Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Board of directors regular meeting

2000 E. Horsetooth Road, Fort Collins, CO 80525
Thursday, May 30, 2024, 9 a.m.

Call to order

1. Consent agenda — *Motion to approve*
    a. Minutes of the regular meeting of April 25, 2024
    b. Revision to wholesale transmission service tariff (WT-25) — *Resolution 04-24*

Public comment

Board action items

2. Executive session — *Motion (2/3 vote required)*
    a. Renewable resource negotiations
    b. Reconvene regular session
3. Support for a virtual power plant — *Resolution 05-24*

Management presentations

4. Draft 2024 Integrated Resource Plan
5. Average wholesale rate projections and 2025 tariff schedule charges

Management reports

6. Rawhide Just Transition Plan
7. Water Resources Reference Document update

Monthly informational reports - April

8. Legal, environmental and compliance report
9. Resource diversification report
10. Operating report
11. Financial report
12. General management report

Strategic discussions

Adjournment

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2024 board meeting planning calendar

Updated May 22, 2024

June 7-12, 2024

APPA National Conference (San Diego, CA)

July 25, 2024

Board action items	Management presentations	Management reports	Monthly informational reports
2024 Integrated Resource Plan	Fiber management intergovernmental agreement amendment	Legislative session recap	Q2 performance dashboard
Rawhide Just Transition Plan	One-year WEIS participation (April 1, 2023 – March 31, 2024) & SPP RTO West update		Legal, environmental and compliance report
	Unit F upgrade update		Resource diversification report
	Rawhide Just Transition Plan		Operating report
Committee report			Financial report
Defined Benefit committee report			General management report

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Aug. 29, 2024

Defined Benefit Plan committee meeting

Board action items	Management presentations	Management reports	Monthly informational reports
Fiber management intergovernmental agreement amendment			Legal, environmental and compliance report
			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		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: 5/22/2024

To: Board of directors

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

Subject: Consent agenda – May

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

Attachments

- Minutes of the regular meeting of April 25, 2024
- Revision to wholesale transmission service tariff (Tariff WT-25)

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Regular meeting minutes of the board of directors

2000 E. Horsetooth Road, Fort Collins, CO
Thursday, April 25, 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[1] and David Hornbacher
Representing Loveland: Mayor Jacki Marsh and Kevin Gertig

Platte River staff

Jason Frisbie (general manager/CEO)
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)
Jennifer Hammitt (director, legal affairs)
Esther Velasquez (sr. executive assistant)
Josh Pinsky (IT service desk technician II)
Mitch Tomaier (IT systems administrator)
Kylie Kwiatt (administrative assistant II)
Shelley Nywall (director, finance)
Javier Camacho (director, public/external affairs, strategic communications/social marketing)
Kendal Perez (manager, strategic communications and community relations)
Leigh Gibson (sr. external affairs specialist)
Bryce Brady (manager, distributed energy solutions)
Paul Davis (manager, distributed energy resources)
Chris Fields (sr. fuels and water resources engineer)
Kristin Turner (sr. manager, accounting)
Jason Harris (sr. manager, financial reporting and budgeting)
Wade Hancock (sr. manager, financial planning and rates)
Alaina Hawley (sr. supervisor, distributed energy solutions)

Guests

Chris Telli (FORVIS, LLP)
Anna Thigpen (FORVIS, LLP)

[1] Left the meeting at 12:08 p.m.

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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.

Chair Gertig welcomed everyone. Jason Frisbie, general manager and chief executive officer, introduced Esther Velasquez, senior executive assistant, and Kylie Kwiatt, administrative assistant II. Melie Vincent, chief operating officer of generation, transmission, and markets, introduced the staff presenting at the meeting. Dave Smalley, chief financial officer and deputy general manager, introduced Chris Telli and Anna Thigpen of FORVIS, LLP, who would present the 2023 financial audit later in the meeting. Director Bergsten introduced new board member and mayor Gary Hall from Estes Park, and everyone welcomed him to the Platte River Power Authority Board of Directors.

1. Board secretary delegation of duties

Mr. Frisbie gave a brief overview of the delegation of duties outlined in the Organic Contract and Fiscal Resolution. Mr. Frisbie noted that for the first time in fifty years, both the board secretary and assistant secretary were not present at the meeting to maintain the official records of Platte River, including all resolutions and the minutes of meetings of the board of directors. He asked the board to accept delegating those duties to Esther Velasquez and Jennifer Hammitt, director, legal affairs, for the April 25, 2024, meeting.

Director Hall moved to accept the delegation of board secretary and assistant secretary duties. Director Marsh seconded. The motion carried 8-0.

Action items

2. Consent agenda

a. Approval of the regular meeting minutes of March 28, 2024

Director Marsh moved to approve the consent agenda as presented; Director Hornbacher 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. Two members of the public addressed the board.

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Board action items

3. 2023 FORVIS financial audit report

Dave Smalley introduced Chris Telli and Anna Thigpen of FORVIS, LLP, to present the 2023 financial audit report.

Mr. Telli provided an overview of the auditors' clean, unmodified opinion of April 8, 2024. In 2023, Platte River adopted a new accounting standard: Governmental Accounting Standards Board Statement No. 96 (GASB 96), *Subscription-Based Information Technology Arrangements*.

Ms. Thigpen provided further details on the audit results. Ms. Thigpen mentioned one audit adjustment, a reclassification in the footnote disclosure for the deferred outflow of resources accounts related to pension, which did not affect the financial statements. There will be a new GASB Statement No. 101, *Compensated Absences*, implemented for the 2024 fiscal year. Ms. Thigpen reviewed the financial statements and pointed out the Statements of Net Position were restated for 2022 due to implementing GASB 96 in 2023.

Director Bergsten and Mr. Telli thanked FORVIS and Platte River staff for their efforts to implement the new standard.

Mr. Telli thanked management, Platte River staff, and board members for their long-term commitment.

Director Bergsten moved to approve the 2023 FORVIS financial audit report as presented; Director Peck seconded. The motion carried 8-0.

4. Acceptance of 2023 annual report

Eddie Gutiérrez, chief strategy officer, provided an overview of the 2023 Annual Report, which contains the FORVIS, LLP independent auditor report and 2023 financial statements. The report highlights the success of our teams through an extraordinary year at Platte River and celebrates Platte River's fiftieth anniversary in service to our owner communities.

Director Hornbacher moved to accept the 2023 Annual Report as presented; Director Bergsten seconded. The motion carried 8-0.

Management presentations

5. Evolution of distributed energy solutions (presenter: Bryce Brady)

Raj Singam Setti, chief operating officer, innovation and resource strategy integration, introduced Bryce Brady, manager of distributed energy solutions, and remarked that the following presentation would continue the virtual power plant (VPP) series. The presentation outlined how programs are evolving into electrification distributed energy solutions for powering the VPP.

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Mr. Brady presented Platte River's energy transition and how program models are changing to meet customers' new needs and those of the utility. He explained how Platte River has seen significant changes in customer behavior over the past few years. To meet these needs, Mr. Brady outlined how Platte River is developing a virtual power plant to provide flexible, dispatchable load to support reliability, reduce carbon, provide equity, and support electric vehicles with collaboration throughout the region and with its owner communities to provide trusted customer support, guidance, and resources to enable effective energy use across the technology spectrum of distributed energy resources.

Director Bergsten commented that the Efficiency Works™ customer energy programs showed how the owner communities and Platte River came together to create an exceptional resource in the region. He added the information presented emphasizes how energy efficiency is no longer the focus, and Platte River is making great progress in meeting customers' shifting needs. Director Arndt thanked staff for focusing on customers' viewpoints and said that electric vehicle charging is an area where regional collaboration may be beneficial. Director Hornbacher appreciated the balance of detail provided, suggested a chart would be visually helpful, and is pleased Platte River is reaching out to students who will be the upcoming workforce as VPP capabilities roll out. Director Hall supported the transformative direction. Chair Gertig complimented the presentation and said continued improvements in building efficiency and educating consumers while progressing toward electrification will provide stability.

6. VPP series: Virtual power plant (presenter: Paul Davis)

Mr. Singam Setti introduced Paul Davis, manager of distributed energy resources, and noted that his presentation would also continue the VPP series. Mr. Davis's presentation focused on collaboration efforts among the owner communities and Platte River staff and the next steps moving forward.

Mr. Davis described what a VPP is and how it may be able to deliver a portion of the dispatchable capacity required to support a reliable, financially sustainable, decarbonized electric system through both customer and utility distributed energy resources (DERs). He covered the most effective way to dispatch those resources and manage associated costs while balancing the benefits, challenges, and opportunities for the VPP to reduce load. Mr. Davis stated that software-based platforms, such as AutoGrid, may facilitate and accelerate the deployment of the VPP.

Director Bergsten asked if the DER aggregators are active in the energy markets. Mr. Davis responded that some of them are active in other markets. Discussion ensued among directors and staff on how DERs would integrate within the system and interact in the market without disrupting the distribution system.

Mr. Davis reminded the board that Platte River hired a consultant in 2022 to help develop a roadmap and assess gaps by looking at drivers, goals, desired outcomes, challenges, benefits, services, and functional capabilities and identifying technology. Director Marr asked how many electric vehicles (EVs) would need to participate in each owner community to beneficially contribute to the VPP potential achievable megawatt availability. Mr. Davis responded that 50,000 total

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devices need to be enrolled in the DER programs; of those, about 40,000 will need to be EVs by 2030.

Mr. Davis discussed a draft resolution in support of a virtual power plant for consideration at the May board meeting and welcomed any feedback. He also summarized the next steps and predicted timeline.

Director Hall asked about the scope of adding staff, office space and computer systems needed to support a VPP. Mr. Davis responded that a VPP will require staff but not necessarily additional positions; this will be determined as the five entities continue to evaluate the systems. Mr. Singam Setti added that the data science aspect and DER assets will need to be considered throughout the evaluation phase. Discussion ensued among directors and staff regarding technology roadmaps, implementation of customer devices and integrating multiple systems.

10-minute break (11:10 - 11:20 a.m.)

7. Water and Chimney Hollow Reservoir update (presenter: Chris Fields)

Dr. Chris Fields, senior fuels and water resources engineer, summarized current water supply conditions and reviewed construction progress at Chimney Hollow Reservoir.

Dr. Fields showed a brief video of the project and mentioned that Northern Water offers participant tours. Director Hall asked if the reservoir is for storage only or if there will be energy generated also. Dr. Fields noted the participants explored an energy generation project early in the reservoir planning phase, but the numbers did not support on-site generation. Director Bergsten asked if in future years when Windy Gap does not pump water, will Platte River still need CB-T water for operations. Dr. Fields responded that staff is currently evaluating that and all participants would like to continue to use the in-lieu program. Discussion ensued among directors and staff on the value of water to the owner communities and project tours.

Dr. Fields also previewed the updated Platte River Water Resources Reference document, which will be available for the board's review in the May board packet.

8. Integrated Resources Plan community engagement update (presenter: Eddie Gutiérrez)

Mr. Gutiérrez gave an overview of Platte River's Integrated Resources Plan (IRP) community engagement efforts. He stated that Platte River continues to meet with various community groups to gather feedback and engage communities about Platte River's energy resource transition. He also previewed the scheduled meetings in all four owner communities, beginning in June.

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Management reports

9. Wholesale rate projections (presenter: Dave Smalley)

Mr. Smalley explained how Platte River provides proposed wholesale rate projections to the owner communities for budgeting processes and previewed the proposed rate increase for 2025. Staff will provide further details about rate drivers at the May board meeting.

Chair Gertig thanked staff for proactively working with the owner community finance teams. Director Marr asked how the deferred revenue and expense policy will influence rates in the near and long term. Mr. Smalley explained the policy concentrates on the energy transition period, not long-term strategy. Right now Platte River is focused on accumulating the deferred revenues to offset the rate pressures in 2027, 2028 and 2029. Discussions ensued among directors and staff about replacing generation units with renewable energy, costs associated with new resources, how they impact rates and rate forecasting, and cost-saving measures.

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

Mr. Singam Setti previewed the first six chapters of the draft 2024 Integrated Resource Plan (IRP). He mentioned that staff will present the results, review each portfolio strategy in more detail, along with a risk-adjusted portfolio to address current market dynamics, and discuss a three-year action plan during the May board meeting.

Director Peck asked how the new rules from the U.S. Environmental Protection Agency (EPA), which call for 90% decarbonization by 2032, will affect Platte River. Mr. Frisbie responded the legal team is reviewing the ruling and has covered it in more detail in the legal report under agenda item 12. Mr. Singam Setti explained wind and solar are at the core of decarbonizing the portfolio, along with dispatchable capacity (storage, virtual power plant, and aeroderivative turbines) that will be available to manage the intermittent wind and solar resources as needed for reliability.

Monthly informational reports for March

11. Q1 performance dashboard (presenter: Jason Frisbie)

Mr. Frisbie remarked that all reliability metrics were either met or exceeded. Environmental responsibility surpassed estimates due to coal resources operating below budget estimates even though wind and solar came in below budget. The difference between projections and actuals is because of a reduction of overall generation from baseload resources. Staff continues to work with the Southwest Power Pool to estimate other purchases better so carbon is not overstated. First quarter financial results were also favorable.

12. Legal, environmental and compliance report (presenter: Jennifer Hammitt)

Jennifer Hammitt noted the EPA's new decision was the only item of significance from the last report. The EPA finalized its rules on electric generating units and greenhouse gas emissions. The rules primarily apply to coal-fired generating units, calling for a reduction of 90% by 2032. The rules

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do not affect existing gas-fired units; a later rulemaking will address existing units. The new rules focus on existing units with capacity factors over 40%, so they will likely not affect Platte River.

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

Mr. Singam Setti reviewed the information provided in the resource diversification report. Platte River issued its all-dispatchable resource request for proposals in February; the response period closed yesterday—staff will review proposals over the next month. Staff has also worked on a new solar power purchase agreement and is monitoring a new tariff that may prohibit or limit imported solar panels.

14. Operating report (presenter: Melie Vincent)

Ms. Vincent highlighted operating results for March and year to date. As a result of mild weather, both demand and energy were lower than budgeted, yet the net variable cost to serve owner community load was slightly higher than anticipated. Congestion in the market prevents Platte River from selling excess wind to areas like California at higher rates. A recent windstorm damaged some solar panels, and repairs have been slow. Batteries are also problematic and will be down while parts are on order, with a lead time of 28 weeks.

15. Financial report (presenter: Dave Smalley)

Mr. Smalley highlighted financial results for March and year-to-date. March was a good month, with a favorable net income of $3 million. Revenues for surplus and municipal sales were below budget, but lower operating costs more than offset lower sales.

16. General management report (presenter: Jason Frisbie)

Mr. Frisbie complimented staff efforts on the audit, annual report, and IRP, saying it takes much time to compile all these large documents simultaneously.

Roundtable and strategic discussion topics

Directors provided updates from their individual communities.

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Adjournment

With no further business, the meeting adjourned at 12:23 p.m. The next regular board meeting is scheduled for Thursday, May 30, 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

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Memorandum

Date: 5/22/2024

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
Wade Hancock, senior manager, financial planning and rates

Subject: **Wholesale Transmission Service tariff (Tariff WT-25)**

The board of directors must review the rates for electric power and energy furnished by Platte River no less frequently than once each year. This is required by the Amended Contracts for the Supply of Electric Power and Energy between Platte River and each of the owner communities and by Platte River's General Power Bond Resolution. Platte River staff reviews and modifies the Wholesale Transmission Service tariff, under which Platte River offers transmission service to third parties, on an annual basis, in the second quarter after the audited year-end financial results are available. The rates reflect the most recent costs of operation and maintenance and actual transmission usage.

Platte River collects transmission revenues through two separate tariffs. The Firm Power Service Tariff includes a charge for transmission service for the owner communities. The Wholesale Transmission Service Tariff includes multiple rates of varying duration for transmission services charged to other utilities and power marketers that use Platte River's transmission system. The Wholesale Transmission Service tariff is also charged to Platte River for merchant sales.

Platte River plans to join the Southwest Power Pool's regional transmission organization expansion in the Western Interconnection (SPP RTO-West) in April 2026. To prepare to include Platte River's transmission assets in the market, Platte River contracted with NewGen Strategies and Solutions, LLC (NewGen) to redesign the Annual Transmission Revenue Requirement (ATRR) calculation to align with formula-based rate methodologies the Federal Energy Regulatory Commission (FERC) has approved for other organized market participants. The purpose of the ATRR is to allow transmission-owning entities to recover their transmission-related expenses. All transmission owners within SPP RTO-West will be required to file an ATRR.

The proposed wholesale transmission service components and changes from the previous year's tariff are discussed below. The rates were calculated using the 2023 year-end financial and operational information and are listed in the attached tariff schedule.

Real power loss factor

Based on the 2023 loss analysis, the real power loss factor is decreasing to 0.91% from 0.99%.

Reactive supply and voltage control from generation sources service

The reactive supply and voltage control (RSVC) charge is increasing 27.9% per megawatt of reserved capacity. The RSVC revenue requirement (numerator) is increasing primarily due to lower margins from surplus sales. The transmission usage (denominator) decreased 2.5% due to decreased owner community loads.

NewGen is reviewing this schedule to be converted to the formula rate methodology for next year's tariff.

Point-to-point transmission service

Long-term and short-term firm point-to-point transmission service and non-firm point-to-point transmission service are increasing 12.4% per megawatt of reserved capacity. The net increase is the result of a 9.7% increase in the adjusted transmission revenue requirement (numerator), as noted below, and a 2.5% decrease in transmission usage (denominator), as noted above.

Transmission revenue requirement

The revenue requirement is increasing 9.7%, primarily due to the change in the calculation method to the formula-based rate to use capital investment return versus margin. Operations and maintenance expenses also increased, primarily personnel expenses. The increases were partially offset by a credit for point-to-point transmission sales.

Recommendation

Platte River staff recommends the board adopt the updated rates stated in the Wholesale Transmission Service Tariff (Tariff WT-25), under which Platte River offers transmission service to third parties, as proposed in the attached tariff schedule, with an effective date of June 1, 2024. Platte River continues to reserve the right to offer discounted transmission rates for specific transmission paths.

Attachments

- Final: Wholesale Transmission Service Tariff (Tariff WT-25)
- Redline: Wholesale Transmission Service Tariff (Tariff WT-25)
- Resolution No. 04-24

Wholesale Transmission Service Tariff (Tariff WT-25)

Platte River Power Authority (Platte River) offers transmission service through this Wholesale Transmission Service Tariff (Tariff WT-25). Tariff WT-25 does not apply to any entity taking service under Platte River's Firm Power Service Tariff; Standard Offer Energy Purchase Tariff; or Large Customer Service Tariff. Tariff WT-25 may or may not be equivalent to Platte River's open access transmission service tariff (OATT), posted on Platte River's Open Access Same-Time Information System (OASIS) web site.

A summary of the charges follows.

(1) Scheduling, System Control, and Dispatch Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(2) Reactive Supply and Voltage Control from Generation Sources Service

The charges equal the following:

Yearly	$1,352.06 per megawatt of Reserved Capacity per year
Monthly	$112.67 per megawatt of Reserved Capacity per month
Weekly	$26.00 per megawatt of Reserved Capacity per week
Daily	$5.20 per megawatt of Reserved Capacity per day
Hourly	$0.33 per megawatt of Reserved Capacity per hour

(3) Regulation and Frequency Response Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(4) Energy Imbalance Service

Platte River is not a Balancing Authority or market operator and does not offer this service. To the extent the Balancing Authority or Western Energy Imbalance Service (WEIS) Market Operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Balancing Authority or WEIS Market Operator.

(5) Operating Reserve—Spinning Reserve Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(6) Operating Reserve—Supplemental Reserve Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(7) Long-Term and Short-Term Firm Point-to-Point Transmission Service

The charges can be up to the following limits:

Yearly delivery	$88,224.47 per megawatt of Reserved Capacity per year
Monthly delivery	$7,352.04 per megawatt of Reserved Capacity per month
Weekly delivery	$1,696.62 per megawatt of Reserved Capacity per week
Daily delivery	$339.32 per megawatt of Reserved Capacity per day
Hourly delivery	$21.21 per megawatt of Reserved Capacity per hour

Daily rate of $339.32 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,696.62.

Hourly rate of $21.21 not to exceed the product of the number of megawatts reserved for the day times the maximum daily demand charge of $339.32 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,696.62.

(8) Nonfirm Point-to-Point Transmission Service

The charges can be up to the following limits:

Monthly delivery	$7,352.04 per megawatt of Reserved Capacity per month
Weekly delivery	$1,696.62 per megawatt of Reserved Capacity per week
Daily delivery	$339.32 per megawatt of Reserved Capacity per day
Hourly delivery	$21.21 per megawatt of Reserved Capacity per hour

Daily rate of $339.32 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,696.62.

Hourly rate of $21.21 not to exceed the product of the number of megawatts reserved for the day times the maximum daily demand charge of $339.32 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,696.62.

Real power losses

Real Power Losses are associated with all Transmission Service and Network Integration Transmission Service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer and Network Customer must replace losses associated with all Transmission Service and Network Integration Transmission Service as calculated by the Transmission Provider or the Balancing Authority. Transmission Customer and Network Customer will pay based on the Real Power Loss factor of 0.91% for Transmission Service and Network Integration Transmission Service on the Transmission Provider’s transmission capacity in the Public Service Company of Colorado (PSCo) Balancing Authority. Transmission Customer and Network Customer will pay a pass-through charge of Western Area Power Administration (WAPA) assessed losses for Transmission Service and Network Integration Transmission Service on the Transmission Provider’s transmission capacity in the WAPA Balancing Authority Area. Transmission Customer and Network Customer will pay both the Real Power Loss factor and the WAPA pass-through charges for Transmission Service and Network Integration Transmission Service using transmission capacity in both PSCo and WAPA Balancing Authority Areas.

Transmission Revenue Requirement

The charge for Network Integration Transmission Service is calculated pursuant to the Federal Energy Regulatory Commission (FERC) Pro Forma Open Access Transmission Tariff Attachment H based on Platte River's annual transmission revenue requirement of $49,391,902. This transmission revenue requirement is calculated in accordance with the FERC pro-forma Network Service Rate calculation requirement.

WEIS Joint Dispatch Transmission Service

Platte River, as a WEIS Joint Dispatch Transmission Service Provider, will provide WEIS Joint Dispatch Transmission Service on Platte River's transmission facilities to a WEIS Joint Dispatch Transmission Service Customer commensurate with, and to accommodate, the energy dispatched within the WEIS Market, as set forth in the WEIS Tariff. The rate Platte River for WEIS Joint Dispatch Transmission Service is set forth below:

Hourly delivery:
- On-Peak Hours: the on-peak rate $0.00/MWh
- Off-Peak Hours: the off-peak rate $0.00/MWh

Wholesale Transmission Service Tariff (Tariff WT-~~24~~25)

Platte River Power Authority (Platte River) offers transmission service through this Wholesale Transmission Service Tariff (Tariff WT-~~24~~25). Tariff WT-~~24~~ 25 does not apply to any entity taking service under Platte River's Firm Power Service Tariff; Standard Offer Energy Purchase Tariff; or Large Customer Service Tariff. Tariff WT-~~24~~ 25 may or may not be equivalent to Platte River's open access transmission service tariff (OATT), posted on Platte River's Open Access Same-Time Information System (OASIS) web site.

A summary of the charges follows.

(1) Scheduling, System Control, and Dispatch Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(2) Reactive Supply and Voltage Control from Generation Sources Service

The charges equal the following:

Yearly	$1,352.06 per megawatt of Reserved Capacity per year
Monthly	$112.67 per megawatt of Reserved Capacity per month
Weekly	$26.00 per megawatt of Reserved Capacity per week
Daily	$5.20 per megawatt of Reserved Capacity per day
Hourly	$0.33 per megawatt of Reserved Capacity per hour

~~Yearly~~	~~$1,056.85 per megawatt of Reserved Capacity per year~~
~~Monthly~~	~~$88.07 per megawatt of Reserved Capacity per month~~
~~Weekly~~	~~$20.32 per megawatt of Reserved Capacity per week~~
~~Daily~~	~~$4.06 per megawatt of Reserved Capacity per day~~
~~Hourly~~	~~$0.25 per megawatt of Reserved Capacity per hour~~

(3) Regulation and Frequency Response Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(4) Energy Imbalance Service

Platte River is not a Balancing Authority or market operator and does not offer this service. To the extent the Balancing Authority or Western Energy Imbalance Service (WEIS) Market Operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Balancing Authority or WEIS Market Operator.

(5) Operating Reserve—Spinning Reserve Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(6) Operating Reserve—Supplemental Reserve Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(7) Long-Term and Short-Term Firm Point-to-Point Transmission Service

The charges can be up to the following limits:

Yearly delivery	$88,224.47 per megawatt of Reserved Capacity per year
Monthly delivery	$7,352.04 per megawatt of Reserved Capacity per month
Weekly delivery	$1,696.62 per megawatt of Reserved Capacity per week
Daily delivery	$339.32 per megawatt of Reserved Capacity per day
Hourly delivery	$21.21 per megawatt of Reserved Capacity per hour

Daily rate of $339.32 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,696.62.

Hourly rate of $21.21 not to exceed the product of the number of megawatts reserved for the day times the maximum daily demand charge of $339.32 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,696.62.

~~Yearly delivery~~	~~$78,477.13 per megawatt of Reserved Capacity per year~~
~~Monthly delivery~~	~~$6,539.76 per megawatt of Reserved Capacity per month~~
~~Weekly delivery~~	~~$1,509.18 per megawatt of Reserved Capacity per week~~
~~Daily delivery~~	~~$301.84 per megawatt of Reserved Capacity per day~~
~~Hourly delivery~~	~~$18.87 per megawatt of Reserved Capacity per hour~~

~~Daily rate of $301.84 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,509.18.~~

~~Hourly rate of $18.87 not to exceed the product of the number of megawatts reserved for the day times the maximum daily demand charge of $301.84 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,509.18.~~

(8) Nonfirm Point-to-Point Transmission Service

The charges can be up to the following limits:

Monthly delivery	$7,352.04 per megawatt of Reserved Capacity per month
Weekly delivery	$1,696.62 per megawatt of Reserved Capacity per week
Daily delivery	$339.32 per megawatt of Reserved Capacity per day
Hourly delivery	$21.21 per megawatt of Reserved Capacity per hour

Daily rate of $339.32 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,696.62.

Hourly rate of $21.21 not to exceed the product of the number of megawatts reserved for the day times the maximum daily demand charge of $339.32 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,696.62.

~~Monthly delivery $6,539.76 per megawatt of Reserved Capacity per month~~
~~Weekly delivery $1,509.18 per megawatt of Reserved Capacity per week~~
~~Daily delivery $301.84 per megawatt of Reserved Capacity per day~~
~~Hourly delivery $18.87 per megawatt of Reserved Capacity per hour~~

~~Daily rate of $301.84 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,509.18.~~

~~Hourly rate of $18.87 not to exceed the product of the number of megawatts reserved for the day times the maximum daily demand charge of $301.84 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,509.18.~~

Real power losses

Real Power Losses are associated with all Transmission Service and Network Integration Transmission Service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer and Network Customer must replace losses associated with all Transmission Service and Network Integration Transmission Service as calculated by the Transmission Provider or the Balancing Authority. Transmission Customer and Network Customer will pay based on the Real Power Loss factor of ~~0.99%~~0.91% for Transmission Service and Network Integration Transmission Service on the Transmission Provider's transmission capacity in the Public Service Company of Colorado (PSCo) Balancing Authority. Transmission Customer and Network Customer will pay a pass-through charge of Western Area Power Administration (WAPA) assessed losses for Transmission Service and Network Integration Transmission Service on the Transmission Provider's transmission capacity in the WAPA Balancing Authority Area. Transmission Customer and Network Customer will pay both the Real Power Loss factor and the WAPA pass-through charges for Transmission Service and Network Integration Transmission Service using transmission capacity in both PSCo and WAPA Balancing Authority Areas.

Transmission Revenue Requirement

The charge for Network Integration Transmission Service is calculated pursuant to the Federal Energy Regulatory Commission (FERC) Pro Forma Open Access Transmission Tariff Attachment H based on Platte River's annual transmission revenue requirement of ~~$45,044,265~~$49,391,902. This transmission revenue requirement is calculated in accordance with the FERC pro-forma Network Service Rate calculation requirement.

WEIS Joint Dispatch Transmission Service

Platte River, as a WEIS Joint Dispatch Transmission Service Provider, will provide WEIS Joint Dispatch Transmission Service on Platte River's transmission facilities to a WEIS Joint Dispatch Transmission Service Customer commensurate with, and to accommodate, the energy dispatched within the WEIS Market, as set forth in the WEIS Tariff. The rate Platte River for WEIS Joint Dispatch Transmission Service is set forth below:

Hourly delivery:
On-Peak Hours: the on-peak rate $0.00/MWh
Off-Peak Hours: the off-peak rate $0.00/MWh

RESOLUTION NO. 04-24

Background

A. Platte River Power Authority's "Wholesale Transmission Service Tariff" sets the terms, conditions, and rates for unbundled transmission service to entities other than Platte River's owner communities.

B. Platte River's board typically reviews Platte River's wholesale transmission service tariff rate annually in May, reflecting audited financial results for the prior year.

C. In calculating its wholesale transmission service revenue requirement, Platte River uses: (1) its previous year actual operations and maintenance costs, and other applicable income and expenses, such as administrative and general costs, to account for Platte River's costs for its transmission system; (2) debt service (principal and interest) for capital costs associated with building, maintaining, and operating its transmission system; and (3) a debt service coverage margin to allow it to prudently invest in capital to meet the transmission needs of its owner communities and third-party wholesale transmission service customers.

D. Platte River's staff recommends in a memorandum dated May 22, 2024, that the board approve the rates in Tariff WT-25, which supersede Platte River's existing wholesale transmission service tariff rates (in Tariff WT-24), to reflect audited and updated year-end financial results.

Resolution

The Board of Directors of the Platte River Power Authority approves the rates stated in Tariff WT-25, as recommended by staff, to become effective June 1, 2024.

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

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Memorandum

Date: 5/22/2024

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Sarah Leonard, general counsel

Subject: **Executive session**

Consistent with Colorado law governing open meetings, the Platte River Board of Directors may convene an executive session for the purposes of determining positions relative to matters that may be subject to negotiations, developing strategy for negotiations, and instructing negotiators. Staff therefore recommends the board convene an executive session to enable staff to confer with the board about negotiation strategies and instructions for long-term power purchase agreements, given recent trends in pricing and other terms for new renewable energy facilities. Convening an executive session to discuss these issues is permitted by section 24-6-402(4)(e)(I) of the Colorado Revised Statutes.

The board will take no action during executive session.

There is no documentation for public use.

Platte River
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Memorandum

Date: 5/22/2024

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Raj Singam Setti, chief operating officer, innovation and sustainable resource integration
Paul Davis, manager, distributed energy resources

Subject: **Dispatchable capacity from a virtual power plant**

Platte River must have reliable dispatchable capacity to achieve the Resource Diversification Policy goals. Dispatchable capacity enhances reliability and manages the costs of operating an electric system that increasingly relies on intermittent noncarbon energy resources. Virtual power plants (VPPs) can provide some of the dispatchable capacity that is needed. VPPs consist of integrated and aggregated utility and customer distributed energy resources (DER), such as battery storage, electric vehicles and smart appliances.

Platte River and the owner communities will need to invest in significant staff and financial resources to develop a VPP. This investment is needed to develop and operate customer programs and utility technology systems that can support customer participation and DER management as part of a VPP.

Platte River and the owner communities developed a DER integration roadmap that addresses how DER can be integrated and how various utility systems must interact to support DER participation in a VPP. We are now working to implement the roadmap.

A DER management system (DERMS) has a central role. An enterprise DERMS will enable Platte River to dispatch DER to help maintain a reliable electric supply for the owner communities, while tenant DERMS will enable the owner communities to manage DERs to provide distribution system benefits. Procurement of a DERMS is in process and will involve a team of Platte River and owner community staff. We expect to complete the procurement process during the remainder of this year.

Advanced distribution management systems (ADMS) will play a growing role in DER management. As DER on the electric system increase, ADMS and DERMS will play a synergistic role in operating DERs to enhance distribution reliability and efficiency. To do this, ADMS is expected to provide near real-time information about the status of the distribution system, including the current status of the distribution network and its ability to accommodate changes in DER consumption and output. This will be important to ensure that VPP capacity is deliverable while operating within the distribution system's available capacity. In addition to supporting VPP operation, ADMS also serves distribution use cases, and includes or integrates with supervisory control and data acquisition, outage management and distribution management system advanced applications like power flow modeling.

Platte River and the owner communities have already identified functional use cases for ADMS to support VPP operation and will continue to work together to identify functional use cases related to distribution operations. We believe a coordinated procurement and implementation process, leading to a common ADMS platform (with the potential to customize to support unique owner community needs) can benefit all. Platte River will coordinate with the owner communities to evaluate the feasibility of a common ADMS solution that can meet specific requirements each owner community identifies.

We need to collaborate to ensure our investments in programs and systems provide the expected results and meet customer expectations as we work to achieve a noncarbon electric system that is environmentally responsible, reliable and financially sustainable.

Attachment

- Resolution No. 05-24: support for a Virtual Power Plant

RESOLUTION NO. 05-24

Background

A. In the years since its board of directors adopted the 2018 Resource Diversification Policy, Platte River Power Authority (Platte River) has taken many steps to advance the Resource Diversification Policy goals, including adding new renewable resources and battery energy storage systems, joining a real-time energy dispatch market, committing to join a full regional transmission organization by 2026, and collaborating with our owner communities to lay the foundations for a virtual power plant.

B. Dispatchable capacity is essential to maintaining reliability as intermittent renewable resources on Platte River's system increase. Dispatchable capacity has three components—energy storage, flexible combustion turbine technology (which is mature but has long lead times for permitting and construction), and virtual power plant capabilities (which are in early stages and must continue to advance).

C. Virtual power plants consist of integrated and aggregated distributed energy resources (DERs) that can be controlled through advanced software to provide capacity and energy services to the electric grid, similar to conventional power plants. Utility customers who are willing to offer flexible DERs to grid operators can receive compensation for providing these services.

D. Developing and operating an effective virtual power plant is a multiyear, ongoing process that requires sustained, coordinated efforts among Platte River and our owner communities to integrate enabling systems, programs, and technology solutions to enroll and operate flexible, customer-owned DERs. Required functions include interconnection, program management, enrollment and device registration, data management, telecom and telemetry, control and dispatch, visibility, forecasting, network power flow analysis, measurement and verification, and settlements.

E. Collaboration among Platte River and our owner communities will be critical for enabling systems needed to control the virtual power plant (such as DER management systems), programs to inform and enroll customers and support their participation, and distribution-side capabilities such as customer information systems, advanced metering infrastructure, meter data management systems and a distribution network model to support flow analysis for DER assets.

F. As virtual power plant technology and programs evolve and mature, helping to further our shared decarbonization goals, Platte River and our owner communities will need to regularly update existing systems, policies, and procedures (and develop new ones when needed) so that flexible DERs can continue to support the reliability and financial sustainability of our collective electric systems.

Resolution

By this resolution, the board of directors of Platte River Power Authority formally expresses support for:

(1) collaborative efforts among Platte River and our owner communities to implement the actions, programs, and systems necessary to develop and operate an effective virtual power plant, and

(2) Platte River to budget for and fund activities to build, operate, maintain, and keep current shared infrastructure and organizational functions necessary to successfully deploy and integrate virtual power plant capabilities that will benefit our collective utility systems and further our Resource Diversification Policy goals.

In addition, the board encourages all owner communities and Platte River to proactively seek opportunities to centralize virtual power plant infrastructure, systems, programs, data, and other functions at Platte River when economies of scale can lower total costs incurred and improve integration and interoperability.

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: 5/22/2024

To: Board of directors

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

Subject: **Draft 2024 Integrated Resource Plan**

The presentation of our 2024 Integrated Resource Plan (IRP) will provide an overview of how the IRP integrates with our long-term strategic goals and customer expectations.

Staff will present the recommended plan for expanding renewable energy, dispatchable capacity, and reducing carbon emissions. This will include an explanation of different portfolios analyzed and the resource planning assumptions, such as electric demand projections, distributed energy resources, wind, solar, and battery storage cost projections and parameters.

An overview of our energy and capacity planning processes will be provided, detailing the methodologies employed to ensure that we meet future energy demands efficiently. We will also highlight strategies for enhancing customer engagement with virtual power plants and distributed energy resources, solutions, and programs.

The 2024 IRP aligns with Platte River's strategic objectives and serves as a blueprint for our ongoing commitment to reliability, financial sustainability, and environmental responsibility. The recommended portfolio maintains flexibility for future needs and our commitment to maintaining reliability and a clean energy transition.

Attachment

- Draft 2024 Integrated Resource Plan

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

DRAFT 2024 Integrated Resource Plan

May 2024

Table of contents

Glossary

Term or acronym	Definition
IRP	Integrated resource plan or integrated resource planning process
RDP	Resource Diversification Policy
DER	Distributed energy resources
WAPA	Western Area Power Administration
PRM	Planning reserve margin
MW	Megawatt
WMEG	Western Markets Exploratory Group
RP22	Platte River's Resource Plan 2022
JDA	Joint dispatch agreement
WEIS	Western Energy Imbalance Service market
SPP	Southwest Power Pool
EV	Electric vehicle
RFP	Request for proposal
RTO West	Regional Transmission Organization West
GW	Gigawatt
PPA	Power purchase agreement
CPI	Consumer Price Index
CDPHE	Colorado Department of Public Health and Environment
EPA	U.S. Environmental Protection Agency
VPP	Virtual power plant
HVAC	Heating, ventilation and air conditioning
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
MWh	Megawatt-hours
DG	Distributed generation
ITC	Federal solar tax credit

NEM	Net energy metering
TOU	Time of use
NREL	National Renewable Energy Laboratory
GWh	Gigawatt-hour
BE	Beneficial building electrification
ELCC	Effective Load Carrying Capability
DR	Demand response
LOLE	Loss of Load Expectation
ODTY	One Day in Ten Years
EPRI	Electric Power Research Institute
WECC	Western Electricity Coordination Council
LOLH	Loss of Load Hours
MISO	Midwest Independent System Operator
ERCOT	Electric Reliability Council of Texas

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1. Executive summary

Platte River Power Authority's 2024 Integrated Resource Plan (IRP) presents a comprehensive strategy aimed at reducing 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 explores how to firm an energy portfolio composed primarily of weather-dependent, renewable resources with the dispatchable capacity needed to maintain reliability.

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 economy, primarily 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 this 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. These presentations were coupled with two engagement sessions hosted by Platte River to share IRP milestones, and supported by 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. By 2030, all portfolios will emit some carbon due to the limited availability of commercially viable noncarbon dispatchable options.

After 2030, no new thermal generation is modeled and long-duration energy storage is planned. Carbon pricing was incorporated 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 the potential of 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.

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

Conclusion

We are pleased to present you with 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 working on the fourth iteration as factors continue to change and evolve around us.

As you review our latest plan, we hope your takeaways include 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 more diversified, low-carbon energy portfolio for a sustainable future.

2. 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. Planning strategies are included throughout this document highlighting how Platte River will address high-level policy goals while incorporating staff recommendations and research in addition to third-party studies, legislative, regulatory, market and technology changes.

Platte River's IRP is developed with community 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 and Chapter 3 describes our process and timeline, the progress we made since the last IRP, and the industry challenges we are facing, 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.
- The majority of the report is focused on providing technical background data, assumptions and methodology that influence and shape our IRP, including demand, impacts of distributed energy resources (DER) and electrification, extreme weather events and more. Chapter 6 of this report details the IRP design including the studies, portfolios and our modeling methodology.
- The modeling results are shown in Chapter 7 and the resulting action plan from this IRP is highlighted in Chapter 8.

Public power utilities

Platte River is one of more than 2,000 community-owned electric utilities in the U.S. They are operated by local governments and provide their owner communities with reliable, responsive, not-for-profit electric service. Over 49 million U.S. citizens depend on public power.

Public utilities like Platte River advocate for policies that:

- Provide reliable electrical services at reasonable costs
- Advance diversity and equity in the electric utility industry
- Promote effective competition in the wholesale electricity marketplace
- Protect the environment and the health and safety of electricity consumers
- Safeguard the ability of communities to provide infrastructure services that their consumers require

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 public power energy provider that would provide its owner communities with long-term energy above the limited amount of federal hydropower allotted. 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.

Following the passage of 1975 legislation, the four communities executed the organic contract establishing Platte River as a political subdivision of the state of Colorado. The organic contract is an agreement between the four owner communities that sets forth Platte River's purposes 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 has long been guided by three foundational pillars that drive its mission and are among the requirements for achieving the RDP. Together with our vision and values, these pillars inform all Platte River 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 leadership activities:

- 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 an additional 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 commit to working toward 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 that must occur to meet the 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

3. IRP process overview

3.1 What is an IRP?

A utility IRP[1] compares the supply-side resources (generated or purchased by the utility) with the demand-side resources (contributed by customers, including DER) 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 plan 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 ensure reliable supplies during the planning horizon. An IRP model optimally selects from demand- and supply-side resources while meeting the planning reserve margin (PRM)[2] or some other reliability criteria, to ensure adequate supply of electricity under all reasonably expected variations of weather, customer demand and generation resource availability.

A key component of an IRP is an action plan that provides specific actions and activities the utility plans to conduct during the next three to five years before developing the next IRP. An IRP is a snapshot in time while 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.

3.2 Why do an IRP now?

Platte River's Board adopted the RDP[3] in December 2018 to support the owner communities' clean energy goals. The policy directs Platte River's CEO to proactively work toward a 100% noncarbon energy mix by 2030, without compromising Platte River's foundational pillars of reliability, environmental responsibility and financial sustainability.

[1] In this document the acronym IRP is used in two different ways, an integrated resource plan or an integrated resource planning process

[2] 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] See https://www.prpa.org/wp-content/uploads/2018/12/12.06.2018-Resource-Diversification-Policy.pdf

In 2020, Platte River developed an IRP that outlined several paths to work toward this 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 served as a wakeup call about the increased frequency of extreme weather events and the necessity of power supply reliability. 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, this IRP was expedited to support the accelerated integration of renewable resources. Assumptions for this IRP were finalized in summer 2023. As such, this IRP provides portfolios or snapshots of the future viewed from 2023. As various decision drivers and technologies evolve, this IRP will need an update. Platte River staff will continue to update its plans and provide the next IRP in 2028.

3.2.1 IRP timeline

The 2024 IRP process started in 2022 with 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.

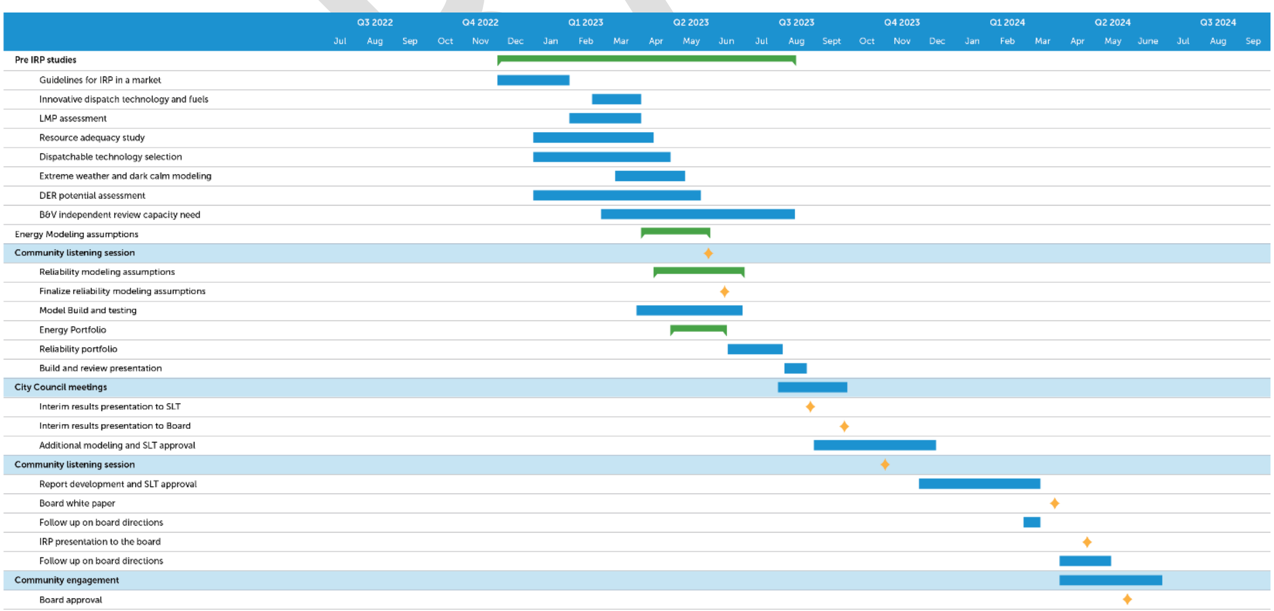


Figure 2. Timeline of 2024 Integrated Resource Plan activities and milestones

3.3 Progress since the last IRP

Following the submission of the 2020 IRP, Platte River continued working toward achieving the RDP, 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.
- 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 at 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 power purchase agreement to build Platte River's largest and lowest cost solar project, which when operational will provide up to 150 MW of power.

2021

- Completed installation of the 22 MW Rawhide Prairie Solar project, including a 2 megawatt-hour battery.
- Together with 13 western utilities, joined to form the Western Markets Exploratory Group (WMEG) to identify potential market solutions. WMEG began exploring the potential for a staged approach to new market services, including day-ahead energy sales, transmission system expansion and other power supply and grid solutions consistent with existing state regulations.
- To foster innovation necessary to achieve a noncarbon electric system that includes integrated DERs, Platte River created the transition and integration division, combining DER and energy solutions with resource planning and information and operations technology departments.
- 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.
- To increase positive community impacts, 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

- Modeling and resource planning efforts determined the need for an accelerated 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) which added about 105 MW more capacity by 2030 than the 2020 IRP. RP22 called for 450 MW of solar, 200 MW of wind, 200 MW of 4-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 web site 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 a request for proposals to competitively procure 150-250 MW of wind generation. Responses to the request for proposal (RFP) were received late in 2023, with evaluation of the responses continuing in 2024.
- Began operating in the SPP WEIS market.
- Awarded a contract 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 incentivizing customers to overcome financial hurdles and investing nearly $10,000 training local contractors on building electrification.

- Actively supported over 100 customers upgrading their homes in the residential income-qualified segment with plans to grow supporting over 250 customers annually in future years.
- Embarked on a collaborative distributed energy storage initiative with the owner communities, with plans to deploy up to 25 MW of four-hour distributed energy storage across various system points, fostering heightened system reliability and cost-effectiveness of renewable energy integration.
- Announced plans 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, aiming 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-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. Some jurisdictions introduced incentives to facilitate the development of renewable energy projects. The pandemic highlighted the importance of resilient and sustainable energy systems. Some countries committed to green recovery plans and climate mitigation efforts. This resulted in heightened interest in renewable generation to stimulate economic growth, create jobs and reduce carbon emissions. This accelerated the demand for solar, wind and energy storage systems. Significantly higher demand and sustained challenges with supply chains contributed to the cost of renewables and energy storage projects nearly doubling post pandemic.

3.4.2 Supply chain issues

The supply chains were badly impacted 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 pressure of demand from all the countries. 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]. Renewable supply chains may have recovered from pandemic-related stress but the huge surge in demand across the globe is increasing pressure. In the case of the U.S., the Inflation Reduction Act has significantly increased incentives to expand the domestic supply chain of renewable generation. This has added further strain on the supply chain as manufacturers are rushing to develop manufacturing in the US.

This supply chain pressure has directly impacted Platte River's resource procurement as well. 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 delay risks exist for projects being planned for 2026 and 2027 additions.

3.4.3 Renewable resource pricing

Due to supply chain issues and significant increases in demand, the prices for renewables have significantly increased since the last IRP. As shown in the chart below from Level Ten Energy.[5] power purchase agreement (PPA) prices in the U.S. doubled by the end of 2023 compared to 2020 levels.

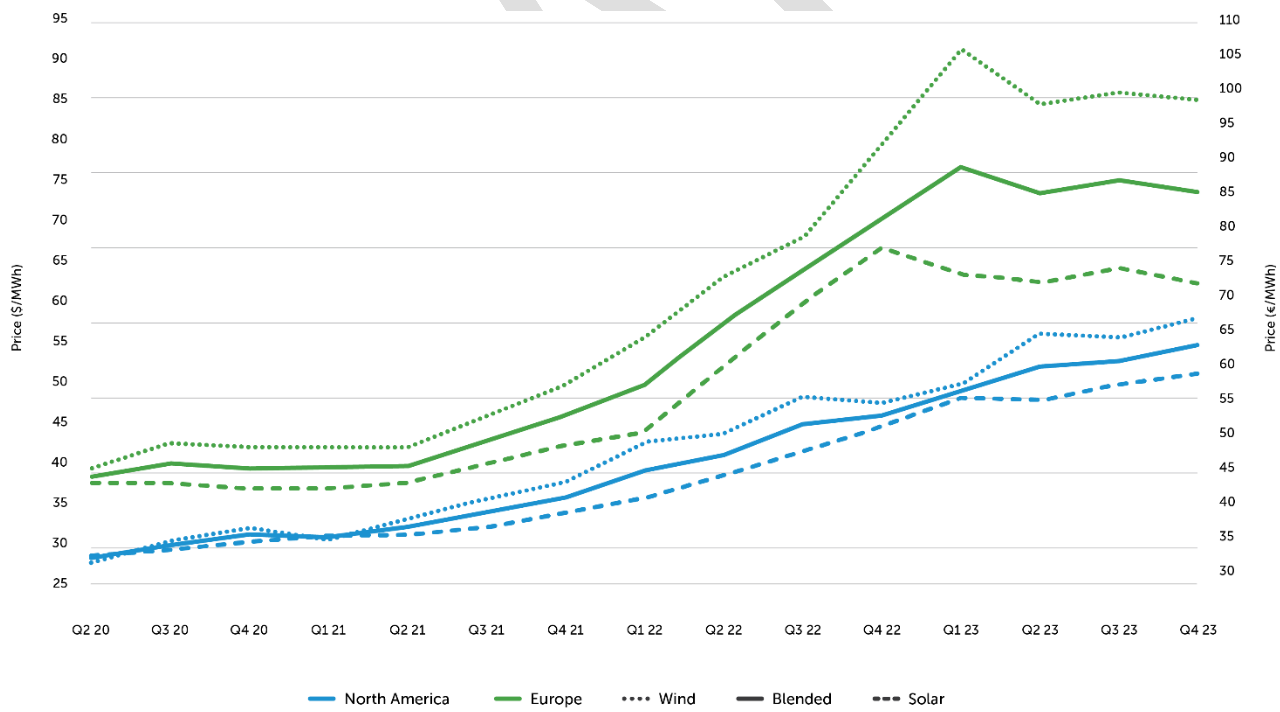


Figure 3. PPA prices in the U.S. between 2020 and 2023

[4] https://www.iea.org/reports/renewable-energy-market-update-june-2023/executive-summary

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

Major drivers for this price increase are higher demand, higher cost of capital, higher inflation rates, higher transmission costs, higher risk premiums and some 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. According to the U.S. Energy Information Administration, the U.S. is expected to add 62.8 GW[6] of new capacity in 2024 which is 55% more than the 40.4 GW added in 2023. This represents the highest level of annual additions since 2003.

From this new capacity, solar additions of 36.4 GW are 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. Wind additions are leveling off. This significant increase in demand, both domestically and globally, has put an upward pressure on prices.

Table 1. U.S. demand for renewable generation

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

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) have a significant impact on the 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].

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

[7] https://fred.stlouisfed.org/series/DGS10

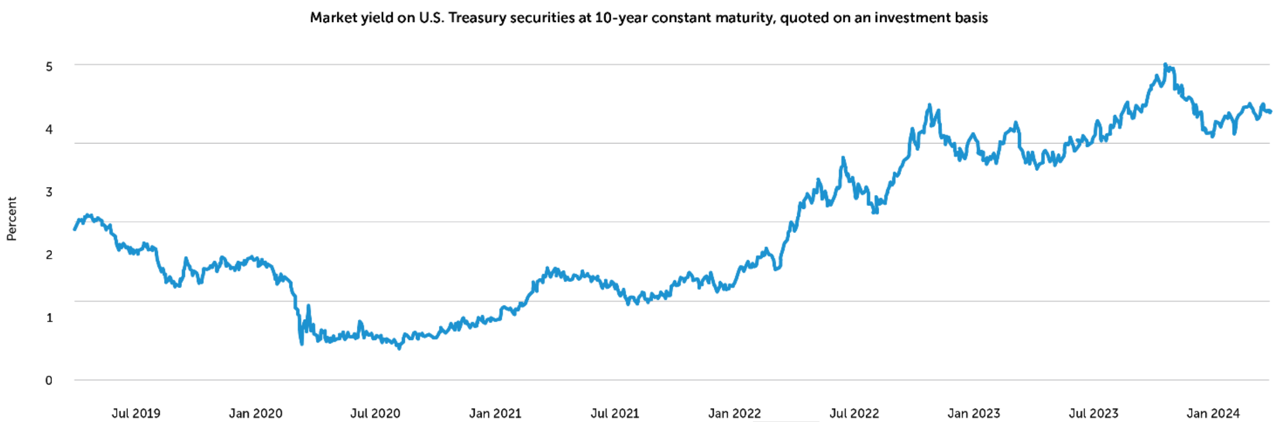


Figure 4. Market yield on U.S. Treasury securities at 10-year constant maturity, quoted on an investment basis

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, resulting in higher 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 higher than the prior three years 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 seen in Figure 5.

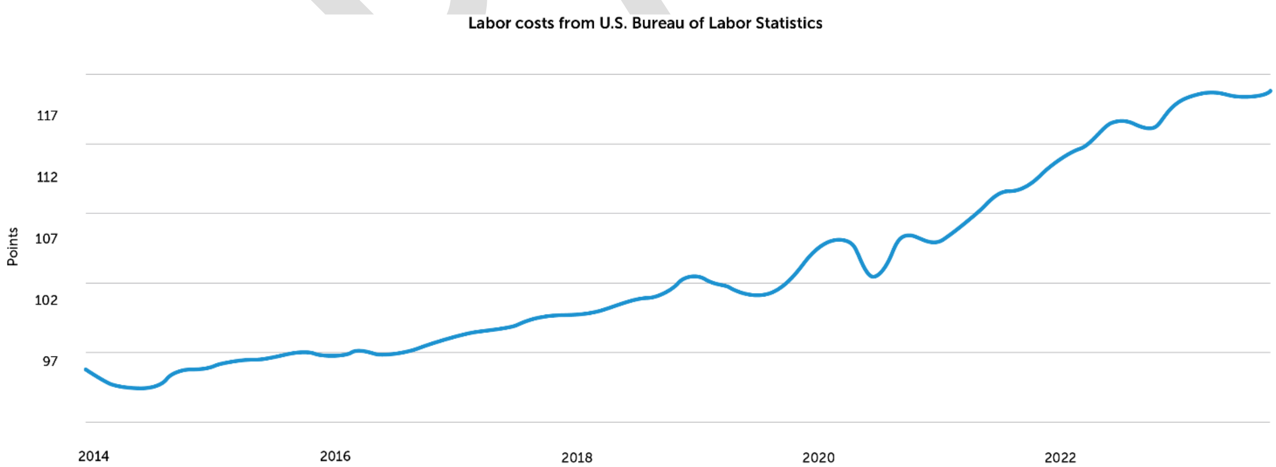


Figure 5. Labor costs from U.S. Bureau of Labor Statistics

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

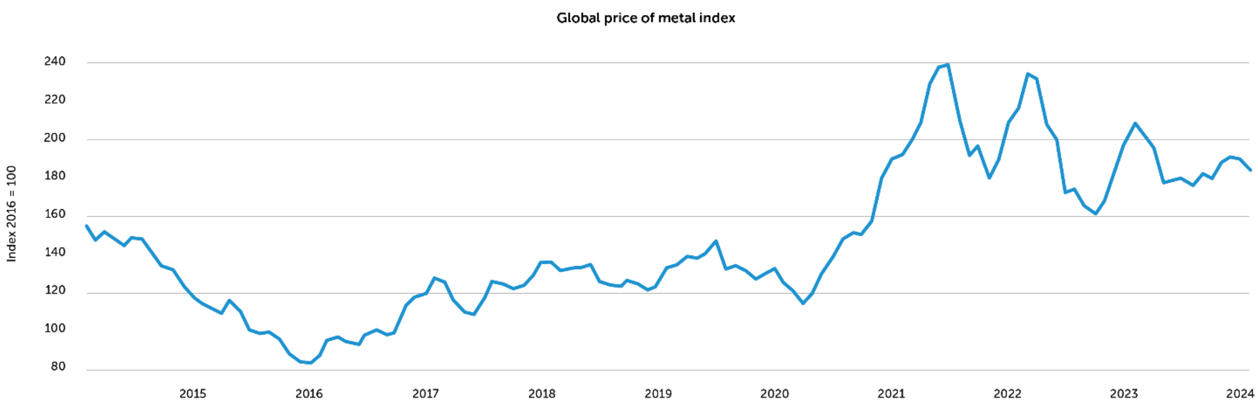


Figure 6. Global price of metal index

Higher transmission costs: Transmission costs to interconnect renewables are increasing at two levels. First, the inflationary pressures are increasing transmission interconnection equipment costs. Second, as more and more renewables 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.

Higher risk premiums: Recent inflation and uncertainty about future inflation have developers assuming that the recent increase in equipment and labor prices will continue in the coming years. For example, developers have experienced a significant increase in engineering, construction, and procurement costs and assume these annual cost increases will continue for the next few years.

Additionally, many purchasers of renewable projects have agreed to significant price increases with developers to ensure previously signed PPAs are ultimately constructed. Many customers are pursuing projects with only well-capitalized developers, resulting in greater demand and higher prices from the more desirable developers.

Additionally, Anti-Dumping and Countervailing Duties and Uyghur Forced Labor Prevention Act policies created some uncertainty for imports from certain countries which also put upward pressure on prices. This policy, coupled with other factors mentioned earlier, have pushed the price of renewable generation higher. The Inflation Reduction Act and the policies noted above will expand domestic manufacturing, but it may take a few years to implement before starting a downward pressure on prices.

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

3.5 Resource planning refresh in 2022

Following the onset of 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 optimally adds renewables, storage and dispatchable resources while considering the project development timeline and supply chain issues. Another consideration was to ensure that most, if not all, new resources are ready in 2028 to give at least one full year of operating experience to Platte River staff before retiring Rawhide Unit 1. This resulted in 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 the 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. As a direct consequence of 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

Closely working 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, customer adoption of EVs and distributed solar have rapidly expanded. Similarly, there is an 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 under 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 complies with all 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 it 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 municipal utilities in Colorado.

3.6.1 Colorado policy review

Since the passage of Platte River's RDP, 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 process:

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 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, including plans to retire all coal generation assets by the end of 2029. 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 (the 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 the Air Pollution Control Division (the Division) and the CDPHE to regulate toxic air contaminants. It also gave the 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 Division will then make available to the public.

SB23-198: Concerned with verifying 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 prior to 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 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.

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

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			✓

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. Platte River anticipates that legislators may introduce bills that will require utilities to update their Clean Energy Plans to demonstrate at least a 97% reduction in emissions from 2005 levels by 2040.

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 9.1.

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 power purchase agreements 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 proposed rulemaking for power plants with coal- or natural gas-fired generating units. In May 2023, the EPA announced proposed rules to reduce greenhouse gas emissions from power plants. Platte River will continue to follow this process and provide comment through trade associations as the EPA makes those opportunities available.

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 and highly localized community engagement strategy for the 2024 IRP. The strategy involved collaborating with the four owner communities' distribution utility's communications and community relations staff. The owner communities' staffs made recommendations on 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 recognize 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 generation and transmission public power 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
- Impacts of climate change and extreme weather modeling
- Equity and affordability
- The increasing trend of beneficial electrification and growth in demand and load
- Clarity on what is a dispatchable resource

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

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 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 (LPPC).

3.7.2 Campaigns and resources

Platte River's first brand awareness and public education campaign launched soon after the initiation of the 2024 IRP community engagement process. 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.

Both organic and paid media were employed 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

While the activities noted above received equal effort, the following resources were developed and continue to be maintained 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.

All questions asked during the community engagement phase were captured and answered, and 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

A dedicated email was created for IRP specific questions and comments at 2024IRP@prpa.org. This approach allows for direct communication with engaged citizens and allows staff to track.

3.7.3 Results

The 2024 IRP reflects an extensive collaboration among Platte River teams as well as significant gathering of 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, its accountability to its owner communities and the state of Colorado's clean energy goals and underscore the value of equally maintaining our three foundational pillars.

One of the major takeaway messages we identified across each outreach effort: as time passes, 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.

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

The challenge Platte River faces is to create a transition plan that retires 431 MW of coal – which currently provides more than half of the low-cost energy and reliable capacity – and replace it with low or no-carbon energy and capacity, within six years.

4.1 Key variables and strategic considerations

Platte River must consider whether the advancements identified in the RDP have been met while working toward the goal. Other variables detailed 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) to meet customer demand efficiently and sustainably. Effective energy planning can significantly impact emissions by integrating renewable energy sources.

Capacity planning is crucial for utilities to ensure they 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 can 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 refer to 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 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, 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.

While the overall results were significantly beneficial to Platte River during JDA participation, the opportunity to join an energy imbalance market was the next step in the path toward full energy market participation. This led to the three 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.

4.1.6 Resource adequacy

Resource adequacy refers to the ability of Platte River to have sufficient resources to deliver electricity to all consumers, at all times, even under challenging conditions. Resource adequacy is a critical aspect of resource planning and operation, ensuring that there is enough generation capacity available 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 wholly owned 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 the existing transmission lines.

Platte River anticipates the financial obligations associated with completing transmission network upgrades to interconnect the new resources. 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 the long-term capital budget. The 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 these 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, speed up and slow down quickly to produce more or less power when needed. The reliability challenges faced 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 (Appendix 9.4) to analyze different weather patterns from the past five decades across a broad region to understand the frequency and impact of such extreme weather and dark calm events. The findings emphasize the need for a diversified energy portfolio and the development of 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 incorporate carbon pricing into future electricity prices.

The carbon-imposed cost portfolio imposes additional costs disincentivizing dispatch of high-carbon energy sources, unless they prove to be 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 towards more sustainable pathways.

The evaluation process for including technologies in such a portfolio prioritizes renewable energy sources like wind and solar due to their minimal environmental 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 uses revenues from its wholesale power rates to help fund the owner communities' transition to a noncarbon energy future. 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 as follows:

- 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 have 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. Per 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.

5. Electricity demand 2024-2043

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, electric vehicles 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 day times, 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 developing flexible plans and frequent plan updates, to ensure 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. Consequently, 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. It is combined with the DER forecast to develop a composite 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 utilized 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. Below is the total and peak load history for Platte River, aggregated by year.

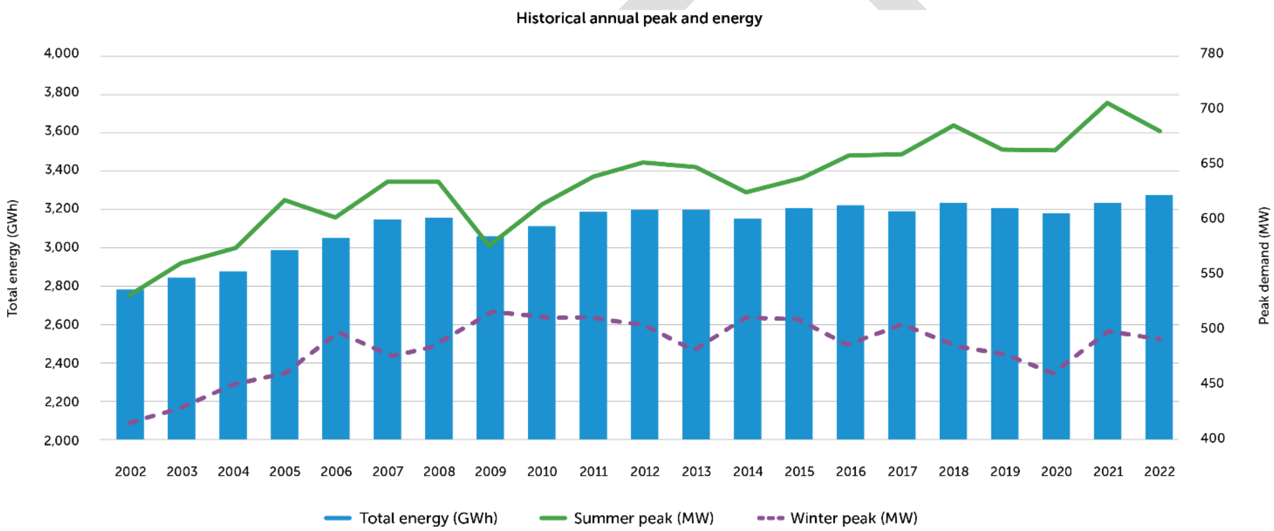


Figure 7. Historical annual peak and energy

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 was 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.

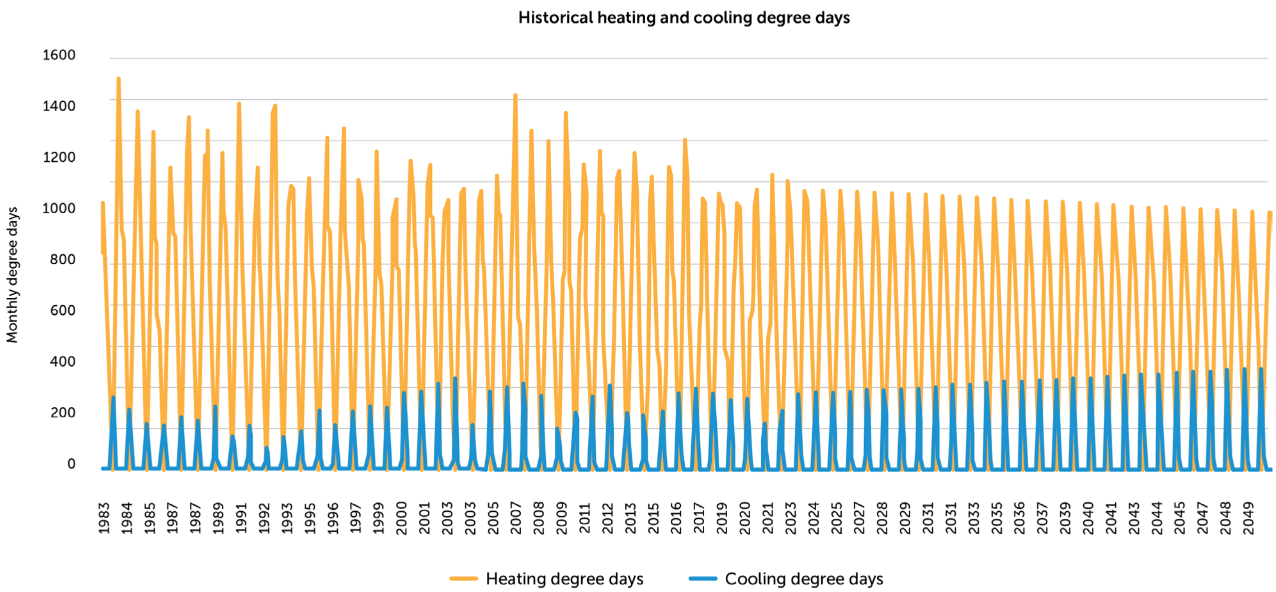


Figure 8. Historical heating and cooling degree days

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/cooling degree days.

Number of households. Number of households was utilized 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, economic growth in Larimer County was assumed to reflect 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.

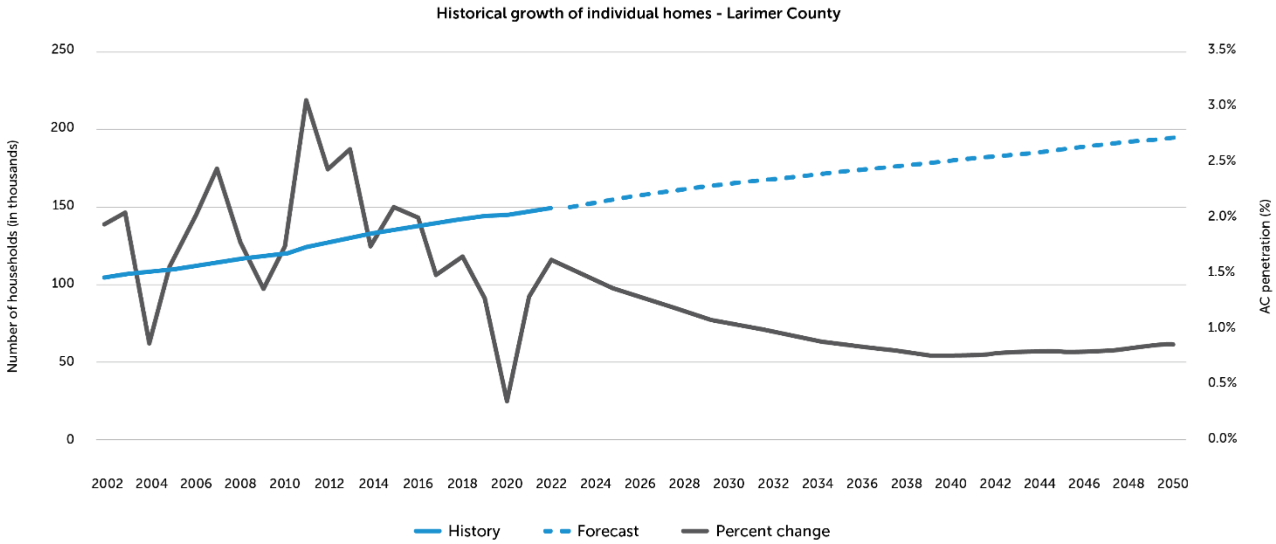


Figure 9. Historical growth of individual homes

Air conditioning use. A large driver for load growth over the past 20 years is an increase in the percentage of central air conditioning systems in single-family homes. 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.

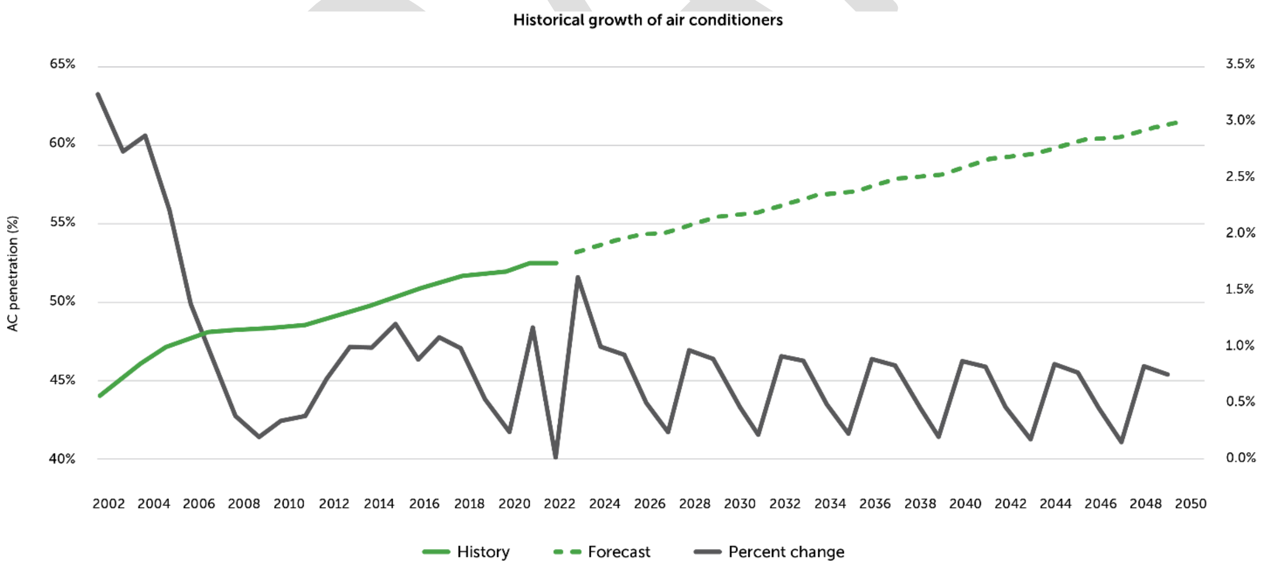


Figure 10. Historical growth of air conditioners

5.2.3 Forecast results

The base load forecast is projecting consistent growth in both peak load and total energy. The chart below 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.

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

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

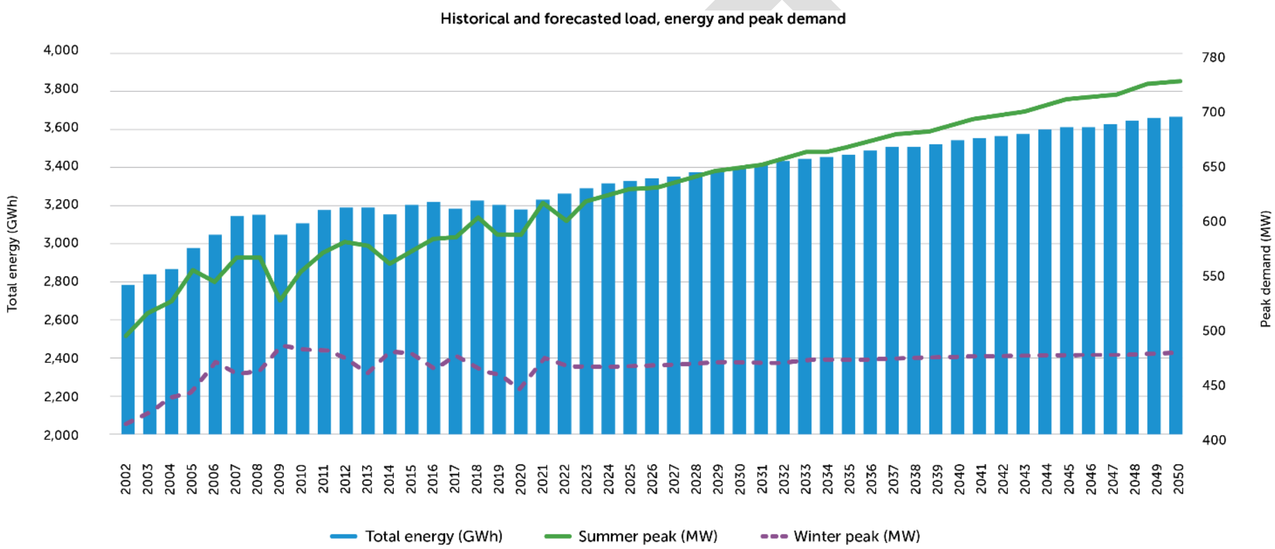


Figure 11. Historical and forecasted load, energy and peak demand

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.

Below is a comparison of the average hourly shape, by month, for the 10 years of historical hourly data and the 2023 projections. Increases in average hourly load are observed between the load history and forecast, however this reflects load growth observed during 2013-2022. The forecasted load shape is commensurate with historical load shapes.

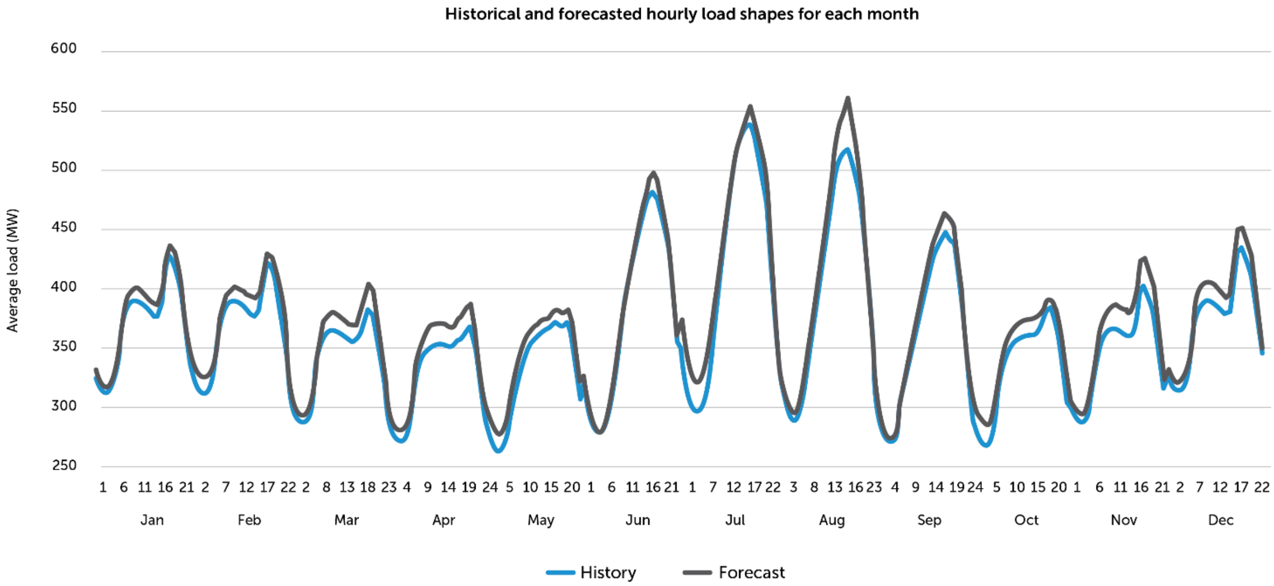
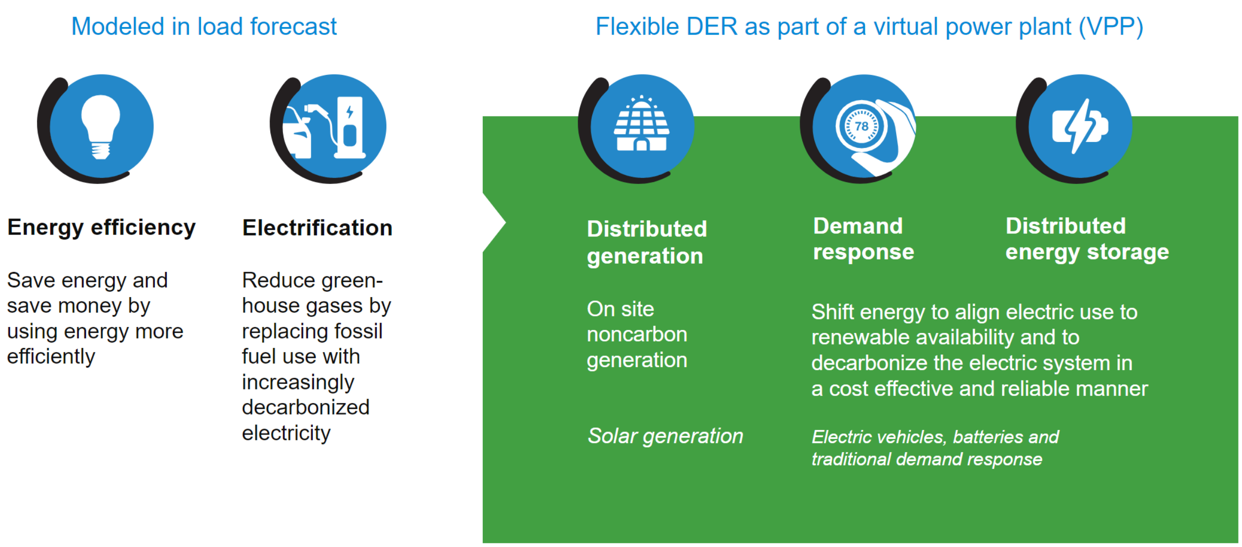


Figure 12. Historical and forecasted hourly load shapes for each month

5.3 DER integration, flexible DERs and the virtual power plant

DER encompasses a range of technologies installed and used at a customer's premises or within the distribution system and 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 entails some of the following areas of activity:

- **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 to 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/or 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”). 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/technology factors and inputs (e.g., technology cost and performance; federal/state/local codes, standards, or incentives) and program/utility factors and inputs (e.g., incentives, 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/technology factors and inputs (e.g., technology cost and performance; federal/state/local codes, standards, or incentives) and program/utility factors and inputs (e.g., incentives, rates, avoided costs)
- 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 discussed below.

5.3.2 Energy efficiency

Energy efficiency programs focus on helping 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^{TM} brand, which are jointly funded and administered by Platte River and its owner communities. These programs provide communities with 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. The potential market segments from which energy savings is anticipated to be achieved are shown in figures 13 and 14 below.

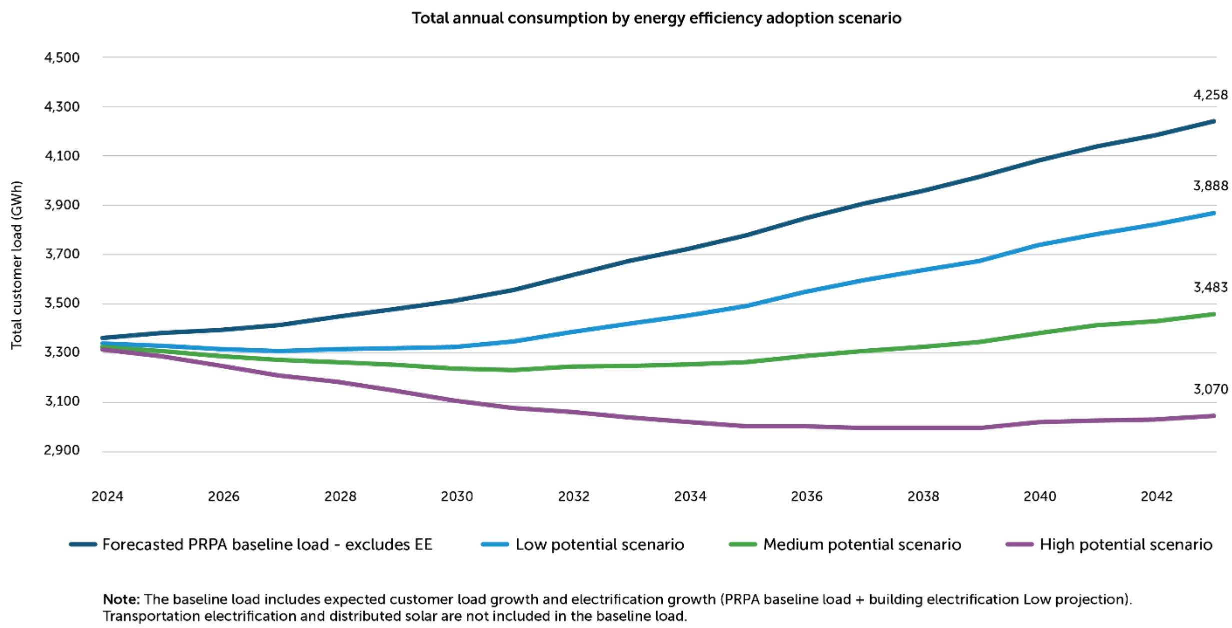


Figure 13. Total annual consumption by energy efficiency adoption scenario

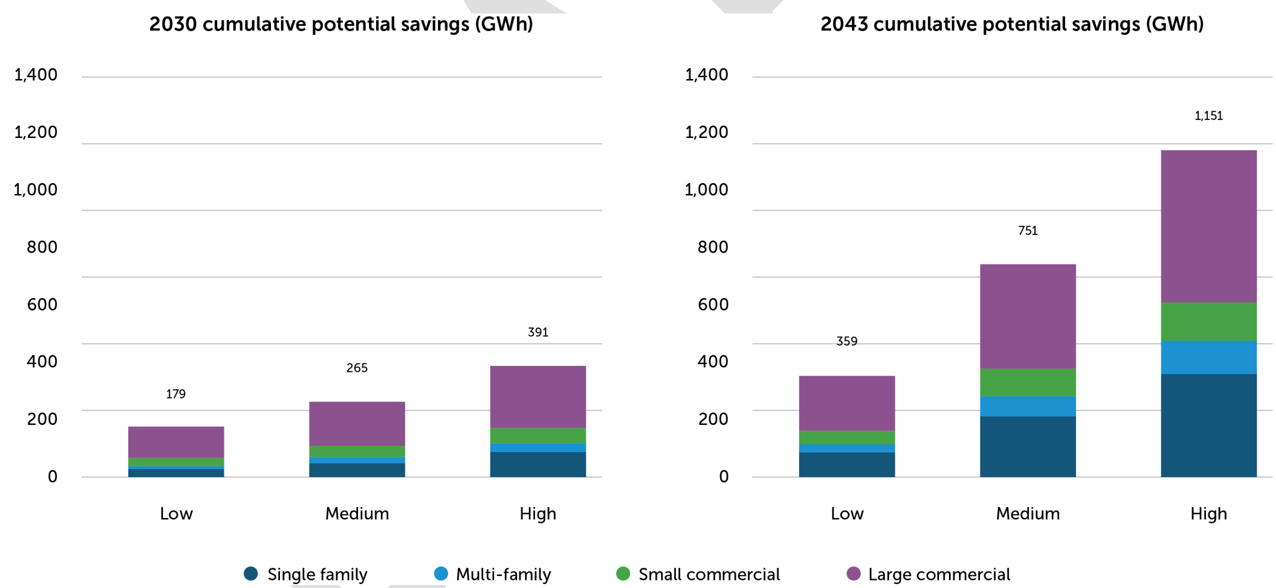


Figure 14. Cumulative potential savings (GWh)

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. However, participation rates result in savings that 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.

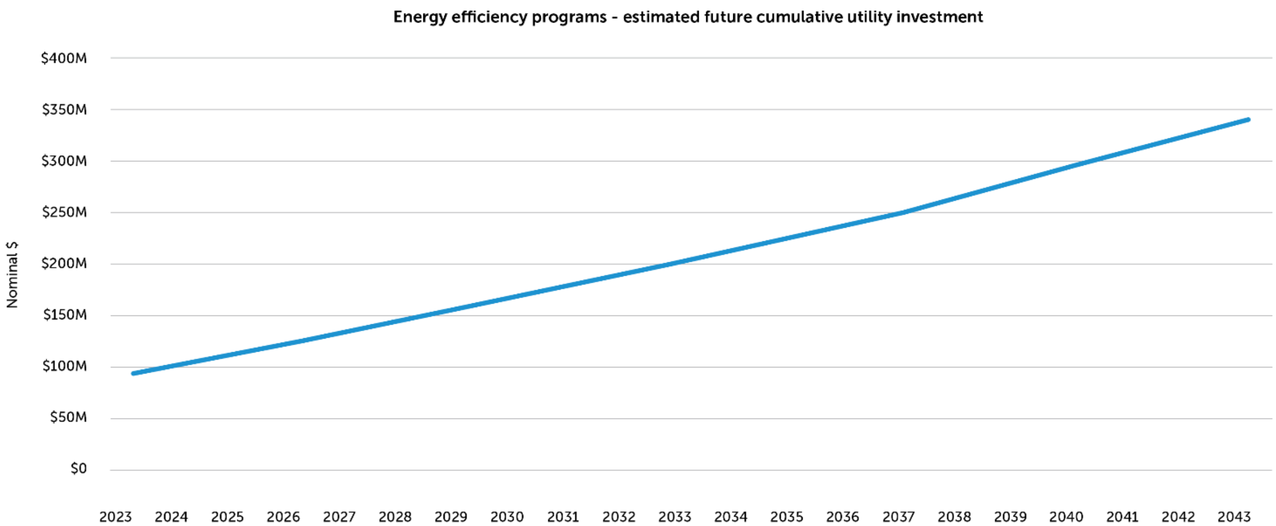


Figure 15. Energy efficiency programs - estimated future cumulative utility investment

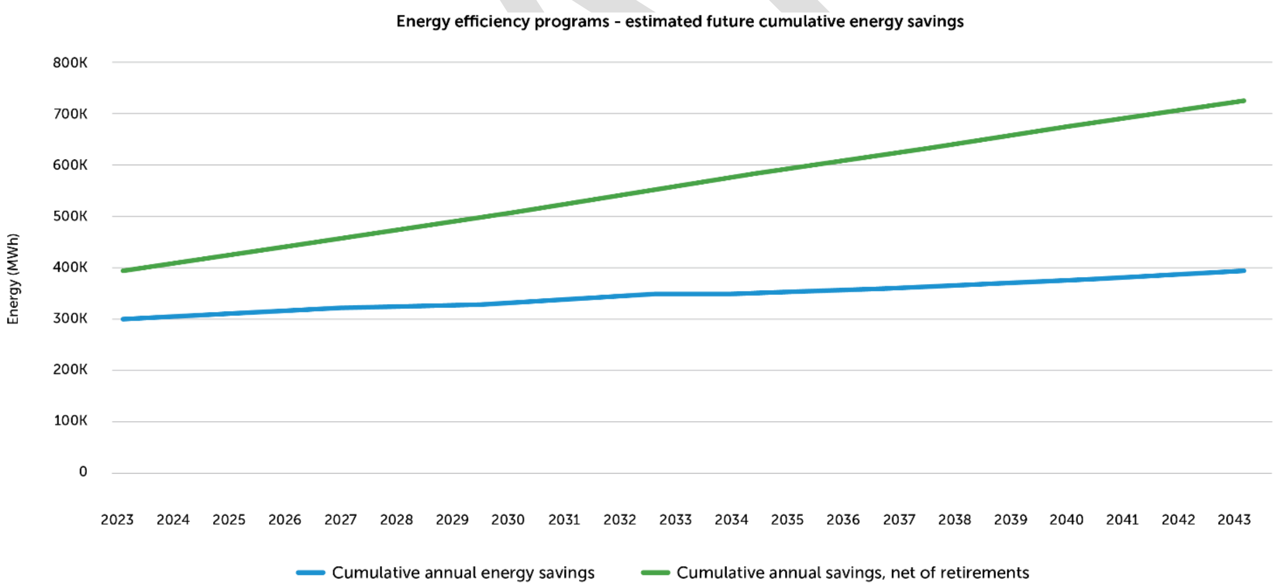


Figure 16. Energy efficiency programs - estimated future cumulative energy savings

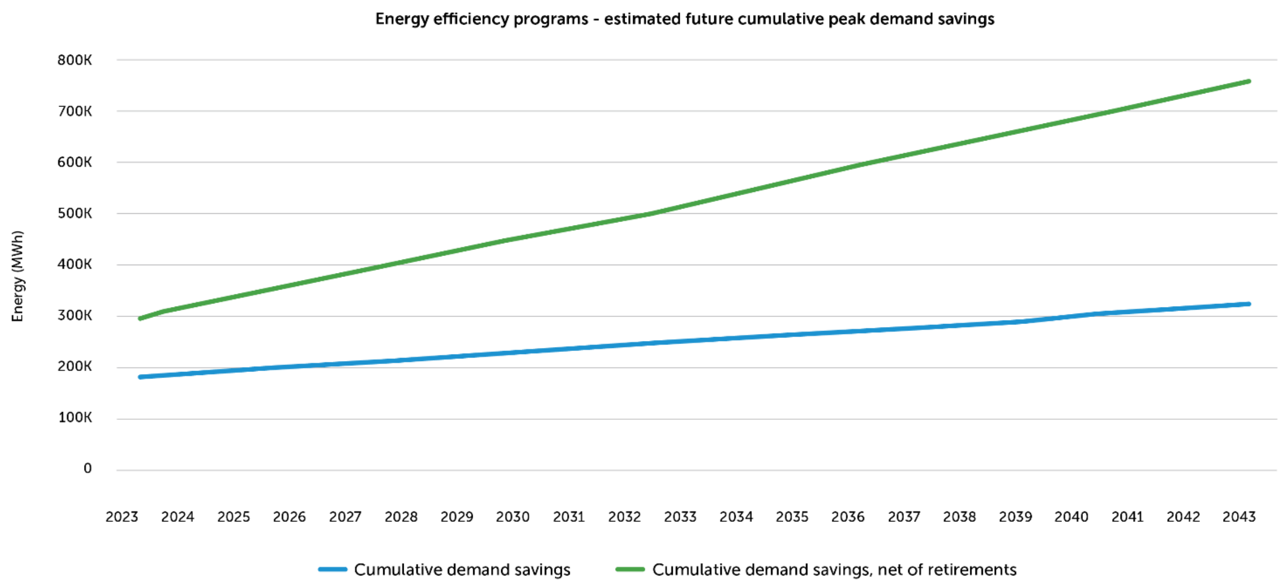


Figure 17. Energy efficiency programs - estimated future cumulative peak demand savings

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 beneficial electrification provides additional economic benefits, grid benefits and environmental benefits, it is referred to as beneficial building electrification. Typically, beneficial 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, beneficial 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 below. Additional details on building electrification impacts can be found in the APEX Analytics study included in the appendix.

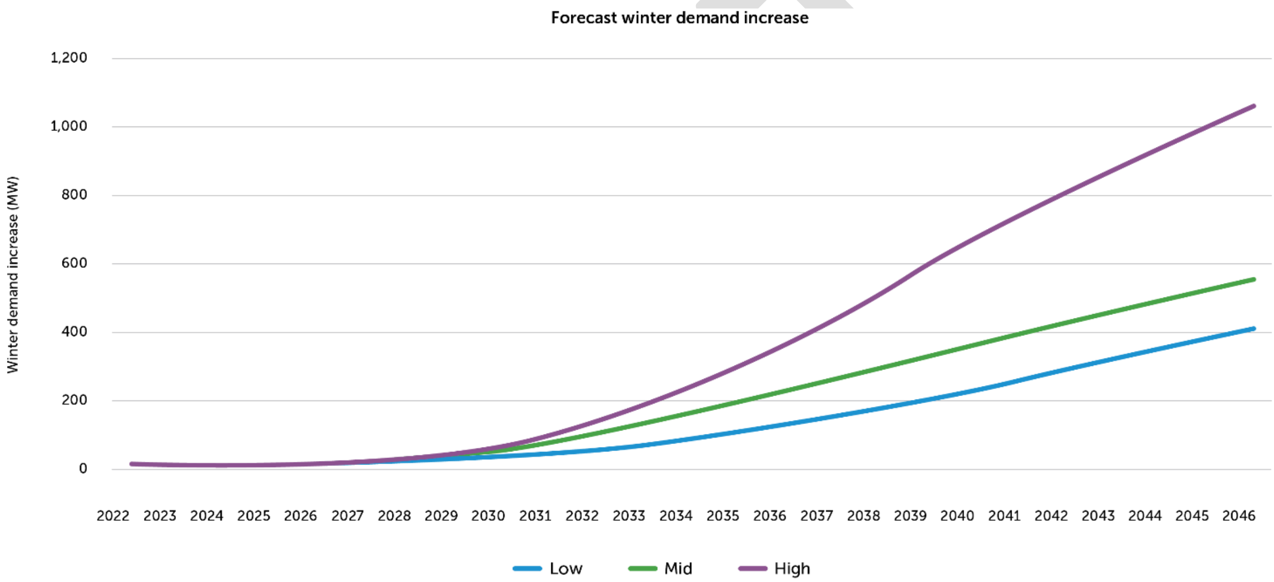


Figure 18. Forecasted winter demand increase

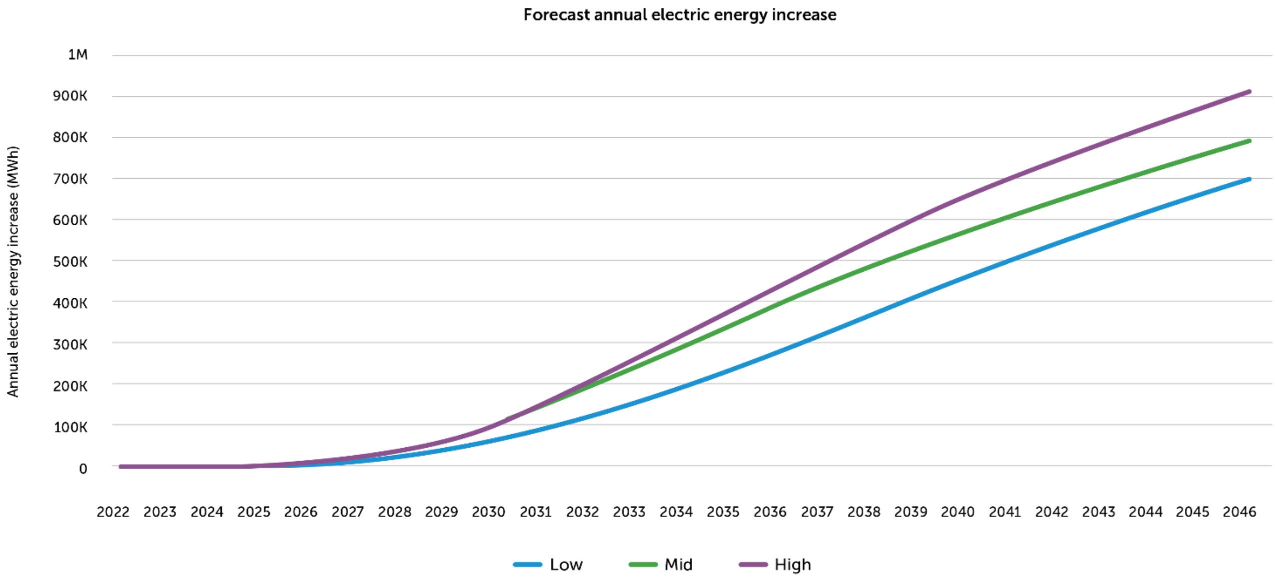


Figure 19. Forecasted annual electric energy increase

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 owner/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/program interventions; technology availability and cost declines; and market factors (e.g., electric rates, fuel prices). No utility rebates were evaluated. Table 4 summarizes the driving factors for each scenario considered in the study.

Table 4. Primary drivers for transportation electrification

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[9])	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

[9] 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.

The following figures depict the anticipated adoption for the three scenarios in terms of number of vehicles, annual energy and summer peak demand.

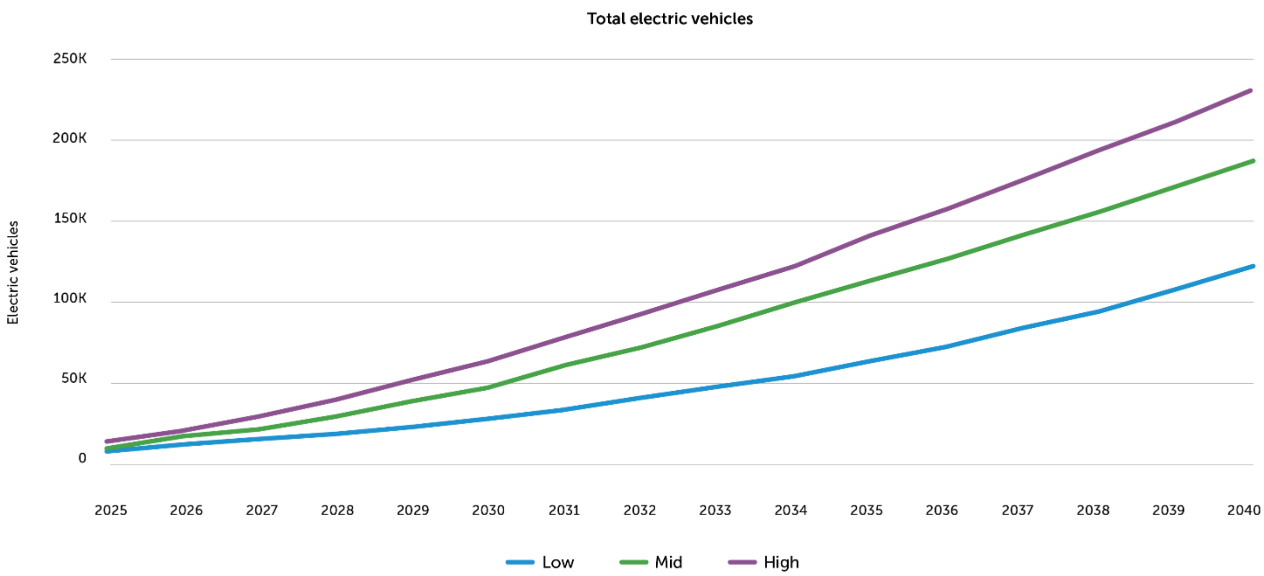


Figure 20. Total electric vehicles

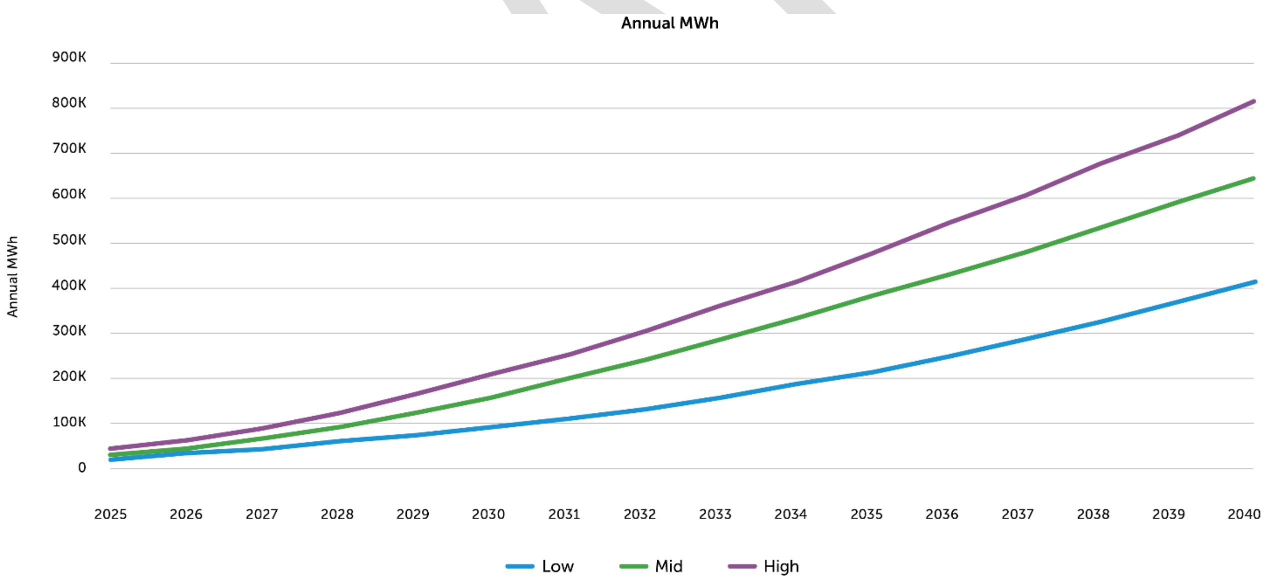


Figure 21. Annual MWh

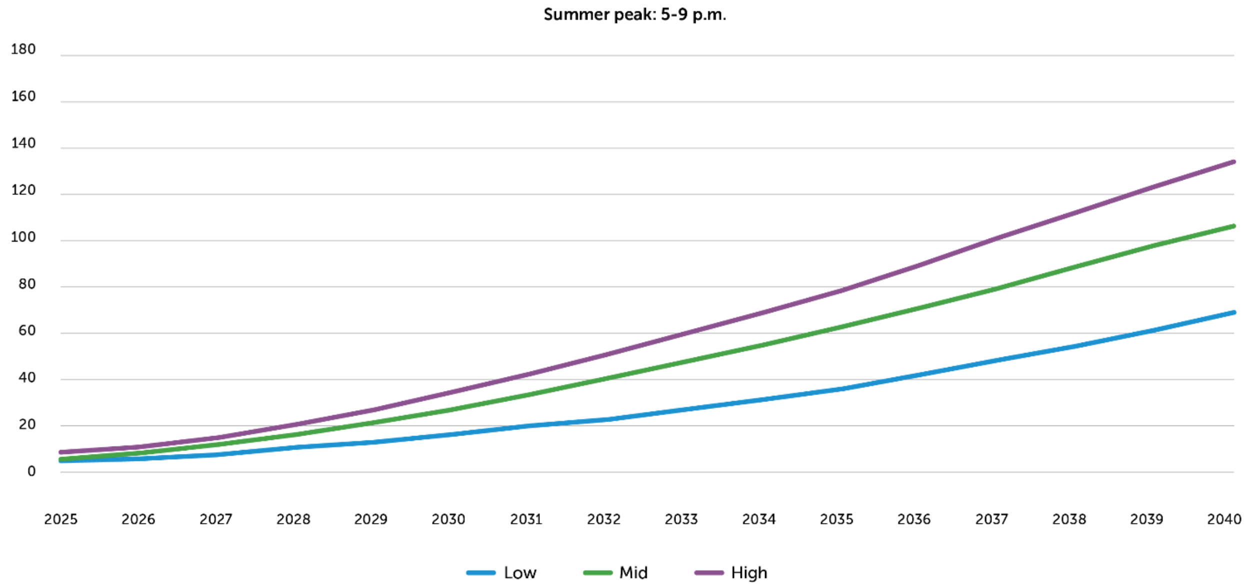


Figure 22. Summer peak: 5-9 p.m.

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 beneficial electrification upgrades
- Providing incentives to the income qualified community sector to support beneficial electrification initiatives
- Developing programs to support distributors selling beneficial electrification equipment in the commercial HVAC sector
- Engaging and training local contractors about the benefits of beneficial 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 beneficial building electrification continues to grow, customer programs will encourage energy efficiency upgrades like building envelope improvements. In combination with the beneficial electrification upgrades, these improvements will allow for the potential to call on demand response activities for longer durations in the future.

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 web site. The web site 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 the state of $5,000 per public charging port. This incentive aims to promote public charger hosting by local business and multifamily properties 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 offering focusing on supporting commercial customers to optimize building more complex systems. The programming 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 both large commercial and industrial customers to optimize complex building automation systems and local HVAC contractors performing ongoing maintenance services, to many small and medium commercial properties in the owner communities.

Including income-qualified communities in the energy transition

For more over 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 this 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.

Since the relaunch, the programming has increased energy savings at commercial properties from an annual average of 4 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 ongoing, monitor-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 to 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 generation solar 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 does not align with their usage patterns.

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 were varied across four scenarios. Distributed storage was assumed to be adopted in relation to solar. Some solar was assumed to be adopted alone, some was assumed to be adopted paired 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.

Table 5. Adoption of distributed generation – solar and storage

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

A range of assumptions has been considered. 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 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 selling excess solar and distributed storage output that is exported 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 static, 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 is anticipated to lead to higher energy costs as the sun sets and after the sun is down.

The **medium export-rate scenario** is based on the idea that the financial value of solar will erode due to higher solar adoption by customers, Platte River and other utilities in the region; the depression of energy prices when solar is plentiful, followed by elevation of prices as 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 assumed to be driven by rates and the rate structure as well as on assumed incentives that could be paid to customers to adopt distributed storage and to enroll distributed storage in a VPP for dispatch by Platte River. The combined impact of changes to net energy metering, export compensation and VPP incentives, coupled with declines in storage costs, is 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.

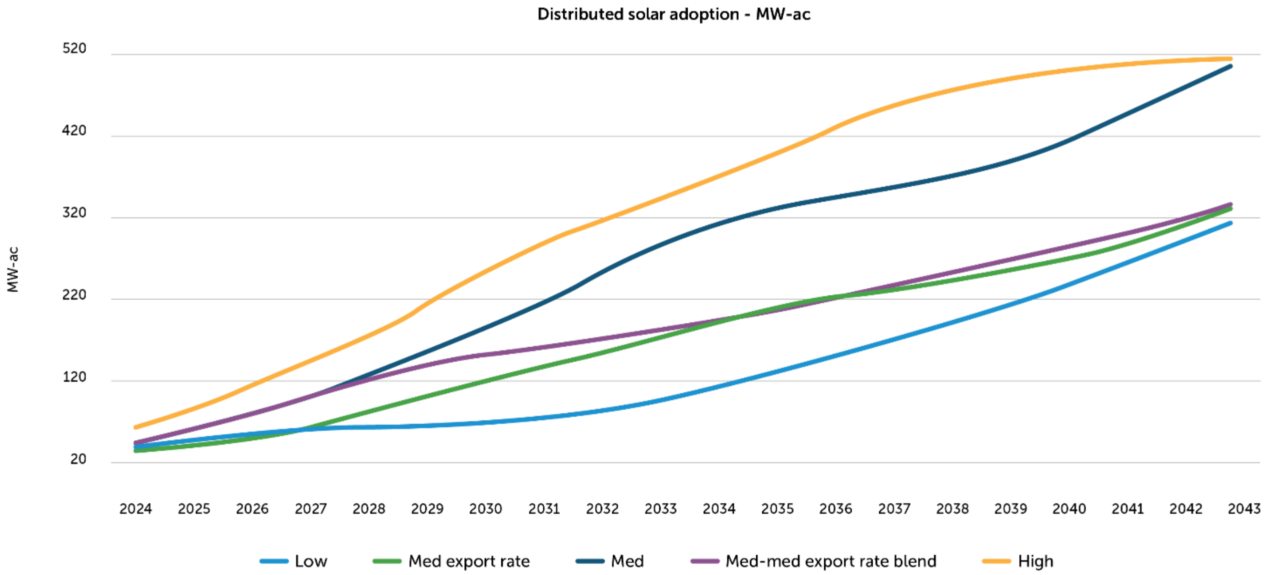


Figure 23. Distributed solar adoption - MW-ac

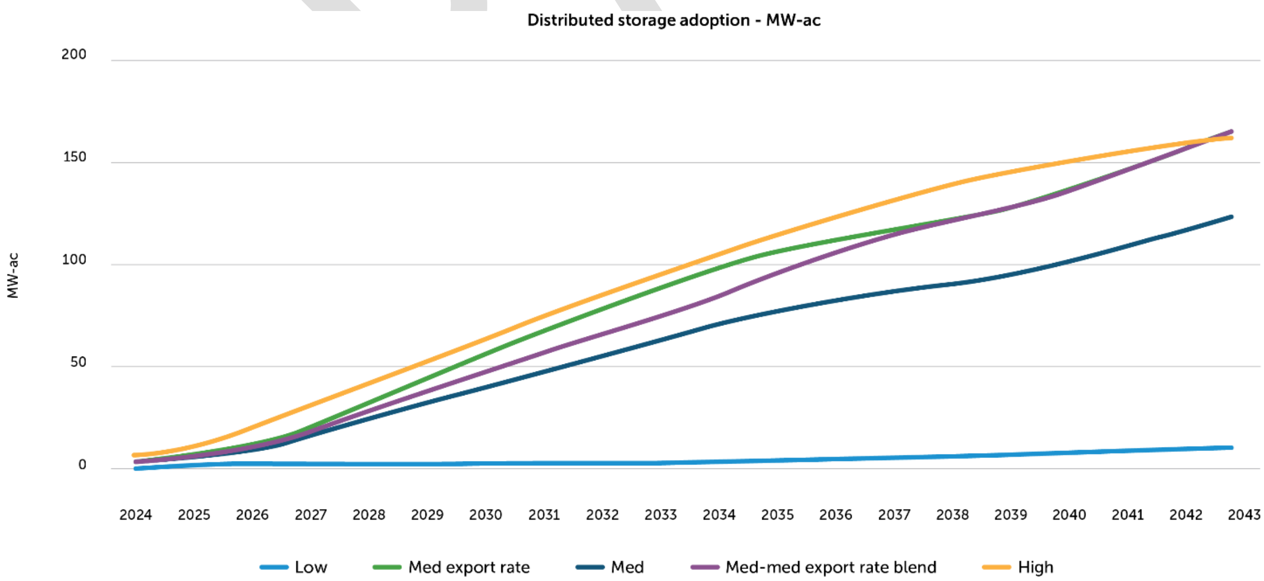


Figure 24. Distributed storage adoption - MW-ac

Monitoring and forecasting distributed generation solar and distributed storage adoption. The rise of distributed generation within the 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%).

The figure below illustrates the growth of distributed solar capacity within Platte River's network, a result 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.

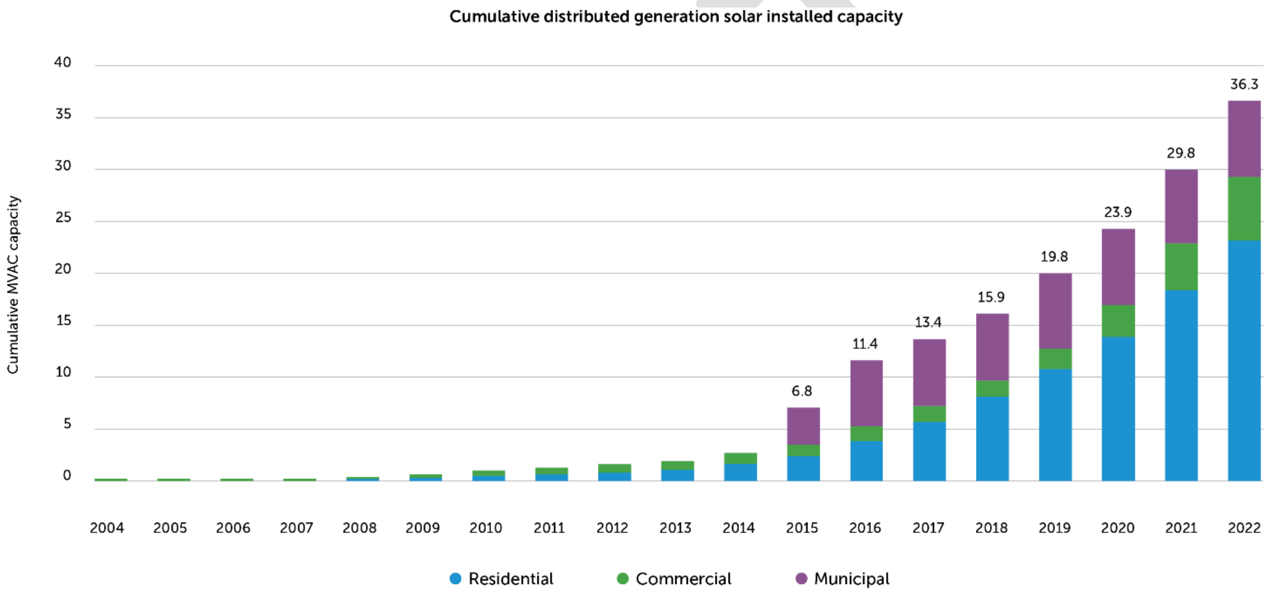


Figure 25. Cumulative distributed generation solar installed capacity

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 interconnections of distributed storage systems, culminating in 2022 with the highest number of installations to date. 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 that 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.
    - It did not include utility cost of VPP-enabling technology and systems. Enabling technology and systems are required regardless of the decision to offer particular flexible DER programs.
- 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. The graph below 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.

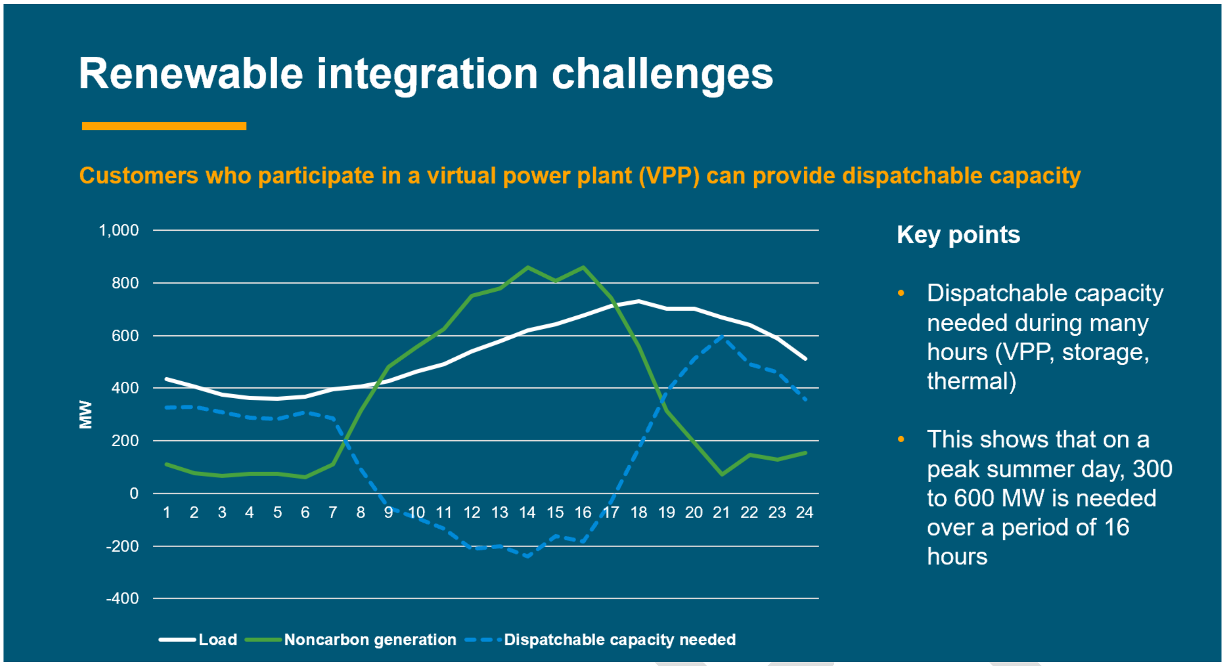


Figure 26. Renewable integration challenges

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.

Table 6. Primary drivers of achievable VPP capacity

	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

Within each scenario, a variety of flexible DER approaches were evaluated in an interactive model to determine how various DERs 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.

Table 7. Flexible DER operating characteristics – load

Measure group	Measure sub-group	Characteristics						
		Curtailment potential	Event duration (hours)	Pre-charge time	Pre-charge sizing	Rebound time	Rebound sizing (per hour)	Event frequency (per year)
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 8. Flexible DER operating characteristics – storage

Measure group	Measure sub-group	Characteristics					
		Size (kW)	Curtailment potential	Round trip efficiency	Typical event duration (hours)	Typical rebound / pre-charge time	Typical event frequency (per year)
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+

Notes:

- 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.

From the tables above, 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 as expected to have more limitations due to impacts on comfort and productivity.

The following figures 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.

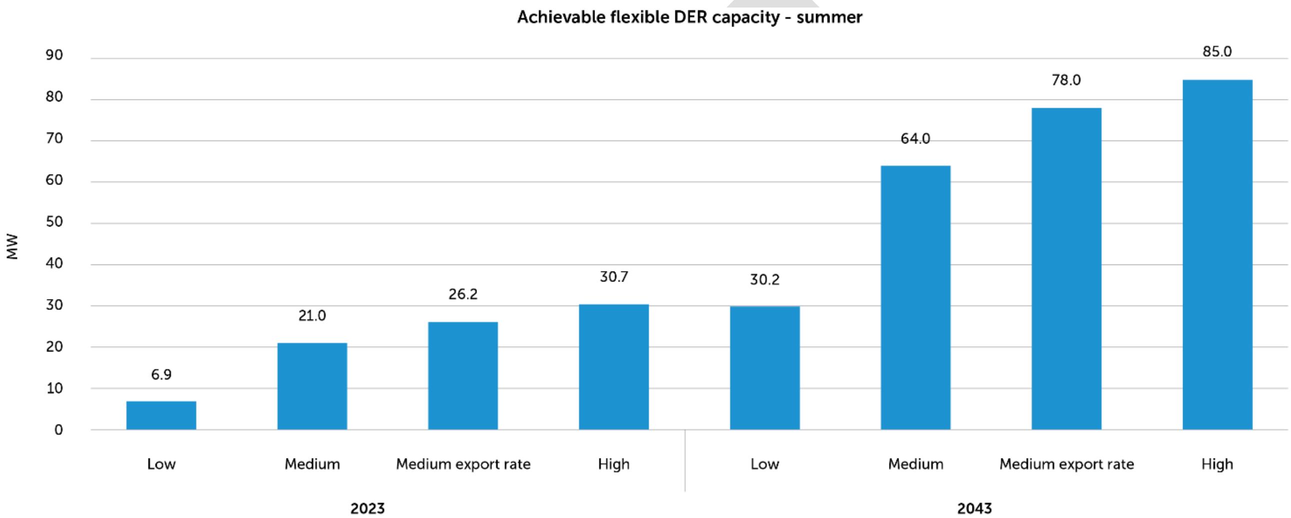


Figure 27. Achievable flexible DER capacity - summer

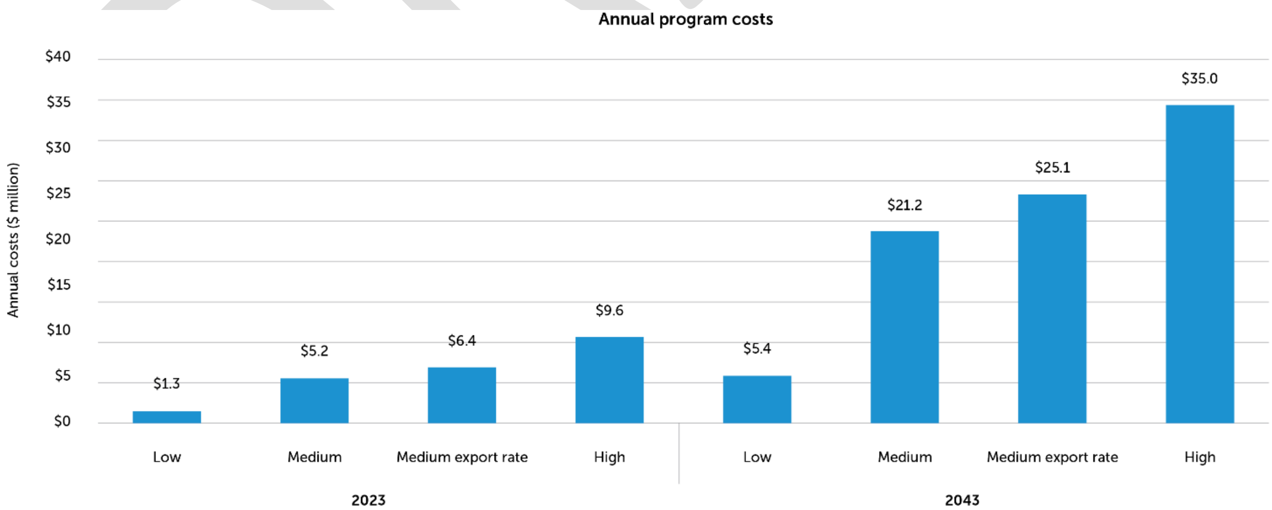


Figure 28. Annual program costs

Key takeaways from the study regarding flexible DERs include the following:

- 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 goals of providing energy in a manner that is reliable, environmentally responsible and financially sustainable, 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 (e.g., compressor load-control switches) or increasingly, through wi-fi enabled thermostats (i.e., "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 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 the VPP may reach an estimated 70 MW by 2030 and 200 MW by 2040. As experience is gained operating the VPP, it is possible that other uses for the enrolled capacity may emerge.

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 to 25 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.

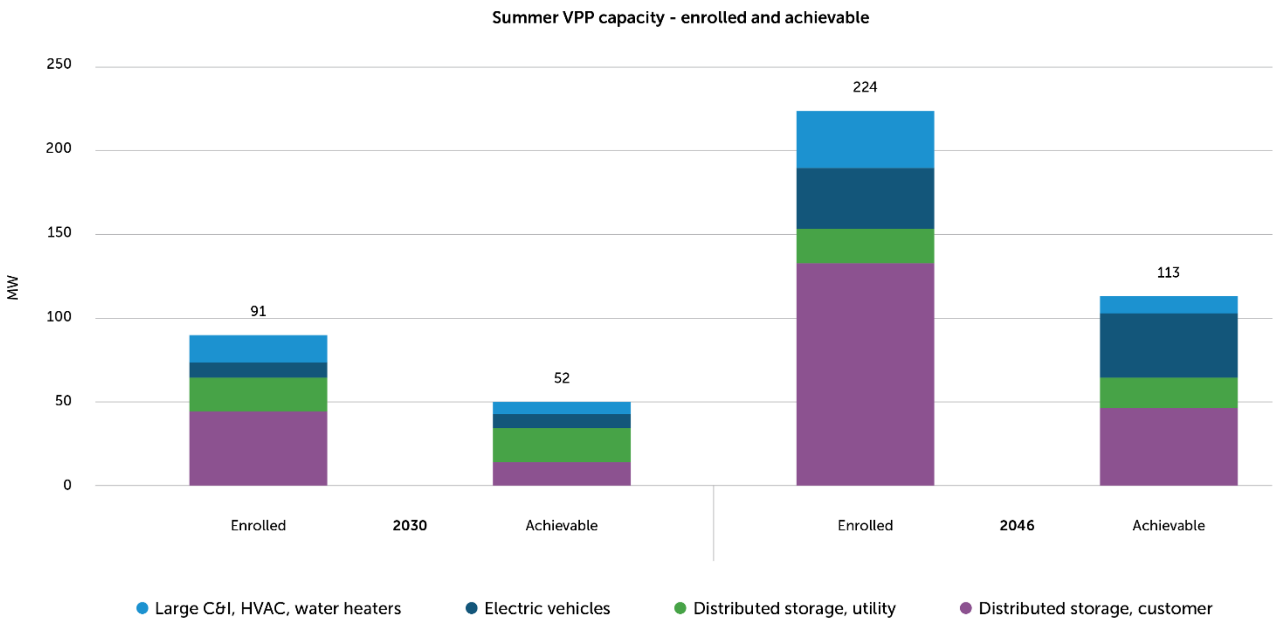


Figure 29. Summer VPP capacity - enrolled and achievable

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.

As this report is being completed, Platte River is preparing a request for proposals 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.

Table 9. Summary and logic for selected scenarios

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.

5.4 Load forecast with DER (final) 2024-2043

Section 5.2 of this chapter covered load forecast prior to 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 in negative terms as this is the reduction in customer energy needs from Platte River 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.

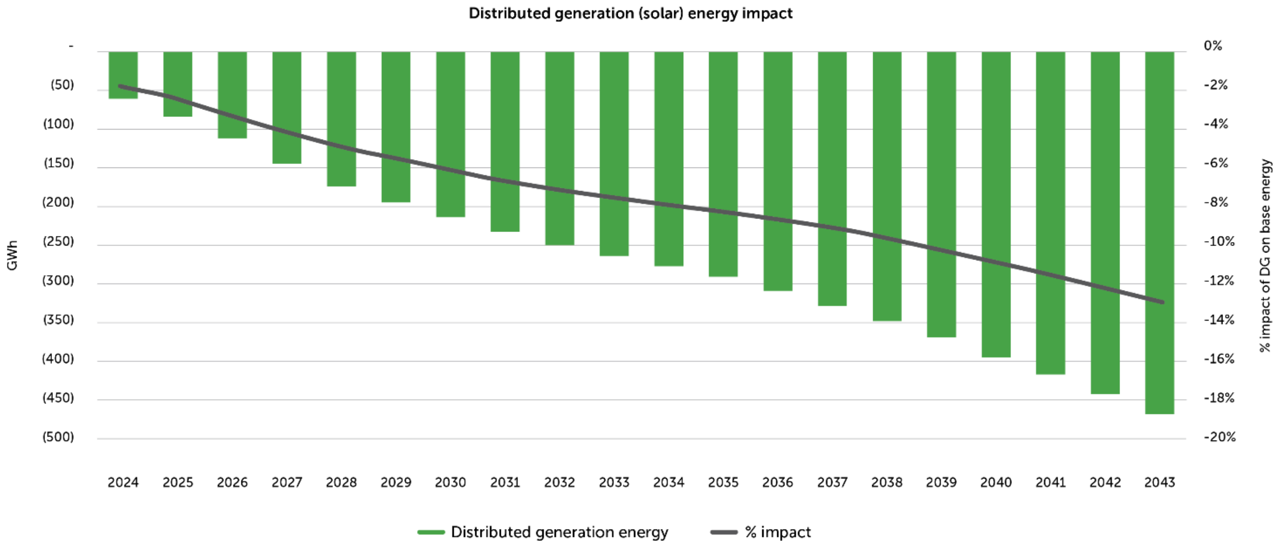


Figure 30. Distributed generation (solar) energy impact

5.4.1.2 Building electrification

Building electrification, mostly consists 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. Being the heating load, most of the building electrification energy requirements will be in winter, but we show annual values in the chart.

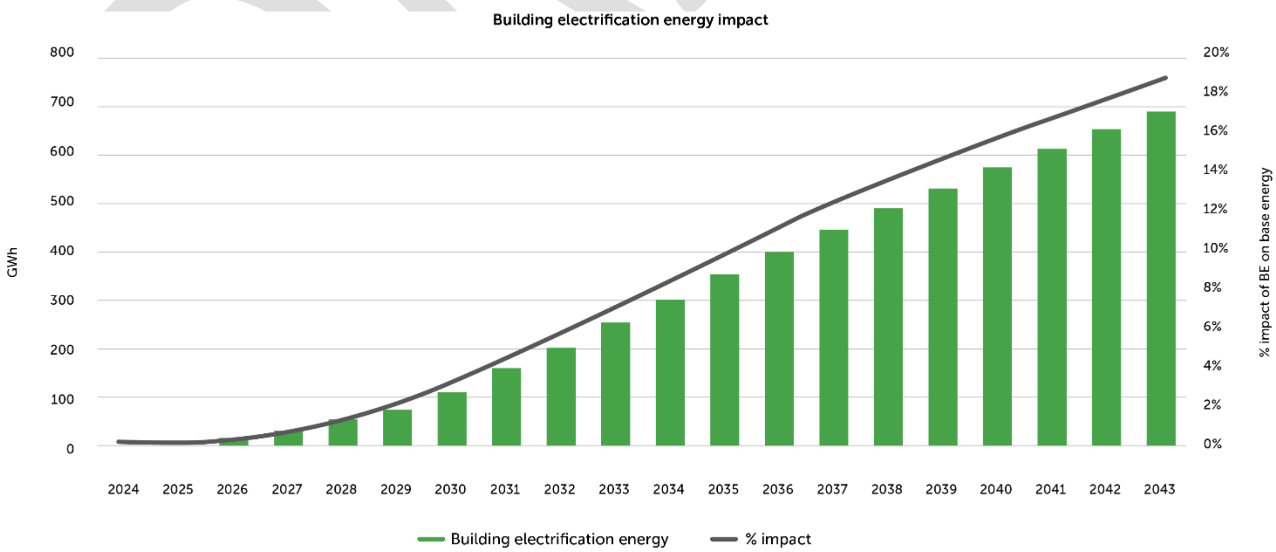


Figure 31. Building electrification energy impact

5.4.1.3 Electric vehicles

EV 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 % 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.

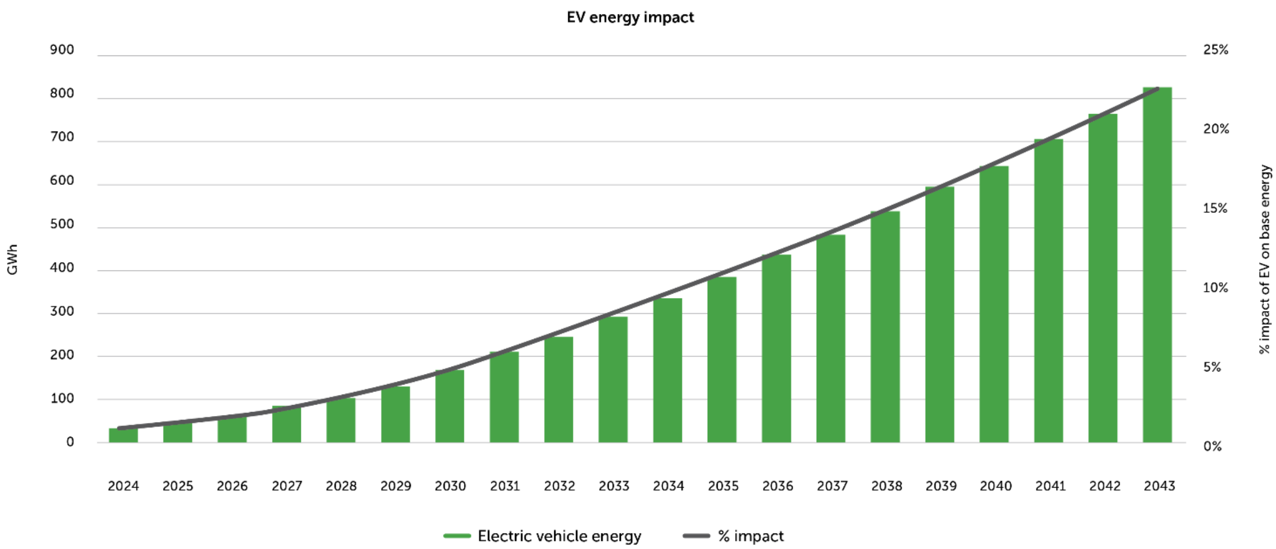


Figure 32. EV energy impact

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 in negative terms as this is the reduction in customer peak demand due to the rooftop solar. The bars show summer peak capacity in MW 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 MW 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, similar to the 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.

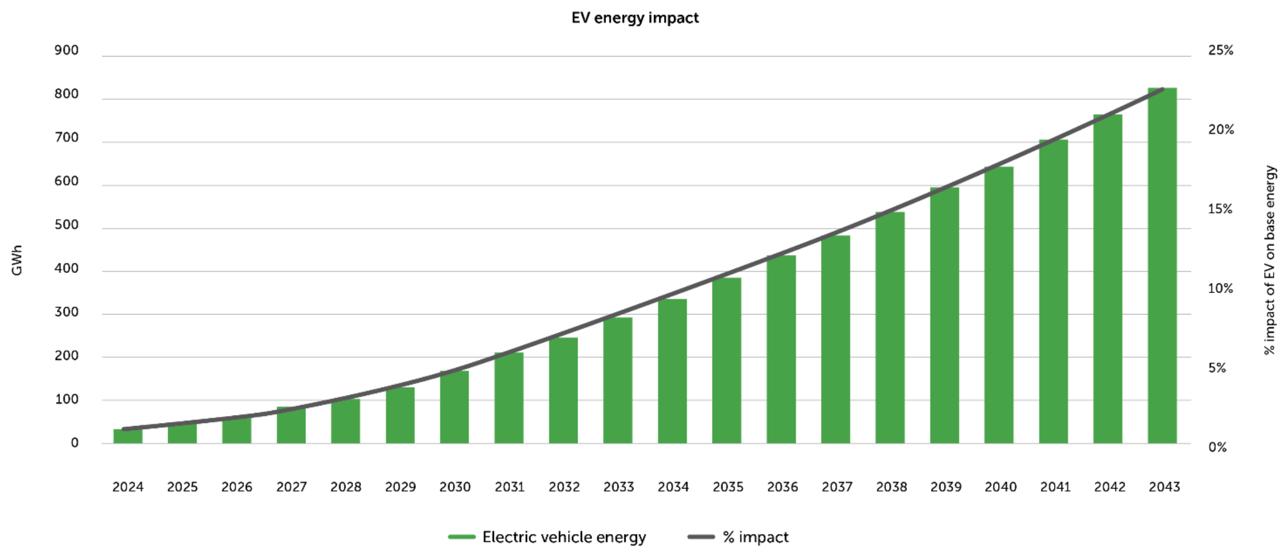


Figure 33. Distributed generation (solar) summer peak demand impact

5.4.2.2 Demand response

Following chart shows the summer peak capacity contribution from demand response or flexible resources such as home battery storage and EV charging load. This is shown in negative terms as this is the reduction in overall customer peak demand. The bars show summer peak capacity in MW and the solid line shows % 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%.

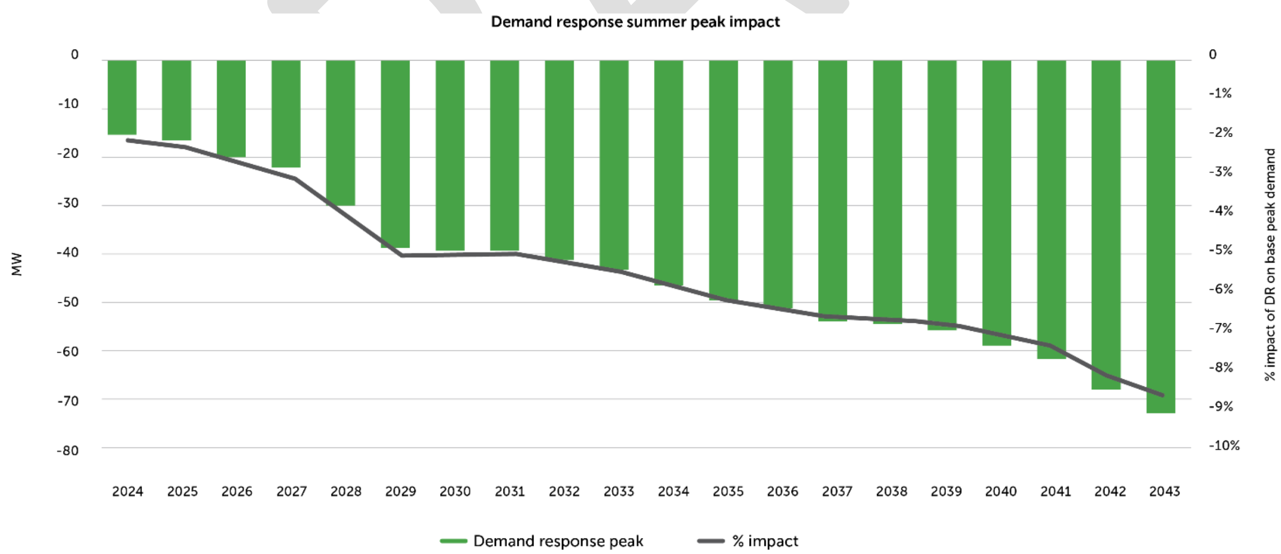


Figure 34. Demand response summer peak impact

5.4.2.3 Building electrification

Building electrification starts from a very small level but is expected to grow rapidly in the next decade. Being the heating load, most of the building electrification contribution is 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 MW and the solid line shows % 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.

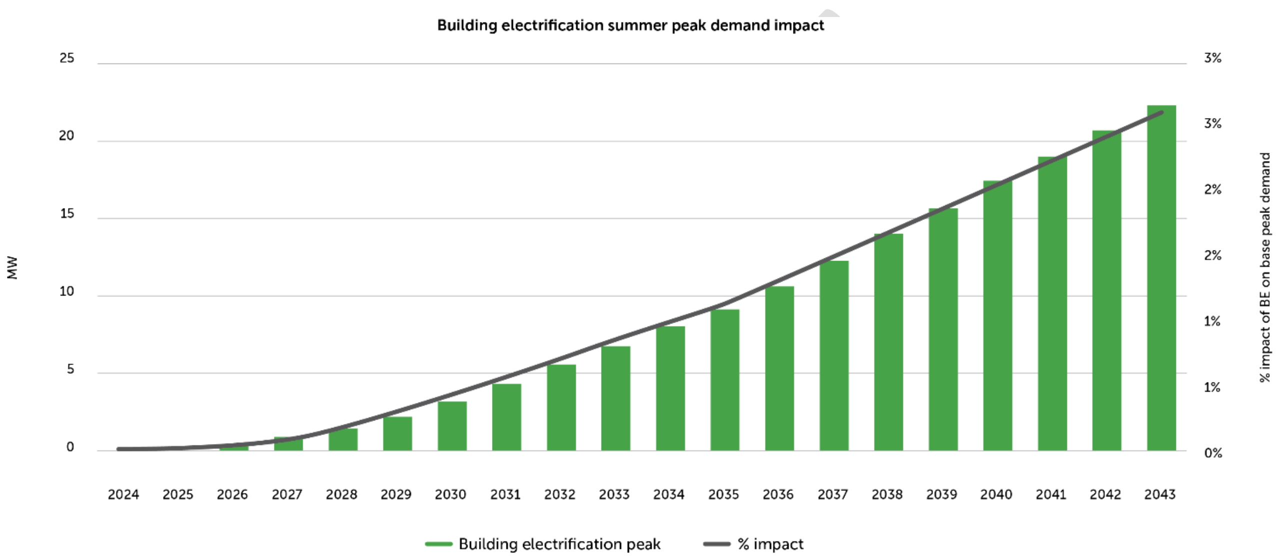


Figure 35. Building electrification summer peak demand impact

5.4.2.4 Electric vehicles

Electric vehicle load starts from a very small level but is expected to grow rapidly in the next decade. This is part of the EV load that is *inflexible* and can't be managed or move away from the summer peak hour. The bars show summer peak capacity in MW and the solid line shows % 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 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 of the assumption that it will be controlled at the time of summer peak hour and moved to a later, lower demand hour.

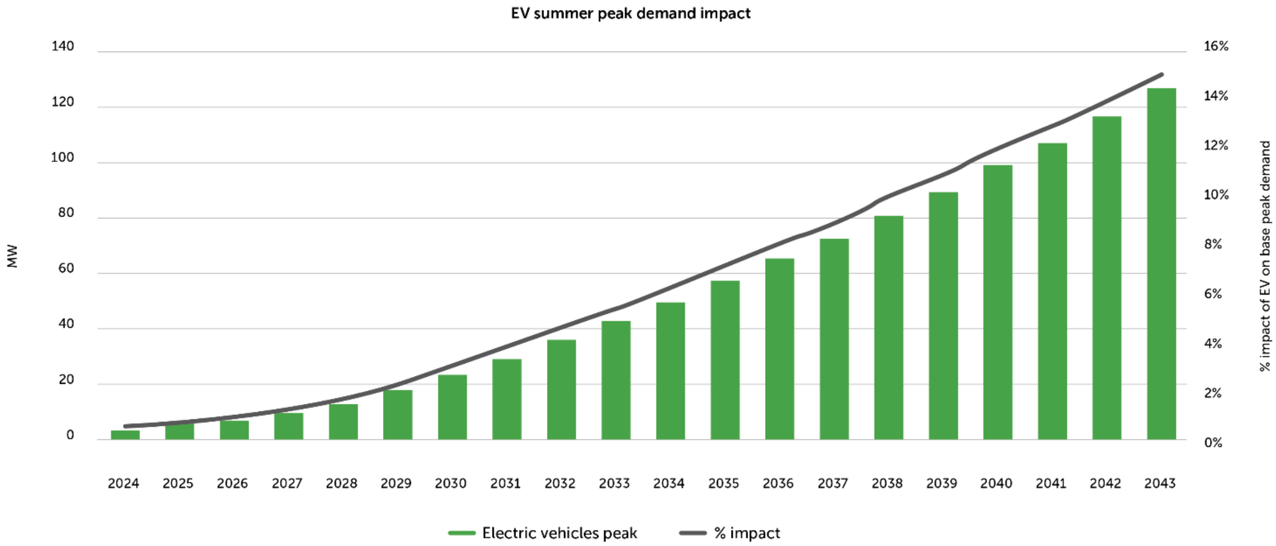


Figure 36. EV summer peak demand impact

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 increases, the additional load impacts outpace 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.

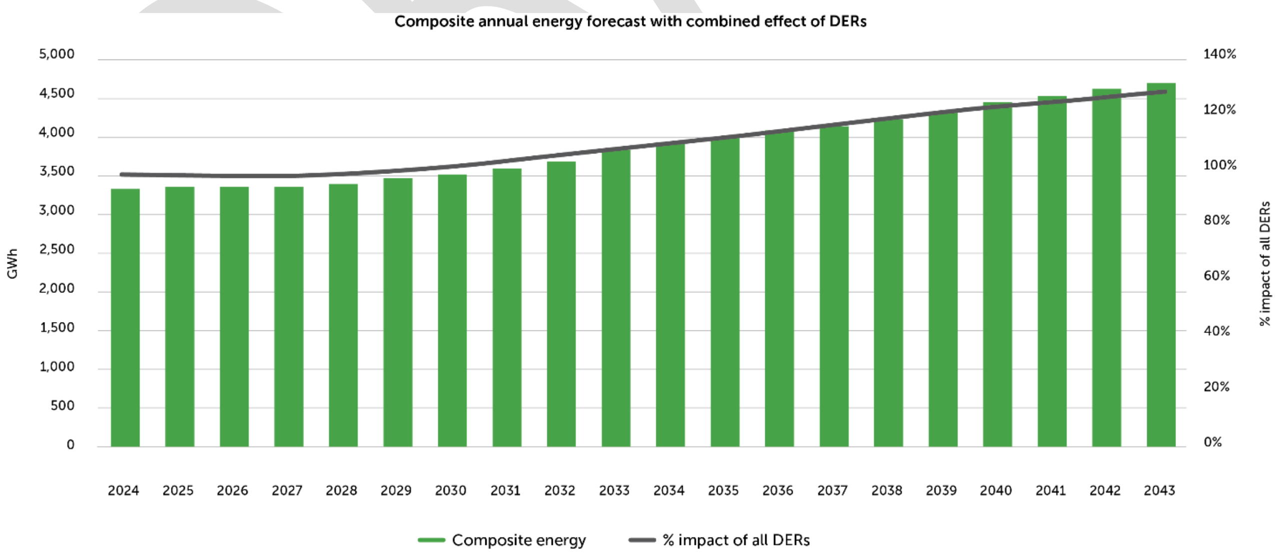


Figure 37. Composite annual energy forecast with combined effect of DERs

The green bars in Figure 37 show composite annual energy in GWh that Platte River's supply system has to produce, and the solid black line shows combined percent impact of all the DERs. The combined effect of DERs reduces the annual energy through 2029 and increases afterwards, due to rapid increase in beneficial electrification and EV load, reaching 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 MW that Platte River's supply system will have to provide, and the solid black line shows combined percent impact of all the DERs. The combined effect of DERs reduces the summer peak demand through 2035 and increase afterwards, due to rapid increase in building electrification and EV load, reaching 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.

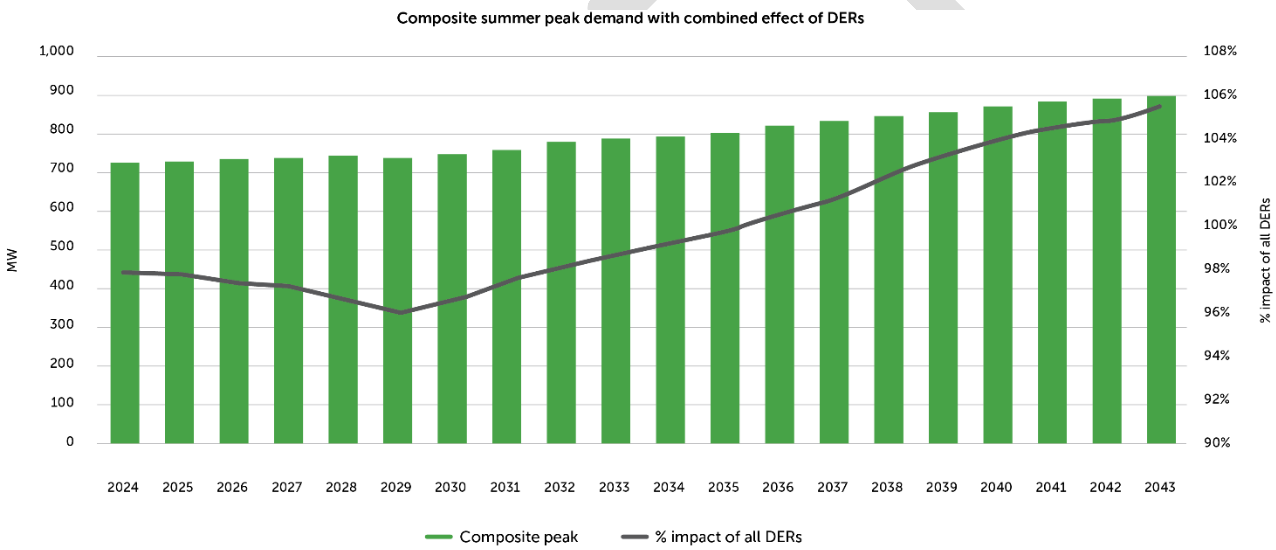


Figure 38. Composite summer peak demand with combined effect of DERs

6. IRP design

6.1 Studies

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

- Reserve Margin 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
- Low or no carbon emissions technology and fuels assessment by Black & Veatch
- Locational Marginal Prices assessment by ACES
- Fundamental market analysis of supply and demand in the region by Siemens (not available on the microsite)

6.2 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 that relies on state-of-the-art supply side and DER resources.

6.3 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 operation responsibilities. In a market, a load serving entity (or an integrated utility) is required to bring enough resources to ensure reliable supply to 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 ample 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.

6.3.1 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 deaths[10] and billions of dollars in economic losses.

Historically, typical 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 the breakdown in the distribution system.[11]

Distribution system interruptions are typically localized and impact a small number of customers. Reliability events that stem from interruptions on the generation or transmission system, or lack of generation, are more widespread 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 of renewable energy from these intermittent resources for extended periods.**

In our IRP process, Platte River focuses on planning for 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 of time. We label these incidents as dark calms. We have found that the dark calm events occur frequently and can last from a day to as long as seven days.

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 to always ensure reliability of supply.

There are a few additional 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.
- **Resilience** is the ability to adapt and recover from a disruption in a minimal time and with minimal impact.

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

[11] https://www.energy.gov/articles/economic-benefits-increasing-electric-grid-resilience-weather-outages

While the above 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 as discussed below.

6.3.2 Planning for a reliable future portfolio

6.3.2.1 Reliability metrics for planning

The North American Electric Reliability Corporation, the regulatory authority tasked to assure reliability and security of the electric grid in North America, defines requirements for resource adequacy in Standard BAL-502-RFC-02[12]. The 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[13].

This metric has traditionally guided investment in generation to provide an acceptable level of reliability and has been 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,

$$PRM = \frac{\text{Firm Capacity} - \text{Peak Demand}}{Peak\ Demand}$$

Historically, PRM covered the planned or unplanned outages (breakdowns of equipment) and load forecast error due to weather and economic growth uncertainty. Following the retirement of dispatchable coal generation (which provided 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[14]. 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).

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

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

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

In a recent report[15], 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, such as Platte River's goal of 100% noncarbon energy portfolio by 2030.
- 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 39 from New York ISO[16] 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. The old idea of planning for the peak load hour is giving way to planning for the net peak hour, or preferably, every hour.

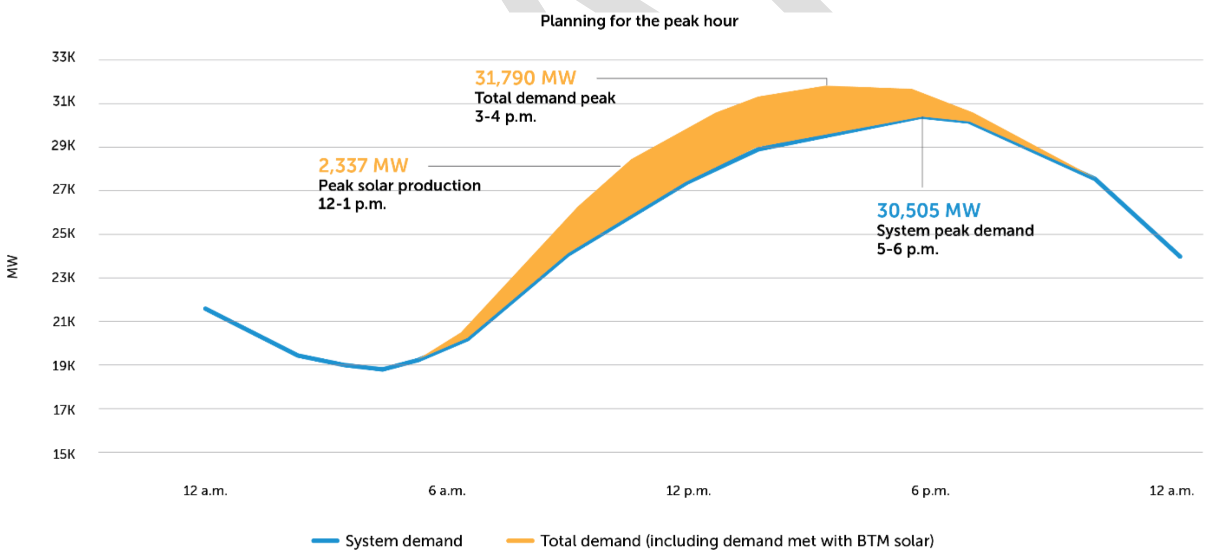


Figure 39. Planning for the peak hour

Similar phenomenon is experienced in other parts of the country. Wind generation can have a similar impact of shifting the net peak demand to different hours. In fact, the Western Electricity Coordination Council (WECC), the entity responsible for assuring 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%[17].

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

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

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

6.3.2.2 Platte River PRM for future planning

For the 2020 IRP, Platte River used a 15% PRM as the reliability metric. With the changing portfolio mix in the region[18] and with the backdrop of ongoing discussions in the industry, we engaged Astrape Consulting to perform a resource adequacy[19] study for this 2024 IRP. This study computed PRM and ELCC[20] 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 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 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[21] report. Power markets like the Midwest ISO and SPP are also looking at higher PRMs than they previously had recommended due to coal retirement and more intermittent energy integration.

Astrape proposed a PRM of 19.9% for 2030 after an exhaustive analysis of Colorado utilities including Xcel Colorado, Colorado Spring Utilities and Black Hills Colorado, in their modeling platform Strategic Energy & Valuation Model, which is 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 40.

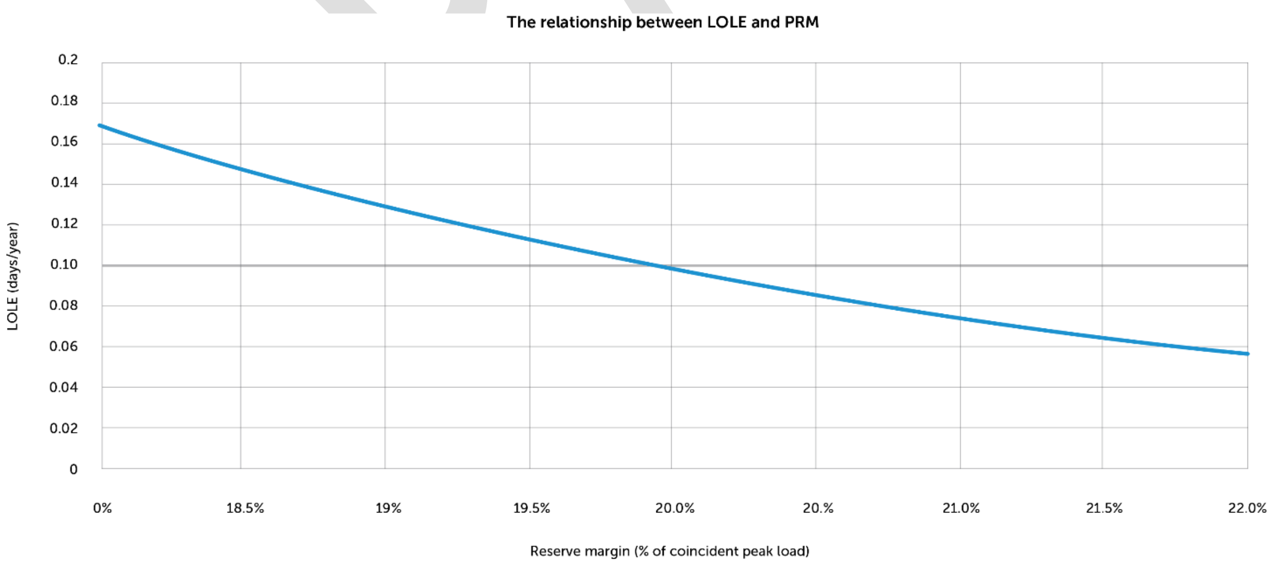


Figure 40. The relationship between LOLE and PRM

[18] Platte River has filed a voluntary clean energy plan committing to reduce its 2030 CO_2 emissions by at least 80% from the 2005 levels.

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

[20] ELCC of a resource can be defined as the measurement of that resource's ability to produce energy at the time of peak demand.

[21] https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf

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 will 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. There are many metrics being considered by utilities and other entities. 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.

6.3.2.3 ELCC values for renewables and limited energy resources

The ELCC of a renewable or energy limited resource is equivalent to a reduction in contribution to peak demand from these resources. 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%.

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

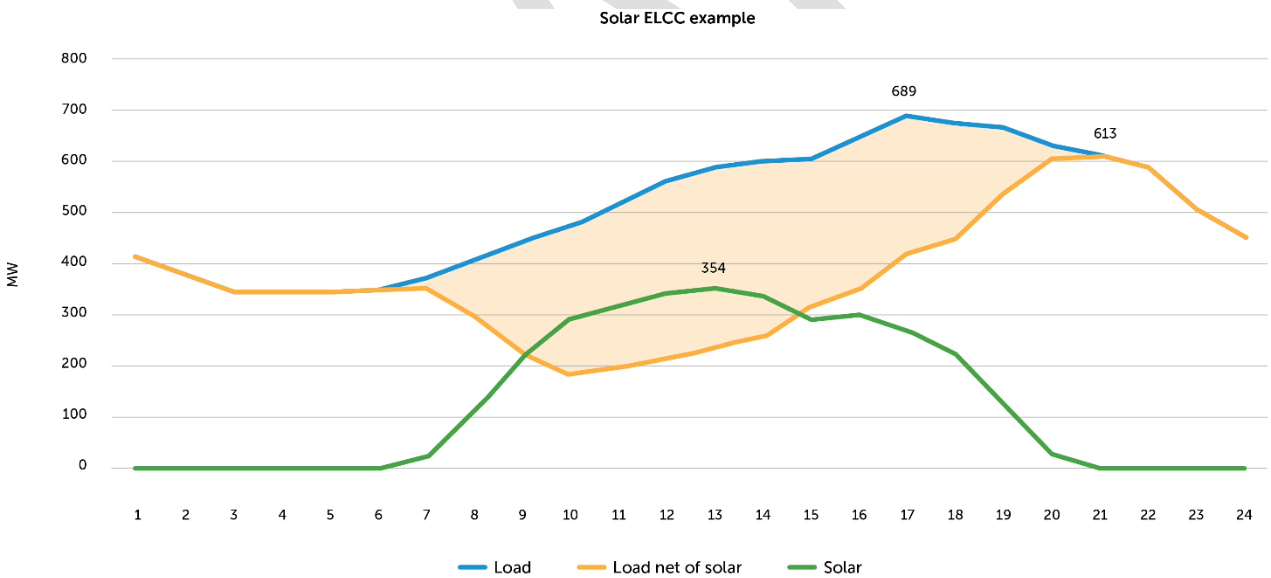


Figure 41. Solar ELCC example

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 less 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, or the effect solar had on the peak is that it reduced it by 76 MW.

As we install more solar, its impact on reducing peak will be zero since the peak demand hour has already moved to 9 p.m., after sunset when solar stops producing. In this example, 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 42 shows the ELCC values of solar, wind and four-hour storage through time as computed by Astrape consulting and used by Platte River in this IRP modeling. As utilities in Colorado add more of these resources over time, their ELCC contributions go down.

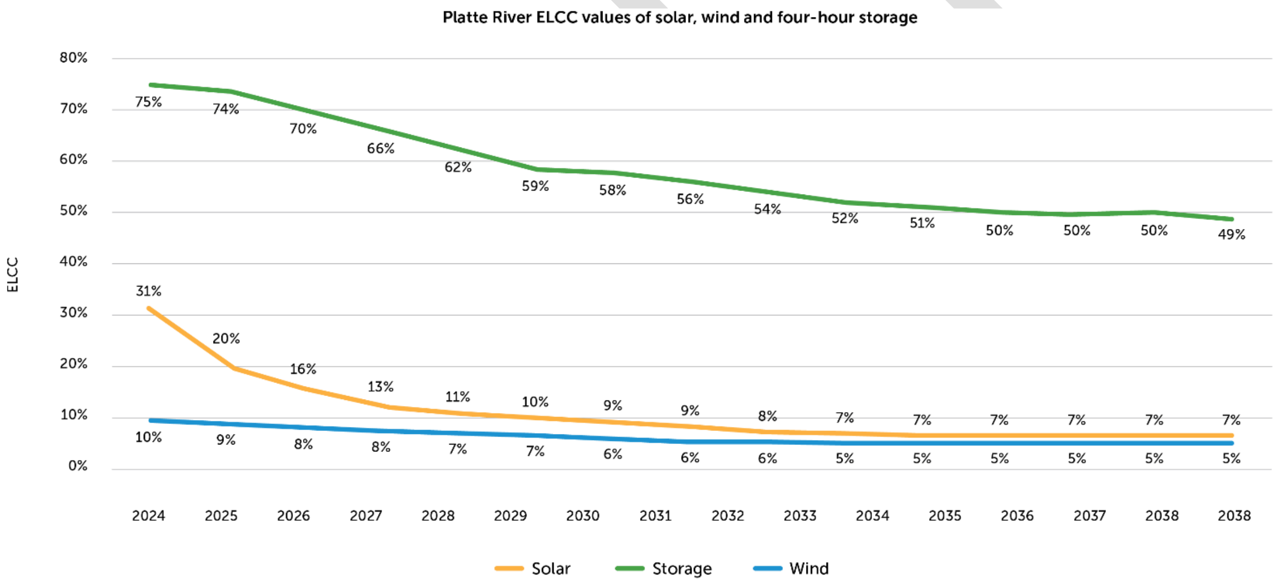


Figure 42. Platte River ELCC values of solar, wind and four-hour storage

Table 10 shows ELCC values of longer duration battery storage and some DER technologies computed by Astrape and used by Platte River in this IRP. The installation of more resources of the same type reduces its ELCC. For example, the ELCC of distributed solar is 8.5% if the Colorado utilities install 500 MW and drops to 5.8% when 4,000 MW are installed.

Table 10. ELCC values of long duration energy storage and DERs

Technology	Penetration (MW)	Average ELCC (%)	Marginal ELCC (%)
8-hour batteries	500	92.7%	91.6%
8-hour batteries	1000	90.5%	84.4%
8-hour batteries	1500	87.0%	75.6%
100-hour batteries	500	92.7%	91.6%
100-hour batteries	1000	91.9%	90.8%
100-hour batteries	1500	91.4%	90.0%
Distributed generation solar	500	8.5%	7.9%
Distributed generation solar	1000	8.0%	7.2%
Distributed generation solar	2000	7.2%	5.8%
Distributed generation solar	4000	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%

6.3.2.4 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 43.

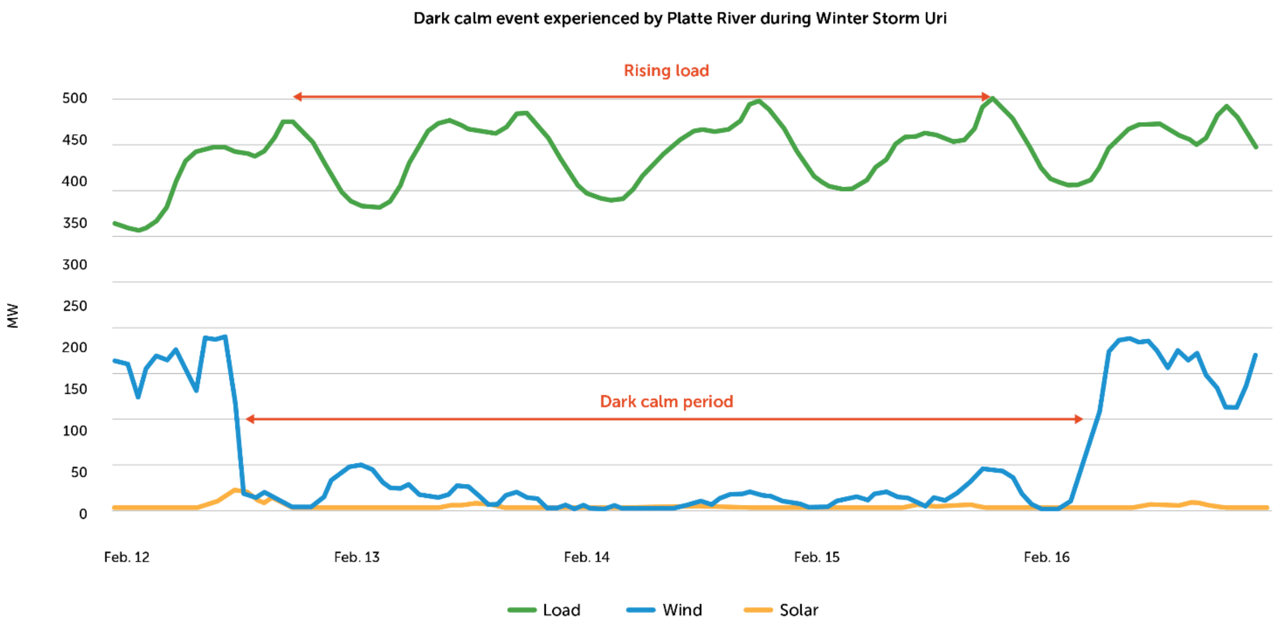


Figure 43. Dark calm event experienced by Platte River during Winter Storm Uri

During this 2021 dark calm, Platte River was able to serve its customers' load reliably due to the availability of dispatchable coal resources. Following the retirement of coal 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[22].

ACES reviewed hourly weather profiles for 70 locations west of Mississippi for the past five decades (1973-2019) with a focus on estimating the frequency, duration and depth of extreme weather and dark calm events. Since these events are uncommon, ACES had to review weather data across a wide region and over a long period of time to enhance confidence in the findings. Figure 44 shows locations of the airports where data was collected.

[22] https://www.prpa.org/wp-content/uploads/2023/04/2024IRP-Extreme-weather-events-and-Dark-Calm-Analysis-by-ACES.pdf

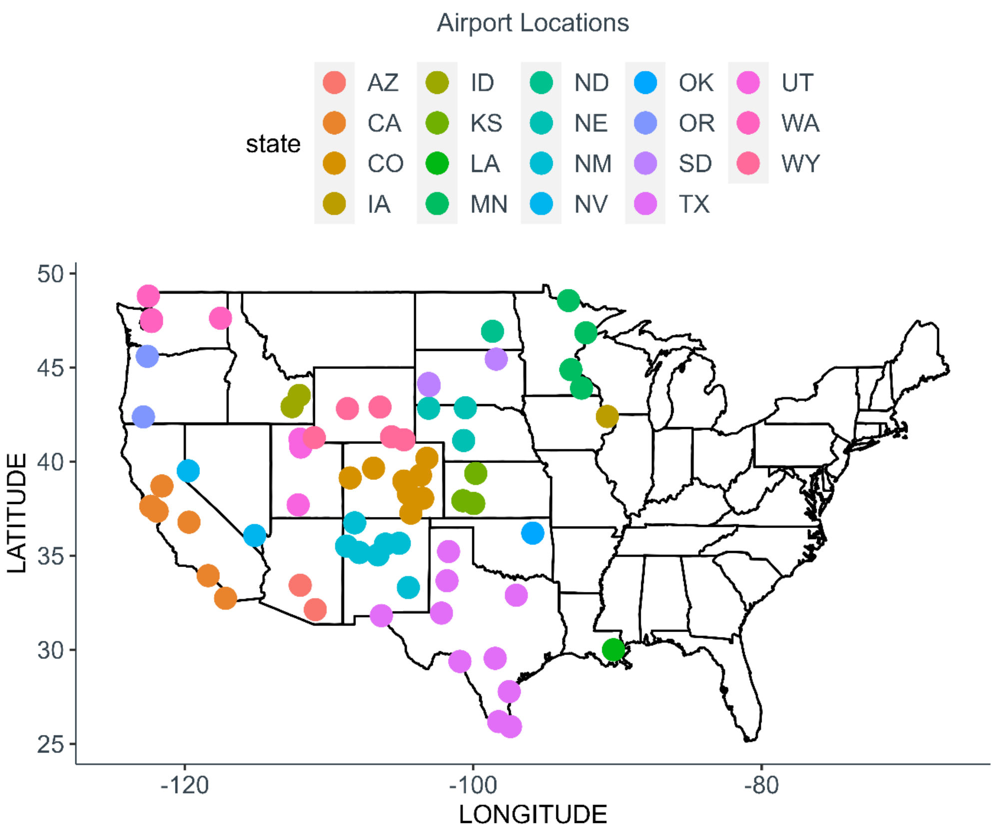


Figure 44. Locations of extreme weather events

6.3.2.5 Extreme weather events

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

Table 11. Heat wave summary - west region

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

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.

Table 12. Cold wave summary - west region

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

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. Since our focus with extreme weather modeling is on reliability, we focused on extreme weather impact on load only. The study found that during these events, on average, the load could increase by about 10% relative to the normal load during that time of the year. So, for reliability assessment during extreme weather, we increased the hourly load by 10%.

6.3.2.6 Dark calm events

Frequency and duration of dark calm events was assessed for the Midwest Independent System Operator (MISO) North, covering parts of Illinois, Indiana, Wisconsin and Michigan; MISO Central, covering parts of Minnesota, Iowa and North Dakota; and the Electric Reliability Council of Texas (ERCOT), covering the northwest part of Texas. Table 13 shows the frequency and duration of different levels of dark calm events.

Table 13. Dark calm events by location

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

As shown in the table, 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.

To parameterize 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, an average of two events with a duration of 48 hours means any given year would expect a total of 96 dark calm hours due to events lasting 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.

Table 14. Dark calm event duration and frequency

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

6.3.2.7 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 are completed using transmission network modeling software, integrating forecasted owner community loads, existing and planned generation, along with 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. Evaluation of long-term transmission requirements includes long-term load and generation forecasts in conjunction 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. In the event 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 in conjunction with regional transmission planning committees.

6.3.3 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 is planning to meet its future peak demand with 19.9% PRM to ensure reliability of supply. We also discussed that renewable and energy limited resources contribute ELCC capacity toward the peak demand which is lower than the maximum or the nameplate capacity.

Figure 45 shows the capacity requirements and the capacity contribution from the existing and committed resources.

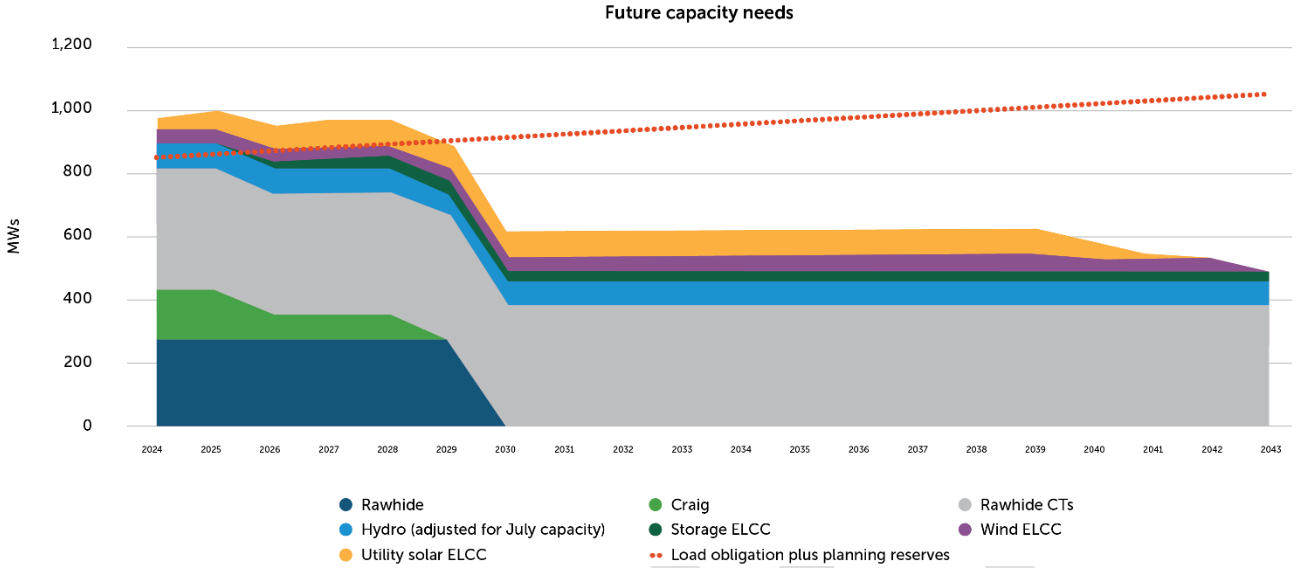


Figure 45. Future capacity needs

The dotted red line shows the capacity requirement 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 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 date. The IRP process offers recommendations to fill this gap with the lowest cost, least emitting reliable resources.

Figure 46 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.

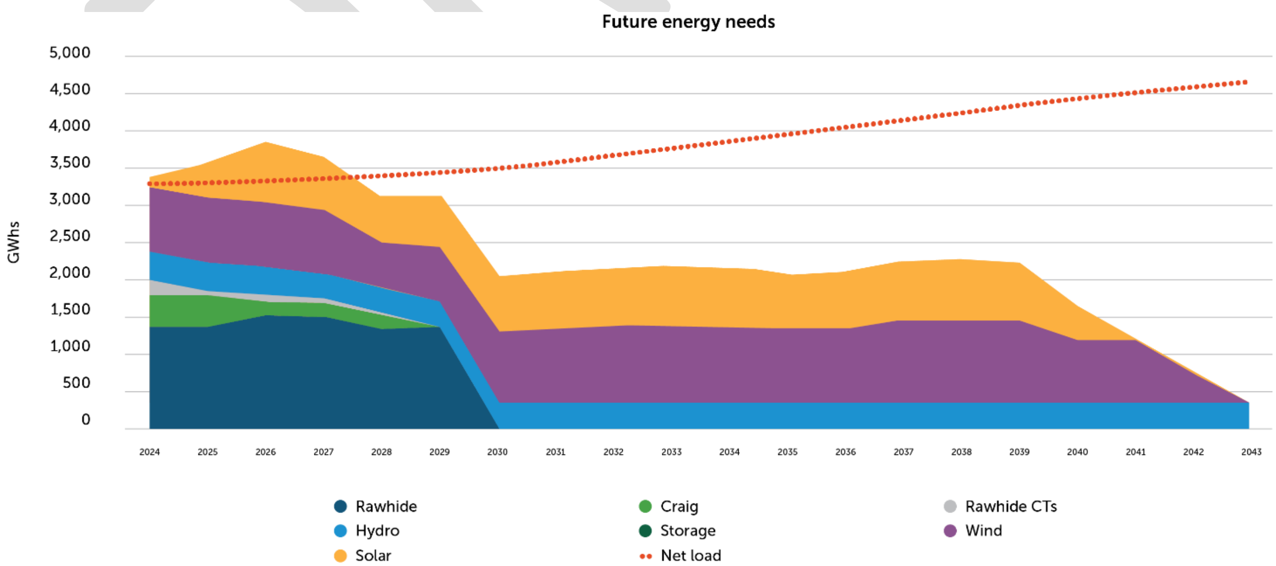


Figure 46. Future energy needs

As seen in the above charts, capacity and energy gaps appear in 2030 but Platte River plans to bring new resources online before 2030. In fact, as of this writing, we are conducting a competitive procurement process seeking resources to be operational by 2028. This would give us a full year to test the availability and reliability of our new portfolio before retiring the last coal plant by the end of 2029.

6.4 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 to meet the RDP. Portfolio 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, the existing combustion turbines were kept in all portfolios. Due to the lack of available dispatchable noncarbon options by 2030, all portfolios emit some CO2 in 2030 as thermal units are dispatched to balance the system during times of shortage. 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 long duration energy storage becomes available in 2035. All portfolios considered a carbon price on the future electricity prices. Below is a brief description of all the portfolios.

6.4.1 No new carbon

In this portfolio, the model 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 and reduce the risk associated with adding new thermal generation.

6.4.2 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.

6.4.3 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.

6.4.4 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 like dark calm and extreme weather events continue to become more severe, as they have in the recent past.

6.4.5 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 no additional constraints are added to guide resource selection or operation.

6.5 Methodology

Developing future power supply portfolios is a multi-step, iterative process. Figure 47 illustrates the initial steps and the subsequent iteration through the remaining steps.

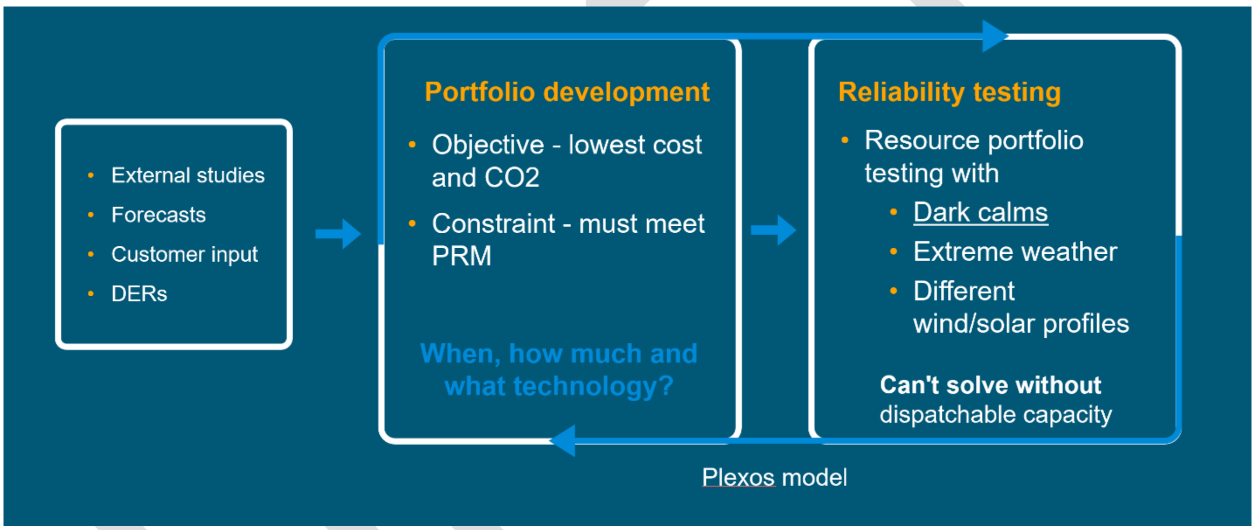


Figure 47. IRP process

6.5.1 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: New sources of demand such as beneficial electrification and electric vehicles are forecasted 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, some technologies can be eliminated from consideration.

Stakeholder engagement: A critical step in the process involves collecting 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 served by Platte River.

6.5.2 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 penetrations 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 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.

6.6 Reliability testing of portfolios

Since reliability is a foundational pillar, careful attention is paid to ensure 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 are useful summary tools, but they do not test or guarantee reliability during extreme weather events or dark calms. Additional reliability testing through the Monte Carlo functionality in Plexos was used 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, the model was parameterized to vary system conditions across:

1. **Weather**: wind and solar profiles reflecting conditions from 1997-2019 (hourly profiles for 24 years) were 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 timing of the outages is randomly drawn by the software. The duration of the outage is also hypothetical, but the software does parameterize the draws to align with the 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 15 summarizes the potential load forecast error outcomes.

Table 15. Potential load forecast error outcomes

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

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 a number of 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 output over the course of the event. These generators can experience a variety of issues including snow cover or icing, overcast skies or debris and/or dust buildup due to high winds. In the summer months, solar output during a dark calm event averages 10% since summer outages are often limited to extended overcast weather.

d. **Wind**: During the winter months, wind generation during a dark calm averages 5% of its nameplate output over the course of the event. This reduced production is primarily due to blade icing, but overspeed 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.

6.7 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). Details discussing the Plexos model are provided in Appendix 9.6.

7. IRP study results

This chapter presents the modeling results for each portfolio with comparisons of their most important metrics including cost, CO2 emission reductions and renewable energy penetration—metrics that align with Platte River's foundational pillars of financial sustainability and environmental responsibility. As noted previously, Platte River developed every portfolio considered in this IRP to meet our reliability criteria (another foundational pillar).

7.1 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.

7.1.1 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 were 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 48 and 49 illustrate annual peak and energy forecasts for quick reference.

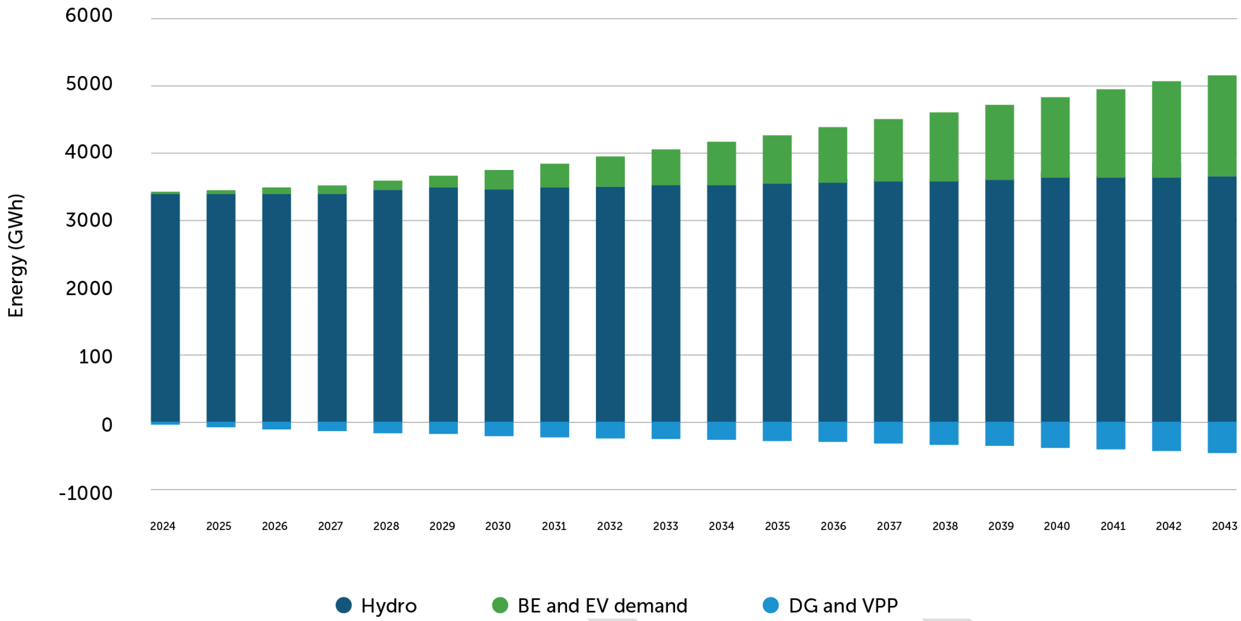


Figure 48. Annual peak demand forecast (MW)

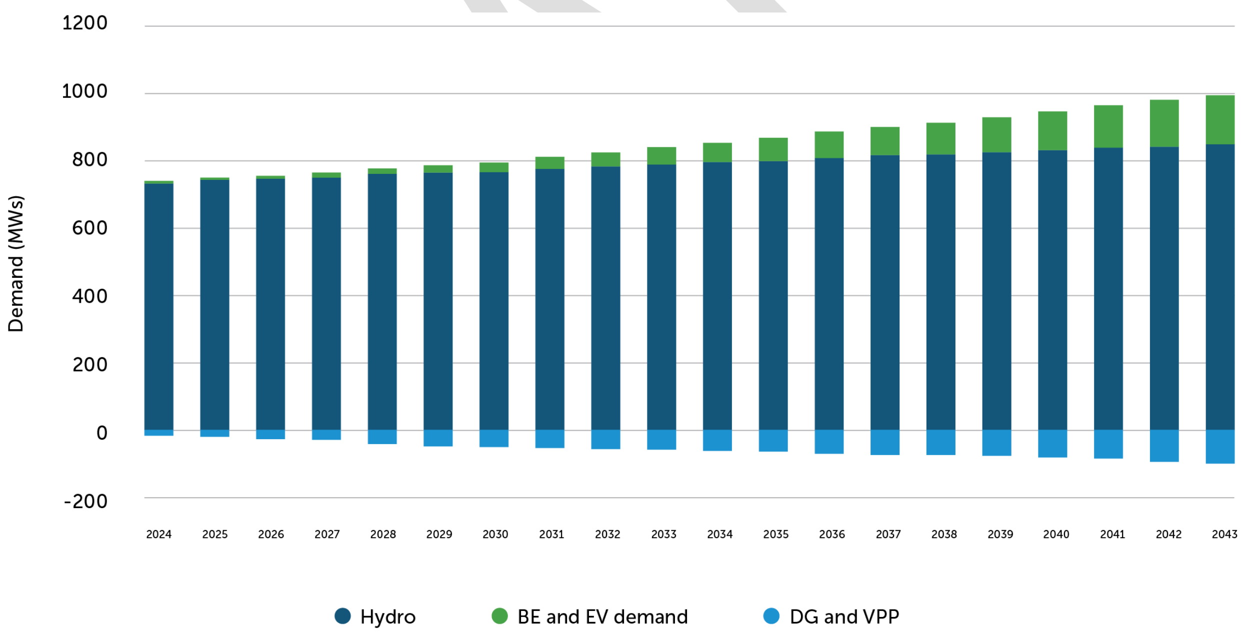


Figure 49. Annual energy forecast (GWh)

Figures 48 and 49 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 16 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.

Table 16. Existing and committed resources

	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

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. With a goal to provide 100% noncarbon energy by 2030 and commitment to completely retire coal generation by the end of 2029, 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 17 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.

Table 17. Summary of five portfolios

	Portfolio 1 No new carbon	Portfolio 2 Minimal new carbon	Portfolio 3 Carbon-imposed cost	Portfolio 4 Additional new carbon (lowest cost)	Portfolio 5 Optimal new carbon
2024-2029 incremental additions					
Wind	300	300	400	300	400
Solar	450	500	350	300	300
Four-hour storage	2,850	1,050	275	100	175
Long-duration storage	10	10	10	10	10
Dispatchable thermal	0	80	160	240	200
Final 2043 Portfolio					
Wind	885	885	985	985	885
Solar	600	600	550	450	600
Four-hour storage	2,850	1,100	400	175	275
Long-duration storage	10	160	10	110	160

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.

7.2 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.

7.2.1 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 later additions of either short-duration or long-duration storage. Table 18 shows annual resource additions over the planning horizon for this portfolio.

Table 18. No new carbon portfolio annual resource additions

	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
CTs	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
CTs 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

7.2.2 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 19 shows annual resource additions over the planning horizon for this portfolio.

Table 19. Minimal new carbon portfolio annual resource additions

	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
CTs	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
CTs 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

7.2.3 Carbon-imposed cost portfolio

The carbon-imposed cost attempts to measure the economic and environmental cost of CO_2 for society. Due to the increased cost for CO_2 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 20 shows annual resource additions over the planning horizon for this portfolio.

Table 20. Carbon-imposed cost portfolio annual resource additions

	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
CTs	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
CTs 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

7.2.4 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 portfolio 3, 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 21 shows annual resource additions over the planning horizon for this portfolio.

Table 21. Optimal new carbon portfolio annual resource additions

	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
CTs	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
CTs 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

7.2.5 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 22 shows annual resource additions over the planning horizon for this portfolio.

Table 22. Additional new carbon portfolio annual resource additions

	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
CTs	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
CTs New	0	0	0	0	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240
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	2730	2776	2878

7.3 Comparative analysis of portfolios

7.3.1 Portfolio costs

As part of "least-cost" resource planning and optimization, the Plexos model was parameterized to capture 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 50 compares the annual cost of all five portfolios.

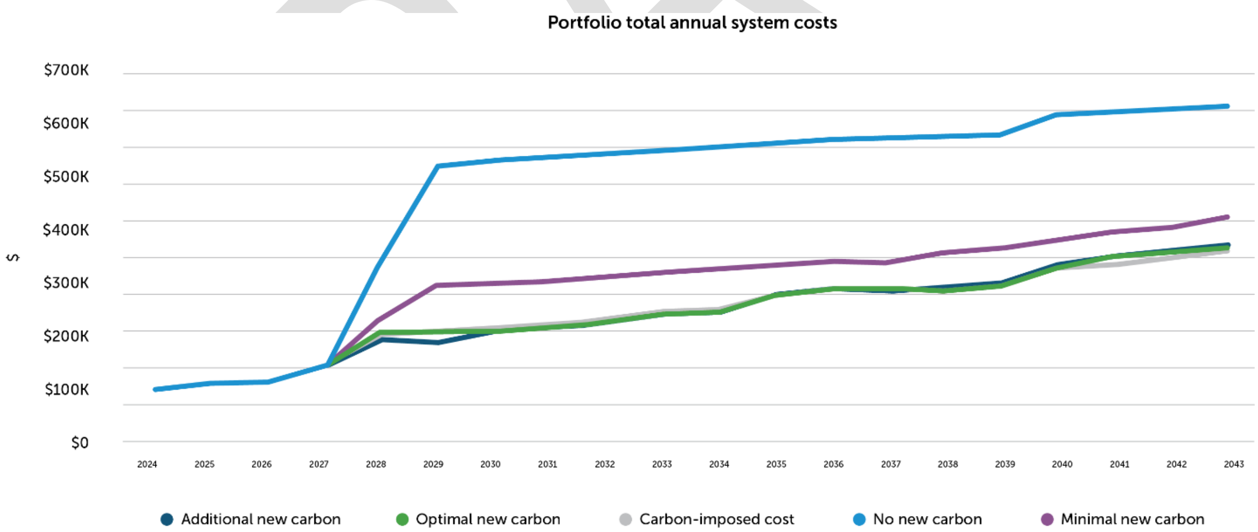


Figure 50. Portfolio total annual system costs

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 23, 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.

Table 23. Portfolio net present value cost comparison

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

As noted previously in this report, the portfolios rely on different technologies to supply differing services. Cost, energy and capacity breakouts in Table 24 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 29% of the total cost while supplying 58% of the firm capacity and only 7% of the energy. In contrast, noncarbon resources account for 49% of the cost while contributing 91% of the energy but only 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. Storage contributes to capacity needs while supporting renewable energy integration.

Table 24. Optimal new carbon portfolio: cost, energy and capacity contribution breakout

Optimal new carbon portfolio 2030-2043 cost, energy and capacity summary	% of total cost*	% of total generation	% of capacity
Thermal	29%	7%	58%
Hydro wind and solar	49%	91%	23%
Battery storage	15%	-3%	19%

*Note that market purchases and sales were excluded so this column does not sum to 100%

7.3.2 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)[23] 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 51 shows annual percent reduction of CO2 emissions for each portfolio relative to Platte River's 2005 baseline emissions.

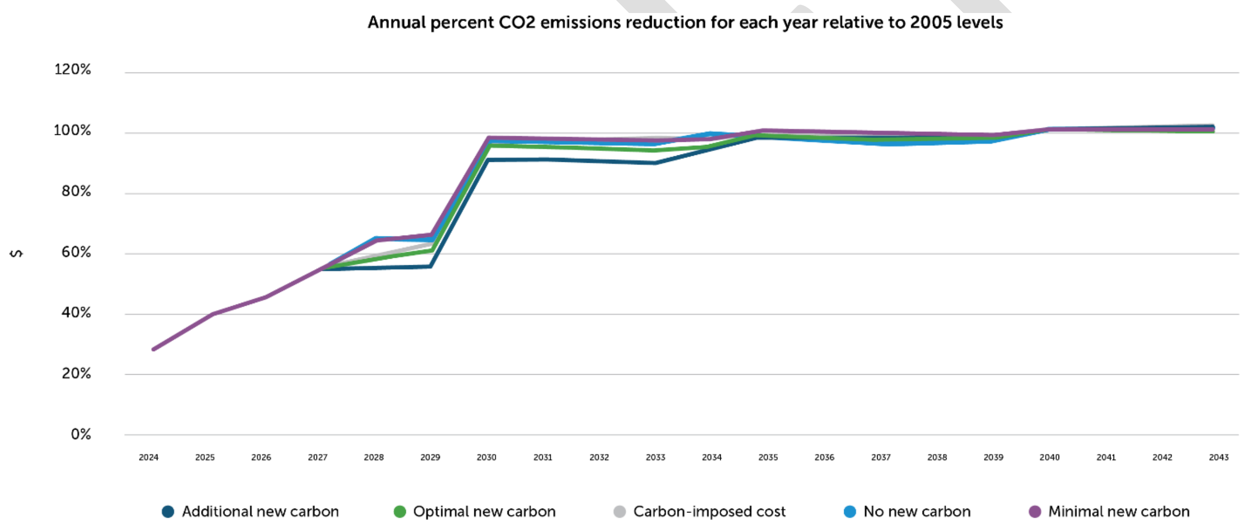


Figure 51. Annual percent CO2 emissions reduction for each year relative to 2005 levels

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 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.

[23] 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).

All portfolios comply with:

- The framework in SB23-198 requiring Platte River to model at least one plan that can demonstrate 46% CO_2 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% CO_2 reduction (from 2005 levels) by 2030.

7.4 Recommendation

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

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

The **no new carbon portfolio** does not add any new CO_2 emitting sources, but it is the most expensive due to heavy reliance on four-hour storage batteries. It builds 2,850 MW of new batteries, almost three times our expected peak demand in 2030. Consequently, it costs about twice as much as some other portfolios. As a not-for-profit entity, Platte River must pass these higher costs to the owner communities, causing significant rate shock.

The no new carbon portfolio does not offer the least CO_2-emitting path as it relies heavily on existing dispatchable generation to complement renewable generation. This portfolio fails the financial sustainability test and is not as effective in reducing CO_2 emissions post-2030 compared to 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 many four-hour storage batteries. It builds 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 CO2 than some other portfolios that also meet reliability and affordability goals. 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 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.

7.5 Risk assessment and sensitivity analysis

Platte River developed all five portfolios using several assumptions, assessments and forecasts about commodity prices, customer load growth, cost 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.

7.5.1 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.

7.5.1.1 Execution risks

- **Cost escalation** – as mentioned 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, while batteries seem to be recovering from post-COVID disruptions. As the portfolio transformation unfolds, Platte River must be prepared to pivot to the best portfolio mix based on the latest cost projections.
- **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. These issues can be anticipated but proactive management is difficult due to their project-specific nature.
- **Technology evolution** – Our proposed portfolios assume a specific timeline of technology readiness. This forecast is based on our best estimate 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 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.

7.5.1.2 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 7.5.2 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 7.5.3, we assess the combined risk of renewable cost increases and market price changes and review potential portfolio modifications to reduce this risk.

7.5.2 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.

7.5.2.1 Natural gas prices

Natural gas prices can impact a portfolio in two ways. First, the price of this fuel directly influences the 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 52, as well as associated market prices for each sensitivity.

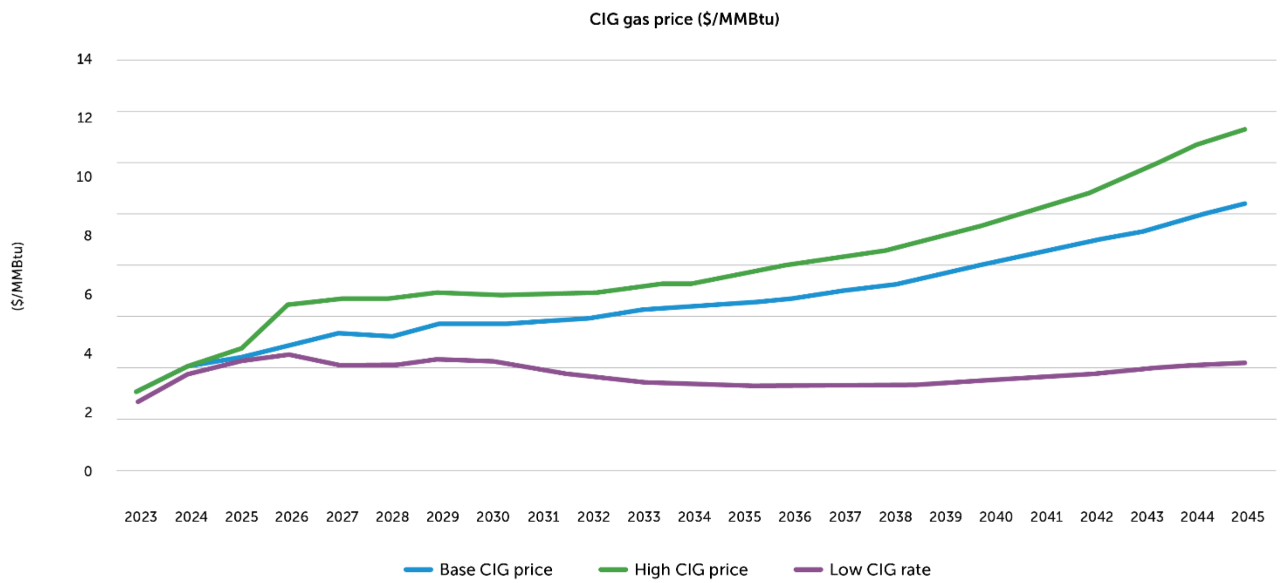


Figure 52. CIG gas price ($/MMBtu)

7.5.2.2 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 due to 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.

7.5.2.3 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.

7.5.2.4 Renewable energy prices

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

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 within 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 25 compares the base assumption to the higher price sensitivity for a selection of 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.

Table 25. Renewable PPA prices

	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

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 26 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 (ANC) portfolio. For the base case runs, the cost of the no new carbon portfolio is 93.6% higher relative to the ANC while the sensitivity case is 88.0% higher. There is very little change in the relative cost differences for the remaining portfolios.

Table 26. Renewable energy price sensitivity

	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%

7.5.2.5 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 27 compares the net present value costs across the base case assumptions and the sensitivities described above.

Table 27. Net present value cost comparison with gas prices and renewable prices

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

At a high level, the no new carbon portfolio and the minimal new carbon portfolio are uncompetitive in every case. Table 28 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.

Table 28. Portfolio ranking with sensitivity analysis

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

The top three portfolios are more competitive, and their relative value depends on the future trajectory of prices and the impacts of CO_2 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.

7.5.3 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 53 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.

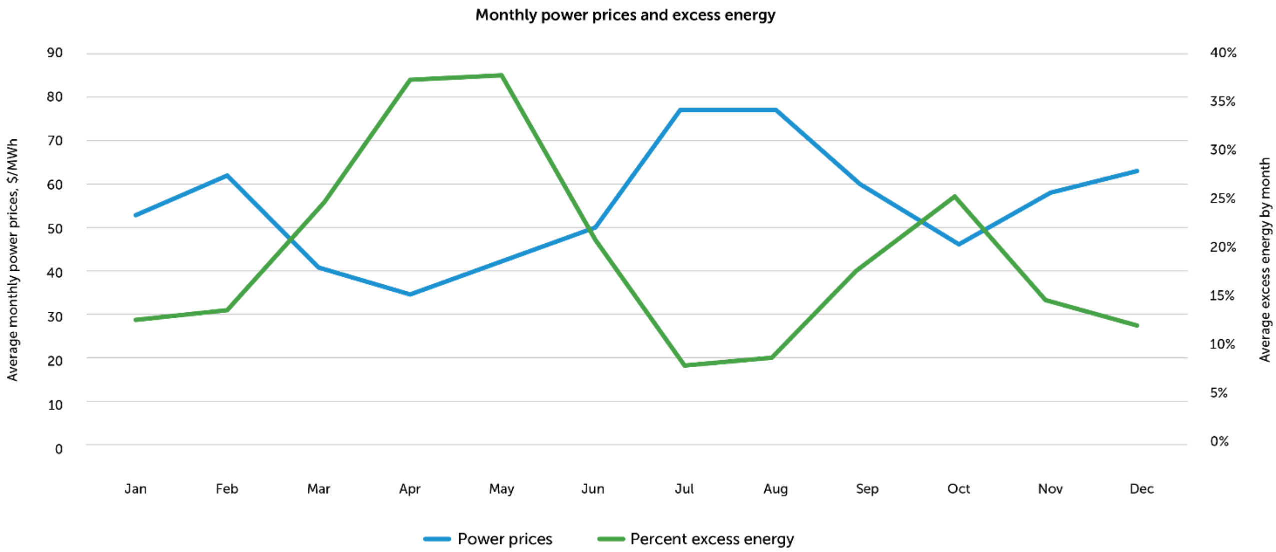


Figure 53. Monthly power prices and excess energy

The orange line shows average monthly prices while the blue 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.

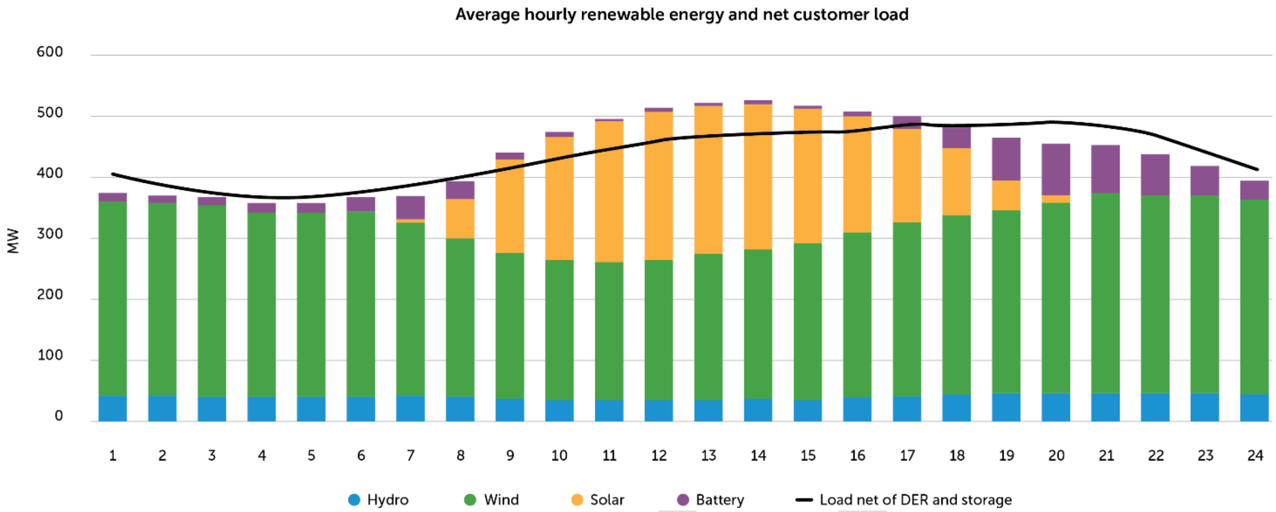


Figure 54. Average hourly renewable energy and net customer load

Figure 54 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. Platter River will continue to monitor commodity prices, including gas and market power price forecasts as well as the cost of renewable energy, to refine and rebalance the plan as necessary to ensure the portfolio continues to meet our financial sustainability pillar. If necessary, we can adjust the renewable mix or storage capacity to mitigate risk, provided it is cost-effective.

8. Action plan

Platte River will continue to work toward the RDP goal over the next five years. Platte River will 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.

8.1 2024-2028: Execution phase

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Renewable energy acquisition	Contract for new 130 MW solar from the 2022 solar RFP	2024	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications • Technology evolution Operational risks (section 7.5.1.2) • Market evolution
	Contract for new 250 MW wind from the 2023 wind RFP	2024	
	Begin commercial operation of 150 MW Black Hollow Sun solar project	2025	
	Begin commercial operation of a 130 MW solar project	2027	
Dispatchable capacity (reliability)	Contract to add up to 25 MW of distributed energy storage from 2021 solar and storage RFP	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 four-hour battery energy storage system	2024	
	Review results from all-dispatchable-resource RFP	2024	
	Begin adding up to 200 MW of dispatchable thermal generation resources. Major activities include: • 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	2024	
	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	
	Issue RFP for dispatchable thermal resource equipment 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	
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 the SPP RTO West	2025	
	Join SPP RTO West market operations on April 1	2026	
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	
	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:	2027	

	• Receive studies from external consultants • Execute community engagement activities to educate public, collect stakeholder feedback • Conduct modeling and analyze portfolios • Compile draft report		

8.2 2028-2030: Transition 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	2028	
	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	
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	

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Memorandum

Date: 5/22/2024

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
Wade Hancock, senior manager, financial planning and rates

Subject: **Average wholesale rate projections and 2025 tariff schedule charges**

Platte River staff prepared the attached white paper that includes the average wholesale rate projections and the proposed 2025 rate tariff schedule charges. Staff recommends for 2025 a 6.3% average wholesale rate increase, to $75.60/MWh (from $71.13/MWh in the 2024 Strategic Budget). The actual rate increase to each owner community varies based on energy usage and load profile assumptions.

The white paper includes the proposed 2025 Firm Power Service Tariff charges and the Standard Offer Energy Purchase Tariff avoided energy rate. Staff develops the proposed charges ahead of Platte River's normal budget process to accommodate the owner communities' budget preparation and rate development schedules.

At the May board meeting, staff will provide an accompanying presentation of the white paper material.

This presentation is for informational purposes only and does not require board action during the May board meeting.

Attachment

- Average wholesale rate projections and 2025 rate tariff schedule charges white paper

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Average wholesale rate projections and 2025 rate tariff schedule charges

Platte River Power Authority white paper

May 2024

Overview

Platte River establishes service offerings and supporting rate structures that complement its foundational pillars, vision, mission and values, strategic plan, and underlying policies of the organization. Platte River establishes its tariffs and charges to achieve Strategic Financial Plan targeted financial metrics.

Platte River's Board of Directors is required to review the rates for electric power and energy furnished to the owner communities at least once each calendar year. This is required by the Amended Contracts for the Supply of Electric Power and Energy between Platte River and each of the owner communities, and by Platte River's General Power Bond Resolution.

This white paper discusses the 2025 average wholesale rate and long-term financial and rates projections over the ten-year planning horizon in the following sections:

- The short story
- What is driving rate increases?
- What actions are being taken to alleviate rate pressure?
- Why do rate projections change?
- What are the 2025 rate tariff schedules?
- What's next?
- Appendices
    - Appendix A: Rate tariff schedule charges
    - Appendix B: Owner community impacts
    - Appendix C: Rate competitiveness
    - Appendix D: Historical average wholesale rates
    - Appendix E: Modeling assumption uncertainties

The 2025 average wholesale rate increase and long-term projections:

- 6.3% average wholesale rate increase recommended for 2025
  - $75.60/MWh from the $71.13/MWh 2024 budget
  - 5.9% due to increases in tariff charges and 0.4% due to decreases in projected load
- Long-term average wholesale rate projections based on current assumptions
  - 6.3% (2025 – 2029)
  - 5.3% (2030 – 2031)
  - 2.1% (2032 – 2034)

While long-term indicative average wholesale rates are provided, the board will approve only the 2025 Rate Tariff Schedules in October 2024.

The short story

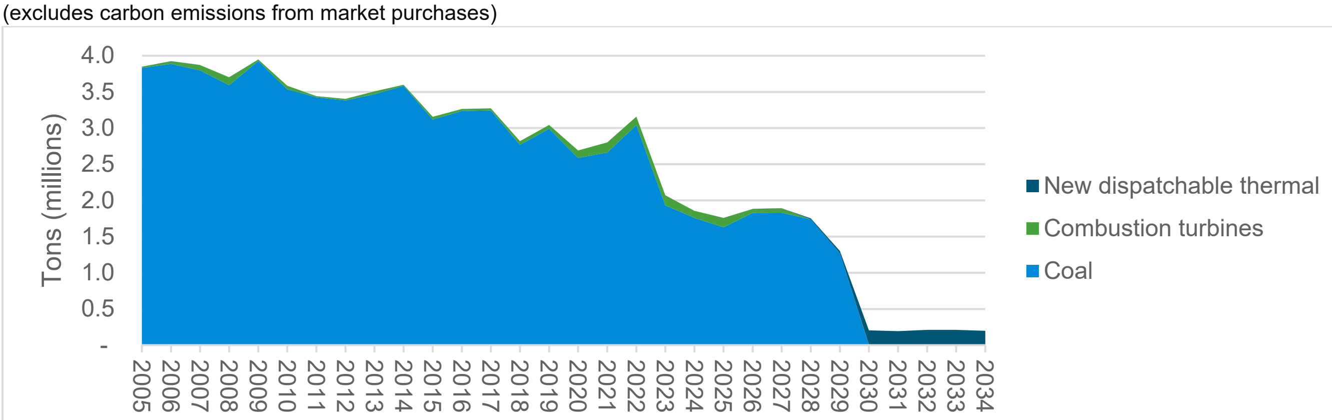
- Per the board-adopted Resource Diversification Policy (RDP) from 2018, Platte River and its owner communities of Estes Park, Longmont, Loveland and Fort Collins are pursuing a 100% noncarbon energy mix. Within that policy, there are important advancements that must occur in the near term to achieve 100% and successfully maintain Platte River's three foundational pillars: reliability, environmental responsibility and financial sustainability.
- Per the RDP, Platte River is working toward replacing its existing dispatchable resources that support the essential service of providing energy to its owner communities. Platte River's traditional low-cost coal generation will be replaced with what is currently more expensive noncarbon energy. New dispatchable technologies are also required to maintain reliability. Because electricity is a vital public health and safety service, it is imperative that no one should be without power.
- This resource transition is no small task and had to be planned and completed in less than 11 years to be successfully operational by 2030. Costs are increasing due to supply chain issues, labor, services and equipment.
- The increased costs of these new resources result in wholesale rate increases to the owner communities. Platte River uses rate strategies to lessen the impact and minimize significant rate increases in a single year or multiple years. The future projected rate increases will fluctuate based on changes in costs. Not until Platte River's new resources are secured with contracts and in service during this transition period will there be less uncertainty and fluctuations in the rates. Uncertainty in costs will always exists but it is more substantial during this period because Platte River is going through such a significant change.
- To support the resource transition, Platte River recommends a 6.3% increase in the 2025 average wholesale rate for the owner communities. The rate increase to each owner community varies based on energy usage and load profiles but combined achieve the average 6.3% (Appendix B).

What is driving rate increases?

Short answer: Primarily the expenses associated with the transition of assets to achieve the board-adopted RDP goal.

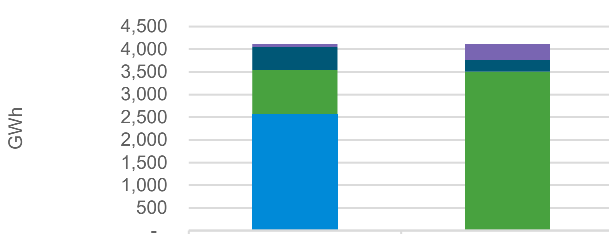
The RDP goal results in a reduction in carbon emissions. Since 2005, carbon emissions have trended downward due to generation portfolio changes. In 2034, carbon emissions from owned dispatchable thermal resources are projected to decrease approximately 3.6 million tons relative to 2005.

Figure 1: Tons of carbon emitted from owned dispatchable thermal resources
(excludes carbon emissions from market purchases)



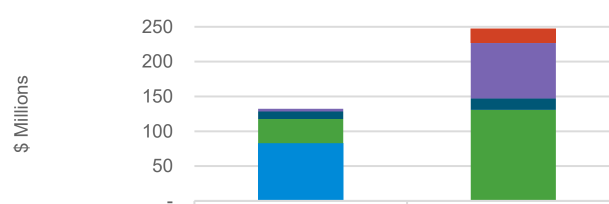
Highlighting this change, Figure 2 displays the power supply by resource in 2018, when the RDP was adopted, relative to 2030. Noncarbon and lower carbon emitting dispatchable thermal resources replace approximately the same quantity of energy. Figure 3 shows the changing resource expenses from 2018 to 2030, an approximate $115 million increase in 2030 based on uncertain future resource expense and inflation assumptions. This highlights the transition is replacing low-cost coal generation with higher cost noncarbon and dispatchable thermal resources.

Figure 2: Resource asset transition GWh



	2018	2030
Natural gas	67	362
Purchased power	502	249
Noncarbon	970	3,507
Coal	2,576	-
Total	4,115	4,118

Figure 3: Resource asset transition expense*

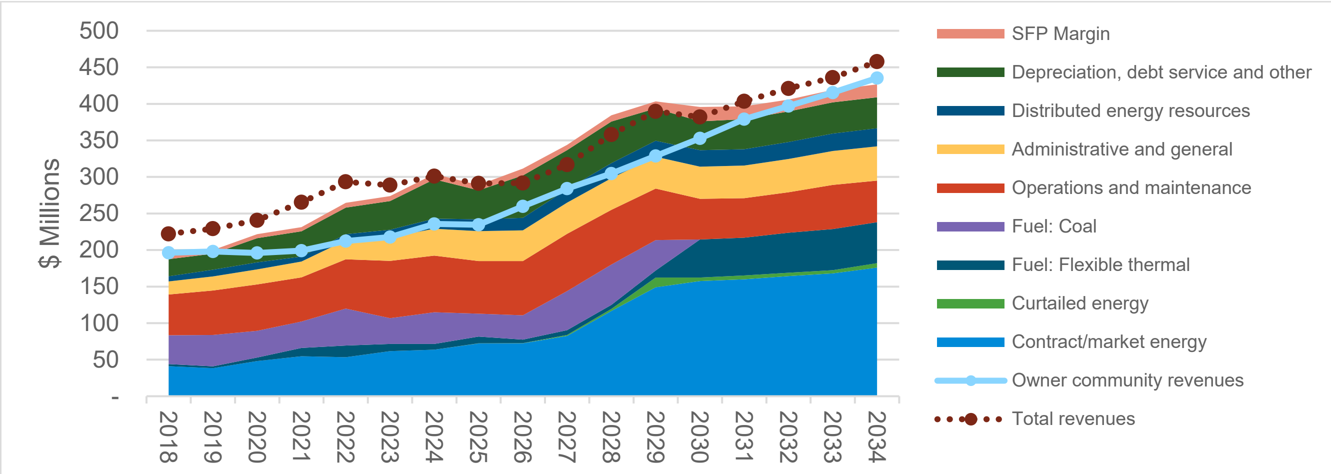


	2018	2030
Storage	$-	$20.4
Natural gas	$4.0	$79.8
Purchased power	$10.9	$16.4
Noncarbon	$34.5	$130.6
Coal	$83.0	$-
Total	$132.4	$247.2

**Exclusively purchased power, fuel, emissions, operations and maintenance and new resource debt service expenses*

As our resource portfolio transitions, total operating and nonoperating expenses, including similar expenses associated with Figure 3, continue to increase throughout the transition period (Figure 4). The owner community revenues are projected to increase $238 million, or 121% from 2018 to 2034.

Figure 4: Operating and nonoperating expenses and owner community revenues



The 2024 Integrated Resource Plan's recommended power supply portfolio is the foundation of current rate projections and serves as the planning basis for budgetary, financial planning and long-term ratemaking purposes, as Platte River pursues the goal outlined in the RDP. The recommended Integrated Resource Plan scenario was refined in the first quarter of 2024 to include changes in the projections for quantity, timing and prices of wind, solar and storage resources, load forecast, market, resource dispatch, capital investment and operations and maintenance expenses.

Based on the retirement of all coal-fired generation by the end of 2029, the current resource planning case assumes procurement of new noncarbon and dispatchable thermal resources with sufficient time to test operational reliability. These resources are expected to be online before the retirement of existing units.

Case comparison

Relative to projections shared with the board last year, over the planning horizon (2025 to 2034), owner community revenues collected directly from rate increases are an additional $213 million. This is required to fund the $223 million increase because of lower surplus sales revenues and owner community revenues due to lower loads, and increased capital investment. Offsetting the increases are lower operating expenses:

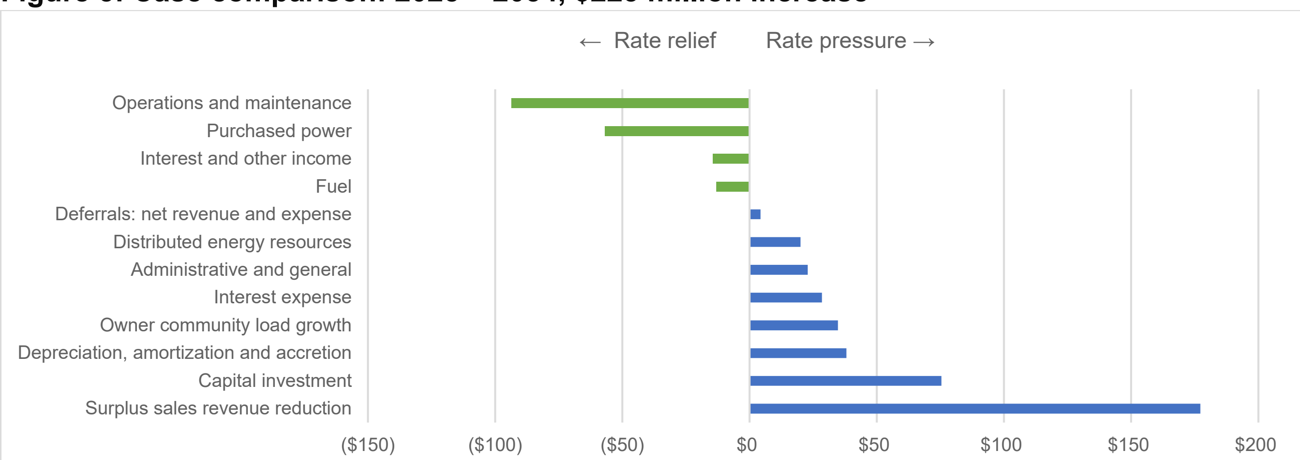
- Changes in projected revenues
    - *Lower surplus energy sales*. Margin from surplus energy sales reduces Platte River's owner community revenue requirement. Updated projections include lower market prices, which decrease surplus sales revenue and associated margin. Partially offsetting the lower sales are increased transmission revenue projections. Surplus sales market

prices are one of the more significant assumptions that fluctuates regularly causing volatility during the planning horizon.

- *Lower owner community loads*. While long-term load forecasts show expected future owner community load growth (reflecting the net impacts of building electrification, electric vehicle penetration and distributed energy resources), the projected loads are lower relative to the previous forecast, which increase the average wholesale rate.

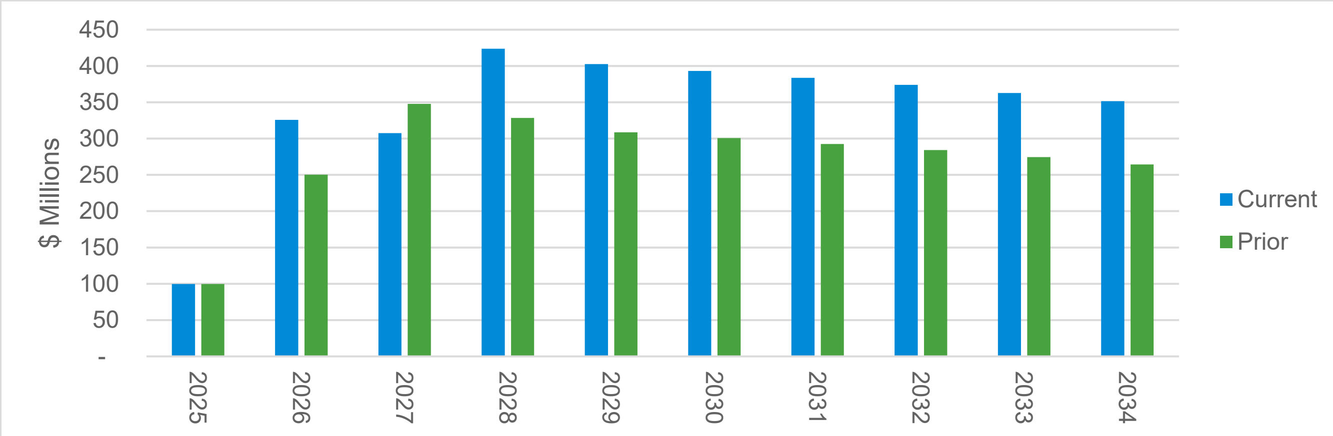
- Changes in projected expenses
  - *Increased capital investment*. Capital investment increases include assets to firm and deliver noncarbon generation resources and a distributed energy resources management system. Higher capital investments will require Platte River to issue more debt, with higher annual debt service and coverage requirements.
  - *Lower operating expenses*. Operating expenses are projected to be lower. Transmission operations and maintenance expense decreases because of Southwest Power Pool Regional Transmission Organization West (SPP RTO West) market participation. Projected prices under noncarbon purchase power agreements are higher than previous estimates offset by delayed in-service dates. Fuel expenses are lower due to less emissions expense and less generation from coal and existing natural gas resources. Platte River projects greater expense for administrative and general, distributed energy resources and depreciation, amortization and accretion.

Figure 5: Case comparison: 2025 – 2034, $223 million increase



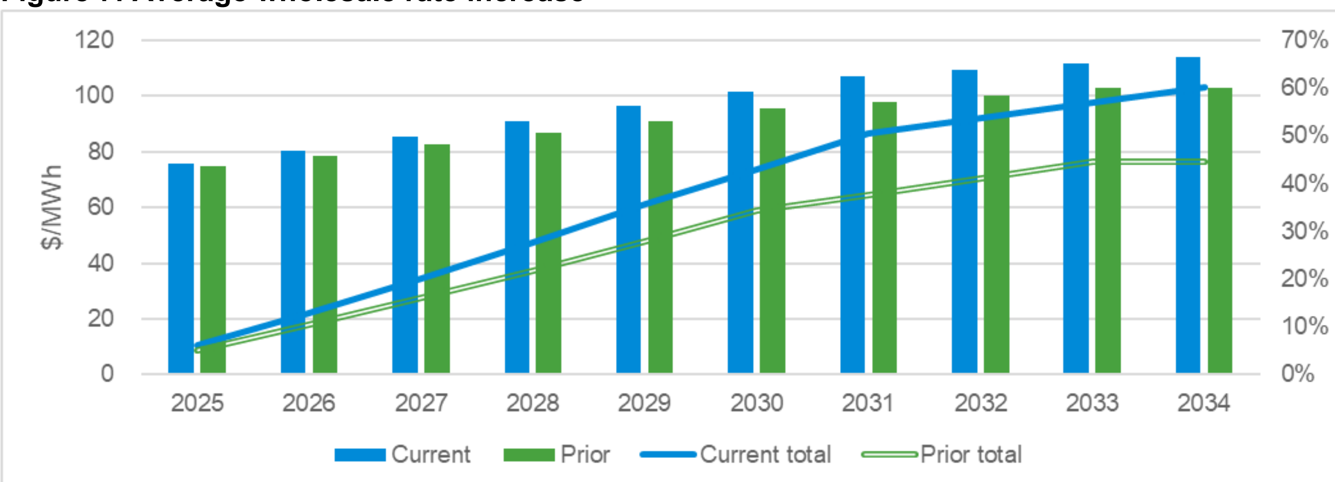
Lower revenue and increased expenses result in lower cash projections to fund capital investment. Because of higher capital investment, debt issuance projections (Figure 6) increased $96 million, adding rate pressure in the form of principal and interest repayments and debt service coverage.

Figure 6: Debt outstanding



Rate projections throughout the planning horizon are higher than prior communications as shown in Figure 7.

Figure 7: Average wholesale rate increase



What actions are being taken to alleviate rate pressure?

Short answer: Applying rate stability strategies set in the Strategic Financial Plan

Strategic Financial Plan

Platte River's Strategic Financial Plan is a foundational document to financial planning and rate setting. The Strategic Financial Plan provides direction to preserve long-term financial sustainability and manage financial risk by defining financial metrics and rate stability strategies. The objectives of the Strategic Financial Plan are to generate adequate cash flows, maintain sufficient liquidity for operational stability, maintain access to low-cost capital and provide wholesale rate stability.

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 has implemented rate strategies to help reduce rate pressure and give the owner communities greater rate predictability. Every year staff reviews the financial projections for the latest resource portfolio to determine long-term rate projections. Staff has maximized the rate stability strategies to minimize the rate impact to the owner communities from supply chain constraints, fluctuating market prices and increasing inflation. The strategies help smooth rates and avoid single year or multi-year significant rate increases. Please refer to the Strategic Financial Plan, available on www.prpa.org, for financial metric and the rate stability strategy details.

Deferred revenue and expense accounting policy

In addition to attentive budgeting, managing revenues and expenses and general rate smoothing, staff uses board-approved accounting policies to smooth revenues and expenses to lessen rate pressure. Because Platte River is transitioning its resource portfolio by retiring coal-fired units and replacing those units with noncarbon and new dispatchable thermal resources, in 2022, the board adopted the deferred revenue and expense accounting policy. The policy's purpose is to help reduce rate pressure and achieve rate smoothing by establishing a mechanism to defer revenues earned and expenses incurred in one period to be recognized in one or more future periods.

Platte River anticipates deferring revenues of approximately $111.4 million from 2022 to 2025 to later recognize (between 2026 and 2030). Since policy adoption, Platte River has deferred $53.2 million in revenues to recognize during the transition. Recognizing deferred revenues through the transition period is sufficient and no deferred expenses are currently projected.

Actual deferred amounts are determined annually at year end. The long-term projections incorporate actual deferred revenue and expenses then future deferral and recognition estimates are updated.

Figure 8: Deferred revenues

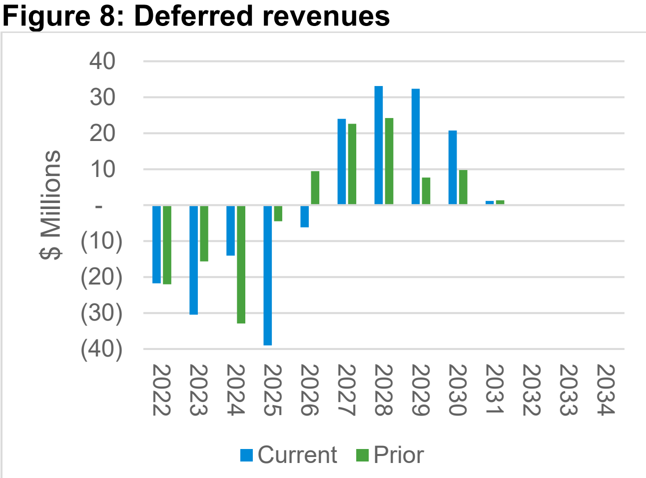
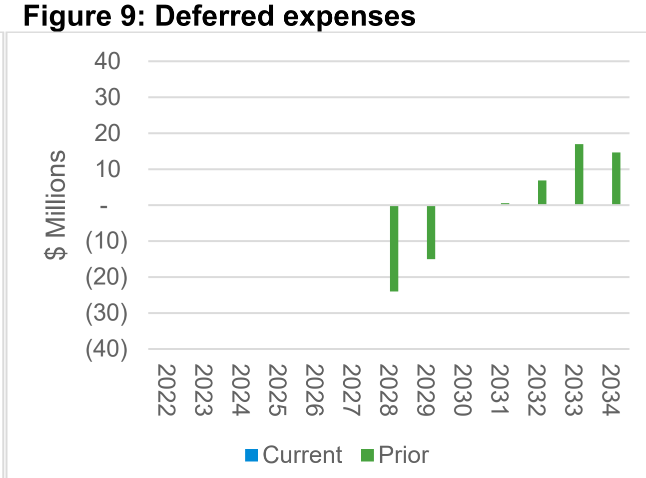


Figure 9: Deferred expenses



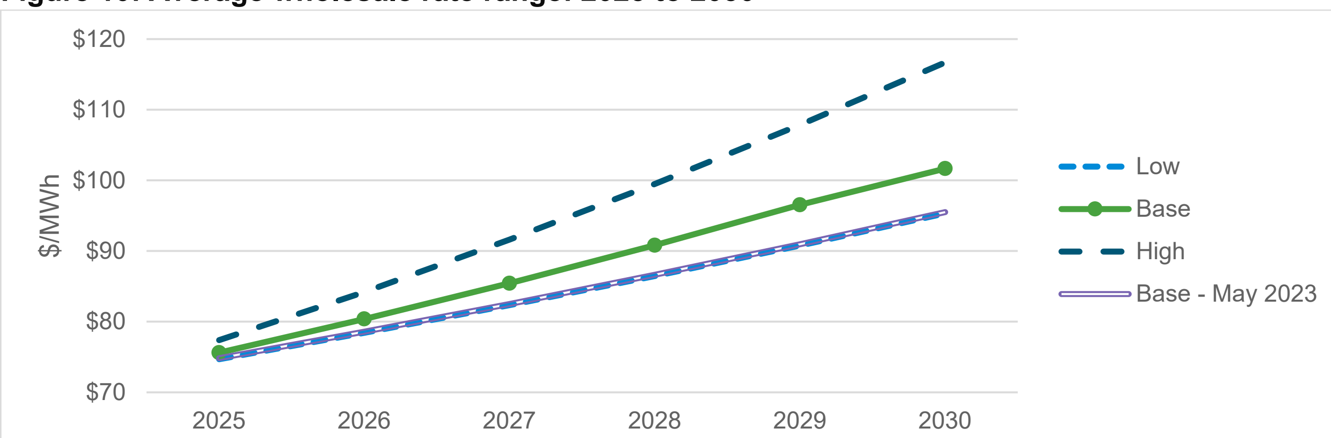
Why do rate projections change?

Short answer: Changing assumptions due to uncertainty and the shortening time frame to achieve the RDP goal.

Key assumptions are uncertain (Appendix E). To quantify uncertainties, staff assessed multiple rate cases and sensitivities to develop the recommended rate trajectory, based on the lowest base case projections. All sensitivities achieve Strategic Financial Plan metrics and apply rate smoothing strategies including the deferred revenue and expense accounting policy. Staff analyzed varying market prices, future emissions expenses, and other cost assumptions creating outcomes ranging from 5.0% to 9.0% annual increases through 2030, as shown in Figure 10 below. Key assumptions, including market prices, remain uncertain and can significantly alter projections. The proposed 6.3% rate path is based on current assumptions and subject to future changes as uncertain conditions evolve. If costs increase, there is a potential of larger rate increases as there is less time available to recover those costs to meet the 2030 RDP goal.

All ranges analyzed assumed identical load projections and generation resources. Load modifications can require changes to the generation asset integration quantities and timing.

Figure 10: Average wholesale rate range: 2025 to 2030



What are the 2025 rate tariff schedules?

Rate increases and associated revenues help Platte River maintain a strong financial position and a AA credit rating, which enable it to obtain favorable debt financing. Over the long term, rate increases fund continued infrastructure investment, the resource portfolio transition, general inflationary expenses and market-based expenses.

Platte River has four tariffs. A brief tariff description and the proposed 2025 charges are presented below.

- Firm Power Service Tariff
- Standard Offer Energy Purchase Tariff
- Wholesale Transmission Service Tariff
- Large Customer Service Tariff

Firm Power Service Tariff (Tariff FP-25)

The Firm Power Service tariff specifies charges to the owner communities. The charges reflect cost of service and incorporate Platte River's recommended 6.3% average wholesale rate increase. Staff provides the charges now to support owner community budget preparation and rate development even though the board will not adopt the tariff until fall.

The changes to the individual tariff charges will have varying impacts to each owner community due to each owner community's unique load characteristics and energy consumption. Staff provided the owner community rates staffs the projected overall impacts of the forecasted average rate, load growth and total revenues collected based on Platte River's load estimates. Appendix B contains more detailed analysis of owner community impacts of the average wholesale rate change, as well as analysis of the change to the tariff charges. Impact projections will vary when applied to different load assumptions such as the owner communities' internal forecasts.

Platte River's revenue requirement and charges are unbundled into Platte River's business functions: owner community services, transmission and generation. Charges have been unbundled by fixed and variable costs, collected through either direct allocation or demand or energy charges. Appendix A includes an overview of the Firm Power Service charges.

The variable energy revenue requirement includes costs for intermittent and dispatchable resources collected through a single variable energy charge. However, the owner communities continue to receive their load ratio allocations of delivered hydropower, wind and solar energy. This information is provided to owner community staff.

The individual charges are changing due to the proposed average wholesale rate increase, updated cost of service estimates among the different charges and changes to projected energy and demand loads. Changes from 2024 to 2025 include estimates for general inflationary increases and known budget estimates, including the latest load and market price forecast. These assumptions may vary from the 2025 budget, which is currently under development.

Pending board direction and barring any significant unanticipated events, the recommended charges will remain unchanged and will be Platte River's recommendation for the October adoption of the tariff schedules, to be effective Jan. 1, 2025

Figure 11: Firm Power Service Tariff (Tariff FP-25) charges

	Tariff FP-24	Tariff FP-25 recommendation	$ change	% change
Owner community charge ($/month per allocation)	$13,059	$15,351	$2,292	17.6%
Demand charges ($/kW)				
Transmission	$6.68	$6.70	$0.02	0.3%
Generation: summer	$6.61	$7.42	$0.81	12.3%
Generation: nonsummer	$4.92	$5.94	$1.02	20.7%
Energy charges ($/kWh)				
Fixed cost	$0.01681	$0.01770	$0.00089	5.3%
Variable cost	$0.02427	$0.02458	$0.00031	1.3%

- *Owner community charge*: Increased primarily due to expanded distributed energy resource investments.
- *Transmission demand charge.* Relatively unchanged as the revenue requirement changes are mostly offset by increased demand projections.
- *Generation demand charges*. Increased primarily due to lower surplus sales revenues. Margin from these sales is credited against the fixed generation revenue requirement. Additionally, purchased power expense for hydropower demand charges and reserves increased.
    - *Summer and nonsummer generation demand charge.* Combustion turbine usage and expenses increased. The allocation between nonsummer and summer are based on historical usage and nonsummer generation has increased in recent years.
- *Fixed energy charge*. Increased primarily due to the net impact of lower surplus sales revenues. Margin from these sales is credited against the revenue requirement. Lower owner community load projections relative to last year's projection also created upward pressure.
- *Variable cost energy*. Increased primarily due to solar purchases (Black Hollow Solar project) and SPP Western Energy Imbalance Service market purchases. Partially offsetting the increase are lower coal generation estimates, resulting in lower fuel expenses. Like with the fixed energy charge, a decrease in owner community load projections create upward rate pressure.

Figure 12 shows the 2025 average wholesale rate increase and impacts of the change from changes in tariff charges and projected loads.

Figure 12: Impact of Firm Power Service Tariff (Tariff FP-25) charge changes

Load year: Tariff charges:	2024 budget Tariff FP-24	2025 estimate Tariff FP-24	2025 estimate Tariff FP-25
Revenues (millions)	$235.7	$234.8	$248.5
MWh	3,314,141	3,287,172	3,287,172
$/MWh	$71.13	$71.43	$75.60
Change due to load		0.4%	-
Change due to charges		-	5.9%
$/MWh change			6.3%

Standard Offer Energy Purchase Tariff (Tariff SO-25)

The Standard Offer Energy Purchase tariff rate applies to the purchase of available electricity from power production facilities that have registered with the Federal Energy Regulatory Commission as Qualifying Facilities under the Public Utility Regulatory Policies Act and are electrically connected to Platte River's transmission system or the distribution system of one of Platte River's owner communities. No customers currently receive service under this tariff.

The avoided energy rate is based on an hourly resource model marginal cost analysis of coal-fired generation, natural gas-fired generation and market purchases to serve the balance of load after 'must-take' energy projections, including hydropower and renewables. The 2025 proposed avoided energy rate is in Figure 13. The rate increased primarily due to the increased frequency and higher associated cost of natural gas generation as the marginal resource, partially offset by lower SPP Western Energy Imbalance Service market price projections.

Figure 13: Standard Offer Energy Purchase Tariff (Tariff SO-25) avoided energy rate

	2024 actual	2025 proposed	$ change	% change
Avoided energy rate $/kWh	$0.02191	$0.02328	$0.00137	6.3%

Wholesale Transmission Service Tariff (Tariff WT-25)

The Wholesale Transmission Service tariff under which Platte River offers transmission service to third parties is reviewed and updated on an annual basis in the second quarter after the audited year-end financial results are available. This ensures the rate reflects the most recent costs of operation and maintenance and actual transmission usage. Staff has proposed revisions to the tariff rates for the board to adopt at the May 2024 board meeting. This tariff is effective June of each year.

Large Customer Service Tariff (Tariff LC-25)

Charges under this tariff are established through a separate contract.

What's next?

Staff will present the information detailed in this white paper at the May board meeting. Staff also requests board direction to implement a 6.3% average wholesale rate increase in 2025 to $75.60/MWh from $71.13/MWh in the 2024 budget and the individual charges as calculated in Appendix B.

In September, staff will provide the draft 2025 rate tariff schedules. In October, staff will ask the board to approve the 2025 rate tariff schedules with a Jan. 1, 2025, effective date.

Staff encourages and is available to support wholesale rate communications to stakeholders as requested by the owner communities.

Appendix A

Rate tariff schedule charges

Owner charge

The owner charge is a monthly flat rate multiplied by each owner's share of Platte River's owner community kilowatt hour sales based on the six most recent year-end values. The owner charge is intended to recover fixed costs for distributed energy resources, which are long-term behavioral shifting programs. The six-year period allows owner communities to see change over time, without dramatically impacting year-to-year changes. This is a fixed amount invoiced each month with no variability.

Demand charges

The demand charges are unbundled between transmission and generation and employ minimum billing demands designed to address owner community demand fluctuations to provide greater monthly invoice stability for each owner community as well as revenue certainty for Platte River. The minimum billing demands also emphasize the efficient use of infrastructure to maximize short-term marginal cost savings (avoiding expensive purchases or generation at time of peak) and long-term marginal cost savings (delaying or avoiding future capital investment, such as new generation or transmission resources). The minimum billing demands concentrate the signal to reduce consumption at time of peak, giving the owner communities a greater financial incentive to lower peaks during months with high demands, with less financial incentives to lower peaks during nonpeak months. Because of the minimum billing demand, approximately 90% of projected demand revenues are certain. Only the revenues based on loads above minimum billing demands vary by consumption.

Energy charges

The energy charges are unbundled into fixed and variable components. The fixed energy charge is a transparent mechanism to highlight the cost of firm-energy service. Variable costs, including wind and solar, are recovered through the variable cost energy charge. Platte River assumes the risk of intermittent generation variances and associated costs, not the owner communities. Monthly invoices display load share intermittent energy delivered for flexible service offerings to retail customers. The energy charges provide the least revenue certainty as the revenues vary based on consumption.

Figure 14 includes a high-level summary of the cost components and net revenue requirement of each charge.

Figure 14: Firm Power Service Tariff (Tariff FP-25) cost components

(in millions)	Owner community	Transmission demand	Generation demand	Fixed energy	Variable energy	Total
Costs						
Purchased power: Noncarbon and market					$53.4	$53.4
Purchased power: Hydro demand			$7.0	$3.4		$10.4
Purchased power: Hydro energy					$6.2	$6.2
Purchased reserves			$6.0			$6.0
Fuel: Coal and natural gas					$40.6	$40.6
Operations and maintenance: Fixed baseload			$12.1	$26.9		$39.0
Operations and maintenance: Fixed combustion turbines			$4.2			$4.2
Operations and maintenance: Fixed transmission		$18.6				$18.6
Operations and maintenance: Variable					$7.0	$7.0
Administrative and general	$2.9	$12.1	$9.5	$16.5		$41.0
Distributed energy resources	$16.2					$16.2
Debt service expense	$0.1	$14.8	$0.8	$2.0		$17.7
Margin: Deferred revenues	$0.2	$10.6	$10.6	$17.6		$39.0
Margin	$0.1	$5.7	$5.7	$9.4		$20.9
Credits						
Surplus sales: Margin			($5.9)	($11.1)		($17.0)
Surplus sales: Cost of generation					($26.4)	($26.4)
Transmission revenues		($13.1)				($13.1)
Interest income and other	($1.1)	($2.1)	($5.2)	($6.9)	($0.5)	($15.8)
Total	**$18.4**	**$46.6**	**$44.8**	**$57.8**	**$80.3**	**$247.9**

Appendix B

Owner community impacts

The impact of the recommended 6.3% average wholesale rate increase budget to budget and the recommended charges vary among the owner communities based on their unique load characteristics, including projected load growth among the owner communities. Platte River forecasts load at the system level and establishes the Firm Power Service tariff charges based on the system-level load forecast. Platte River derives owner community loads from the system-level forecasts for budget detail reporting. The projected impact of the Firm Power Service tariff charges will differ among varying forecasts that may be used by the owner communities.

Additionally, the change in the total amount billed to each owner community will not be the same as the average rate increase. Forecasted demand and energy growth will increase the projected invoice total more than the average rate increase. Conversely, projected load decreases, as projected from 2024 to 2025, will increase the total bill less than average rate increase. Figure 15 shows the estimated impact of the rate changes from 2024 to 2025.

Following are the significant drivers of the varying owner community rate impacts:

- Transmission and generation minimum billing demand
- Energy consumption
- Load factors

The minimum billing demands concentrate the signal to avoid consumption at time of peak, which is the summer season peak for generation, and the annual peak for transmission regardless of season. The lower annual coincident and noncoincident peak demand results in lower annual billing demands. Improvements in billing demand, relative to the other owner communities, can also lower an owner community's rate increase relative to the average. As individual owner communities lower billing demands, the associated cost recovery will shift proportionally.

Total energy consumption increases can create downward pressure on the average rate by spreading fixed costs over more energy. Inversely, energy consumption increases will increase the amount billed.

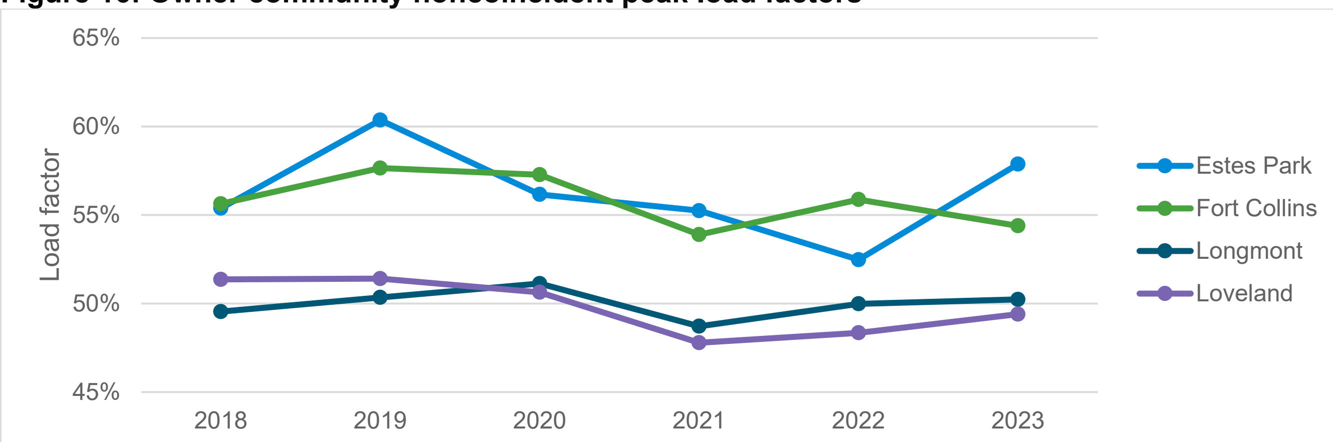
The owner communities with the lowest average rate (Figure 15) also have the highest load factors (Figure 16). Load factor is a measure of electric system efficiency.

Figure 15: Owner community impact

		Estes Park	Fort Collins	Longmont	Loveland*	Platte River
2024	Average rate ($/MWh)	$67.50	$70.29	$72.37	$72.08	$71.13
	Energy sales (GWh)	143.4	1,531.3	871.0	768.4	3,314.1
	Revenues (millions)	$9.7	$107.6	$63.0	$55.4	$235.7
2025	Average rate ($/MWh)	$71.17	$74.52	$76.90	$77.13	$75.60
	Energy sales (GWh)	142.9	1,527.9	865.0	751.4	3,287.2
	Revenues (millions)	$10.2	$113.9	$66.5	$58.0	$248.6
	Average $/MWh change	5.4%	6.0%	6.3%	7.0%	6.3%

**Loveland includes large customer.*

Figure 16: Owner community noncoincident peak load factors



It is also important to recognize the 6.3% average wholesale rate increase is the net impact of projected changing loads and changing charges. Figure 17 is an analysis of 2023 actual loads applied to the Firm Power Service tariff charges, owner allocations and demand minimums from FP-24 and FP-25. This analysis isolates the impact of charge changes.

Figure 17: Charge change impact: 2023 actual loads at Firm Power Service tariff charges

($/MWh)	Tariff FP-24	Tariff FP-25	% Change
Platte River	$72.19	$76.45	5.9%
Estes Park	$67.86	$71.61	5.5%
Fort Collins	$71.29	$75.46	5.8%
Longmont	$73.31	$77.66	5.9%
Loveland *	$73.56	$77.99	6.0%

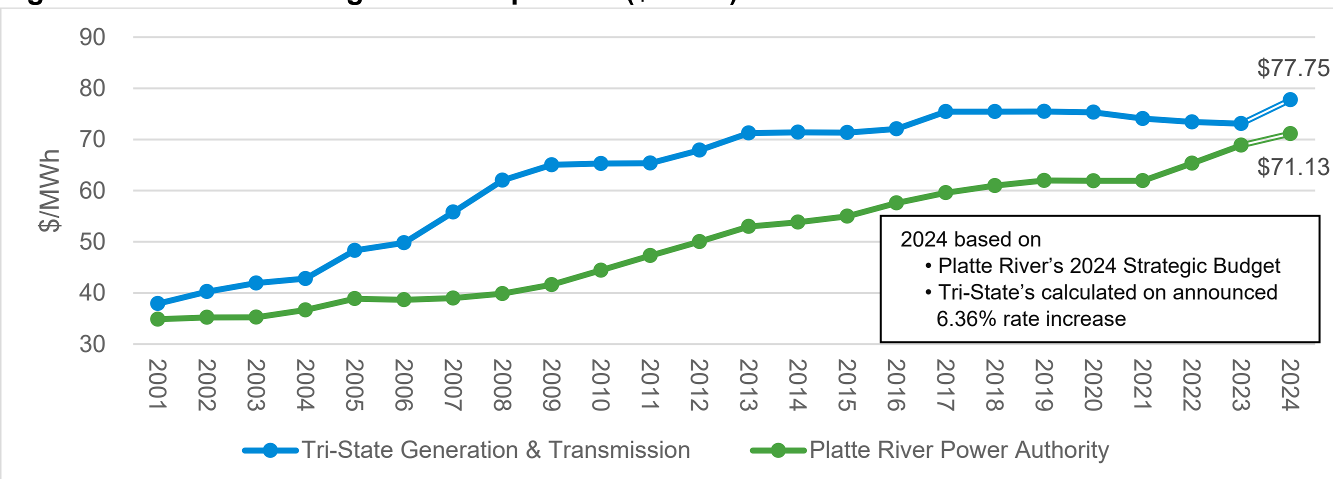
**Loveland includes large customer.*

Appendix C

Rate competitiveness

The direction provided by the board and the Strategic Financial Plan position Platte River to offer competitive rates. Wholesale rates for energy provided to Platte River's owner communities was approximately 6% lower than Tri-State Generation and Transmission Association (Tri-State) in 2023. Platte River and Tri-State organization goals will impact rate differentials. Platte River will continue to pursue to the RDP goals while prioritizing the foundational pillars, which is the primary driver of increasing rates.

Figure 18: Member average rate comparison ($/MWh)



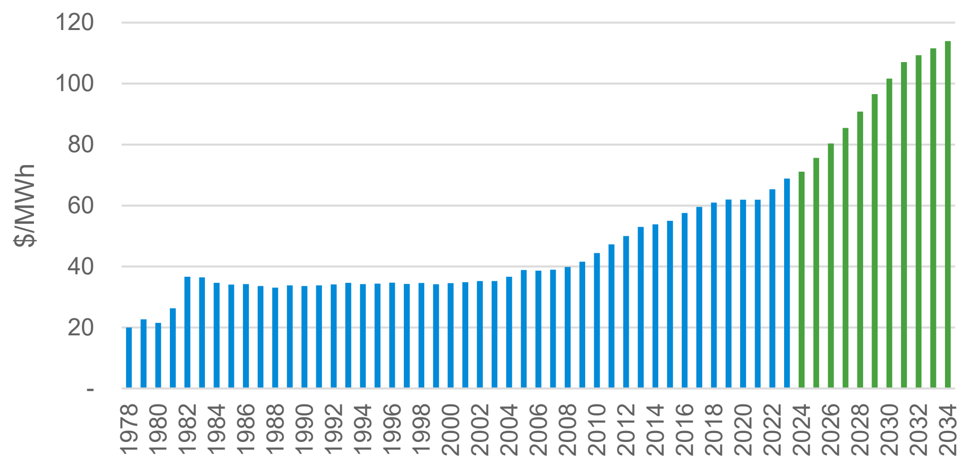
Appendix D

Historical average wholesale rates

From 1978 to 2023, Platte River's average wholesale rate increased an average 2.8% annually. However, there are several distinct periods when the average increase has not been representative of the rate pressure for a specific period. As show in in Figure 19, in the period before Rawhide Unit 1 became operational in 1984, rates increased significantly to fund its construction and initial operation. From the mid-1980s throughout the 1990s rates were stable as Platte River relied heavily on surplus sales revenues from excess baseload capacity. As Platte River's loads grew, and were projected to continue growing, the average wholesale rate began to rise in the early 2000s with increased capital investment in transmission projects and the natural gas combustion turbines. The current rate increase period is occurring as Platte River transitions to a noncarbon based generation resource portfolio, in addition to general inflationary pressures.

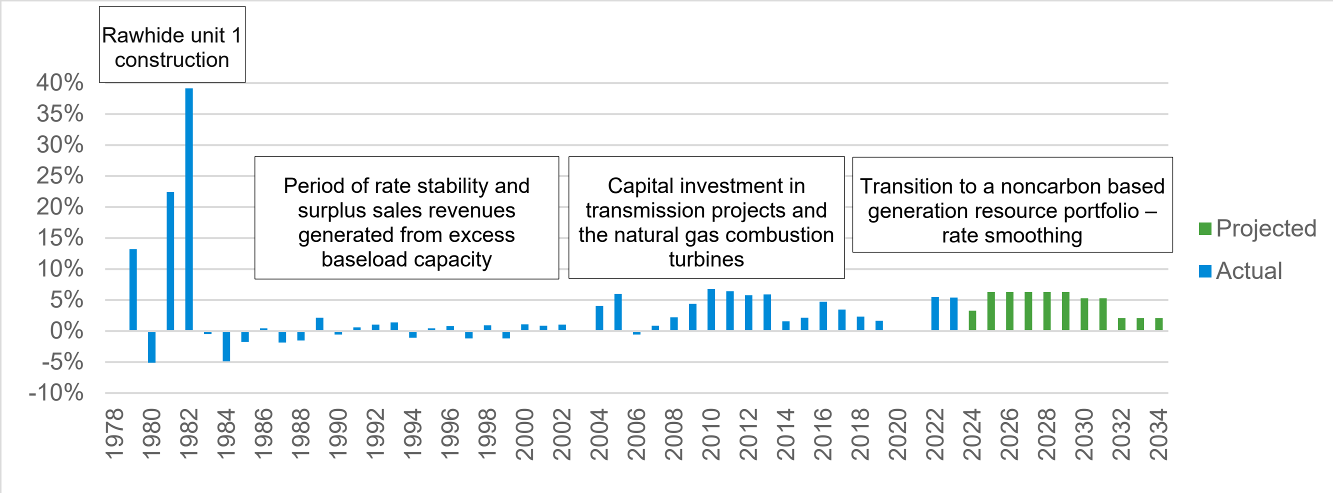
Figure 19: Average wholesale rate ($/MWh)

Period	Avg. annual
1978 - 1984	9.6%
1984 - 2003	0.1%
2003 - 2024	3.4%
2024 - 2034	4.8%



Not shown as clearly in Figure 19 are the significant annual changes in the average wholesale rate during the construction and early operation of Rawhide Unit 1. Figure 20 highlights this annual change. The rate increases associated with Rawhide Unit 1 were significant: 73% from 1978 to 1984. These substantial increases over such a short period contributed to the implementation of the Strategic Financial Plan strategy and the board's preference to smooth rates to avoid significant increases over shorter periods. The resource transition to support the RDP goal is Platte River's most significant generation resource transition since the addition of Rawhide Unit 1. Implementing rate smoothing strategies will avoid increases similar to those in the early 1980s and provide greater financial flexibility and sustainability.

Figure 20: Average wholesale rate change ($/MWh)



Appendix E

Modeling assumption uncertainties

Significant uncertainty exists with key assumptions. Potential assumption changes include, but are not limited to, the items detailed below.

Category	Explanation
Asset integration schedule	Modeling assumptions include the following capacity additions. Changes to the asset integration schedule will impact future results.
Asset sales	To maximize the value of assets, coal inventory sales opportunities and Windy Gap water units will be considered.
Capital investment forecast	The model incorporates the most recent long-term capital forecast including investment in a new dispatchable thermal resource and transmission and interconnection projects to integrate wind. Interconnection feasibility studies will be completed as part of the analysis to determine size and location of wind and solar resource additions. Technology costs for owner assets, including dispatchable thermal generating resources, is uncertain and subject to change. Cost estimate accuracy will become more certain as projects and locations are finalized. Revisions to the capital forecast are integrated as available.
Commodity prices	Platte River's Power Supply Plan, which includes the hourly dispatch modeling and associated costs, is updated throughout the year. Updates include Rawhide Unit 1 and the Craig units fuel assumptions, as well as market prices for electricity and natural gas. Updates change economic dispatch impacting fuel, variable operations and maintenance, purchased power and surplus sales.
Debt issuance costs	Debt structure, issuance costs and the cost of debt vary and are updated throughout the year.
Decommissioning	Craig decommissioning expenses are based on a budgetary estimate and will be refined as decisions are made by participants in the Craig Station. While Rawhide Unit 1 is projected to retire by 2030, assumptions include decommissioning the entire Rawhide Energy Station in 2055 and associated decommissioning expenses accrued through 2055. If the decommissioning date shifts, expenses will be revised accordingly.

Category	Explanation
Deferred revenue and expenses	The amount of deferred revenues and expenses depend on actual results and projections. Deferring expenses creates additional future rate pressure.
Distributed energy resources and strategy	The collaborative distributed energy resource (DER) process among the owner communities and Platte River is an important component to Platte River and its owner communities' ability to achieve noncarbon goals. Wide-spread adoption of DER is expected to provide benefits for the electric system and retail customers. As specific DER programs become established and evolve, rate strategies to incorporate DER will be analyzed.
Economic externalities	Inflation and interest rate volatility will continue to impact financial results. Supply chain constraints have increased capital and purchase power agreement cost projections. Modeling assumptions are revised accordingly, reflecting current conditions.
Emissions expense	Rate projections assume the implementation of the Clean Power Plan (or similar form of regulation) beginning in 2027. Emission regulations and associated future costs have significant uncertainty. Modeling assumptions include a tax applied to 100% of carbon emissions.
Federal hydropower allocations	Persistent drought conditions throughout the western United States have constrained hydropower resources, resulting in reduced energy allocations and increased prices. When there are high levels of snowpack, the spring runoff can produce excess hydropower for Platte River. Staff continues to monitor federal developments and adjust model assumptions accordingly.
Integrated resource plan	Integrated resource planning was mandated by the Energy Policy Act of 1992, requiring all Western Area Power Administration customers to submit every five years future electric needs trajectory and action plans to address that will ensure an adequate supply of reliable, financially sustainable and environmentally responsible electricity. The Integrated Resource Plan development is underway and planned for completion in 2024. Resource modeling assumption revisions will impact future rate projections.
Load forecast	The load forecast is updated at least annually. The latest forecast, completed by a third party, projects energy growth lower than previous

Category	Explanation
	forecasts. Growth attributed to projected building electrification, electric vehicles and distributed energy resources is reflected in the forecast.
Noncarbon energy curtailments	As Platte River transitions to a more noncarbon based resource portfolio, the ability to sell surplus energy significantly impacts wholesale rate projections. At times, noncarbon energy cannot be consumed or sold but there is an associated cost.
Organized energy markets	Platte River joined the SPP Western Energy Imbalance Service market in April 2023. As staff becomes more familiar with Energy Imbalance Service market and collects more data, modeling is refined. Platte River intends to enter the SPP RTO West in April 2026. However, projections require refinement due to the current lack of market data.
Regulations	Platte River faces rising compliance-related risks resulting from aggressive and changing regulatory requirements that are difficult to predict and scope.
Resource Diversification Policy	In December 2018, the board adopted a policy with a goal for Platte River to reach a 100% noncarbon resource mix by 2030. Within that policy, there are important advancements that must occur in the near term to achieve 100% and successfully maintain Platte River's three foundational pillars: reliability, environmental responsibility and financial sustainability, Future decisions to achieve this goal will impact results.
Staffing	Modeling contains estimates for future staffing additions, including salary and benefits expenses, through 2029. Staff is also working through the Rawhide Unit 1 closure transition plan. These assumptions will be further analyzed and revised accordingly.
Surplus sales prices and volumes	Margin from surplus sales reduce Platte River's revenue requirement and benefits the owner communities through lower rates. Significant market price volatility, as experienced in recent years, is one of the most significant drivers of rate uncertainty. In addition to electricity market commodity price risk, hourly dispatch modeling market depth assumptions (ability to sell excess, must-take generation) are reviewed and updated regularly throughout the year. Negative pricing has not been factored into model assumptions but there will be instances when energy supply exceeds demand based on renewable energy production resulting in negative energy prices.

Platte River
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Memorandum

Date: 5/22/2024

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Melie Vincent, chief operating officer – generation, transmission and markets
Travis Hunter, director of power generation

Subject: **Rawhide Just Transition Plan**

Platte River's Just Transition Plan will be submitted to the Colorado Office of Just Transition, as required by House Bill 19-1314, as well as the Western Area Power Administration as part of the 2024 Integrated Resource Plan. 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.

This item is for informational purposes only and does not require board action at the May board meeting.

Attachment

- Rawhide Just Transition Plan

Platte River Power Authority

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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 [XX], formally announcing Unit 1's retirement as part of the 2024 IRP. Because Platte River is committed to closing Unit 1, it 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 approving Resolution XX 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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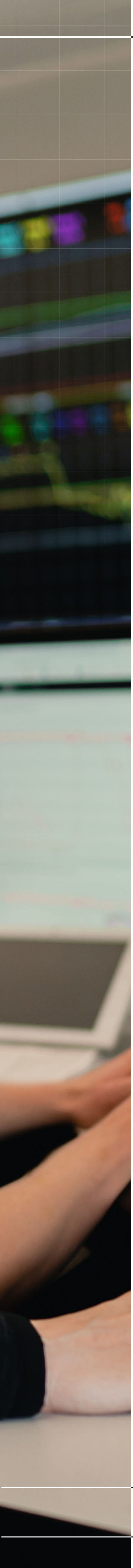
EXCELLENCE



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

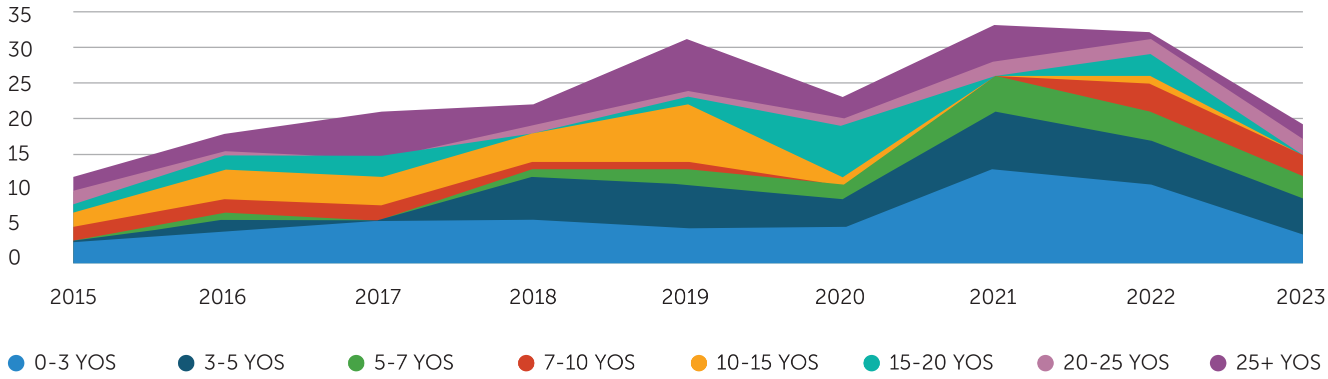


Figure 2: Rawhide Attrition by Years of Service

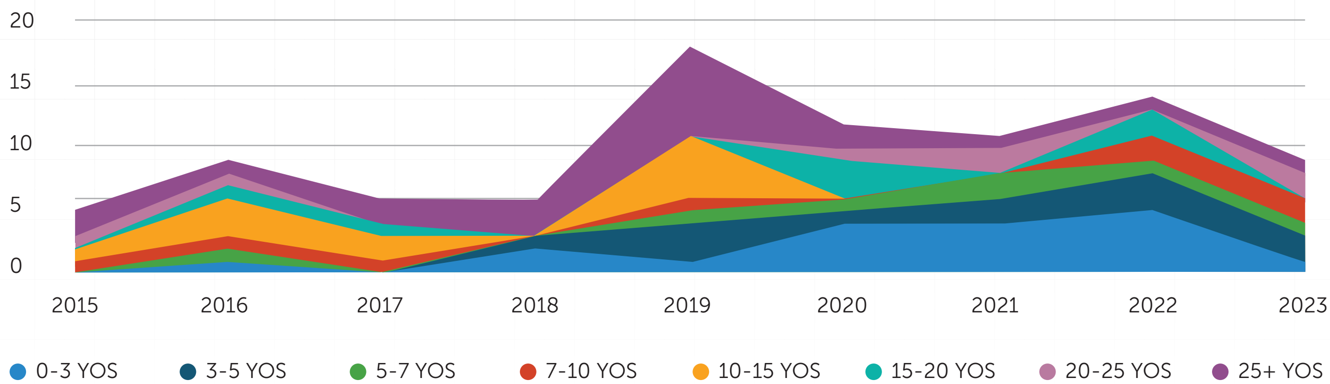


Figure 3 and Figure 4 show the historical reasons for attrition, both for Platte River as a whole and specifically for Rawhide. Retirement drives greater attrition at Rawhide than at Platte River as a whole, another trend that it anticipates will be stable through 2029. Platte River's projections for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

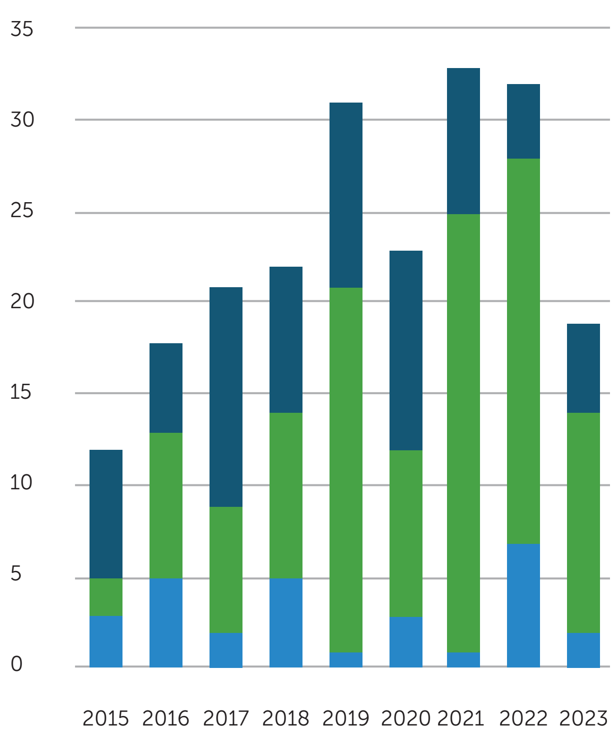
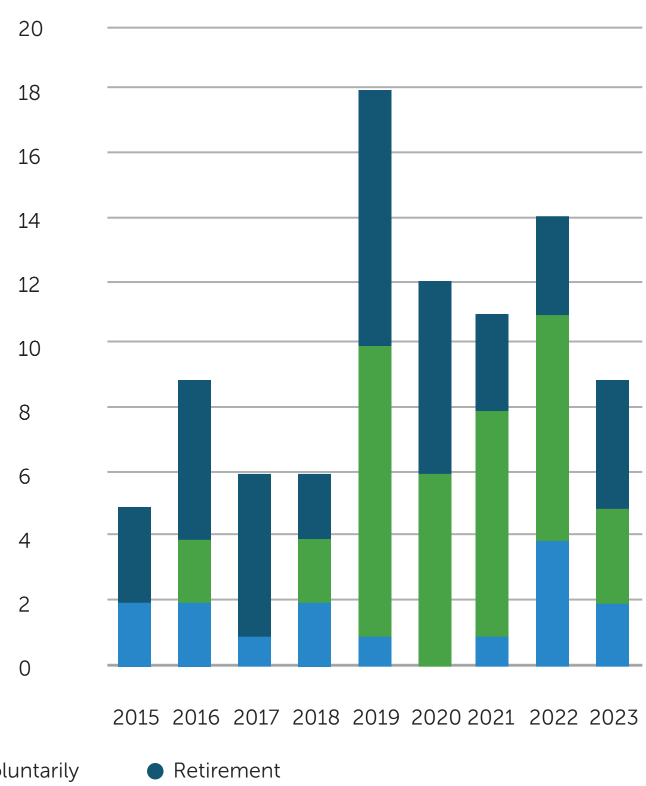


Figure 4: Rawhide Attrition by Reason



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

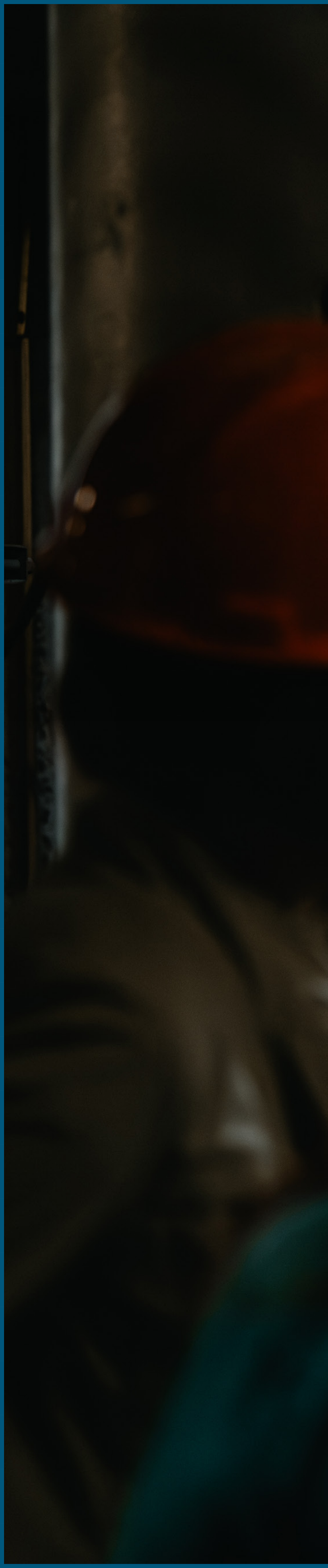
Current headcount
This is the number of employees at Rawhide to support Unit 1 as of May 2022. It does not include contract workers, which are managed by the vendors who employ them.

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:

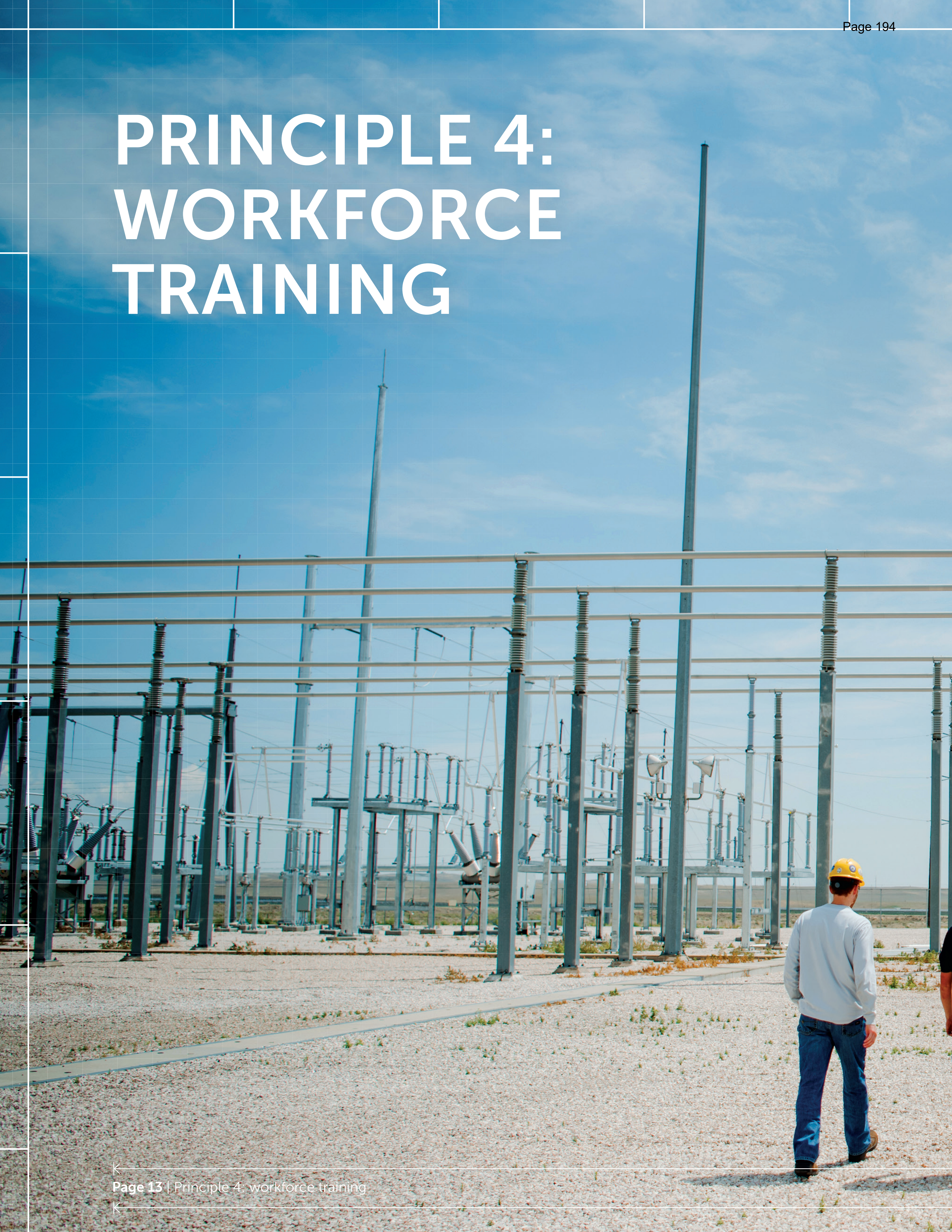
- Power markets and marketing desks (both transmission and generation)
- Compliance
- Information Technology
- Facilities
- Substations

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.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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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Memorandum

Date: 5/22/2024

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Melie Vincent, chief operating officer – generation, transmission and markets
Heather Banks, senior manager, fuels and water

Subject: **Water resources reference document update**

The Platte River Power Authority (Platte River) Water Resources Reference Document provides background on Platte River's water resources, including the history of Platte River's need for water, a list of assets and operating agreements, and a summary of current water-related operations and projects at Platte River.

Platte River's 2024 Water Resources Reference Document, eighth edition, includes activities through 2023. Highlights include:

- Updated operational activities and data through the 2023 water year
- Updated activities on the Windy Gap Firming Project/Chimney Hollow Reservoir Project
- Outcome of 2023 request for proposal for the sale of five unfirmed Windy Gap units

With this eighth edition, staff has condensed the document to improve readability and clarify more technical aspects of the material. This will also be the last annual update to the document. Moving forward, staff will update the document every three years, concurrent with the Water Policy review schedule.

The May board packet contains a copy of the document. A printed version is available upon request. Staff will present an overview at the May board meeting and will be available to answer any questions the board may have.

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

Attachment

- Platte River Power Authority Water Resources Reference Document

Platte River Power Authority

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2024

Platte River Power Authority

Water Resources Reference Document

Eighth Edition

Published: May 22, 2024

Summarizing Platte River Power Authority's water supply, background, activity, agreements and operational historical performance.

Table of contents

Platte River Power Authority Water Resources Reference Document

Introduction

This document provides a brief background on Platte River's water resources, including the history behind Platte River's assets and operating agreements, a summary of current water-related operations and projects at Platte River and how Platte River's Water Resources Policy guides future planning and operations. Platte River updates this document every three years to refresh the operational data summaries and reflect any changes in Platte River's water policy or asset ownership.

Section I – Background and history

1. **Why Platte River needs water**

Water and energy systems are intrinsically linked. Platte River uses water for site operations (such as dust suppression, fire water and potable water needs) and electricity generation (thermoelectric, hydropower and renewable technologies). Platte River requires a consistent water supply to ensure reliable operations.

The Rawhide Energy Station (Rawhide) includes coal, natural gas and solar energy resources. Water is currently needed to support Rawhide Unit 1, a coal-fired unit using steam to generate power. Coal-fired electric generation requires a reliable supply of water for two main purposes: cooling water and process water.

Cooling water cools steam to liquid in a condenser before returning it to the boiler. At Rawhide, Platte River stores cooling water in Hamilton Reservoir. Hamilton Reservoir covers 500 surface acres, has a capacity of 16,000 acre-feet (af),[1] and consumes an average of three million gallons of water per day (approximately nine af/day) as evaporation into the atmosphere. On average, Platte River needs approximately 3,300 af of water annually to maintain the reservoir level. However, the annual amount of water pumped into the reservoir can range from 2,500 to 4,500 af of water. The amount of pumping needed to replenish the water varies depending on many conditions, including the evaporation rate (affected by air temperature, wind conditions, humidity, reservoir temperature and similar factors), precipitation and plant performance. The evaporation rate of a cooling reservoir is higher than the natural evaporation rate in a regular lake or reservoir because the water temperature is higher. The annual average temperature of Hamilton Reservoir is 70 degrees Fahrenheit. The typical windy conditions at Rawhide also cause increased evaporation from Hamilton Reservoir. The water Platte River stores in

[1] An acre-foot is 325,851 gallons, or the volume of water that would cover one acre of land to a depth of one foot.

Platte River Power Authority

Hamilton Reservoir is treated reusable effluent from the City of Fort Collins' Drake Water Reclamation Facility, pumped to Rawhide via a 24-inch pipeline.

Platte River also needs a separate process water supply, for which treated reusable effluent is unsuitable. This process water is used for boiler makeup water, site service water, fire suppression and drinking water. Platte River pumps approximately 400 af of this water per year directly from Horsetooth Reservoir to Rawhide via a separate 10-inch pipeline. The amount has varied, but conservation efforts and equipment upgrades have reduced the amount of process water needed at Rawhide.

Water conservation is a key element of plant operations. All water Platte River uses at Rawhide is recycled as much as possible and used in other plant processes. Rawhide is a zero-discharge facility, meaning that Platte River uses all cooling and process water to extinction. All water used at Rawhide must be fully consumable and reusable, which is a very specific type of water under Colorado water law.

2. Water supply sources

Windy Gap Project

Platte River is a participant in the Windy Gap Project, which delivers water from Colorado's western slope to the front range. Platte River originally owned a contract allocation of 160 units (out of a total of 480 units) of the Windy Gap Project, which Platte River acquired from three of its owner communities in 1974. These allocations included 40 units from the Town of Estes Park, 80 units from the City of Fort Collins and 40 units from the City of Loveland. Each unit of Windy Gap Water is entitled to 1/480th of the annual yield of the project, and yields up to 100 af of water per year, depending on Windy Gap Project production. Platte River presently owns 107 Windy Gap units.

The Windy Gap Project was constructed in the early 1980s and began delivering water in 1985. The Windy Gap Project consists of a diversion dam on the Colorado River, a 255 af reservoir, a pumping plant and a six-mile pipeline to Lake Granby. The Windy Gap Project pumps water to Lake Granby during high flow months, typically April to July, and stores the water in Lake Granby until needed. When needed, the Windy Gap Project delivers water beneath the Continental Divide through the Adams Tunnel under a carriage contract with the U.S. Bureau of Reclamation (Reclamation) for delivery through facilities that are part of the Colorado-Big Thompson (C-BT) project, including Carter Lake and Horsetooth Reservoir (collectively, C-BT Project). The Northern Colorado Water Conservancy District (Northern Water) and Reclamation jointly operate and maintain the C-BT Project (maps shown in Appendix A). Northern Water's Municipal Subdistrict (Municipal Subdistrict) is a separate conservancy district formed by several municipalities to build and operate the Windy Gap Project. The current Windy Gap Project participants and a project map are below:

Platte River
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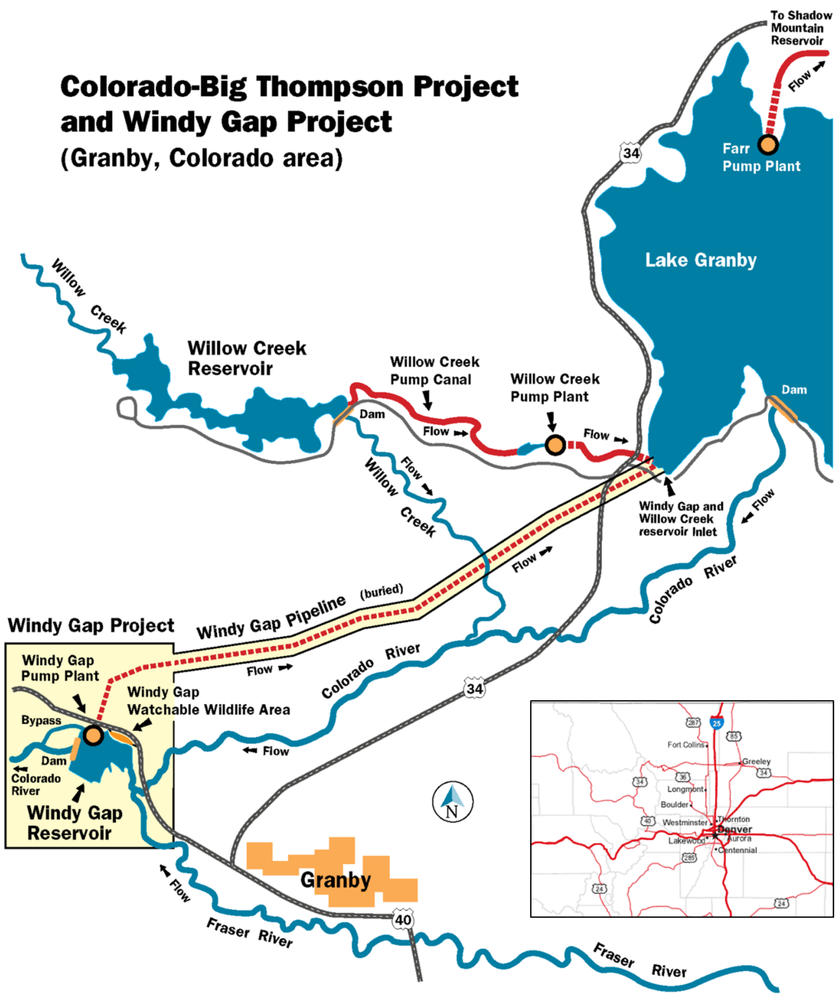
Windy Gap Project participants	
Platte River Power Authority	City of Fort Lupton
City of Longmont	City of Louisville
City and County of Broomfield	Town of Berthoud
City of Greeley	Town of Frederick
City of Loveland	Town of Firestone
City of Boulder	City of Dacono
Town of Erie	Town of Estes Park
Little Thompson Water District	City of Lafayette
Superior Metropolitan District No. 1	Central Weld County Water District



Northern Colorado Water Conservancy District
http://www.northernwater.org/waterprojects/CBTWindyGapmaps.aspx

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The Municipal Subdistrict provides Windy Gap Project water (Windy Gap Water) as a "contract allotment" from the Municipal Subdistrict. This means that Platte River does not own Windy Gap Water rights, but has a contractual right to Windy Gap Water deliveries when water is available. For example, during full production years, 100 Windy Gap units can produce up to 10,000 af of water per year, but during years with less production, the actual yield is less. Annual yields range anywhere from zero af per unit to 100 af per unit.

A key benefit of Windy Gap Water is that it is fully consumable (can be used to extinction). Windy Gap allottees can use and reuse Windy Gap Water because it is imported water, not native to the South Platte basin. After first use within Municipal Subdistrict boundaries, participants may use, lease, transfer or sell all successive use rights (reusable return flows) within or outside of Municipal Subdistrict boundaries. Platte River needs fully consumable water at Rawhide because it is a zero-discharge facility.

Typically, Platte River places an annual Windy Gap order of approximately 4,800 af, 4,200 af of which Platte River provides to the City of Fort Collins in exchange for a like amount of reusable effluent pumped to Rawhide for cooling purposes. Platte River uses the remaining water for Rawhide process water, augmentation and other obligations.

Cache la Poudre River decrees

In addition to its Windy Gap allotment, Platte River historically held two junior water rights on the Cache la Poudre River (Poudre River). Because these rights have a junior (recent) priority date, this water is not available every year and does not give Platte River a firm, reliable supply. In 2022, Platte River exchanged its Poudre River rights with the City of Greeley for leased C-BT rental water from the 2023 water year through the 2030 water year.

3. **Water agreements**

Along with the contract allotments for Windy Gap Water, Platte River is party to the following agreements and decrees that help us exchange, receive, and store water.

Reuse Agreement

When planning Rawhide, Platte River knew that Rawhide would require adequate cooling water and process water. Platte River also recognized that the front range of Colorado is an arid region, so a primary objective was to use water in a responsible and sustainable way. Platte River incorporated the use of treated effluent into the original plant design. In 1978, Platte River and the City of Fort Collins (Fort Collins) developed the Agreement for the Reuse of Water for Energy Generation (Reuse Agreement) allowing Fort Collins to use consumable and reusable water first, and then pump return flows of treated effluent to Hamilton Reservoir at Rawhide for

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cooling.[2] This arrangement ensured that Rawhide's water use would not disadvantage any existing water users or water supplies.

In addition to the 4,200 af of effluent from the Reuse Agreement, Platte River is also entitled to return flows from Windy Gap Water supplied to Fort Collins. The estimated return flows from Fort Collins' use of 4,200 af of Windy Gap Water are approximately 2,310 af, or an average of 55% of the Windy Gap Water Fort Collins uses. The total water available to Platte River under the Reuse Agreement, absent water received under the three-party Memorandum of Understanding (MOU) described below, includes 4,200 af of reusable effluent plus approximately 2,310 af of Windy Gap return flows, for a total of 6,510 af.

Memorandum of Understanding

When Anheuser-Busch, Inc., now Anheuser-Busch InBev (AB InBev), came to Fort Collins, it needed a fully consumable water supply for its operations. In 1988, Platte River, Fort Collins and AB InBev signed an MOU allowing Fort Collins to designate the Windy Gap Water owed to Fort Collins under the Reuse Agreement for the AB InBev brewery[3]. The parties expected that AB InBev using Windy Gap Water would reduce the return flows available to Platte River under the Reuse Plan. To compensate Platte River for the reduced return flows, AB InBev agreed to pay a portion of Platte River's annual variable operating costs for Windy Gap Water. The total amount of reusable effluent usually available to Platte River is around 5,400 af per year, as shown in the table below. This meets Platte River's current cooling water needs for Rawhide with some reserve water available for future generation or other uses.

[2] The Reuse Agreement is a three-way agreement between Fort Collins, Water Supply and Storage Company (WSSC) and Platte River. The Reuse Agreement and associated Decree W-9322-78 are based on a series of exchanges that use "new foreign water" supplied by Fort Collins and WSSC to produce 4,200 af of reusable effluent for Platte River's use each year. Fort Collins uses the new foreign water to generate reusable effluent return flows of 4,200 af that it provides to Platte River. To compensate Fort Collins and WSSC for this reusable effluent, Platte River transfers a total of 4,200 af of Windy Gap Water to Fort Collins annually.

[3] Coincidentally, AB InBev's estimated water need of 4,200 af matched the amount of Windy Gap Water provided to Fort Collins under the Reuse Agreement. Because AB InBev uses a land application process to treat brewery waste, it does not send as much wastewater to Fort Collins' Drake Water Reclamation Facility, reducing return flows into the system. Under the MOU, Platte River agreed to accept less Windy Gap Water return flows, approximately 800 af instead of the 2,310 af expected under the Reuse Agreement, in exchange for payments toward variable operating costs for Windy Gap Water and other costs incurred when Windy Gap Water is in short supply.

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Average annual reusable effluent water available to Platte River

Reusable effluent water sources	Annual quantity (af)	Comments
Reuse Agreement exchange	4,200	Contractual quantity
MOU: Windy Gap return flows	1,200	Estimate
Total reusable effluent available	5,400	Estimate

North Poudre storage agreement

In 1979, Platte River entered an agreement with the North Poudre Irrigation Company (North Poudre) allowing Platte River to use North Poudre's Fossil Creek Reservoir inlet ditch and temporarily store reusable effluent in Fossil Creek Reservoir when space is available and storage does not harm North Poudre. This agreement, which expires in 2024, preserves treated effluent that cannot be pumped to Rawhide at the same rate that Fort Collins delivers it to the Drake Water Reclamation Facility. This agreement allows Platte River to store and withdraw treated effluent from Fossil Creek Reservoir. When the agreement expires, Platte River will no longer be able to store and withdraw treated effluent from Fossil Creek Reservoir, but will maintain the perpetual right to use the Fossil Creek inlet ditch. Platte River seeks to negotiate a new storage agreement with North Poudre soon.

Water Platte River holds in Fossil Creek Reservoir would be lost when the reservoir fills and spills (annually). The Platte River board of directors authorized Platte River to lease unpumped reusable effluent, beginning in 1994, to avoid this uncompensated loss. When Platte River leases Fossil Creek Reservoir water it shares a percentage of the proceeds with North Poudre.

Soldier Canyon outlet agreement

In 1981, Platte River entered into an agreement with Fort Collins for three cubic feet per second (cfs) of capacity in the Soldier Canyon outlet to pump process water from Horsetooth Reservoir to Rawhide via the 10-inch pipeline.[4]

Larimer County agreement – Strang Gravel Pit augmentation

Platte River and Larimer County entered an agreement in 1993 allowing the county to receive up to 100 af of reusable effluent Platte River receives under the MOU to augment water needs for Larimer County's Strang Gravel Pit. Larimer County notifies Platte River each year of the actual quantity of water it needs for augmentation. Larimer County's augmentation is typically less than 12 af per year.

[4] The Soldier Canyon outlet agreement allows Platte River to connect to and operate a tap from the existing Fort Collins raw water delivery system at a point on the system below where the system connects to the Soldier Canyon outlet from Horsetooth Reservoir. From that point, the water is pumped via Platte River's 10-inch pipeline from the tap to Rawhide.

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Carter Lake outlet agreements

The Carter Lake outlet agreements, part of the Southern Water Supply Project, are allotment contracts signed in 1994 and 2001 that provide Platte River with total delivery capacity of up to 18 cfs[5] from the Carter Lake outlet. After assessing potential water needs for a future generation resource on the southern end of the Platte River system, Platte River sold 13 cfs of outlet capacity to other project participants, retaining five cfs[6] of capacity. Platte River does not currently use this capacity, but maintains it for its future value to either deliver water to a generation resource on the southern end of Platte River's system or to deliver leased Windy Gap Water out of Carter Lake.

Water decrees

There are several water rights decrees that support how Platte River exchanges, delivers and stores water. Two of these are the reuse decree, which authorizes the exchanges needed for the Reuse Agreement, and the Hamilton Reservoir storage decree, which allows Platte River to store and operate the 16,000 af cooling reservoir at Rawhide. The 24-inch pipeline that supplies water to Hamilton Reservoir has several associated exchange decrees that provide flexibility in pumping water through the pipeline.

4. Current annual water use – summary

Cooling water

As described above, Platte River currently uses an annual average of approximately 3,300 af of reusable effluent for cooling water. Cooling water use at Rawhide varies from 2,500 to 4,500 af annually, depending on weather and operating conditions.

Augmentation water

Each year, Platte River provides approximately 200 af of additional reusable effluent to Fort Collins and the Poudre River to meet the augmentation requirements of the Reuse Agreement, the Rawhide Energy Station property (Rawhide Creek), Platte River's headquarters property (headquarters well), and the Larimer County Strang Gravel Pit augmentation agreement.

Process water

Platte River pumps an average of 400 af of Windy Gap Water directly from Horsetooth Reservoir to Rawhide via the 10-inch pipeline from the Soldier Canyon outlet. Platte River uses this water for process water at the plant.

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[5] Capacity of 18 cfs equates to 35.7 af/day.

[6] Capacity of five cfs equates to 9.9 af/day.

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Platte River's water use summary

Platte River water use	Typical annual quantity (af)	Type of water
Rawhide cooling water: 24-inch pipeline	3,300	Reusable effluent
Augmentation requirements	200	Reusable effluent
Rawhide process water: 10-inch pipeline	400	Windy Gap
Total use	**3,900**	

A diagram showing the general arrangement for Rawhide water supply and use follows:

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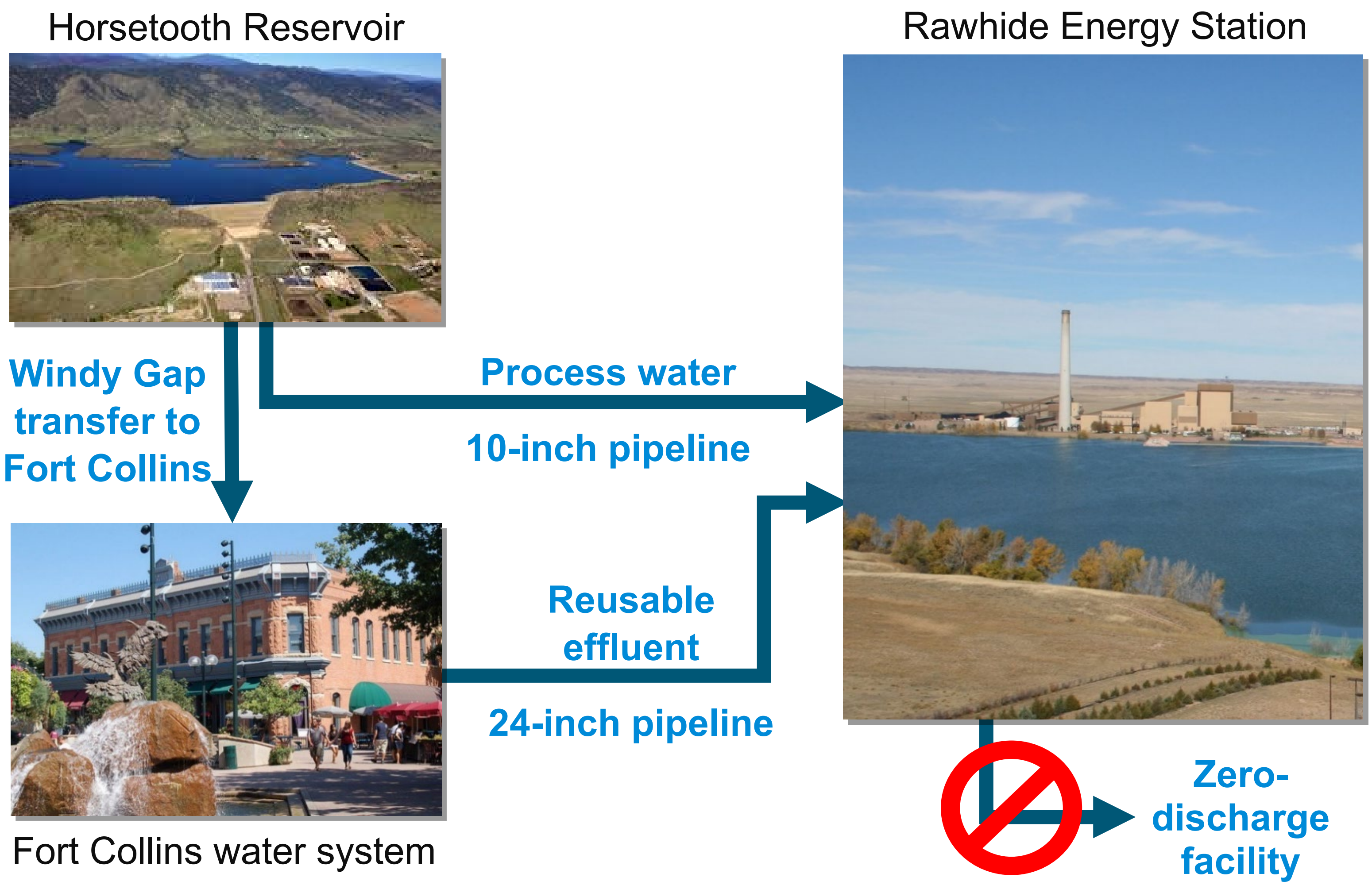
Rawhide Energy Station water supply



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Section II – Current activity

1. Water for generation operations and Windy Gap Project performance

Platte River requires a minimum of 4,200 af of Windy Gap Water per year to complete the water exchanges under the Reuse Agreement and MOU. Without Windy Gap Water to exchange, Platte River would receive significantly less reusable treated effluent under the Reuse Agreement and MOU. Platte River also needs approximately 400 to 600 af of Windy Gap Water each year for direct pumping to Rawhide as service and process water. Both water sources are critical to Rawhide's reliable operation. Historically, Platte River's annual Windy Gap order has been approximately 4,800 af, as shown in the following breakdown:

Platte River's average annual water requirements and contractual obligations

Windy Gap Project order components	Average annual quantity (af)
Reuse Plan, contractual requirement	4,200
Process water, 10-inch pipeline pumped to Rawhide	600
Total average annual order	**4,800**

Windy Gap Water is Platte River's primary water source and is needed every year. During the early years of Windy Gap's operation, orders and the volumes delivered to other project participants were relatively small. But delivery issues emerged as other water users began to increase their orders because the Windy Gap Water rights are junior to other rights and because the C-BT Project through which Windy Gap Water is stored and delivered has some inherent limitations. This means that, during its lifetime, the Windy Gap Water supply has been less reliable than anticipated. Weather conditions such as severe drought or extreme snowpack limit Windy Gap Water availability. Although Rawhide has never been curtailed due to a lack of water, continued dependence on favorable weather to secure Platte River's water supply is not a reliable long-term strategy.

For example, in dry years, the Windy Gap Water decrees are not in priority and the Windy Gap Project cannot pump because water is not available. In some especially wet years, the Windy Gap Project would be able to pump but cannot due to lack of storage. Currently, Lake Granby is the only storage option for Windy Gap Water. However, water conveyed and stored for the C-BT Project has priority over water conveyed and stored for the Windy Gap Project. Therefore, in wet years, when the C-BT system is full, there is no conveyance or storage capacity for Windy Gap Project water. This means that the Windy Gap Project cannot store water in wet years to use in dry years. And if Lake Granby reaches capacity and spills due to wet year inflows, Windy Gap Water is the first to spill.

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Because the Windy Gap Project yields are unreliable in both wet and dry years, the project's current firm yield is zero. Firm yield is the amount of water that can be delivered on a reliable basis, in all years, and is typically determined by yield in a critical drought period.

To address uncertain deliveries, Northern Water developed the "Criteria for Integrated Operations of the Colorado-Big Thompson and Windy Gap Projects" (Integrated Operations) in 1991. Through Integrated Operations, Northern Water may deliver C-BT Project water to Windy Gap participants in lieu of Windy Gap Water. The Windy Gap Project must replace all C-BT Project water attributable to these in-lieu deliveries with later-pumped Windy Gap Water. Northern Water may require Windy Gap Project participants who request in-lieu deliveries to incur additional expenses or make other water available as collateral so that in-lieu deliveries do not harm C-BT Project beneficiaries.

In extremely dry years, even Integrated Operations may not allow use of in-lieu Windy Gap Water. This situation occurred during the 2002-2003 water year, when the C-BT system did not have enough unallocated reserve water in storage to support the in-lieu program. During that period, Platte River had to lease reusable water from a front range municipality. This water was used for critical process water needs and enabled Rawhide Unit 1 to continue operations. Fortunately, a large snowfall in March 2003 provided enough water to enable the Windy Gap Project to pump and Windy Gap Water became available. It is uncertain how Platte River would have obtained the water for Rawhide operations without this snowfall.

Like the extreme dry year of 2002-2003, the 2012-2013 water year had no Windy Gap Water available, but Platte River was able to obtain water using the in-lieu process. Had the reserves in the C-BT system been depleted, or if C-BT water were unavailable on the rental market, Integrated Operations would not have been an option. In some years, Platte River and Fort Collins have been able to work out an arrangement during these "Windy Gap short" periods to provide water for the MOU and cooling water. In particular, the 2012-2013 drought period would have been much more costly to Platte River had this agreement not been in place and had the Windy Gap Project not pumped in the late spring of 2013. This enabled Platte River to revert to normal operations halfway through the year. But acquiring reusable water through the rental market can be uncertain, unreliable and, at times, very expensive.

Although rental water is easier to acquire in wet years, availability and pricing are subject to market volatility. Platte River first seeks rental water from the owner communities. If water is not available from the owner communities, Platte River reaches out to other regional partners to lease C-BT water. In some cases, Platte River has secured long-term C-BT lease agreements and rights of first refusal to lease C-BT water when available from other municipalities. These resources provide additional security for Rawhide's process water needs. On average, Platte River leases around 1,300 af of C-BT water for use as collateral, and in some years has required as much as 2,200 af of leased water to meet its water needs.

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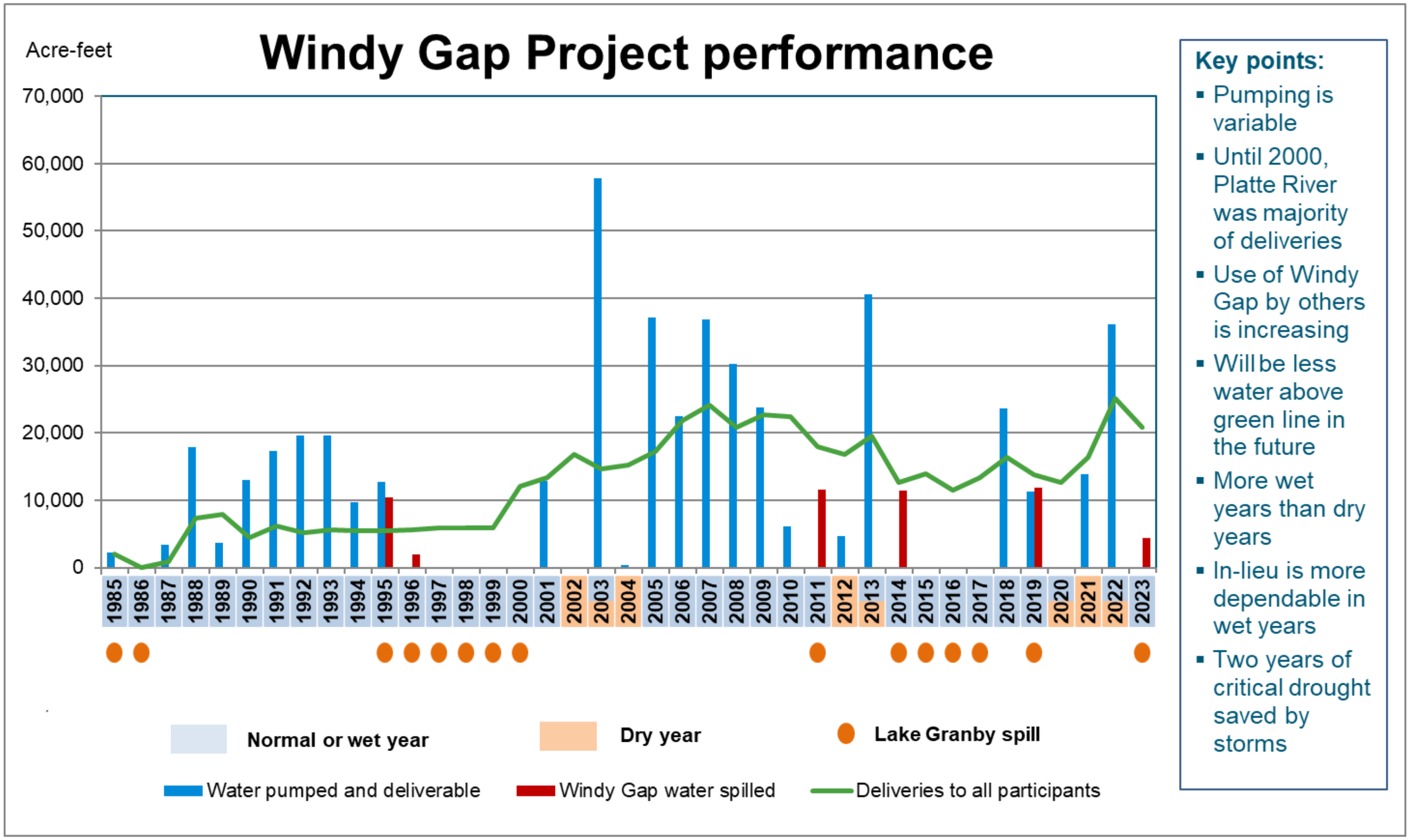
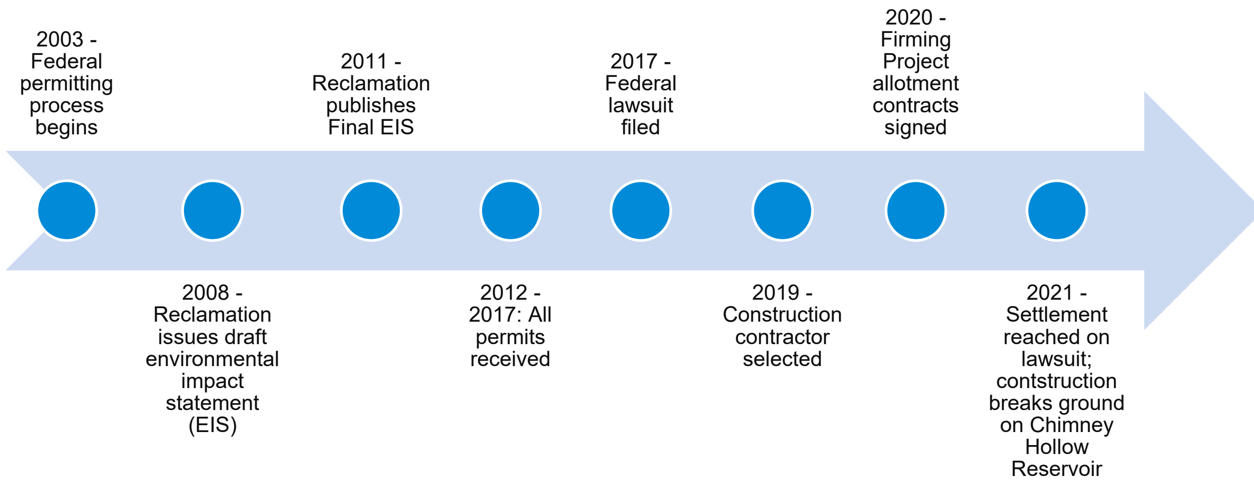
The chart below shows the historical Windy Gap Project performance and the associated impacts of both wet and dry years, as discussed above:



2. History and status of the Windy Gap Firming Project and Chimney Hollow Reservoir

As described above, the Windy Gap Project was completed in 1985, and six years later the participants adopted Integrated Operations to address deliverability issues. The participants recognized that Integrated Operations could provide relief under certain conditions but would be ineffective during extreme weather. In the mid-1990s, the participants began to discuss the Windy Gap Firming Project (Firming Project) to better resolve deliverability issues.

The Firming Project is a new reservoir, named Chimney Hollow Reservoir, into which Windy Gap Water will be pumped in wet years and stored for use in dry years (when the Windy Gap Project does not pump), significantly improving operational reliability and reducing volatility. Platte River commissioned a study of water supply alternatives, which confirmed that participation in the Firming Project was the most effective means to secure Platte River's water supply. In July 2000, Platte River signed an interim agreement with Northern Water and the Municipal Subdistrict to continue its participation in the Firming Project. Major Firming Project milestones include:



3. Firming Project/Chimney Hollow Reservoir project schedule

Chimney Hollow Reservoir construction is expected to be complete by the fall of 2025, with initial filling beginning in late 2025 or early 2026.

4. Firming Project storage requirements

Platte River's storage allotment in Chimney Hollow Reservoir is 16,000 af. Over the course of the project's development, this volume fluctuated based on the results of multiple water

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resources studies and changes in estimated project costs and schedule. Ecological Resource Consultants completed the most recent water resources model in 2020, incorporating updated forecasts for Platte River's water needs and the latest operational parameters of the Firming Project to determine Platte River's expected annual firm yield across a variety of storage and Windy Gap unit ownership combinations.

The model indicated that for a one-in-57-year drought (two consecutive years of no Windy Gap pumping) 16,000 af of Chimney Hollow storage will provide Platte River at least 5,200 af per year of firm supply if Platte River owns 80 or more Windy Gap units. This yield would meet Platte River's current operational demand of approximately 4,800 af per year. The study also concluded that no combination of storage and supply would yield enough for a one-in-250-year drought (three consecutive years with no Windy Gap pumping). In these years, Platte River will need to modify operations, including reduced effluent pumping and leasing rental water.

Firming Project model analysis (based on 60-120 units)*

Firming Project storage (af)	Windy Gap unit ownership level	Annual firmed Windy Gap (af) *historic hydrology: 1 in 50 years*	Annual firmed Windy Gap (af) with two years of no pumping *occurrence interval: 1 in 57 years*	Annual firmed Windy Gap (af) with three years of no pumping *occurrence interval: 1 in 250 years*
8,000	60 - 100	3,050 - 3,415	2,875 - 2,985	2,060 - 2,140
10,000	60 - 100	3,545 - 4,150	3,365 - 3,735	2,410 - 2,675
12,000	60 - 100	3,955 - 4,750	3,910 - 4,445	2,800 - 3,180
14,000	100 - 120	5,265 - 5,595	4,970 - 5,230	3,560 - 3,745
16,000	60 - 120	4,410 - 6,110	4,410 - 5,755	3,575 - 4,120

* All scenarios are based on the provisions of the updated carriage contract that includes prepositioning, diversion shrink, carryover shrink and environmental impact mitigation measures.

Platte River has begun to assess the water needs of its future energy mix. When Platte River retires Rawhide Unit 1, the total water needs at the Rawhide site will likely change, but the magnitude and direction of that change are not yet clear. Potential water demands for future generation vary significantly depending on generation type, and as Platte River implements a new resource mix, the Firming Project will ensure that water supply will not limit Platte River's planning. Ultimately, Chimney Hollow Reservoir will change the Windy Gap Project's total reliable annual yield from zero af of water to about 30,000 af, improving the reliability of water deliveries to participants. There is a significant value to a firm and reliable water supply for both immediate and future needs.

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5. Firming Project participants

Firming Project participants	WG units	Storage (af)	Percentage of project	Ratio of volume/units *Years to fill**
City and County of Broomfield	56	26,464	29.4%	4.7
Platte River Power Authority	107	16,000	17.8%	1.5
City of Loveland	40	10,000	11.1%	2.5
City of Greeley	49	9,189	10.2%	1.9
City of Longmont	80	7,500	8.3%	0.9
Town of Erie	20	6,000	6.7%	3.0
Little Thompson Water District	20	4,850	5.4%	2.4
Superior Metropolitan District No. 1	15	4,726	5.2%	3.2
City of Fort Lupton	13	1,190	1.3%	0.9
City of Louisville	9	2,835	3.1%	3.2
City of Lafayette	3	900	1.0%	3.0
Central Weld County Water District	1	346	0.4%	3.5
Total	**413**	**90,000**	**100%**	**Avg = 2.56**

* Based on the assumption of full Windy Gap Project pumping and allocation.

6. Firming Project costs

The Firming Project's estimated cost is $755 million. Cash assessments made separately from construction financing totaled $90 million and were used for permitting, planning, design, environmental mitigation and enhancements and to settle a federal lawsuit that challenged the Firming Project before construction began. Initial Costs and Expenses (C&E) for the construction phase were estimated at $600 million and Completion C&E was estimated at $65 million.[7] Platte River's estimated total cost of the project, based on 16,000 af of storage, is $141.6 million. Of that amount, Platte River funded approximately $117.9 million through a pooled financing arrangement with other Firming Project participants. The pooled financing includes bonds issued by the Municipal Subdistrict and a loan from the Colorado Water Conservation Board.

[7] Initial C&E and Completion C&E are defined in Platte River's Firming Project allotment contract and were intended to include all funds necessary to construct and complete the Firming Project.

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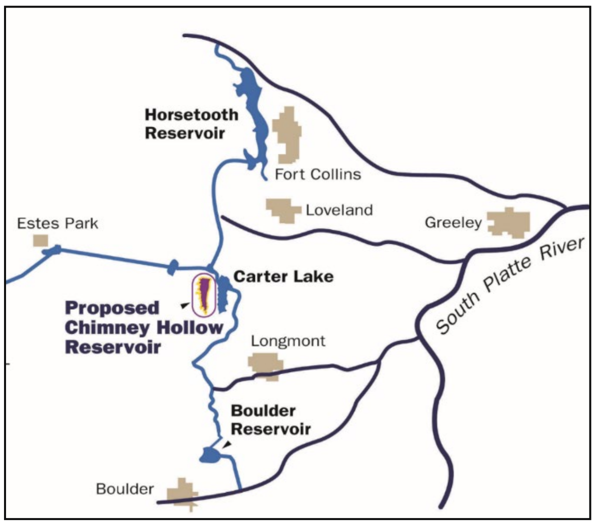
7. **Chimney Hollow Reservoir operation**

The Municipal Subdistrict and participants will develop a set of operating guidelines before Chimney Hollow Reservoir is completed. The Municipal Subdistrict and participants currently expect Chimney Hollow Reservoir to fill and discharge water via gravity flow. The operating guidelines will cover routine operation, scheduling water in and out of Chimney Hollow Reservoir and evaporation/seepage loss calculation methodology. A general map of the proposed Chimney Hollow Reservoir follows with a more detailed map shown in Appendix A-6:



Northern Colorado Water Conservancy District
http://www.northernwater.org/waterprojects/CBTWindyGapmaps.aspx

Section III – Water Policy and operations

Platte River's water operations are based on three guiding principles: (a) securing and protecting a water supply for Platte River's current operational needs, (b) planning for Platte River's future water supply needs while contemplating the future needs of the owner communities, and (c) maximizing the value of water resources by managing water as an asset.

1. **Water Policy objectives**

   a. **Securing and protecting a water supply for Platte River's operational needs**

As described in Section II, Platte River currently needs approximately 4,800 af of water per year. This meets operational needs when water and weather conditions are normal. In years with extreme wet or dry conditions, Platte River has met its water supply needs either through the leverage achieved from the Windy Gap units (because Platte River's pro-rata allocation is higher based on contract allotment ownership level) or through alternative arrangements. Participation in the Firming Project will provide additional supply security.

b. Planning for Platte River's future water supply needs

Platte River's primary future consideration for water is future generation needs. Platte River must also consider future uncertainties, including climate impacts and new environmental legislation and regulation.

Various power generation methods, ranging from emerging technologies to mature processes, could satisfy Platte River's strategic initiatives and future load growth. Several shifts in the energy industry could influence Platte River's future resource mix, including:

- Potential federal regulation of greenhouse gases
- Changes in the price of solar generation and wind resources
- Sustained low natural gas prices
- Advancements in energy storage
- Growth of distributed energy resources

Platte River considered many generation technologies as it developed its integrated resource plans. Most potential future generation sources would require less water than traditional coal-fired units. Platte River will research future resource water requirements, but expects the identified reserve of approximately 4,000 af to be more than adequate to serve any future generation resources Platte River might consider.

Platte River faces other future uncertainties, such as new water agreements or changes to existing water agreements, water usage and water rights appropriation. Platte River's regional water partnerships, resiliency and a firm water supply will remain critical. Platte River's participation in the Firming Project and the water exchange agreement with the City of Greeley are both prime examples of working toward a sustainable water supply and resilient infrastructure.

c. Maximizing the value of water resources by managing water as an asset

Platte River's practice is to maximize the operational and economic value of water resources through various activities within limits the board of directors has defined as discussed below.

Platte River leases unpumped reusable effluent generated under the Reuse Agreement and MOU. The amount of unpumped reusable effluent varies, but averages approximately 1,900 af annually, based on a typical supply of 5,400 af and a typical use of 3,500 af. Platte River does not deliberately accumulate unpumped water but accumulates some water in years when it

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either cannot be pumped or does not need to be pumped. Variations in unpumped reusable effluent occur based on the availability of water under the Reuse Agreement, the amount of return flows from Fort Collins and AB InBev and the amount of water needed at Rawhide. Unpumped effluent is stored in Fossil Creek Reservoir (when space is available) for later pumping or leasing to others.

Summary of Platte River's reusable effluent supply and use

Water supply and use – reusable effluent	Annual quantity available (af)	Annual quantity used (af)	Total (af)
Supply			
Reuse Agreement	4,200		
Windy Gap return flows	1,200		
Total supply	**5,400**		
Use			
Pump to Rawhide		3,300	
Augmentations		200	
Total use		**3,500**	
Approximate unpumped reusable effluent (annual)			**1,900**

*This table reflects normal water use and availability.

Historically, reusable effluent has had only a few lease markets with modest value, mainly agriculture and industrial augmentation. Platte River's supply of unpumped effluent has been limited over the past several years due to water supply conditions, but when unpumped effluent is available, Platte River seeks lease opportunities.

Platte River also leases Windy Gap units to others. This type of lease involves Windy Gap units that Platte River does not need for current operations.

Beyond leasing activities and once Chimney Hollow Reservoir is complete, Platte River will continue to maximize the value of its water portfolio by finding the optimal balance of Windy Gap units and storage capacity in Chimney Hollow Reservoir. Through selling a select amount of its Windy Gap units and pairing the remaining units with storage capacity in Chimney Hollow Reservoir, Platte River will achieve a more reliable and resilient water portfolio going forward. A summary of Windy Gap unit sales to date is provided in Section IV.

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2. Water costs –operating expenses

The following table summarizes Platte River's average annual operating costs for the Windy Gap Project and Chimney Hollow Reservoir. These figures do not include pumping and treatment costs at Rawhide. There may be some additional operational costs for the a few years during the first fill and start-up of the Chimney Hollow Reservoir, which are not reflected below. The amounts shown are Platte River's typical costs, excluding the amounts allocated and charged to AB InBev.

Platte River's net annual water cost summary

Operating costs*	Typical annual amount	Comments
Windy Gap pumping cost	$15k	Windy Gap Project pumping costs
Windy Gap carriage costs	$55k	Carriage costs for use of C-BT system to convey Windy Gap Water to Horsetooth Reservoir
Windy Gap assessment costs (operations and maintenance expenses)	$250k	Annual charges based on Windy Gap unit ownership
Windy Gap excess capacity charge/in-lieu borrowing charge	$15k	Assessed on water delivered or exchanged to east slope
Windy Gap indirect cost allocation	$50k	Assessed annually based on Windy Gap unit ownership
Chimney Hollow Reservoir operations and maintenance	$355k	Estimated annual charges based on Platte River's storage allotment in Chimney Hollow Reservoir – charges incurred once the reservoir is put into operation upon completion of construction
Chimney Hollow Reservoir indirect cost allocation	$85k	Assessed annually based on Chimney Hollow Reservoir capacity
Typical annual costs	**$825k**	

* Platte River's net costs are shown, excluding the charges covered by AB InBev through the MOU.

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Section IV – Current Water Resources Policy

Platte River's board-approved Water Resources Policy directs and authorizes the general manager/CEO to:

1. **Maintain adequate water supplies for all existing and projected future operations.**

   a. Maintain Platte River's participation level in the Windy Gap Firming Project at a storage level of 16,000 af.

   b. Lease water required for Platte River operations and contractual commitments when needed.

   c. Participate in resource planning efforts to incorporate planning for future water needs, with considerations for type and location of future generation resources.

   d. Continue to research and explore alternative water supply opportunities.

   e. Review and modify existing water agreements and pursue new agreements to improve operations, increase reliability and maximize the value of water resource assets.

2. **Manage water as an asset.**

   a. Lease water to others when available (effluent or Windy Gap units).

   b. Sell Windy Gap units while maintaining a minimum level of 100 units. Compensation may be monetary, may involve storage rights or may involve some other consideration that provides value to Platte River.

   c. Maintain a minimum of five cfs of Carter Lake Outlet Capacity while leasing excess capacity.

The complete Water Resources Policy is included in Appendix B for reference.

This Water Resources Policy allows Platte River to pursue activities that help Platte River meet contractual commitments and operational needs while maximizing the operational and economic value of its water resources. Below is an overview of some of the actions Platte River has taken under the Water Policy:

- In late 2017, Platte River completed a series of transactions that increased its Firming Project capacity from 12,000 af to 14,136 af. Platte River also sold 23 Windy Gap units and secured short-term C-BT water lease options, generating approximately $39 million in total revenue.

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- In early 2018, Platte River acquired additional storage which resulted in a final Firming Project participation level of 16,000 af.

- In 2019, Platte River sold 17 Windy Gap units and 13 cfs of surplus Carter Lake outlet capacity. These agreements generated additional revenue of approximately $37 million, helping offset future project costs, securing C-BT water lease options and providing added water security until the Firming Project is complete.

- In 2020, Platte River sold 10 Windy Gap units at a combined price of $27 million.

- Platte River commissioned a study by the Burns & McDonnell engineering firm, completed in 2020, to explore options for additional raw process water storage at Rawhide. Because Rawhide Unit 1 is scheduled to retire by 2030, Platte River may not need this project. Platte River will retain the study results in case Platte River needs additional on-site water storage in the future.

- In 2022, Platte River leased C-BT water from the City of Greeley from the 2023 water year through the 2030 water year in exchange for Platte River's transfer of its Poudre River rights. Under the lease agreement, Platte River retains use of the Poudre River rights through 2030. This lease secures Platte River's estimated process water needs through Rawhide Unit 1's retirement. The agreement is a notable example of a mutually beneficial regional water partnership.

- In 2022, Platte River relinquished its remaining conditional exchanges associated with its 24-inch pipeline. These exchanges were originally contemplated as contract exchanges of water between Platte River and entities owning structures that intersect the 24-inch pipeline, but they have never been used. Platte River, with the help of an outside consultant, determined that these potential exchanges were not needed for current or future Platte River operations. If Platte River identifies a future opportunity, Platte River can accomplish exchanges of this type through mutual agreement.

- In 2023, Platte River issued a request for proposals for the sale of up to five unfirmed Windy Gap units. By late 2023, Platte River completed transactions with two different entities for the sale of three Windy Gap units for a total price of $12.3 million. Platte River expects to complete the sale of the other two Windy Gap units in 2024.

These water transactions have given Platte River the additional storage capacity needed to reduce operational risks during droughts, generated revenue of approximately $115 million and strengthened Platte River's relationships and partnerships within the Northern Colorado water community.

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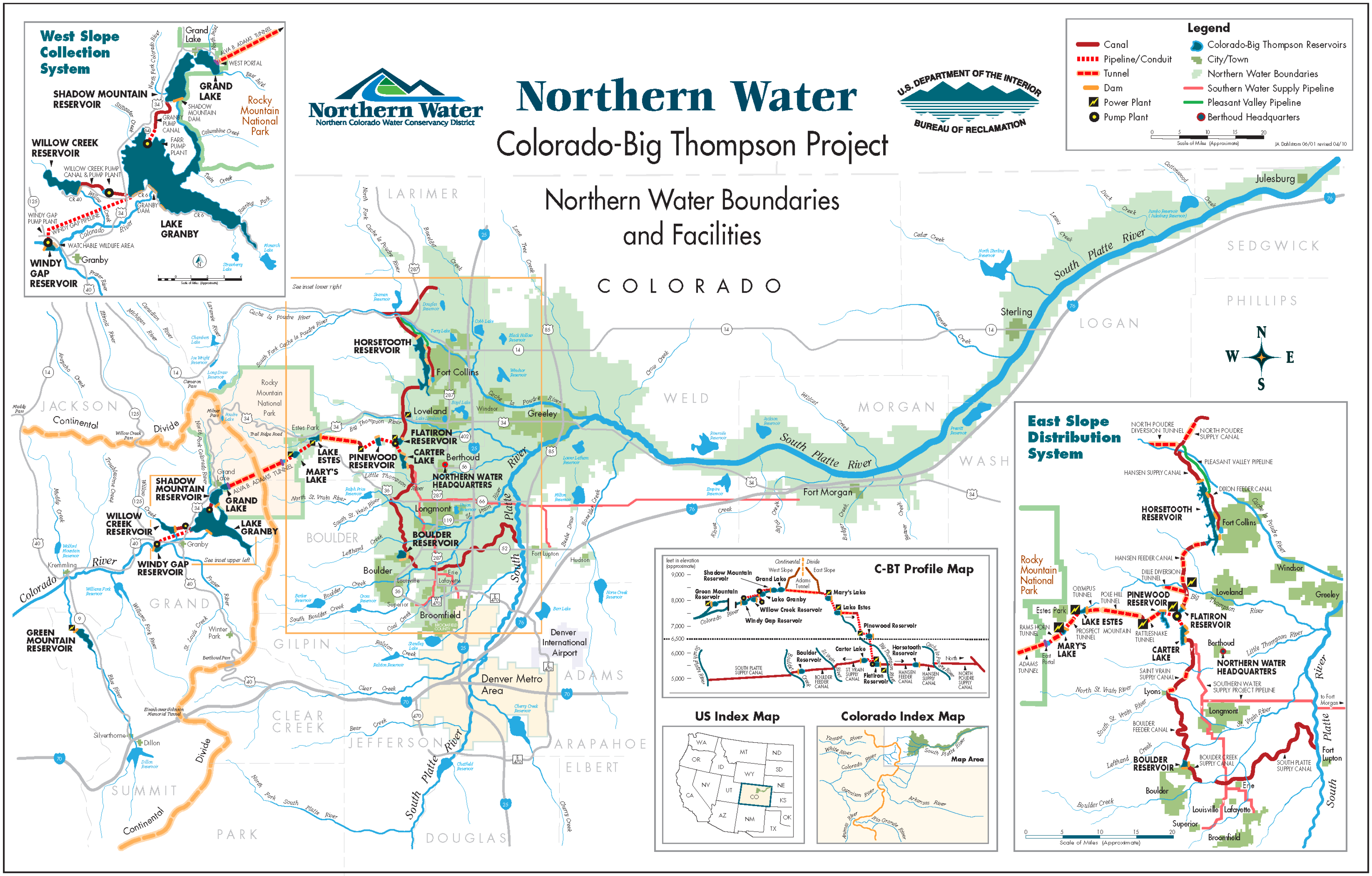
Section V – Going forward

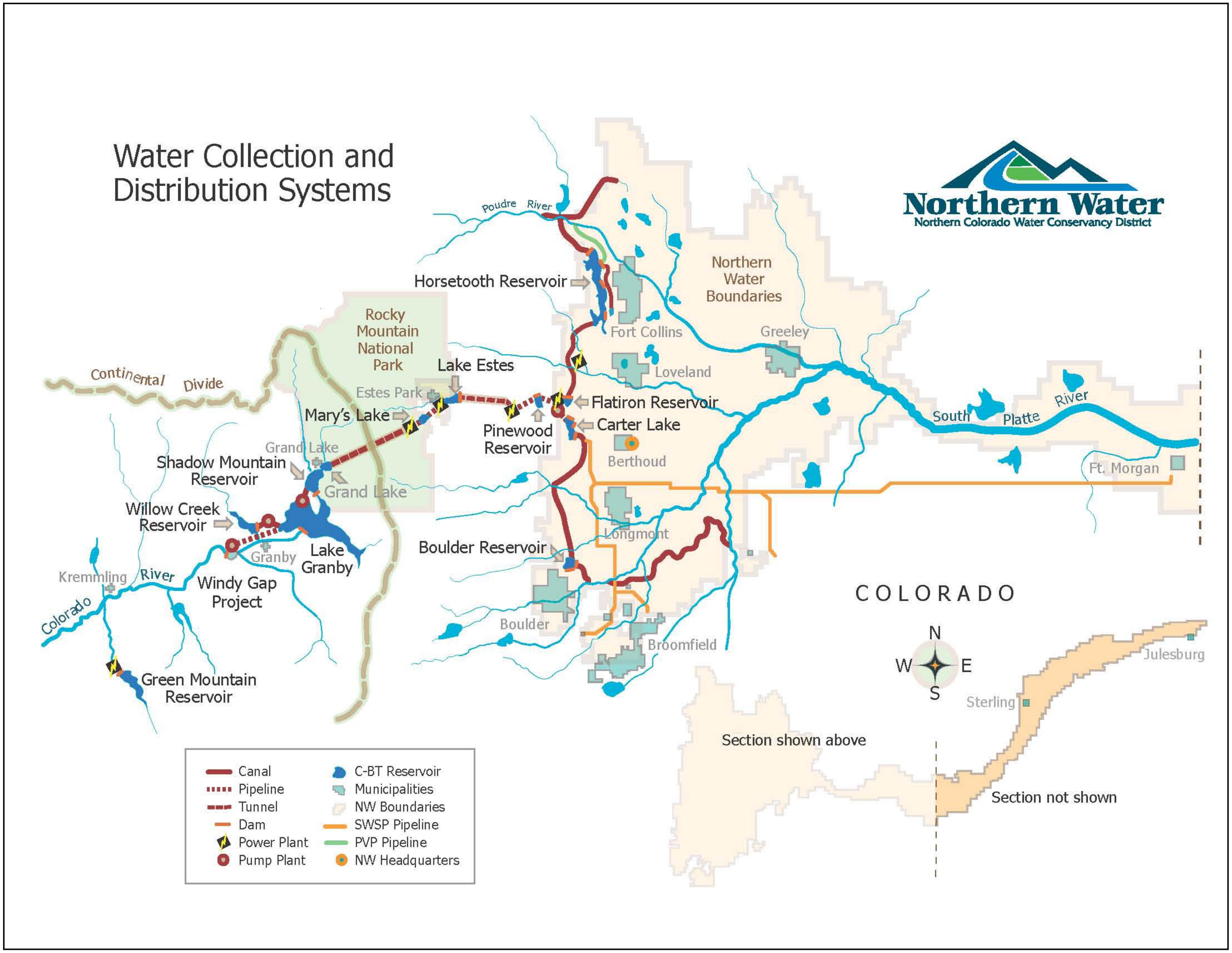
Platte River has actively assessed, managed and optimized its water resources portfolio under the guidance of the Water Resources Policy. The resulting transactions, including the sale of Windy Gap units and acquisition of additional storage in Chimney Hollow Reservoir give Platte River a more balanced and firm water portfolio for reliable operations.

Aside from the Windy Gap Project and the Firming Project, Platte River will continue to assess various aspects of its water resources and seek further opportunities to manage water as an asset.

Appendix A – Maps

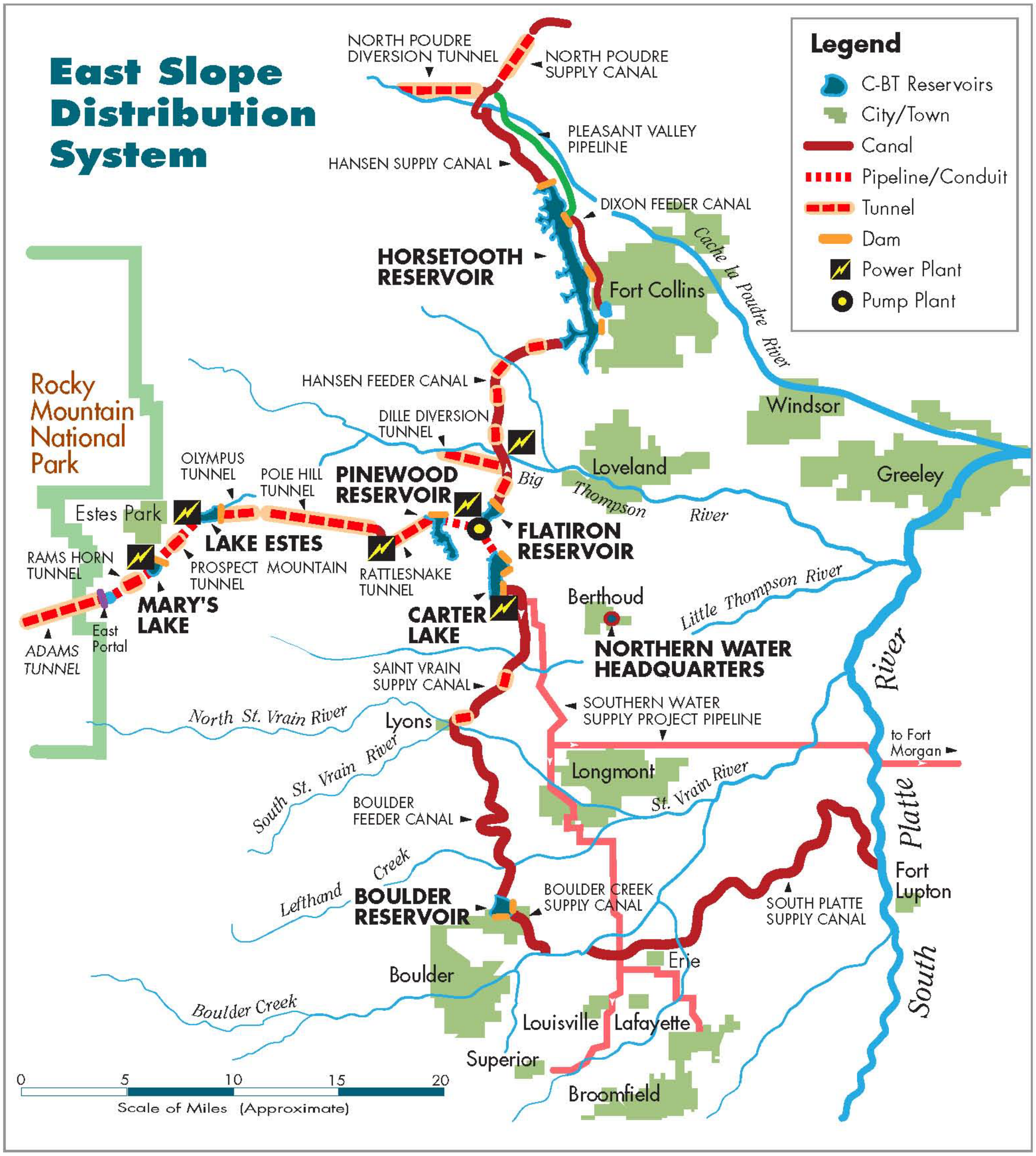


Northern Colorado Water Conservancy District
http://www.northernwater.org/waterprojects/CBTWindyGapmaps.aspx

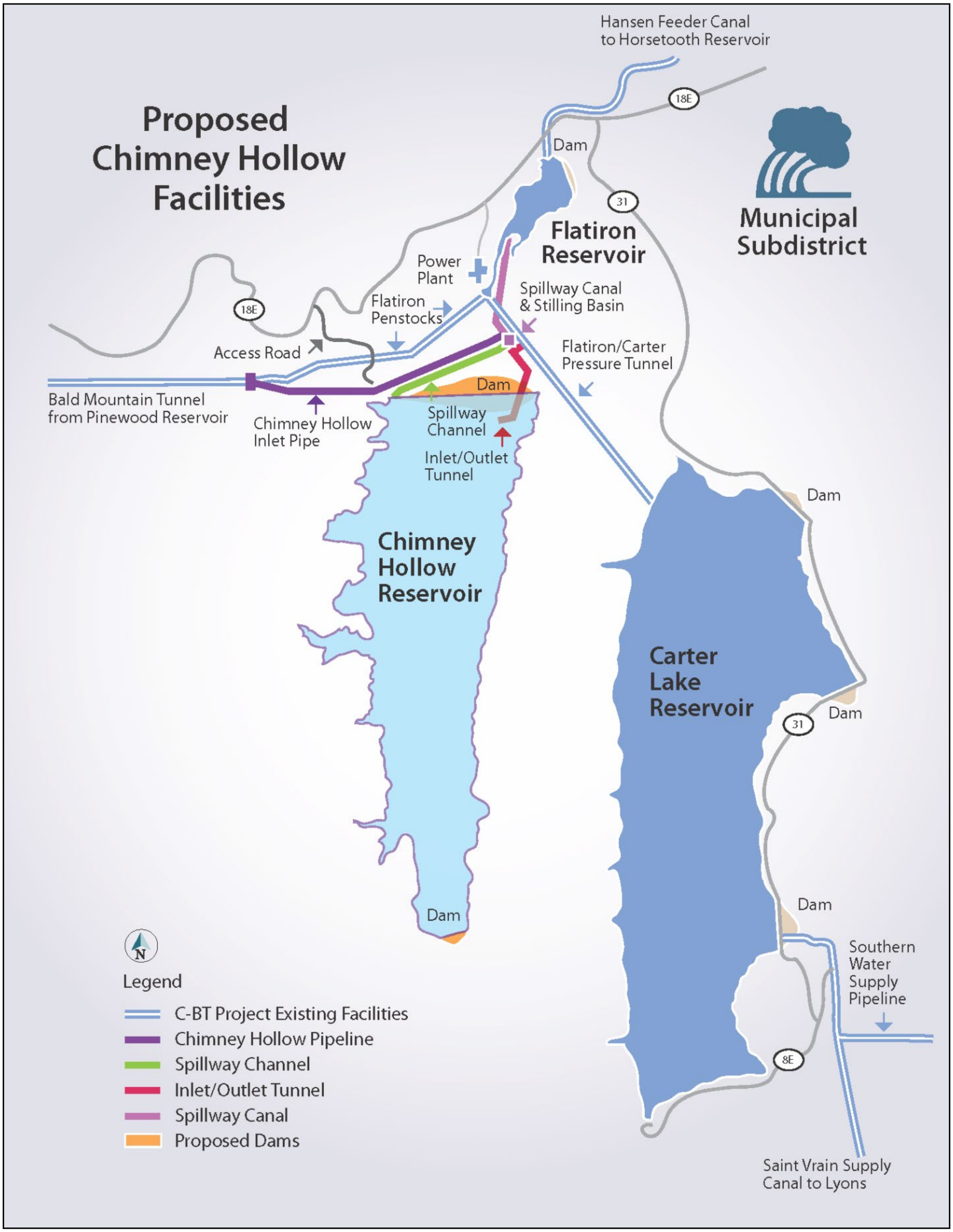


Northern Colorado Water Conservancy District
http://www.northernwater.org/waterprojects/CBTWindyGapmaps.aspx


West Slope Collection System
SHADOW MOUNTAIN RESERVOIR
Grand Lake
North Inlet
ALVA B. ADAMS TUNNEL
WEST PORTAL
East Inlet
GRAND LAKE
North Fork Colorado River
SHADOW MOUNTAIN DAM
Rocky Mountain National Park
34
Stillwater Creek
GRANBY PUMP CANAL
64
Columbine Creek
FARR PUMP PLANT
WILLOW CREEK RESERVOIR
WILLOW CREEK PUMP CANAL & PUMP PLANT
Twin Creek
CR 40
Willow Creek
CR 6
GRANBY DAM
125
Roaring Fork
CR 6
34
WINDY GAP PUMP PLANT
WINDY GAP PIPELINE
Colorado River
40
LAKE GRANBY
WATCHABLE WILDLIFE AREA
Monarch Lake
Granby
Strawberry Lake
WINDY GAP RESERVOIR
40
Fraser River
Green Mountain
Inset of Green Mountain
40
Colorado River
Kremmling
Blue River
9
POWER PLANT
Henney
FR 30
GREEN MOUNTAIN RESERVOIR
Map area not to scale
Legend
C-BT Reservoirs
City/Town
Canal
Pipeline/Conduit
Tunnel
Dam
Power Plant
Pump Plant
N
Map not to scale



Northern Colorado Water Conservancy District
http://www.northernwater.org/waterprojects/CBTWindyGapmaps.aspx



Northern Colorado Water Conservancy District
http://www.northernwater.org/waterprojects/CBTWindyGapmaps.aspx

Appendix B – Water Resources Policy Document

Platte River Power Authority	Policy	Version #: 1.2 Effective date: 05/10/2023 Next review date: 05/10/2026
	TITLE: Water Resources Policy	Page 1 of 3

Purpose:

This policy provides direction to the Platte River General Manager/CEO on activities related to securing a reliable source of water for operations and the management of water rights and resources as an asset of the organization.

Policy:

Water is critical to the reliable operation of the Rawhide Energy Station (Rawhide) and may be necessary for the reliable operation of future generation resources. Platte River's initial ownership of 160 units of the Windy Gap Project (one third of the total project) was anticipated to be sufficient supply for the initial and future needs of the organization. Based on this assumption, and in an effort to make the most efficient and responsible use of water, Platte River entered into several significant water agreements, including but not limited to the Reuse Agreement, the Memorandum of Understanding, the North Poudre Storage Agreement, the Soldier Canyon Outlet Agreement and the Carter Lake Outlet Agreement. These agreements are discussed in detail in the **Platte River Power Authority Water Resources Reference Document.**

Operational history has revealed the limitations of the Windy Gap Project; it is often constrained by the junior priority of its water rights as well as by the project's dependence on the use of Colorado-Big Thompson infrastructure for storage and delivery of water. While ownership of a significant number of Windy Gap units proved advantageous during periods in which the Windy Gap Project failed to fully deliver water, the Windy Gap Firming Project (of which Chimney Hollow Reservoir is the primary component) will offer greater reliability than unit ownership alone. Moreover, growth in the Northern Colorado region has placed increased pressure on water resources and necessitates more active management of the Platte River water resources as an asset of the organization and member communities. By participating in the Windy Gap Firming Project, Platte River will reduce its overall need for Windy Gap Project units and gain flexibility to manage the units as an asset in future water resources operations.

It is the intent of the board that this policy will position Platte River to pursue activities that will: increase the reliability of water deliveries to meet contractual commitments and the operational needs of the organization; and, maximize the operational and economic value of its water resources, which include but are not limited to Windy Gap units, outlet capacity, storage allocations in the Windy Gap Firming Project, and treated effluent received through the operation of water exchanges.

Consequently, the General Manager/CEO is instructed to:

1. Maintain adequate water supplies for all existing and projected future operations. To do so, the General Manager/CEO is authorized to:

a. Maintain Platte River's participation level in the Windy Gap Firming Project (Chimney Hollow Reservoir) at a storage level of 16,000 acre feet.
b. Lease water required for Platte River operations and contractual commitments as needed.
c. Participate in Platte River's resource planning efforts to incorporate planning for future water needs, with considerations for type and location of future generation resources.
d. Continue to research and explore alternative water supply opportunities.
e. Review and modify existing water agreements and pursue new agreements to improve operations, increase reliability, and maximize the value of water resources assets.

2. Manage water as an asset. To do so, the General Manager/CEO is authorized to:

   a. Lease water:
      i. Lease reusable effluent
         - Water that cannot be pumped or exchanged from Fossil Creek Reservoir is at risk of uncompensated loss. Pumping activity should be managed to minimize storage of effluent, but Platte River will also be proactive in the markets through which any at-risk water may be leased.

      ii. Lease of Windy Gap units
         - Leases of Windy Gap units can be of any duration and/or quantity, so long as Platte River maintains control of a minimum of one hundred (100) units.

      iii. The General Manager/CEO will inform the board of leasing activity.

   b. Sell Windy Gap Units:
      i. Platte River may sell Windy Gap units, so long as Platte River maintains control of a minimum of one hundred (100) units.
      ii. Compensation may be monetary, may involve water storage rights, or may involve other forms of consideration that provide value.
      iii. The General Manager/CEO will inform the board of any sale of Windy Gap units.

   c. Sell/Lease Carter Lake outlet capacity
      i. Maintain a minimum of five (5) cfs of Carter Lake outlet capacity.
      ii. Platte River may lease Carter Lake outlet capacity, so long as five (5) cfs can be made available for operational needs when required.
      iii. The General Manager/CEO will inform the board of the sale or lease of Carter Lake outlet capacity.

Document owner: Fuels and Water Manager	**Effective date:** 05/10/2023
Authority: Board of Directors	**Review frequency:** Every 3 years
Counsel review: General Counsel	**Review date:** 05/10/2026

Implementing parties and assigned responsibilities:

The General Manager/CEO will have primary responsibility for implementation.

Associated Items (if applicable):

Platte River has prepared, and annually updates, the **Platte River Power Authority Water Resources Reference Document.** This reference provides a detailed explanation of Platte River's water resources and infrastructure, the operational uses of water, and the underlying agreements that support our water portfolio and define the rights and obligations associated with our water assets. The **Water Resources Reference Document** forms the underpinnings for this policy.

Definitions (if applicable):

Version	Date	Action	Author	Change tracking (new, review, revision)
Original	12/08/2016	Original policy by Board Resolution 24-16	Heather Banks	Original
1.1	02/27/2020	Updated to AP style and revised to account for current asset ownership	Heather Banks	Revision
1.2	05/10/2023	Updated to incorporate "Chimney Hollow Reservoir" reference	Heather Banks	Revision

Platte River
Power Authority

Appendix C – Glossary

Glossary of water terms

for Platte River Water Resources Reference Document

A

Acre-foot (af): The volume of water that would cover one acre of land to a depth of one foot.

Augmentation: A requirement to put water into a stream to prevent reductions in streamflow caused by pumping from a well (or some other water use) from affecting the amount of water available to water rights holders on that stream and the remainder of the stream system.

C

C-BT: Colorado-Big Thompson Project. The Colorado-Big Thompson Project collects water from the upper Colorado River basin on the Western Slope and delivers the water beneath the Continental Divide to Colorado's Eastern Slope. The C-BT Project uses a complex system of reservoirs, pump plants, tunnels, pipelines and power plants, and relies on two basic forces of nature: melting snow and gravity. After flowing through the power generation facilities, water is stored in three Eastern Slope terminal reservoirs: Horsetooth Reservoir west of Fort Collins; Carter Lake southwest of Berthoud; and Boulder Reservoir northeast of Boulder.

cfs: Cubic feet per second. One cfs equals 1.98 af per day.

Chimney Hollow Reservoir Project: The central component of the Windy Gap Firming Project, Chimney Hollow Reservoir is the result of a collaborative effort by 12 project participants to improve the reliability of the Windy Gap Project. The reservoir will be located just west of Carter Lake in Larimer County. Its 90,000 af of dedicated storage capacity will supply a reliable 30,000 af of water each year to project participants. This project will not take water away from irrigated agriculture or other users but will utilize the existing water rights currently associated with the Windy Gap Project.

Colorado Water Division 1: One of seven water divisions in the state of Colorado. Division 1 includes the South Platte River Basin, the Republican River Basin and the Laramie River Basin. Geographically, Division 1 is located in the northeast quadrant of Colorado.

Cooling water: Reusable effluent water stored in Hamilton Reservoir and used to cool Rawhide Unit 1.

E

EIS: Environmental Impact Statement—a document prepared to describe the potential environmental impacts of a proposed action. It also describes impacts of alternatives and plans to mitigate the consequences.

F

Firm water: Water that can be relied upon and is available even during a drought.

Fully consumable water: Water that can be used and reused to extinction. Imported, non-native water in which the return flows have not been historically relied upon.

I

Integrated Operations: A protocol in which C-BT Project water may be delivered to Windy Gap participants in-lieu of Windy Gap Water when it is not available. In-lieu recipients must replace in-lieu C-BT water with Windy Gap Water pumped in subsequent periods.

M

Municipal Subdistrict: The Municipal Subdistrict is a separate conservancy district within the Northern Colorado Water Conservancy District, formed by several municipalities to build and operate the Windy Gap Project.

N

New foreign water: Water introduced into the Cache la Poudre Basin from the Colorado and Michigan River Basins and whose return flows historically have not been used by others.

Northern Water: Northern Colorado Water Conservancy District. Along with Reclamation, jointly operates and maintains the C-BT Project.

P

Process water: Reusable Windy Gap Water used at Rawhide for service water, boiler water, fire water and other plant processes as appropriate.

R

Reclamation: United States Bureau of Reclamation

Return flows: As pertaining to the Reuse Agreement, wastewater collection and return flow includes wastewater collected from domestic, commercial and industrial users, treated at wastewater treatment facilities, and returned to the hydrologic system or released for reuse as reclaimed wastewater (reusable effluent). This is typically an average of 55% of the original quantity of water first used by the municipality.

Reusable effluent: Fully consumable water used by a municipality and treated in a water reclamation facility. This water can be used to extinction.

W

Windy Gap Firming Project: A water reservoir project in the Front Range designed to store, or “firm,” the supply of Windy Gap Water. The Firming Project (of which Chimney Hollow Reservoir is the major component), was reviewed and approved under the National Environmental Policy Act and by state and local governments through substantial negotiations. Windy Gap Water will be pumped into Chimney Hollow Reservoir in wet years and stored for use in dry years when the Windy Gap Project does not pump.

Windy Gap Project: The Windy Gap Project consists of a diversion dam on the Colorado River, a 445 af reservoir, a pumping plant and a six-mile pipeline to Lake Granby. Windy Gap Water is pumped and stored in Lake Granby before delivery to water users via the Colorado-Big Thompson Project's East Slope distribution system.

Windy Gap unit: A Windy Gap unit is equivalent to 100 af of water during years of full Windy Gap production.

WSSC: Water Supply and Storage Company.

Platte River Power Authority

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Legal, environmental and compliance report

April 2024

Platte River
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Overview of recent developments

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 to approve the Long-Term Experimental and Management Plan for Glen Canyon Dam. The district court ruled in the Bureau's favor, and the plaintiff environmental groups appealed to the Ninth Circuit Court of Appeals (the Ninth Circuit). On April 24, 2024, the Ninth Circuit affirmed the district court's ruling in favor of the Bureau. The full report is on page 3 of this document.

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, the DOE will coordinate all federal environmental reviews for permitting transmission projects under a strict two-year time limit. The full report is on page 4 of this document.

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. The EPA's final rules exempt existing coal-fired units that permanently end operations before Jan. 1, 2032. The EPA also removed existing natural gas-fired combustion turbines from the scope of the final rules. For new and reconstructed fossil fuel-fired combustion turbines, the EPA's final rules maintained the proposed rules' structure, creating three subcategories (low load, intermediate load, and base load) based on annual capacity factors, with more stringent controls at higher capacity factors. The full report is on page 4 of this document.

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 would require Platte River to install a continuous monitoring emissions system for particulate matter emissions. The full report is on page 5 of this document.

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 may be subject to groundwater monitoring, corrective action, and closure, including areas outside of previously regulated and managed impoundments. The full report is on page 6 of this document.

Compliance matters

There are no new compliance matters to report.

Monitoring—status unchanged

Page 7 of this document provides a list of matters previously reported but unchanged since our last report.

Recently concluded matters

Page 9 of this document provides a list of matters that have concluded within the last three months.

Platte River
Power Authority

Active matters

Legal matters

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

Background:

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.

Save the Colorado and other plaintiffs claimed to have given the Bureau data regarding climate impacts from the proposed adaptive management program during the NEPA process. Plaintiffs said the Bureau's Decision failed to consider their climate data, and that the environmental impact statement failed to consider climate impact (although climate change was not an issue at the time Congress adopted the Colorado River Storage Project Act).

On Dec. 23, 2022, the district court granted the Bureau's motion for summary judgment and denied the plaintiffs' motion. This was a favorable decision for CRSP and Platte River's hydropower interests. But on Feb. 16, 2023, the plaintiffs appealed the decision to the Ninth Circuit Court of Appeals (Ninth Circuit). On Feb. 6, 2024, the parties argued the case to the Ninth Circuit.

Current Status:

On April 24, 2024, the Ninth Circuit affirmed the district court's ruling in favor of the Bureau, finding that the Glen Canyon Dam management plan did not violate NEPA. This, like the lower court decision, is a favorable outcome for CRSP and Platte River's hydropower interests. The plaintiffs (now appellants) have 90 days from the Ninth Circuit'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 regional transmission organizations (RTOs).

Environmental matters

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

Background:

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.

Platte River
Power Authority

For new and reconstructed fossil fuel-fired combustion turbines, the EPA maintained the proposed rules' structure, creating three subcategories based on the function a combustion turbine serves and its annual capacity factor. The three subcategories are:

- Low load "peaking units" or combustion turbines with capacity factors of less than 20%;
- Intermediate load units or combustion turbines with capacity factors between 20% and 40%; and
- Base load units or combustion turbines that operate above the 40% capacity factor for intermediate load turbines.

Base load units are required to meet a standard based on 90% carbon dioxide capture starting in 2032. For intermediate units, the EPA removed specific technology-based standards, instead setting a standard based on highly efficient natural gas combustion. For low-load peaking units, the final rule is based on low-emitting fuels and good combustion practices.

The EPA published the final rules in the *Federal Register* on May 9, 2024 and they will go into effect on July 8, 2024, unless stayed. The state of Colorado then has 24 months to implement the rules in a state implementation plan, which would apply to Platte River. The state's plan may be more stringent than the federal rules, but would need to at least meet the federal standards for EPA approval.

Current Status:

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.

Platte River
Power Authority

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

Finally, and 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). The new CCR rule is in response to a 2018 court decision that found a previous provision (which exempted inactive coal ash impoundments at inactive facilities from regulation as CCR) did not comply with federal law. 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'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 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

Current Status:

Comments on the Municipal Energy Agency of Nebraska (MEAN) 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.

Progress on the Southwest Power Pool's western regional transmission organization

Current Status:

Platte River and the other participants are working with the Southwest Power Pool (SPP) to further develop the western regional transmission organization (RTO West), including setting up committees and drafting tariff provisions to incorporate western operations. On Jan. 19, 2024, the participants voted to endorse SPP tariff Attachment AE, setting up the market structure RTO West will use going forward. SPP plans to file the updated tariff provisions with FERC in mid-2024.

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

Current Status:

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.

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Environmental matters

Groundwater and waste management

Current status:

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
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Recently concluded matters (last three months)

Legal matters

El Paso Electric Co. v. Federal Energy Regulatory Commission

FERC issued Order 1000 in 2011. Order 1000 requires FERC-jurisdictional utilities to create regional organizations to plan transmission expansions and allocate costs to the beneficiaries of the new transmission projects. Although Platte River is not subject to FERC jurisdiction, Platte River is a party to the WestConnect Planning and Participation Agreement, along with other FERC-jurisdictional and non-jurisdictional utilities in the planning region (Arizona, Colorado, Nevada, New Mexico, Utah and Wyoming).

In 2014, El Paso Electric Co. and several other FERC-jurisdictional utilities filed initial appeals in the Fifth Circuit Court of Appeals (Fifth Circuit) challenging FERC's approval of WestConnect cost allocation provisions. These provisions allowed utilities not subject to FERC jurisdiction (Coordinating Transmission Owners or CTOs) to opt out of cost allocation for regional transmission projects that CTO governing bodies do not approve. The appeals claimed CTOs' ability to opt out of cost allocation could impose unjust and unreasonable rates on customers of FERC-jurisdictional participants.

Platte River took part in settlement negotiations between the jurisdictional and non-jurisdictional utilities to modify the cost allocation and governance provisions of the Planning and Participation Agreement. The parties filed a settlement agreement with FERC in February 2022 and the Fifth Circuit stayed the case to await FERC's decision. On Dec. 15, 2022, FERC rejected the parties' proposed settlement agreement. On Aug. 2, 2023, the Fifth Circuit Court of Appeals (Fifth Circuit) found that the cost allocation scheme FERC approved for WestConnect might require FERC-jurisdictional utilities to subsidize non-jurisdictional utilities on regional transmission projects. Therefore, the Fifth Circuit overturned FERC's orders.

When Platte River joins a regional transmission organization (like SPP's RTO West), the RTO will be the planning region for Order 1000 purposes, filling the role WestConnect previously filled.

Environmental matters

Early Settlement Agreement to Resolve 2022 Air Permit Exceedances

On Nov. 29, 2023, Platte River entered into an early settlement agreement with the Colorado Air Pollution Control Division (Division), to settle compliance advisories for two exceedances in 2022. The first exceedance, on Jan. 1, 2022, was due to erratic nitrogen oxides (NOx) emissions readings from an unanticipated computer update. NOx emissions from combustion turbine Unit F exceeded the three-hour rolling average limit for two hours. The second exceedance, on April 18, 2022, was due to a plug in a slurry tank that feeds the sulfur dioxide (SO_2) scrubber on Rawhide Unit 1. The scrubber malfunction caused Unit 1 to exceed the three-hour SO_2 rolling average for one hour.

Platte River met with Division staff after the Division's annual air compliance audit to discuss these exceedances. Platte River promptly reported the exceedances when they occurred and established after-action review plans and additional processes to ensure that these issues would not recur. The Division complimented Platte River's prompt response and exemplary compliance history, demonstrating our high credibility with regulators. The Division proposed, and Platte River paid, a $21,000 fine to settle these two exceedance reports.

Compliance matters

There are no recently concluded compliance matters.

Platte River Power Authority

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Resource diversification report

April 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. Since receiving these proposals in November 2023, Platte River has been working with the wind developers to fully understand the total effective cost of delivering the output of each wind project to Platte River's load. By partnering with legal, the team is developing a term sheet to ensure agreement on key terms, targeting this additional wind capacity to come online in 2027.

Construction started on transmission facility improvements necessary to interconnect the 150 MW Black Hollow Sun Solar, LLC project. Platte River and QCells recently obtained the required permits to allow the construction to begin on the project. The anticipated commercial operation date is spring 2025.

Platte River is currently in active negotiations to secure up to 150 MW of additional nameplate solar capacity, with the goal to begin commercial operations in late 2026 or early 2027. This project is currently being held up as a result of another petition from U.S. solar manufacturers to have the U.S. Department of Commerce investigate potential illegal trade practices that injure the U.S. solar industry. The petition asks the Department of Commerce impose tariffs on solar modules manufactured in Southeast Asia. If tariffs are imposed, solar Power Purchase Agreement prices will increase because of the higher costs for solar panels.

Platte River issued its all-source dispatchable resources RFP on Feb. 22, 2024, seeking proposals to help us consider all possible resource options to maintain system reliability after existing coal units retire in 2028 and 2029. We received 21 notices of intent to submit proposals and 14 proposals from 10 different entities. Platte River is reviewing and vetting the proposals.

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		150			
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 finalize the 2024 Integrated Resource Plan (IRP) report and provided an update on the balance of the year 2024 power supply plan. Key activities included:

- Completed risk analysis of the 2024 IRP:
  - Reviewed past expansion planning runs and budget runs to understand how cost projections have evolved over time and potential sources of rate pressure.
  - Began evaluating the feasibility of using aeroderivative turbines from a different vendor.
- Worked with various departments to file planning reserve margin projections for the Resource Adequacy report to the Colorado Energy Office, as required by state law HB23-1039.
- Provided May-December balance year 2024 power supply plan (PSP) update to the finance team for the first time, including,
  - Developing a process for predicting balance year power prices based on recent Western Energy Imbalance Service (WEIS) prices, recent bilateral trades and forward market prices in the nearby liquid trading hubs. The process will be refined and used in future PSP developments.
  - Developing a range of power supply costs for the balance year.
- Continued our support for the resource procurement process:
  - Developed scenarios for different quantities of MW and prices to help with decision-making in ongoing negotiations.
  - Continued participation and support for dispatchable technology assessment study and all-source dispatchable resources RFP.
  - Worked with finance to build an Excel workbook to compare bids received through the all-source RFP. The workbook implemented the “annuity method,” as used by the Colorado Public Utilities Commission (and other regulatory jurisdictions), to allow comparison of bids with different project lives and different sizes.
- Continued evaluating options from different price forecast vendors to produce an additional price forecast for the Southwest Power Pool Regional Transmission Organization West.
- Continued to support the operations department with daily updates of WEIS market data and dashboards. Supported acquisition of new renewable/load forecasts from two new vendors – Tesla and Meteologica.
- Supported clean-up and correction of data feeds for actual load.
- Coordinated and verified data and assisted in developing a new renewable forecast dashboard.

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 (VPP).

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.

- Site selection – We continue to work with owner community staff to identify their preferred storage locations. We have identified a preferred primary and backup location for Longmont and Loveland. Work continues in Estes Park and Fort Collins.
- Site control – We will negotiate leases or license agreements with the landowners of the preferred sites and sublease or sublicense to the developer for the development and operational phases of the project. Most of the preferred sites are located on owner-community property. We have shared a draft “term sheet” for the land use licenses with the legal counsels for Longmont and Loveland and with the developer.

- Permitting and interconnection – Work can proceed once site control is established.
- Developer agreements – We are working with the developer on a master agreement that provides key terms that will be common to all the projects. This will be followed by one 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. The developer anticipates it will then take 20 months to complete the project and achieve commercial operation. Note that site selection and site control discussions with each owner community may proceed at different paces. As a result, some projects may begin before others.

Platte River and the owner communities are finalizing an RFP with two scopes of work that support the development of a VPP: (1) design and implementation of an enterprise DER management system (DERMS) for Platte River and tenant DERMS for the owner communities and (2) design and implementation support for VPP customer programs. We expect to issue the RFP by the end of May 2024. Platte River and owner community staff will be involved in the proposal review and evaluation process, which is expected to run into the third quarter of the year.

Work continues to develop an application for a Smart Grid Grant under the Grid Resilience and Innovation Partnerships Program. This program was established under the Bipartisan Infrastructure Law and administered by the U.S. Department of Energy (DOE). Platte River and the owner communities are working to submit an application for an “Efficiency Works Virtual Power Plant” project. The project encompasses key systems required for DER integration, VPP programs to gain customer participation and a plan that provides community benefits, such as community and labor engagement as well as workforce development. Applications are due May 22, 2024. Awardees are expected to be notified fall of 2024. If awarded, grant-funded work may begin after signing a funding agreement with the DOE, which will occur spring of 2025.

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Operating report

April 2024

Executive Summary

The region experienced mild weather with occasional snow in April, 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 fuel savings and lower wind production 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 few issues during the month. The unit experienced a forced outage, on April 9, and remained offline for approximately 10 hours, due to flame scanners erroneously showing no flame. On April 10, Rawhide Unit 1 had a forced curtailment to 170 MW for approximately nine hours to inspect both ID fans. On April 11, Rawhide Unit 1 had a forced curtailment to 175 MW for approximately 12 hours, due to ID fan issues. Rawhide equivalent availability factor was slightly 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 below budget.

Craig units 1 and 2 experienced a minor curtailment and a planned outage in April. Craig Unit 1 was curtailed for approximately two hours, due to a scrubber leak on April 7. Craig Unit 2 had a planned outage for boiler repairs on April 22 with an estimated return date of May 3. 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 to replace baseload generation during the Rawhide Unit 1 outage and forced curtailments as well as to facilitate sales. CT equivalent availability factor was slightly below budget, as CT units A-D each had scheduled maintenance during the month, and CT Unit F remains out of service for system upgrades. Net capacity factor was slightly below budget for the month, due to 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 below budget for the month. The Roundhouse Wind project experienced WEIS market curtailments and underproduction for approximately 30 hours starting April 6 due to high winds causing over-speeding. It also experienced underproduction for approximately 33 hours due to icing starting April 20. The Medicine Bow Wind project had a brief maintenance outage on tower 6 for approximately two hours on April 17, and an outage on April 24 for approximately three hours for turbine repair. Solar generation was below budget. The Rawhide Prairie Solar project experienced WEIS market curtailments. Net capacity factors for wind and solar were below budget for the month. The Rawhide Prairie Solar battery system was out of service during the entire month of April. As such, the battery was not charged or discharged. Year to date, net capacity factors for wind and solar are below budget.

Surplus sales

Surplus sales volume was below budget due to baseload generation outages and mild temperatures in the region, resulting in significantly below budget sales volume. 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, while pricing was 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 slightly below budget.

Total resources

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

Variances

April operational results

Owner community load	Budget	Actual	Variance	% variance	
Owner community demand	422 MW	393 MW	(29 MW)	(6.9%)	■
Owner community energy	243 GWh	233 GWh	(10 GWh)	(4.3%)	■
Net variable cost* to serve owner community energy	$5.4M	$4.6M	($0.8M)	(10.3%)	●
	$22.27/MWh	$19.97/MWh	($2.30/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	$1.2M
Lower wind generation volume	$0.44M

Upward pressure Generation and market outcomes pushing costs higher	
Lower bilateral and market sales volume	$0.81M
Higher coal generation fuel pricing	$0.37M
Higher market purchases volume	$0.25M

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

YTD operational results

Owner community load	Budget	Actual	Variance	% variance	
Owner community demand	1,845 MW	1,781 MW	(64 MW)	(3.4%)	■
Owner community energy	1,054 GWh	1,019 GWh	(35 GWh)	(3.3%)	■
Net variable cost* to serve owner community energy	$20.7M	$17.1M	($3.6M)	(14.6%)	●
	$19.60/MWh	$16.74/MWh	($2.86/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	$3.8M
Lower wind generation volume	$2.5M

Upward pressure Generation and market outcomes pushing costs higher	
Lower bilateral and market sales volume	$3.1M
Higher coal generation fuel pricing	$1.1M
Higher market purchases volume	$0.75M

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

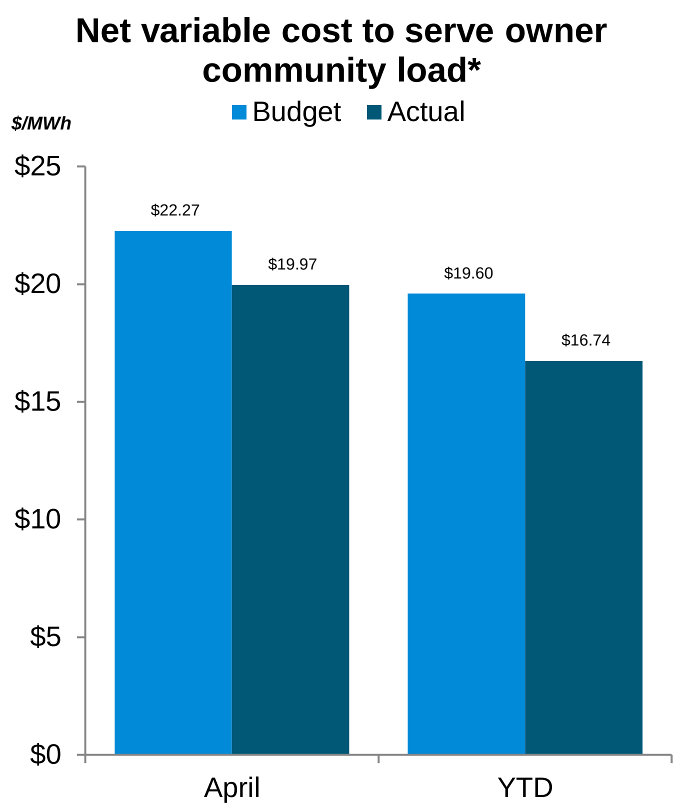
Loss of load

System disturbances

There was one system disturbance resulting in loss of load during the month of April.

2024 goal		April actual		YTD total	
0	●	1	■	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.**

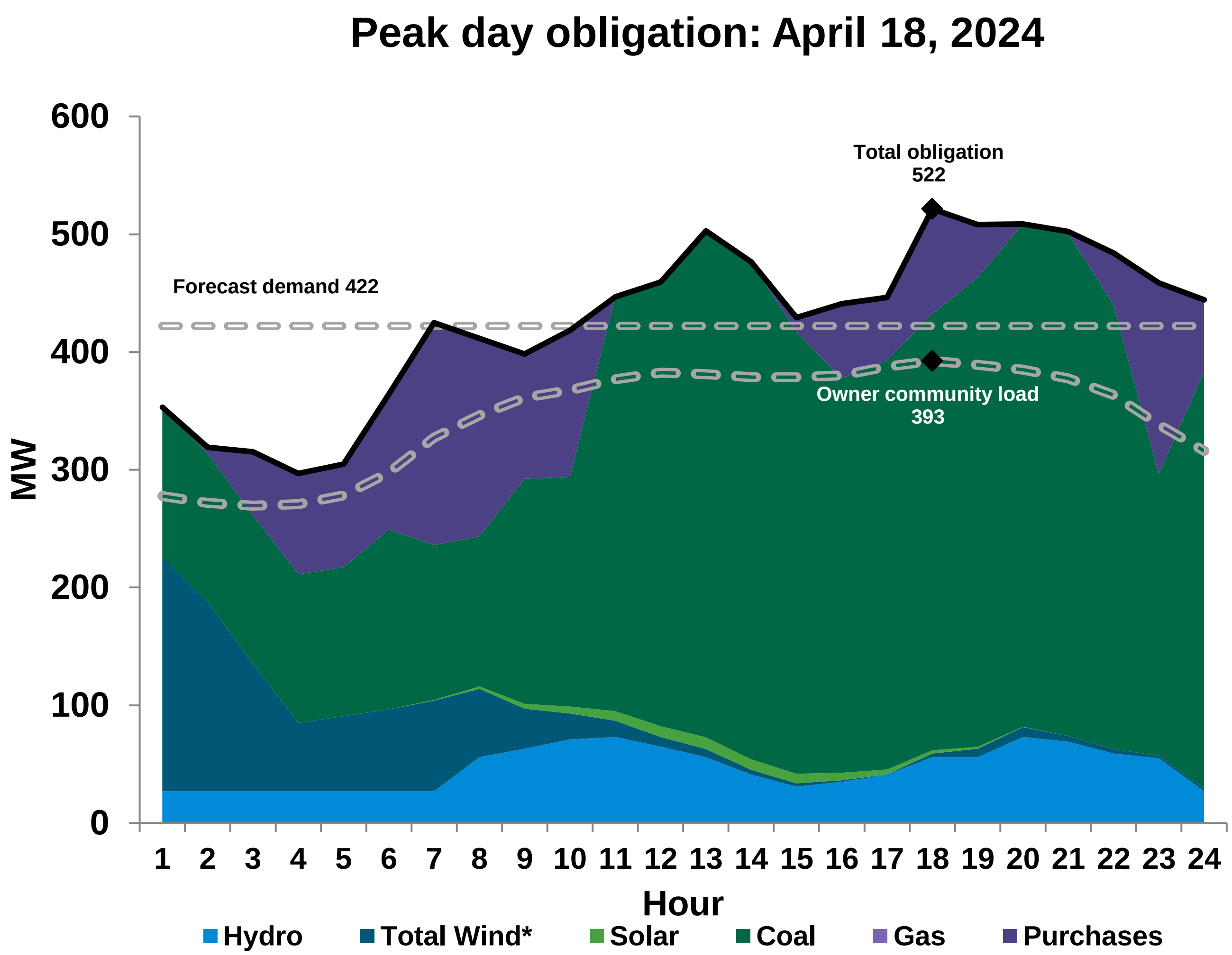
Events of significance

- On April 4, an official settlement dispute was sent to the developer of the Rawhide Prairie Solar project addressing the battery issue.
- On April 9, at 5:13 am, Rawhide Unit 1 tripped offline due to a loss of flame detection on coal mill 101. The trip was caused by coal mill 103 tripping due to a momentary loss of coal flow to the feeder which has since been corrected. Mill 103 had sufficient flame detection, prior to the mill tripping offline, but since mill 101 did not have sufficient flame detection when mill 103 temporarily tripped offline, the boiler management system automatically tripped Rawhide Unit 1. Rawhide Unit 1 was back online and returned to service at 2:52 p.m.
- On April 18, evaluations and repairs were completed to the Horseshoe – Foothills 115-kV structure L65.
- On April 22, the Ault – Rawhide and Ault – Carey 230 kV line outages began. Real-time conditions determined the Rawhide generation injection limitations on the maximum and minimum. To maintain reliability and maximize the ability to purchase energy at low market prices, the economic minimum for Rawhide Unit 1 was adjusted to 140 MW during the outage. The outage will continue into May.
- On April 26, at 11:58 p.m., Marys Lake circuit switcher 1364 opened, removing the 69-kV feed into Estes Park, as heavy snow was reported in the area. Shortly thereafter, several other local 115-kV lines tripped, including the Lyons – Estes and Estes – Polehill lines, causing a blackout in Estes Park at 1:20 a.m. on April 27. 11.76 MW of load was lost at the time. At 1:23 a.m., Platte River power system operators, in conjunction with the Western Area Power Administration and Tri-State Generation & Transmission, began implementing the coordinated operating plan which was developed in 2023 to quickly restore load to Estes Park. Within 15 minutes of the blackout, all load which could be restored through the transmission system was restored by re-establishing the 69-kV connection through Adams Tunnel and using that source to re-energize the transformers at the Mary's Lake and Estes Park substations. There were several distribution outages in the area at that time.
- On April 27, at 1:37 a.m., the Marys Lake – Estes 115-kV east line tripped again, causing 9.2 MWs of load served through the Estes Substation to be dropped. The line was returned to service and load was restored within 5 minutes.
- On April 27, numerous additional trips of 115-kV lines in Estes Park or serving Estes Park occurred throughout the remainder of the morning, though none resulted in additional losses of load. By 12:20 p.m., all 115-kV lines returned to service. The investigation and event reporting regarding the trips are ongoing, though wet, heavy snow is believed to have been the cause of the faults.

Peak day

Peak day obligation

Peak demand for the month was 393 megawatts which occurred on April 18, 2024, at hour ending 18:00 and was 29 megawatts below budget. Platte River's obligation at the time of the peak totaled 522 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.

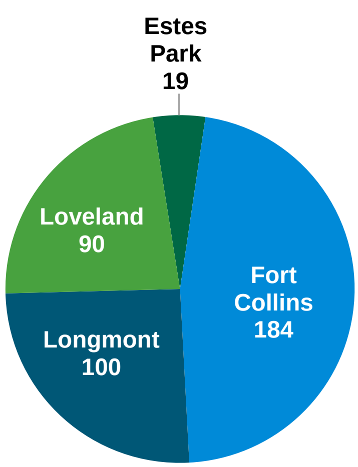
Owner community loads

	April budget	April actual	Minimum	Actual variance	
Coincident demand (MW)	422	393	507	(6.9%)	■
Estes Park	18	**19**	13	5.6%	●
Fort Collins	196	184	**231**	(6.1%)	■
Longmont	110	100	**144**	(9.1%)	■
Loveland	98	90	**119**	(8.2%)	■
Non-coincident demand (MW)	425	403	516	(5.2%)	■
Estes Park	21	21	**21**	0.0%	◆
Fort Collins	197	184	**231**	(6.6%)	■
Longmont	111	103	**144**	(7.2%)	■
Loveland	96	95	**120**	(1.0%)	◆
Energy sales (MWh)	243,403	232,871		(4.3%)	■
Estes Park	11,273	10,653		(5.5%)	■
Fort Collins	112,854	108,117		(4.2%)	■
Longmont	63,374	60,148		(5.1%)	■
Loveland	55,902	53,953		(3.5%)	■

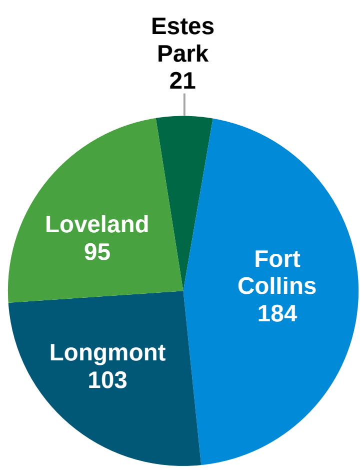
Variance key: Favorable: ● | Near budget: ◆ | Unfavorable: ■

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.

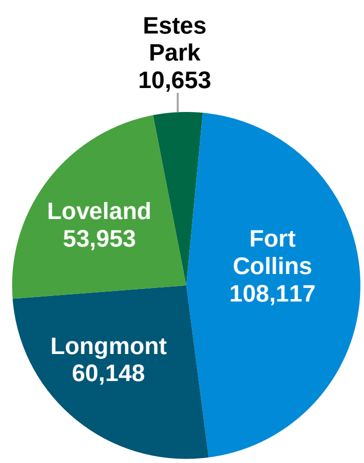
Actual April coincident demand = 393 MW



Actual April non-coincident demand = 403 MW

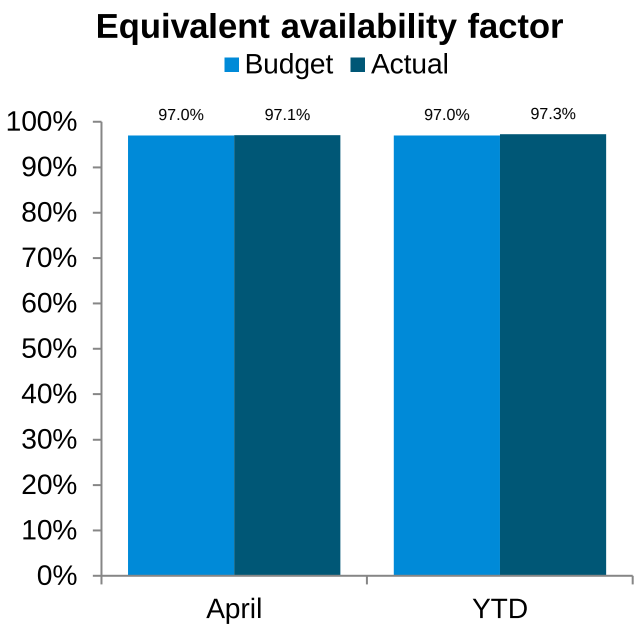


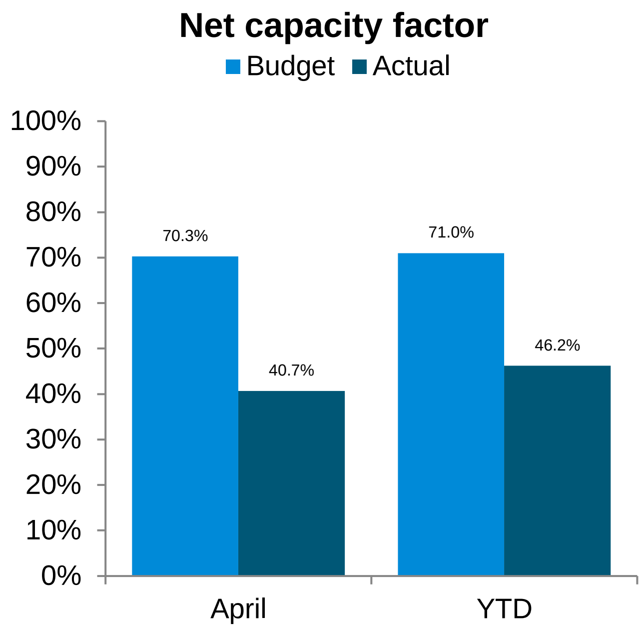
Actual April energy sales = 232,871 MWh



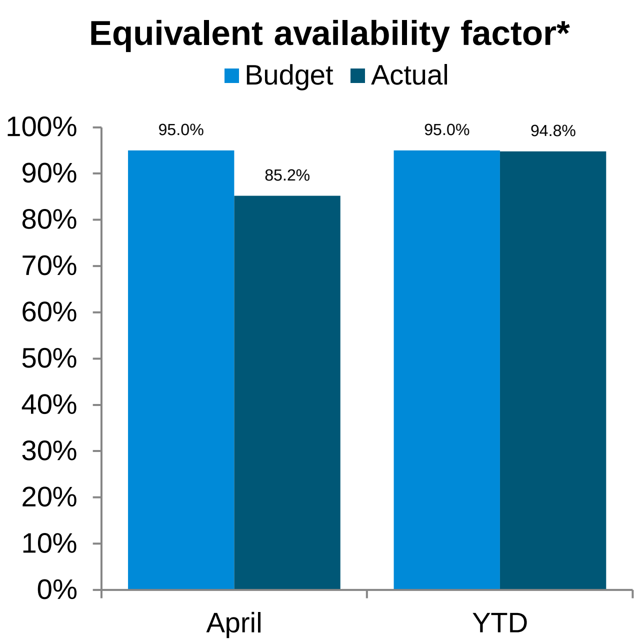
Thermal resources

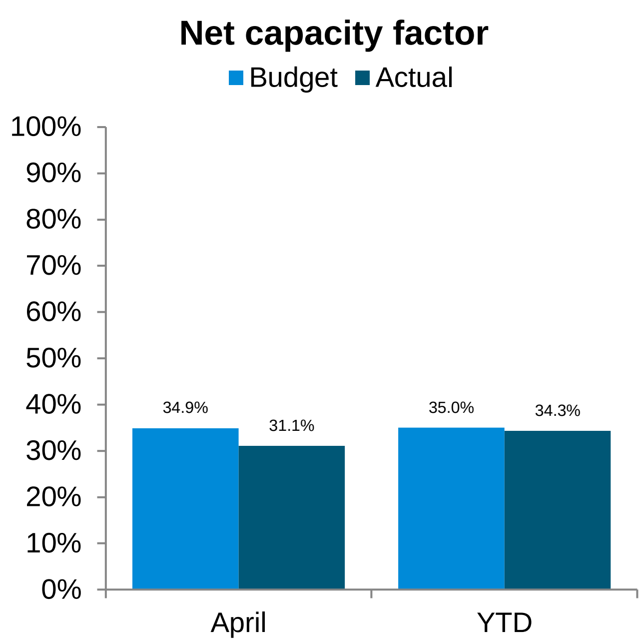
Power generation - Rawhide





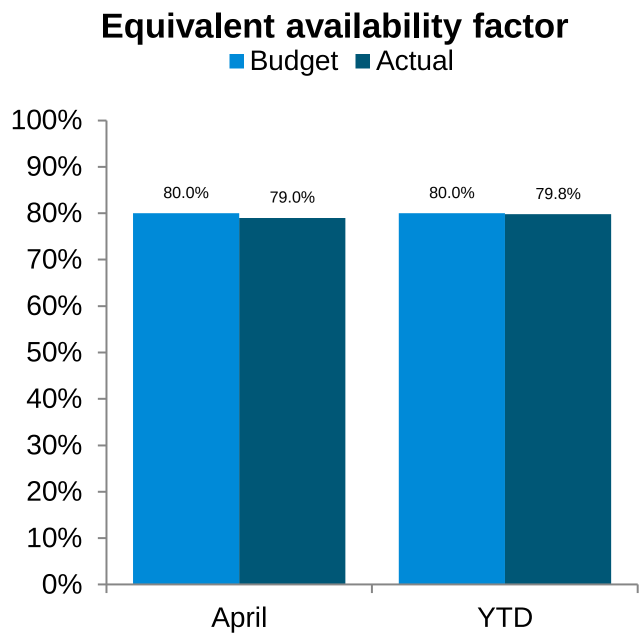
Power generation - Craig

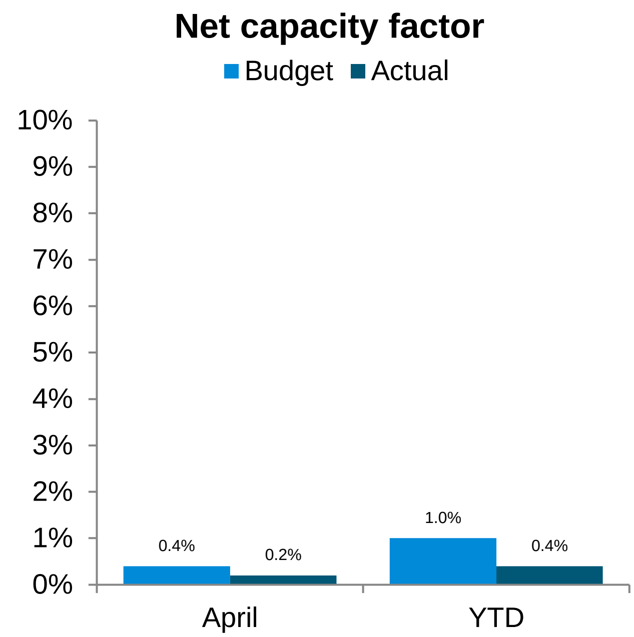




*** Estimated due to a delay of the actual results**

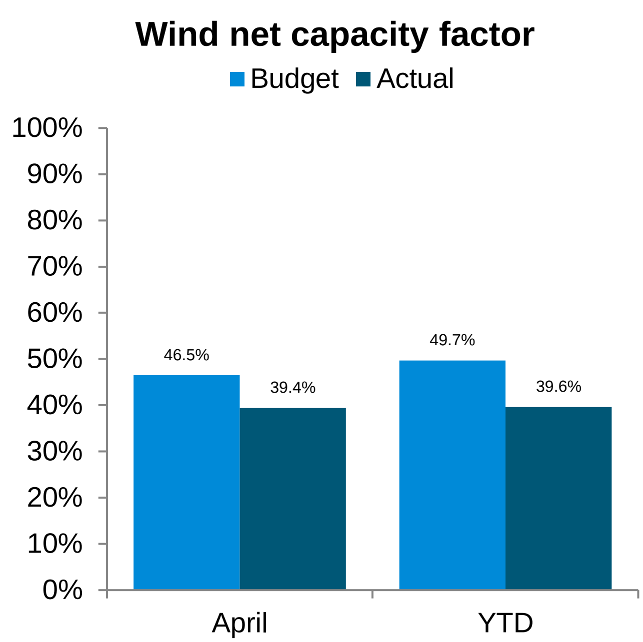
Power generation – combustion turbines

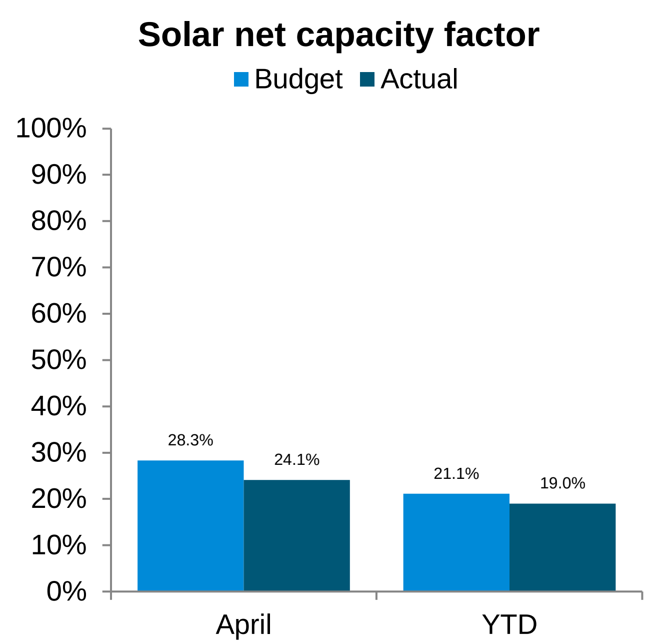




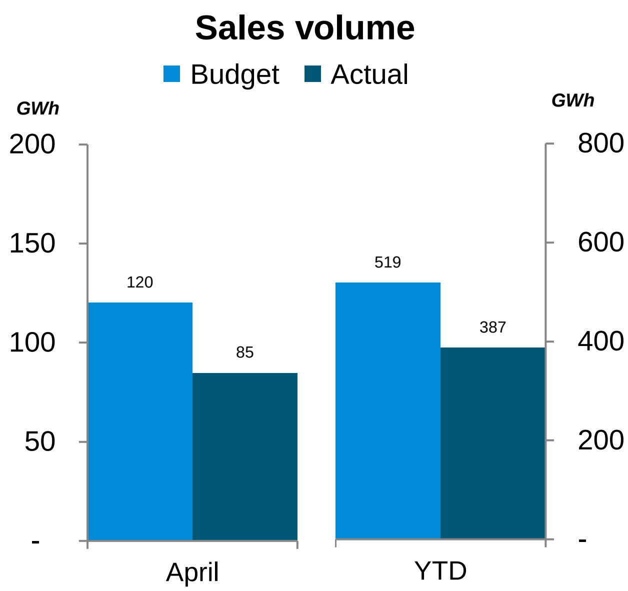
Renewable resources

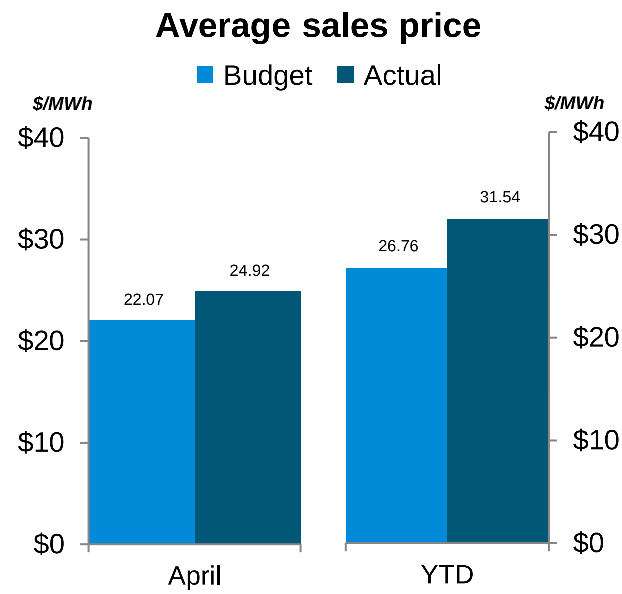
Power generation – wind and solar production



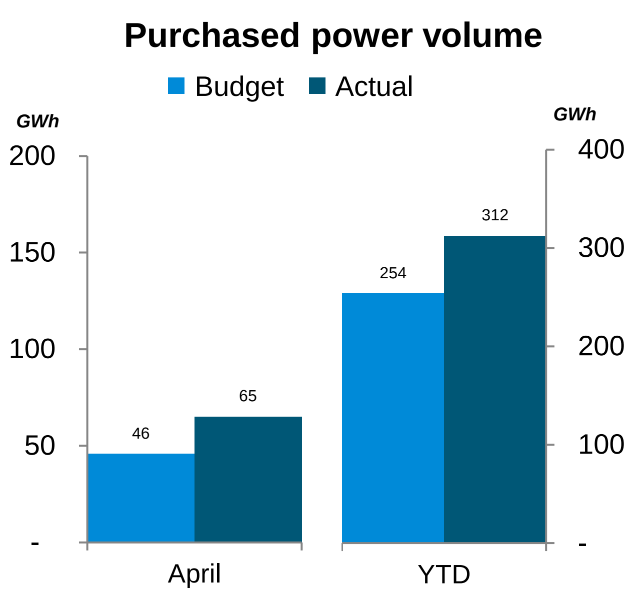


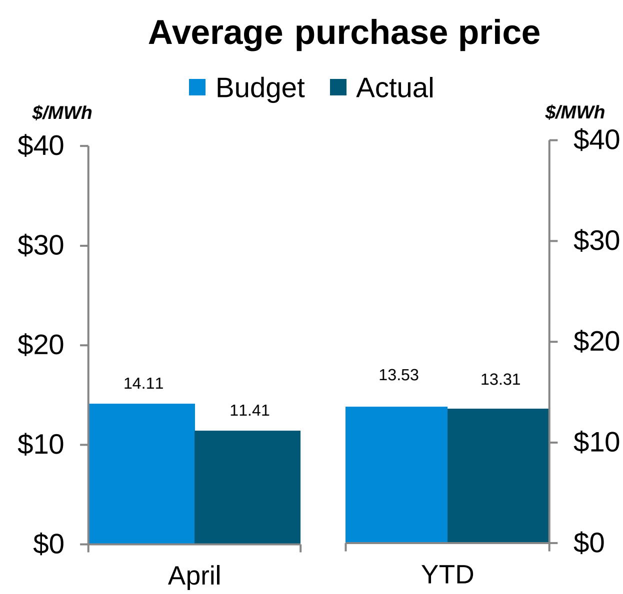
Surplus sales



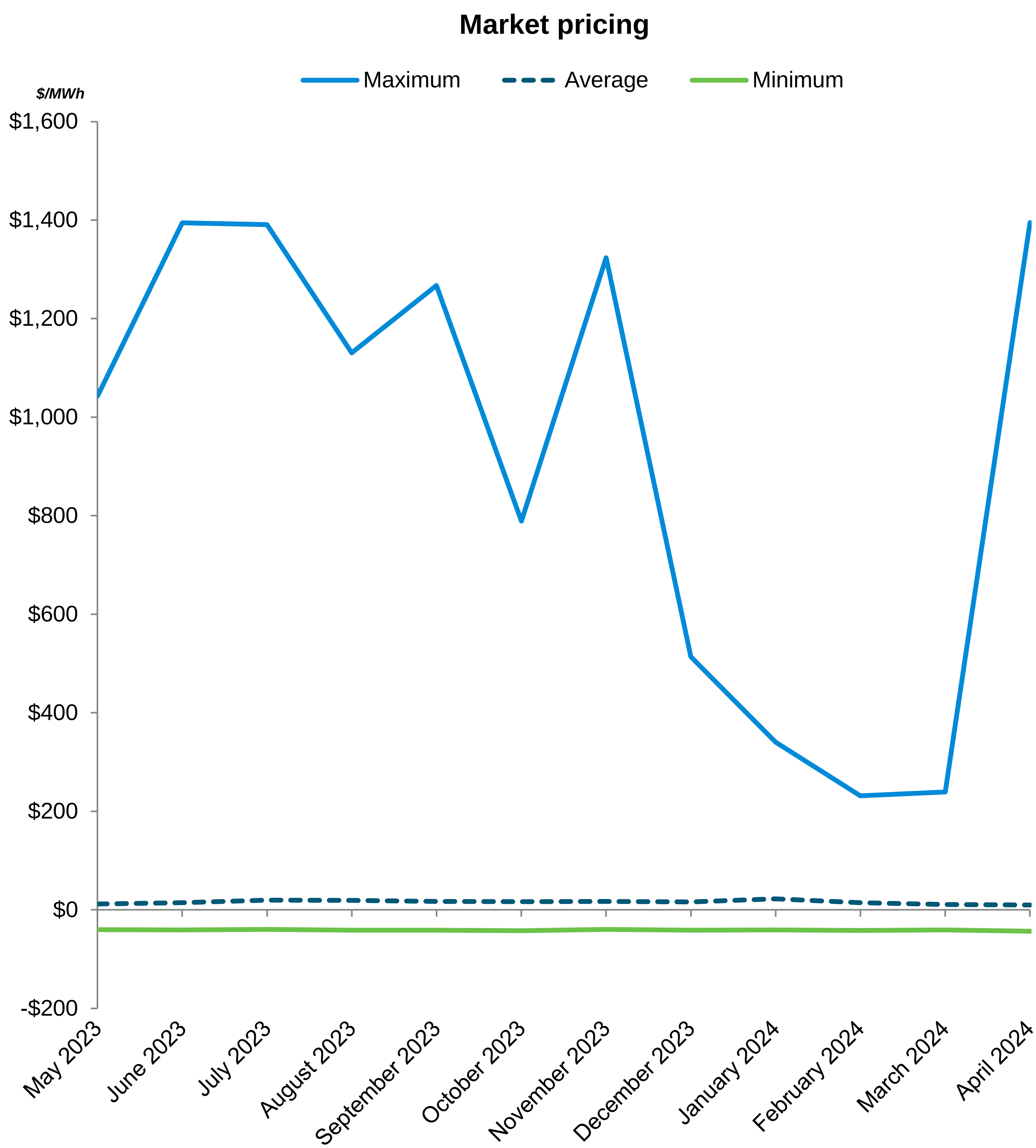


Purchased power

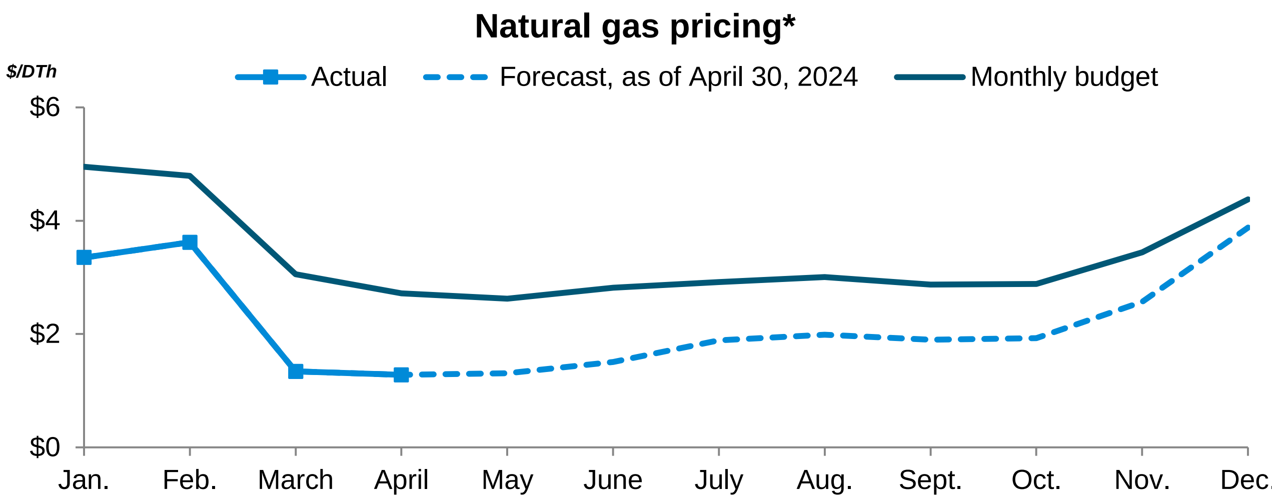




Market pricing



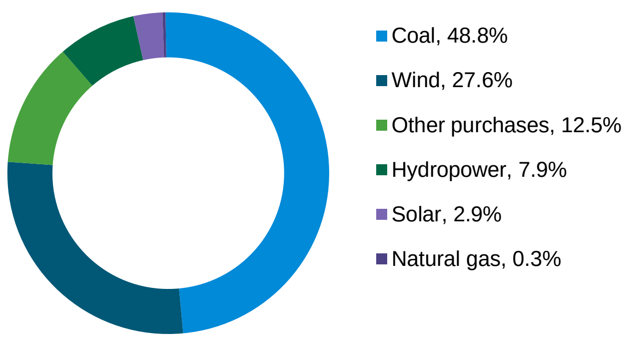
Natural gas pricing



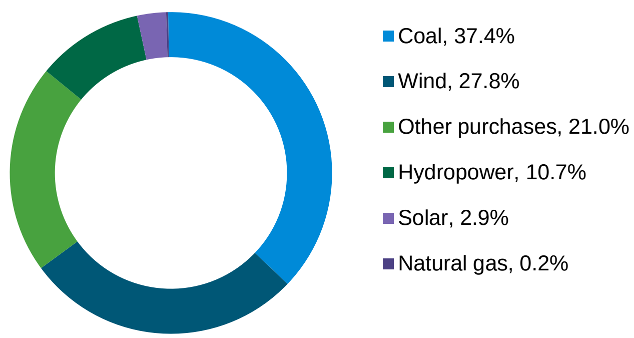
***Forecast based on Argus North American Natural Gas forward curves. Pricing does not include transport.**

Total resources

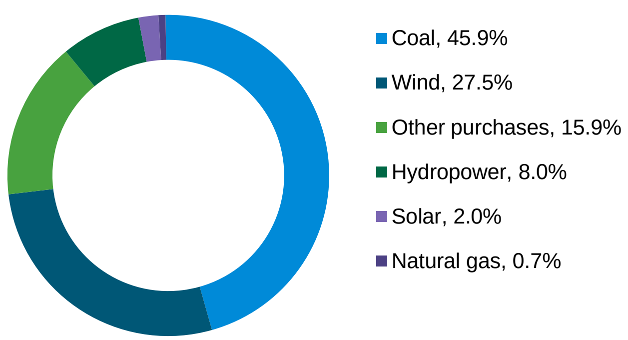
April generation budget



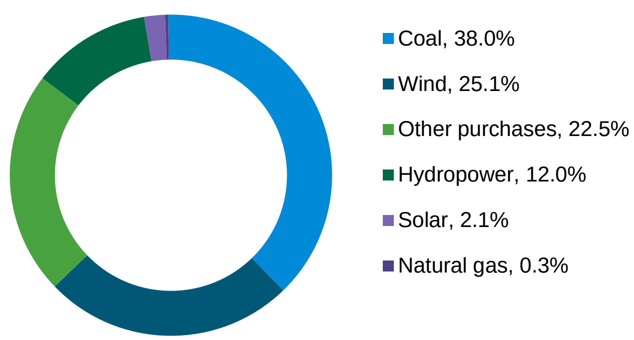
April generation actual

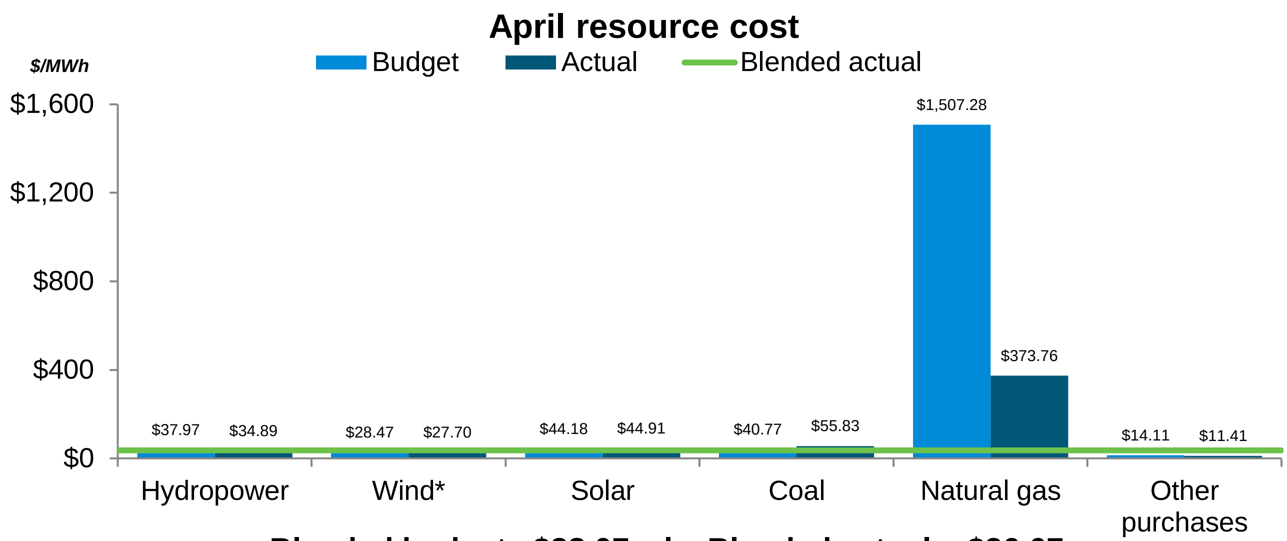


YTD budget

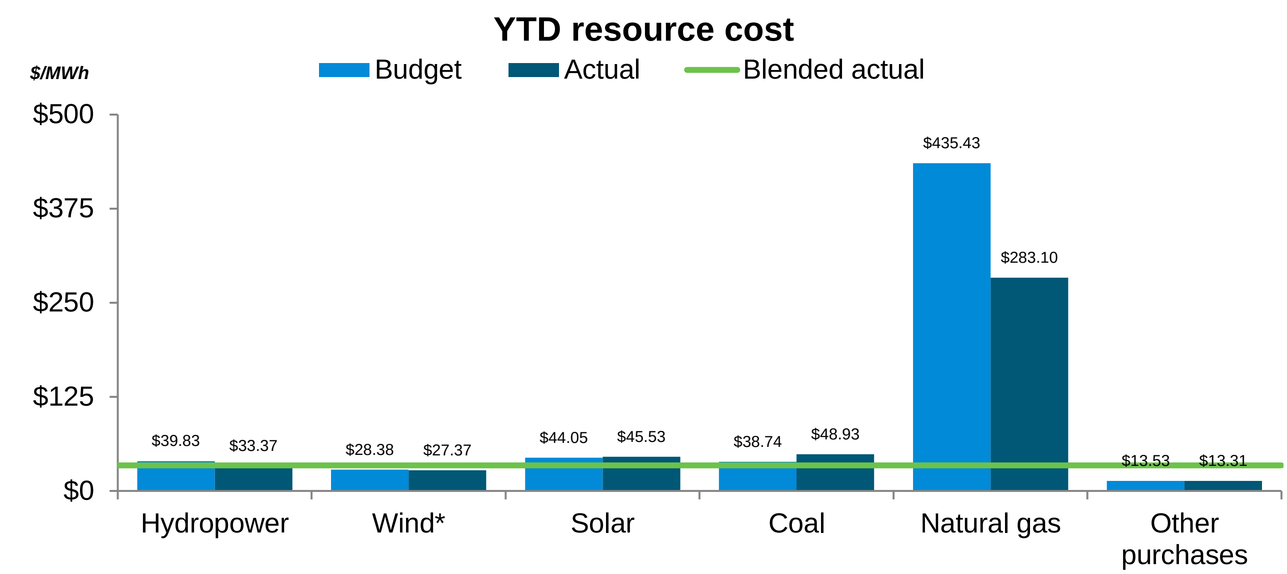


YTD actual





Blended budget $38.07 | Blended actual: $36.67



Blended budget $34.92 | Blended actual: $34.22

***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

Financial report

April 2024

Financial highlights year to date

Platte River reported favorable results year to date. Change in net position of $3.1 million was favorable by $5 million compared to budget primarily due to below-budget operating expenses, partially offset by below-budget revenues and above-budget unrealized losses.

Key financial results [1] ($ millions)	April Budget	April Actual		Favorable (unfavorable)		Year to date Budget	Year to date Actual		Favorable (unfavorable)		Annual budget
Change in net position	$ (1.9)	$ (1.2)	●	$ 0.7	36.8%	$ (1.9)	$ 3.1	●	$ 5.0	263.2%	$ 7.3
Fixed obligation charge coverage	1.14x	1.58x	●	0.44x	38.6%	1.50x	1.95x	●	0.45x	30.0%	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.

Change in net position estimate

The current estimate for year-end change in net position prior to deferring revenues ranges from $16.9 million to $48.6 million. Based on current assumptions, the expected change in net position prior to deferring revenues is $28.4 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	$ 16.9	$ (4.4)	(21%)	$ 9.8	$ 7.1
Expected	$ 21.3	$ 28.4	$ 7.1	33%	$ 21.3	$ 7.1
High	$ 21.3	$ 48.6	$ 27.3	128%	$ 41.7	$ 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 as favorable results expected elsewhere are able to be deferred along with lowering the Strategic Financial Plan target minimums to maintain metrics.

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 below budget primarily due to projects being completed below budget or deferred to future periods, below-budget wages due primarily to vacancies and below-budget distributed energy resources expenses.
- **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.

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.

Budgetary highlights year to date

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

Key budgetary results ($ millions)	April Budget	April Actual		Favorable (unfavorable)		Year to date Budget	Year to date Actual		Favorable (unfavorable)		Annual budget
Total revenues	$ 22.2	$ 21.1	■	$ (1.1)	(5.0%)	$ 95.9	$ 92.9	■	$ (3.0)	(3.1%)	$ 313.0
Sales to owner communities	17.3	16.9	■	(0.4)	(2.3%)	72.8	71.6	◆	(1.2)	(1.6%)	235.7
Sales for resale - long-term	1.5	1.2	■	(0.3)	(20.0%)	6.7	5.1	■	(1.6)	(23.9%)	20.1
Sales for resale - short-term	1.7	1.4	■	(0.3)	(17.6%)	9.5	9.4	◆	(0.1)	(1.1%)	36.4
Wheeling	0.8	0.6	■	(0.2)	(25.0%)	3.2	2.9	■	(0.3)	(9.4%)	8.9
Interest and other income	0.9	1.0	●	0.1	11.1%	3.7	3.9	●	0.2	5.4%	11.9
Total operating expenses	$ 20.2	$ 17.6	●	$ 2.6	12.9%	$ 82.3	$ 73.0	●	$ 9.3	11.3%	$ 242.7
Purchased power	5.0	4.6	●	0.4	8.0%	21.8	19.9	●	1.9	8.7%	63.8
Fuel	3.7	2.8	●	0.9	24.3%	15.5	12.2	●	3.3	21.3%	51.1
Production	5.9	4.6	●	1.3	22.0%	20.9	18.0	●	2.9	13.9%	55.8
Transmission	1.7	1.5	●	0.2	11.8%	7.4	6.8	●	0.6	8.1%	21.4
Administrative and general	2.9	3.3	■	(0.4)	(13.8%)	12.7	13.1	■	(0.4)	(3.1%)	36.9
Distributed energy resources	1.0	0.8	●	0.2	20.0%	4.0	3.0	●	1.0	25.0%	13.7
Capital additions	$ 5.9	$ 3.8	●	$ 2.1	35.6%	$ 26.1	$ 12.3	●	$ 13.8	52.9%	$ 53.2
Debt service expenditures	$ 1.5	$ 1.5	◆	$ -	0.0%	$ 6.4	$ 6.4	◆	$ -	0.0%	$ 18.7

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

Total revenues, $3 million below budget

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

- **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.
- **Wheeling** was below budget $0.3 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, $9.3 million below budget

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

- **Fuel** was $3.3 million below budget.

  Coal - Rawhide Unit 1 103% of the overall variance, $3.4 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 18% of the overall variance, $0.6 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 (21%) of the overall variance, $0.7 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 $3.1 million below budget. Projects were either completed below budget or expenses not required. The below-budget expenses include: 1) Rawhide non-routine projects, 2) transmission non-routine projects and 3) wheeling. The above-budget expenses include: 1) personnel, 2) digital consulting services and 3) Craig operating expenses. The net below-budget variance is expected to be spent by the end of the year.

- **Purchased power** was $1.9 million below budget. The below-budget expenses include: 1) wind generation, 2) purchased reserves due to a lower rate than anticipated, 3) net energy delivered to Tri-State Generation and Transmission Association, Inc. (Tri-State) under the forced outage assistance agreement and 4) solar generation. The above-budget expenses include: 1) market and bilateral 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 the unpredictability of the completion of customers' energy efficiency projects, below-budget program consulting services and personnel expenses.

Capital additions, $13.8 million below budget

Year-end estimates as of April 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	$ 63	$ 148	$ 148
	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)	$ -
**	**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)	$ -

	Project ($ thousands)	2024 budget	Estimate	Favorable (unfavorable)	Carryover request
	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)	$ -
**	**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
	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, at budget

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

Debt service expenditures ($ thousands)	April Budget	April Actual		Favorable (unfavorable)		Year to date Budget	Year to date Actual		Favorable (unfavorable)		Annual budget
Total principal	$ 1,113	$ 1,078	●	$ 35	3.1%	$ 4,747	$ 4,737	◆	$ 10	0.2%	$14,015
Power revenue bonds	1,066	1,066	◆	-	0.0%	4,263	4,263	◆	-	0.0%	13,146
Lease and subscription liabilities	47	12	●	35	74.5%	484	474	●	10	2.1%	869
Total interest expense	$ 420	$ 416	◆	$ 4	1.0%	$ 1,675	$ 1,691	◆	$ (16)	(1.0%)	$ 4,667
Power revenue bonds	416	416	◆	-	0.0%	1,665	1,665	◆	-	0.0%	4,642
Lease and subscription liabilities	4	-	●	4	100.0%	10	26	■	(16)	(160.0%)	25
Total debt service expenditures	$ 1,533	$ 1,494	●	$ 39	2.5%	$ 6,422	$ 6,428	◆	$ (6)	(0.1%)	$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	8,909					
Total revenue bonds outstanding	134,779					
Less: due within one year	(12,790)					
Total long-term debt, net	$ 121,989					

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

At this time, capital additions are expected to be above budget at the end of the year. A budget contingency appropriation of approximately $10.9 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.

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 following the expiration date which was in effect through and including 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

April 2024

Non-GAAP budgetary basis (in thousands)

	Month of April		Favorable
	Budget	**Actual**	(unfavorable)
Revenues			
Operating revenues			
Sales to owner communities	$ 17,317	**$ 16,908**	$ (409)
Sales for resale - long-term	1,516	**1,278**	(238)
Sales for resale - short-term	1,712	**1,409**	(303)
Wheeling	765	**577**	(188)
Total operating revenues	21,310	**20,172**	(1,138)
Other revenues			
Interest income[1]	887	**940**	53
Other income	9	**22**	13
Total other revenues	896	**962**	66
Total revenues	$ 22,206	**$ 21,134**	$ (1,072)
Expenditures			
Operating expenses			
Purchased power	$ 4,966	**$ 4,550**	$ 416
Fuel	3,658	**2,778**	880
Production	5,932	**4,611**	1,321
Transmission	1,727	**1,555**	172
Administrative and general	2,850	**3,276**	(426)
Distributed energy resources	1,043	**874**	169
Total operating expenses	20,176	**17,644**	2,532
Capital additions			
Production	528	**870**	(342)
Transmission	3,084	**1,928**	1,156
General	2,164	**1,031**	1,133
Asset retirement obligations	78	**16**	62
Total capital additions	5,854	**3,845**	2,009
Debt service expenditures			
Principal	1,113	**1,078**	35
Interest expense	420	**416**	4
Total debt service expenditures	1,533	**1,494**	39
Total expenditures	$ 27,563	**$ 22,983**	$ 4,580
Revenues less expenditures	$ (5,357)	**$ (1,849)**	$ 3,508

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

Schedule of revenues and expenditures, budget to actual

April 2024 year-to-date

Non-GAAP budgetary basis (in thousands)

	April year to date Budget	April year to date Actual	Favorable (unfavorable)	Annual budget
Revenues				
Operating revenues				
Sales to owner communities	$ 72,821	**$ 71,588**	$ (1,233)	$ 235,737
Sales for resale - long-term	6,635	**5,083**	(1,552)	20,086
Sales for resale - short-term	9,555	**9,429**	(126)	36,356
Wheeling	3,195	**2,912**	(283)	8,942
Total operating revenues	92,206	**89,012**	(3,194)	301,121
Other revenues				
Interest income[1]	3,473	**3,633**	160	11,569
Other income	256	**274**	18	282
Total other revenues	3,729	**3,907**	178	11,851
Total revenues	$ 95,935	**$ 92,919**	$ (3,016)	$ 312,972
Expenditures				
Operating expenses				
Purchased power	$ 21,794	**$ 19,853**	$ 1,941	$ 63,776
Fuel	15,529	**12,229**	3,300	51,119
Production	20,891	**18,007**	2,884	55,842
Transmission	7,411	**6,818**	593	21,412
Administrative and general	12,683	**13,047**	(364)	36,863
Distributed energy resources	4,016	**3,016**	1,000	13,664
Total operating expenses	82,324	**72,970**	9,354	242,676
Capital additions				
Production	5,382	**1,719**	3,663	12,363
Transmission	12,539	**7,498**	5,041	21,957
General	7,842	**3,068**	4,774	17,979
Asset retirement obligations	311	**29**	282	933
Total capital additions	26,074	**12,314**	13,760	53,232
Debt service expenditures				
Principal	4,747	**4,737**	10	14,015
Interest expense	1,675	**1,691**	(16)	4,667
Total debt service expenditures	6,422	**6,428**	(6)	18,682
Total expenditures	$ 114,820	**$ 91,712**	$ 23,108	$ 314,590
Contingency reserved to board	-	**-**	-	56,000
Total expenditures and contingency	$ 114,820	**$ 91,712**	$ 23,108	$ 370,590
Revenues less expenditures and contingency	$ (18,885)	**$ 1,207**	$ 20,092	$ (57,618)

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

Financial statements

Statements of net position

Unaudited (in thousands)

	April 30 2024	April 30 2023
Assets		
Electric utility plant, at original cost		
Land and land rights	**$ 19,446**	$ 19,446
Plant and equipment in service	**1,483,534**	1,468,867
Less: accumulated depreciation and amortization	**(989,585)**	(949,153)
Plant in service, net	**513,395**	539,160
Construction work in progress	**42,177**	27,346
Total electric utility plant	**555,572**	566,506
Special funds and investments		
Restricted funds and investments	**26,156**	25,588
Dedicated funds and investments	**169,448**	163,800
Total special funds and investments	**195,604**	189,388
Current assets		
Cash and cash equivalents	**60,910**	38,973
Other temporary investments	**48,194**	49,037
Accounts receivable - owner communities	**16,880**	16,344
Accounts receivable - other	**4,764**	8,636
Fuel inventory, at last-in, first-out cost	**19,530**	11,355
Materials and supplies inventory, at average cost	**18,487**	16,729
Prepayments and other assets	**10,482**	9,599
Total current assets	**179,247**	150,673
Noncurrent assets		
Regulatory assets	**130,937**	128,320
Other long-term assets	**8,615**	7,123
Total noncurrent assets	**139,552**	135,443
Total assets	**1,069,975**	1,042,010
Deferred outflows of resources		
Deferred loss on debt refundings	**2,052**	2,810
Pension deferrals	**9,787**	14,849
Asset retirement obligations	**27,414**	24,401
Total deferred outflows of resources	**39,253**	42,060
Liabilities		
Noncurrent liabilities		
Long-term debt, net	**121,989**	137,029
Net pension liability	**28,274**	30,520
Other long-term obligations	**93,406**	94,295
Lease and subscription liabilities	**493**	916
Asset retirement obligations	**37,299**	31,639
Other liabilities and credits	**12,486**	7,508
Total noncurrent liabilities	**293,947**	301,907
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	**16,420**	16,525
Accrued interest	**2,081**	2,320
Accrued liabilities and other	**6,081**	4,204
Total current liabilities	**39,862**	38,038
Total liabilities	**333,809**	339,945
Deferred inflows of resources		
Deferred gain on debt refundings	**108**	122
Regulatory credits	**104,294**	74,257
Pension deferrals	**-**	287
Lease deferrals	**704**	852
Total deferred inflows of resources	**105,106**	75,518
Net position		
Net investment in capital assets	**410,330**	400,282
Restricted	**24,075**	23,269
Unrestricted	**235,908**	245,056
Total net position	**$ 670,313**	$ 668,607

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 April	April year to date 2024	April year to date 2023
Operating revenues			
Sales to owner communities	**$ 16,908**	**$ 71,588**	$ 69,225
Sales for resale	**2,687**	**14,512**	17,185
Wheeling	**577**	**2,912**	3,349
Total operating revenues	**20,172**	**89,012**	89,759
Operating expenses			
Purchased power	**4,550**	**19,853**	17,195
Fuel	**2,778**	**12,229**	15,622
Operations and maintenance	**6,246**	**25,299**	24,793
Administrative and general	**3,378**	**13,341**	9,987
Distributed energy resources	**882**	**3,072**	2,009
Depreciation, amortization and accretion	**3,461**	**13,871**	12,793
Total operating expenses	**21,295**	**87,665**	82,399
Operating income	**(1,123)**	**1,347**	7,360
Nonoperating revenues (expenses)			
Interest income	**955**	**3,586**	2,114
Other income	**22**	**274**	246
Interest expense	**(416)**	**(1,691)**	(1,856)
Amortization of bond financing costs	**110**	**443**	492
Net (decrease)/increase in fair value of investments	**(709)**	**(831)**	2,328
Total nonoperating revenues (expenses)	**(38)**	**1,781**	3,324
Change in net position	**(1,161)**	**3,128**	10,684
Net position at beginning of period, as previously reported	**671,474**	**667,185**	657,923
Net position at end of period	**$ 670,313**	**$ 670,313**	$ 668,607

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 April	April year to date 2024	April year to date 2023
Cash flows from operating activities			
Receipts from customers	**$ 22,414**	**$ 90,961**	$ 96,321
Payments for operating goods and services	**(11,706)**	**(59,108)**	(59,972)
Payments for employee services	**(4,601)**	**(20,878)**	(16,942)
Net cash provided by operating activities	**6,107**	**10,975**	19,407
Cash flows from capital and related financing activities			
Additions to electric utility plant	**(2,442)**	**(10,914)**	(5,496)
Payments from accounts payable incurred for electric utility plant additions	**(3,701)**	**(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	**(12)**	**(500)**	-
Net cash used in capital and related financing activities	**(6,155)**	**(18,923)**	(13,134)
Cash flows from investing activities			
Purchases and sales of temporary and restricted investments, net	**(65)**	**(5,753)**	(17,669)
Interest and other income, including realized gains and losses	**958**	**3,891**	2,352
Net cash provided by/(used in) investing activities	**893**	**(1,862)**	(15,317)
Increase/(decrease) in cash and cash equivalents	**845**	**(9,810)**	(9,044)
Balance at beginning of period in cash and cash equivalents	**60,065**	**70,720**	48,017
Balance at end of period in cash and cash equivalents	**$ 60,910**	**$ 60,910**	$ 38,973
Reconciliation of net operating income to net cash provided by operating activities			
Operating income	**$ (1,123)**	**$ 1,347**	$ 7,360
Adjustments to reconcile operating income to net cash provided by operating activities			
Depreciation	**3,413**	**13,677**	13,256
Amortization	**(403)**	**(1,611)**	(1,853)
Operating expenses relating to other long-term obligations	**241**	**963**	963
Changes in assets and liabilities that provided/(used) cash			
Accounts receivable	**2,242**	**2,744**	5,847
Fuel and materials and supplies inventories	**2,277**	**(387)**	(2,151)
Prepayments and other assets	**(974)**	**(4,390)**	(3,340)
Regulatory assets	**96**	**386**	377
Deferred outflows of resources	**(2,019)**	**(1,043)**	916
Accounts payable	**(1,380)**	**(7,461)**	(5,434)
Asset retirement obligations	**2,329**	**2,316**	(99)
Other liabilities	**976**	**2,679**	2,050
Deferred inflows of resources	**432**	**1,755**	1,515
Net cash provided by operating activities	**$ 6,107**	**$ 10,975**	$ 19,407
Noncash capital and related financing activities			
Additions of electric utility plant through incurrence of accounts payable	**1,387**	**1,387**	1,093
Additions of electric utility plant through leasing and subscription	**-**	**132**	-
Amortization of regulatory asset (debt issuance costs)	**6**	**24**	27
Amortization of bond premiums, deferred loss and deferred gain on refundings	**(117)**	**(467)**	(519)

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 April**	**April year to date 2024**	**April year to date 2023**
Net revenues			
Operating revenues	**$ 20,172**	**$ 89,012**	$ 89,759
Operations and maintenance expenses, excluding depreciation, amortization and accretion	**17,834**	**73,794**	69,606
Net operating revenues	**2,338**	**15,218**	20,153
Plus interest income on bond accounts and other income [1]	**962**	**3,907**	2,368
Net revenues before rate stabilization	**3,300**	**19,125**	22,521
Rate stabilization			
Deposits	**-**	**-**	-
Withdrawals	**-**	**-**	-
Total net revenues	**$ 3,300**	**$ 19,125**	$ 22,521
Bond service			
Power revenue bonds	**$ 1,482**	**$ 5,928**	$ 5,928
Coverage			
Bond service coverage ratio	**2.23**	**3.23**	3.80

Fixed obligation charge coverage	**Month of April**	**April year to date 2024**	**April year to date 2023**
Total net revenues, above	**$ 3,300**	**$ 19,125**	$ 22,521
Fixed obligation charges included in operating expenses [2]	**1,622**	**6,889**	7,473
Adjusted net revenues before fixed obligation charges	**$ 4,922**	**$ 26,014**	$ 29,994
Fixed obligation charges			
Power revenue bonds, above	**$ 1,482**	**$ 5,928**	$ 5,928
Fixed obligation charges [2][3]	**1,634**	**7,389**	7,473
Total fixed obligation charges	**$ 3,116**	**$ 13,317**	$ 13,401
Coverage			
Fixed obligation charge coverage ratio	**1.58**	**1.95**	2.24

(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 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

April 2024

Business Strategies

Communications, marketing and external affairs

During April, communications, marketing and external affairs staff:

Communications

- Published the third in a series of public education articles about Platte River's path to a clean, reliable energy future, focusing on how dispatchable resources enable the energy transition.
- Finalized the 2023 Annual Report. Platte River's Board of Directors accepted the report during the April meeting.
- Supported Estes Park Power & Communications during a late winter storm that resulted in brief transmission outages, helping coordinate communications with Platte River operations and the Western Area Power Administration.
- Distributed a press release highlighting how the partnership between Efficiency Works Homes and Energy Outreach Colorado delivers a broader range of support for income-qualified customers, helping them use their energy effectively and participate in the region's transition to a noncarbon future.
- Finalized a draft of the first six chapters of the 2024 Integrated Resource Plan (IRP) for inclusion in the April board meeting packet.
- Focused social media coverage on the Rawhide Energy Station's 40th anniversary, Lineworker Appreciation Day, Platte River's participation in Earth Day with Fort Collins and Longmont, and the appointment of Estes Park Mayor Gary Hall to Platte River's board of directors.
- Along with plant staff, organized Take Your Kid To Work Day activities at Rawhide involving over 80 people.

Community relations

- Took part in Earth Day events in Fort Collins and Longmont, focused on Platte River's environmental stewardship and distributing tree seedlings.
- Sponsored Arbor Day events in all four owner communities; council proclamations at Johnson Elementary School in Fort Collins and Loveland City Council.

Marketing

- Deployed Platte River's spring digital marketing campaign, Giving You the Power introducing Platte River to the owner communities. Additional tactics will be deployed in May.
- Deployed a targeted campaign for small and medium businesses and multifamily properties to promote Efficiency Works Business programs.
- Deployed targeted email and social media campaign to promote limited time rebates for the Efficiency Works Store during Earth Month.

- Developed a series of infographics for Efficiency Works Homes (rebate application journey, becoming a service provider and heat pumps).

External affairs

- Hosted Colorado River Energy Distributors Association board meeting at headquarters.
- Conducted an IRP presentation for the Estes Park rotaries.
- Alongside environmental and engineering staff, presented to the Larimer County planning department on Platte River's Section 1041 land permit pre-application.

Grants

- Submitted a letter of support for the Colorado Energy Office's application for federal assistance for the adoption of the latest and zero building energy codes.

Human resources

Human Resources leadership identified and worked to clearly define department strategy and how its pillars of workforce culture, employee experience, and service delivery contribute to Platte River's successes. Within that work, priority initiatives and related strategic outcomes were aligned with organizational strategy.

Safety

- Safety assisted in coordinating and participating in 2024 Take Your Kid to Work Day at Rawhide.
- Safety staff coordinated with Flood and Peterson to conduct Distracted & Defensive Driving Awareness training at Rawhide and headquarters.

Injury statistics	2022 year end	2023 year end	YTD through April 2023	YTD through April 2024
Recordable injury rate	1.25	1.98	2.33	1.11
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 April.

Emergency response team

- Rawhide hosted Larimer County office of Emergency Services for a site visit and walk to familiarize each group with capabilities, resources, and needs in the event of a major incident at Rawhide or within the county.
- Rawhide hosted two scheduled emergency response team (ERT) trainings in April.

- The emergency services specialist continued work on transition and implementation of new software for paging, reporting, and data retention for the ERT.

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. Staff submitted their initial department budgets and the next steps include management review over the next few months.

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

Credit rating agencies update

In an annual letter to the credit rating agencies, Platte River provided a financial summary and significant events for 2023. The report also included environmental, social and governance factors and performance indicators specific to Platte River. Rating agencies use the information to conduct their annual surveillance of Platte River. No rating actions are expected as a result of the surveillance.

Financial audit report filing

Staff filed an electronic copy of Platte River's audited financial report for Dec. 31, 2023, with Colorado's Office of the State Auditor in April, as required by the Local Government Budget Law.

Continuing disclosure filing

Pursuant to the continuing disclosure certificates executed by Platte River in issuing its Series JJ and KK bonds, Platte River's audited financial report and annual report for Dec. 31, 2023, were filed with the Municipal Securities Rulemaking Board through the Electronic Municipal Market Access dataport.

Certificate of no default filing

As required by Platte River's General Power Bond Resolution No. 5-87, a certificate of no default, a certificate of insurance compliance and 2023 audited financial statements were filed with Platte River's bond trustee, Computershare Corporate Trust.

Post-closure reclamation liability filing

Platte River is required to file a solid waste facilities closure estimate and proof of financial assurance annual report with the state of Colorado. The report estimates the current closure and post closure care costs for the Rawhide ash disposal facility and the post closure costs of other impoundments on-site and demonstrates Platte River's ability to pay the future costs. The report, filed in April, estimated closure costs to be $14,927,344.

Form EIA-861 filing

Form EIA-861, Annual Electric Power Industry Report, was updated for the reporting year 2023 and submitted to the Energy Information Administration, a division of the U.S. Department of Energy. The form collects information such as peak load, generation, electric purchases, sales, revenues, customer counts and demand-side management programs, green pricing and net metering programs, and distributed generation capacity. The form is required reporting and Platte River completed its submission for the April 2024 deadline.

FERC Form No. 714 filing

FERC Form No. 714 filing, Annual Electric Balancing Authority Area and Planning Area Report was submitted for the reporting year 2023. Platte River is required as an electric utility that constitutes a planning area and has a peak load greater than 200 megawatts based on net energy for load for the reporting year to complete applicable schedules in FERC Form No. 714. Platte River completed its submission for the June 2024 deadline.

Facilities

Facilities staff has been getting multiple capital projects underway. The headquarters mechanical redundancy project is approximately 65% completed and should be operational by early to mid-June. This project will provide cooling redundancy for the headquarters building and relieve the peak loads on the system.

Clean energy transition and integration

Distributed energy solutions

In April, the Distributed Energy Solutions team transitioned the 2025 program planning focus from identifying future program modifications to determining process changes and budget estimates for continued program evolution, supporting further building and transportation electrification initiatives, and continued energy efficiency support for customers. This continued programming transition will be implemented and administered under the brand Efficiency Works™, finding common alignment for all five entities to support both common and individual entity goals.

While staff are looking to the future and supporting the utility energy transition, current key department achievements year to date (YTD) include the following:

Investment	Carbon	Equity	Customers
$2.0 M	**1,462**	**103**	**1,302**
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

The table below lists programming impact year to date within our owner communities. Additional detailed department achievements in April include the following:

- The Efficiency Works Homes team issued a request for proposals for energy advising, home assessment and other technical services on May 1, 2024. They will aim to contract with vendors for three years for the period of 2025-2027. The anticipated selection of vendors will occur throughout the summer of 2024, with services starting Jan. 1, 2025.
- Efficiency Works Consumer Engagement staff officially launched the expansion of the appliance recycling program, allowing customers to remove older inefficient appliances from their homes and businesses at no cost.
- Since launching in 2020 through 2023, the Community Efficiency Grant (CEG) has served 103 energy-efficiency retrofit projects completed by multifamily properties and nonprofit businesses with a mission to serve the income qualified community.

  The CEG provided an additional $1.1 million in funding on top of the standard rebate offering of $1.17 million for a total of over $2.28 million invested into the efficiency of spaces used by and that benefit the income qualified families in our owner communities. In 2024, the CEG eligibility definition was expanded beyond those with a mission to serve the income qualified community to all multifamily properties and nonprofit businesses that provide critical local community services, such as childcare centers, family support organizations, and rehabilitation providers.

Program metrics (YTD)	
2,931	**MWh saved** 5,237 MWh savings in progress
281	**KW peak demand reduced** 219 KW peak reduction in progress
389	**MWh electrified**
39,155	**natural gas therms saved**
750,664	**water gallons saved**
28	**events and trainings**
2,721	**local students engaged**

Through the end of April, there are 17 CEG projects underway in the communities, with over $400,000 of incentives available to support the energy upgrades.

Through April 2024, Efficiency Works programs have provided services for energy efficiency, building electrification, water savings and electric vehicles and have invested $2.0 million in providing these services to customers, excluding staff costs. 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. Owner communities may provide additional directive funding 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.

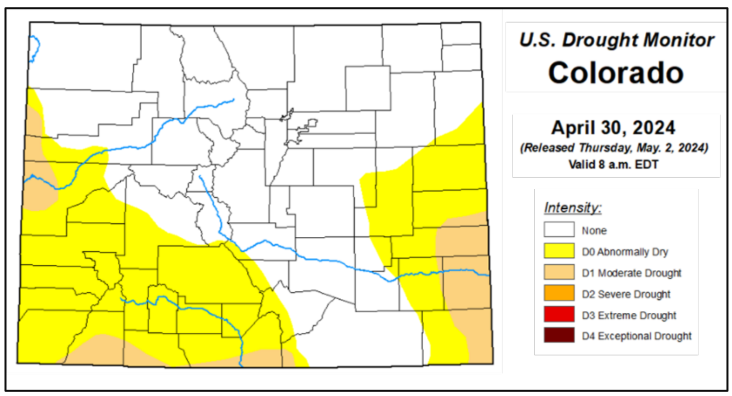
Strategic Initiatives

- Oracle Cloud Fusion Enterprise Resource Planning system implementation
  - The second conference room pilot for Oracle Utilities Work and Asset Cloud Service and Oracle Field Service Cloud was completed successfully on April 11.
  - The project's go-live has been rescheduled for September 8, due to a lack of resources to complete the work required to meet the previous schedule.
  - The project budget status is green, and the project is expected to come in under budget.
  - The project schedule status is yellow; the project managers are evaluating resource availability and working to find a way to meet the September 8 date.
- OSI Energy Management System implementation
  - Factory accepting testing of the system is scheduled for mid-May and preparations are being made for that process. This will be the first fully functional test of the new energy manage system in the new environment.
  - Work required to comply with critical infrastructure protection standards for the new environment has started. The plan is to have the first (draft) round of evidence ready for review by August 1. This effort is expected to take roughly 1,500-2,000 hours between May and August. Review and finalization of the evidence is expected to take another 1,500-2,000 hours between August and go-live in November.
- Data Strategy and Governance practice development and implementation
  - The team completed phase one (Document) of the project which consisted of:
    - Reviewing existing documentation.
    - Meeting with users from across the organization to catalog data sources, use cases and data flows.

   - Assessing the current state of data management and analytics maturity.
   - Developing a gap analysis report and developing plans to address issues.
- The team started on phase two (Strategize) of the project, which will include:
   - Aligning data strategy with organizational goals.
   - Developing/adapting data governance structures.
   - Identifying required roles and resources.
   - Creating the resource model.
   - Defining the data management plan.

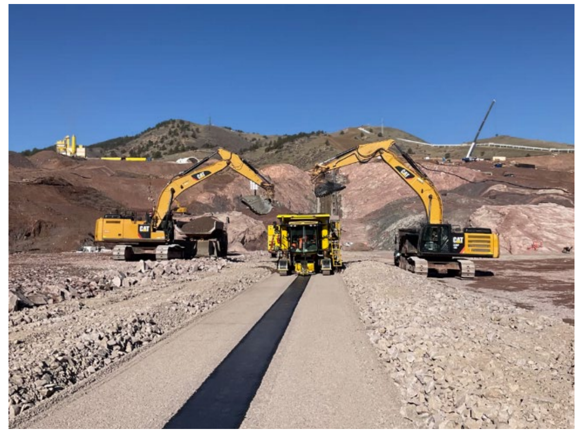
Operations

Fuels and water



Moving out of winter into spring, drought conditions in Colorado are generally mild with only small pockets of dryness in the southeast and southwest corners of the state and a generally drought-free Northern Colorado (see graphic). Combined with above-average East Slope reservoir storage levels and a spring runoff season that is forecast to be near average, the overall hydrologic outlook for Northern Colorado is favorable, heading into summer, although the implications are mixed for Platte River. As detailed in previous general management reports, the Windy Gap Project will not pump this year, because Lake Granby will be full, and Platte River will need to lease temporary water supplies for the remainder of the water year. However, these same robust water conditions should also free up supplies in the rental water market. Staff is in the process of securing sufficient rental supplies of Colorado-Big Thompson project water to satisfy Platte River's remaining 2024 Reuse Plan obligations.

The main dam at Chimney Hollow reservoir continues to rise at a rate of nearly four feet per week (see image) and the contractor anticipates the dam will reach its full height by the end of 2024. At the south end of the reservoir, the saddle dam foundation was prepared in 2023 and the contractor will soon begin final construction of the traditional clay core dam, which is also scheduled for completion in 2024. Inside the inlet-outlet tunnel, the contractor has completed tunneling operations and is now focused on grouting and lining the tunnel. Operations will then shift toward constructing the downstream tunnel slab and installing the pipeline. Through April, the Chimney Hollow reservoir project was approximately 63% complete and is scheduled for completion in the fall of 2025.



Chimney Hollow asphalt core construction

Resolutions

Long-haul optical fiber assets

The Fiber Optic Executive Committee (Fiber Committee) met on Monday, April 8, 2024. The Fiber Committee provides policy direction to Platte River on use of Platte River’s long-haul optical fiber assets (fiber connecting the local loops around each owner community). The owner communities and Platte River entered into an Intergovernmental Agreement for Fiber Management in 2019 (Fiber IGA). The Fiber Committee recommends the board approve an amendment to the Fiber IGA. The amendment removes the requirement for Platte River to maintain long-haul license revenues in a separate long-haul fiber account. The separate account was intended to be a temporary solution while conveying ownership of excess long-haul fiber to the owner communities. The governing bodies of each owner community and the Platte River board must approve the proposed amendment. Staff will provide more details at the July board meeting.