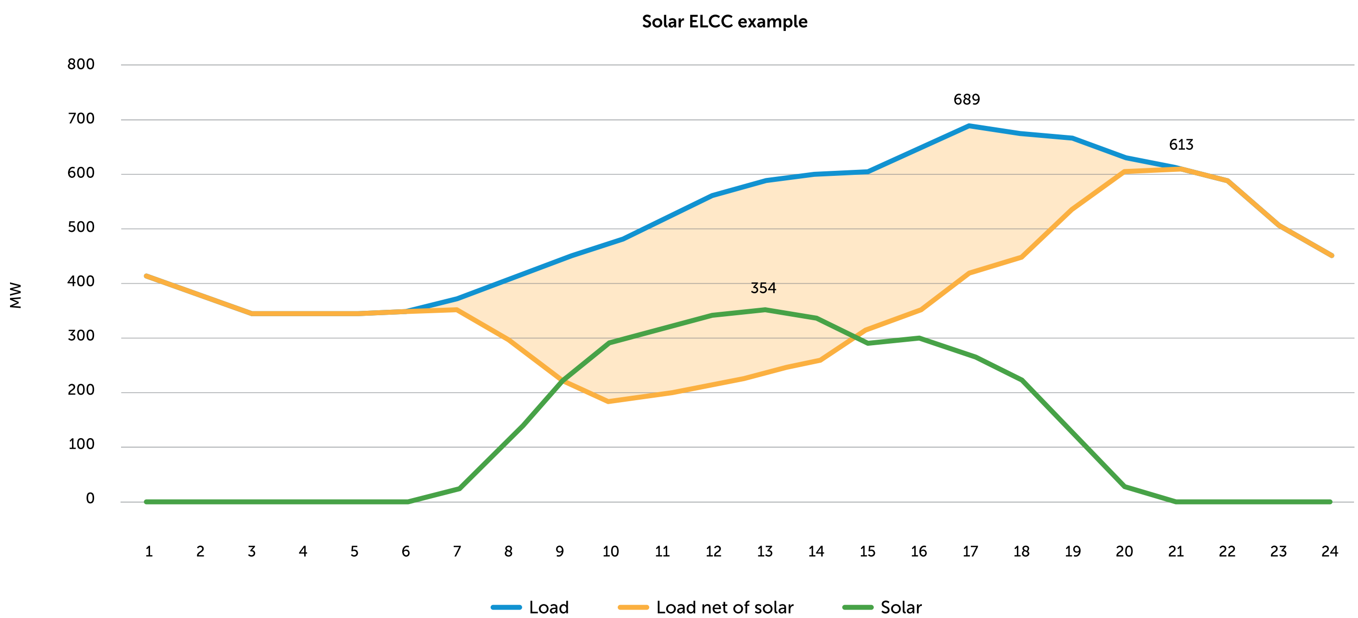


Figure 48. *Solar ELCC example*

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.

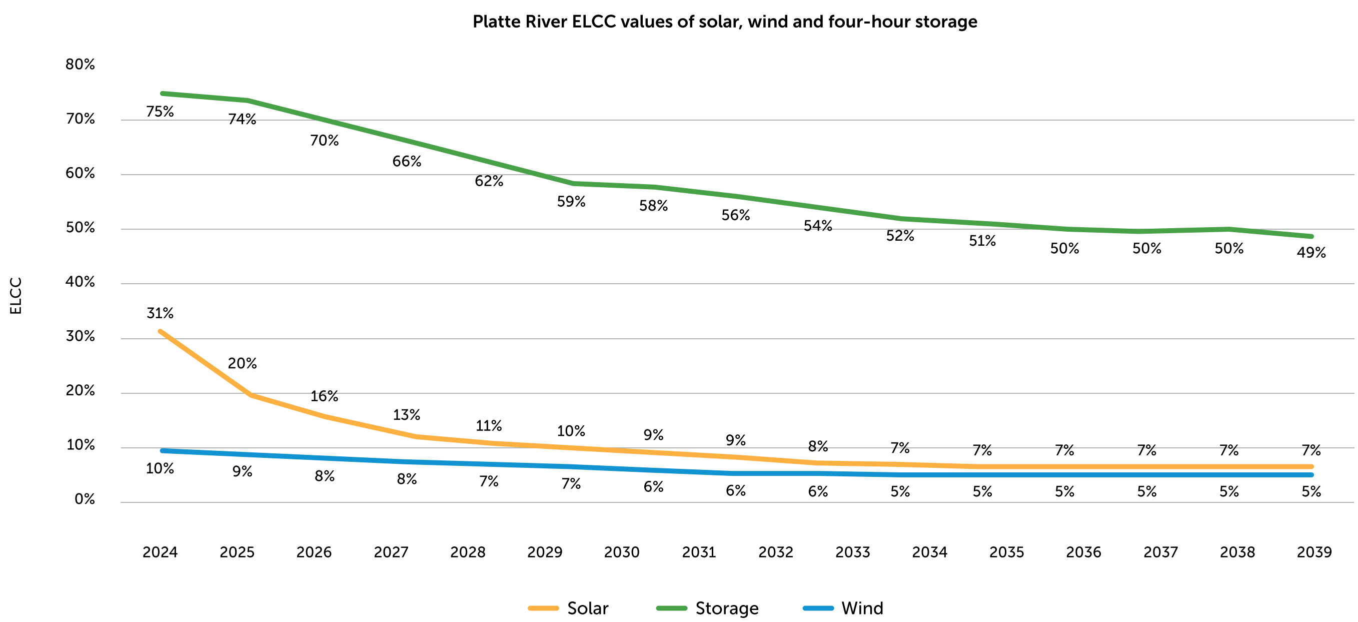


Figure 49. *Platte River ELCC values of solar, wind and four-hour storage*

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.

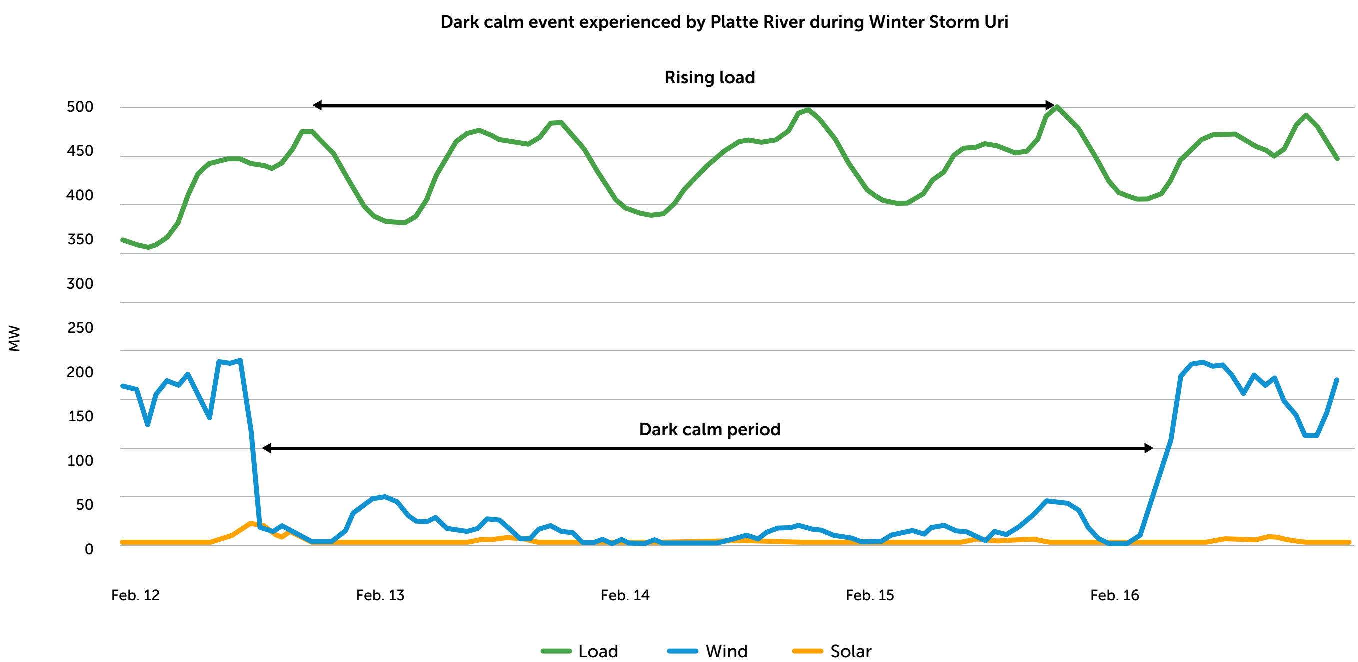


Figure 50. *Dark calm event experienced by Platte River during Winter Storm Uri*

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.[28]

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.

[28] 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
MISO Central				
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
MISO North				
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
Northwest ERCOT				
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	**248.16**

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.

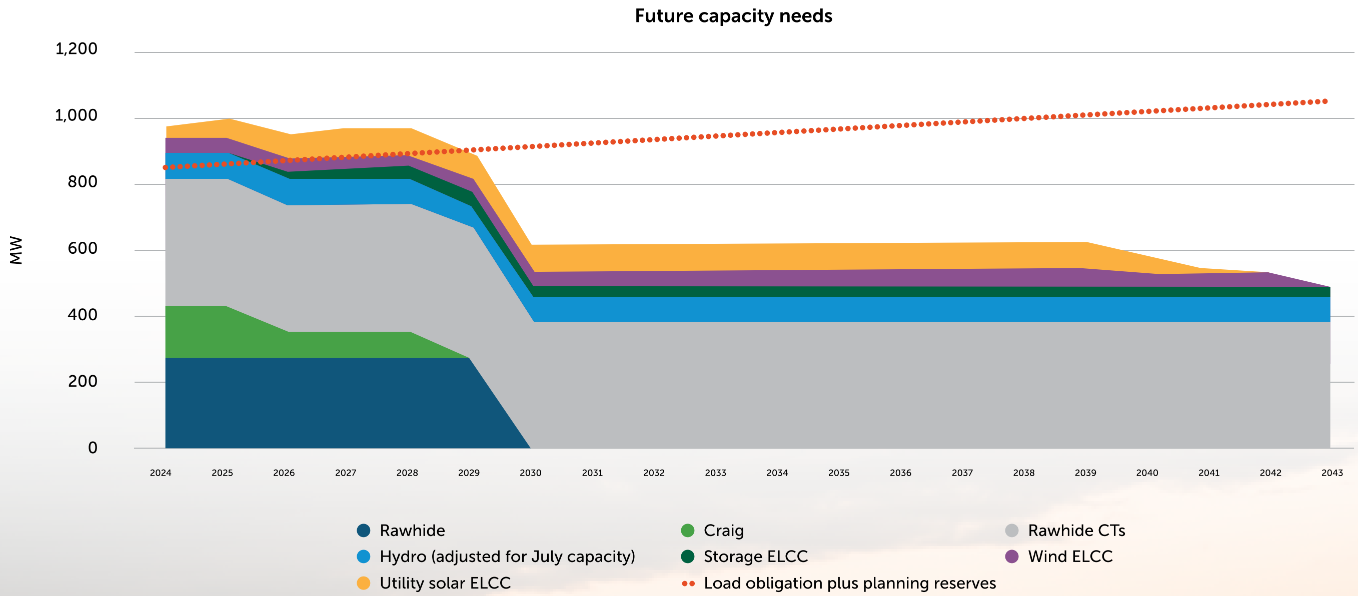


Figure 52. *Future capacity needs*

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.

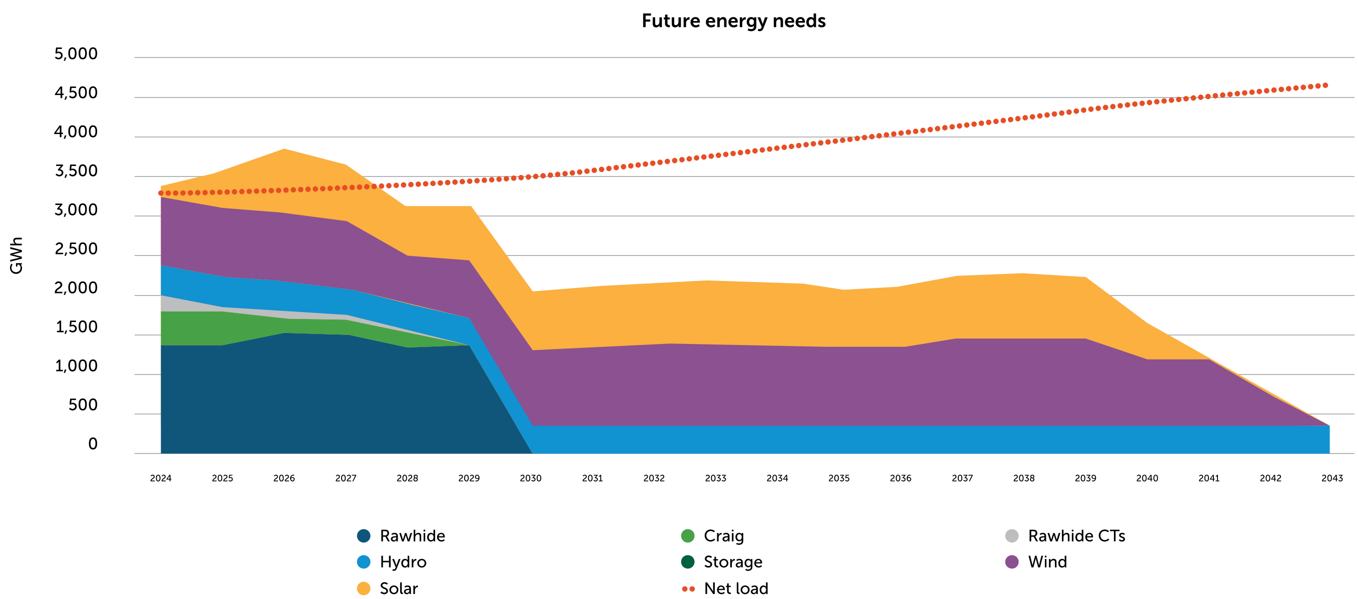


Figure 53. *Future energy needs*

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 CO2 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 CO2 emissions. All dispatchable thermal generation is assumed to switch to 100% green hydrogen by 2040 and reach zero CO2 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 CO2, 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.

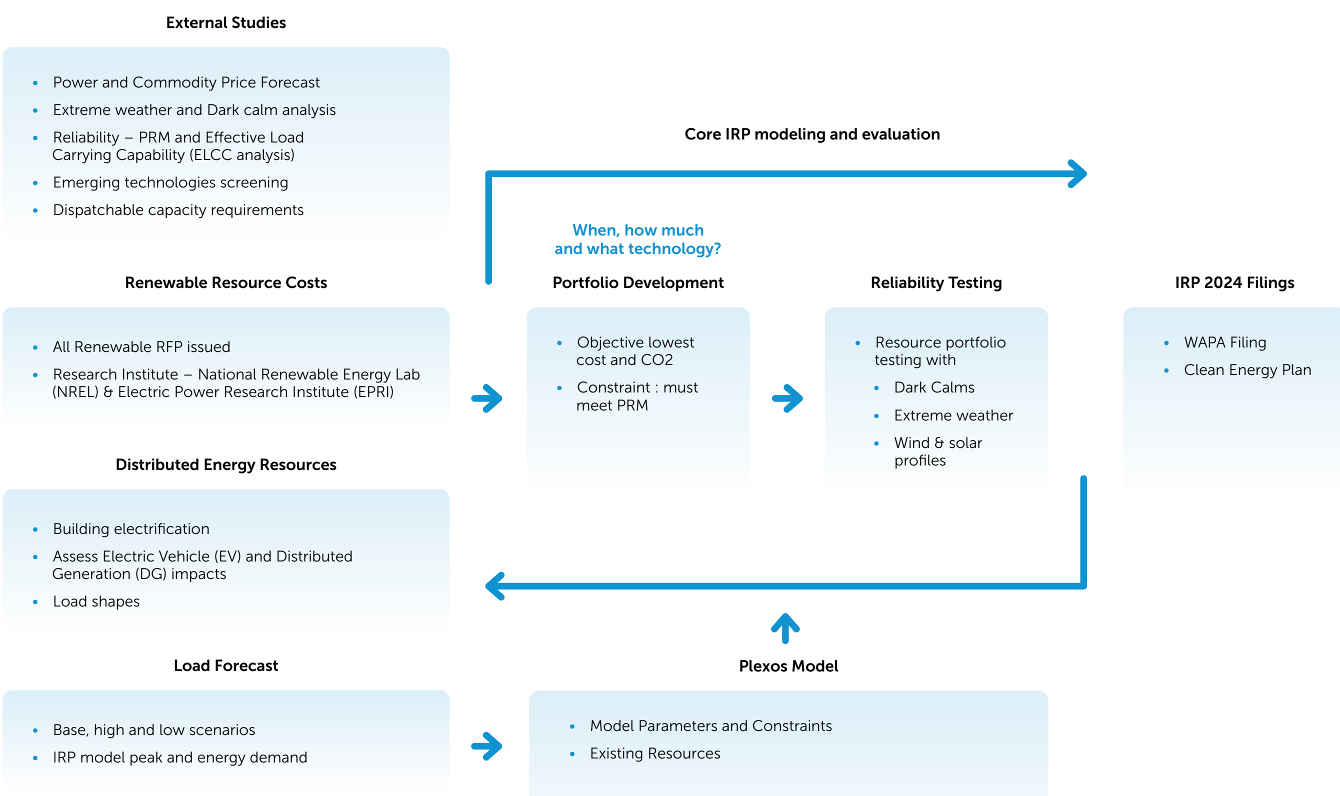


Figure 54. *IRP process*

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 may 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).

08
IRP study results

This chapter presents the modeling results for each portfolio, with comparisons of their most important metrics including cost, CO_2 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.

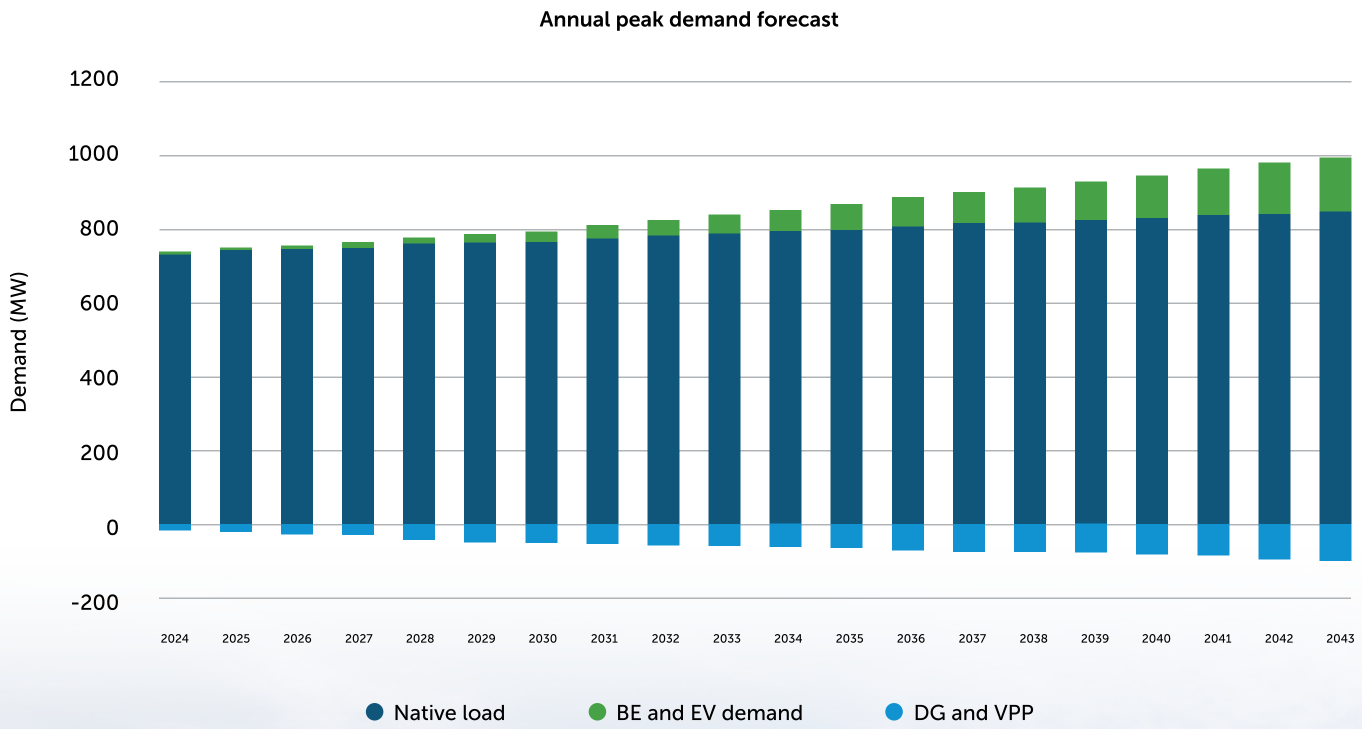


Figure 55. *Annual peak demand forecast*

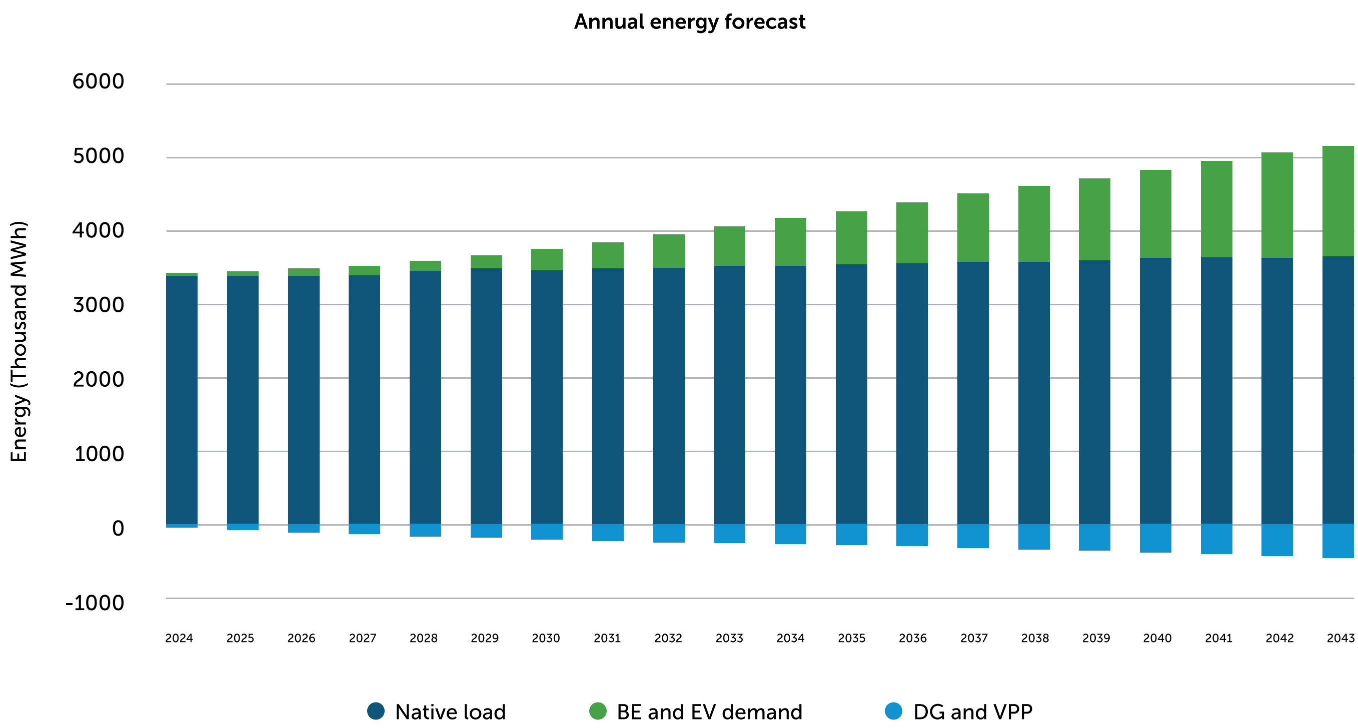


Figure 56. *Annual energy forecast*

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_2 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)
2024-2029 incremental additions (MWs)					
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
Final 2043 Portfolio (MWs)					
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.

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
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	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
Solar (new)	0	150	300	300	450	450	450	450	500	500	500	500	500	550	600	700	550	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	300	300	360	300	300	300	400	400	400	400	400	400	560	660	660	885
Storage 4-hr	2	2	27	52	1452	2852	2852	2852	2852	2852	2852	2852	2852	2852	2852	2852	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
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
Total	**1234**	**1399**	**1520**	**1772**	**3457**	**4806**	**4607**	**4628**	**4698**	**4716**	**4827**	**4843**	**4861**	**4929**	**4997**	**5117**	**5088**	**5090**	**5186**	**5263**

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

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
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	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
Solar (new)	0	150	300	300	450	500	500	500	500	500	550	550	600	700	700	750	600	500	600	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	300	300	360	300	300	300	300	400	400	400	400	400	560	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
Storage LT	0	0	0	0	10	10	10	10	10	10	10	10	10	10	60	60	60	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
Total	**1234**	**1399**	**1520**	**1772**	**2637**	**3136**	**2937**	**2958**	**2978**	**2996**	**3057**	**3173**	**3241**	**3359**	**3427**	**3497**	**3468**	**3520**	**3641**	**3693**

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

8.2.3 Carbon-imposed cost portfolio

The carbon-imposed cost attempts to measure the economic and environmental cost of CO2 for society. Due to the increased cost for CO2 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
Total	**1234**	**1399**	**1520**	**1772**	**2242**	**2391**	**2192**	**2238**	**2333**	**2426**	**2462**	**2628**	**2646**	**2664**	**2782**	**2852**	**2873**	**3025**	**3071**	**3173**

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

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
Total	**1234**	**1399**	**1520**	**1772**	**2257**	**2281**	**2082**	**2128**	**2173**	**2216**	**2327**	**2493**	**2511**	**2529**	**2647**	**2717**	**2788**	**2840**	**2936**	**3038**

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

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
Total	**1234**	**1399**	**1520**	**1772**	**2147**	**2146**	**1947**	**1968**	**2013**	**2056**	**2267**	**2383**	**2401**	**2519**	**2537**	**2607**	**2678**	**2770**	**2816**	**2918**

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.

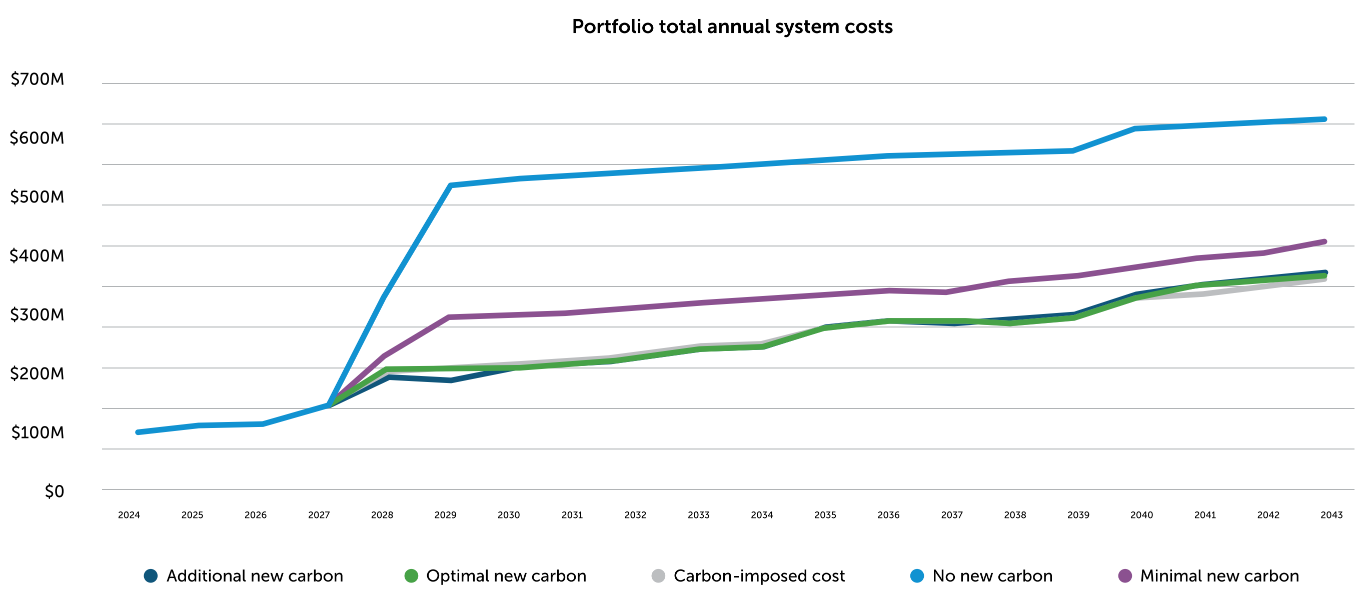


Figure 57. *Portfolio total annual system costs*

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%
Total	**100.0%**	**100.0%**	**100.0%**

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)[29] 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.

[29] 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).

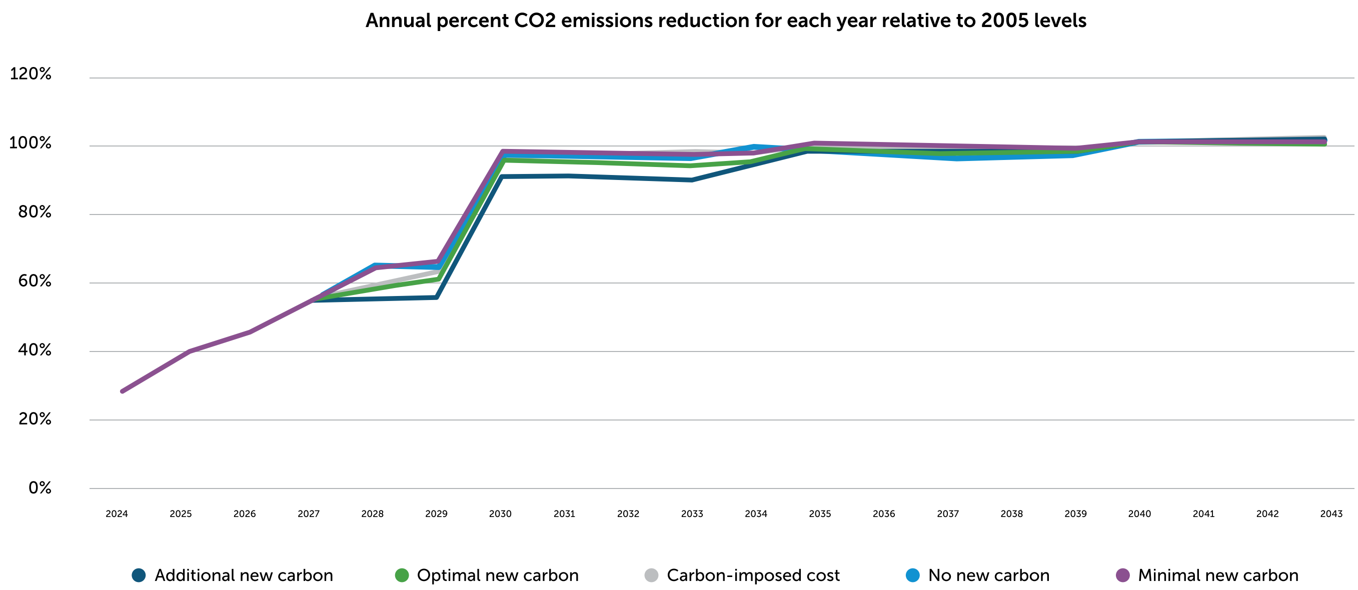


Figure 58. *Annual percent CO2 emissions reduction for each year relative to 2005 levels*

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 CO2 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 CO2-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 CO2 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_2 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_2 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.

	Base and sensitivity comparison			Intra portfolio cost comparison	
Portfolio	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 CO2 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.

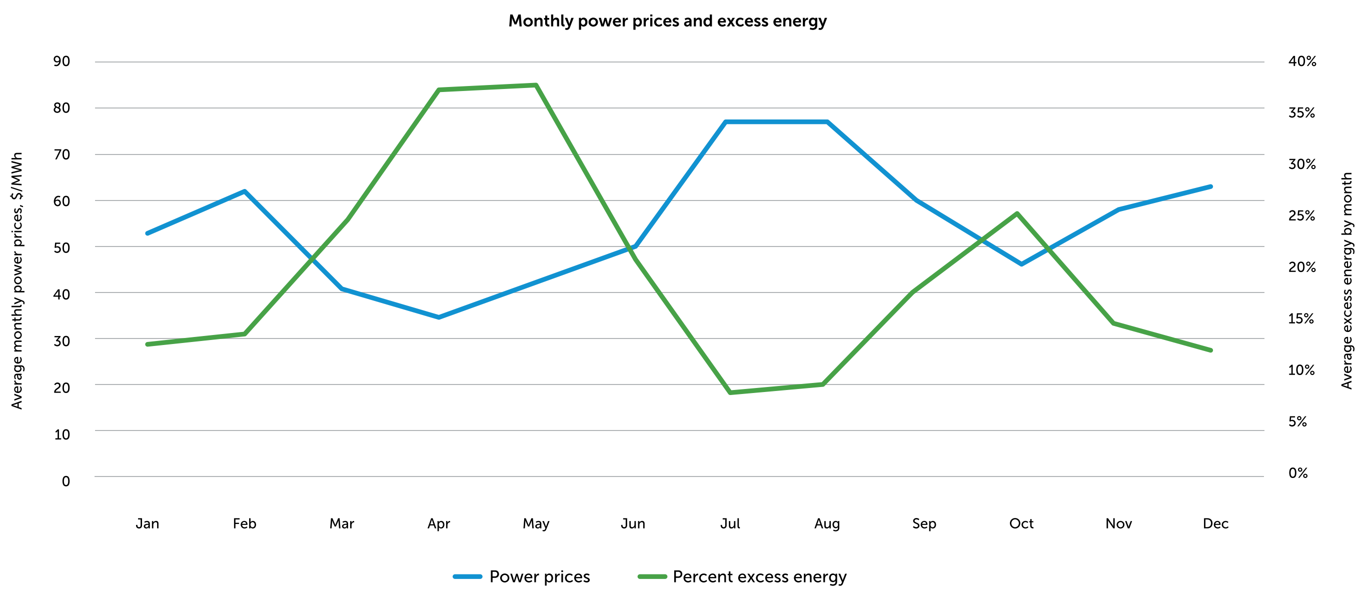


Figure 59. *Monthly power prices and excess energy*

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.

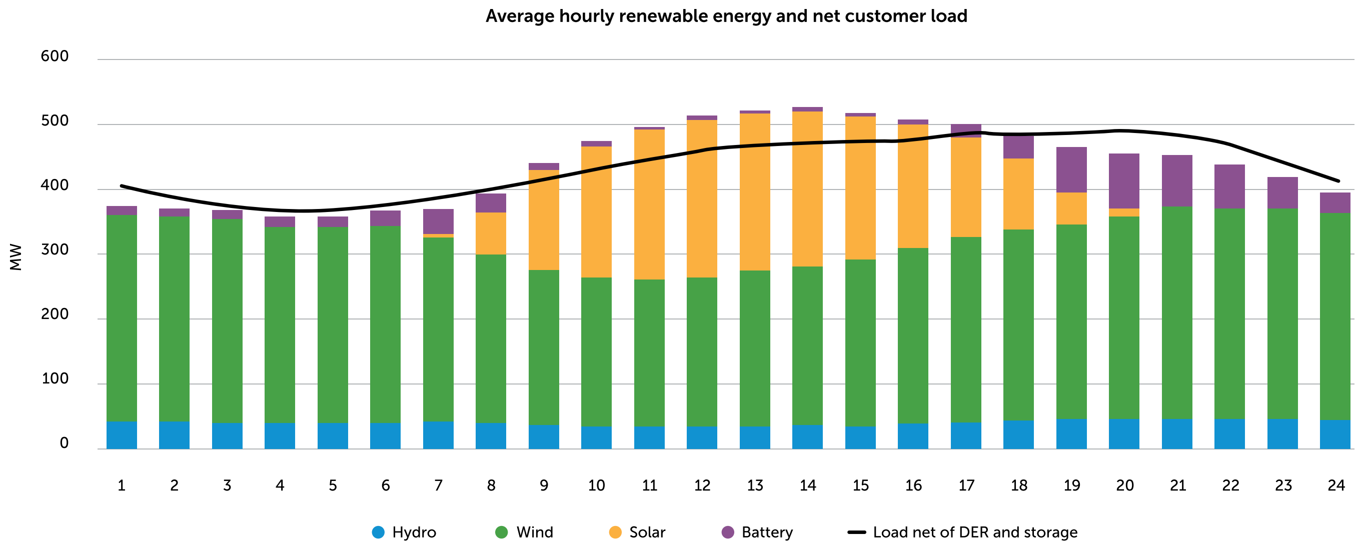


Figure 60. *Average hourly renewable energy and net customer load*

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

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

<table>
<tr><th>Resource plan component</th><th>Anticipated actions</th><th>Approximate timing</th><th>Key risks that may impact actions</th></tr>
<tr><td rowspan="4">Renewable energy acquisition</td><td>Contract for new 107 MW solar from the 2022 solar RFP</td><td>2024</td><td rowspan="4">Execution risks (section 7.5.1.1)
Cost escalation
Siting complications
Technology evolution
Operational risks (section 7.5.1.2)
Market evolution</td></tr>
<tr><td>Contract for new 250 MW wind from the 2023 wind RFP</td><td>2024</td></tr>
<tr><td>Begin commercial operation of 150 MW Black Hollow Solar project</td><td>2025</td></tr>
<tr><td>Begin commercial operation of a 130 MW solar project</td><td>2027</td></tr>
<tr><td rowspan="4">Dispatchable capacity (reliability)</td><td>Contract to add up to 20 MW of distributed energy storage from 2021 solar and storage RFP</td><td>2024</td><td rowspan="4">Execution risks (section 7.5.1.1)
Cost escalation
Siting complications
Technology evolution
DER adoption rates
Operational risks (section 7.5.1.2)
Fuel and market price risk
Regulatory risk on carbon accounting and emissions
Market evolution</td></tr>
<tr><td>Issue RFP for four-hour battery energy storage system</td><td>2024</td></tr>
<tr><td>Review results from all-dispatchable-resource RFP</td><td>2024</td></tr>
<tr><td>Begin adding up to 200 MW of dispatchable thermal generation resources. Major activities include:
Apply for air and land use permits
Identify actions related to ordering some long lead time equipment, especially related to power transmission
Develop initial project design and enlist engineering, procurement and construction contractor</td><td>2024</td></tr>
</table>

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	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications • Technology evolution • DER adoption rates Operational risks (section 7.5.1.2) • Fuel and market price risk • Regulatory risk on carbon accounting and emissions • Market evolution
	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) • Technology evolution • DER adoption rates Operational risks (section 7.5.1.2) • Market evolution VPP system integration Third-party DER device aggregators
	Launch VPP customer programs	2026	
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) • Cost escalation • Siting complications Operational risks (section 7.5.1.2) • Market evolution
Markets	Begin training staff to prepare for SPP RTO West market entry	2024	Operational risks (section 7.5.1.2) • Market evolution 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: • Receive studies from external consultants • Execute community engagement activities to educate public, collect stakeholder feedback • Conduct modeling and analyze portfolios • Compile draft report	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	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications • Technology evolution Operational risks (section 7.5.1.2) • Market evolution
Dispatchable capacity (reliability)	Testing, commissioning, and operation of new dispatchable thermal resource	2028	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications • Technology evolution • DER adoption rates Operational risks (section 7.5.1.2) • Fuel and market price risk • Regulatory risk on carbon accounting and emissions • Market evolution
	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

Appendix A: IRP checklist for WAPA

Document section	Requirement	Included in this IRP	Section number
IRP design, IRP study results **Power markets** **Energy efficiency** **DER integration, flexible DERs and the virtual power plant** **IRP portfolios**	Does the IRP evaluate the full range of alternatives for new energy resources, including: • new generating capacity? • power purchases? • energy conservation and efficiency? • cogeneration and district heating/cooling applications? • renewable energy resources?	✓	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: • Actions the customer expects to take in accomplishing the goals identified in the IRP? • Milestones to evaluate accomplishment of those actions during implementation? • Estimated energy and capacity benefits for each action planned?	✓	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.

Headquarters

Fort Collins, Colorado

2023 peak demand of owner communities

680 MW

General manager/CEO

Jason Frisbie

2023 deliveries of energy

4,506,208 MWh

Began operations

1973

2023 deliveries of energy to owner communities

3,161,533 MWh

Staff

268

Transmission system

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.

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.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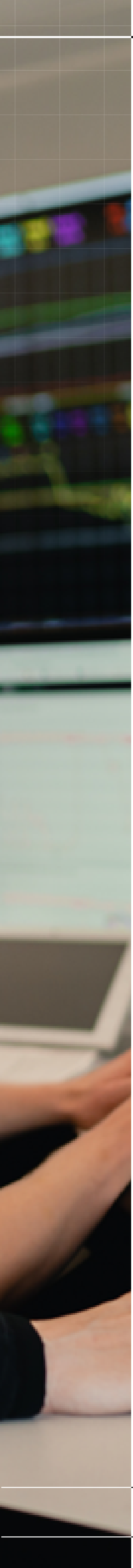


PRINCIPLE 1: TRANSPARENCY

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

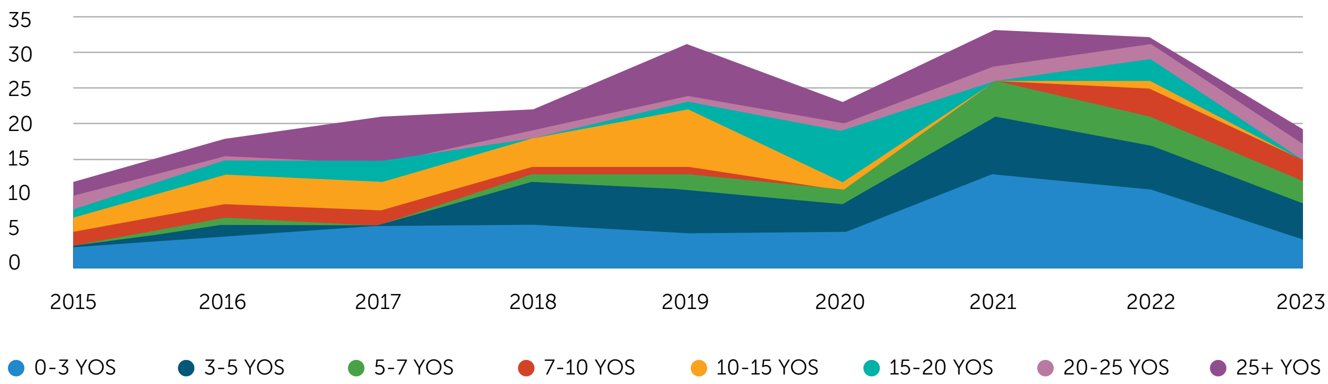


Figure 2: Rawhide Attrition by Years of Service

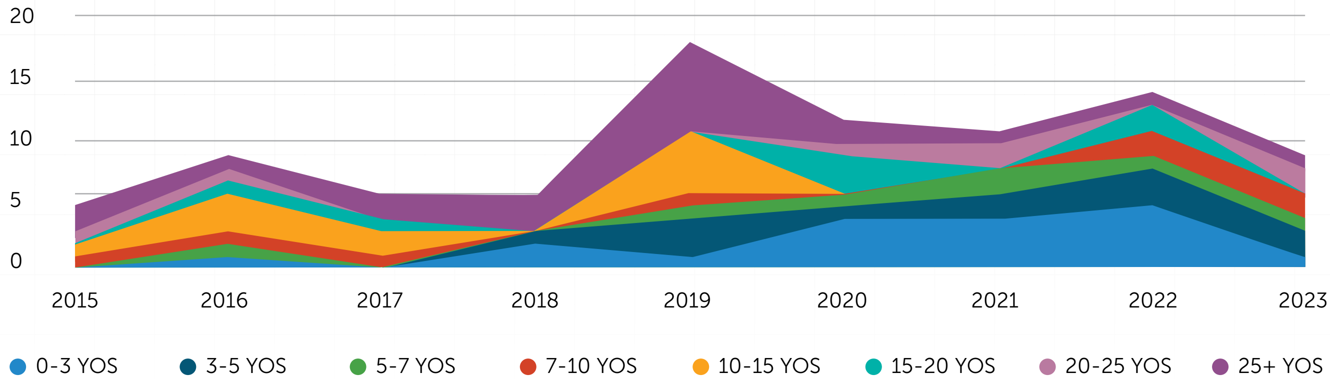
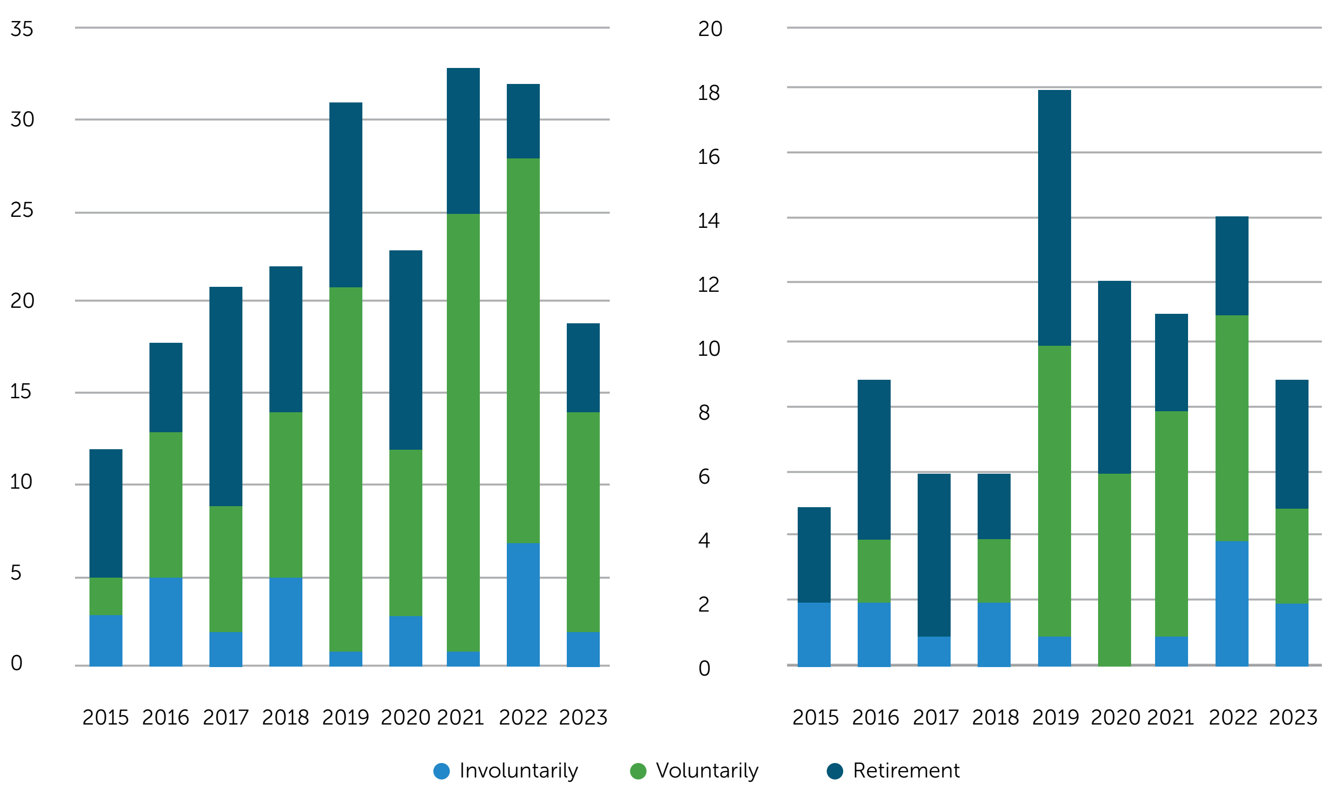


Figure 3 and Figure 4 show the historical reasons for attrition, both for Platte River as a whole and specifically for Rawhide. Retirement drives greater attrition at Rawhide than at Platte River as a whole, another trend that it anticipates will be stable through 2029. Platte River's projections for 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 As of Jan. 1, 2024	Target headcount At retirement Dec. 2029	Target headcount Post 2030	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

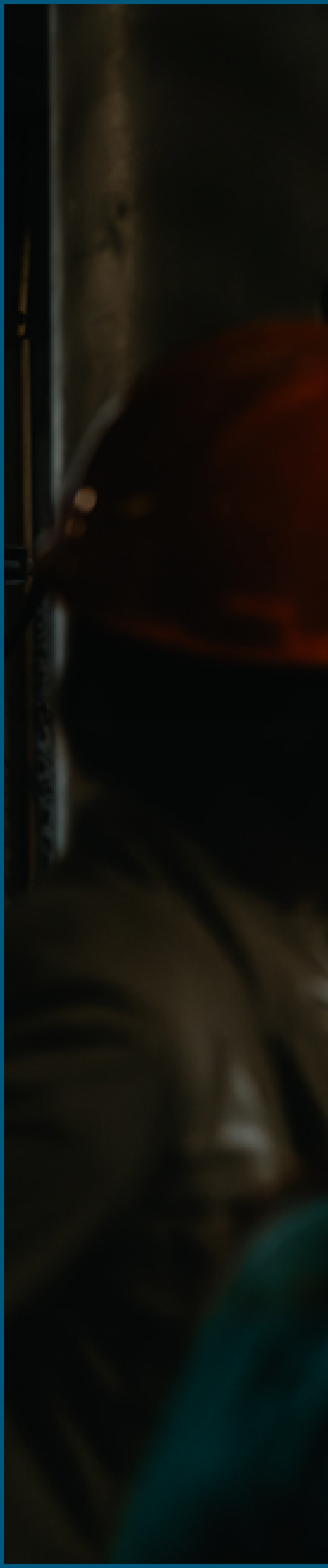
Current headcount
This is the number of employees at Rawhide to support Unit 1 as of May 2022. It does not include contract workers, which are managed by the vendors who employ them.

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.




DANGER

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:

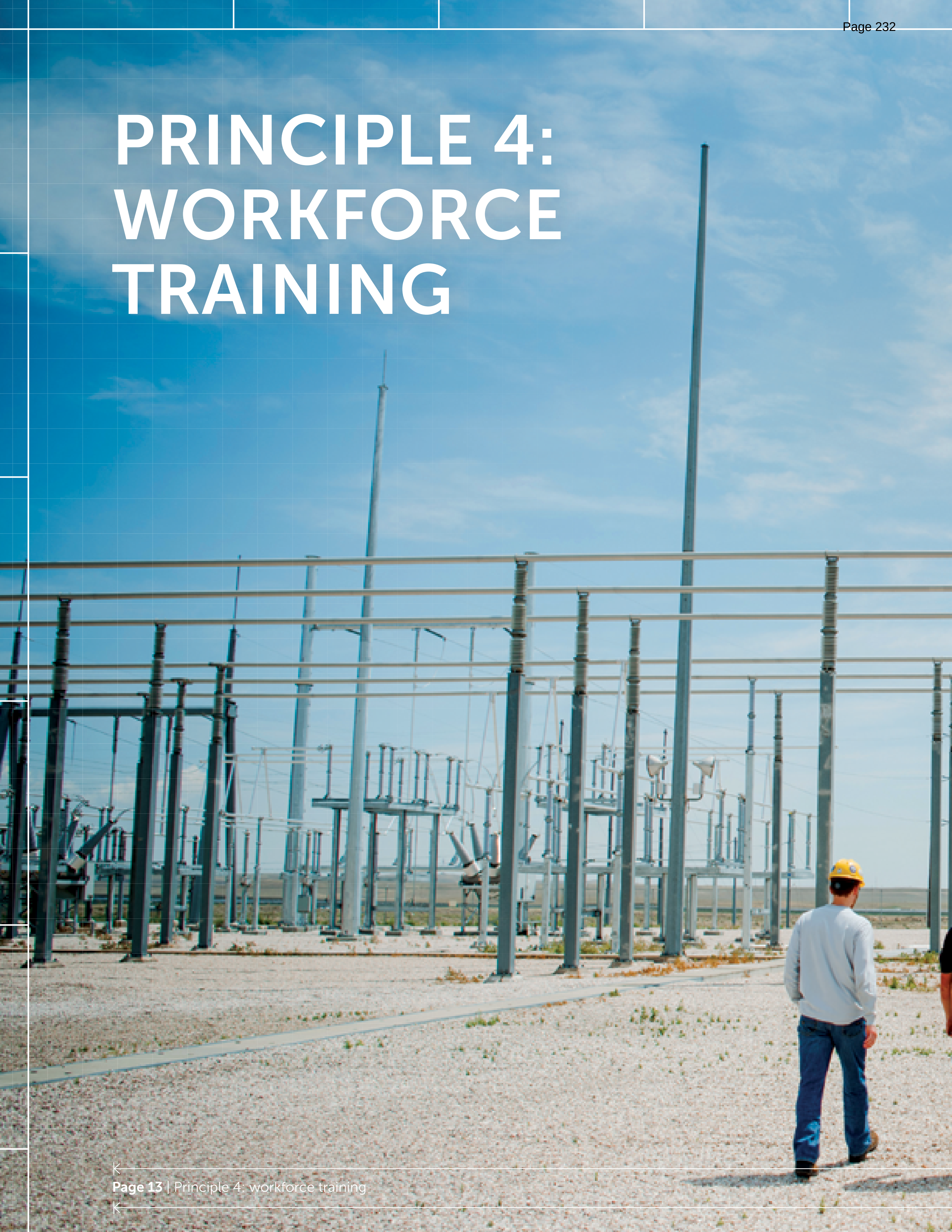
- Power markets and marketing desks (both transmission and generation)
- Compliance
- Information Technology
- Facilities
- Substations

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

Platte River
Power Authority

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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 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 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 _________ day of __________________, 2024.

____
Secretary

Adopted:
Vote:

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Memorandum

Date: 7/17/2024

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Melie Vincent, chief operating officer – generation, transmission and markets

Subject: **Rawhide Just Transition Plan**

In August, Platte River will submit its Just Transition Plan to the Colorado Office of Just Transition, as required by House Bill 19-1314. The plan is also a part of the 2024 Integrated Resource Plan to be submitted to the Western Area Power Administration. The Just Transition Plan follows the six principles stated in Platte River's board-approved resolution 08-2020: Workforce Resolution. The plan supports Platte River's ongoing commitment to retain employees through the energy transition and avoid involuntary separations due to Rawhide Unit 1's retirement.

Staff will ask the board to approve the Just Transition Plan at the July meeting.

Attachments

- Rawhide Just Transition Plan
- Resolution 08-24: Just Transition Plan Approval

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.

Headquarters

Fort Collins, Colorado

2023 peak demand of owner communities

680 MW

General manager/CEO

Jason Frisbie

2023 deliveries of energy

4,506,208 MWh

Began operations

1973

2023 deliveries of energy to owner communities

3,161,533 MWh

Staff

268

Transmission system

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.

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.


MARKET
09
22
EXCELLENCE

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

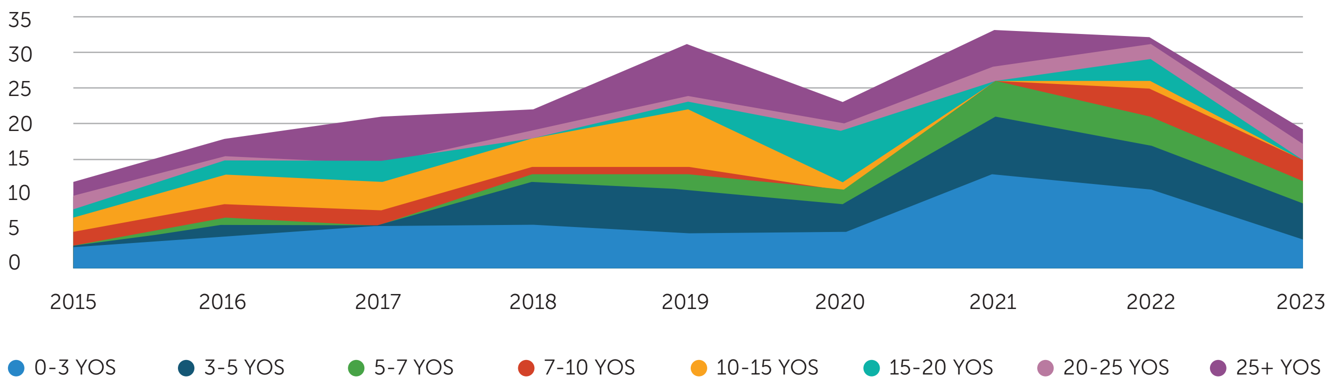


Figure 2: Rawhide Attrition by Years of Service

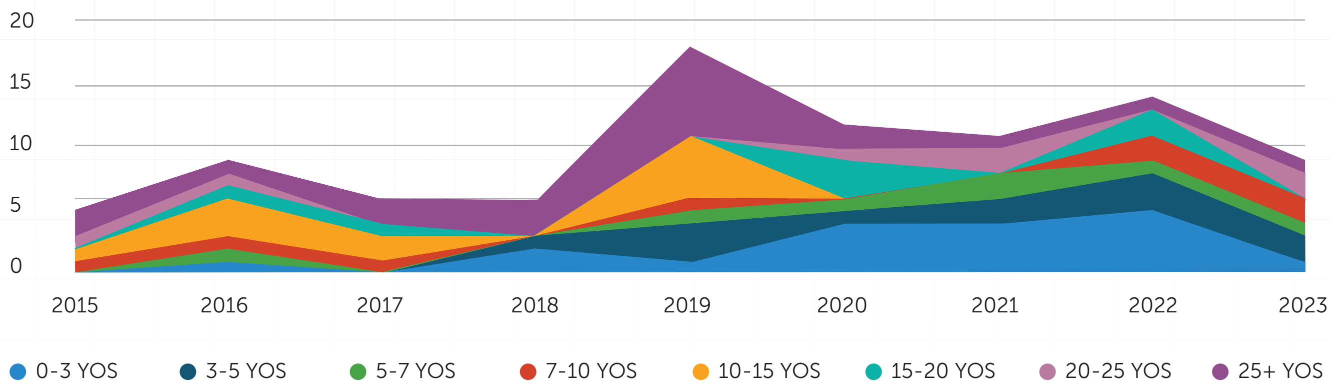


Figure 3 and Figure 4 show the historical reasons for attrition, both for Platte River as a whole and specifically for Rawhide. Retirement drives greater attrition at Rawhide than at Platte River as a whole, another trend that it anticipates will be stable through 2029. Platte River's projections for 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

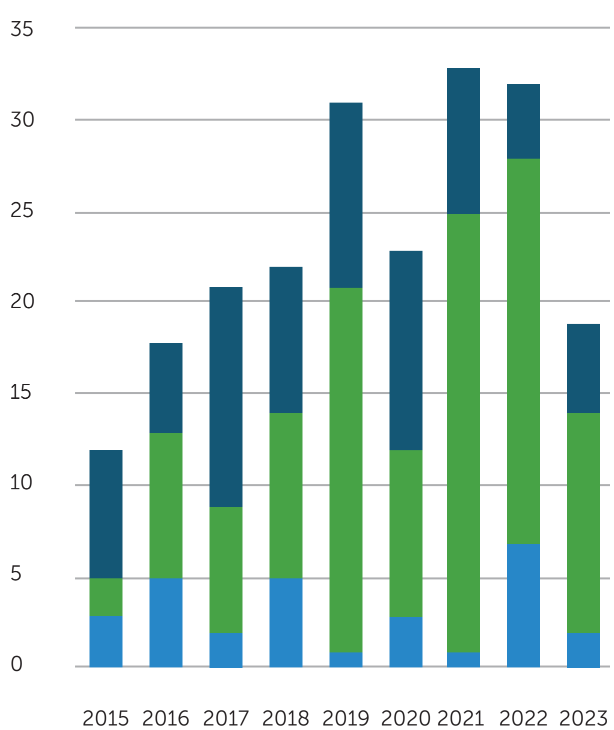
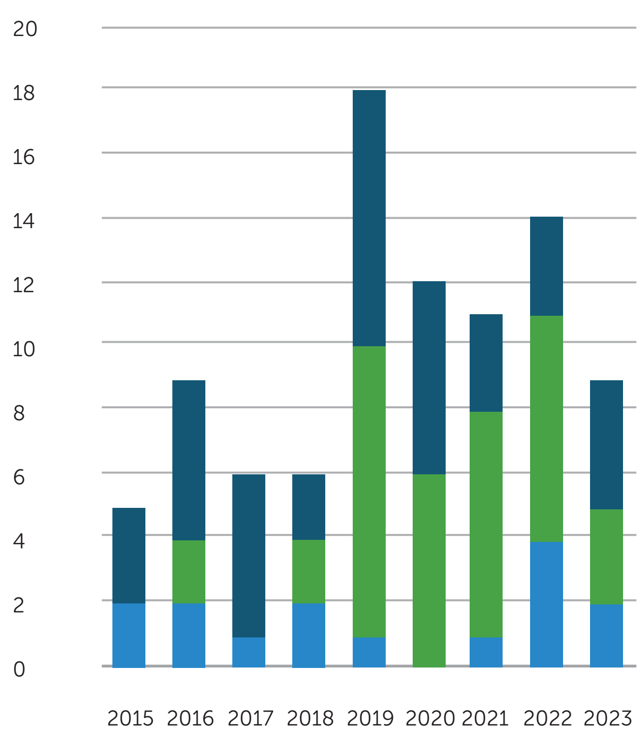


Figure 4: Rawhide Attrition by Reason



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 As of Jan. 1, 2024	Target headcount At retirement Dec. 2029	Target headcount Post 2030	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

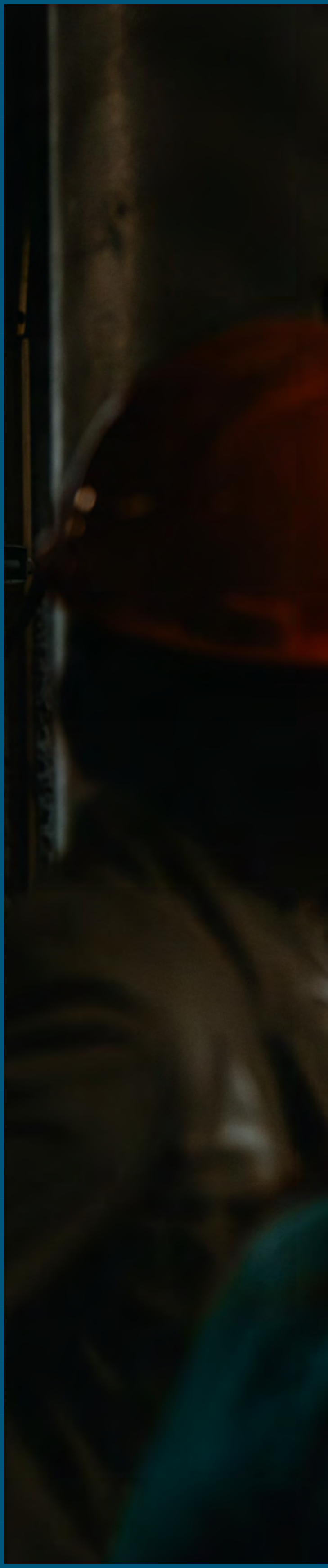
Current headcount
This is the number of employees at Rawhide to support Unit 1 as of May 2022. It does not include contract workers, which are managed by the vendors who employ them.

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.


MSA

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

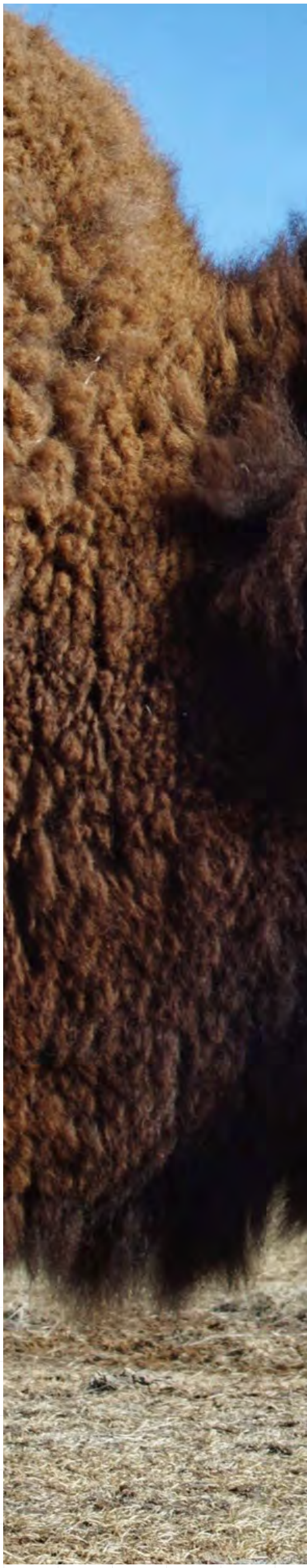
For those employees whose paths lead away from Platte River, Platte River management will seek to ease their transitions with placement support and incentives, where appropriate.

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.



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2024 JUST TRANSITION PLAN

RESOLUTION NO. 08-24

Background

A. Platte River Power Authority (Platte River) was formed to provide electric generation and transmission services to its owner communities.

B. Since 1984, the Rawhide Unit 1 coal plant (Rawhide Unit 1) has provided low-cost, reliable energy due to the skill and dedication of the outstanding employees who support its operation.

C. On Dec. 6, 2018, Platte River's board of directors (board) passed Resolution No. 28-18, adopting Platte River's Resource Diversification Policy and directing Platte River leadership to proactively work toward the goal of reaching a 100% noncarbon resource mix by 2030.

D. On May 28, 2019, Colorado's governor signed House Bill 19-1314 ("Just Transition Support for Coal-Related Jobs") into law, establishing the Colorado Office of Just Transition and requiring utilities that accelerate retirement of coal-fired generating units to submit a workforce transition plan.

E. On June 16, 2020, Platte River announced its initial plans to retire Rawhide Unit 1 by 2030, in keeping with Platte River's 2020 Integrated Resource Plan and Resource Diversification Policy goals.

F. On July 30, 2020, Platte River's board passed Resolution No. 08-20, committing Platte River's management to plan for and implement a responsible transition process for Rawhide employees following six principles:

- Transparency
- Workforce Planning
- Workforce opportunities
- Workforce training
- Retention strategies
- Transition support

G. On June 27, 2022, Platte River submitted its verified, voluntary Clean Energy Plan to the Colorado Public Utilities Commission, reflecting Platte River's plan to retire Rawhide Unit 1 by Dec. 31, 2029.

RESOLUTION NO. 08-24

H. Platte River's 2024 Integrated Resource Plan shows Rawhide Unit 1 retiring by Dec. 31, 2029. The 2024 Integrated Resource Plan will include Platte River's Just Transition Plan for its workforce, following the six principles from Resolution No. 08-20.

Resolution

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

1. the board approves the accelerated retirement of Rawhide Unit 1 by Dec. 31, 2029, as shown in Platte River's 2024 Integrated Resource Plan,
2. the board approves the Platte River Just Transition Plan as presented at this meeting, and
3. the board authorizes and directs staff to submit Platte River's Just Transition Plan to the Office of Just Transition within 30 days of this resolution.

AS WITNESS, I have signed my name as secretary and have affixed the corporate seal of the Platte River Power Authority this __________ day of ___________________, 2024.

____
Secretary

Adopted:
Vote:

Platte River
Power Authority

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Memorandum

Date: 7/17/2024

To: Board of Directors

From: Jason Frisbie, general manager and chief executive officer
Dave Smalley, chief financial officer and deputy general manager
Shelley Nywall, director of finance

Subject: **First Amendment to Intergovernmental Agreement for Fiber Management – Long-Haul revenues**

The Fiber Optic Executive Committee (Fiber Committee) met on Monday, April 8, 2024. The Fiber Committee includes Platte River's general manager and the broadband or utility directors of each of Platte River's owner communities. The committee provides policy direction to Platte River on the use of long-haul fiber (fiber connecting the local loops around each owner community).

At the meeting, the Fiber Committee recommended approval of an amendment to the Intergovernmental Agreement for Fiber Management (Fiber IGA) between Platte River and its owner communities. The amendment removes a requirement for Platte River to maintain long-haul lease revenues in a separate long-haul fiber account. Maintaining this separate account does not follow proper accounting practices as Platte River continues to own, operate and maintain the long-haul fiber assets. The account was initially created in response to SB 05-152, which restricted local governments' ability to engage in broadband activities. This bill has since been repealed. Although Platte River and the owner communities discussed distributing excess long-haul fiber to the owner communities, the parties determined that Platte River would retain ownership of this fiber and the related lease revenue.

Removing the separate long-haul fiber account will not affect the owner communities or Platte River's maintenance responsibilities. As required, each owner community will ask its city council or town board to approve the amendment. Staff recommends the board approve the amendment and will ask the board to adopt a resolution to amend the Fiber IGA at the August board meeting.

Attachments

- First Amendment to Intergovernmental Agreement for Fiber Management
- Draft resolution

Draft for board discussion July 25, 2024
NOT APPROVED

RESOLUTION NO. XX-24

Background

A. In 2019 Platte River Power Authority (Platte River) and the communities of Estes Park, Fort Collins, Longmont, and Loveland (owner communities) signed an Intergovernmental Agreement for Fiber Management (“Fiber IGA”).

B. Under C.R.S. § 29-1-203 the owner communities and Platte River are empowered to enter into intergovernmental agreements through which the parties may cooperate in the provision of a service or function lawfully authorized to each.

C. Platte River and the owner communities wish to amend the existing Fiber IGA to remove all provisions concerning the Long-Haul Fiber Account.

D. Staff recommends in a memorandum dated August 21, 2024, that the board adopt the attached amendment to the Fiber IGA.

Resolution

The board of directors of Platte River Power Authority adopts and approves the attached amendment to the Intergovernmental Agreement for Fiber Management.

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

____
Secretary

FIRST AMENDMENT TO INTERGOVERNMENTAL AGREEMENT FOR FIBER MANAGEMENT

This First Amendment to the Intergovernmental Agreement for Fiber Management ("**Amendment**") is made and entered into ___________________, (the "**Effective Date**") by and between The Town of Estes Park ("**Estes Park**"), the City of Fort Collins ("**Fort Collins**"), the City of Longmont ("**Longmont**"), the City of Loveland ("**Loveland**"), collectively the "**Municipalities**," individually a "**Municipality**," and Platte River Power Authority ("**Platte River**"), sometimes individually referred to in this Amendment as a "**Party**" and collectively as the "**Parties**."

RECITALS

A. The Parties entered into an Intergovernmental Agreement for Fiber Management, dated May 15, 2019, ("Fiber IGA").

B. To conform with standard accounting practices the Parties desire to amend the Fiber IGA to remove the Long-Haul Fiber Account as a separate account maintained by Platte River.

AGREEMENT

1. **Section 4.B** of the Fiber IGA is amended to delete the language shown in strikeout below:

4.B The Executive Committee consists of the utility or broadband directors of each of the four Municipalities and Platte River's General Manager, each of whom shall have one vote. Provided, however, that Platte River shall have the final decision-making authority with respect to decisions of the Executive Committee that impact the reliability of Platte River's electric system. The Executive Committee will meet as necessary or as requested by members of the Executive Committee. The Executive Committee will evaluate Platte River's fiber management, provide policy direction to Platte River relating to the leasing of Excess Fiber on the Long-Haul ~~and operation of the Long-Haul Fiber Account~~, resolve any disputes that arise in the management of the Fiber Optic Network and address any other policy issues that require executive decision-making authority.

2. The first paragraph of **Section 9** of the Fiber IGA is amended to delete the language shown in strikeout below and add the new language shown in underlined, contrasting font:

9. **Excess Fiber Leasing.**

In October 1998, the Platte River Board of Directors adopted Resolution 17-98 which authorized the General Manager to negotiate dark fiber leases on behalf of the Municipalities. Since that time, Platte River has been leasing dark fiber within the Local Loops in Fort Collins, Loveland and Estes Park to third parties and returning the revenue associated therewith to the Municipality within whose electric service area the leased dark fiber is located. Platte River~~has retained revenue from leases~~ maintains ownership of~~dark fiber~~ the Excess Fiber within the Long-Haul~~to cover its operating expenses.~~ and will retain revenues from Long-Haul leases.

3. **Section 9.d** of the Fiber IGA is deleted.

~~9.d So long as Platte River retains ownership of the Excess Fiber within the Long-Haul, net revenues (gross revenues less administrative expenses deducted in accordance with Section 6 of this Agreement) from Long-Haul Leases shall be maintained in an account to be managed by Platte River for the benefit of the Municipalities (the "Long-Haul Fiber Account"). The Long-Haul Fiber Account shall be used by Platte River, in a manner consistent with the policy direction provided by the Executive Committee, to pay for expenses associated with the Long-Haul which are not covered in the Fiber Optic Network Accounting Policy, including, but not limited to easement acquisition and technology upgrades to, or expansion of, the Long-Haul. Expenses shall not exceed the balance in the account. In the event that ownership of the Excess Fiber within the Long-Haul is transferred to the Municipalities, funds remaining in the Long-Haul Fiber Account shall be transferred with such ownership in the same proportion (i.e., if ownership is transferred to each Municipality equally, the account balance shall be distributed equally); and~~

SIGNATURE PAGES FOLLOW

SIGNATURES

PLATTE RIVER POWER AUTHORITY

By: ______________________________
General Manager/CEO

ATTEST:

By: ______________________________
Secretary

APPROVED AS TO FORM:

By: ______________________________
Senior Counsel

TOWN OF ESTES PARK, COLORADO

By: ______________________________
Mayor

Date:_________________

ATTEST:

By: ______________________________
Town Clerk

CITY OF FORT COLLINS, COLORADO

By: ______________________________
City Manager

Date:__________________

ATTEST:

By: ______________________________
City Clerk

APPROVED AS TO FORM:

By: ______________________________
Deputy City Attorney

CITY OF LOVELAND, COLORADO

By: ______________________________
City Manager

Date:__________________

ATTEST:

By: ______________________________
City Clerk

APPROVED AS TO FORM:

By: ______________________________
Assistant City Attorney

CITY OF LONGMONT, COLORADO

By: ______________________________
Mayor

Date:__________________

ATTEST:

By: ______________________________
City Clerk

APPROVED AS TO FORM AND SUBSTANCE:

By: ______________________________
Director of Longmont Power & Communications

APPROVED AS TO FORM:

By: ______________________________
Assistant City Attorney

PROOFREAD:

By: ______________________________

Platte River Power Authority

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Memorandum

Date: 7/17/2024

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Melie Vincent, chief operating officer, generation, transmission, and markets
Jeremy Clark, director, power markets

Subject: **One-year WEIS participation and SPP RTO West update**

At the July board meeting, Platte River staff will provide a high-level overview of Platte River's first year of participation in the Southwest Power Pool (SPP) Western Energy Imbalance Service market and a status report on SPP Regional Transmission Organization - West implementation, preparing for market go-live on April 1, 2026.

This presentation is for informational purposes only and does not require board action.

Platte River
Power Authority

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Memorandum

Date: 7/17/2024

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Melie Vincent, chief operating officer – generation, transmission and markets

Subject: **Flat Iron - Estes Park transmission line update**

In the last two years, Estes Park has experienced three outages from loss of transmission service. Two of these outages followed the completion of the Flat Iron - Estes Park transmission line upgrade. In this presentation, Platte River staff will provide a high-level review of the sequence of events for each outage and the actions taken following each outage. Bart Barton, senior vice-president and regional manager of Western Area Power Administration - Rocky Mountain Region, will discuss the options available to improve reliability and provide a timeline of decision points and action items. Time is allotted for board discussion.

This presentation is for informational purposes only and does not require board action.

Platte River
Power Authority

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Memorandum

Date: 7/17/2024

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Eddie Gutiérrez, chief strategy officer
Javier C. Camacho, director of public and external affairs, strategic communications and social marketing

Subject: **2024 Legislative session recap**

This presentation will provide a recap of the 2024 Colorado legislative session, including a high-level overview of the General Assembly and the outcome of priority tracked legislation. The presentation will also preview next steps for the external affairs team and anticipated legislation for the 2025 Colorado legislative session.

This presentation is for informational purposes only and does not require board action.

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Performance dashboard

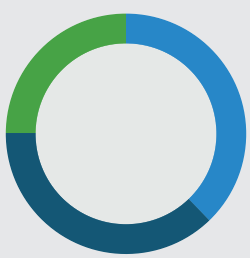
June 30, 2024

Reliability

Transmission	Fiber communications	Rawhide Unit 1	Rawhide Unit 1	Rawhide frame combustion turbines
100%	0	98.2%	0	100%
Goal: no loss of load to the owner communities	Goal: no unplanned communication outages to the owner communities	Goal: adjusted equivalent availability factor ≥ 97%	Goal: no controllable outages	Goal: delivery reliability ≥ 90%

Environmental responsibility

System total

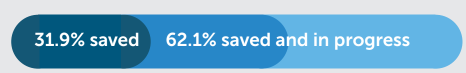


Noncarbon projection 35.9%

Energy savings from completed projects

5,741 MWh saved

0.4% YTD actual load



Budgeted energy savings for Efficiency Works
18,016 MWh, 0.5% of Platte River's annual budgeted load

Financial sustainability

Credit rating

AA

Strategic financial plan indicators

Fixed obligation charge coverage ratio	Change in net position as a percentage of operating expenses	Adjusted debt ratio	Days adjusted liquidity on hand
2.24x	10.3%	24%	416
Target annual minimum 1.50x	Target annual minimum 3% of operating expenses	Target minimum Less than 50%	Target minimum 200 days

Platte River
Power Authority

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Legal, environmental and compliance report

May and June 2024

Platte River
Power Authority

Overview of recent developments

Legal matters

Federal Energy Regulatory Commission's Order 1920 on regional transmission planning and cost allocation

On May 13, 2024, the Federal Energy Regulatory Commission (FERC) issued Order No. 1920, a final rule to reform its policies on regional transmission planning and cost allocation. Order No. 1920 requires transmission providers to engage in long-term planning processes, over a 20-year timeframe, with at least three different plausible scenarios that include different resource additions, natural gas and other prices, and extreme weather events. Transmission providers must coordinate transmission planning with generator interconnection processes, consider alternative transmission technologies, and propose cost allocation for planned projects. Order No. 1920 represents a major change to transmission planning rules; it will require local and regional planning entities to rewrite their processes to incorporate long-range planning and transparency. There are already multiple lawsuits challenging the rule, so its future status is uncertain. Order 1920 does not apply directly to Platte River. The full report is on page 3 of this document.

Southwest Power Pool's petition for a declaratory order on tariff provisions and conflict with state law

On May 23, 2024, the Southwest Power Pool (SPP), Platte River's proposed future regional transmission organization (RTO) operator, filed a petition with FERC for a declaratory order on whether SPP's tariff requires SPP to file an unexecuted generator interconnection agreement that an SPP RTO member (the Omaha Public Power District) determined violated state law. This question has broader implications for public power's participation in RTOs, including in SPP's proposed western regional transmission organization (RTO West). The full report is on page 4 of this document.

Progress on SPP's western regional transmission organization

Platte River entered SPP's Western Energy Imbalance Service market on March 31, 2023. Over the past year or so, Platte River has collaborated with other regional utilities, as well as SPP, to explore the potential for SPP to expand its current 14-state regional transmission organization into RTO West. RTO West will include day-ahead as well as real-time operational and tariff services. The target "go-live" date for RTO West is April 2026. On June 4, 2024, SPP filed its proposed tariff changes with FERC, reflecting revisions to expand the RTO into the western interconnection and initiate RTO West. Comments are due by July 5. The full report is on page 4 of this document.

Environmental matters

There are no new environmental matters to report.

Platte River Power Authority

Compliance matters

There are no new compliance matters to report.

Monitoring—status unchanged

Page 6 of this document provides a list of matters previously reported but unchanged since our last report.

Recently concluded matters

Page 7 of this document provides a list of matters that have concluded within the last three months.

Platte River
Power Authority

Active matters

Legal matters

Federal Energy Regulatory Commission's Order 1920 on regional transmission planning and cost allocation

On May 13, 2024, the Federal Energy Regulatory Commission (FERC) issued Order No. 1920, a final rule to reform its policies on regional transmission planning and cost allocation. Order No. 1920 follows a notice of proposed rulemaking in April 2022, seeking comment on how to best reform transmission planning, cost allocation, and generator interconnection. The rule was published in the Federal Register on June 11, 2024, and the first compliance filings will be due June 12, 2025 (unless the rule is stayed or extended).

Order No. 1920 follows previous FERC transmission planning rules, including Order No. 888 (issued in 1996), Order No. 890 (issued in 2007), and Order No. 1000 (issued in 2011). Order No. 1920 requires transmission providers to engage in long-term planning processes over a 20-year timeframe (instead of the current practice of five- or 10-year timelines), with at least three different plausible scenarios that include different resource additions, natural gas and other prices, and extreme weather events. The scenarios must incorporate and consider seven mandatory benefits, including avoided or deferred maintenance, reduced outage risk, reduced planning reserve margins, cost savings, reduced energy losses, extreme weather mitigation, and capacity cost benefits. Transmission providers may consider more scenarios, factors, and benefits than the required minimum. Transmission providers must coordinate transmission planning with generator interconnection processes, consider alternative transmission technologies, and propose cost allocation for planned projects. Although the notice of proposed rulemaking considered requiring transmission providers to consult with state entities (public utility commissions), the final rule does not mandate consultation but does allow for input from state entities. Transmission providers must also comply with new transparency requirements and publicly post the criteria, models, and assumptions used in local and regional planning. In sum, Order No. 1920 represents a major change to transmission planning rules, and will require local and regional planning entities to rewrite their processes to incorporate long-range planning and transparency.

Order No. 1920 was issued 2-1, with Chairman Willie Phillips and Commissioner Allison Clements in concurrence. Commissioner Mark Christie wrote a strong dissent, alleging that the order, as issued, is a jurisdictional overreach that will cost consumers trillions of dollars and should not have eliminated the need for state agreement, allowing cost allocation to apply to transmission projects in "non-consenting" states. There are already multiple lawsuits challenging the rule, so its future status is uncertain. Order 1920 does not apply directly to Platte River, but we will monitor the ongoing proceedings and how Order No. 1920 may affect us as we enter into a regional transmission organization (RTO).

Platte River
Power Authority

Southwest Power Pool's petition for a declaratory order on tariff provisions and conflict with state law

On May 23, 2024, the Southwest Power Pool (SPP), Platte River's proposed future RTO operator, filed a petition with FERC for a declaratory order on whether SPP's tariff requires SPP to file an unexecuted generator interconnection agreement that an SPP RTO member (the Omaha Public Power District or OPPD) determined violated state law.

The question before FERC is what tariff language controls in a dispute between OPPD and a battery project developer (Eolian) over whether Nebraska state law allows private entities to own and operate battery projects in the state. OPPD's board of directors determined Nebraska law does not permit Eolian's proposed battery projects. OPPD therefore refused to sign a generator interconnection agreement with Eolian. Both section 39.1 of SPP's tariff and section 3.12 of the SPP membership agreement state that, if (with respect to a public power utility) there is a conflict between the tariff and a state law, regulation, or rate schedule, the state requirements excuse the public power utility from complying with the tariff. But SPP's tariff also requires SPP, as the transmission provider for all RTO members, to file unexecuted generator interconnection agreements if the interconnecting transmission owner and the generation interconnection customer cannot agree on terms and the interconnection customer requests filing. So SPP petitioned FERC to determine SPP's obligations.

This question has broader implications for public power's participation in RTOs, including in SPP's proposed western regional transmission organization (RTO West). Section 39.1 of the tariff and section 3.12 of the membership agreement assure public power utilities they will not be required to violate state laws because they participate in RTOs or similar markets. Platte River filed comments supporting OPPD's position that the tariff protects OPPD from taking actions its board has determined violate state law. Our trade group representatives at the American Public Power Association and Large Public Power Council also filed supporting comments. We and others in the public power community will keep a close eye on this proceeding and its potential effects on public power.

Progress on SPP's western regional transmission organization

Background:

Platte River entered the Southwest Power Pool (SPP) Western Energy Imbalance Service market on March 31, 2023. Over the past year or so, Platte River has collaborated with other regional utilities, as well as SPP, to explore the potential for SPP to expand its current 14-state regional transmission organization into RTO West.

RTO West will include day-ahead as well as real-time operational and tariff services. Potential participants include Basin Electric Cooperative, Colorado Springs Utilities, Deseret Generation and Transmission Cooperative, Municipal Energy Agency of Nebraska (MEAN), Platte River Power Authority, Tri-State Generation and Transmission Association, and the Western Area Power Administration (encompassing three divisions—the Rocky Mountain Region, the Upper Great Plains Region, and the Colorado River Storage Project). The target "go-live" date for RTO West is April 2026.

Platte River
Power Authority

To begin the RTO West expansion, SPP required prospective participants to make financial commitments. Platte River worked with the legal teams from SPP and the other participants to draft the template for a series of bilateral agreements (Commitment Agreements) to enable SPP to recover its development costs if RTO West does not go forward as planned. (If RTO West launches as planned, SPP will recover its development costs over time through its administrative fees.) Most participants, including Platte River, signed Commitment Agreements by June 30, 2023.

SPP's current cost estimate for the RTO West expansion is approximately $40 million. Platte River's estimated share is roughly $5 million. Under the Commitment Agreements, the obligation to reimburse SPP for its development costs arises only for participants that withdraw before the go-live date or if RTO West does not launch in the Western Interconnection. On Jan. 19, 2024, the participants voted to endorse SPP tariff Attachment AE, setting up the market structure RTO West will use going forward.

Current Status:

On June 4, 2024, SPP filed proposed tariff revisions with FERC, reflecting revisions to expand the RTO into the western interconnection and initiate RTO West. Comments are due by July 5. Platte River and other Colorado public power utilities (Colorado Springs Utilities and MEAN) plan to file joint comments in support. We will update the board on developments in the FERC proceeding.

Environmental matters

There are no active environmental-related matters to report.

Compliance matters

There are no active compliance-related matters to report.

Platte River
Power Authority

Monitoring—status unchanged

Legal matters

Municipal Energy Agency of Nebraska complaint challenging Colorado's Power Pathway

Comments on MEAN's complaint were due March 21, 2024. Various parties, including the Colorado Utility Consumer Advocate, commented in the docket or moved to intervene. Public Service Company of Colorado filed a Motion to Dismiss the complaint, which MEAN answered on April 12, 2024. Platte River will closely follow this proceeding and update the board with any developments that may affect our transmission planning or rates.

Proposed revisions to Colorado Air Quality Control Commission Regulation No. 3 for sources in disproportionately impacted communities

On Aug. 21, 2023, a coalition of non-governmental organizations, including GreenLatinos, 350 Colorado, and Earthworks, sued the Air Quality Control Commission (Air Commission) in Denver County District Court. The lawsuit alleges that the rules the Air Commission adopted on May 18 do not comply with Colorado's Environmental Justice Act and are otherwise arbitrary and capricious. If the lawsuit succeeds, the likely outcome is a remand to the Air Commission for a new rulemaking. Platte River will monitor this lawsuit and update the board with any developments.

Environmental matters

Groundwater and waste management

Platte River continues to monitor groundwater and has completed lining and improvements at the monofill. There have been no new developments since our last report.

Compliance matters

There are no compliance-related matters in monitored status this month.

Platte River
Power Authority

Recently concluded matters (last three months)

Legal matters

Save the Colorado v. Bureau of Reclamation (Glen Canyon Dam)

On Oct. 1, 2019, Save the Colorado and other environmental groups sued in the United States District Court for Arizona challenging the Bureau of Reclamation (Bureau) record of decision (Decision) to approve the Long-Term Experimental and Management Plan for Glen Canyon Dam. Glen Canyon Dam is a large hydropower dam that is part of the Colorado River Storage Project (CRSP). Platte River is one of the largest offtakers of hydropower from CRSP, accounting for almost 13% of its output.

In 2009, the United States Department of Interior and the Bureau proposed adaptive management programs for the Glen Canyon Dam to protect environmental resources. Under the National Environmental Policy Act (NEPA), this kind of action requires an environmental impact statement. In December 2016, the Bureau issued its Decision on the environmental impact statement, which identified alternatives for managing Glen Canyon Dam.

On April 24, 2024, the Ninth Circuit Court of Appeals affirmed the district court's ruling in favor of the Bureau, finding that the Glen Canyon Dam management plan did not violate NEPA. This is a favorable outcome for CRSP and Platte River's hydropower interests. The plaintiffs (now appellants) have 90 days from the Ninth Circuit Court's ruling to petition the Supreme Court to hear the case. Unless they do so, and the Supreme Court chooses to hear the case (both of which are unlikely), this case is over.

Department of Energy Coordinated Interagency Transmission Authorizations and Permits Program

On April 25, 2024, the U.S. Department of Energy (DOE) issued a final rule establishing the Coordinated Interagency Transmission Authorization and Permits (CITAP) Program to improve federal environmental reviews of transmission projects and shorten long permitting timelines.

Under the CITAP Program, DOE will coordinate all environmental review and permitting between participating federal agencies and project developers by leading an interagency pre-application process intended to make sure agencies can review and decide whether to permit transmission projects within a binding two-year timeline. DOE will work with the other federal agencies to prepare a single environmental review document, as required by NEPA. State and federal agencies can then use this document to support their permit decisions. Finally, the CITAP Program will provide project developers and stakeholders with an online portal to upload and find information and documents, providing a "one stop shop" for communications about transmission project permitting.

Platte River is not immediately affected by this rule but will pay close attention to how it shapes future permitting timelines for utilities both in and out of RTOs.

Platte River
Power Authority

Environmental matters

Environmental Protection Agency's new regulations for greenhouse gas emissions from power plants

On April 25, 2024, the U.S. Environmental Protection Agency (EPA) issued final rules to regulate carbon dioxide emissions from the power sector, replacing the Clean Power Plan from 2015 and the Affordable Clean Energy rule from 2018. This follows last year's proposed rules, in which the EPA proposed more stringent source performance standards for greenhouse gas (GHG) emissions from new and reconstructed fossil fuel-fired stationary combustion turbines based on highly efficient generation, hydrogen co-firing, and carbon capture and sequestration technologies. The EPA also proposed to establish new emission guidelines for existing fossil-fueled steam generators.

The EPA's final rules exempt existing coal-fired units that permanently end operations before Jan. 1, 2032. This means Rawhide Unit 1 is excluded from the scope of the rule. The EPA also removed existing natural gas-fired combustion turbines from the scope of the final rules because it plans to issue another rule to regulate GHG emissions from existing units later this year.

On May 9, 2024, a coalition of 23 states and the National Rural Electric Cooperative Association filed a lawsuit challenging the final EPA GHG rules. The lawsuit could take many years, but it is possible the court could stay the rule so it does not go into effect until the court issues a ruling. In the meantime, Platte River will evaluate how these rules affect its proposed new generation units and modeling scenarios with both low-load and intermediate-load use cases.

EPA's new regulations under the Mercury and Air Toxics Standards for coal-fired power plants

Also on April 25, 2024, the EPA issued a final rule updating the Mercury and Air Toxics Standards (MATS) for coal-fired power plants. The new MATS rule lowers the mercury and toxic metals emissions limits by 67% for all coal plants. The new rule, as written, would require Platte River to install a continuous monitoring emissions system (CEMS) for particulate matter emissions. There is no exclusion in the MATS rule for units with planned closure dates before 2030.

Platte River's Rawhide Unit 1 currently complies with the stricter MATS standards. But Platte River is evaluating the potential costs to install CEMS on Unit 1 and determining if it is subject to other compliance obligations.

EPA's new regulations on legacy impoundments of coal combustion residuals

Also on April 25, 2024, the EPA issued a final rule updating the requirements that apply to legacy surface impoundments of coal combustion residuals (CCR, commonly known as coal ash). Under the new rule, all areas where a utility disposed of CCR are now subject to groundwater monitoring, corrective action, and closure, including areas outside of previously regulated and managed impoundments.

Platte River Power Authority

Platte River's environmental team will work with its consultants to determine if Platte River has any new regulatory requirements at its Rawhide facility. If we find any currently unknown legacy CCR management units, Platte River will work with the state of Colorado and the EPA to meet the monitoring and other requirements of the updated CCR rule.

Compliance matters

There are no recently concluded compliance matters.

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Resource diversification report

May and June 2024

Resource integration

In late 2023, Platte River issued a request for proposals (RFP) to acquire 150 – 250 megawatts (MW) of additional nameplate wind capacity. Platte River has been working with two short-listed wind developers to fully understand the total effective cost of delivering the output of wind for each project to Platte River's load. By partnering with legal, the team has been exchanging term sheets with the two developers, with the goal of reaching an agreement on the key terms to be incorporated into a power purchase agreement, bringing this additional wind capacity online in 2027.

Platte River and Qcells have jointly started construction on the 150 MW Black Hollow Sun solar project and transmission facility. These improvements are necessary to interconnect to the Platte River transmission system. The anticipated commercial operation date of the project is spring 2025.

Platte River has recently finalized terms to secure an additional 107 MW of nameplate solar capacity, increasing the Black Hollow Sun Solar project to 257 MW of nameplate solar capacity. The anticipated commercial operation date for this incremental 107 MW of solar is before summer 2026. The full 257 MW of nameplate solar has already obtained the necessary construction permits from the Town of Severance.

Platte River issued its all-dispatchable resource RFP on February 22, seeking proposals to help us consider all possible resource options to maintain system reliability after remaining coal units retire in 2028 and 2029. We received responses in late April, and after a thorough evaluation, we decided to continue work to construct and own 200 MW of new aeroderivative gas generation at Rawhide Energy Station.

Platte River also issued an RFP to purchase 75-100 MW of four-hour battery storage under an Energy Storage Services Agreement that will provide flexibility to use the full capability of this resource over a 20-year term. Platte River issued the RFP on June 13, 2024, and responses are due late July 2024. We seek proposals in locations that will lower costs and allow Platte River to defer transmission improvements.

The table below summarizes Platte River's latest resource expansion initiatives, tailored to align with our evolving power supply objectives.

	2023	2024	2025	2026	2027	2028	2029	2030
Existing Resources								
Rawhide 1	278	278	278	278	278	278	278	
Craig 1 & 2	151	151	151	151	74	74		
Peaking capacity	388	388	388	388	388	388	388	388
Wind	231	231	231	231	231	231	231	285
Solar	52	52	52	52	52	52	52	52
New Resources (*)								
Solar			150	107				
Wind					200		200	
Storage				25	75	100		
Dispatchable capacity						166		

(*) In-service year for new resources is based on first year such resource is available during the summer months.

Integrated resource planning 2024

The Resource Planning team continued to support finalization of the 2024 Integrated Resource Plan (IRP) report, supported all-source dispatchable resource solicitation and started to prepare for the second update to the power supply plan for 2025 budget development. Key activities included:

- 2024 IRP:
  - Added analyses for the five selected portfolios to test price changes and other execution risks.
  - Answered questions from various internal stakeholders as part of the report review.
  - Developed summary presentations for the board meeting and other communications.
- Resource procurement process:
  - Developed scenarios for different MW size blocks and prices to help with negotiations and decision making for ongoing procurement and negotiation processes.
  - Refined the model for bid evaluation to compare bids received through the all-source dispatchable resource solicitation.
  - Collaborated with finance, the team evaluated various bids for the internal decision-making process.

DER system integration

Platte River and the four owner communities are working together to integrate distributed energy resources (DERs), whether owned by customers or the utility, into the electric system. This collaborative endeavor includes the DER Advisory Committee, DER Planning and Programs teams, and additional working groups of Platte River personnel and owner communities.

The table below summarizes our planning forecast of DER adoption and the projected enrolled and achievable potential for DERs that can be managed by the virtual power plant.

DER planning forecast (MW)

	2023 actual	2030 forecast	2040 forecast
Customer DER adoption forecast [1]			
Distributed solar, rated output, MW	36.6	155	282
Distributed storage, rated output, MW	1.4	47	135
Electric vehicles, summer peak, MW	2.5	26	107
Utility DER forecast [2]			
Distributed solar, rated output, MW	6.3	6.3	6.3
Distributed storage, rated output, MW	0	20	20
VPP: DERs enrolled [3]			
Electric vehicles, enrolled MW	0	10	38
Distributed storage, enrolled MW	0	67	155
Demand response, enrolled MW	0	15	31
Total VPP, enrolled MW	0	92	224
Total VPP, achievable MW	0	52	113

1. Customer DER adoption forecast is the projected customer-driven uptake of solar, storage, and electric vehicles based on costs, incentives, and customer evaluations of technology and fuel expenses.
2. Utility DER forecast includes existing distributed solar owned by or procured by Loveland Water and Power and Fort Collins Utilities and distributed storage projects currently in development by Platte River and the owner communities.
3. VPP enrolled MW capacities represent the capacity of DERs projected to be enrolled in VPP management, including customer and utility DER. Achievable MW capacities are projected to be dispatchable after adjusting for customer and DER vendor usage limitations.

Work continues to develop distribution-scale storage projects, which are intended to provide one five-MW, four-hour storage project per owner community for a total of 20 MW and 80 MWh. Storage is a critical component of dispatchable capacity to support a noncarbon electric system. By locating some of the storage in the owner communities, Platte River can explore additional locational distribution benefits for the owner communities. Currently, the main areas of focus for the project are:

- Site selection – Platte River continues to work with owner community staff to identify their preferred storage locations; initial preferred primary and backup locations have been identified for each owner community.
- Site control – Site control is needed for the duration of the project’s construction, operational life and decommissioning period. The preferred primary sites are located on property owned by the owner communities. On June 13, legal staff from Platte River, the owner communities and the project developers met to discuss the general content and process to establish contracts to support site control for the projects.
- Permitting and interconnection – Preliminary discussions for permitting and interconnection have begun.

- Developer agreements –Working with the developer, our team is formulating a master agreement with key terms common to all projects. This will be followed by a single energy storage service agreement for each site.

Once site control, permits and all agreements are in place for each site, Platte River will issue a notice to proceed with project construction. The developer anticipates it will take 20 months to complete the project and achieve commercial operation.

The Department of Local Affairs notified Platte River and Estes Park of a grant award supporting a portion of the project cost in Estes Park. There is further information in the Business Strategies section of the general management report.

Platte River issued an RFP for a Distributed Energy Resource Management System (DERMS) and Virtual Power Plant (VPP) Programs on May 29. Many DERMS and VPP program vendors attended our pre-bid virtual meeting held on June 6. Bids are due August 1, 2024. Platte River and owner community staff will work together to evaluate proposals. Assuming acceptable proposals, our team anticipates awarding the contract to one or more vendors and beginning contract negotiations before the end of the year.

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Operating report

May 2024

Executive Summary

The region experienced mild weather, with a soft market and light loads, for several days throughout the month of May which resulted in owner community demand and energy coming in below budget. Owner community demand and energy are below budget, year to date. The overall net variable cost to serve owner community load was below budget for the month, due to coal and gas fuel savings offset by below budget surplus sales. Year to date, the net variable cost to serve owner community load is below budget.

Thermal resources

Rawhide Unit 1 had a great operational month with no outages or curtailments. Rawhide equivalent availability factor was above budget and net capacity factor was below budget for the month, due to lower dispatch in the Southwest Power Pool Western Energy Imbalance Service (SPP WEIS). Year to date, Rawhide equivalent availability factor is slightly above budget and net capacity factor is below budget.

Craig units 1 and 2 experienced a planned outage and a few forced outages throughout the month. For approximately 10 hours, on May 30, Craig Unit 1 had a forced outage due to loss of pressure. Craig Unit 2 came back from a planned outage for boiler repairs, on May 2, after being offline for 11 days. On May 5, Craig Unit 2 had a forced outage for approximately 11 hours, due to an ammonia valve leak. On May 7, Craig Unit 2 had a forced outage for approximately six hours, due to feedwater pump issues. Craig equivalent availability factor and net capacity factor were below budget for the month. Year to date, Craig equivalent availability factor and net capacity factor are slightly below budget.

The combustion turbines (CTs) were run for CT Unit F testing as well as to facilitate sales during the month of May. CT equivalent availability factor was slightly above budget. Net capacity factor was below budget for the month, due to a soft bilateral market, lower surplus sales and lower dispatch in SPP WEIS. Year to date, CT equivalent availability factor and net capacity factor are slightly below budget.

Renewable resources

Wind generation was above budget for the month. The Roundhouse Wind project did experience above budget production, despite WEIS market curtailments. Roundhouse also had varying curtailments throughout the entire month, due to turbine availability. Solar generation was above budget, despite the Rawhide Prairie Solar project having experienced WEIS market curtailments. Net capacity factors for both wind and solar were above budget for the month. The Rawhide Prairie Solar battery system was out of service during the entire month of May. As such, the battery was not charged or discharged. Year to date, net capacity factors for both wind and solar are below budget.

Surplus sales

Surplus sales volume was below budget due to mild temperatures in the region, resulting in significantly below budget bilateral sales volume. Average surplus sales pricing was below budget for the month. Year to date, surplus sales volume is below budget and average surplus sales pricing is above budget.

Purchased power

Overall purchased power volume and pricing were below budget for the month. The SPP WEIS average purchased power price was below budget for the month and below generation costs. Year to date, purchased power volume is above budget and pricing is below budget.

Total resources

Total blended resource costs were slightly above budget for the month, due to significantly above budget natural gas costs. Year to date, total blended resource costs are slightly below budget.

Variances

May operational results

Owner community load	Budget	Actual	Variance	% variance	
Owner community demand	466 MW	439 MW	(27 MW)	(5.6%)	■
Owner community energy	250 GWh	235 GWh	(15 GWh)	(6.0%)	■
Net variable cost* to serve owner community energy	$5.9M	$5.2M	($0.7M)	(6.1%)	●
	$23.39/MWh	$21.97/MWh	($1.42/MWh)		

*Net variable cost = total resource variable costs + purchased power costs - sales revenue

Market impacts to net variable cost

Downward pressure Generation and market outcomes pushing costs lower	
Coal generation fuel savings	$0.61M
Gas generation fuel savings	$0.27M

Upward pressure Generation and market outcomes pushing costs higher	
Lower bilateral sales volume	$0.51M
Higher Craig generation fuel pricing	$0.24M

Variance key: Favorable: ● | Near budget: ◆ | Unfavorable: ■

YTD operational results

Owner community load	Budget	Actual	Variance	% variance	
Owner community demand	2,311 MW	2,221 MW	(90 MW)	(3.9%)	■
Owner community energy	1,305 GWh	1,255 GWh	(50 GWh)	(3.8%)	■
Net variable cost* to serve owner community energy	$26.5M	$22.2M	($4.3M)	(12.8%)	●
	$20.33/MWh	$17.72/MWh	($2.63/MWh)		

*Net variable cost = total resource variable costs + purchased power costs - sales revenue

Market impacts to net variable cost

Downward pressure Generation and market outcomes pushing costs lower	
Coal generation fuel savings	$4.4M
Lower wind generation volume	$2.4M

Upward pressure Generation and market outcomes pushing costs higher	
Lower bilateral and market sales volume	$3.5M
Higher coal generation fuel pricing	$1.3M

Variance key: Favorable: ● | Near budget: ◆ | Unfavorable: ■

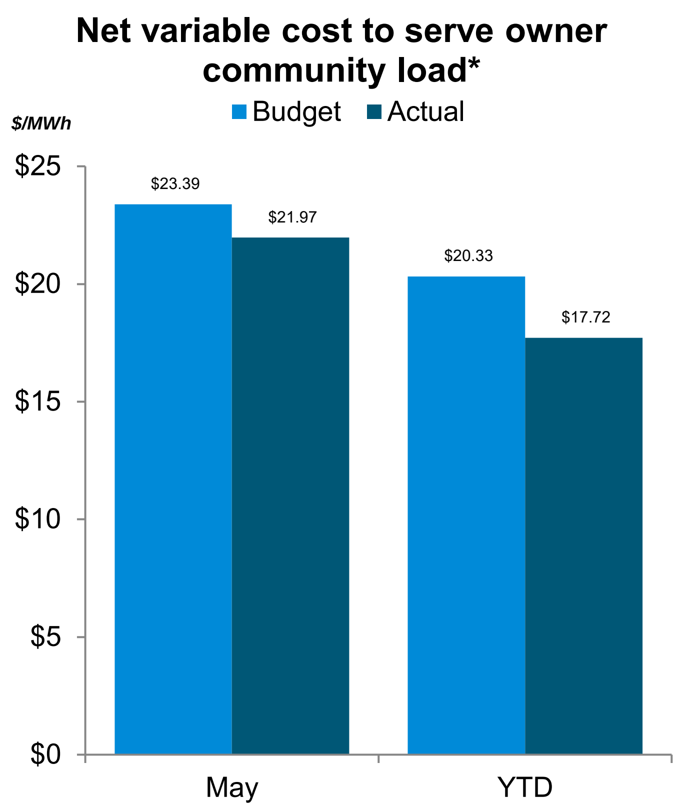
Loss of load

System disturbances

There were no system disturbance resulting in loss of load during the month of May.

2024 goal		May actual		YTD total	
0	●	0	●	1	■

Net variable cost to serve owner community load



*** The net variable operating cost to serve owner community load is equal to the sum of fuel, renewable purchases, energy purchases less surplus energy sales. The net variable cost is divided by total owner community load to determine average net variable cost to serve owner community load.**

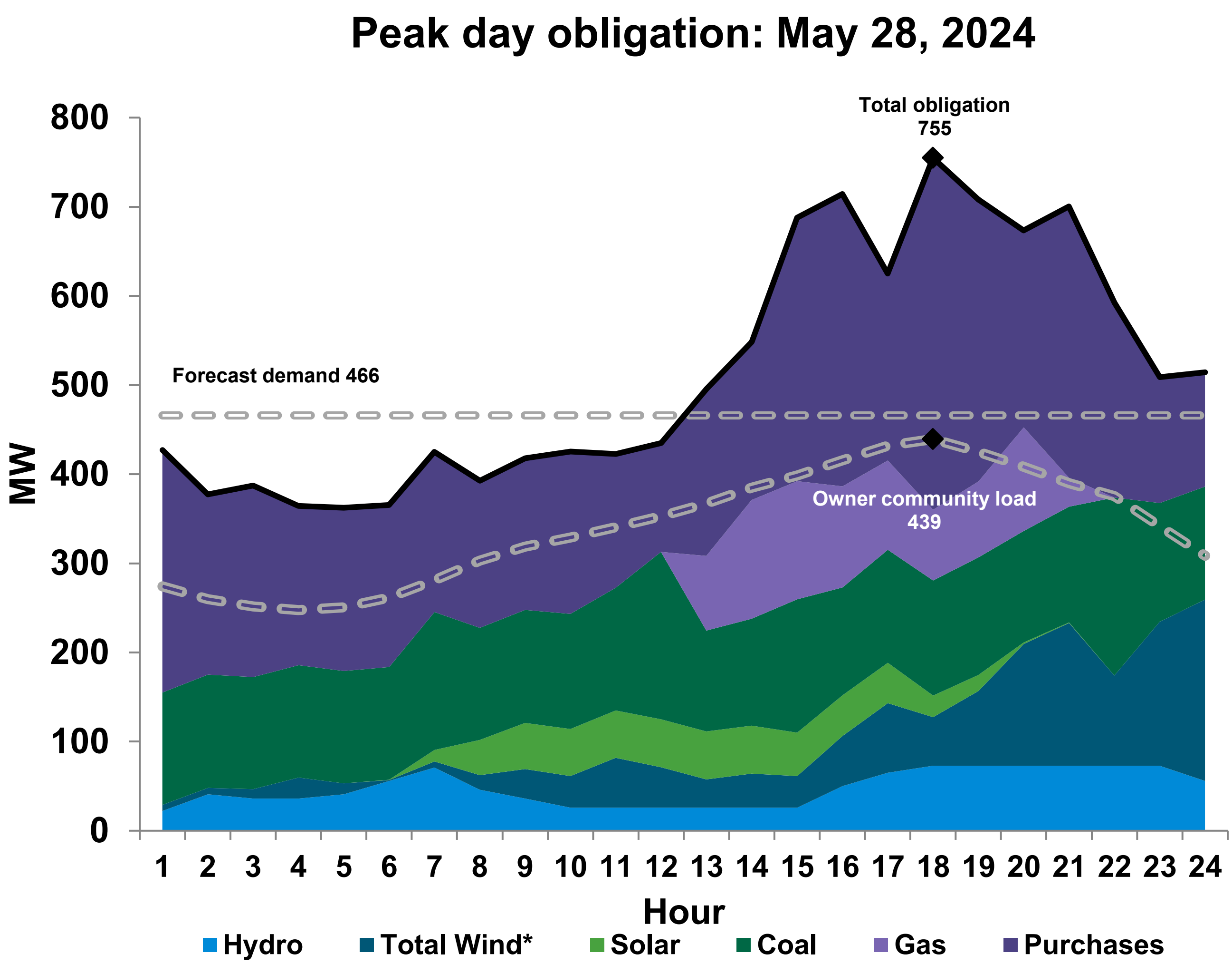
Events of significance

- On May 10, the SPP West reliability coordinator (RC) issued a conservative operations advisory for the entire SPP RC footprint for approximately 15 hours, due to a forecast of severe to extreme geomagnetic activity.
- On May 13, the Drake – Timberline 115-kV line tripped and did not reclose, though this did not result in a loss of load. The line returned to service on May 14. Bird feces were the suspected cause of the trip.
- On May 22, the Rawhide – Laporte 230-kV line tripped and reclosed at the Laporte terminal. The Rawhide terminal was closed at 7:04 a.m. Bird feces were the suspected cause of the trip.
- On May 23, the Ault – Rawhide and Ault – Carey 230-kV line outages were successfully completed with no system disturbances. The weather was favorable during the outages and the generation desk maintained the appropriate injection limitations on the maximum and minimum.
- On May 29, CT Unit F was returned to service after being in an outage since December of 2023. Compressor blade upgrades, a combustion inspection, generator inspection, and wet compression project were completed during the outage.

Peak day

Peak day obligation

Peak demand for the month was 439 megawatts which occurred on May 28, 2024, at hour ending 18:00 and was 27 megawatts below budget. Platte River's obligation at the time of the peak totaled 755 megawatts. Demand response was not called upon at the time of peak.



* Some off-system wind renewable energy credits and associated energy have been sold to another utility and, therefore, cannot be claimed as a renewable resource by Platte River or its owner communities.

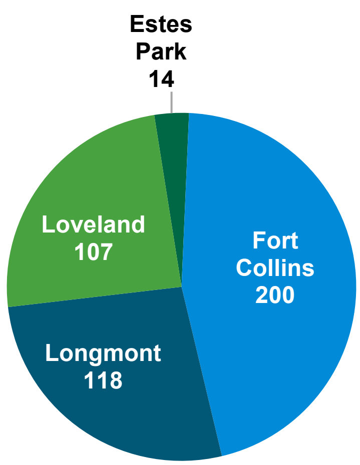
Owner community loads

	May budget	May actual	Minimum	Actual variance	
Coincident demand (MW)	466	439	507	(5.6%)	■
Estes Park	13	**14**	13	7.7%	●
Fort Collins	209	200	**231**	(4.0%)	■
Longmont	127	118	**144**	(7.1%)	■
Loveland	117	107	**119**	(8.5%)	■
Non-coincident demand (MW)	473	449	516	(5.1%)	■
Estes Park	18	20	**21**	11.1%	●
Fort Collins	210	200	**231**	(4.8%)	■
Longmont	128	122	**144**	(4.7%)	■
Loveland	117	107	**120**	(8.5%)	■
Energy sales (MWh)	250,442	235,303		(6.0%)	■
Estes Park	10,526	10,566		0.4%	◆
Fort Collins	116,245	108,962		(6.3%)	■
Longmont	65,677	61,901		(5.7%)	■
Loveland	57,994	53,874		(7.1%)	■

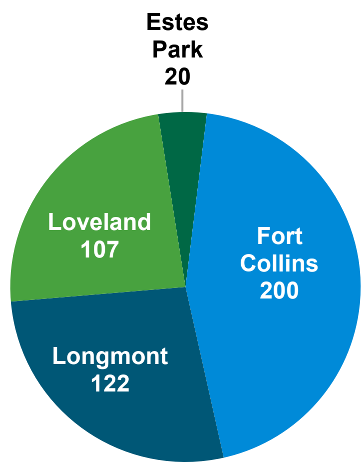
Variance key: Favorable: ● | Near budget: ◆ | Unfavorable: ■

Note: The bolded values above were those billed to the owner communities, based on the maximum of either the actual metered demand or the annual minimum ratchet.

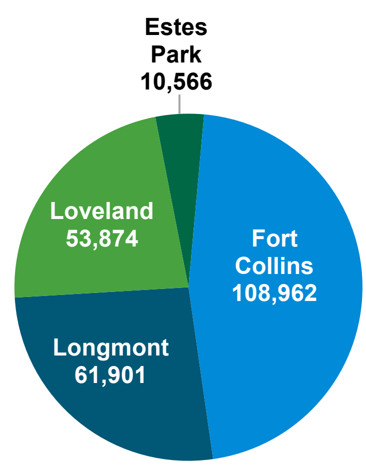
Actual May coincident demand = 439.3 MW



Actual May non-coincident demand = 449 MW

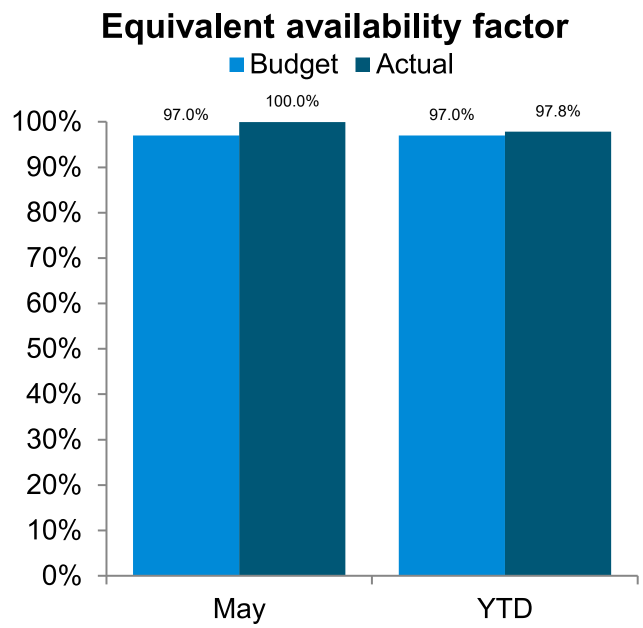


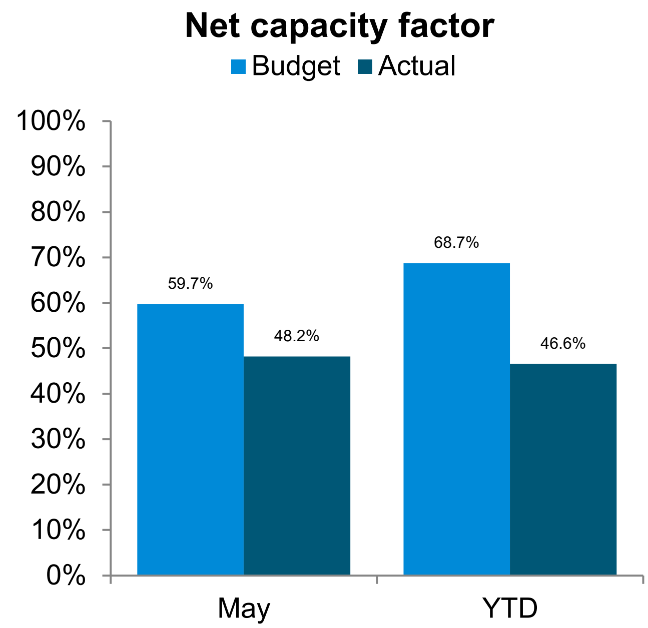
Actual May energy sales = 235,303 MWh



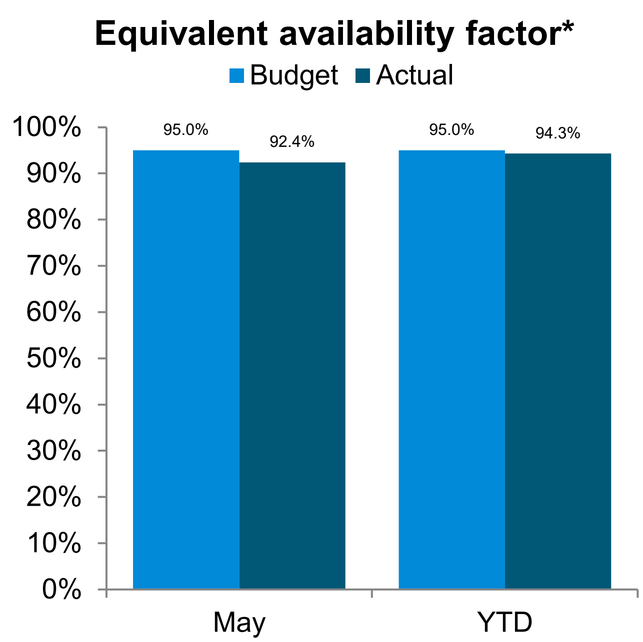
Thermal resources

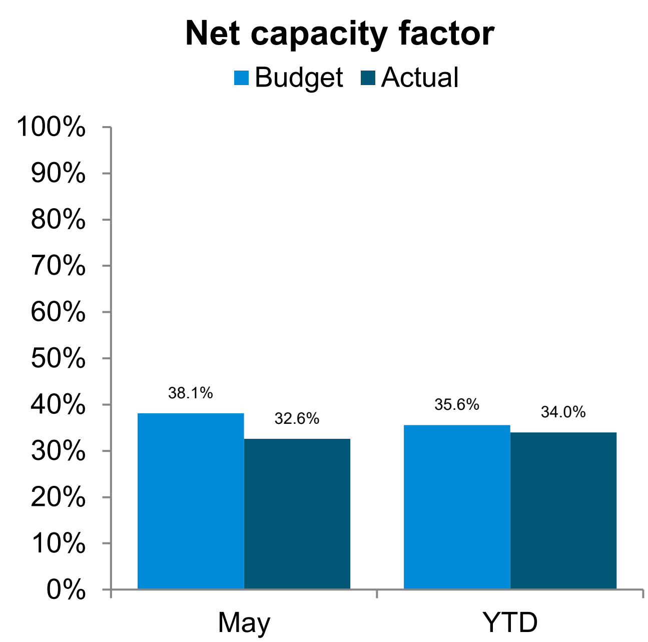
Power generation - Rawhide





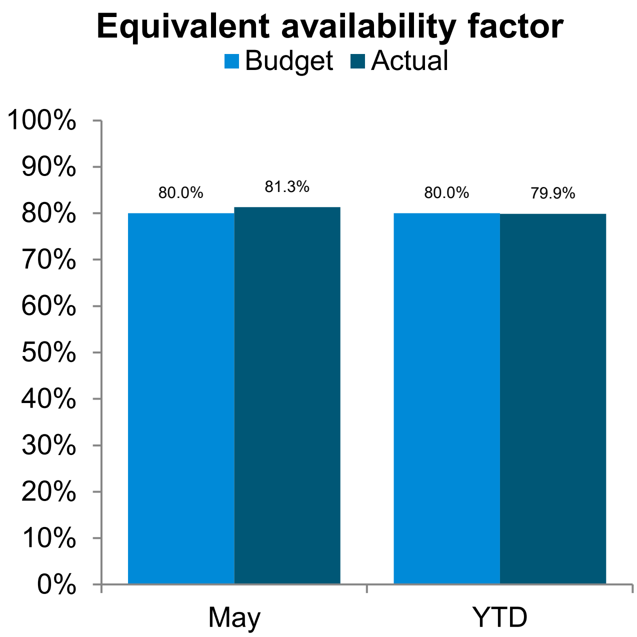
Power generation - Craig

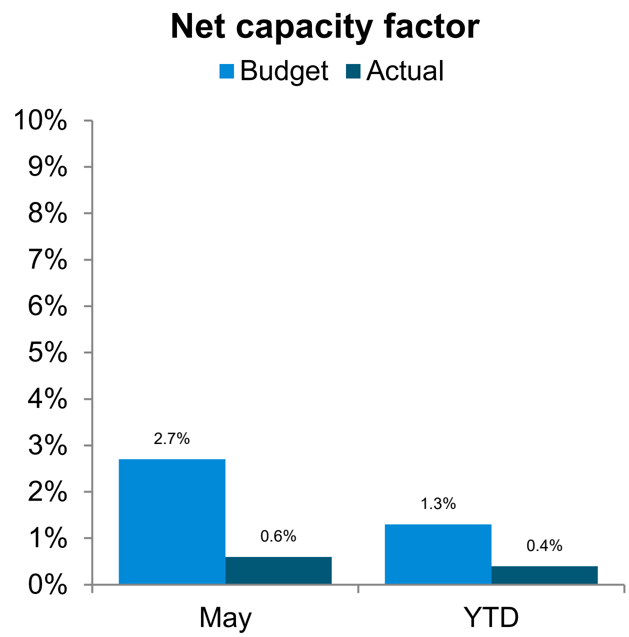




*** Estimated due to a delay of the actual results**

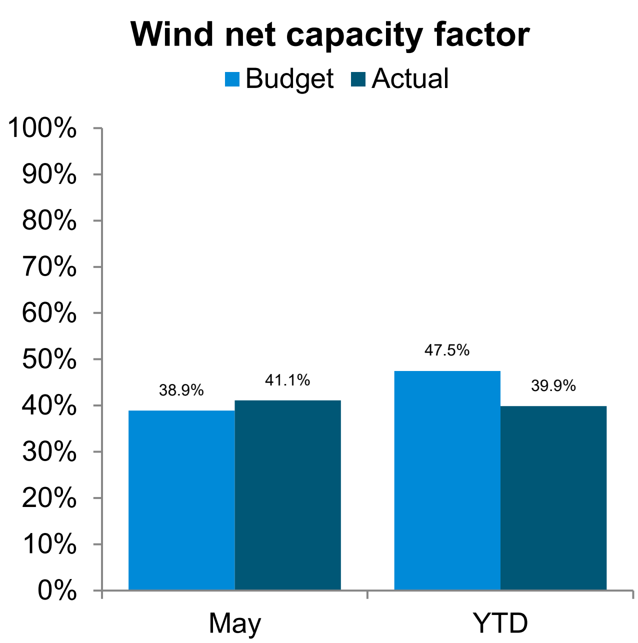
Power generation – combustion turbines

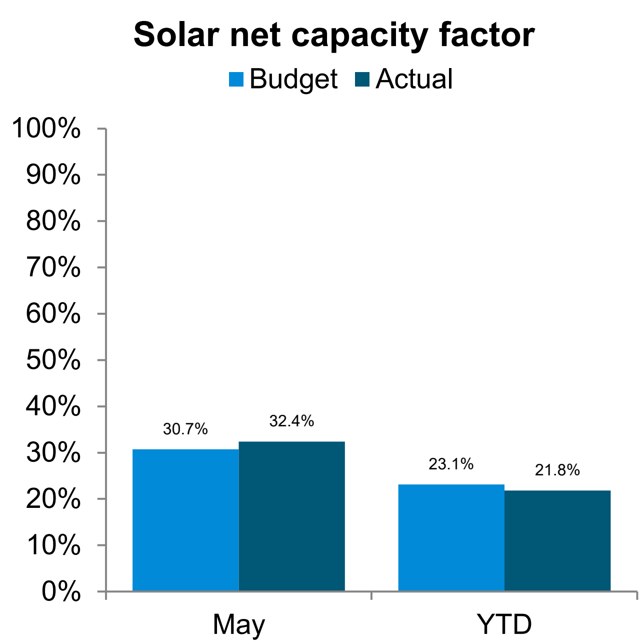




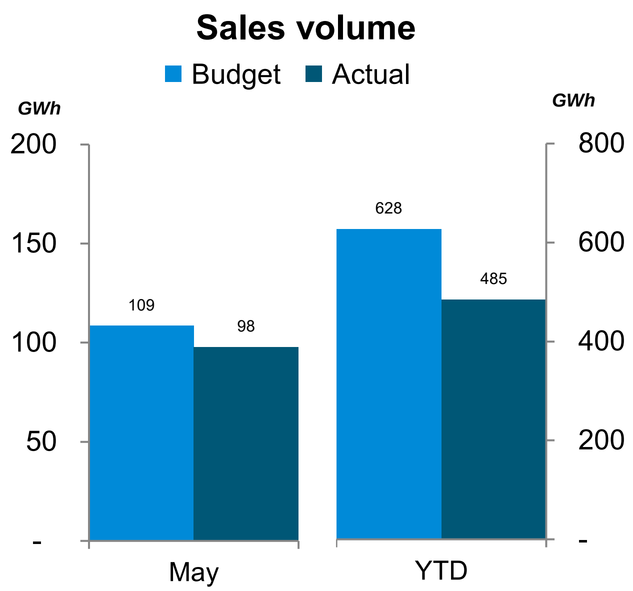
Renewable resources

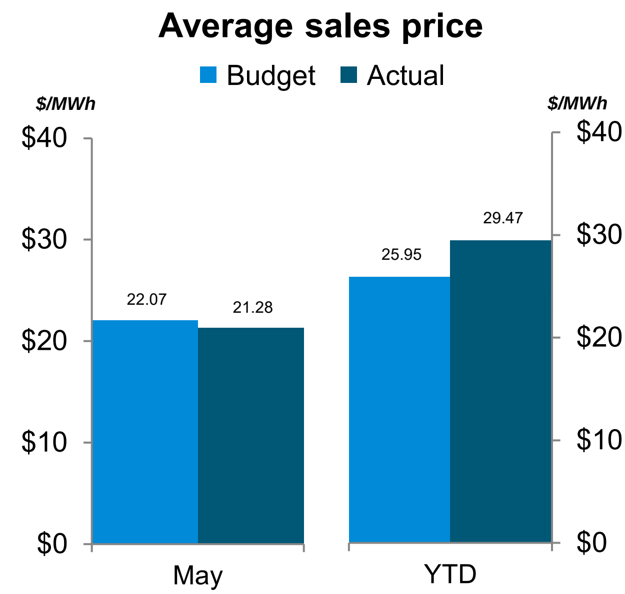
Power generation – wind and solar production



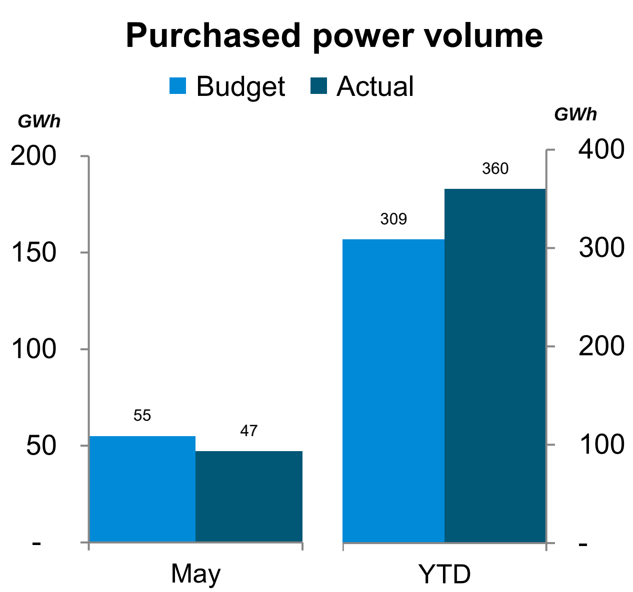


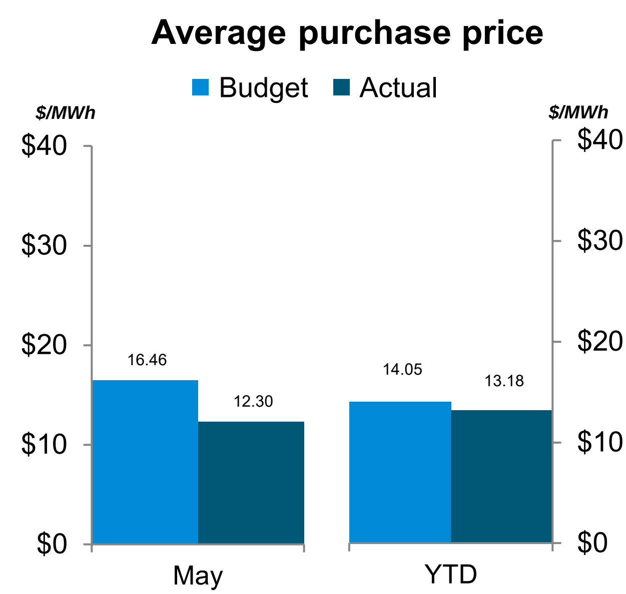
Surplus sales



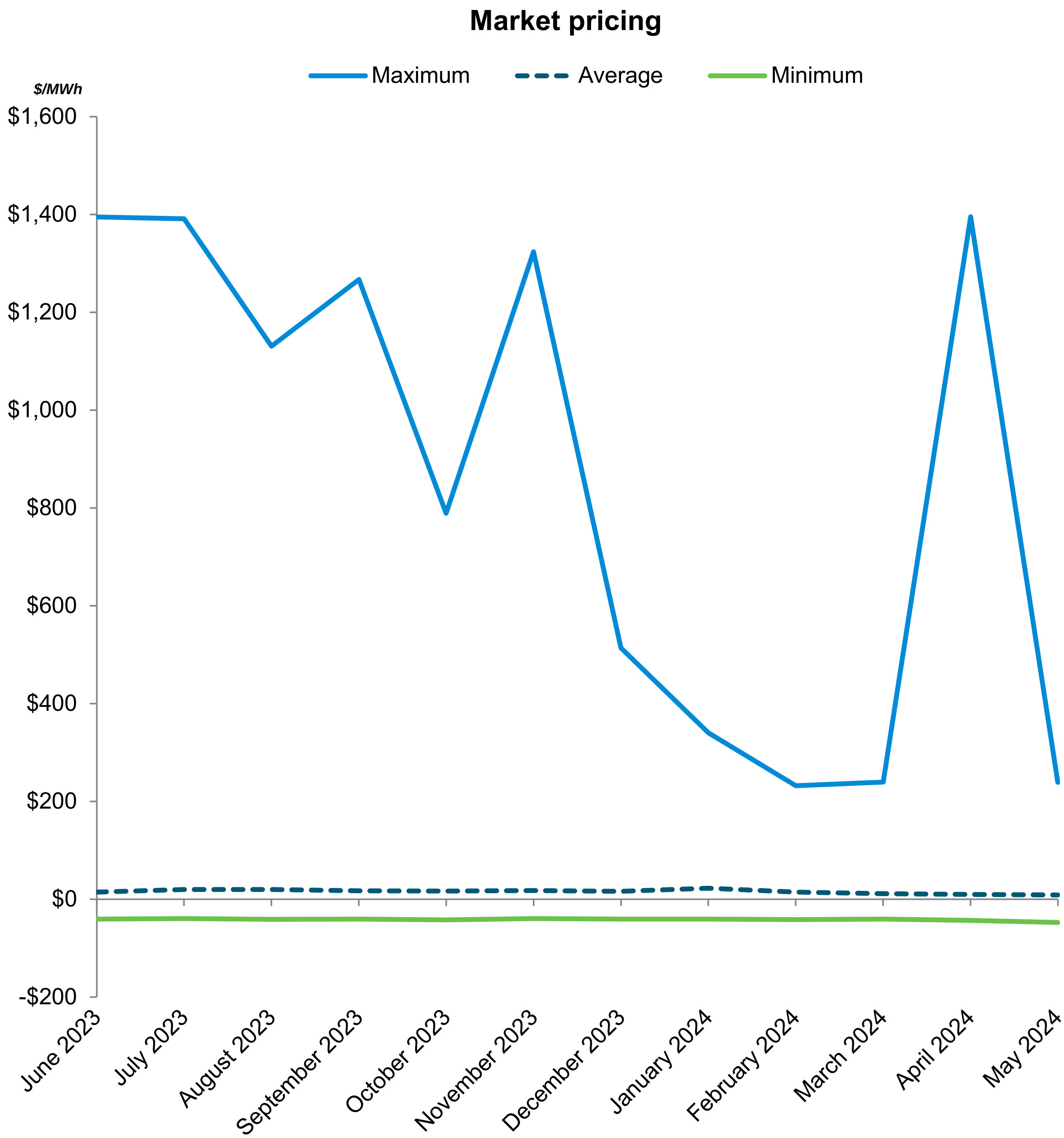


Purchased power

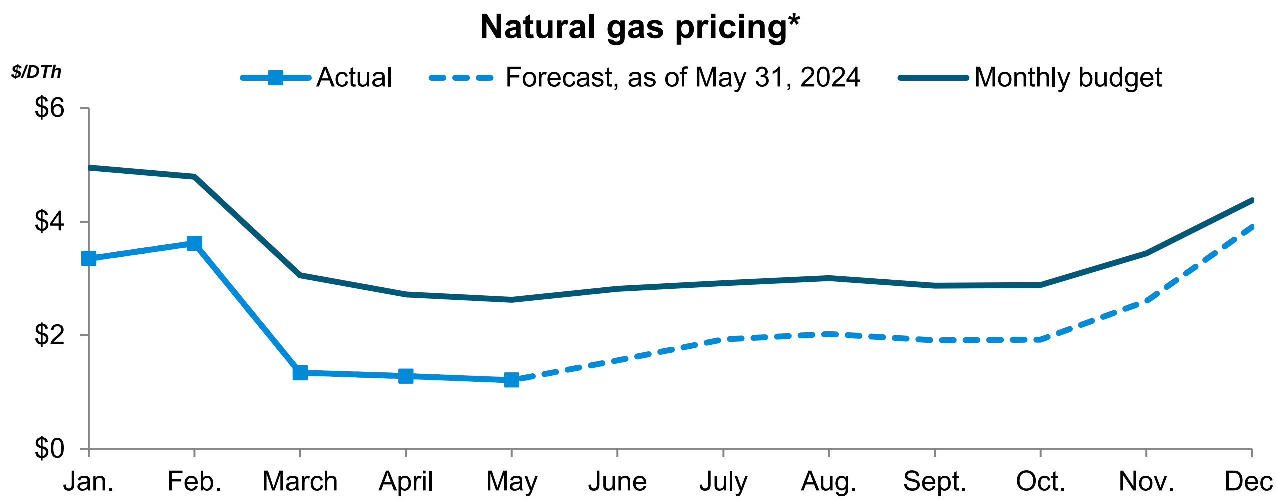




Market pricing



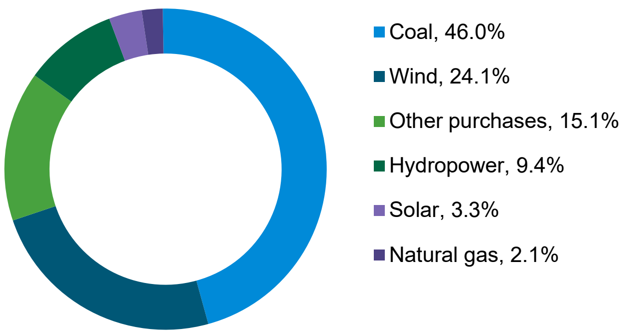
Natural gas pricing



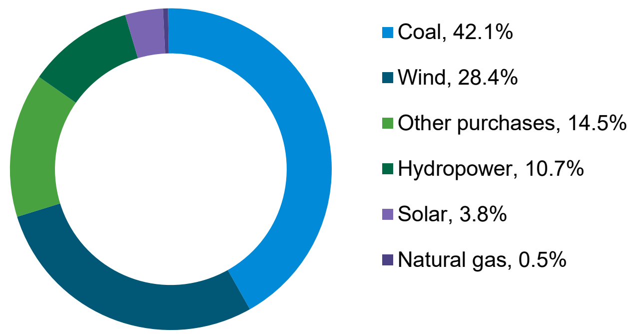
***Forecast based on Argus North American Natural Gas forward curves. Pricing does not include transport.**

Total resources

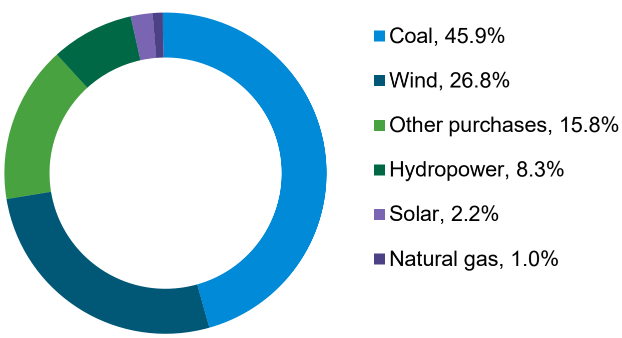
May generation budget



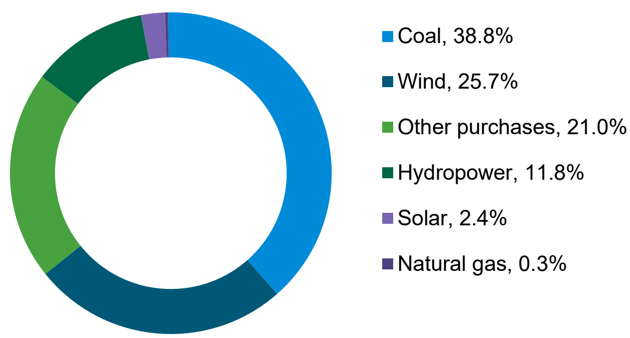
May generation actual

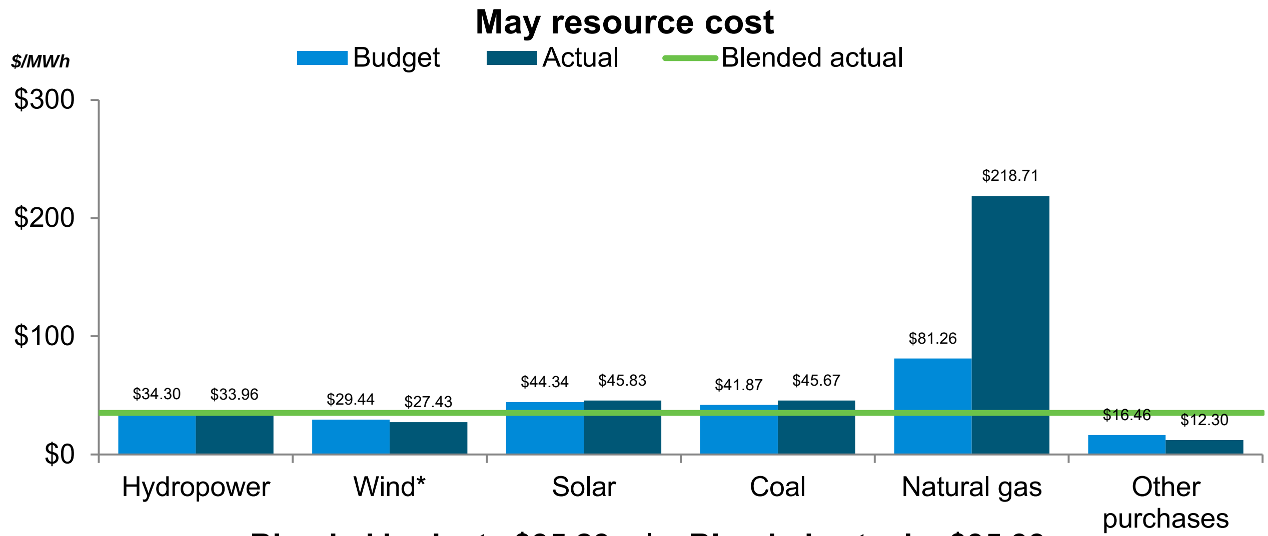


YTD budget

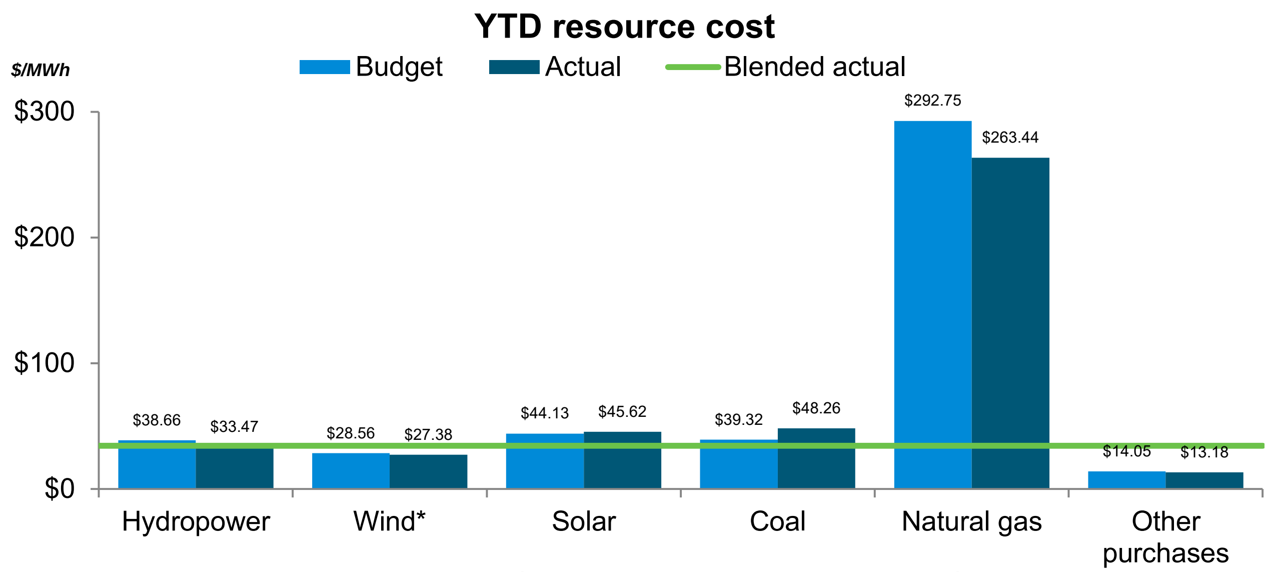


YTD actual





Blended budget $35.23 | Blended actual: $35.33



Blended budget $34.97 | Blended actual: $34.44

***Some off-system wind RECs and associated energy have been sold to another utility and, therefore, cannot be claimed as a renewable resource by Platte River or its owner communities.**

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Operating report

June 2024

Executive Summary

The region experienced hot weather which made for a strong market for several days throughout the month of June. Despite the hot weather, owner community demand was below budget and energy was near budget. Owner community demand and energy are below budget, year to date. The overall net variable cost to serve owner community load was significantly below budget for the month, due to coal and gas fuel savings offset by higher purchase volume. Year to date, the net variable cost to serve owner community load is below budget.

Thermal resources

Rawhide Unit 1 had a great operational month with no outages or curtailments. Rawhide equivalent availability factor was above budget and net capacity factor was significantly below budget for the month, due to lower dispatch in the Southwest Power Pool Western Energy Imbalance Service (SPP WEIS). Year to date, Rawhide equivalent availability factor is slightly above budget and net capacity factor is significantly below budget.

Craig units 1 and 2 experienced a good operational month with one curtailment in June. On June 5, Craig Unit 1 was curtailed for approximately 15 hours due to feeder issues. Craig equivalent availability factor was above budget and net capacity factor was below budget for the month. Year to date, Craig equivalent availability factor is slightly above budget and net capacity factor is below budget.

The combustion turbines (CTs) were run to serve contracts, facilitate sales, and serve owner community load during the month of June. CT Unit F was declared unavailable for approximately 18 hours, on June 1, due to a failed start. CT Unit C had a planned outage, for approximately 8 hours on June 4, to replace a coupling on the aux lube oil pump. CT equivalent availability factor was slightly below budget. Net capacity factor was above budget for the month, despite lower dispatch in SPP WEIS. Year to date, CT equivalent availability factor and net capacity factor are slightly below budget.

Renewable resources

Wind generation was above budget for the month. The Roundhouse Wind project produced above budget generation, despite WEIS market curtailments and approximately five hours of underproduction due to high winds which caused over-speeding on June 18. Roundhouse also had varying curtailments throughout the entire month, due to turbine availability. Solar generation was slightly below budget and the Rawhide Prairie Solar project experienced WEIS market curtailments. Net capacity factor for wind was above budget and solar was slightly below budget for the month. The Rawhide Prairie Solar battery system was out of service during the entire month of June. As such, the battery was not charged or discharged. Year to date, net capacity factor for wind is below budget and solar is slightly below budget.

Surplus sales

Surplus sales volume was above budget mainly due to a higher bilateral sales volume, as a result of hot weather in the region. Average surplus sales pricing was above budget for the month. Year to date, surplus sales volume is below budget and average surplus sales pricing is above budget.

Purchased power

Overall purchased power volume was significantly above budget and pricing was below budget for the month. The SPP WEIS average purchased power price was significantly below budget for the month and below generation costs. Year to date, purchased power volume is above budget and pricing is below budget.

Total resources

Total blended resource costs were slightly below budget for the month, mainly due to below budget natural gas costs per megawatt hour. Year to date, total blended resource costs are slightly below budget.

Variances

June operational results

Owner community load	Budget	Actual	Variance	% variance	
Owner community demand	659 MW	615 MW	(44 MW)	(6.7%)	■
Owner community energy	285 GWh	284 GWh	(1 GWh)	(0.4%)	◆
Net variable cost* to serve owner community energy	$3.6M	$2.5M	($1.1M)	(30.6%)	●
	$12.65/MWh	$8.78/MWh	($3.87/MWh)		

*Net variable cost = total resource variable costs + purchased power costs - sales revenue

Market impacts to net variable cost

Downward pressure Generation and market outcomes pushing costs lower	
Coal generation fuel savings	$1.30M
Higher bilateral sales volume	$0.87M

Upward pressure Generation and market outcomes pushing costs higher	
Higher purchase volume	$0.61M
Higher wind generation volume	$0.50M

Variance key: Favorable: ● | Near budget: ◆ | Unfavorable: ■

YTD operational results

Owner community load	Budget	Actual	Variance	% variance	
Owner community demand	2,970 MW	2,836 MW	(134 MW)	(4.5%)	■
Owner community energy	1,590 GWh	1,539 GWh	(51 GWh)	(3.2%)	■
Net variable cost* to serve owner community energy	$30.1M	$24.7M	($5.4M)	(15.2%)	●
	$18.95/MWh	$16.07/MWh	($2.88/MWh)		

*Net variable cost = total resource variable costs + purchased power costs - sales revenue

Market impacts to net variable cost

Downward pressure Generation and market outcomes pushing costs lower	
Coal generation fuel savings	$5.7M
Higher bilateral sales pricing	$2.2M

Upward pressure Generation and market outcomes pushing costs higher	
Lower bilateral and market sales volume	$3.3M
Higher coal generation fuel pricing	$1.6M

Variance key: Favorable: ● | Near budget: ◆ | Unfavorable: ■

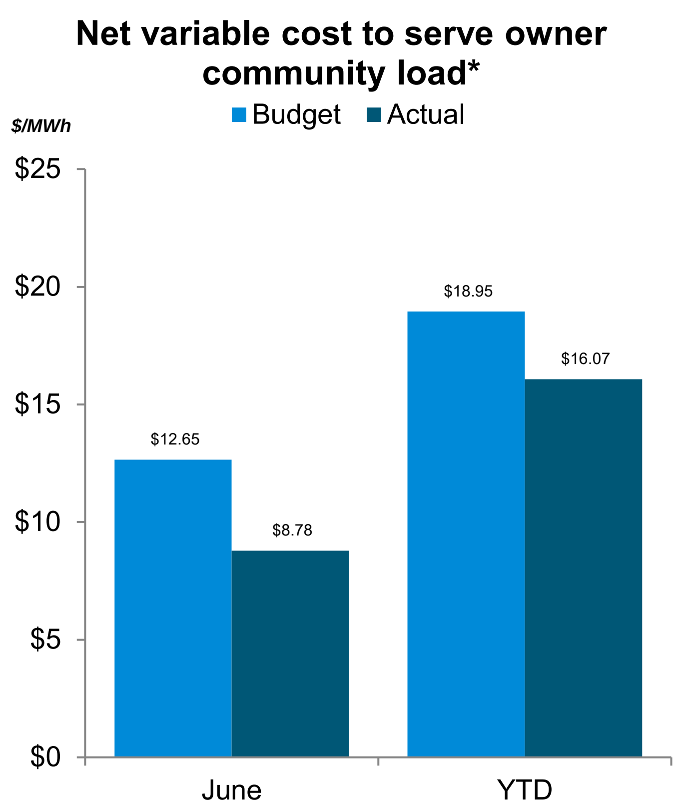
Loss of load

System disturbances

There were no system disturbances resulting in loss of load during the month of June.

2024 goal	June actual	YTD total
0 ●	0 ●	1 ■

Net variable cost to serve owner community load



*** The net variable operating cost to serve owner community load is equal to the sum of fuel, renewable purchases, energy purchases less surplus energy sales. The net variable cost is divided by total owner community load to determine average net variable cost to serve owner community load.**

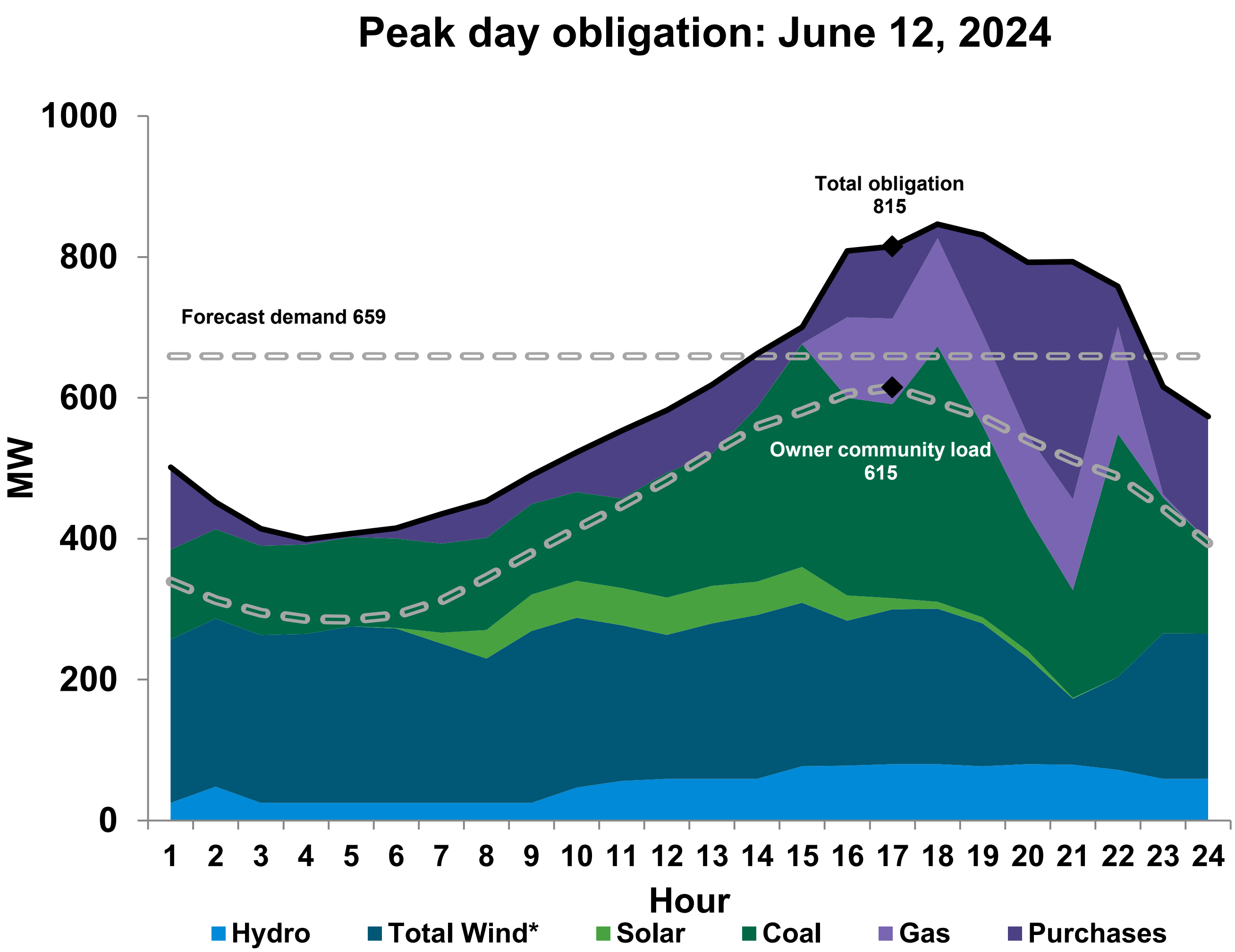
Events of significance

- June brought 17 days where temperatures were at or above 90°F. As such, all five combustion turbines were online to facilitate bilateral sales for several days throughout the month.
- On June 1, 2024, a one-hour firm energy sales contract and a firm capacity and energy sales contract began. One long-term sales contract came to an end, on June 30, 2024.
- Though no formal resolution has been made, Greenbacker reduced the Rawhide Prairie Solar project charge for energy by $3.00 MWh, essentially accepting Platte River's dispute for the battery storage project being unavailable.

Peak day

Peak day obligation

Peak demand for the month was 615 megawatts which occurred on June 12, 2024, at hour ending 17:00 and was 44 megawatts below budget. Platte River's obligation at the time of the peak totaled 815 megawatts. Demand response was called upon at the time of peak.



*** Some off-system wind renewable energy credits and associated energy have been sold to another utility and, therefore, cannot be claimed as a renewable resource by Platte River or its owner communities.**

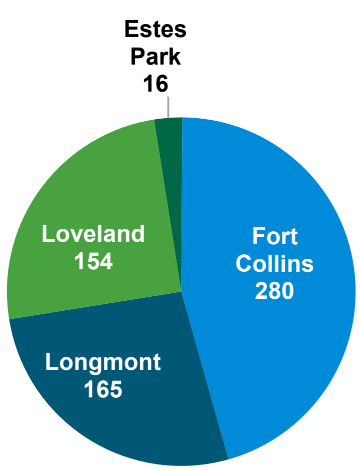
Owner community loads

	June budget	June actual	Minimum	Actual variance	
Coincident demand (MW)	659	615	507	(6.7%)	■
Estes Park	17	**16**	13	(5.9%)	■
Fort Collins	294	**280**	231	(4.8%)	■
Longmont	183	**165**	144	(9.8%)	■
Loveland	165	**154**	119	(6.7%)	■
Non-coincident demand (MW)	662	629	516	(5.0%)	■
Estes Park	17	17	**21**	0.0%	◆
Fort Collins	296	**280**	231	(5.4%)	■
Longmont	184	**178**	144	(3.3%)	■
Loveland	165	**154**	120	(6.7%)	■
Energy sales (MWh)	285,423	284,416		(0.4%)	◆
Estes Park	10,053	9,379		(6.7%)	■
Fort Collins	130,320	130,997		0.5%	◆
Longmont	77,119	77,424		0.4%	◆
Loveland	67,931	66,616		(1.9%)	◆

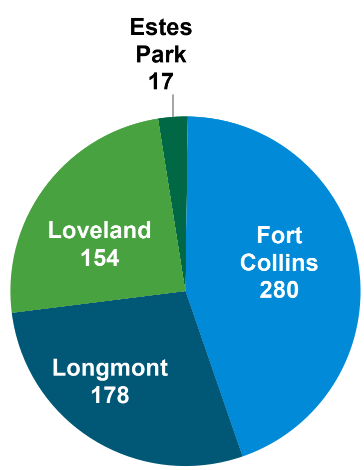
Variance key: Favorable: ● | Near budget: ◆ | Unfavorable: ■

Note: The bolded values above were those billed to the owner communities, based on the maximum of either the actual metered demand or the annual minimum ratchet.

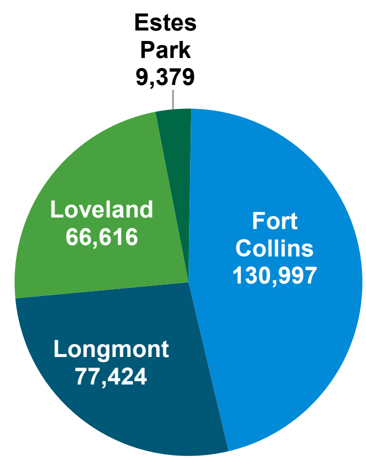
Actual June coincident demand = 615 MW



Actual June non-coincident demand = 629 MW

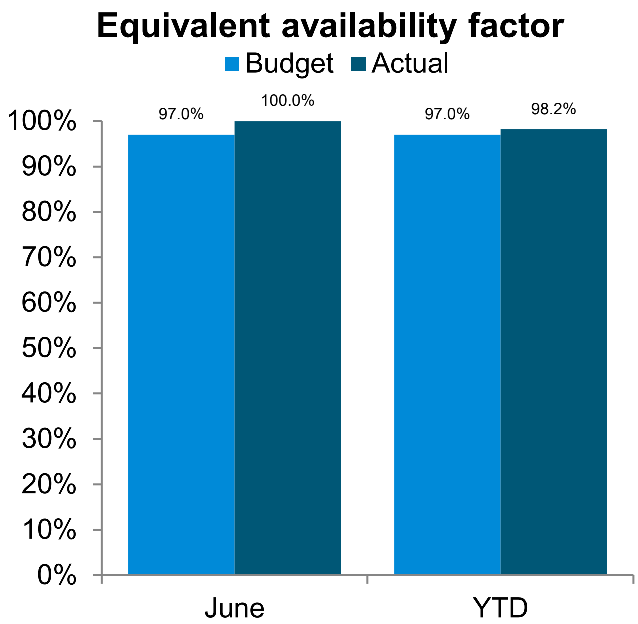


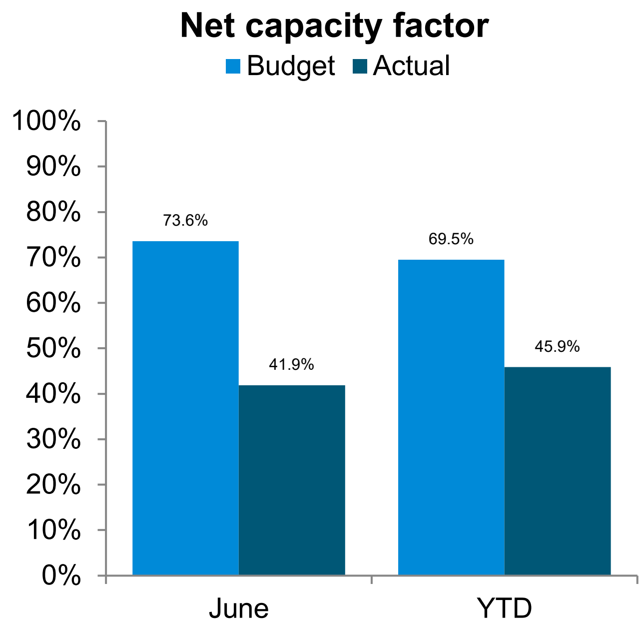
Actual June energy sales = 284,416 MWh



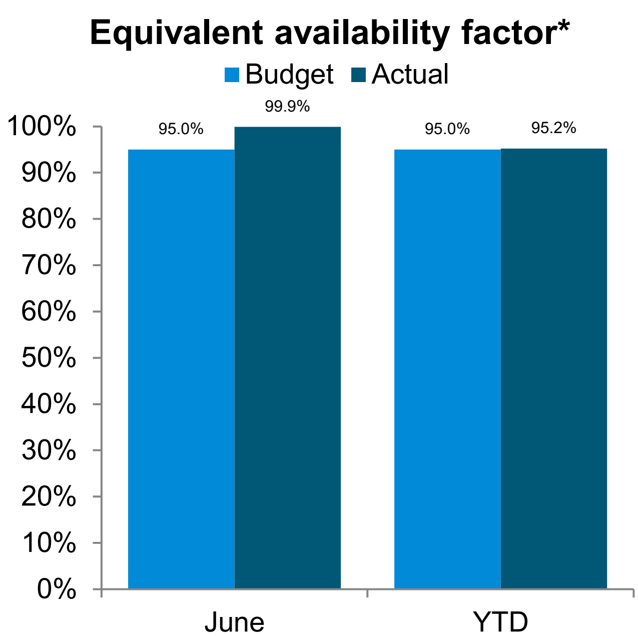
Thermal resources

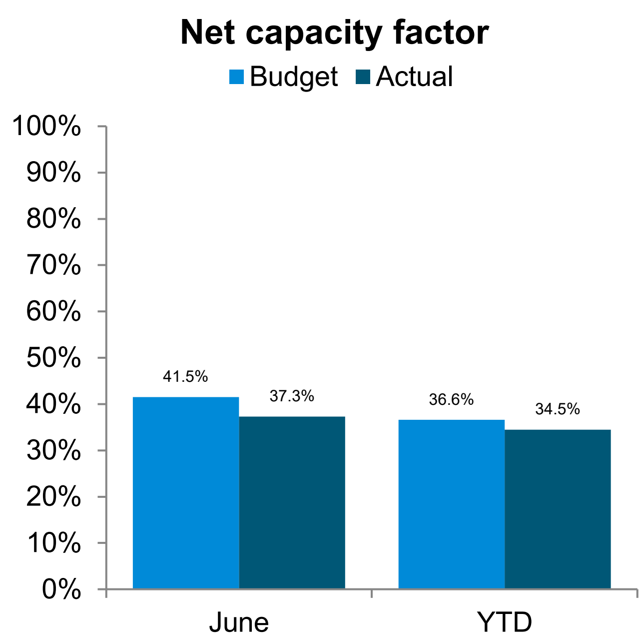
Power generation - Rawhide





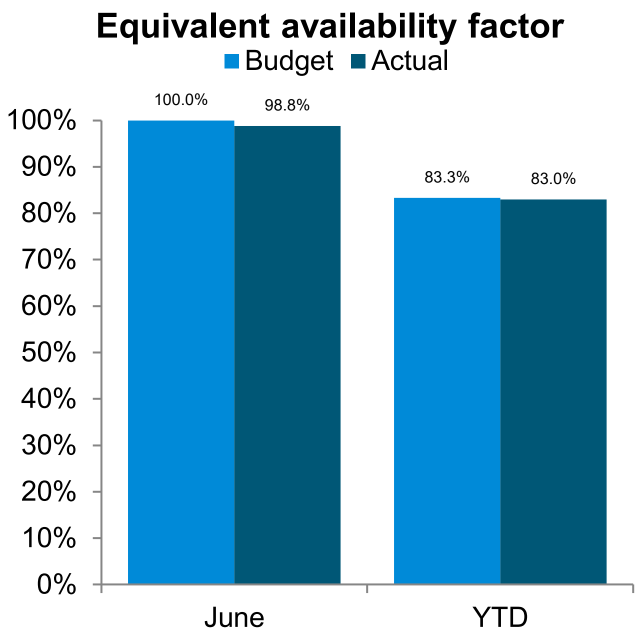
Power generation - Craig

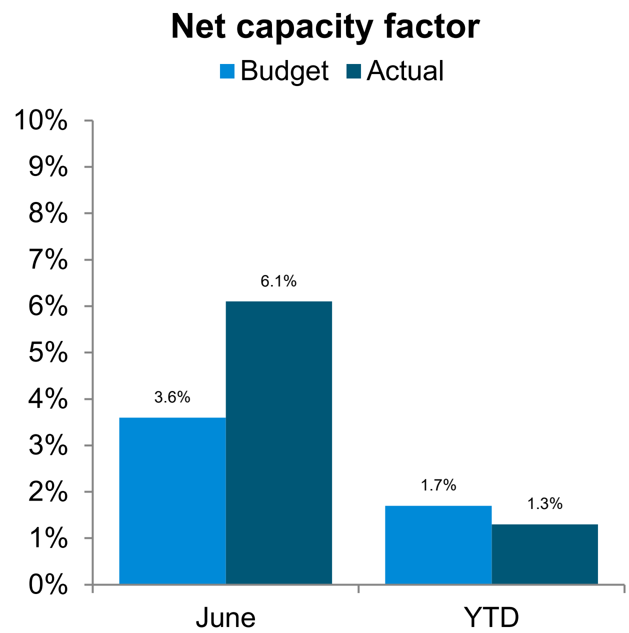




*** Estimated due to a delay of the actual results**

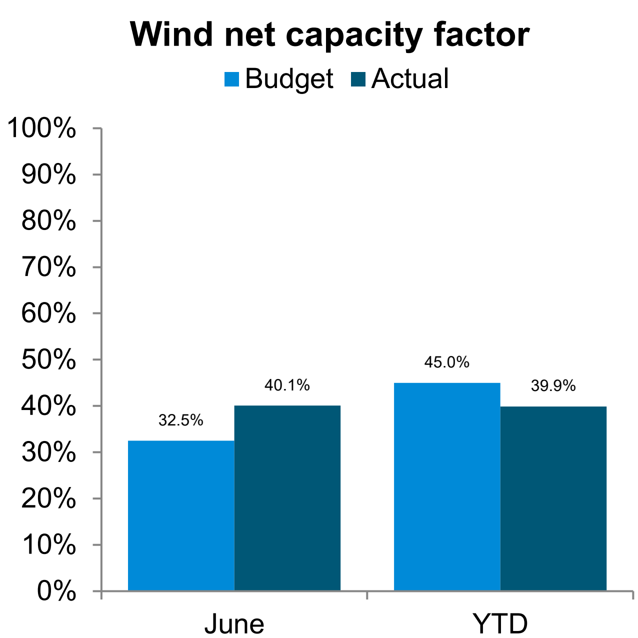
Power generation – combustion turbines

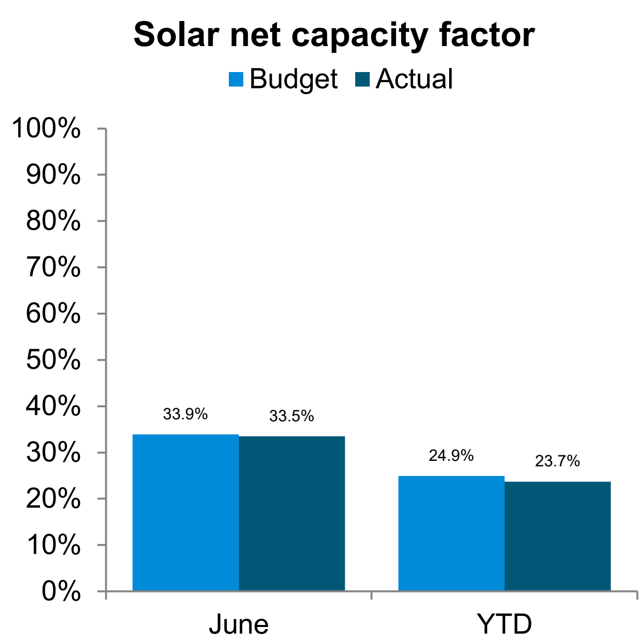




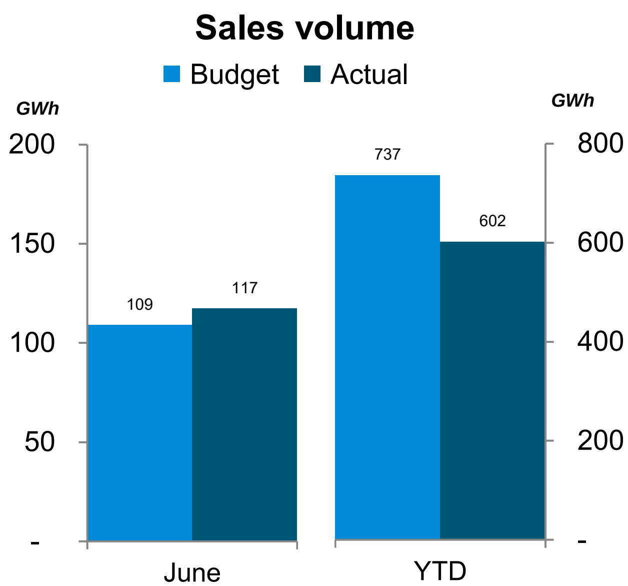
Renewable resources

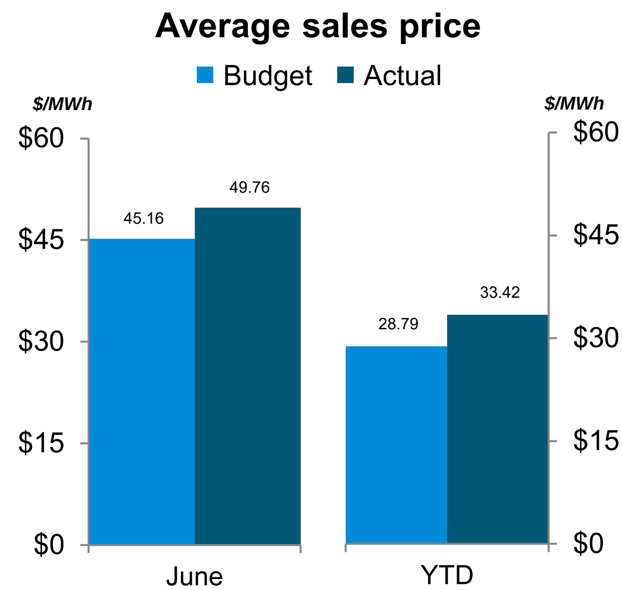
Power generation – wind and solar production



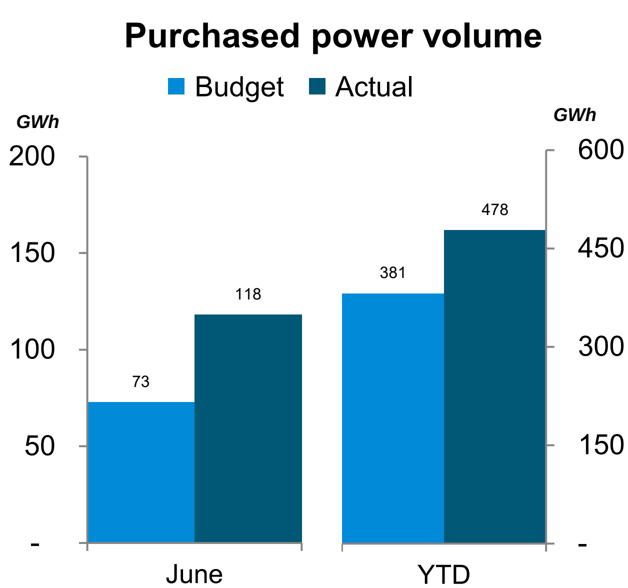


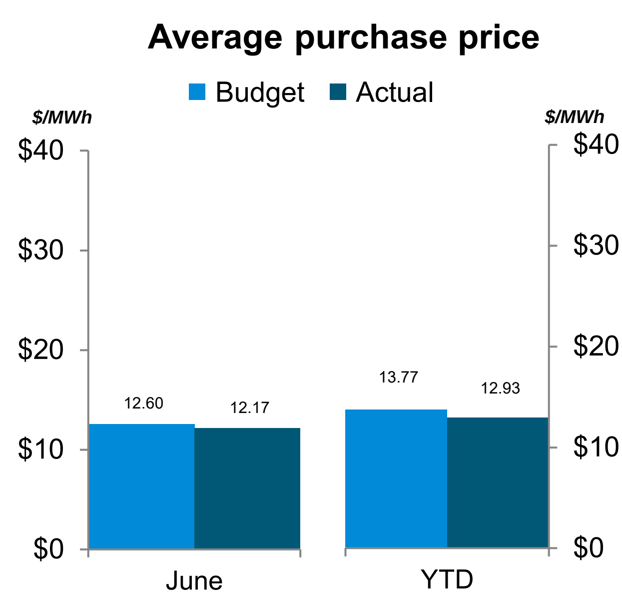
Surplus sales



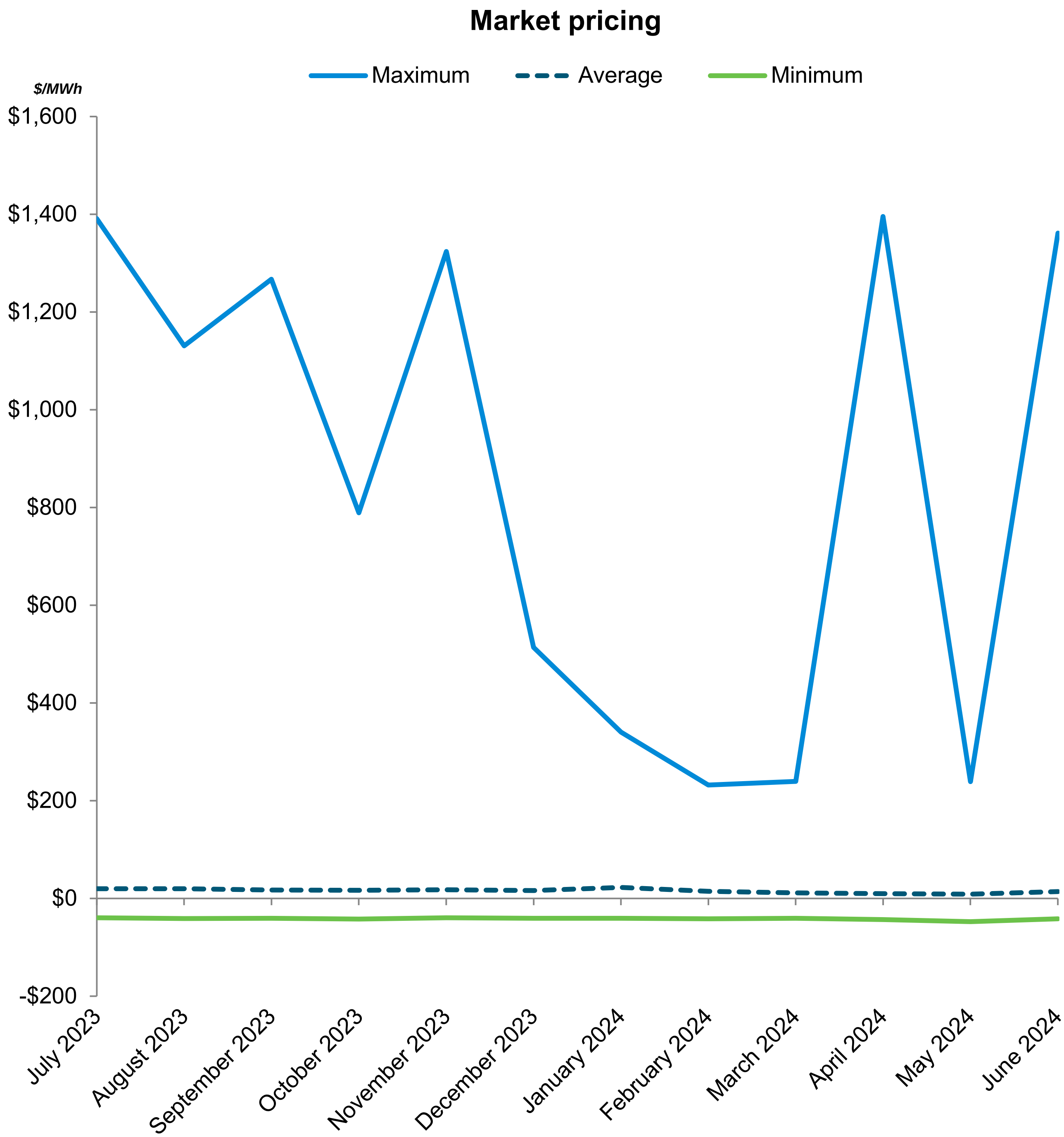


Purchased power

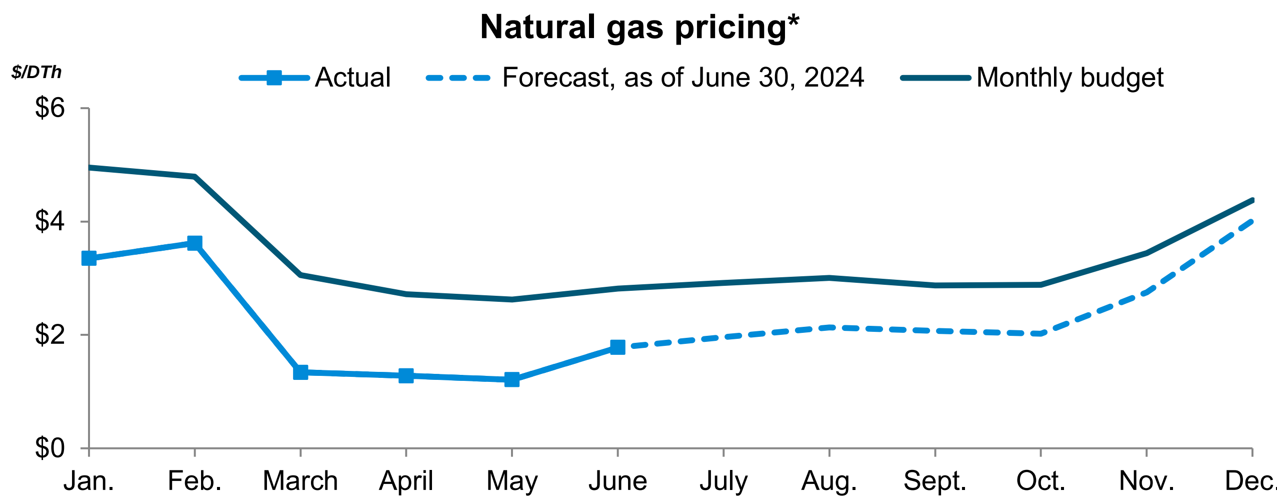




Market pricing

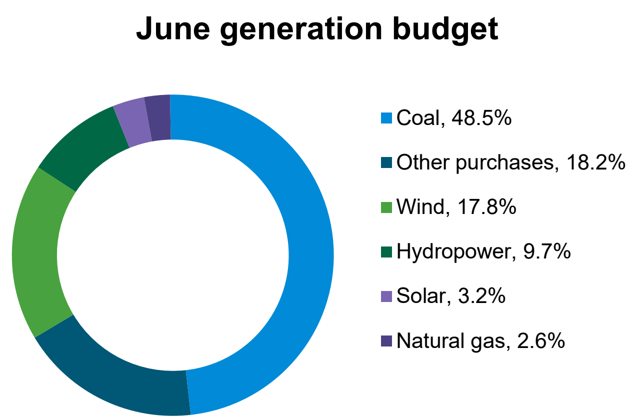


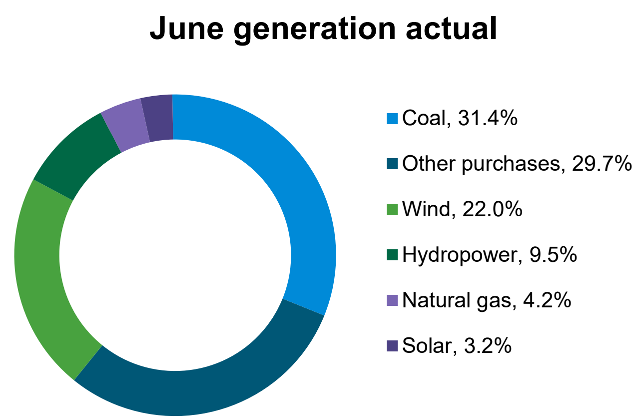
Natural gas pricing

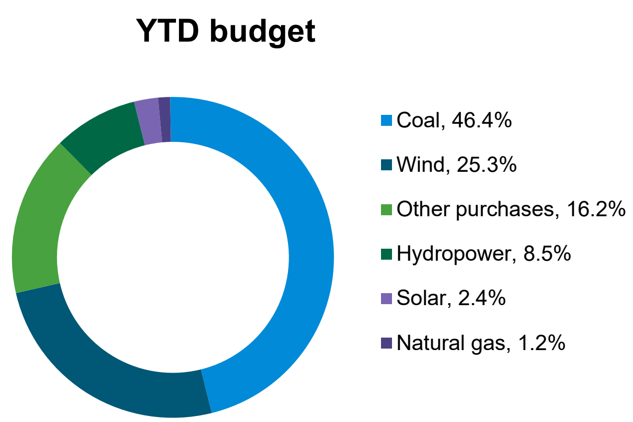


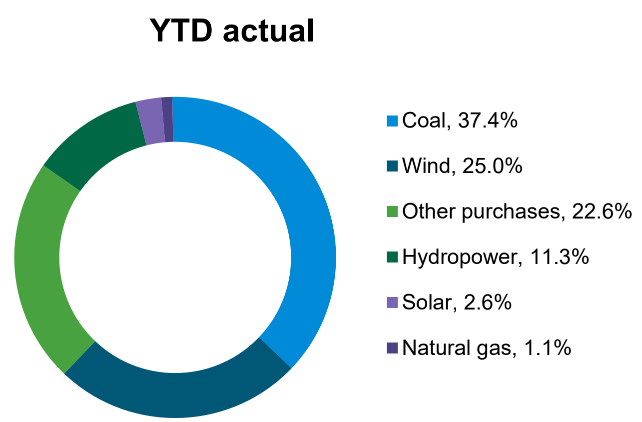
***Forecast based on Argus North American Natural Gas forward curves. Pricing does not include transport.**

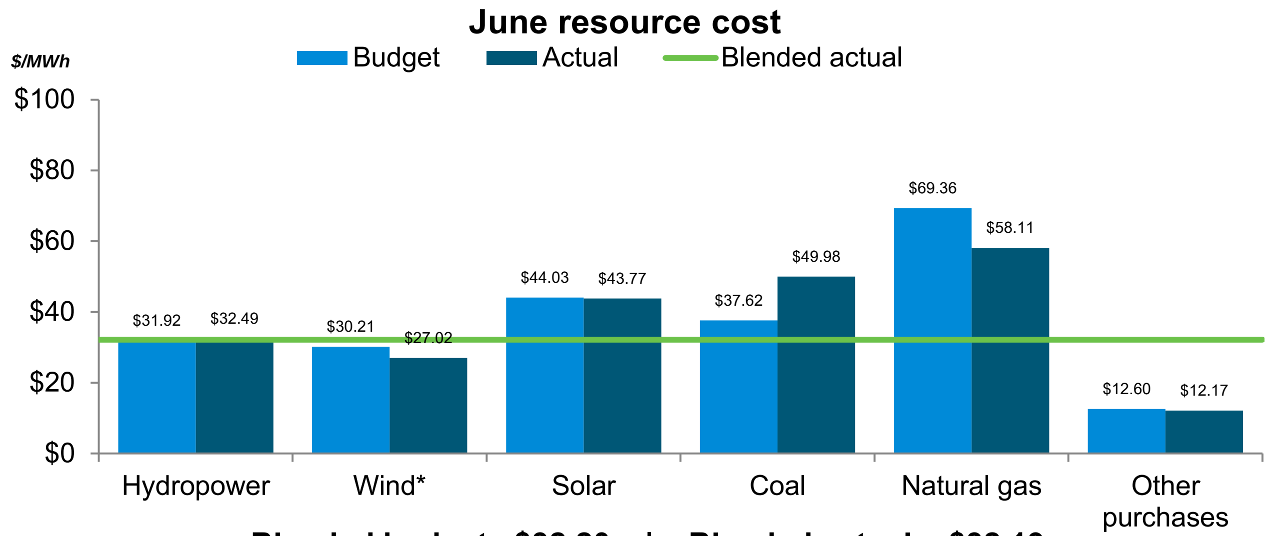
Total resources



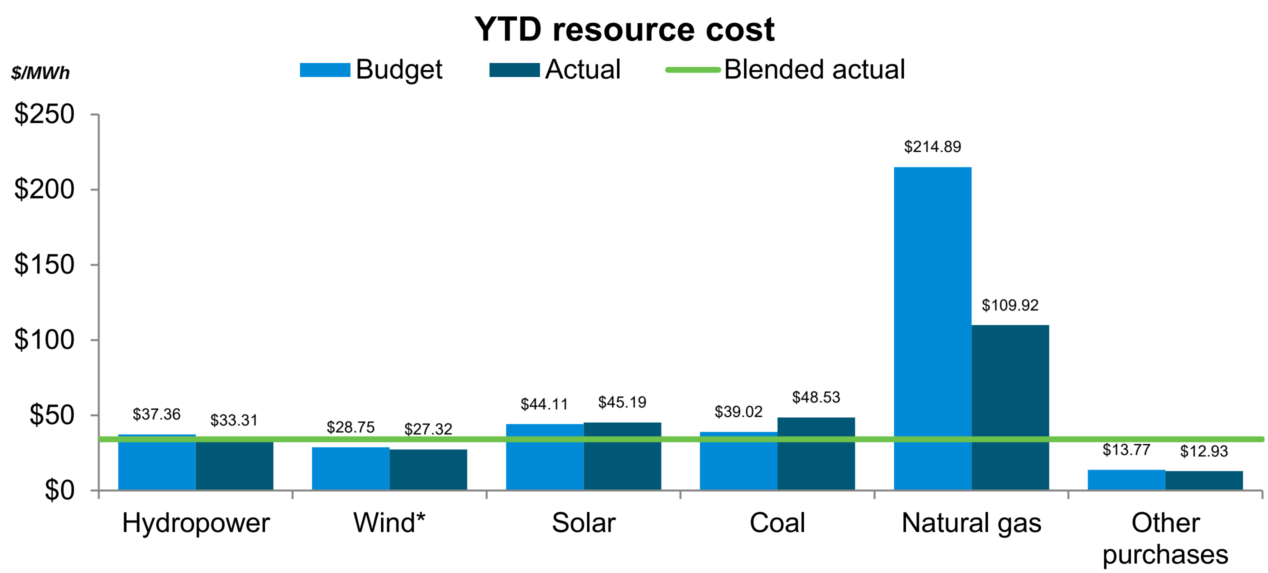








Blended budget $32.20 | Blended actual: $32.19



Blended budget $34.50 | Blended actual: $34.01

***Some off-system wind RECs and associated energy have been sold to another utility and, therefore, cannot be claimed as a renewable resource by Platte River or its owner communities.**

Estes Park • Fort Collins • Longmont • Loveland

Financial report

May 2024

Financial highlights year to date

Platte River reported favorable results year to date. Change in net position of $3.4 million was favorable by $6.2 million compared to budget primarily due to below-budget operating expenses, partially offset by below-budget revenues.

Key financial results (1) ($ millions)	May Budget	May Actual		Favorable (unfavorable)		Year to date Budget	Year to date Actual		Favorable (unfavorable)		Annual budget
Change in net position	$ (0.8)	$ 0.3	●	$ 1.1	137.5%	$ (2.8)	$ 3.4	●	$ 6.2	221.4%	$ 7.3
Fixed obligation charge coverage	1.51x	1.62x	●	0.11x	7.3%	1.50x	1.89x	●	0.39x	26.0%	1.93x (2)

>2% ● Favorable | 2% to -2% ◆ At or near budget | <-2% ■ Unfavorable

(1) The key financial results for the annual budget reflect projected deferred revenues of $14 million according to the deferred revenue and expense accounting policy discussed in the other financial information section. The actual deferral will be determined at the end of the year.

(2) Reflects correction of an error in calculating this metric as defined in the Strategic Financial Plan approved by the board of directors in December 2023.

Budgetary highlights year to date

The following budgetary highlights are presented on a non-GAAP budgetary basis.

Key budgetary results ($ millions)	May Budget	May Actual		Favorable (unfavorable)		Year to date Budget	Year to date Actual		Favorable (unfavorable)		Annual budget
Total revenues	$ 22.2	$ 21.2	■	$ (1.0)	(4.5%)	$ 118.1	$ 114.1	■	$ (4.0)	(3.4%)	$ 313.0
Sales to owner communities	17.6	17.0	■	(0.6)	(3.4%)	90.4	88.6	◆	(1.8)	(2.0%)	235.7
Sales for resale - long-term	1.4	1.4	◆	0.0	0.0%	8.0	6.4	■	(1.6)	(20.0%)	20.1
Sales for resale - short-term	1.6	1.3	■	(0.3)	(18.8%)	11.1	10.7	■	(0.4)	(3.6%)	36.4
Wheeling	0.7	0.6	■	(0.1)	(14.3%)	3.9	3.5	■	(0.4)	(10.3%)	8.9
Interest and other income	0.9	0.9	◆	0.0	0.0%	4.7	4.9	●	0.2	4.3%	11.9
Total operating expenses	$ 19.1	$ 17.8	●	$ 1.3	6.8%	$ 101.4	$ 90.8	●	$ 10.6	10.5%	$ 242.7
Purchased power	5.0	4.7	●	0.3	6.0%	26.8	24.6	●	2.2	8.2%	63.8
Fuel	3.8	3.1	●	0.7	18.4%	19.3	15.3	●	4.0	20.7%	51.1
Production	4.5	4.3	●	0.2	4.4%	25.4	22.3	●	3.1	12.2%	55.8
Transmission	1.9	1.7	●	0.2	10.5%	9.3	8.6	●	0.7	7.5%	21.4
Administrative and general	2.8	2.8	◆	0.0	0.0%	15.5	15.8	◆	(0.3)	(1.9%)	36.9
Distributed energy resources	1.1	1.2	■	(0.1)	(9.1%)	5.1	4.2	●	0.9	17.6%	13.7
Capital additions	$ 5.7	$ 4.3	●	$ 1.4	24.6%	$ 31.8	$ 16.6	●	$ 15.2	47.8%	$ 53.2
Debt service expenditures	$ 1.5	$ 1.5	◆	$ -	0.0%	$ 7.9	$ 8.0	◆	$ (0.1)	(1.3%)	$ 18.7

>2% ● Favorable | 2% to -2% ◆ At or near budget | <-2% ■ Unfavorable

Total revenues, $4 million below budget

Key variances greater than 2% or less than (2%)

- **Sales to owner communities** were below budget $1.8 million. Energy revenues were $2 million or 3.7% below budget due to below-budget energy. Demand revenues were $0.2 million or 0.6% above budget as non-coincident and coincident billing demand were above budget 0.6% and 0.5%, respectively.
- **Sales for resale - long-term** were below budget $1.6 million due to below-budget wind generation resold to third parties and below-budget calls on capacity contracts.
- **Sales for resale - short-term** were below budget $0.4 million as energy volume was 19.2% below budget, partially offset by 19.2% above-budget average prices.

- **Wheeling** was below budget $0.4 million primarily due to below-budget point-to-point transmission sales.
- **Interest and other income** was above budget $0.2 million primarily due to higher interest income earned on investments.

Total operating expenses, $10.6 million below budget

Key variances greater than 2% or less than (2%)

- **Fuel** was $4 million below budget.
  Coal - Rawhide Unit 1 98% of the overall variance, $3.9 million below budget. Generation was below budget due to lower-cost energy available in the Western Energy Imbalance Service (WEIS) market, an unplanned outage and curtailments. Additional fuel was required due to a less efficient heat rate, partially offsetting the below-budget variance.
  Natural Gas 22% of the overall variance, $0.9 million below budget. Generation was below budget primarily due to no calls on capacity contracts. Price was below budget due to lower market prices.
  Coal - Craig units (20%) of the overall variance, $0.8 million above budget. Additional fuel was required due to a less efficient heat rate. Price was above budget due to an updated price from Trapper Mine as total projected production from the mine decreased, increasing cost per ton delivered. Generation was below budget primarily due to lower-cost energy available in the WEIS market and curtailments, partially offsetting the above-budget variance.

- **Production, transmission, and administrative and general** were $3.5 million below budget. Projects were either completed below budget or expenses not required. The below-budget expenses include: 1) Rawhide non-routine projects, 2) critical infrastructure protection compliance, 3) wheeling, 4) facilities maintenance, 5) environmental services and 6) chemicals. The above-budget expenses include: 1) personnel, 2) Craig operating expenses, 3) digital consulting services and 4) software and hardware. The net below-budget variance is expected to be spent by the end of the year.

- **Purchased power** was $2.2 million below budget. The below-budget expenses include: 1) wind generation, 2) purchased reserves due to a lower rate than anticipated and 3) net energy delivered to Tri-State Generation and Transmission Association, Inc. (Tri-State) under the forced outage assistance agreement. The above-budget expenses include: 1) market purchases to replace baseload generation during unplanned outages and curtailments, serve sales and to take advantage of lower-cost energy in the WEIS market and 2) hydropower purchases due to favorable water conditions.

- **Distributed energy resources** were $0.9 million below budget due to the unpredictability of the completion of customers' energy efficiency projects, below-budget program consulting services and personnel expenses.

Capital additions, $15.2 million below budget

Year-end estimates as of May 2024

The projects listed below are projected to end the year with a budget variance of more than $100,000. In addition, the amounts below are costs for 2024 and may not represent the total cost of the project. Further changes to capital projections are anticipated and staff will continue to monitor spending estimates to ensure capital projects are appropriately funded.

Project ($ thousands)	2024 budget	Estimate	Favorable (unfavorable)	Carryover request
Below budget projects				
Transformer T3 replacement - **Timberline Substation** - This project will be below budget as construction will be delayed until after the higher priority Solar substation 230 kV - Severance Substation project is completed in late 2024. *The below-budget funds will be requested to be carried over into 2025.*	$ 3,521	$ 1,700	$ 1,821	$ 1,821
Relay panel and breaker replacements - **Airport Substation** - This project will be below budget due to a delay to align the construction schedule with an existing City of Loveland project occurring in 2025. Also, procurement of materials will not occur in 2024 as originally anticipated. *The below-budget funds will be requested to be carried over into 2025.*	$ 1,827	$ 183	$ 1,644	$ 1,644
Compressor blade upgrade - **combustion turbine Unit F** - This project will be below budget as a different vendor was selected with favorable pricing.	$ 1,861	$ 1,511	$ 350	$ -
115 kV transmission line replacement - **Drake transmission line** - This multiyear project will be below budget due to a scope reduction after testing revealed all structures will not need to be replaced. *The below-budget funds will be requested to be carried over into 2025.*	$ 364	$ 164	$ 200	$ 200
* **Switch and CVT replacements** - **Timberline Substation** - This project will be below budget as it is delayed until after the transformer work at Timberline Substation, which is not expected until early 2025. The revised project schedule will gain efficiencies with contractor mobilization and outages. *The below-budget funds will be requested to be carried over into 2025.*	$ 211	$ 86	$ 125	$ 125
Above budget projects				
Solar substation 230 kV - Severance Substation - This project will be above budget due to design and cost increases. Primary cost drivers include professional services, land rights and crossing agreements, grading materials, substation materials and substation construction services.	$ 10,156	$ 19,857	$ (9,701)	$ -
Bay connection and transmission line to Severance Substation - **noncarbon resources** - This project will be above budget due to procurement of materials occurring in 2024 rather than 2025. Alignment with the Solar substation 230 kV - Severance Substation project this year will allow efficiencies with project labor. Total multiyear project costs are not expected to change.	$ 1,529	$ 2,129	$ (600)	$ -

	Project ($ thousands)	2024 budget	Estimate	Favorable (unfavorable)	Carryover request
	Dust collection system replacement - coal transfer building - This project will be above budget for additional design and procurement costs in order to meet deadlines for installation during the 2025 major outage. Total multiyear project costs are not expected to change.	$ 191	$ 407	$ (216)	$ -
	Dust collection system replacement - crusher building - This project will be above budget for additional design and procurement costs in order to meet deadlines for installation during the 2025 major outage. Total multiyear project costs are not expected to change.	$ 222	$ 399	$ (177)	$ -
**	**Gas control valve replacement - combustion turbine Unit C** - This project will be above budget due to increases for additional electrical components, third party electrical design and retuning of the combustion turbine.	$ 452	$ 592	$ (140)	$ -
	Switchgear replacement - Soldier Canyon Pump Station - This project will be above budget due to price escalations for labor and materials. The scope was also increased to include variable frequency drives for each pump.	$ 209	$ 339	$ (130)	$ -
	Out-of-budget projects				
	Mechanical pond pumps and control valves - headquarters - This project will replace the mechanical system pond pumps and control valves to improve building heating and cooling during peak seasons.	$ -	$ 253	$ (253)	$ -
**	**FlexStart and FlexRamp upgrade - combustion turbine Unit F** - This project will install upgrades to enable faster start times and greater ramp flexibility of combustion turbine Unit F.	$ -	$ 202	$ (202)	$ -
	Radio upgrades - Rawhide - This project will upgrade the radio repeaters and include radio handsets in order to provide a priority interrupt feature and allow coverage in all areas of the plant in case of emergency situations.	$ -	$ 107	$ (107)	$ -
	Delayed projects				
	Distributed energy resources management system - This project will be delayed to allow additional time for scope development, the request for proposal process and vendor selection. *The below-budget funds will be requested to be carried over into 2025.*	$ 2,485	$ -	$ 2,485	$ 2,485
	Circuit breakers replacement 592, 596 - Ault Substation WAPA - This project will be delayed due to a change in WAPA's schedule. *The below-budget funds will be requested to be carried over into 2025.*	$ 878	$ -	$ 878	$ 878
	Circuit breakers replacement 492, 1092, 3124, 3224 - Ault Substation WAPA - This project will be delayed due to a change in WAPA's schedule. *The below-budget funds will be requested to be carried over into 2025.*	$ 752	$ -	$ 752	$ 752
	Network replacement - headquarters - This project will be delayed due to internal resources shifting to higher priority projects. *The below-budget funds will be requested to be carried over into 2025.*	$ 345	$ -	$ 345	$ 345

Project ($ thousands)	2024 budget	Estimate	Favorable (unfavorable)	Carryover request
Canceled projects				
Transformer nitrogen generator - Rawhide Unit 1 - This project was canceled. The nitrogen bottles will be replaced as an operating expense rather than installation of a nitrogen generator which is more economical with the remaining life of Rawhide Unit 1.	$ 152	$ -	$ 152	$ -

* Project details or amounts have changed since last report.

** Project is new to the report.

Debt service expenditures, $0.1 million above budget

Debt service expenditures include principal and interest expense for power revenue bonds and for lease and subscription liabilities.

Debt service expenditures ($ thousands)	May Budget	May Actual		Favorable (unfavorable)		Year to date Budget	Year to date Actual		Favorable (unfavorable)		Annual budget
Total principal	$ 1,076	$ 1,114	■	$ (38)	(3.5%)	$ 5,823	$ 5,850	◆	$ (27)	(0.5%)	$ 14,015
Power revenue bonds	1,066	1,066	◆	-	0.0%	5,329	5,329	◆	-	0.0%	13,146
Lease and subscription liabilities	10	48	■	(38)	(380.0%)	494	521	■	(27)	(5.5%)	869
Total interest expense	$ 417	$ 419	◆	$ (2)	(0.5%)	$ 2,092	$ 2,110	◆	$ (18)	(0.9%)	$ 4,667
Power revenue bonds	416	416	◆	-	0.0%	2,081	2,081	◆	-	0.0%	4,642
Lease and subscription liabilities	1	3	■	(2)	(200.0%)	11	29	■	(18)	(163.6%)	25
Total debt service expenditures	$ 1,493	$ 1,533	■	$ (40)	(2.7%)	$ 7,915	$ 7,960	◆	$ (45)	(0.6%)	$ 18,682

>2% ● Favorable | 2% to -2% ◆ At or near budget | <-2% ■ Unfavorable

The outstanding principal for Series JJ and KK represents debt associated with transmission assets ($104.6 million) and the Rawhide Energy Station ($21.3 million). Principal and interest payments are made June 1 and interest only payments are made Dec. 1. The table below shows current debt outstanding.

Series	Debt outstanding ($ thousands)	Par issued ($ thousands)	True interest cost	Maturity date	Callable date	Purpose
Series JJ - April 2016	$ 102,320	$ 147,230	2.2%	6/1/2036	6/1/2026	$60M new money for Rawhide & transmission projects & refund portion of Series HH ($13.7M NPV/12.9% savings)
Series KK - December 2020	23,550	$ 25,230	1.6%	6/1/2037	N/A*	Refund a portion of Series II ($6.5M NPV/27.6% savings)
Total par outstanding	125,870					
Unamortized bond premium	8,737					
Total revenue bonds outstanding	134,607					
Less: due within one year	(12,790)					
Total long-term debt, net	$ 121,817					

Fixed rate bond premium costs are amortized over the terms of the related bond issues.

*Series KK is subject to prior redemption, in whole or in part as selected by Platte River, on any date.

Contingency appropriation

$56 million reserved to board

At this time, capital additions are expected to be above budget at the end of the year. A budget contingency appropriation of approximately $11.3 million may be required to cover the additional expenditures in 2024. Staff will evaluate the budgetary results at the end of the year and apply the contingency appropriation accordingly.

Capital summary		$ millions
2024 capital budget	$	53.2
2024 estimated capital expenses		56.2
Below budget variance	$	(3.0)
Estimated capital carryovers from 2024 to 2025		(8.3)
Estimated contingency transfer required	**$**	**(11.3)**

Other financial information

- **Deferred revenue and expense accounting policy** - This policy allows deferring revenues and expenses to reduce rate pressure and achieve rate smoothing during the portfolio transition to meet the Resource Diversification Policy goal. Staff will evaluate the financial statements at the end of the year and apply the policy accordingly, which would impact the change in net position.

- **Forced outage assistance agreement** - This agreement, which involved Platte River's Rawhide Unit 1 and Tri-State's Craig Unit 3, provided that each party supply replacement energy to the other party during a forced outage of either unit. The agreement was terminated on the expiration date of March 31, 2024. Upon termination of the agreement, the Energy Account Balance was reduced to zero and Tri-State was invoiced $1 million.

- **Accounting standard** - Platte River is subject to the updated recognition and measurement guidance for compensated absences under GASB 101 *Compensated Absences*. Results presented in the financial statements may not represent full implementation of the standard as staff evaluates the impact. Implementation will occur during 2024.

- **Excess coal sale** - Platte River sold $2.4 million of excess coal from the stockpile at the Craig Station in April resulting in no gain or loss.

Budget schedules

Schedule of revenues and expenditures, budget to actual

May 2024

Non-GAAP budgetary basis (in thousands)

	Month of May		Favorable
	Budget	**Actual**	(unfavorable)
Revenues			
Operating revenues			
Sales to owner communities	$ 17,584	**$ 16,993**	$ (591)
Sales for resale - long-term	1,413	**1,383**	(30)
Sales for resale - short-term	1,559	**1,274**	(285)
Wheeling	684	**564**	(120)
Total operating revenues	21,240	**20,214**	(1,026)
Other revenues			
Interest income[1]	964	**987**	23
Other loss	(3)	**-**	3
Total other revenues	961	**987**	26
Total revenues	$ 22,201	**$ 21,201**	$ (1,000)
Expenditures			
Operating expenses			
Purchased power	$ 5,047	**$ 4,737**	$ 310
Fuel	3,771	**3,081**	690
Production	4,504	**4,252**	252
Transmission	1,916	**1,753**	163
Administrative and general	2,794	**2,761**	33
Distributed energy resources	1,046	**1,201**	(155)
Total operating expenses	19,078	**17,785**	1,293
Capital additions			
Production	1,395	**205**	1,190
Transmission	2,285	**2,575**	(290)
General	1,966	**1,513**	453
Asset retirement obligations	78	**42**	36
Total capital additions	5,724	**4,335**	1,389
Debt service expenditures			
Principal	1,076	**1,114**	(38)
Interest expense	417	**419**	(2)
Total debt service expenditures	1,493	**1,533**	(40)
Total expenditures	$ 26,295	**$ 23,653**	$ 2,642
Revenues less expenditures	$ (4,094)	**$ (2,452)**	$ 1,642

[1] Excludes unrealized holding gains and losses on investments.

Schedule of revenues and expenditures, budget to actual

May 2024 year-to-date

Non-GAAP budgetary basis (in thousands)

	May year to date		Favorable	Annual
	Budget	**Actual**	(unfavorable)	budget
Revenues				
Operating revenues				
Sales to owner communities	$ 90,404	**$ 88,581**	$ (1,823)	$ 235,737
Sales for resale - long-term	8,049	**6,467**	(1,582)	20,086
Sales for resale - short-term	11,114	**10,702**	(412)	36,356
Wheeling	3,879	**3,476**	(403)	8,942
Total operating revenues	113,446	**109,226**	(4,220)	301,121
Other revenues				
Interest income[1]	4,437	**4,619**	182	11,569
Other income	253	**274**	21	282
Total other revenues	4,690	**4,893**	203	11,851
Total revenues	$ 118,136	**$ 114,119**	$ (4,017)	$ 312,972
Expenditures				
Operating expenses				
Purchased power	$ 26,841	**$ 24,590**	$ 2,251	$ 63,776
Fuel	19,301	**15,311**	3,990	51,119
Production	25,395	**22,259**	3,136	55,842
Transmission	9,328	**8,572**	756	21,412
Administrative and general	15,476	**15,807**	(331)	36,863
Distributed energy resources	5,062	**4,217**	845	13,664
Total operating expenses	101,403	**90,756**	10,647	242,676
Capital additions				
Production	6,778	**1,925**	4,853	12,363
Transmission	14,823	**10,073**	4,750	21,957
General	9,807	**4,581**	5,226	17,979
Asset retirement obligations	389	**70**	319	933
Total capital additions	31,797	**16,649**	15,148	53,232
Debt service expenditures				
Principal	5,823	**5,850**	(27)	14,015
Interest expense	2,092	**2,110**	(18)	4,667
Total debt service expenditures	7,915	**7,960**	(45)	18,682
Total expenditures	$ 141,115	**$ 115,365**	$ 25,750	$ 314,590
Contingency reserved to board	-	**-**	-	56,000
Total expenditures and contingency	$ 141,115	**$ 115,365**	$ 25,750	$ 370,590
Revenues less expenditures and contingency	$ (22,979)	**$ (1,246)**	$ 21,733	$ (57,618)

[1] Excludes unrealized holding gains and losses on investments.

Financial statements

Statements of net position

Unaudited (in thousands)

	May 31 2024	May 31 2023
Assets		
Electric utility plant, at original cost		
Land and land rights	**$ 19,446**	$ 19,446
Plant and equipment in service	**1,484,516**	1,469,278
Less: accumulated depreciation and amortization	**(992,588)**	(952,527)
Plant in service, net	**511,374**	536,197
Construction work in progress	**44,881**	28,298
Total electric utility plant	**556,255**	564,495
Special funds and investments		
Restricted funds and investments	**27,779**	27,112
Dedicated funds and investments	**170,418**	163,710
Total special funds and investments	**198,197**	190,822
Current assets		
Cash and cash equivalents	**57,261**	39,550
Other temporary investments	**50,996**	48,886
Accounts receivable - owner communities	**16,957**	16,404
Accounts receivable - other	**3,891**	5,987
Fuel inventory, at last-in, first-out cost	**20,096**	11,950
Materials and supplies inventory, at average cost	**18,016**	16,513
Prepayments and other assets	**8,878**	8,904
Total current assets	**176,095**	148,194
Noncurrent assets		
Regulatory assets	**130,777**	128,411
Other long-term assets	**8,615**	7,123
Total noncurrent assets	**139,392**	135,534
Total assets	**1,069,939**	1,039,045
Deferred outflows of resources		
Deferred loss on debt refundings	**1,995**	2,744
Pension deferrals	**9,787**	14,849
Asset retirement obligations	**26,971**	26,787
Total deferred outflows of resources	**38,753**	44,380
Liabilities		
Noncurrent liabilities		
Long-term debt, net	**121,817**	136,834
Net pension liability	**28,274**	30,520
Other long-term obligations	**93,406**	94,295
Lease and subscription liabilities	**445**	916
Asset retirement obligations	**37,257**	34,334
Other liabilities and credits	**12,566**	7,598
Total noncurrent liabilities	**293,765**	304,497
Current liabilities		
Current maturities of long-term debt	**12,790**	12,215
Current portion of other long-term obligations	**889**	889
Current portion of lease and subscription liabilities	**668**	338
Current portion of asset retirement obligations	**933**	1,547
Accounts payable	**15,480**	17,455
Accrued interest	**2,497**	2,784
Accrued liabilities and other	**6,210**	4,668
Total current liabilities	**39,467**	39,896
Total liabilities	**333,232**	344,393
Deferred inflows of resources		
Deferred gain on debt refundings	**107**	120
Regulatory credits	**104,039**	73,894
Pension deferrals	**-**	287
Lease deferrals	**704**	852
Total deferred inflows of resources	**104,850**	75,153
Net position		
Net investment in capital assets	**411,903**	399,431
Restricted	**25,282**	24,328
Unrestricted	**233,425**	240,120
Total net position	**$ 670,610**	$ 663,879

Note: Certain previously stated line items have been updated or reclassified to conform with final audited financial statements including restatement of prior year where applicable.

Statements of revenues, expenses and changes in net position

Unaudited (in thousands)

	Month of May	May year to date 2024	May year to date 2023
Operating revenues			
Sales to owner communities	**$ 16,993**	**$ 88,581**	$ 85,641
Sales for resale	**2,657**	**17,169**	18,254
Wheeling	**564**	**3,476**	4,043
Total operating revenues	**20,214**	**109,226**	107,938
Operating expenses			
Purchased power	**4,737**	**24,590**	22,496
Fuel	**3,081**	**15,311**	18,014
Operations and maintenance	**5,825**	**31,123**	33,233
Administrative and general	**2,803**	**16,144**	12,355
Distributed energy resources	**1,208**	**4,280**	2,757
Depreciation, amortization and accretion	**3,594**	**17,464**	16,162
Total operating expenses	**21,248**	**108,912**	105,017
Operating income	**(1,034)**	**314**	2,921
Nonoperating revenues (expenses)			
Interest income	**958**	**4,543**	2,714
Other income	**-**	**274**	260
Interest expense	**(419)**	**(2,110)**	(2,320)
Amortization of bond financing costs	**111**	**554**	615
Net increase/(decrease) in fair value of investments	**681**	**(150)**	1,766
Total nonoperating revenues (expenses)	**1,331**	**3,111**	3,035
Change in net position	**297**	**3,425**	5,956
Net position at beginning of period, as previously reported	**670,313**	**667,185**	657,923
Net position at end of period	**$ 670,610**	**$ 670,610**	$ 663,879

Note: Certain previously stated line items have been updated or reclassified to conform with final audited financial statements including restatement of prior year where applicable.

Statements of cash flows

Unaudited (in thousands)

	Month of May	May year to date 2024	May year to date 2023
Cash flows from operating activities			
Receipts from customers	**$ 21,011**	**$ 111,972**	$ 114,704
Payments for operating goods and services	**(11,575)**	**(70,683)**	(70,070)
Payments for employee services	**(4,833)**	**(25,711)**	(21,453)
Net cash provided by operating activities	**4,603**	**15,578**	23,181
Cash flows from capital and related financing activities			
Additions to electric utility plant	**(3,052)**	**(15,355)**	(7,458)
Payments from accounts payable incurred for electric utility plant additions	**(1,388)**	**(2,136)**	(3,493)
Proceeds from disposal of electric utility plant	**-**	**17**	-
Payments related to other long-term obligations	**-**	**(5,390)**	(4,145)
Payments on lease and subscription liabilities	**(51)**	**(550)**	-
Net cash used in capital and related financing activities	**(4,491)**	**(23,414)**	(15,096)
Cash flows from investing activities			
Purchases and sales of temporary and restricted investments, net	**(4,744)**	**(10,497)**	(19,520)
Interest and other income, including realized gains and losses	**983**	**4,874**	2,968
Net cash used in investing activities	**(3,761)**	**(5,623)**	(16,552)
Decrease in cash and cash equivalents	**(3,649)**	**(13,459)**	(8,467)
Balance at beginning of period in cash and cash equivalents	**60,910**	**70,720**	48,017
Balance at end of period in cash and cash equivalents	**$ 57,261**	**$ 57,261**	$ 39,550
Reconciliation of net operating income to net cash provided by operating activities			
Operating income	**$ (1,034)**	**$ 314**	$ 2,921
Adjustments to reconcile operating income to net cash provided by operating activities			
Depreciation	**3,428**	**17,105**	16,676
Amortization	**(403)**	**(2,014)**	(2,336)
Operating expenses relating to other long-term obligations	**241**	**1,203**	1,203
Changes in assets and liabilities that provided/(used) cash			
Accounts receivable	**797**	**3,540**	8,436
Fuel and materials and supplies inventories	**(95)**	**(482)**	(2,529)
Prepayments and other assets	**1,363**	**(3,027)**	(2,885)
Regulatory assets	**96**	**482**	222
Deferred outflows of resources	**443**	**(600)**	(1,471)
Accounts payable	**(793)**	**(8,254)**	(4,019)
Asset retirement obligations	**(41)**	**2,275**	2,596
Other liabilities	**213**	**2,892**	2,608
Deferred inflows of resources	**388**	**2,144**	1,759
Net cash provided by operating activities	**$ 4,603**	**$ 15,578**	$ 23,181
Noncash capital and related financing activities			
Additions of electric utility plant through incurrence of accounts payable	**1,241**	**1,241**	607
Additions of electric utility plant through leasing and subscription	**-**	**132**	-
Amortization of regulatory asset (debt issuance costs)	**6**	**31**	33
Amortization of bond premiums, deferred loss and deferred gain on refundings	**(117)**	**(584)**	(649)

Note: Certain previously stated line items have been updated or reclassified to conform with final audited financial statements including restatement of prior year where applicable.

Schedule of net revenues for bond service and fixed obligations

Unaudited (in thousands)

Bond service coverage	**Month of May**	**May year to date 2024**	**May year to date 2023**
Net revenues			
Operating revenues	**$ 20,214**	**$ 109,226**	$ 107,938
Operations and maintenance expenses, excluding depreciation, amortization and accretion	**17,654**	**91,448**	88,855
Net operating revenues	**2,560**	**17,778**	19,083
Plus interest income on bond accounts and other income [1]	**987**	**4,893**	2,987
Net revenues before rate stabilization	**3,547**	**22,671**	22,070
Rate stabilization			
Deposits	**-**	**-**	-
Withdrawals	**-**	**-**	-
Total net revenues	**$ 3,547**	**$ 22,671**	$ 22,070
Bond service			
Power revenue bonds	**$ 1,482**	**$ 7,410**	$ 7,410
Coverage			
Bond service coverage ratio	**2.39**	**3.06**	2.98

	Month of May	**May year to date 2024**	**May year to date 2023**
Fixed obligation charge coverage			
Total net revenues, above	**$ 3,547**	**$ 22,671**	$ 22,070
Fixed obligation charges included in operating expenses [2]	**1,722**	**8,611**	9,001
Adjusted net revenues before fixed obligation charges	**$ 5,269**	**$ 31,282**	$ 31,071
Fixed obligation charges			
Power revenue bonds, above	**$ 1,482**	**$ 7,410**	$ 7,410
Fixed obligation charges [2][3]	**1,773**	**9,162**	9,001
Total fixed obligation charges	**$ 3,255**	**$ 16,572**	$ 16,411
Coverage			
Fixed obligation charge coverage ratio	**1.62**	**1.89**	1.89

[1] Excludes unrealized holding gains and losses on investments.

[2] Fixed obligation charges included in operating expenses are debt-like obligation payments including those for demand or capacity on contracted assets and any debt service associated with off-balance sheet obligations.

[3] This value also includes lease and subscription debt service expenditures which are not included in operating expenses.

Note: Certain previously stated line items have been updated to accord with the Strategic Financial Plan as adopted by the board in December 2023

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Financial report

June 2024

Financial highlights year to date

Platte River reported favorable results year to date. Change in net position of $11.3 million was favorable by $8.3 million compared to budget primarily due to below-budget operating expenses and above-budget unrealized gains on investments and interest income, partially offset by below-budget revenues.

Key financial results [1] ($ millions)	June Budget	June Actual		Favorable (unfavorable)		Year to date Budget	Year to date Actual		Favorable (unfavorable)		Annual budget
Change in net position	$ 5.7	$ 7.9	●	$ 2.2	38.6%	$ 3.0	$ 11.3	●	$ 8.3	276.7%	$ 7.3
Fixed obligation charge coverage	3.65x	4.11x	●	0.46x	12.6%	1.83x	2.24x	●	0.41x	22.4%	1.93x [2]

>2% ● Favorable | 2% to -2% ◆ At or near budget | <-2% ■ Unfavorable

(1) The key financial results for the annual budget reflect projected deferred revenues of $14 million according to the deferred revenue and expense accounting policy discussed in the other financial information section. The actual deferral will be determined at the end of the year.

(2) Reflects correction of an error in calculating this metric as defined in the Strategic Financial Plan approved by the board of directors in December 2023.

Budgetary highlights year to date

The following budgetary highlights are presented on a non-GAAP budgetary basis.

Key budgetary results ($ millions)	June Budget	June Actual		Favorable (unfavorable)		Year to date Budget	Year to date Actual		Favorable (unfavorable)		Annual budget
Total revenues	$ 29.1	$ 29.9	●	$ 0.8	2.7%	$ 147.3	$ 144.0	■	$ (3.3)	(2.2%)	$ 313.0
Sales to owner communities	21.8	21.3	■	(0.5)	(2.3%)	112.2	109.8	■	(2.4)	(2.1%)	235.7
Sales for resale - long-term	1.7	1.7	◆	0.0	0.0%	9.7	8.2	■	(1.5)	(15.5%)	20.1
Sales for resale - short-term	4.0	4.9	●	0.9	22.5%	15.1	15.6	●	0.5	3.3%	36.4
Wheeling	0.6	1.0	●	0.4	66.7%	4.6	4.5	■	(0.1)	(2.2%)	8.9
Interest and other income	1.0	1.0	◆	0.0	0.0%	5.7	5.9	●	0.2	3.5%	11.9
Total operating expenses	$ 19.5	$ 18.6	●	$ 0.9	4.6%	$ 120.9	$ 109.4	●	$ 11.5	9.5%	$ 242.7
Purchased power	4.8	5.5	■	(0.7)	(14.6%)	31.6	30.1	●	1.5	4.7%	63.8
Fuel	4.4	3.5	●	0.9	20.5%	23.7	18.8	●	4.9	20.7%	51.1
Production	4.3	4.4	■	(0.1)	(2.3%)	29.7	26.7	●	3.0	10.1%	55.8
Transmission	1.8	1.6	●	0.2	11.1%	11.2	10.2	●	1.0	8.9%	21.4
Administrative and general	3.2	2.7	●	0.5	15.6%	18.7	18.6	◆	0.1	0.5%	36.9
Distributed energy resources	1.0	0.9	●	0.1	10.0%	6.0	5.0	●	1.0	16.7%	13.7
Capital additions	$ 5.7	$ 7.8	■	$ (2.1)	(36.8%)	$ 37.5	$ 24.4	●	$ 13.1	34.9%	$ 53.2
Debt service expenditures	$ 1.5	$ 1.5	◆	$ -	0.0%	$ 9.4	$ 9.5	◆	$ (0.1)	(1.1%)	$ 18.7

>2% ● Favorable | 2% to -2% ◆ At or near budget | <-2% ■ Unfavorable

Total revenues, $3.3 million below budget

Key variances greater than 2% or less than (2%)

- **Sales to owner communities** were below budget $2.4 million. Energy revenues were $2.1 million or 3.1% below budget due to below-budget energy. Demand revenues were $0.3 million or 0.8% below budget as coincident and non-coincident billing demand were below budget 0.8% and 0.4%, respectively.

- **Sales for resale - long-term** were below budget $1.5 million due to below-budget wind generation resold to third parties and below-budget calls on capacity contracts.

- **Sales for resale - short-term** were above budget $0.5 million as average prices were 20.6% above budget, partially offset by 14.6% below-budget energy volume.

- **Wheeling** was below budget $0.1 million primarily due to below-budget point-to-point transmission sales.
- **Interest and other income** was above budget $0.2 million primarily due to higher interest income earned on investments.

Total operating expenses, $11.5 million below budget

Key variances greater than 2% or less than (2%)

- **Fuel** was $4.9 million below budget.
  Coal - Rawhide Unit 1 102% of the overall variance, $5 million below budget. Generation was below budget due to lower-cost energy available in the Western Energy Imbalance Service (WEIS) market, an unplanned outage and curtailments. Additional fuel was required due to a less efficient heat rate, partially offsetting the below-budget variance.
  Natural Gas 16% of the overall variance, $0.8 million below budget. Generation was below budget primarily due to no calls on capacity contracts. Price was below budget due to lower market prices.
  Coal - Craig units (18%) of the overall variance, $0.9 million above budget. Additional fuel was required due to a less efficient heat rate. Price was above budget due to an updated price from Trapper Mine as total projected production from the mine decreased, increasing cost per ton delivered. Generation was below budget primarily due to lower-cost energy available in the WEIS market and curtailments, partially offsetting the above-budget variance.
- **Production, transmission, and administrative and general** were $4.1 million below budget. Projects were either completed below budget or expenses not required. The below-budget expenses include: 1) Rawhide non-routine projects, 2) wheeling, 3) critical infrastructure protection compliance, 4) resource planning initiatives, 5) chemicals and 6) travel and training. The above-budget expenses include: 1) Craig operating expenses, 2) personnel, 3) digital consulting services and 4) tower maintenance. The net below-budget variance is expected to be spent by the end of the year.
- **Purchased power** was $1.5 million below budget. The below-budget expenses include: 1) wind and solar generation, 2) purchased reserves due to a lower rate than anticipated and 3) net energy delivered to Tri-State Generation and Transmission Association, Inc. (Tri-State) under the forced outage assistance agreement. The above-budget expenses include: 1) market purchases to replace baseload generation during unplanned outages and curtailments, serve sales and to take advantage of lower-cost energy in the WEIS market and 2) hydropower purchases due to favorable water conditions.
- **Distributed energy resources** were $1 million below budget due to program consulting services, personnel expenses and the unpredictability of the completion of customers' energy efficiency projects.

Capital additions, $13.1 million below budget

Year-end estimates as of June 2024

The projects listed below are projected to end the year with a budget variance of more than $100,000. In addition, the amounts below are costs for 2024 and may not represent the total cost of the project. Further changes to capital projections are anticipated and staff will continue to monitor spending estimates to ensure capital projects are appropriately funded.

Project ($ thousands)	2024 budget	Estimate	Favorable (unfavorable)	Carryover request
Below budget projects				
Transformer T3 replacement - **Timberline Substation** - This project will be below budget as construction will be delayed until after the higher priority Solar substation 230 kV - Severance Substation project is completed in late 2024. *The below-budget funds will be requested to be carried over into 2025.*	$ 3,521	$ 1,700	$ 1,821	$ 1,821
Relay panel and breaker replacements - **Airport Substation** - This project will be below budget due to a delay to align the construction schedule with an existing City of Loveland project occurring in 2025. Also, procurement of materials will not occur in 2024 as originally anticipated. *The below-budget funds will be requested to be carried over into 2025.*	$ 1,827	$ 183	$ 1,644	$ 1,644
Compressor blade upgrade - **combustion turbine Unit F** - This project will be below budget as a different vendor was selected with favorable pricing.	$ 1,861	$ 1,511	$ 350	$ -
115 kV transmission line replacement - **Drake transmission line** - This multiyear project will be below budget due to a scope reduction after testing revealed all structures will not need to be replaced. *The below-budget funds will be requested to be carried over into 2025.*	$ 364	$ 164	$ 200	$ 200
* **Switch and CVT replacements** - **Timberline Substation** - This project will be below budget as it is delayed until after the transformer work at Timberline Substation, which is not expected until early 2025. The revised project schedule will gain efficiencies with contractor mobilization and outages. *The below-budget funds will be requested to be carried over into 2025.*	$ 211	$ 87	$ 124	$ 124
Above budget projects				
Solar substation 230 kV - Severance Substation - This project will be above budget due to design and cost increases. Primary cost drivers include professional services, land rights and crossing agreements, grading materials, substation materials and substation construction services.	$ 10,156	$ 19,857	$ (9,701)	$ -
Bay connection and transmission line to Severance Substation - **noncarbon resources** - This project will be above budget due to procurement of materials occurring in 2024 rather than 2025. Alignment with the Solar substation 230 kV - Severance Substation project this year will allow efficiencies with project labor. Total multiyear project costs are not expected to change.	$ 1,529	$ 2,129	$ (600)	$ -

Project ($ thousands)	2024 budget	Estimate	Favorable (unfavorable)	Carryover request
Dust collection system replacement - coal transfer building - This project will be above budget for additional design and procurement costs in order to meet deadlines for installation during the 2025 major outage. Total multiyear project costs are not expected to change.	$ 191	$ 407	$ (216)	$ -
Dust collection system replacement - crusher building - This project will be above budget for additional design and procurement costs in order to meet deadlines for installation during the 2025 major outage. Total multiyear project costs are not expected to change.	$ 222	$ 399	$ (177)	$ -
Gas control valve replacement - combustion turbine Unit C - This project will be above budget due to increases for additional electrical components, third party electrical design and retuning of the combustion turbine.	$ 452	$ 592	$ (140)	$ -
Switchgear replacement - Soldier Canyon Pump Station - This project will be above budget due to price escalations for labor and materials. The scope was also increased to include variable frequency drives for each pump.	$ 209	$ 339	$ (130)	$ -
Out-of-budget projects				
Mechanical pond pumps and control valves - headquarters - This project will replace the mechanical system pond pumps and control valves to improve building heating and cooling during peak seasons.	$ -	$ 253	$ (253)	$ -
* **FlexStart and FlexRamp upgrade - combustion turbine Unit F** - This project will install upgrades to enable faster start times and greater ramp flexibility of combustion turbine Unit F.	$ -	$ 168	$ (168)	$ -
Radio upgrades - Rawhide - This project will upgrade the radio repeaters and include radio handsets in order to provide a priority interrupt feature and allow coverage in all areas of the plant in case of emergency situations.	$ -	$ 107	$ (107)	$ -
Delayed projects				
Distributed energy resources management system - This project will be delayed to allow additional time for scope development, the request for proposal process and vendor selection. *The below-budget funds will be requested to be carried over into 2025.*	$ 2,485	$ -	$ 2,485	$ 2,485
Circuit breakers replacement 592, 596 - Ault Substation WAPA - This project will be delayed due to a change in WAPA's schedule. *The below-budget funds will be requested to be carried over into 2025.*	$ 878	$ -	$ 878	$ 878
Circuit breakers replacement 492, 1092, 3124, 3224 - Ault Substation WAPA - This project will be delayed due to a change in WAPA's schedule. *The below-budget funds will be requested to be carried over into 2025.*	$ 752	$ -	$ 752	$ 752
Network replacement - headquarters - This project will be delayed due to internal resources shifting to higher priority projects. *The below-budget funds will be requested to be carried over into 2025.*	$ 345	$ -	$ 345	$ 345

Project ($ thousands)	2024 budget	Estimate	Favorable (unfavorable)	Carryover request
Canceled projects				
Transformer nitrogen generator - Rawhide Unit 1 - This project was canceled. The nitrogen bottles will be replaced as an operating expense rather than installation of a nitrogen generator which is more economical with the remaining life of Rawhide Unit 1.	$ 152	$ -	$ 152	$ -

* Project details or amounts have changed since last report.

** Project is new to the report.

Debt service expenditures, $0.1 million above budget

Debt service expenditures include principal and interest expense for power revenue bonds and for lease and subscription liabilities.

Debt service expenditures ($ thousands)	June Budget	June Actual		Favorable (unfavorable)		Year to date Budget	Year to date Actual		Favorable (unfavorable)		Annual budget
Total principal	$ 1,127	$ 1,129	◆	$ (2)	(0.2%)	$ 6,949	$ 6,979	◆	$ (30)	(0.4%)	$14,015
Power revenue bonds	1,117	1,117	◆	-	0.0%	6,446	6,446	◆	-	0.0%	13,146
Lease and subscription liabilities	10	12	■	(2)	(20.0%)	503	533	■	(30)	(6.0%)	869
Total interest expense	$ 366	$ 366	◆	$ -	0.0%	$ 2,459	$ 2,476	◆	$ (17)	(0.7%)	$ 4,667
Power revenue bonds	366	366	◆	-	0.0%	2,446	2,446	◆	-	0.0%	4,642
Lease and subscription liabilities	-	-	◆	-	0.0%	13	30	■	(17)	(130.8%)	25
Total debt service expenditures	$ 1,493	$ 1,495	◆	$ (2)	(0.1%)	$ 9,408	$ 9,455	◆	$ (47)	(0.5%)	$18,682

>2% ● Favorable | 2% to -2% ◆ At or near budget | <-2% ■ Unfavorable

The outstanding principal for Series JJ and KK represents debt associated with transmission assets ($93 million) and the Rawhide Energy Station ($20.1 million). Principal and interest payments are made June 1 and interest only payments are made Dec. 1. The table below shows current debt outstanding.

Series	Debt outstanding ($ thousands)	Par issued ($ thousands)	True interest cost	Maturity date	Callable date	Purpose
Series JJ - April 2016	$ 90,590	$ 147,230	2.2%	6/1/2036	6/1/2026	$60M new money for Rawhide & transmission projects & refund portion of Series HH ($13.7M NPV/12.9% savings)
Series KK - December 2020	22,490	$ 25,230	1.6%	6/1/2037	N/A*	Refund a portion of Series II ($6.5M NPV/27.6% savings)
Total par outstanding	113,080					
Unamortized bond premium	8,564					
Total revenue bonds outstanding	121,644					
Less: due within one year	(13,400)					
Total long-term debt, net	$ 108,244					

Fixed rate bond premium costs are amortized over the terms of the related bond issues.

*Series KK is subject to prior redemption, in whole or in part as selected by Platte River, on any date.

Projected results

The current estimate for year-end change in net position prior to deferring revenues ranges from $19.4 million to $47.5 million. Based on current assumptions, the expected change in net position prior to deferring revenues is $26.8 million. The table below compares these amounts to the annual budget and calculates the amount of deferred revenues under each scenario. This amount will vary as actual outcomes will differ from assumptions.

Projection	Change in net position before deferral: annual budget	Change in net position before deferral: expected	Variance ($)	Variance (%)	Projected deferred revenue (1)	Change in net position after deferred revenues
Low	$ 21.3	$ 19.4	$ (1.9)	(9%)	$ 12.3	$ 7.1
Expected	$ 21.3	$ 26.8	$ 5.5	26%	$ 19.7	$ 7.1
High	$ 21.3	$ 47.5	$ 26.2	123%	$ 40.6	$ 6.9

Amounts above are in millions

(1) The projected deferred revenue is based on maintaining the SFP metrics.

The expected projection includes overall lower operating expenses partially offset by lower operating revenues. The low and high projections are based on higher variability in revenues and expenses than the expected projection.

Operating revenues

- **Sales to the owner communities and sales for resale - long-term** are anticipated to end the year below budget. Owner community load and peak demand is expected to be below budget. Resource availability and market conditions and are also contributing to the lower anticipated calls on capacity contracts.
- **Sales for resale - short-term** are anticipated to end the year above budget due to stronger pricing expected in the bilateral market.
- **Deferred regulatory revenues** are anticipated to end the year above budget due to projected results being better than planned.

Operating expenses

- **Purchased power** is anticipated to be above budget at the end of the year as purchases replace baseload generation.
- **Fuel** is anticipated to be below budget at the end of the year as baseload generation is replaced with purchases.
- **Other operating expenses** are anticipated to end the year near budget.
- **Depreciation, amortization and accretion** are anticipated to end the year below budget due primarily to timing differences in budgeted and actual in service dates for new assets, partially offset by additional amortization for asset retirement obligations as cost estimates have increased and one Rawhide Energy Station impoundment is planned to be closed earlier than previously expected.

The results have uncertainty primarily because of the unpredictability of bilateral sales and the energy imbalance market. At this time, operating expenses and debt service expenditures are expected to end the year below budget. However, capital additions are expected to be above budget as discussed in the contingency appropriation section.

Contingency appropriation
$56 million reserved to board

At this time, capital additions are expected to be above budget at the end of the year. A budget contingency appropriation of approximately $11.4 million may be required to cover the additional expenditures in 2024. Staff will evaluate the budgetary results at the end of the year and apply the contingency appropriation accordingly.

Capital summary	$ millions	
2024 capital budget	$	53.2
2024 estimated capital expenses		56.3
Below budget variance	$	(3.1)
Estimated capital carryovers from 2024 to 2025		(8.3)
Estimated contingency transfer required	**$**	**(11.4)**

Other financial information

- **Deferred revenue and expense accounting policy** - This policy allows deferring revenues and expenses to reduce rate pressure and achieve rate smoothing during the portfolio transition to meet the Resource Diversification Policy goal. Staff will evaluate the financial statements at the end of the year and apply the policy accordingly, which would impact the change in net position.
- **Forced outage assistance agreement** - This agreement, which involved Platte River's Rawhide Unit 1 and Tri-State's Craig Unit 3, provided that each party supply replacement energy to the other party during a forced outage of either unit. The agreement was terminated on the expiration date of March 31, 2024. Upon termination of the agreement, the Energy Account Balance was reduced to zero and Tri-State was invoiced $1 million.
- **Accounting standard** - Platte River is subject to the updated recognition and measurement guidance for compensated absences under GASB 101 *Compensated Absences*. Results presented in the financial statements may not represent full implementation of the standard as staff evaluates the impact. Implementation will occur during 2024.
- **Excess coal sale** - Platte River sold $2.4 million of excess coal from the stockpile at the Craig Station in April resulting in no gain or loss.

Budget schedules

Schedule of revenues and expenditures, budget to actual

June 2024

Non-GAAP budgetary basis (in thousands)

	Month of June		Favorable
	Budget	**Actual**	(unfavorable)
Revenues			
Operating revenues			
Sales to owner communities	$ 21,778	**$ 21,268**	$ (510)
Sales for resale - long-term	1,653	**1,698**	45
Sales for resale - short-term	4,024	**4,892**	868
Wheeling	692	**1,039**	347
Total operating revenues	28,147	**28,897**	750
Other revenues			
Interest income[1]	947	**958**	11
Other income	21	**18**	(3)
Total other revenues	968	**976**	8
Total revenues	$ 29,115	**$ 29,873**	$ 758
Expenditures			
Operating expenses			
Purchased power	$ 4,786	**$ 5,479**	$ (693)
Fuel	4,383	**3,464**	919
Production	4,305	**4,459**	(154)
Transmission	1,844	**1,633**	211
Administrative and general	3,187	**2,727**	460
Distributed energy resources	971	**855**	116
Total operating expenses	19,476	**18,617**	859
Capital additions			
Production	1,464	**1,919**	(455)
Transmission	1,968	**4,555**	(2,587)
General	2,194	**1,238**	956
Asset retirement obligations	78	**49**	29
Total capital additions	5,704	**7,761**	(2,057)
Debt service expenditures			
Principal	1,127	**1,129**	(2)
Interest expense	366	**366**	-
Total debt service expenditures	1,493	**1,495**	(2)
Total expenditures	$ 26,673	**$ 27,873**	$ (1,200)
Revenues less expenditures	$ 2,442	**$ 2,000**	$ (442)

[1] Excludes unrealized holding gains and losses on investments.

Schedule of revenues and expenditures, budget to actual

June 2024 year-to-date

Non-GAAP budgetary basis (in thousands)

	June year to date		Favorable	Annual
	Budget	**Actual**	(unfavorable)	budget
Revenues				
Operating revenues				
Sales to owner communities	$ 112,183	**$ 109,849**	$ (2,334)	$ 235,737
Sales for resale - long-term	9,702	**8,165**	(1,537)	20,086
Sales for resale - short-term	15,137	**15,594**	457	36,356
Wheeling	4,571	**4,515**	(56)	8,942
Total operating revenues	141,593	**138,123**	(3,470)	301,121
Other revenues				
Interest income[1]	5,384	**5,577**	193	11,569
Other income	274	**292**	18	282
Total other revenues	5,658	**5,869**	211	11,851
Total revenues	$ 147,251	**$ 143,992**	$ (3,259)	$ 312,972
Expenditures				
Operating expenses				
Purchased power	$ 31,627	**$ 30,070**	$ 1,557	$ 63,776
Fuel	23,684	**18,774**	4,910	51,119
Production	29,700	**26,719**	2,981	55,842
Transmission	11,172	**10,205**	967	21,412
Administrative and general	18,663	**18,534**	129	36,863
Distributed energy resources	6,033	**5,072**	961	13,664
Total operating expenses	120,879	**109,374**	11,505	242,676
Capital additions				
Production	8,241	**3,844**	4,397	12,363
Transmission	16,792	**14,628**	2,164	21,957
General	12,001	**5,819**	6,182	17,979
Asset retirement obligations	467	**119**	348	933
Total capital additions	37,501	**24,410**	13,091	53,232
Debt service expenditures				
Principal	6,949	**6,979**	(30)	14,015
Interest expense	2,459	**2,476**	(17)	4,667
Total debt service expenditures	9,408	**9,455**	(47)	18,682
Total expenditures	$ 167,788	**$ 143,239**	$ 24,549	$ 314,590
Contingency reserved to board	-	**-**	-	56,000
Total expenditures and contingency	$ 167,788	**$ 143,239**	$ 24,549	$ 370,590
Revenues less expenditures and contingency	$ (20,537)	**$ 753**	$ 21,290	$ (57,618)

[1] Excludes unrealized holding gains and losses on investments.

Financial statements

Statements of net position

Unaudited (in thousands)

	June 30 2024	June 30 2023
Assets		
Electric utility plant, at original cost		
Land and land rights	**$ 19,446**	$ 19,446
Plant and equipment in service	**1,489,406**	1,469,316
Less: accumulated depreciation and amortization	**(996,153)**	(955,907)
Plant in service, net	**512,699**	532,855
Construction work in progress	**47,688**	29,040
Total electric utility plant	**560,387**	561,895
Special funds and investments		
Restricted funds and investments	**13,629**	13,294
Dedicated funds and investments	**171,181**	163,613
Total special funds and investments	**184,810**	176,907
Current assets		
Cash and cash equivalents	**58,709**	40,106
Other temporary investments	**48,125**	48,757
Accounts receivable - owner communities	**21,232**	18,667
Accounts receivable - other	**7,838**	8,969
Fuel inventory, at last-in, first-out cost	**20,419**	13,368
Materials and supplies inventory, at average cost	**18,127**	16,711
Prepayments and other assets	**8,597**	8,951
Total current assets	**183,047**	155,529
Noncurrent assets		
Regulatory assets	**130,616**	128,503
Other long-term assets	**8,615**	7,123
Total noncurrent assets	**139,231**	135,626
Total assets	**1,067,475**	1,029,957
Deferred outflows of resources		
Deferred loss on debt refundings	**1,938**	2,678
Pension deferrals	**9,787**	14,849
Asset retirement obligations	**26,496**	26,474
Total deferred outflows of resources	**38,221**	44,001
Liabilities		
Noncurrent liabilities		
Long-term debt, net	**108,244**	123,850
Net pension liability	**28,274**	30,520
Other long-term obligations	**93,406**	94,295
Lease and subscription liabilities	**433**	916
Asset retirement obligations	**37,209**	34,255
Other liabilities and credits	**12,646**	7,688
Total noncurrent liabilities	**280,212**	291,524
Current liabilities		
Current maturities of long-term debt	**13,400**	12,790
Current portion of other long-term obligations	**889**	889
Current portion of lease and subscription liabilities	**668**	338
Current portion of asset retirement obligations	**933**	1,547
Accounts payable	**19,412**	17,118
Accrued interest	**366**	416
Accrued liabilities and other	**6,631**	5,089
Total current liabilities	**42,299**	38,187
Total liabilities	**322,511**	329,711
Deferred inflows of resources		
Deferred gain on debt refundings	**106**	119
Regulatory credits	**103,912**	73,633
Pension deferrals	**-**	287
Lease deferrals	**704**	852
Total deferred inflows of resources	**104,722**	74,891
Net position		
Net investment in capital assets	**428,075**	410,000
Restricted	**13,263**	12,878
Unrestricted	**237,125**	246,478
Total net position	**$ 678,463**	$ 669,356

Note: Certain previously stated line items have been updated or reclassified to conform with final audited financial statements including restatement of prior year where applicable.

Statements of revenues, expenses and changes in net position

Unaudited (in thousands)

	Month of June	June year to date 2024	June year to date 2023
Operating revenues			
Sales to owner communities	**$ 21,268**	**$ 109,849**	$ 104,324
Sales for resale	**6,590**	**23,759**	24,165
Wheeling	**1,039**	**4,515**	4,760
Total operating revenues	**28,897**	**138,123**	133,249
Operating expenses			
Purchased power	**5,479**	**30,070**	27,570
Fuel	**3,464**	**18,774**	20,533
Operations and maintenance	**6,037**	**37,160**	38,692
Administrative and general	**2,725**	**18,869**	14,707
Distributed energy resources	**857**	**5,137**	3,526
Depreciation, amortization and accretion	**3,662**	**21,127**	19,528
Total operating expenses	**22,224**	**131,137**	124,556
Operating income	**6,673**	**6,986**	8,693
Nonoperating revenues (expenses)			
Interest income	**924**	**5,468**	3,264
Other income	**18**	**292**	274
Interest expense	**(366)**	**(2,476)**	(2,736)
Amortization of bond financing costs	**110**	**664**	738
Net increase in fair value of investments	**494**	**344**	1,200
Total nonoperating revenues (expenses)	**1,180**	**4,292**	2,740
Change in net position	**7,853**	**11,278**	11,433
Net position at beginning of period, as previously reported	**670,610**	**667,185**	657,923
Net position at end of period	**$ 678,463**	**$ 678,463**	$ 669,356

Note: Certain previously stated line items have been updated or reclassified to conform with final audited financial statements including restatement of prior year where applicable.

Statements of cash flows

Unaudited (in thousands)

	Month of June	June year to date 2024	June year to date 2023
Cash flows from operating activities			
Receipts from customers	$ 20,674	$ 132,646	$ 134,770
Payments for operating goods and services	(10,166)	(80,849)	(83,184)
Payments for employee services	(5,131)	(30,842)	(25,723)
Net cash provided by operating activities	5,377	20,955	25,863
Cash flows from capital and related financing activities			
Additions to electric utility plant	(5,080)	(21,675)	(8,678)
Payments from accounts payable incurred for electric utility plant additions	(1,241)	(2,136)	(3,493)
Proceeds from disposal of electric utility plant	-	17	55
Principal payments on long-term debt	(12,790)	(12,790)	(12,215)
Interest payments on long-term debt	(2,497)	(2,497)	(2,784)
Payments related to other long-term obligations	-	(5,390)	(4,145)
Payments on lease and subscription liabilities	(12)	(563)	-
Net cash used in capital and related financing activities	(21,620)	(45,034)	(31,260)
Cash flows from investing activities			
Purchases and sales of temporary and restricted investments, net	16,720	6,223	(6,040)
Interest and other income, including realized gains and losses	971	5,845	3,526
Net cash provided by/(used in) investing activities	17,691	12,068	(2,514)
Increase/(decrease) in cash and cash equivalents	1,448	(12,011)	(7,911)
Balance at beginning of period in cash and cash equivalents	57,261	70,720	48,017
Balance at end of period in cash and cash equivalents	$ 58,709	$ 58,709	$ 40,106
Reconciliation of net operating income to net cash provided by operating activities			
Operating income	$ 6,673	$ 6,986	$ 8,693
Adjustments to reconcile operating income to net cash provided by operating activities			
Depreciation	3,464	20,569	20,092
Amortization	(403)	(2,416)	(2,818)
Operating expenses relating to other long-term obligations	241	1,444	1,444
Changes in assets and liabilities that provided/(used) cash			
Accounts receivable	(8,223)	(4,683)	3,191
Fuel and materials and supplies inventories	(434)	(916)	(4,146)
Prepayments and other assets	41	(2,986)	(3,174)
Regulatory assets	96	578	66
Deferred outflows of resources	475	(125)	(1,158)
Accounts payable	2,541	(5,713)	(4,074)
Asset retirement obligations	(49)	2,226	2,517
Other liabilities	506	3,398	3,124
Deferred inflows of resources	449	2,593	2,106
Net cash provided by operating activities	$ 5,377	$ 20,955	$ 25,863
Noncash capital and related financing activities			
Additions of electric utility plant through incurrence of accounts payable	2,632	2,632	326
Additions of electric utility plant through leasing and subscription	-	132	-
Amortization of regulatory asset (debt issuance costs)	6	37	40
Amortization of bond premiums, deferred loss and deferred gain on refundings	(117)	(701)	(778)

Note: Certain previously stated line items have been updated or reclassified to conform with final audited financial statements including restatement of prior year where applicable.

Schedule of net revenues for bond service and fixed obligations

Unaudited (in thousands)

Bond service coverage	Month of June	June year to date 2024	June year to date 2023
Net revenues			
Operating revenues	$ 28,897	$ 138,123	$ 133,249
Operations and maintenance expenses, excluding depreciation, amortization and accretion	18,562	110,010	105,028
Net operating revenues	10,335	28,113	28,221
Plus interest income on bond accounts and other income [1]	976	5,869	3,549
Net revenues before rate stabilization	11,311	33,982	31,770
Rate stabilization			
Deposits	-	-	-
Withdrawals	-	-	-
Total net revenues	$ 11,311	$ 33,982	$ 31,770
Bond service			
Power revenue bonds	$ 1,483	$ 8,892	$ 8,892
Coverage			
Bond service coverage ratio	7.63	3.82	3.57

Fixed obligation charge coverage	Month of June	June year to date 2024	June year to date 2023
Total net revenues, above	$ 11,311	$ 33,982	$ 31,770
Fixed obligation charges included in operating expenses [2]	1,660	10,271	10,481
Adjusted net revenues before fixed obligation charges	$ 12,971	$ 44,253	$ 42,251
Fixed obligation charges			
Power revenue bonds, above	$ 1,483	$ 8,892	$ 8,892
Fixed obligation charges [2][3]	1,672	10,835	10,481
Total fixed obligation charges	$ 3,155	$ 19,727	$ 19,373
Coverage			
Fixed obligation charge coverage ratio	4.11	2.24	2.18

[1] Excludes unrealized holding gains and losses on investments.

[2] Fixed obligation charges included in operating expenses are debt-like obligation payments including those for demand or capacity on contracted assets and any debt service associated with off-balance sheet obligations.

[3] This value also includes lease and subscription debt service expenditures which are not included in operating expenses.

Note: Certain previously stated line items have been updated to accord with the Strategic Financial Plan as adopted by the board in December 2023

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

General management report

May and June 2024

Business Strategies

Communications, marketing and external affairs

During May and June, communications, marketing and external affairs staff:

Communications

- Published the fourth in a series of public education articles about Platte River's path to a clean, reliable energy future, focusing on how Platte River is proactively managing its clean energy transition costs.
- Distributed press releases announcing the request for proposals (RFP) for virtual power plant software; results from the NoCo Time Trials; and recognition from the American Public Power Association for the James D. Donovan Individual Achievement Award, presented to Jason Frisbie, and for the Sue Kelly Community Service Award, accepted by Eddie Gutiérrez.
- Produced a video commemorating the 40th anniversary of Rawhide Energy Station.
- Focused social media coverage on community engagement, Rawhide's 40th anniversary, National Safety Month, power generation and noncarbon future goals.

Community relations

- Presented the annual Roy J. Rohla Memorial Scholarship to Fossil Ridge High School graduate Kary Fang during Platte River's June business meeting. Fang will attend UCLA in the fall and pursue a degree in electrical engineering.
- Hosted the fifth annual NoCo Time Trials at Platte River's headquarters, welcoming over 90 middle school student teams to compete in the solar and battery model car competition. In addition to awards for best design and fastest solar and battery cars, Platte River presented scholarships to students committed to pursuing higher education in STEM-related fields.
- Hosted a Bike to Work Day breakfast station, engaging with over 500 community members, in partnership with Forney Industries.
- Sponsored and attended several chambers of commerce events, including the Longmont Chamber of Commerce Golf Tournament, the Loveland Chamber of Commerce Golf Tournament and the Fort Collins Chamber of Commerce State of Business event, where Jason Frisbie provided remarks about Platte River's efforts to achieve the owner communities' shared energy goals.

Marketing

- Launched an omnichannel marketing campaign that seeks to educate Platte River's owner communities on progress toward our 2030 goal, specifically our transition from coal to renewable energy, using dispatchable resources to support reliability. The campaign will run through the summer and into early fall.

External affairs

- Conducted 2024 Integrated Resource Plan presentations for:
    - Longmont Chamber of Commerce Board of Directors
    - Larimer County Environmental and Science Advisory Board
    - Longmont City Council
    - Loveland Chamber of Commerce
- Conducted Rawhide Energy Station tours for:
    - Larimer County Commissioners (individually for each commissioner)
    - Estes Park Mayor Gary Hall, Fort Collins Mayor Jeni Arndt and former Windsor Mayor Paul Rennemeyer
- Attended:
    - Colorado Association of Municipal Utilities spring meeting in Lamar, CO
    - City of Loveland Sustainability Task Force's kickoff meeting
    - Colorado Municipal League conference in Loveland, CO

Grants

- Submitted Grid Resilience and Innovation Partnerships grant application, together with all four owner communities for $33,429,633, with a $50,316,171 cost share commitment.
- Received $350,000 award notification from Colorado Department of Local Affairs and the Department of Energy for the battery project in Estes Park with a $350,000 cost share commitment; now waiting for the grant contract.

Human resources

Human resources leadership initiated a department reorganization to ensure business continuity, maintain seamless operations and prevent disruptions, and to enable all human resources functions continue to support the organization effectively. The benefits of the reorganization include eliminating siloed work, providing growth and development opportunities, supporting Platte River growth and change, and enhancing strategic work and knowledge.

In collaboration with the internal audit department, human resources began a payroll advisory project to enhance payroll operations. The goals of the project include evaluating and improving payroll processes and benchmarking, creating formal payroll documentation, and improving the effectiveness and efficiency of the payroll function.

Human resources staff helped host local high school students who take part in the Pathways in Technology Early Colleges High School program, giving them insights into available Platte River job opportunities for high school graduates. This engagement is part of Platte River's broader strategy to connect with the community and inspire young talent to consider careers within the organization.

Safety

- Platte River safety staff coordinated and hosted guest speakers at headquarters and Rawhide, who covered the topics of emotional resilience and dealing with stress, and the importance of being mindful of your safety.
- Platte River safety staff initiated continual visits to the Laporte Substation and the new Severance Substation construction site to evaluate how the safety team can better support the activities taking place at both locations.

Injury statistics	2022 year end	2023 year end	YTD through June 2023	YTD through June 2024
Recordable injury rate	1.25	1.98	2.98	2.11
DART	0.83	0.39	0.00	0.00
Lost time rate	0.00	0.39	0.00	0.00

Platte River sustained one recordable injury in May, and zero recordable injuries in June.

Emergency response team

- One emergency response team (ERT) member successfully completed the AIMS Community College Colorado State Firefighter One certification course.
- The ERT conducted five on-site trainings at Rawhide.
- Four team members renewed their Colorado state Firefighter Certifications.
- Hosted the Northern Colorado Bomb Squad for a site visit and quarterly training at Rawhide.
- Hosted three vendors to try out new rechargeable extrication tools intended to replace the old hydraulic units that are beyond end-of-service life.
- Assisted county law enforcement and emergency medical services with a non-employee medical situation on the premises.

Financial

2025 budget update

Platte River's 2025 budget process is well underway. We continually look for ways to improve the existing process and to improve work planning and budgeting by better aligning scope, schedules and available resources. Finance staff held review sessions with management in June and July, preparing to submit the preliminary budget to the board in September.

Below is a condensed schedule to show the overall budget process.

March to May	Kickoff presentations and preparation of budget details by departments
June	Data compilation, division budget reviews and reporting
July	Senior leadership and GM/CEO budget review
August	Refine budget and document preparation
September	Budget work session with board
October	Public hearing and board review of budget modifications
November	Prepare final budget document
December	Final budget review with board and request adoption

2024 budget award

Platte River received the Government Finance Officers Association (GFOA) Distinguished Budget Presentation Award for the 2024 Strategic Budget. This is our fifth consecutive year of receiving this award. The budget document was evaluated for compliance with the National Advisory Council on State and Local Budgeting guidelines as well as GFOA's best practice criteria and has been recognized as a very high-quality document that excels as a policy document and communication tool.

Clean energy transition and integration

Distributed energy solutions

During May and June, the Distributed Energy Solutions team continued program evolution to further support our energy transition by launching multiple new features for residential and commercial customers. Some features include electric panel upgrade incentives and multiple upgrade bonus incentives for residential customers, along with fleet electrification study incentives and building operator certificate training for commercial customers. Efficiency Works will implement and manage programs, so that all five entities can achieve common objectives and their individual goals effectively.

As staff look to the future and support the utility energy transition, current key department achievements year to date include the following:

$3.5 M	**2,858**	**157**	**1,966**
Invested in our communities YTD	**MTCO2e saved YTD**	**Income Qualifed (IQ) upgrades YTD**	**Customer participation YTD**
$11.1M annual budget from Platte River and Owner Communities excluding staff	Carbon reductions from customer upgrades based on regional electric generation emission rates	Residential IQ customers served with upgrades, advising and assessments	Commerical and residential customers served with incentives, advising and assessments
Investment	**Carbon**	**Equity**	**Customers**

The table above lists programming impacts year to date within our owner communities. Additional detailed department achievements during May and June include:

- By the end of May 2024, while partnering with Energy Outreach Colorado, the Efficiency Works Homes team exceeded the total number of income qualified residential customers served with home upgrades compared to all of the previous year.
- The Efficiency Works Store on the new Enervee platform will go live on July 1, 2024. The new online platform will showcase thousands of products to connect owner-community customers to the right products so they can use their energy more effectively. The new platform will provide better consumer education and shopping choices. Anyone can take advantage of the information provided and the price comparison when shopping, but qualified buyers (utility customers of the owner communities) can get instant rebates on some products through the site.

5,741	**MWh saved** 5,442 MWh savings in progress
525	**KW peak demand reduced** 207 KW peak reduction in progress
786	**MWh electrified**
78,108	**natural gas therms saved**
1,837,725	**water gallons saved**
40	**events and trainings**
2,721	**local students engaged**

Program metrics (YTD)

- On July 1, the Efficiency Works Business team will launch a new offering with incentives for commercial properties to complete in-depth fleet electrification studies for their facilities. This will help commercial customers complete long-term fleet electrification planning while giving the distribution utilities critical service upgrade information well in advance.
- As leaders in the utility transition conversation, five distributed energy solutions staff members were selected to share best practices of customer energy programs with utilities from across the country at the 18th Rocky Mountain Utility Exchange scheduled for September 23-26 in Vail, Colorado.

Through June 2024, Efficiency Works programs have invested $3.5 million, excluding staff costs, in providing services for energy efficiency, building electrification, water savings and electric vehicles. Currently, Platte River has budgeted $9.5 million for these program offerings, with an additional $1.6 million available through directive funding provided by the owner communities. Additional directive funding is possible as the year progresses.

Digital departments

The digital department encompasses various domains, including enterprise infrastructure, enterprise applications, operational technology, telecommunications and fiber optics, client technology and security, and information and cyber governance.

The following are updates on key in-process and completed department initiatives and activities.

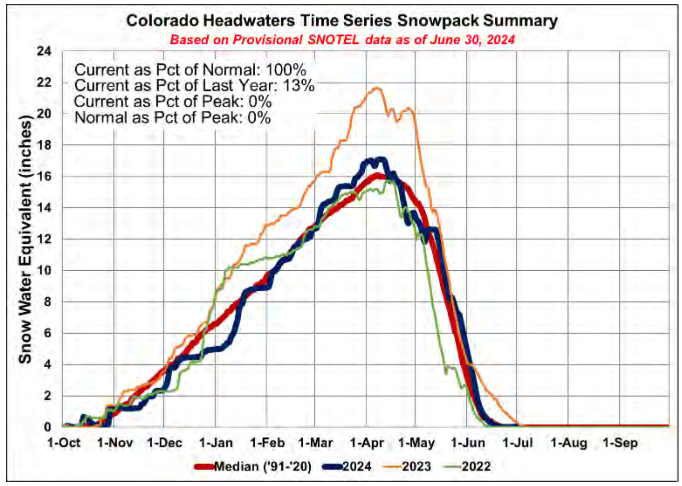
Strategic Initiatives

- Oracle Cloud Fusion Enterprise Resource Planning system implementation
  - On May 20, staff successfully completed System Integration Testing, which focuses on testing the integrations between Oracle modules, Oracle systems, and other systems such as the HR system. Issues identified during the testing have been resolved. The success of this testing was critical for moving forward with user acceptance testing, which is set to begin in July.
  - During May and June, staff completed the overall training plan, with some departments having completed their training materials and scheduling training sessions for end users. Numerous sessions will be devoted to modules that support Platte River business processes.
  - The initial security model to be implemented for go-live has been finalized and approved. The enterprise risk management and audit teams made significant contributions.
  - As of the end of June, the project budget status is green and it is expected to be under budget.
  - As of mid-June, the project schedule status was green.
- OSI Energy Management System implementation
  - The schedule for go-live has now slipped to late January 2025 (as of the latest update to the project plan) due to how long it is taking for the vendor to remediate issues found during factory acceptance testing. This will push back the point-to-point field testing, which in turn impacts the go-live date because it is part of the critical path.
  - The status for the Critical Infrastructure Protection compliance work has changed from red to yellow due to the number of tasks the infrastructure team was able to complete through the end of June.

Operations

Fuels and water

The 2024 spring runoff ended in June and the overall snowpack season can generally be described as "normal." As shown in the graph, this marks the third straight year of snowpack at or above normal and Lake Granby filling to capacity. The full reservoir also prevented the Windy Gap Project from pumping, for the second year in a row, due to a lack of available storage. But this means that water supplies in Northern Colorado are good heading into summer. Platte River staff were able to secure sufficient Colorado-Big Thompson rental supplies for normal Reuse Plan operations throughout the remainder of the water year.



At the Chimney Hollow Reservoir site, the summer season has been ideal for construction progress. After filling a low spot in the bedrock at the west end of the dam foundation, asphalt core placements are now one continuous run over 3,000 feet long and the dam is more than 220 feet tall. The valve house building is also taking shape, as construction of the steel superstructure is underway. At the south end of the reservoir, the saddle dam is beginning to rise from the foundation plinth that was prepared last year (see photo). This traditional clay core dam will be 40 feet tall and 1,250 feet long and will be completed within the year. The main dam is also expected to reach its final height this year, and the overall project is scheduled for completion in the fall of 2025.

Follow up items

American Public Power Association National Conference

Four board members, one utility director and Platte River senior staff attended the American Public Power Association National Conference in San Diego, California this past June. This year's conference focused on changing policy, technology, and how lifestyles are reshaping the energy industry and how they impact our owner communities. As mentioned in the Business Strategies section, staff received two awards and recognition at the conference.