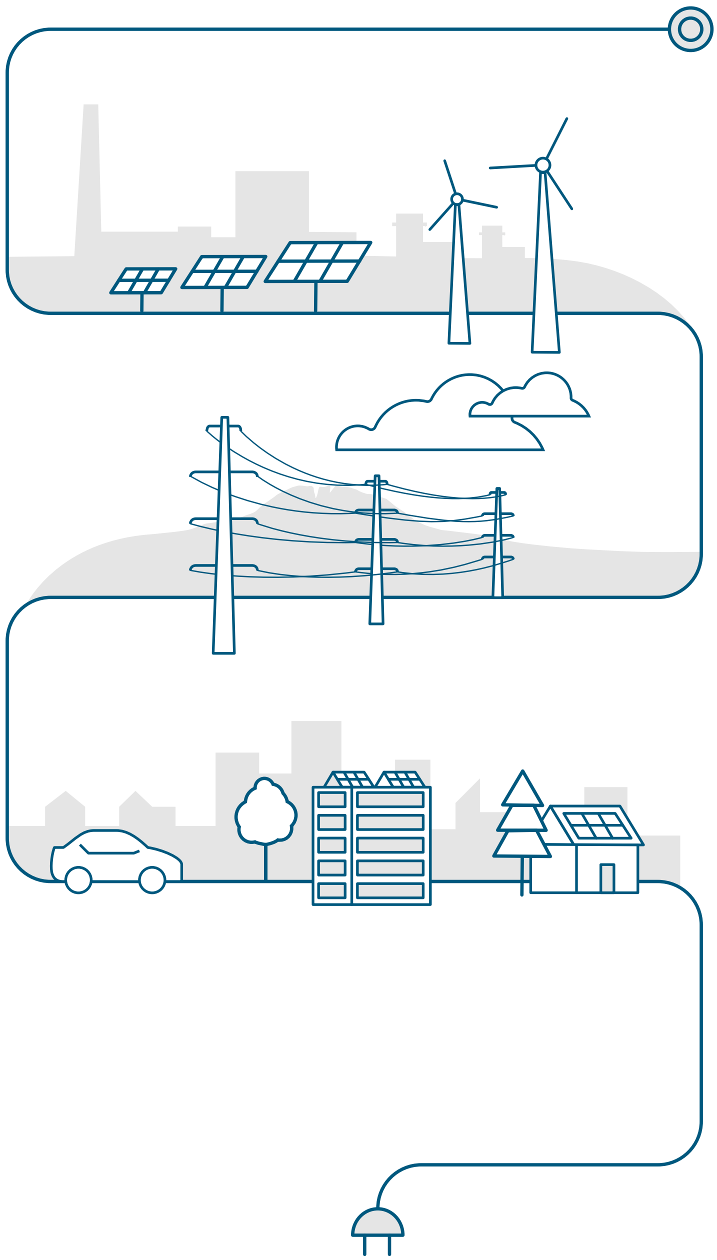
Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland



2020 Integrated Resource Plan

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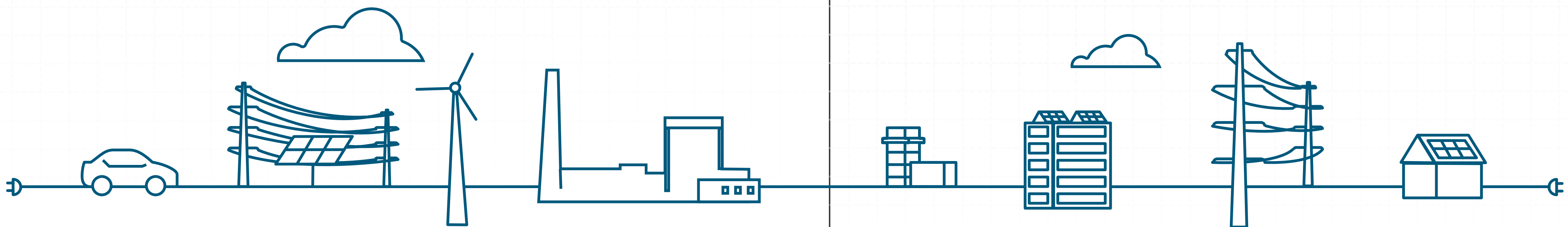
Executive summary



Platte River Power Authority (or Platte River) is pleased to present its 2020 Integrated Resource Plan (or IRP). This IRP builds on the significant progress made by Platte River by adding or committing to almost 400 MW noncarbon generation in 2020. This plan presents a potential roadmap to progressing toward the Resource Diversification Policy goal of a 100% noncarbon resource mix. This policy was adopted by Platte River's Board of Directors (board) in 2018 to proactively work toward the goal of achieving a 100% noncarbon resource mix by 2030 while maintaining three pillars of safely providing reliable, environmentally responsible and financially sustainable energy and services. When adopting this policy, the board also recognized certain caveats related to technology evolution and market development.

This IRP used the best available information today to develop four resource mix portfolios spanning a wide range of future possibilities.

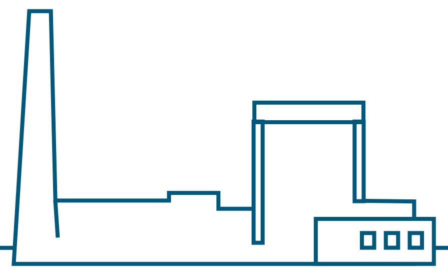
Each of these portfolios is a 20-year plan starting in 2021, integrating both demand-side and supply-side resources to reliably meet the owner communities' electricity needs in a least cost manner. This IRP should be viewed as the continuation of Platte River's journey toward achieving the goal of a 100% noncarbon resource mix, in line with the direction of the board and the goals of Platte River's owner communities of Estes Park, Fort Collins, Longmont and Loveland. The key value proposition of this IRP is the directional view it provides for future decisions.

An IRP is a snapshot of a future path based on the assumptions at a particular point in time (summer/fall 2019 in this case), but the planning is a dynamic process whereby the plans are updated as technology evolves and other assumed variables change. This IRP was developed prior to the COVID-19 impact on electricity demand. While the short term impact at the time of writing this document is 5-7% demand reduction, long term impact is hard to predict. Platte River will update its long term electricity demand forecast and modify supply plans according to the changes brought about by this pandemic in future power supply plans.

Platte River is not required to complete its next IRP until 2021 but several recent developments necessitated accelerating the process. First and foremost is the board's adoption of the Resource Diversification Policy. Second, considerable investments in renewable energy have been made, including the 225 MW Roundhouse Wind Energy Project, the 22 MW Rawhide Prairie Solar project that came online in 2020 and the 50-150 MW of solar being finalized for commercial operation in 2023. Finally, Platte River has committed to join the Western Energy Imbalance Market (WEIM), which will enable Platte River and its regional partners to integrate renewable energy resources more efficiently. Together, these changes require Platte River to re-evaluate and update its long-range plan.

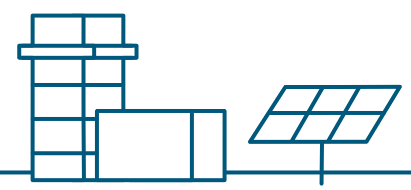
Development of this IRP relies on several assumptions and forecasts made by staff and studies conducted by outside consultants. On the demand side, these assumptions include forecasts for anticipated energy consumption and the level of distributed energy resources (DERs), mainly distributed solar, electric vehicles (EVs) and energy efficiency penetration. On the supply side, the main assumptions include: forecasts of natural gas, coal, and electricity market prices; CO_2 price; costs for new thermal resources; costs for new renewable resources; and the cost of battery storage. Out of these assumptions, the level of DER penetration and the costs of renewables, battery storage, natural gas and the CO_2 are key drivers of the IRP results. Platte River designed the following four portfolios and sensitivities to test variations in these drivers.

Major components of the four portfolios



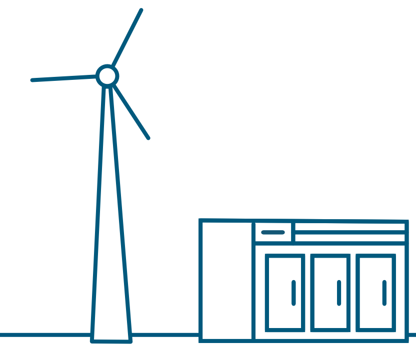
Portfolio 1: continuity

Portfolio 1 (P1) explores continuing the current path of reliably meeting owner communities' load obligations while adding new resources or retiring existing resources only when economical. Following the announcement of plans to retire coal-fired Rawhide Unit 1 by 2030, the key assumption of no forced retirements has been superseded in this portfolio. However, this portfolio provides a valuable baseline to compare costs and CO_2 emissions with the other portfolios.



Portfolio 2: zero coal

Portfolio 2 (P2) explores the path where Platte River retires all its coal fired generation by 2030 while continuing to reliably meet the owner communities' load obligations by adding new resources economically and continuing to meet or exceed all environmental regulations. The recent announcement of plans to retire Rawhide Unit 1 by 2030 aligns well with this portfolio.



Portfolio 3: zero carbon

Portfolio 3 (P3) explores the path where Platte River retires all of its thermal generation by 2030 while continuing to meet the owner communities' load obligations by adding only noncarbon resources and battery storage.

Portfolio 4: integrated utilities

Portfolio 4 (P4) explores the path where the drivers of current industry transition evolve at an accelerated pace to manifest a faster energy transition. For example, the costs of solar, wind and battery technologies in this portfolio are 15-25% lower, and distributed solar and EV adoption rate is two times faster relative to other portfolios. During this rapid industry transition, Platte River would continue to meet the owner communities' load obligations while adding new resources or retiring existing resources economically.

2018

Summer 2018
Coordination with WAPA
Contracting for third-party consulting services

Fall 2018
Community listening sessions

Winter 2018
Gathering of inputs for 2020 IRP modeling

2019

Summer/Fall 2019
Research and generation portfolio analysis
Community input

Winter 2019
Rate impact analysis

2020

Spring 2020
Board and internal review
Community focus groups

Fall 2020
Stakeholder presentations
Filing with WAPA

14
Community engagement sessions

600
Approximate community participants

100+
Emails received from stakeholders

2
Scientific surveys

Outreach and engagement

Platte River staff developed the four portfolio options and this IRP with significant input from regional leaders, stakeholder organizations and the public from the owner communities, then conducted greater outreach once the portfolios were determined. Engagement occurred through digital and traditional media, community listening sessions, scientific surveys and focus group meetings conducted by Colorado State University's (CSU) Center for Public Deliberation (CPD).

Engagement between staff, Platte River's Board of Directors, stakeholders and the public came to a halt in mid-March due to health concerns associated with the COVID-19 pandemic. Not wishing to allow any hinderance to stakeholder or public input, the board delayed formal presentation of any action on the IRP until board meetings could allow for public comment.

Visit prpa.org/irp to view results from the listening sessions, focus groups and scientific surveys

Summary results

The four IRP portfolios were analyzed using Aurora model (Appendix D), a resource planning tool commonly used by U.S. utilities to identify a least-cost combination of resources that meets the constraints of the portfolio. Reliability measures, costs and emissions were tracked for all the portfolios and formed the basis of relative comparison between them.

Each portfolio was first evaluated to ensure its reliability. Portfolios containing thermal resources that can be dispatched to meet load satisfy standard utility reliability metrics. For portfolios relying on 100% renewable resources, there are no industry standards or guidelines for the optimal level of installed capacity that can provide acceptable level of reliability. A given level of battery, wind and solar capacity may be reliable for one particular wind and solar profile but unreliable for another. Staff developed a resource mix to provide a reasonable level of reliability based on the past few years of wind and solar profiles. This level of resources may not be sufficient for a future wind profile with long periods of low output of both wind and solar generation. Some additional reliability may be gained from an energy market but reliance on market purchases during times of low solar and wind output is speculative. Given these facts, the reliability of the zero carbon portfolio at this time is uncertain.

Wholesale rates and CO_2 emission reductions were used to benchmark the financial and environmental performance of each portfolio. Figure 1-1 shows projected wholesale rates for the four portfolios and Figure 1-2 shows the percent of CO_2 reduction relative to 2005 emissions.

It is clear that the wholesale rates for P3 are much higher than other portfolios. P3 rates rise at an annual rate of 9% vs. 2-3% for the other portfolios during 2021-2030. This is due to the high level of investments to procure large quantities of renewables and battery storage needed to provide 100% renewable energy.

Figure 1-2 shows CO_2 reductions for the four portfolios relative to 2005 actual emissions. There is a steady increase in percent reduction from 20% in 2021 to over 40% by 2029. This doubling of reduction is achieved through the gradual retirement of Craig coal units and addition of renewable generation. After 2029, P1 does not achieve any significant reduction. P2 sees emission reduction of above 90% in 2030 and beyond following the retirement of Rawhide Unit 1. P3 achieves 100% reduction with the retirement of all thermal generation in 2030. P4 experiences a large increase in emission reduction in 2036 following the retirement of Rawhide Unit 1.

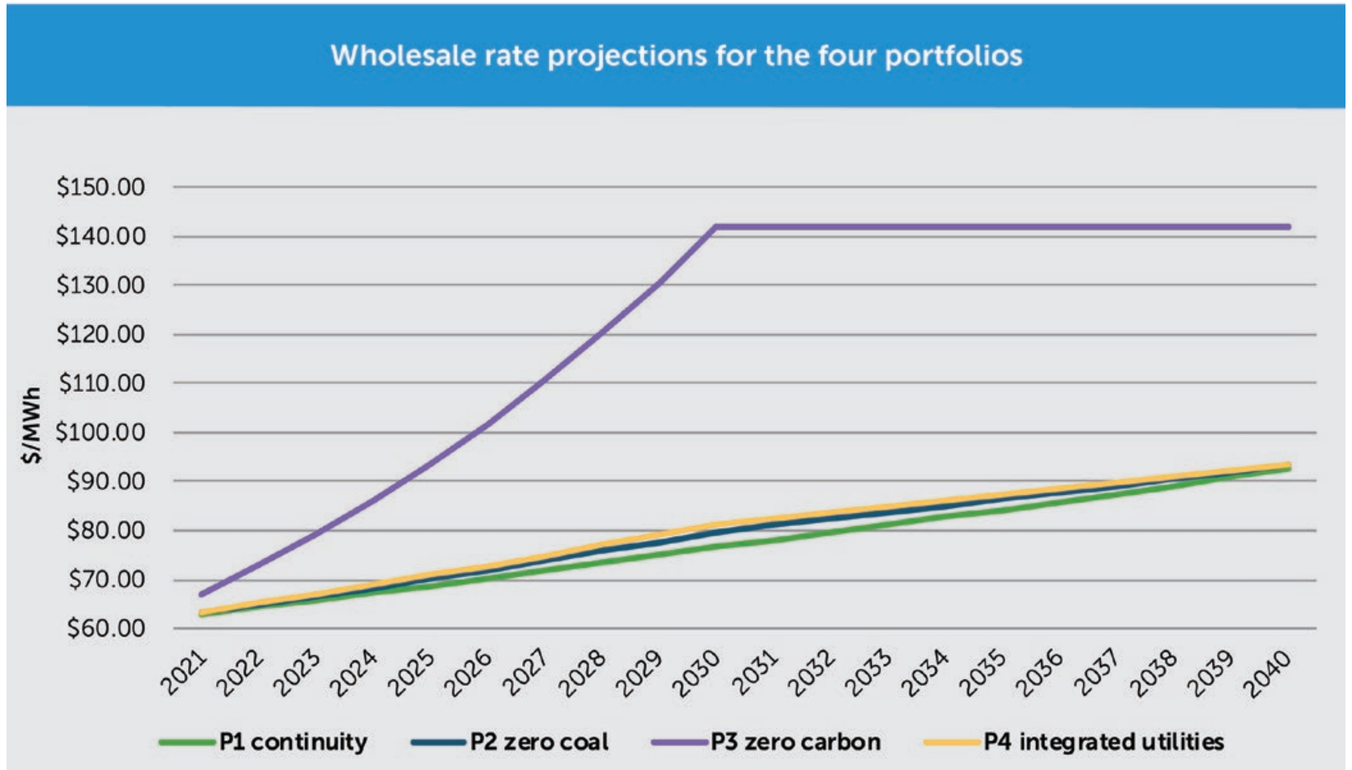


Figure 1-1

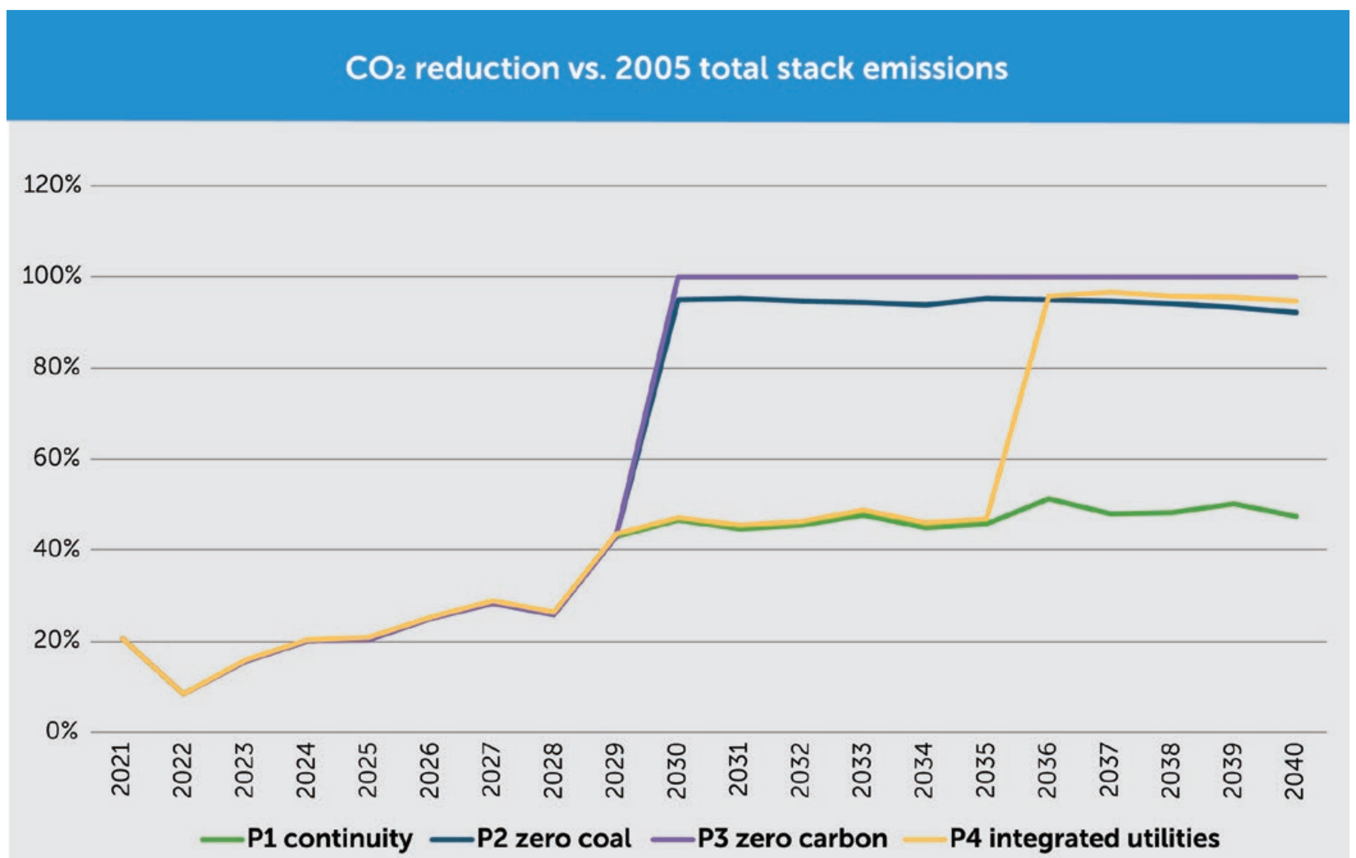


Figure 1-2

Key takeaways

- Platte River is making significant progress towards Resource Diversification Policy goals by adding almost 400 MW of renewables during 2020-2023 which will take the share of noncarbon energy to 60% of the owner community load.
- Portfolio decarbonization will continue with the planned retirements of coal generation in 2025, 2028 and 2030.
- This IRP presents four portfolios to cover wide ranging future possibilities through 2040.
- Following the announcement of Rawhide Unit 1 retirement in 2030, P1 and P4 do not represent a viable future but still provide valuable information for comparison.
- P2 and P3 are aligned with the announcement of retiring coal assets, the Resource Diversification Policy and the state environmental legislation and regulation (SB19-236 and HB19-1261) allowing Platte River to voluntarily file a clean energy plan (CEP) which will show more than 80% reduction in CO_2 in 2030 relative to the actual emissions in 2005.
- P3 has a significant rate impact and it may not fully meet the reliability requirements of the owner communities.
- P2 is the least cost path to comply with the state environmental legislation and the Resource Diversification Policy while maintaining the three pillars of safely providing reliable, environmentally responsible and financially sustainable energy and services. **P2 is the staff recommended portfolio.**
- The role of new gas fired generation in P2 complements the intermittency of renewables and provides back up to guarantee a high level of reliability. Platte River will continue to evaluate technological breakthroughs (prior to making an investment decision) to determine if it can reasonably provide these services from noncarbon sources.
- Planning is a dynamic process. Staff will continue to refine the recommended portfolio with new data and assumptions focusing on evaluating battery storage and DERs to maintain reliability as well as firming up timing, type and size of new resources to replace retiring coal. New resources will be brought online throughout this decade and operational expertise developed prior to retiring Rawhide Unit 1 in 2030. This is critical to ensure a smooth transition to a renewable heavy supply mix with a high level of reliability.
- This IRP is a possible roadmap for the future and not a firm investment plan. Platte River staff is committed to modifying plans to align with the direction of the board and the goals of the owner communities as demonstrated by Platte River's track record since filing the last IRP. The 2016 IRP projected total renewable energy production of 400,000 MWh during 2021-24. With the renewable projects online and under firm commitment, Platte River will produce over 1 million MWh in 2021 and 1.4 million MWh in 2024 – over three times the projections included in the 2016 IRP.

2 Platte River Power Authority overview

History

Until the mid-1960s, many Colorado municipal utilities separately received wholesale electric service from the federal Bureau of Reclamation from its 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 (hydro) 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 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.

Governance

Following the passage of 1975 legislation enabling municipalities to form power authorities, 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.

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

Values

The following values tangibly define Platte River's daily commitment to following the vision and mission to strengthen the organization and improve the quality of life in the communities we serve.

Safety

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

Sustainability

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

Service

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

Operational excellence

We will strive for continuous improvement and superior performance in all we do.

Integrity

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

Innovation

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

Respect

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

3 IRP background

An IRP[1] is typically a 10- to 20-year plan developed by utilities to meet their customers' future electricity needs. An IRP optimally selects from demand- and supply-side resources while meeting the planning reserve margin (PRM[2]) criteria to ensure reliability of supply under all reasonable expectations of supply and demand that vary over time. An IRP only plans for wholesale generation and customer side DERs. It does not consider supply infrastructure like transmission and distribution systems unless needed for specific generation resource delivery. An important component of an IRP is an action plan that provides specific and detailed utility plans and activities during the next three to five years before developing the next IRP.

Utilities started developing IRPs during the 1980s in response to rising costs of nuclear generation and other fuels, and to include energy efficiency and other demand-side options in the supply mix. During the 1990s, with the onset of power sector restructuring and market development, IRPs became less valuable because markets were expected to drive optimal generation investments. Power markets have evolved more slowly than expected, however, with varying degrees of success for enabling generation investments across different parts of the country. With rapidly falling prices of renewable energy resources, battery storage and DERs, IRPs have again emerged as a vital planning tool for utilities. Major stakeholders including regulators, customers and utility decision makers now use IRPs to chart the future course of investment for utilities.

[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. North American Electric Reliability Corporation generally advises utilities to maintain a 15% PRM which means if a utility is expecting a peak demand of 100 MW in a future year it must build or acquire 115 MW of generating capacity to reliably meet that peak demand.

3.1 Why do an IRP now?

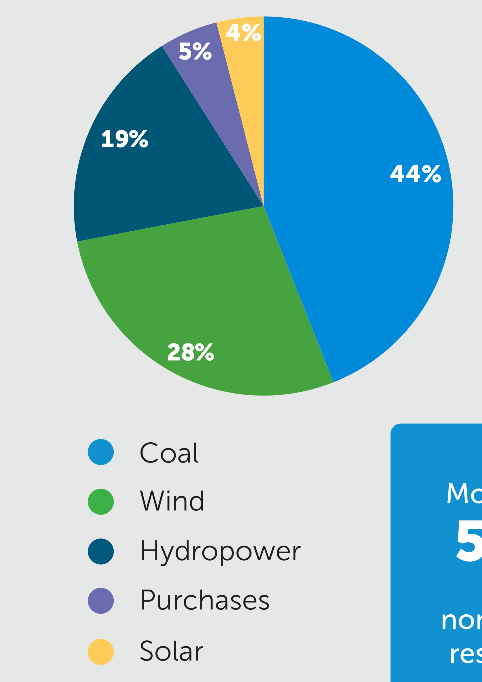
The electric utility industry is rapidly transforming by the three Ds:

1. De-carbonization
2. De-centralization
3. Digitalization

By 2021, Platte River will deliver more than 50% noncarbon energy to its owner communities, placing it as a leader of this historic transformation. This IRP is a continuation of the journey toward achieving a 100% noncarbon energy mix as enabling technologies develop over the next decade.

Platte River filed its last IRP in 2016. According to Western Area Power Administration (WAPA) requirements, the next IRP is not due until 2021. Platte River decided to accelerate the IRP development by one year to respond to its owner communities' desire for a lower carbon energy mix and rapidly declining prices for renewable resources. According to Lazard, an industry leader in power sector investments, the cost of solar has dropped at an average annual rate of 13% over the past five years while the cost of wind has dropped at an annual rate of 7% during the same period[3]. Battery storage costs have also seen rapid declines. Coupled with the falling costs of noncarbon resources, DERs and EVs are becoming more popular among the owner communities. With the vision to maintain Platte River's role as an industry leader and to respond to owner communities' strong desire for lower carbon power supply, the Platte River Board adopted a Resource Diversification Policy[4] in December 2018. The policy calls for a 100% noncarbon energy mix by 2030 provided the necessary technologies and regional markets evolve to ensure reliable and financially sustainable supplies. This IRP provides the beginning of a road map to achieve the noncarbon goals of Platte River's owner communities, its associated costs and expected reliability using the currently available technologies.

Projected deliveries of energy to owner communities in 2021



More than **50%** from noncarbon resources

[3] See Lazard report at https://www.lazard.com/perspective/lcoe2019

[4] See the Resource Diversification Policy on Platte River's website

3.2 Developments since the last IRP

Platte River has taken a leadership role in providing noncarbon energy to its owner communities. By 2021, Platte River will supply approximately 50% noncarbon energy to its owner communities due to successful execution of a strategy to capture market opportunities while focusing on the communities' goals for a fully noncarbon portfolio. With the addition of a 150 MW solar project under negotiations, the level of noncarbon energy is expected to reach 60% by 2024. The 2016 IRP projected total renewable energy production of 400,000 MWh during 2021-24. With the projects online and under firm commitment, Platte River will produce over 1 million MWh in 2021 and 1.4 million MWh in 2024 – more than three times the projections in the 2016 IRP.

Since filing the last IRP in 2016, Platte River's emergence as a leader in Colorado's utility sector is marked by:

2016

- Integrating **30 MW of solar generation** at the Rawhide Energy Station
- Signing an agreement to **retire** the coal-fired Craig Unit 1 by 2025
- Initiating a wholesale **demand response** pilot program
- Initiating a **commercial midstream cooling rebate program** to increase adoption of high efficiency packaged cooling equipment

2017

- Performing a **zero-net carbon study** to explore different paths and associated costs to provide additional noncarbon energy to the owner communities
- Initiating **income-qualified energy efficiency programs** in collaboration with the owner communities and Energy Outreach Colorado
- Evaluating participation with a **regional transmission organization**
- Starting operation under a **joint dispatch agreement** (JDA)

2018

- Signing a 20-year power purchase agreement (PPA) to buy wind energy from the **150 MW Roundhouse Renewable Energy Project**
- Adopting the **Resource Diversification Policy** that calls for a three-pronged approach to reach a 100% noncarbon energy mix by 2030
- Committing to develop and file an **IRP** earlier than WAPA requires
- Introducing the **Efficiency Works Store** to offer select energy-efficient products directly to customers and programs that provide efficiency assessments and efficiency project support for multifamily buildings
- Determining that Platte River's participation in an **energy imbalance market** serves its interests as a significant step toward participation in a full regional energy market
- Extending the **organic contract and power supply agreements** between Platte River and its owner communities to 2060
- Signing a contract for **22 MW of Rawhide Prairie Solar and 2 MWh of battery storage**
- Securing an **additional 75 MW of wind** capacity from the Roundhouse Renewable Energy Project
- Starting a request for proposal process to purchase **50 to 150 MW of additional solar** generating capacity
- Restructuring the **wholesale power supply rate** with the owner communities
- Initiating the collaborative process with the owner communities to develop a **DER strategy**

2019

- Beginning discussions with co-owners of the coal-fired Craig Unit 2 to **retire** it before 2030
- Achieving **100,000 MWh of cumulative energy savings** between 2016 and 2019 in collaboration with the owner communities – approximately 3% of overall load – by investing nearly $36 million in Efficiency Works™ programs
- Launching an **EV distributed charging study**
- Making the commitment to join the **WEIM** operated by the California Independent System Operator, with four other regional utilities

2020

- Announcing that Rawhide Unit 1 will cease producing electricity by 2030, 16 years before its planned retirement date
- Finalizing the decision with co-owners of Craig Unit 2 to retire the unit on Sept. 30, 2028
- The 225 MW Roundhouse Wind Energy Center beginning commercial operation

The aggressive agenda implemented since the 2016 IRP filing clearly reflects the intentions of Platte River's Board, the owner communities and the customers they serve. These activities demonstrate a fundamental shift from a traditional business model toward that of a modern energy provider while maintaining **Platte River's core pillars to safely provide reliable, environmentally responsible and financially sustainable energy and services to the owner communities**.

3.3 Resource Diversification Policy

Platte River's Board unanimously approved the Resource Diversification Policy in December 2018. This policy 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 energy and services.

To achieve this goal, the board recognized that the following conditions must be met:

- 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

This policy provided the framework for the 2020 IRP. Various components of this policy as applicable to the IRP are discussed here.

3.4 Efforts to join a market and development of JDA

In recent years, Platte River has made several attempts to join or form an energy market. Early attempts to join a market such as a regional transmission organization or independent system operator were not favorable due to relatively low-cost generation and relatively high-cost transmission in the region. Market operations typically allow more use of transmission to reduce variable production costs. Many transmission providers in the west were reluctant to forego transmission revenues and, with already-low variable costs, little benefit could be derived from market participation. However, with the ever-increasing penetration of variable energy resources such as wind and solar generation, establishing a regional market has become more compelling given the operational challenges that can arise with large amounts of intermittent generation. To better integrate renewable resources, Platte River now seeks a larger and more diverse market to help it meet long-term noncarbon energy goals.

Following several studies of potential markets, Platte River, Xcel Energy and Black Hills Energy began collaborating in late 2012 to develop the JDA concept, which would create a smaller scale and more regionally focused market option that allows for more efficient use of generating resources. Joint dispatch combines all or some portion of generating resources from the participating companies into a common portfolio for real-time optimization to serve each participant's individual load. The resulting market price associated with joint dispatch energy exchanged by participants for an hour is based on actual highest incremental generation costs during the hour.

The JDA functions like a small energy imbalance market where all participants are required to be balanced prior to entering the hour. After the hour starts, all participating units are dispatched up or down, based upon costs, to most economically serve each participant's load. The current JDA has limitations, however. It does not treat offline generation (even quick start) as available capacity, only performs hourly settlements and will not consider multi-hour dispatch for better system optimization. Nevertheless, the collaboration between Platte River, Xcel Energy and Black Hills Energy under the JDA has led to lower overall energy costs for the participants than if they served their own load using just their own resources.

Platte River was an active member in the Mountain West Transmission Group, which considered joining the Southwest Power Pool's Integrated Marketplace. In early 2018, the Mountain West Transmission Group members determined this option was not feasible. Platte River then began to study participation in other potential market options, including those offered by the Midwest Independent System Operator and by Pennsylvania, New Jersey, Maryland power pool (PJM)/Peak Reliability, as well as the WEIM and the possible formation of a new, stand-alone market. The PJM/Peak Reliability option was dismissed in April 2018 because Peak Reliability announced the discontinuation of its reliability coordinator services by the end of 2019.

Members of the JDA worked to enhance the JDA by attracting a new member – Colorado Springs Utilities – and, at the same time, study the benefits of taking a more manageable step toward an integrated market by joining an existing energy imbalance market. An energy imbalance market is a real-time market in which energy generation from multiple power providers is dispatched at the lowest possible cost to serve the combined customer demand of the region. During 2019, the JDA utilities commissioned the Brattle Group to study the WEIM, which is operated by the California Independent System Operator, and the Western Energy Imbalance Services proposed by the Southwest Power Pool. The study concluded that, as the larger of the two markets, the WEIM offers greater potential to lower production costs due to the size of its market footprint and the diverse resources available. The study also revealed WEIM offers lower administrative costs, and participants of the WEIM are exploring adding day-ahead market services. Day-ahead market services are designed to help utilities plan which resources they will use to generate energy, allowing more renewables to be integrated into the system. In late 2019, Platte River and its JDA partners announced they would join the WEIM. Participation in the WEIM is scheduled to start in 2022.

3.5 Studies conducted for 2020 IRP

The following nine studies were performed to support this IRP. A more detailed description of the studies is provided in Appendix A. All studies are available on the IRP microsite except for the market analysis, which provided data and assumptions for the IRP as discussed in Chapter 7.

1. Generation technology review
2. Regional economic impacts
3. Energy storage technology assessment
4. Coal cycling
5. Thermal generation alternatives
6. Resource adequacy review
7. Market analysis
8. DER potential
9. Life cycle carbon impact

3.6 Objectives of 2020 IRP

Platte River's 2020 IRP provides a 20-year plan designed to meet its owner communities' need for reliable, environmentally responsible and financially sustainable energy and services during the ongoing industry transition, by enhancing the share of renewable resources and DERs. The five-year action plan, incorporated within the IRP, offers a critical component of Platte River's long-range implementation plan to achieve the goals of the Resource Diversification Policy. Consequently, this IRP is anchored primarily by adding noncarbon resources and battery storage while exploring four different long-term energy mix options.

3.7 IRP modeling tool

Platte River used Aurora simulation and modeling tool for the 2020 IRP development. Aurora is an economic dispatch and capacity expansion model developed by Energy Exemplar (energyexemplar.com). More details about the Aurora model are provided in Appendix D.

4 Five-year action plan

This IRP can be seen as the continuation of Platte River's journey toward decarbonizing its portfolio. This journey started almost two decades ago and reached a watershed moment with the board's adoption of the Resource Diversification Policy in 2018. Following this policy adoption, Platte River made some major renewable resource additions that will enable it to supply more than 50% noncarbon energy to its owner communities after the startup of the 225 MW Roundhouse wind project in 2020. During the next five years, this journey of progressive decarbonization will continue with a focus on efficiently integrating the Roundhouse wind and 50-150 MW solar project under solicitation. Additionally, the next five-year action plan will also include efficient integration into the WEIM, preparation for Craig Unit 1 retirement and other activities discussed in this chapter. This action plan will be reviewed on an annual basis as existing projects are completed and new ones are added.

4.1 Roundhouse integration

Platte River added 225 MW of Roundhouse wind energy capacity to its energy mix during the summer of 2020, which is expected to provide about one fourth of our communities' load. Integrating this much intermittent wind energy with existing resources will be a major focus of the operations group within Platte River. Benefits of this large wind resource will be maximized by integrating it with the dispatch of thermal resources.

4.2 Rawhide Prairie Solar and battery storage integration

The Rawhide Prairie 22 MW solar and 2 MWh battery project is expected to start commercial operation during the later part of 2020. As intermittent renewable resources continue to take a larger share of Platte River's supply portfolio, battery storage will play a more crucial role. Platte River's staff will test and study the operation of a 2 MWh battery installed within the Rawhide Prairie Solar project. Experience gained with the control, optimization and operating cost of the storage will be valuable when adding more storage to prepare for thermal resource retirements.

4.3 New solar project completion and integration

Ensuring the on-time permitting, construction and integration of the new 150 MW solar project will be another focus area for Platte River staff. When this solar project comes online in 2023, about 60% of the energy delivered to Platte River's owner communities will come from noncarbon energy resources on an annual basis.

4.4 Western Energy Imbalance Market

Platte River operations and planning staff will be working with stakeholders, including other market participants and the market operator, to integrate into the WEIM by 2022. Integration into the WEIM is expected to improve system reliability and lower operational cost through greater access to a wider and more diversified resource mix in the region.

4.5 Rawhide coal flexibility enhancement

The coal-fired Rawhide Unit 1 was designed to run as a baseload unit and has performed very well in this role. With more and more intermittent renewable generation joining the supply mix, Unit 1 will need to be more flexible to follow the ever-changing load and renewable supply. By changing its operating practices, Platte River has reduced Unit 1's minimum generation level from 140 MW to 100 MW. Over the next few years, Platte River staff will test even lower generation levels and more load following operations. Platte River's goal is to enhance Unit 1's flexibility without compromising reliability or incurring excessive operations and maintenance costs.

4.6 Craig coal retirement readiness

The coal-fired Craig Unit 1 will be retired by 2025 and the Craig Unit 2 will retire by September 2028. Retirement of Craig coal units will bring Platte River closer to the goal of 100% noncarbon resources. With the renewable resources already procured, Platte River can offset the loss of the energy generated by Craig Unit 1 by 2025. However, the replacement of 77 MW of firm capacity (more than 10% of the peak demand in 2019) with intermittent renewables will need to be managed from operational and risk management perspectives, possibly with more batteries or more renewable resources.

4.7 DER strategy development and execution

Platte River and its owner communities are working on a comprehensive strategy for implementing DERs in a cost-effective manner. With a formal strategy in place, Platte River will work with its owner communities to start the implementation process. Existing energy efficiency programs, distributed solar, EV charging and beneficial electrification programs will be merged under this umbrella with new DERs.

5 Community engagement

As a community owned utility, Platte River engages the public in all its major initiatives. During the IRP process, Platte River increased public outreach and engagement efforts to obtain as much public input as possible.

A high level of public input was sought through the following initiatives:

- Multiple rounds of community listening sessions within the owner communities of Estes Park, Fort Collins, Longmont and Loveland
- Focus group meetings within the owner communities
- An IRP microsite and a dedicated email address; using digital technologies to not only inform audiences but also collect more input
- Formal customer surveys
- Stakeholder engagement

5.1 Community listening sessions

Platte River conducted three rounds of community listening sessions and a series of public focus group meetings. During the listening sessions, participants took part in surveys and provided direct input to Platte River leaders regarding future energy options.

Objectives of the listening sessions:

- October-November 2018: Inform the public about the IRP process and plans, and seek their input for different topics and areas to be covered in detail during the plan development process
- October 2019: Update the public on the IRP process and share results from nine independent studies conducted by Platte River to form the analytical basis of the IRP
- Fall 2020: Public presentations to inform stakeholders of Platte River's final IRP

Platte River promoted participation for each round of listening sessions via the news media, IRP microsite, email, word-of-mouth and social media channels. Approximately 50 individuals attended each of the events, for about 200 total participants per round of listening sessions. Local community activists attended each event, along with business and other community leaders. Platte River streamed each of the listening sessions live from its Facebook page, with viewers able to submit questions to panelists, then posted the recording of each on the IRP microsite.

5.2 Focus group meetings

The series of focus group sessions managed by CSU and CPD sought to increase diversity of participation and capture in-depth discussion and opinions concerning Platte River's IRP and the four energy portfolio options. Platte River and the CPD collaborated on outreach and promotion to draw participants to the focus group meetings. Participants received background information on Platte River's four portfolios. Participants discussed advantages and costs/risks associated with each alternative and provided opinions regarding Platte River's direction. The CPD assimilated all data and provided a report to Platte River's leadership, which was published on the IRP microsite. Due to the impact of COVID-19 and the need to curtail public gatherings, the Fort Collins event was canceled but replaced by an online focus group survey, which was built by the CPD to ensure input from Fort Collins customers.

5.3 IRP microsite

Key to the public transparency was the development of a microsite (**prpa.org/irp**), attached to Platte River's website, which contained all available information concerning the 2020 IRP including:

- General description of the IRP and its process
- Frequently asked questions
- Schedule of activities during the process
- Contact information and method to provide digital feedback
- Video recordings of all community listening sessions
- Key documents and research papers
- Results from formal community surveys

The IRP microsite quickly became the central location for stakeholder engagement. Analytics indicate visitors to the site remained on its pages up to five times longer than visitors to other Platte River web pages.

In addition to the microsite, a dedicated email address (**irp2020@prpa.org**) was set up to receive public input on IRP related issues.

5.4 Formal customer surveys

To obtain opinions about future energy resources from a representative cross section of customers, Platte River engaged a third-party research organization to conduct statistically valid surveys among residential and business customers in the four owner communities. Inside Information, a nationally recognized research agency with extensive utility experience, conducted surveys at the beginning of the IRP process and during public deliberation over the four energy portfolio options.

Inside Information conducted two studies within each owner community, one focused on residential opinions and the other on commercial business. Respondents were contacted randomly based upon customer lists provided by each of the owner communities and asked to respond to a series of questions posed in an online survey form. Inside Information followed up with phone surveys within each community until a statistically valid set of responses was obtained from both residential and commercial business audiences.

Platte River posted a series of reports containing survey results on its IRP microsite. The results of the first residential survey have a margin of error of +/-2.9% at a 95% degree of probability. That means for any given statistic, there is a 95% chance that the result does not vary by more than 2.9% in the actual total population. The results of the commercial survey have a slightly larger margin of error of at +/-3.4%.

A second round of surveys was conducted in the spring of 2020 to coincide with the focus group sessions managed by the CPD. Questions posed paralleled those asked during the focus groups, again providing a statistically valid series of responses from a diverse cross-section of customers within Platte River's service territory. Results of the second round of surveys were posted on the IRP microsite.

5.5 Inquiries and input

Anyone with any interest or opinion regarding Platte River and its IRP was encouraged to make inquiries or provide their thoughts through several means, including by mail, phone, email or social media. Contact methods were made available through the IRP microsite. The largest percentage of comments were taken by email through a simple portal from the microsite. Several individual comments or inquiries were received during the process. A nationwide stakeholder group, through its local chapter, deployed a digital software program that enabled its members to send a standardized message (along with limited ability to provide personal thoughts) to Platte River. IRP managers received approximately 100 of the automated notes.

5.6 Stakeholder outreach

Platte River provided a significant amount of information to key groups including board members, the news media, community utility leaders and communications staff to enhance public outreach and engagement. Board members frequently made public remarks about the IRP process and invited the public to attend listening sessions. Plans for community listening sessions were made public well in advance of each event and forwarded to key stakeholders to maximize outreach. The news media provided significant coverage as well, in advance of and following community listening sessions.

5.7 Stakeholder engagement

Platte River also met with several stakeholder organizations during the IRP process, to provide background and key information that may pertain to their interests. Stakeholders included business, government and environmental organizations.

The Northern Colorado Partners for Clean Energy (NCP4CE) is a coalition of organizations in the four communities that own Platte River. NCP4CE is also a member of the Colorado Coalition for a Livable Climate but retains autonomy regarding its work with Platte River and all local initiatives. Platte River conducted five detailed sessions with NCP4CE including conference calls and in-person meetings.

The meetings were conducted on:

- Feb. 14, 2019
- May 28, 2019
- Aug. 16, 2019
- Nov. 12, 2019
- Dec. 19, 2019

Platte River incorporated many suggestions from these public engagements, such as the estimation of CO_2 impact of methane leakage during natural gas production and transportation, and inclusion of the social cost of carbon as an incentive to reduce carbon emissions.

Platte River representatives also engaged with chambers of commerce within the owner communities, presenting background and key information about the IRP. Meetings with local, state and federal elected officials took place on an individual basis and presentations were made to city councils.

5.8 Public engagement outcome and results

Platte River received direct input from between 2,000 and 3,000 residential and commercial business customers during the two-year outreach and engagement process, through community listening sessions, formal surveys and electronic and hard-copy communications with the IRP team. Thousands more were made aware of the IRP process and its issues through digital communications and news media coverage.

Public input was primarily aligned with Platte River's three core pillars of system reliability, environmental responsibility and financial sustainability. Those expressing opinions generally supported the aggressive pursuit of renewable energy resources toward the goal of achieving a 100% noncarbon energy mix. Participants were not willing to sacrifice system reliability and most participants expressed only mild interest in spending more than what was otherwise necessary for quality electric service in pursuit of that goal.

Public engagement came to a halt in mid-March 2020 due to health concerns associated with the COVID-19 pandemic that was rapidly spreading through Colorado, as it was across the nation. During its March board meeting, which was conducted virtually, the board delayed formal presentation and action on the IRP until the public could provide input during its board meetings.

6 IRP demand-side assumptions

Traditionally, customer electricity needs consisted solely of aggregate electricity demand. With the growth of DER, today's customer demand must also include a seamless and economic integration of these resources. This chapter covers methodologies and assumptions for customer load and DER projections.

6.1 Load forecast

The future load forecast is the main driver and a key input for the 2020 IRP. Historically, utility load forecasts were driven by economic activity and efficiency improvements. While these are still the primary drivers, distributed resources are rapidly becoming a significant contributor to future electricity demand, two of which will have the greatest immediate impact on future Platte River load: distributed solar and EV charging. Distributed solar includes behind-the-meter or distribution level solar resources. EVs include new demand for vehicle charging at the customer's home or public locations.

These two DERs will impact future Platte River load in opposite ways. Distributed solar will reduce the overall load while EV charging will increase it. Current penetrations of distributed solar and EV charging are low, so very little historical data exists to predict future loads, but the impact of these DERs will be significant. As a result, projected load related to these two resources was forecasted independently and added to the overall load. Other sources of new load, such as beneficial electrification (converting home heating and water heating from gas to electric) are in early stages of penetration and were not included as a separate load growth item in the forecast. Beneficial electrification could emerge as a significant source of demand for Platte River, but there is very little data to support any meaningful contribution to electricity demand at this time. This will likely be an area of focus in the next IRP.

This load forecast was developed prior to the COVID-19 impact on electricity demand. While the short-term impact at the time of writing this document is 5-7% demand reduction, the long-term impact is hard to predict. Platte River will update its load forecast and adopt supply plans according to the changes brought about by this pandemic.

6.2 Load forecast methodology

Platte River's IRP model requires monthly peak and overall energy forecasts for future planning and optimization. Forecasting methodology meets this requirement as discussed below.

To forecast monthly peak demand and energy, Platte River uses an autoregressive integrated moving average (ARIMA) time series model.

The ARIMA models are extremely flexible and are widely used for time series forecasting. The model developed for Platte River's load forecast accounts for seasonal changes in energy usage as well as a trend that captures increased efficiency and conservation by end-use customers.

6.3 Forecast drivers

Past loads can be explained by temperature, population and changes in air conditioning penetration. During the 1990s and early 2000s, for example, there was a warming trend in degree days and population growth reached a range of 2.5% - 4% annually. Most homes built to meet new housing demand included central air conditioning, while existing homes did not. The combination of warmer temperatures, relatively high population growth and increased penetration of central air conditioning led to high load growth. Since then, temperatures have moderated and population growth (with commensurate air conditioning installations) has slowed.

These factors combined with increased energy conservation practices have resulted in minimal load growth. Figures 6-1 and 6-2 show historical growth patterns for annual energy and peak demand.

In addition to these drivers, future loads are expected to be significantly impacted by the growth of distributed solar and EVs, which were estimated outside of the load forecasting model and added to the aggregate load. Logistic growth curves were used to estimate the capacity of distributed solar installations on the system and the number of EVs in Platte River's service territory.

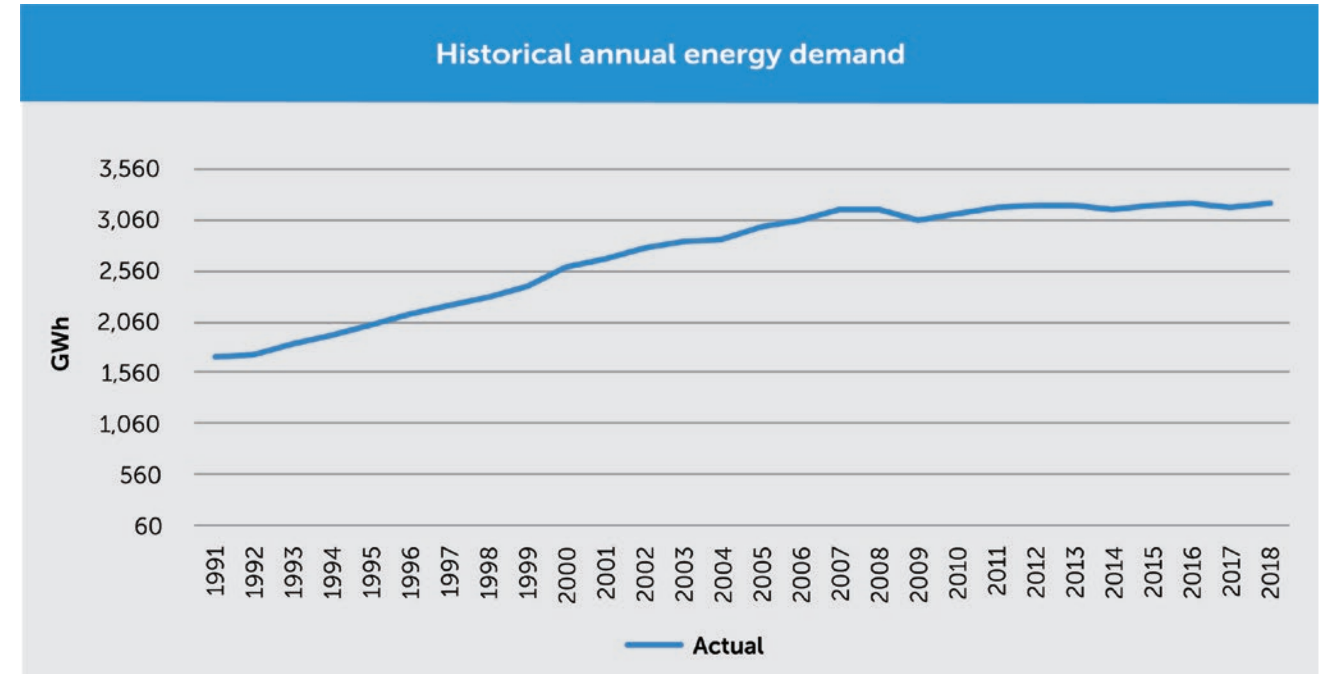


Figure 6-1

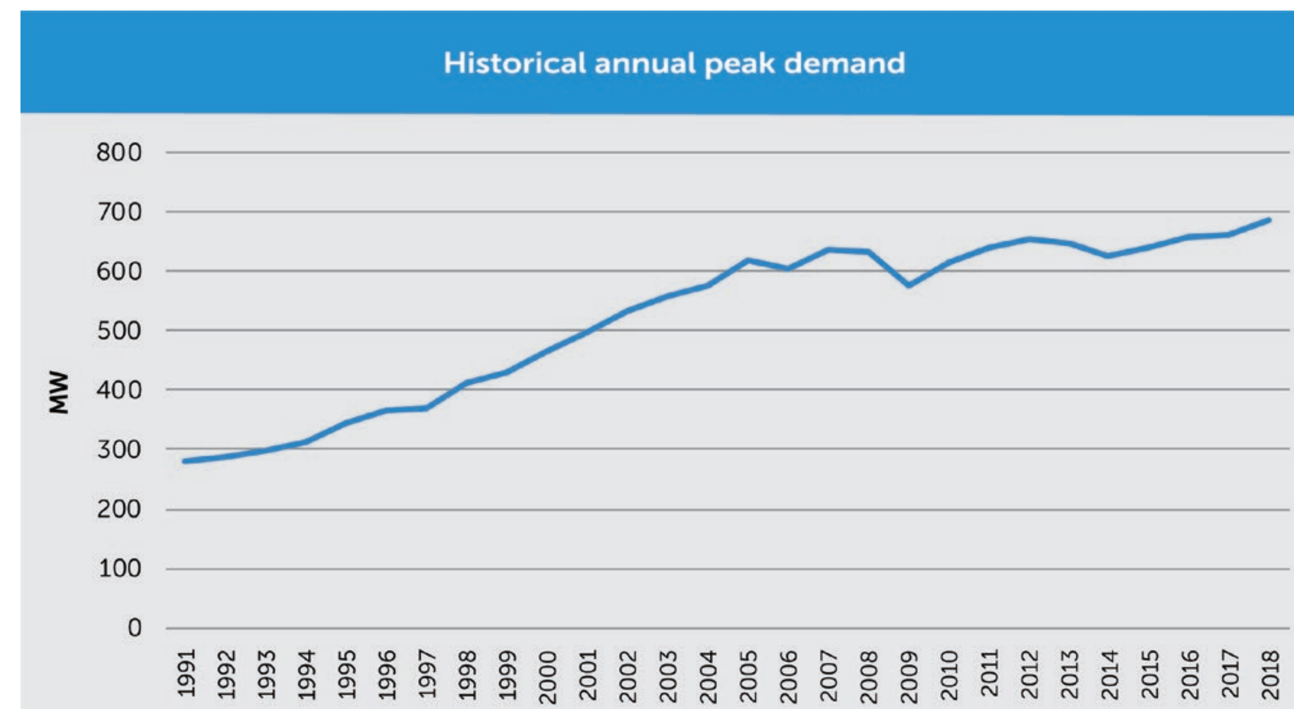


Figure 6-2

6.3.1 Degree days

As noted above, temperature influences energy demand and overall consumption, particularly during summer months when customers rely on air conditioning to maintain indoor comfort. Platte River's forecasting model uses total degree days per month[5] with no distinction made between cooling degree days and heating degree days. A negative value is associated with a heating degree day and a positive value is associated with a cooling degree day. The resulting sinusoidal curve enables a forecast providing nearly identical information to the separate measurement of heating degree days and cooling degree days but does so in one measure, thus reducing overall model complexity.

A trend and seasonal pattern are evident in historical degree day data beginning in the early 1980s. A simple linear regression was used to model the trend and seasonal pattern as well as to generate a forecast of degree days that is incorporated into the load forecasts. See Figure 6-3.

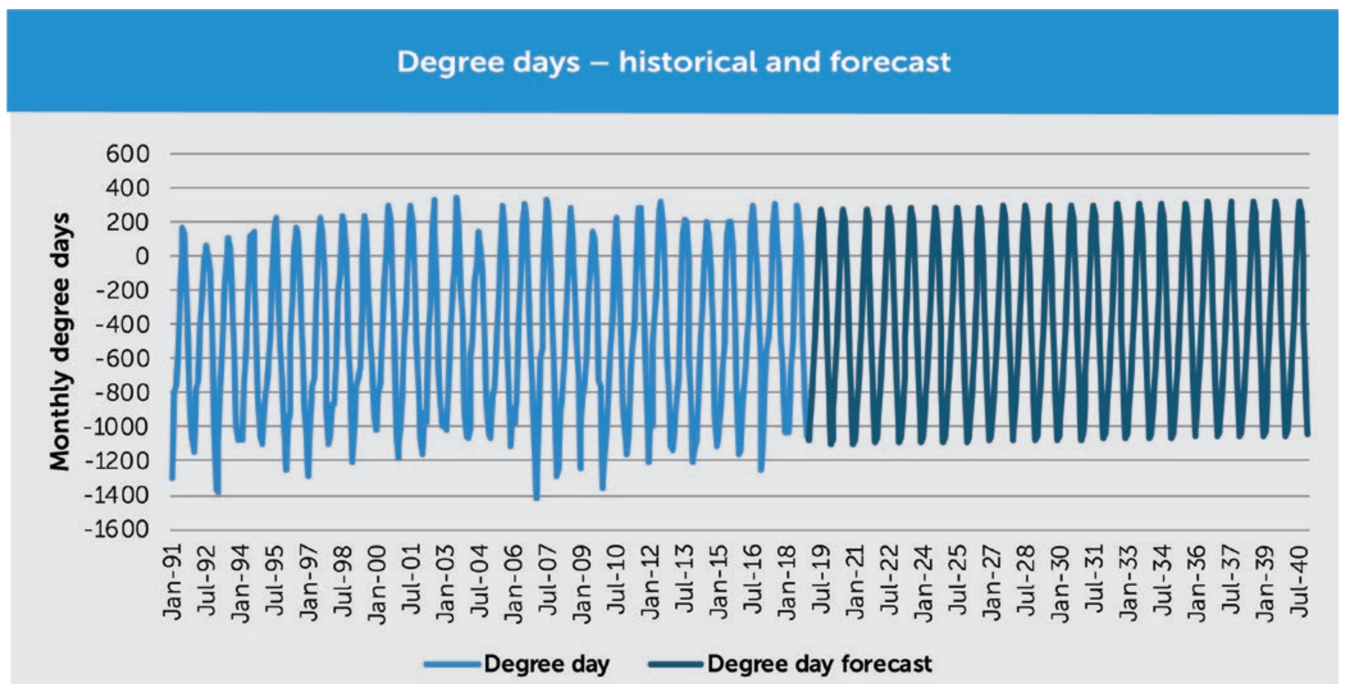


Figure 6-3

[5] Total degree days per month is calculated as the sum of (max temp + min temp)/2 – 65 for each day over a month. Thus, positive values reflect cooling degree days and negative values reflect heating degree days.

6.3.2 Population

Population growth is a key driver for load forecast. Data from the Colorado Department of Local Affairs demography office[6] shows population growth rates before the early 2000s were, on average, higher than growth rates after. The state demographer's office forecasts a declining rate of growth for the Fort Collins (FC) metropolitan statistical area (MSA) which covers the northeastern Colorado area and includes major load centers within Platte River service territory. Reduced land availability for northern Front Range development is one driver for the declining growth as shown in Figure 6-4. As a result, the increase in electricity demand attributable to new growth will likely decline in the future.

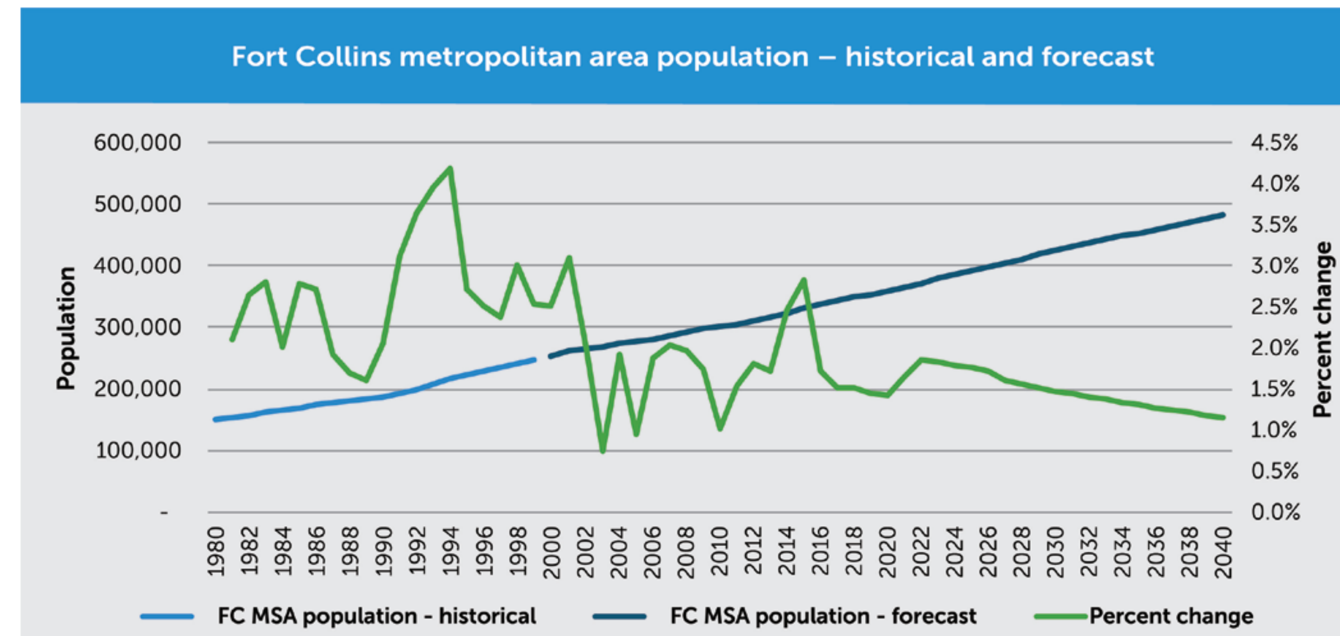


Figure 6-4

[6] https://demography.dola.colorado.gov/population/

6.3.3 Single-family homes, window to central air conditioning conversion

The annual penetration rates of central air conditioning (AC) in the single-family housing stock measures changes in how electricity is used by customers to cool their homes as well as other changes in the housing stock and the overall economic activity in the region. For example, the rate of AC penetration growth was higher before the financial crisis in 2008 than afterward, reflecting the growth in new single-family homes with central AC. After the financial crisis, the penetration growth rate slowed due to a shift away from new single-family housing construction to multifamily housing. Based on Larimer and Boulder County property records, approximately 25% of single-family homes had central AC units in 1980 compared to approximately 50% in 2018. This structural change has altered Platte River's demand dynamics from a winter peaking to summer peaking system.

The penetration rates for central AC flatten out from 2007 through 2010, reflecting a slowdown in the construction of new homes due to the national recession that occurred during this time. After 2010, penetration rates began to grow again but at a slower rate. The rate change stemmed from a change in the composition of new housing stock, with multi-family housing comprising a larger portion of new units.

Platte River estimated future penetration rates using a logistic curve, adjusted to match the growth seen in recent years, and assuming a maximum penetration rate of 85% because costs for installing AC in some older housing stock may be prohibitive. Due to this factor, the projection calls for single-family AC penetration rates to continue rising but at lower levels on a year-over-year basis as shown in Figure 6-5. This projection, in turn, reduces Platte River's load growth forecasts.

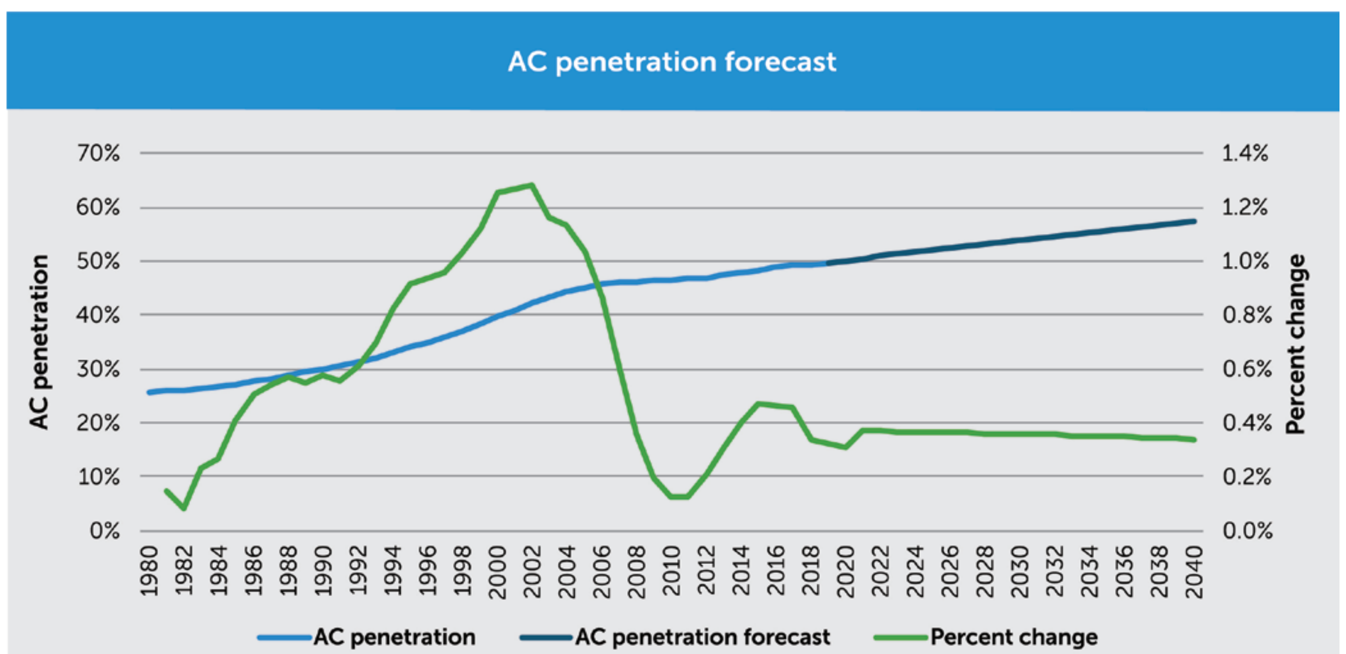


Figure 6-5

6.3.4 Distributed solar

A hosting capacity study performed by Fort Collins was used in developing an upper limit of 100 MW of distributed solar for Platte River's service territory without requiring additional investment in the distribution system. Staff used a logistic curve to develop a growth pattern from the historical actual level to the forecasted upper limit by 2030. Based on these assumptions, year-over-year growth in distributed solar capacity will likely increase until 2025 followed by a lower growth rate until the system reaches its hosting capacity in the early 2030s. The near-term high growth in distributed solar will partially offset new demand from population growth and contribute to lower growth in Platte River's wholesale energy sales to its owner communities. The projected growth of distributed solar is shown in Figure 6-6.

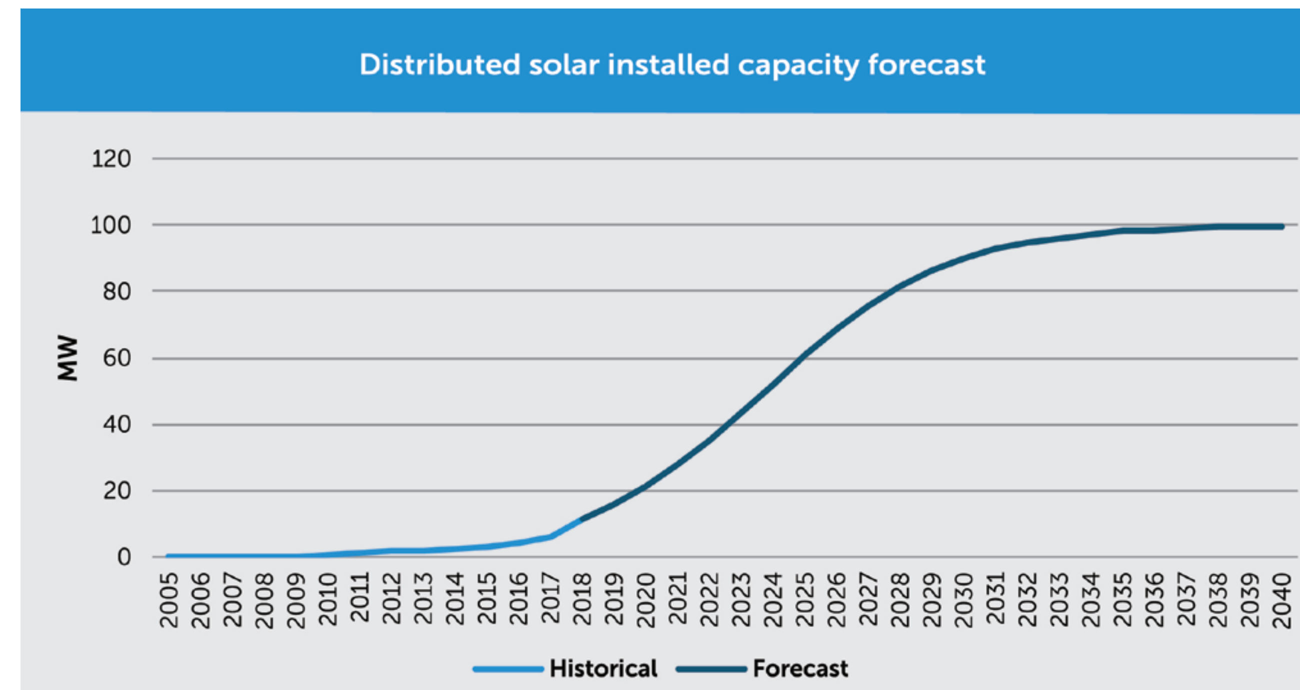


Figure 6-6

6.3.5 EVs

The penetration of EVs within the transportation sector will increase in northern Colorado, with energy consumption from charging influencing the Platte River system. A study conducted by BCS Inc. for the Colorado Energy Office[7] provided three forecasts for EV stock through the year 2030: low, medium and high growth scenarios. Platte River's projections used the medium scenario as it is consistent with observed data. Figure 6-7 shows a forecast of total number of EVs in our service area. By 2040, Platte River projects EV charging will reach approximately 10% of overall annual energy consumption as shown in Figure 6-8.

It is assumed that a very small fraction of the total EVs charge at the time of peak, therefore, the peak demand increase due to EVs is small as shown in Figure 6-9.

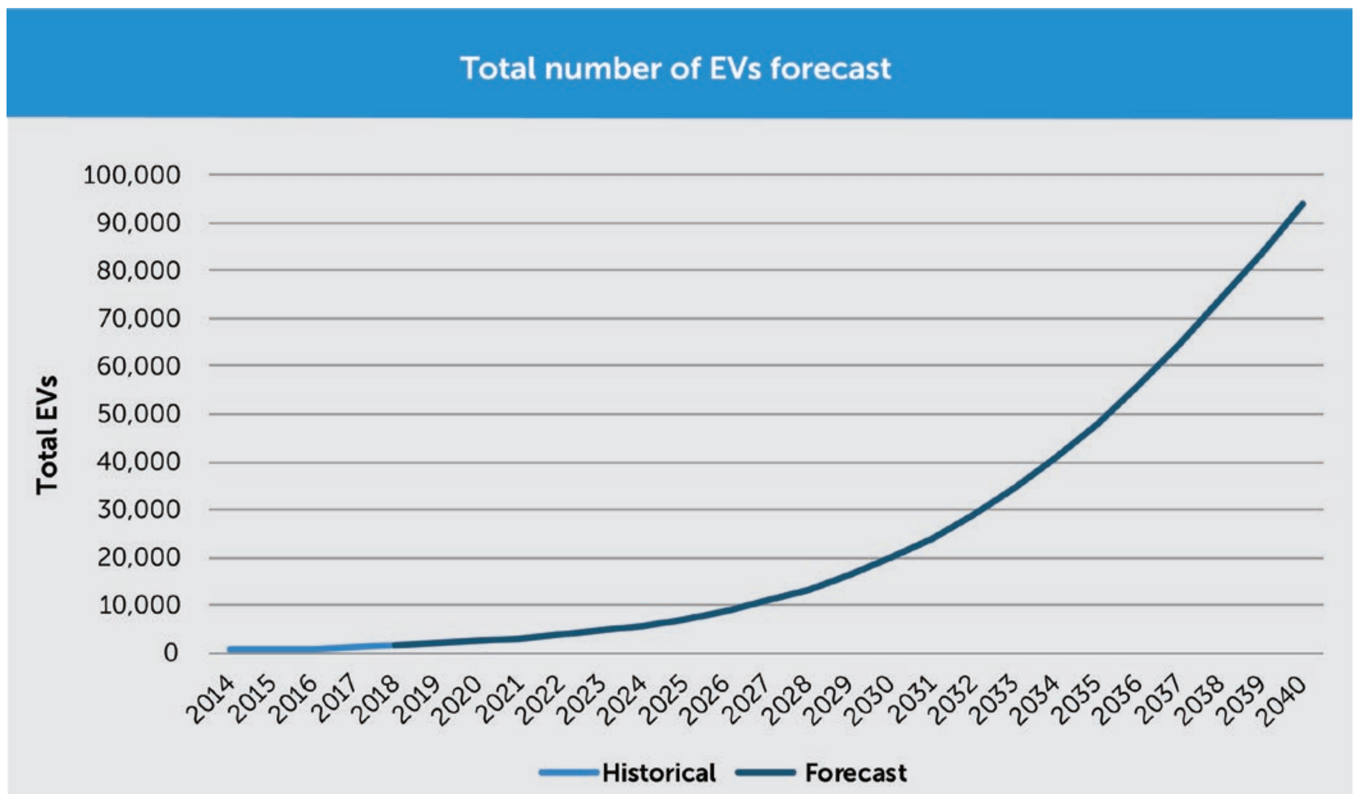


Figure 6-7

[7] https://www.colorado.gov/pacific/sites/default/files/atoms/files/EV%20Market%20Study%202015_0.pdf

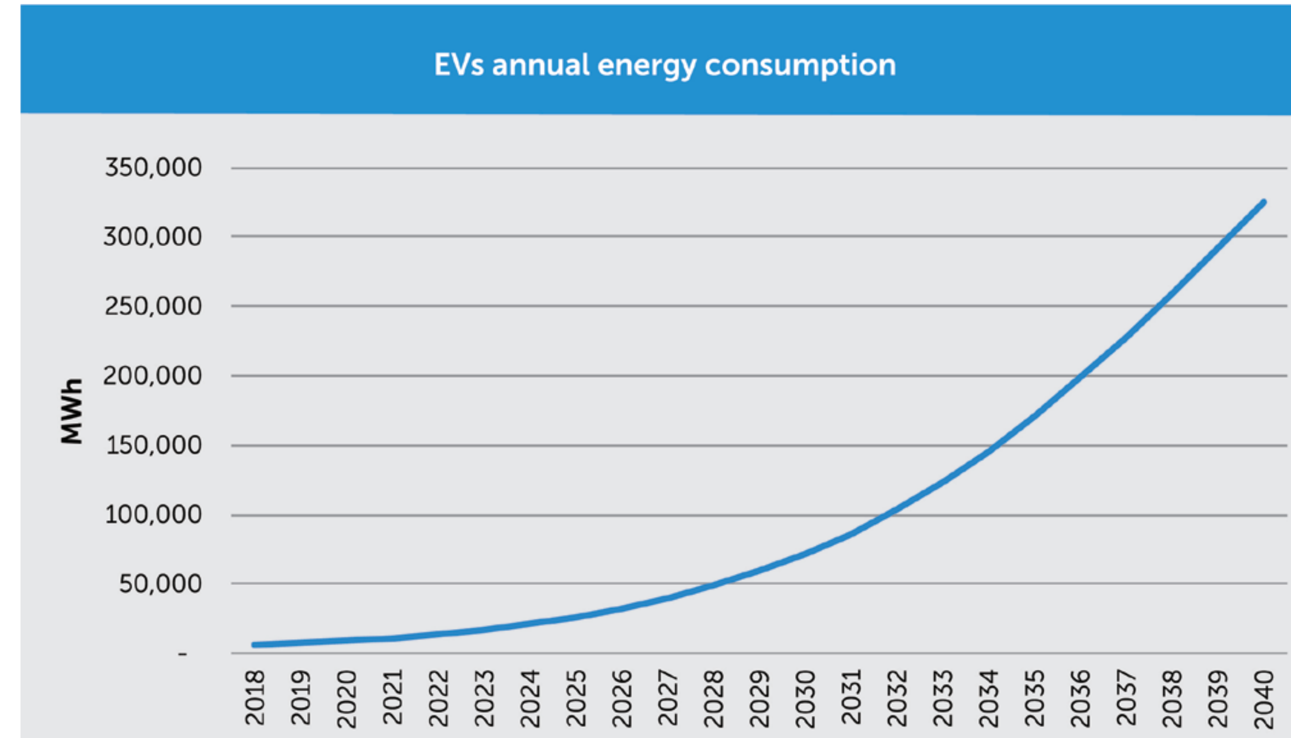


Figure 6-8

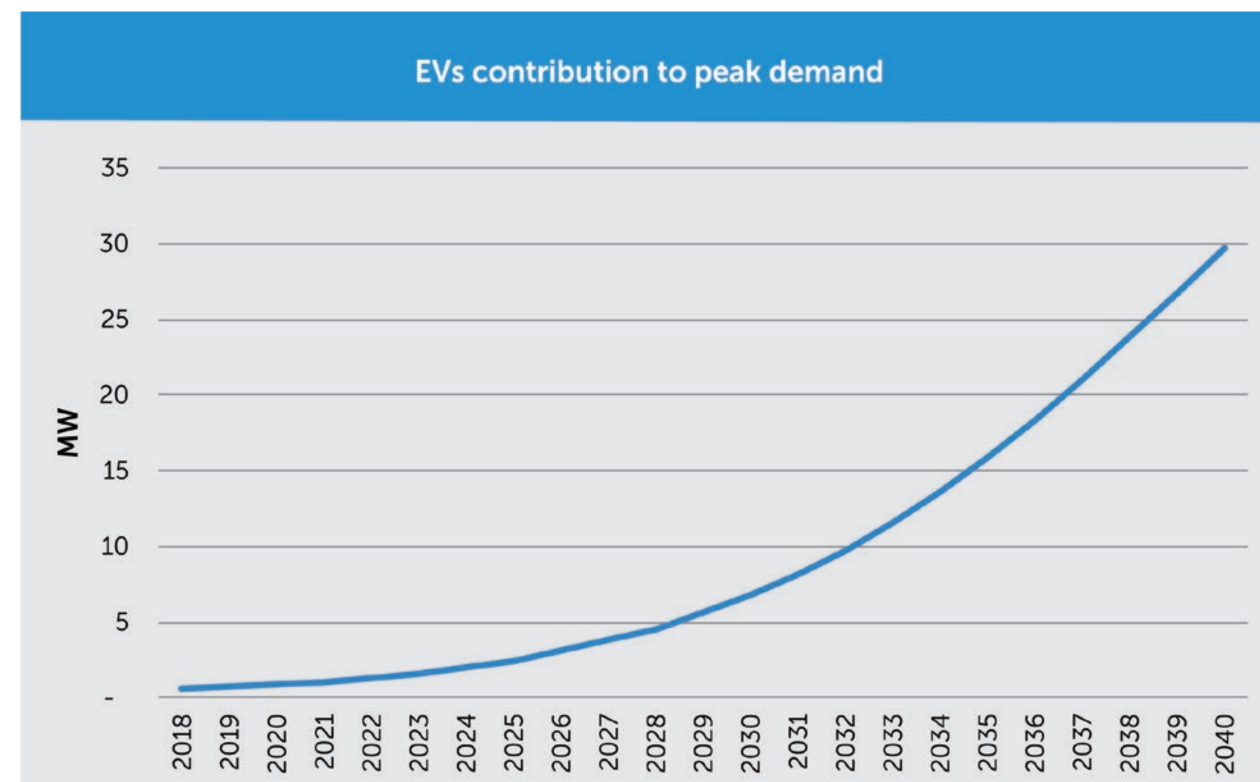


Figure 6-9

6.4 Energy efficiency/conservation trend

The forecasting model includes a trend to capture improvements in energy efficiency and conservation. For more than 10 years, annual residential energy use in Fort Collins, Longmont and Loveland trended downward, like the nationwide trend. Figure 6-10 shows annual average household energy consumption for the U.S. and three of Platte River's owner communities (no independent data available for Estes Park). Reasons for this decline include; technology improvements, regulatory changes and updated building code.

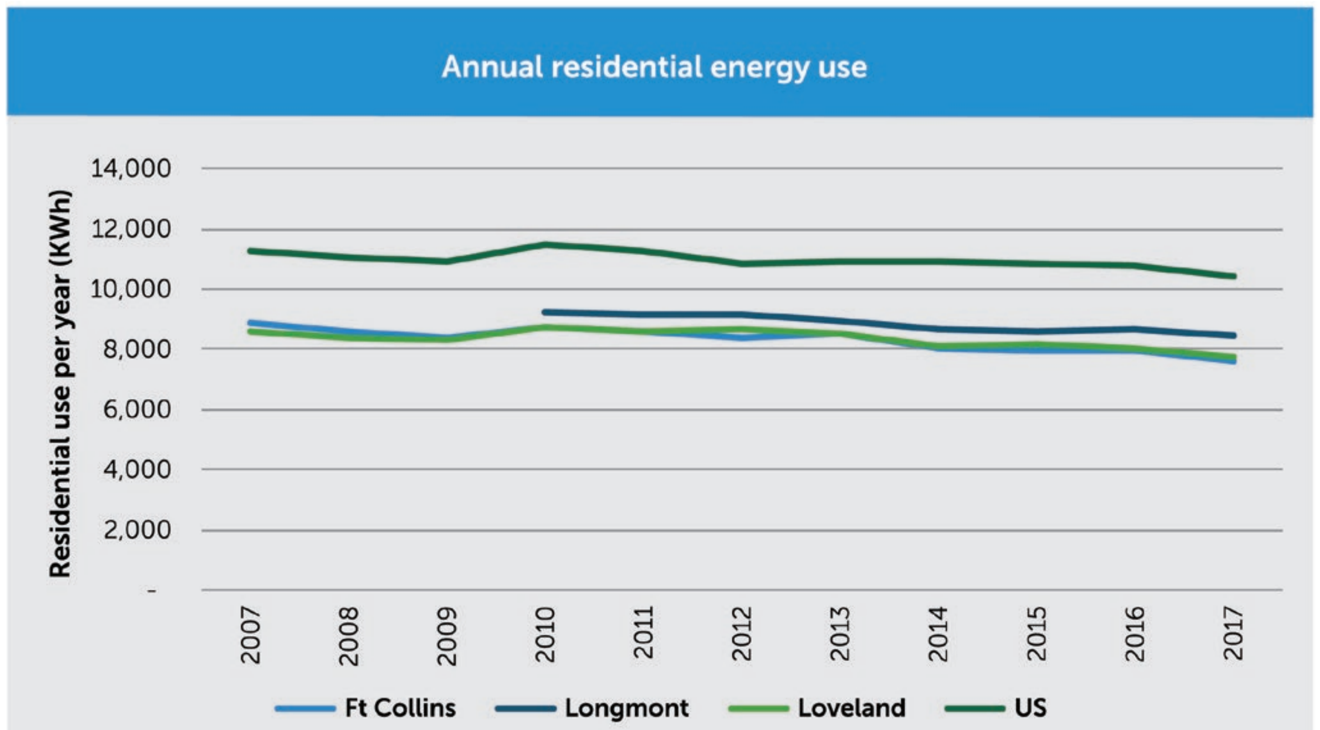


Figure 6-10

6.5 Load forecast

Platte River developed load forecasts with 70% and 90% confidence intervals to show the possible range of future growth. The confidence intervals only include a general forecasting error and do not include changes in forecast drivers, such as high or low EV penetration rates. The annual energy forecast with upper and lower confidence intervals is shown in Figure 6-11.

The annual peak demand forecast with 70% and 90% confidence intervals is shown in Figure 6-12.

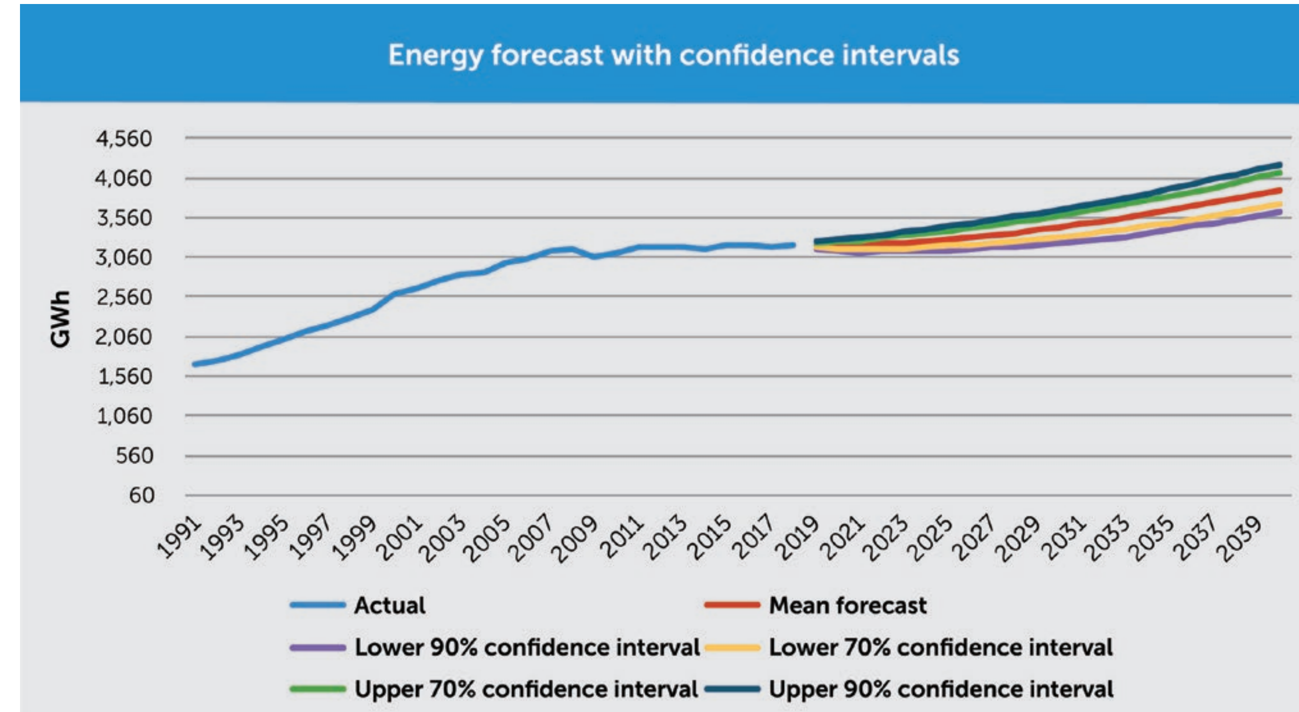


Figure 6-11

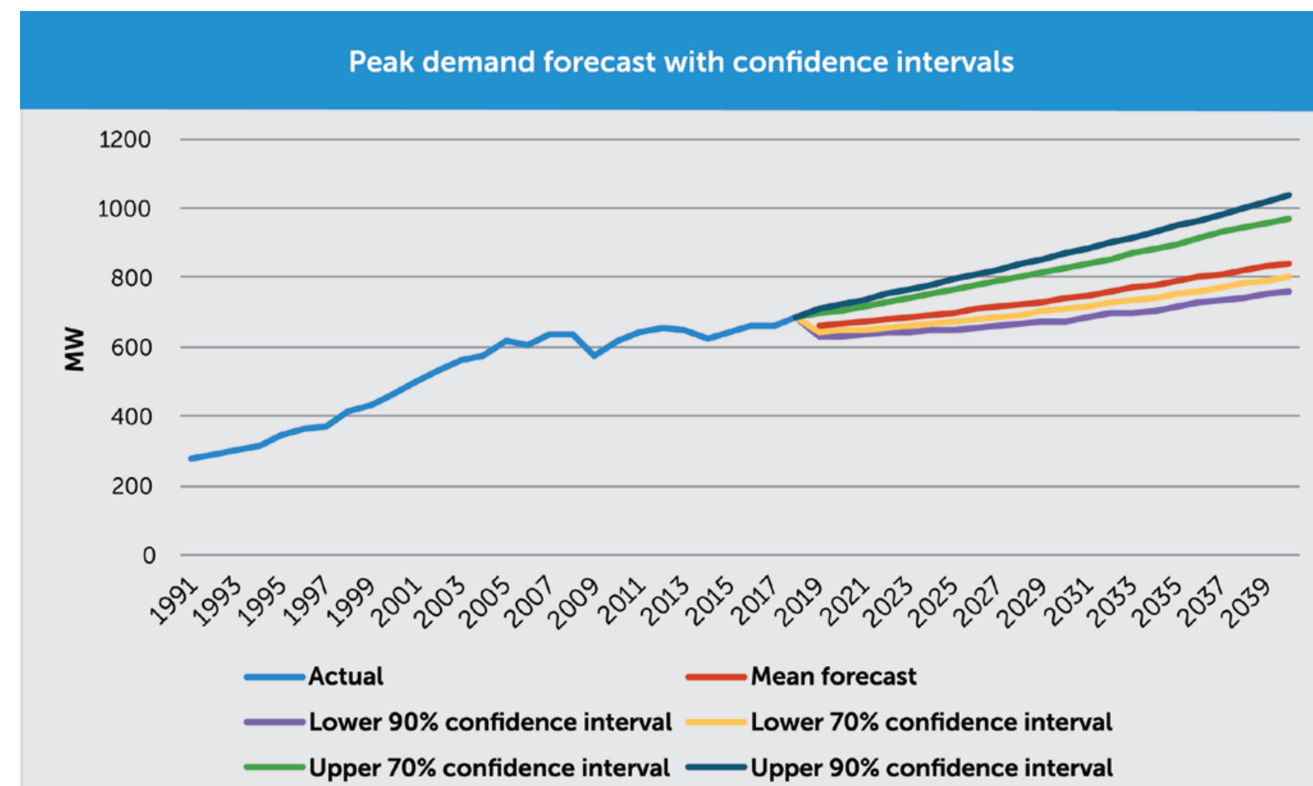


Figure 6-12

6.6 DERs

Historically, electric utilities defined "demand-side management" products and programs to include energy efficiency and demand response programs. However, this term is no longer adequate to describe the range of options and approaches available to utilities and their customers. Utilities increasingly define these approaches as DERs, which include any technologies, programs or resources implemented on the distribution system or within a customer's premise, whether in front of or behind the retail meter. This includes energy efficiency, demand response, distributed generation, distributed solar, distributed energy storage and beneficial electrification.

Platte River seeks to integrate DER options or programs into its portfolio when they support Platte River's three pillars. Elements of DER that influence current load forecasting are discussed above but a more detailed discussion of existing and future DER programs is provided below.

6.7 Existing DER programs and activities

Platte River closely collaborates with its owner communities to evaluate, design and implement DER programs. This collaboration is important for three reasons:

1. DERs are located within the owner communities' distribution systems or within their customers' facilities
2. Potential benefits are shared between Platte River and the owner communities' electric systems
3. Implementation of DER programs often benefit from the economies of scale that come from collaboration among the owner communities

In addition to the collaborative initiatives described here, owner communities offer DER programs independently from Platte River based on their individually determined values, policies or goals. Those programs are not included in Platte River's resource portfolio but are included to the extent they affect Platte River's current load and future load forecast. Platte River and its owner communities have made significant investments in energy efficiency programs and will pursue other resources as technologies evolve, as customer interest in these technologies increase and as the electric system needs change. A brief discussion of existing DERs follows below.

6.7.1 Energy efficiency

Energy efficiency programs focus on helping customers reduce their energy consumption through a variety of interventions including outreach, education and incentives. Platte River and the owner communities deliver a growing portfolio of energy efficiency programs offered under the Efficiency Works 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.

Since 2002, Platte River and its owner communities have invested nearly $70 million in energy efficiency programs, serving thousands of residential and commercial customers by providing efficiency assessments, efficiency advice and rebates for efficiency improvements. In addition to these investments, customers have invested approximately $100 million to implement efficiency improvement measures. Figure 6-13 shows historical investments in energy efficiency programs while Figures 6-14 and 6-15 show associated energy and peak demand savings since 2002. Over this time, energy efficiency programs have achieved annual energy and demand savings of 251,000 MWh and 39.1 MW, respectively. Staff have assumed a finite lifetime for savings from the programs and retire the savings when the estimated lifetime is exceeded. As a result, these programs are currently estimated to have reduced Platte River's load by 206,000 MWh in annual energy consumption and 31.9 MW of demand. Investment in efficiency resources are cost effective compared to the cost of supply-side resources otherwise needed.

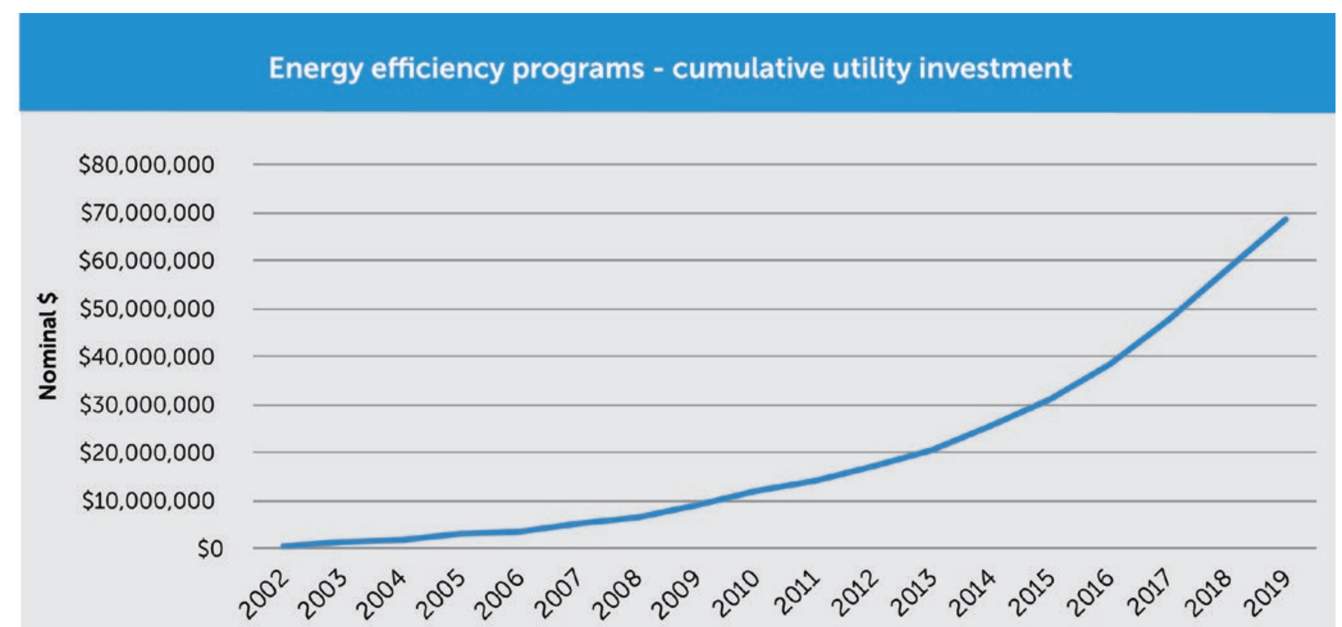


Figure 6-13

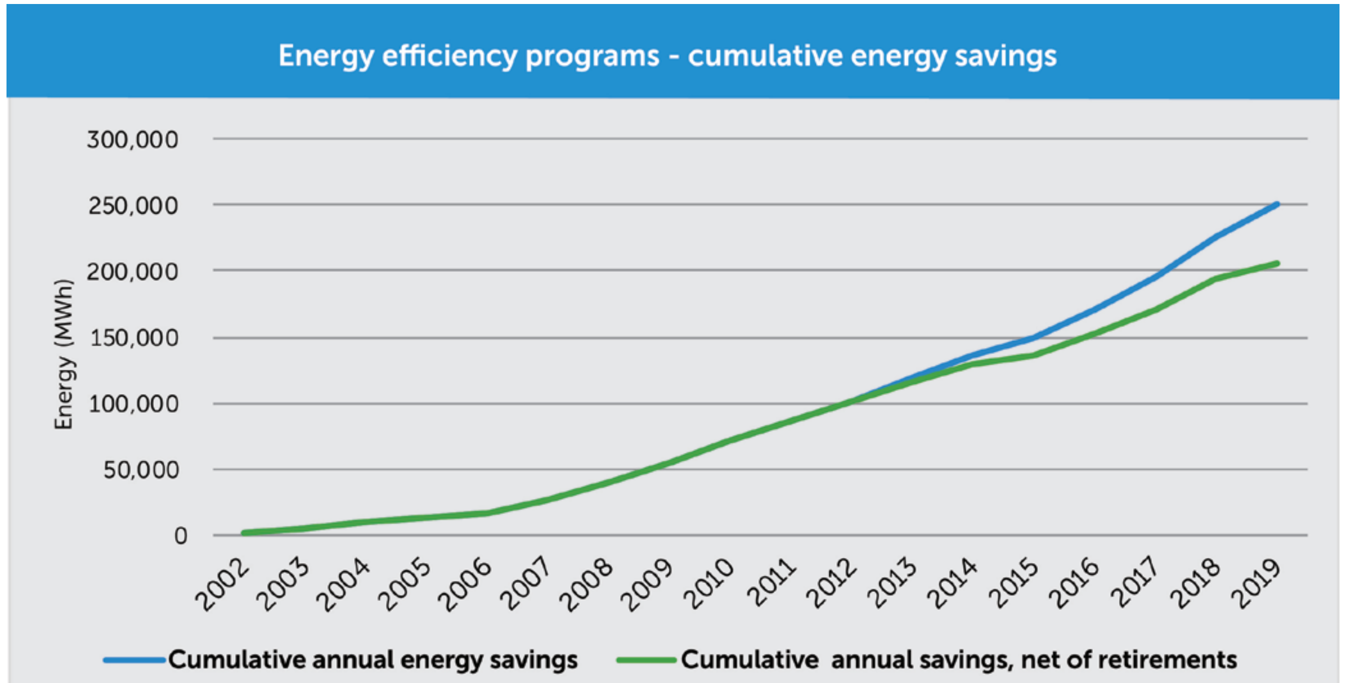


Figure 6-14

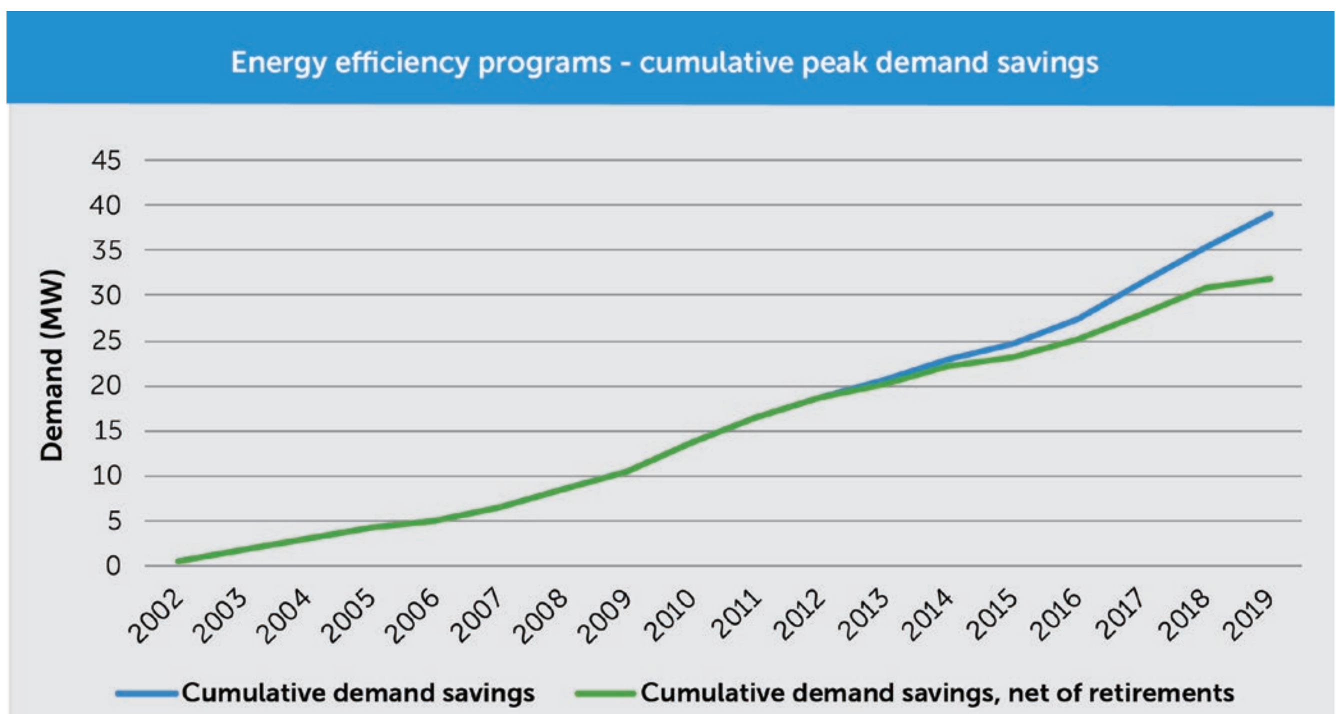


Figure 6-15

6.7.2 Demand response

Demand response programs incentivize customers to shift energy use from times of high demand or high cost to the periods of low demand or low cost. Benefits of demand response programs accrue from their ability to delay or eliminate the need for new generating capacity, transmission capacity or distribution investments. The success of energy efficiency programs in reducing overall energy consumption, combined with the availability of ample generation and transmission capacity, have reduced the economic benefit for demand response programs[8]. However, some owner communities have initiated rate-based demand response programs to reduce financial impacts from Platte River's wholesale rates, which employ both an "energy" and "demand" component.

For example, Fort Collins Utilities adopted time-of-day rates for all residential customers starting in 2018. This rate structure provides customers with an off-peak energy rate most hours and a higher on-peak energy rate four to five hours each weekday. The on-peak period brackets peak load hours that typically set Fort Collins' wholesale peak demand charges from Platte River. This rate is intended to promote conservation and load shifting from on-peak to off-peak times. In addition, Platte River and the owner communities have initiated a demand response pilot program in which Platte River can operate demand response assets controlled by Fort Collins Utilities and Longmont Power & Communications. Currently, this pilot provides approximately 3 MW of summer peak capacity savings, available for a few hours on peak demand days. This program enables Platte River to test communication and control system integration and to evaluate demand response program performance. The lessons learned from these performance evaluations will be used in future demand response program design. The existing voltage reduction program with the City of Longmont and thermostat program with the City of Fort Collins will be an important part of this and may be expanded in the future for managing loads during summertime peaks.

6.7.3 Distributed generation

Distributed generation programs are primarily run by the owner communities. Staff are modeling these programs due to their growing impact on net demand to be served by Platte River. Growth of distributed generation within the communities is driven primarily by the individual customers' adoption of (rooftop) solar generation to reduce their purchases of electricity. By the end of 2019, distributed solar within Platte River's owner communities totaled an estimated 19.7 MW (alternating-current basis), with 48% coming from residential net-metered solar, 9% commercial net-metered solar, and 43% owned or purchased directly by the owner communities. Figure 6-16 shows the growth of distributed solar capacity on Platte River's system.

[8] Demand response programs are not avoiding imminent investment in capacity expansion.

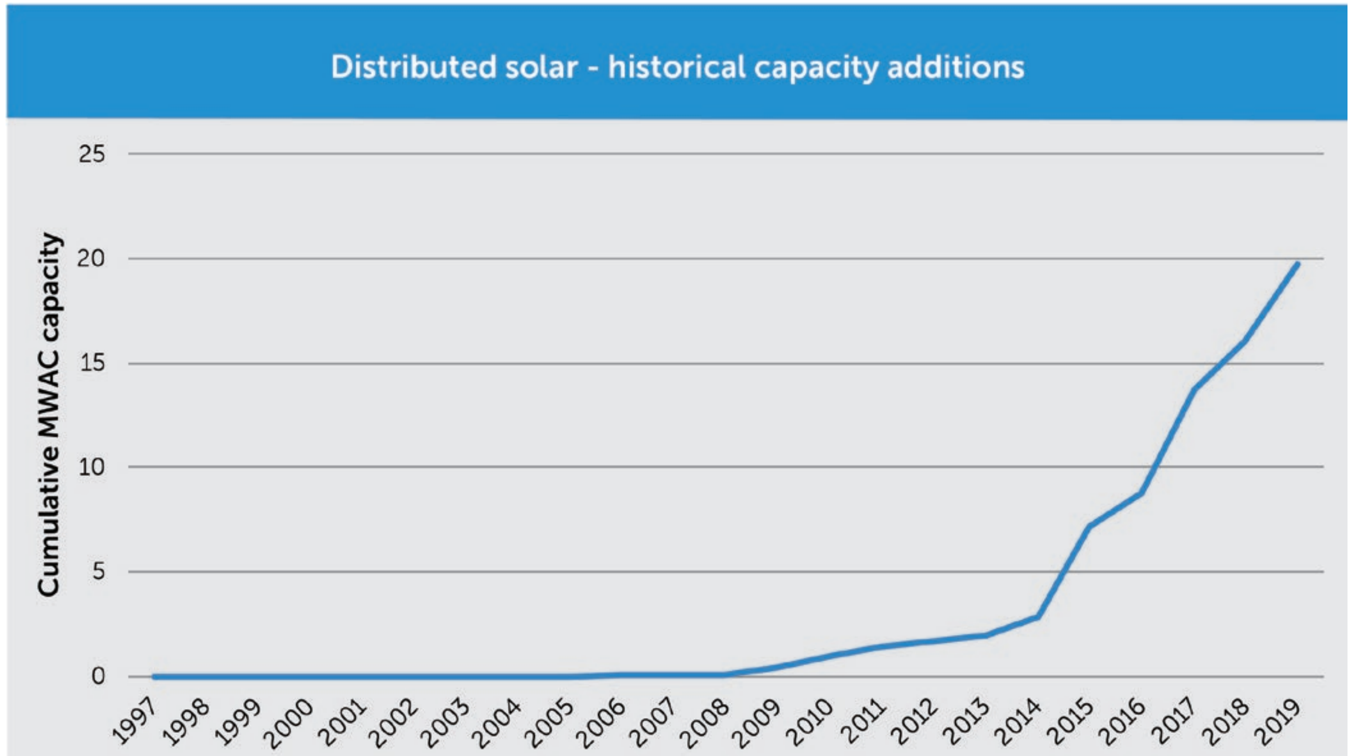


Figure 6-16

Distributed solar expansion stems from various incentives available and customer desire to reduce carbon emissions from electrical generation, notwithstanding its higher price. Responses to a recent request for proposal received by Platte River revealed that small scale distributed solar was more than twice the cost of utility-scale solar. While distributed solar capacity may continue to grow due to various incentives, customer preferences and specific locational advantages, its cost will likely continue to remain higher relative to the utility-scale solar due to economies of scale.

6.7.4 Beneficial electrification

Beneficial electrification refers to new uses for electricity that replace other sources of energy while also providing economic benefits, grid benefits and environmental benefits. As Platte River's owner communities pursue carbon emission reduction, beneficial electrification will become an attractive alternative. If load growth from beneficial electrification can be integrated flexibly and augmented with demand response capabilities, they may become a demand element complementary to (increased) supplies of intermittent renewable energy generation.

Electrification of the transportation sector, for example, is perhaps one of the most significant opportunities for beneficial electrification. EVs can help reduce overall emissions in communities where they replace conventional gasoline-powered vehicles. EVs can also provide flexibility to grid operations if properly integrated into the system, by leveraging intelligent charging to help add more renewables to the grid. Intelligent EVs may be connected to the real-time grid operation and programmed to prefer charging during hours with excess renewable energy availability. Platte River estimates EV energy consumption may exceed 70 GWh per year by 2030 and 300 GWh by 2040. To better understand charging patterns and future charging demand, Platte River has recently launched a smart charging pilot program for residential customers. Customers that enroll in this service are eligible to receive a $200 rebate on qualifying smart charging equipment. More than 100 EV customers have enrolled in this pilot and a program for managing these EV loads on the grid is currently under development.

6.7.5 Distributed energy storage

Distributed energy storage refers to batteries and other energy storage technologies connected to the distribution grid or at the customer's premises. As of the end of 2019, the communities had a total distributed storage capacity of 0.26 MW. Customers mostly use battery storage to reduce their peak demand and as a backup supply. Platte River is installing a 65 kWh battery at its headquarters building in Fort Collins. The purpose of this installation is to test control and operational optimization methodologies to reduce peak demand as a commercial customer. Battery control and operating strategies will become critical as technology improves, costs fall and the need to complement growing intermittent renewable generation rises.

6.7.6 Software for DER integration

Software architecture development will become critical for the integration of expanding DERs. Presently, Platte River is updating existing systems for this purpose but will eventually require a DER management system. This system will be designed, implemented and operated in close coordination with the owner communities to maximize the benefits of DER technologies. This architecture will enable power system operators to efficiently interface with multiple DERs when monitoring and balancing supply and demand on the grid. The initial goal for this system will be to provide a price signal or schedule to the various distributed resources connected with the owner communities' distribution networks. This system will allow customers to minimize their costs while simultaneously providing system operators capabilities and controls to reduce overall system costs while maintaining a high level of reliability.

6.8 Future DER programs

Platte River continues investigating the long-term potential of DERs along with collaborative implementation and integration strategies, engaging the services of HDR, Inc. to conduct a DER potential study for this IRP. In parallel, Platte River embarked on a DER strategic planning process, in collaboration with the owner communities (discussed in Section 6.9).

The DER potential study determined how DERs can support Platte River's development of a diversified resource mix. It estimated how much is achievable at a lower total cost relative to the cost of utility scale supply-side resources. The study also considered the rate at which distributed resources may be adopted over time and the utility incentives and administration costs required to achieve it. In addition, the study assessed how distributed resources will affect Platte River's hourly and annual loads.

The following sections provide an overview of the DER potential study process and results, as well as how the study results were incorporated into the IRP modeling. The study categorized results into three major areas: (1) energy efficiency, (2) demand response and (3) distributed generation. Long-term potential of these three categories is also discussed below.

6.8.1 Energy efficiency potential

HDR evaluated more than 50 common energy efficiency measures, ranging from more efficient lighting to advanced controls and retro commissioning, across multiple facility types, to estimate the technical, economic and achievable potential for energy efficiency (see appendix C for details). Technical potential is the energy and demand savings that would result if all energy efficiency measures were implemented without considering cost or other market barriers. Economic potential is the savings that would occur if all energy efficiency measures implemented have a cost that is less than the supply-side costs (including a carbon tax), were they implemented, regardless of market barriers. Finally, achievable potential is the portion of economic potential that can be achieved due to utility program interventions intended to help overcome market barriers. These interventions include marketing, education, energy advising and financial incentives or rebates.

HDR developed a detailed model to determine the cost-benefit analysis of various energy efficiency measures and their evolution over time. The results of this analysis estimated the achievable energy and demand savings for each hour of the year. In addition, it estimated costs to achieve the energy savings, comprising Platte River's costs for incentives and administration, as well as customer costs. The model also projects how these savings will grow over the years, with a portion of the energy efficiency savings assumed to be retired at end-of-life if the energy efficiency measures are not renewed.

Platte River used HDR's energy efficiency potential results to develop a forecast of energy efficiency potential and energy efficiency costs for the IRP model, starting from Platte River's existing energy efficiency program results and costs. This was important because it will take time to transition from existing program performance toward performance anticipated by the energy efficiency potential study.

All the energy efficiency measures were categorized into three portfolio options corresponding to three estimates of avoided supply-side costs:

- **Low energy efficiency potential:** The avoided cost assumptions for this case reflect how new resources are added only on an as needed or economical basis. The avoided capacity cost for energy efficiency was based on capacity cost of an aeroderivative gas turbine and avoided energy costs were based on forecasted market prices for electricity.
- **Medium energy efficiency potential:** Avoided costs for this case reflect anticipated costs of renewable resources. For this case, the avoided capacity cost for energy efficiency was based on batteries and avoided energy costs were based on a combination of delivered wind and solar energy costs.
- **High energy efficiency potential:** Avoided costs for this case were also chosen to reflect high-renewable portfolios, but with increased battery storage capacity.

The results indicate cumulative energy savings potential through 2030 of 340,000 MWh for the low energy efficiency case to 460,000 MWh for the high energy efficiency case. The cumulative investment ranges from $153 million to $253 million through 2030. Figures 6-17 and 6-18 show the growth in energy savings for the three energy efficiency cases and the annual utility cost for these programs.

For the low energy efficiency potential case, more energy efficiency becomes cost effective after 2030 as avoided supply-side costs rise. This drives greater energy efficiency potential and greater investment. For the medium energy efficiency potential and high energy efficiency potential cases, this potential is realized in early years, driving higher results and investments before 2030. However, after 2030, there is less cost-effective potential.

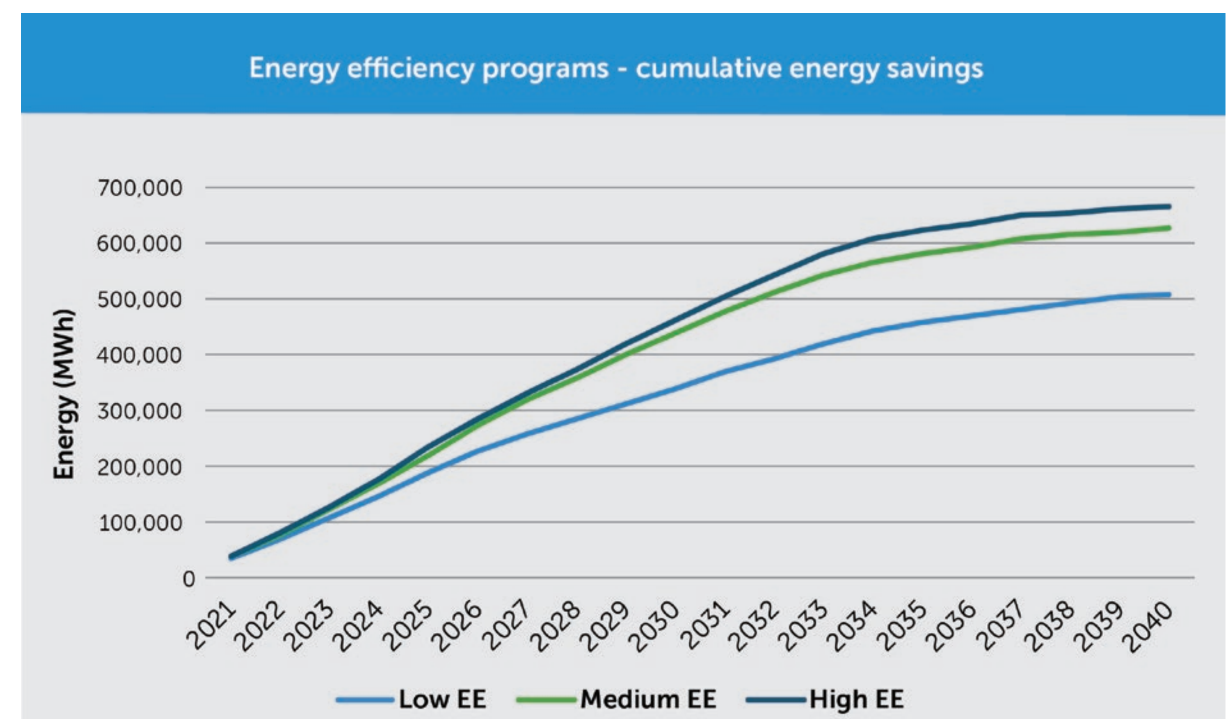


Figure 6-17

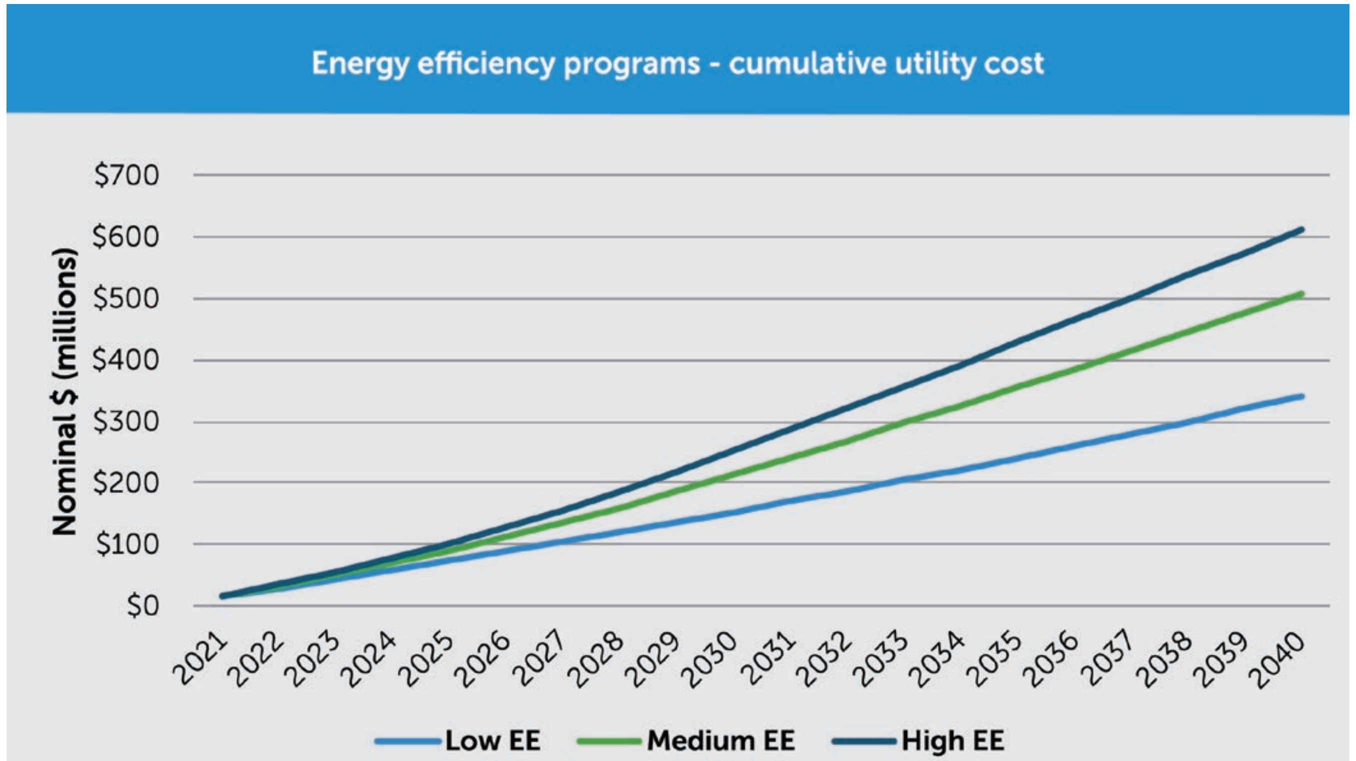


Figure 6-18

6.8.2 Demand response potential

HDR provided three levels of demand response potential based on the same avoided supply-side cost scenarios as described in the energy efficiency section. HDR evaluated traditional demand response technologies, including distribution voltage reduction and direct load control for common building loads like air conditioning and lighting. In addition, HDR evaluated EV charging and control of distributed batteries located in homes and businesses.

The figures 6-19 and 6-20 show the achievable demand response potential and utility cost for incentives and administration of demand response programs for the three cases. For the low demand response case, HDR found that distribution voltage reduction, direct-load-control of commercial and industrial air conditioners and interruption of select industrial processes provided achievable potential. These programs could achieve 5 MW of demand response potential by 2030 at a cumulative cost of just over $3 million. The medium demand response cases added control of residential heating, ventilation and air conditioning (HVAC) and electric water heaters as well as increased industrial process demand response potential. The result is a total of 19 MW by 2030 at a cumulative cost of $16 million. The high case includes increased penetration of HVAC control, resulting in a total of 38 MW at a cumulative cost of $34 million.

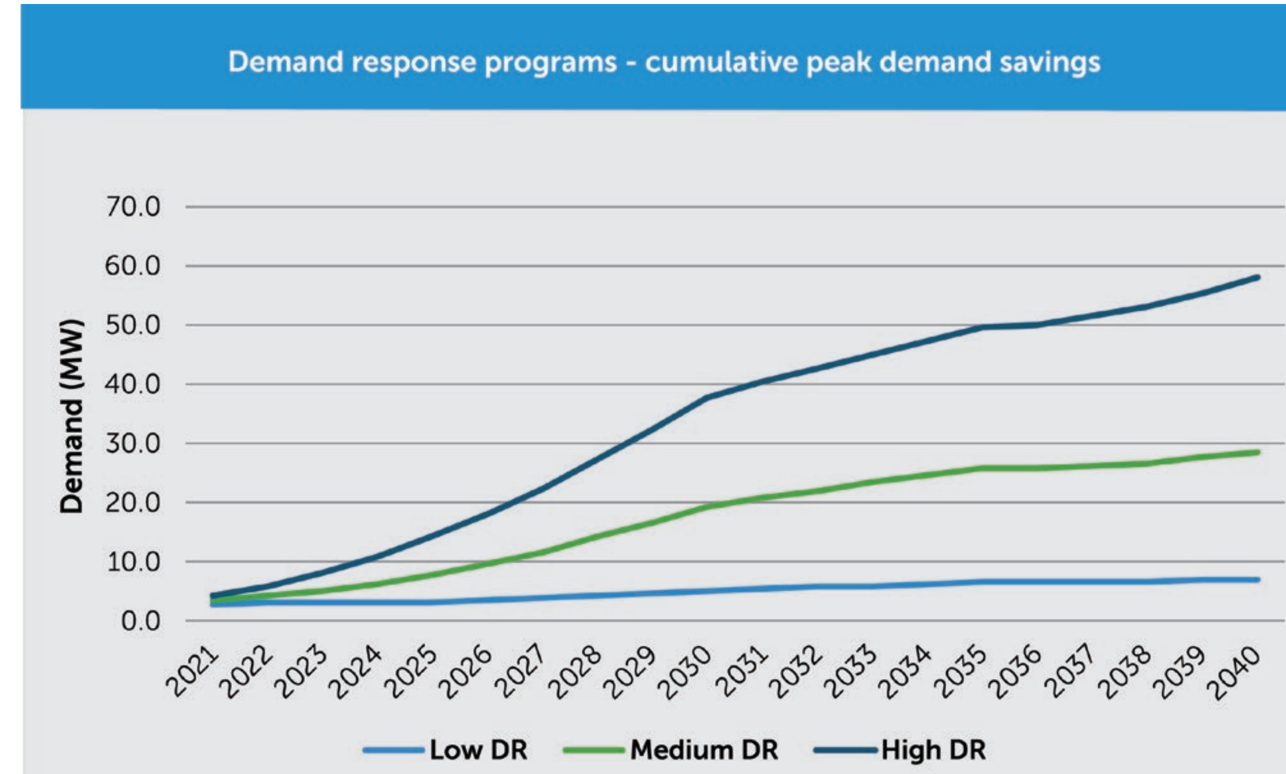


Figure 6-19

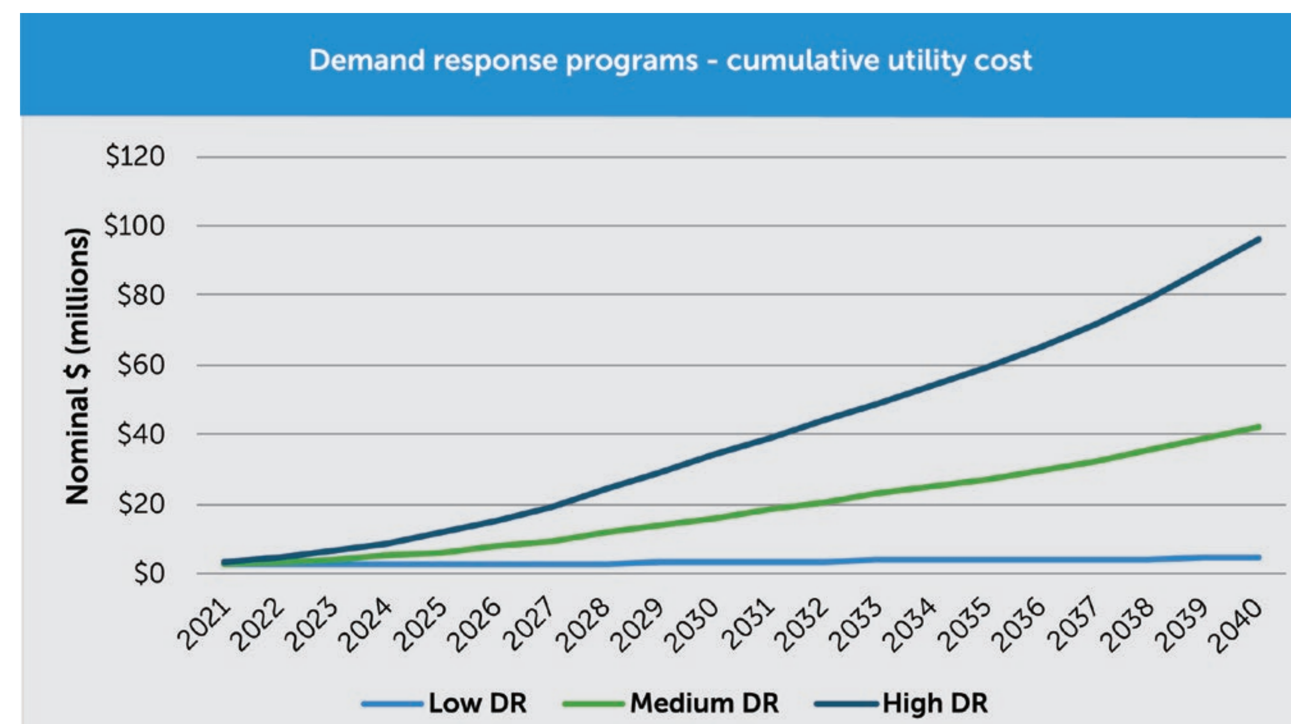


Figure 6-20

Note that some demand response technologies and program models were not evaluated as part of this demand response potential study. For example, it did not include an evaluation of retail time-of-use or real-time pricing rate structures. Such pricing structures may provide economic incentives to customers to shift use from high-cost to low-cost times. This may be facilitated by enabling technologies that can automate shifting of electric use for selected electric appliances or other equipment. However, effective use of these rate structures and technologies will require alignment and coordination of system operational needs as well as alignment and coordination of wholesale and retail rate structures. This work is part of the DER strategic planning process described in Section 6.9.

6.9 DER strategy

Continued growth in DERs will require a more coordinated approach between Platte River and its owner communities to expand and integrate them in a reliable and financially sustainable manner. Platte River and its owner communities recently initiated a DER strategic planning process. While Platte River has made significant investments in energy efficiency programs, other forms of distributed resources, such as demand response, distributed generation, distributed energy storage and beneficial electrification are expected to grow in prominence. These forms of DERs have the potential to provide significant benefits to Platte River's customers and the electric system but only when challenges are met concerning:

- Ability to determine and evaluate in a coordinated fashion wholesale utility, retail utility and customer benefits and costs associated with DERs;
- Development of wholesale and retail rate structures that appropriately reflect and allocate the costs and benefits of DER investments;
- Development of policies and standards to maximize DER reliability, flexibility and predictability; and
- Ability to meet customers' interests and expectations for DERs.

Through the DER strategic planning process, Platte River and its owner communities intend to address these issues and collaborate to develop a common vision, objectives and initiatives. In addition, the team will collaborate with stakeholders and the public to develop a common framework for evaluating DER initiatives and business models.

The DER strategic planning process will continue through mid- to late-2021 and will have significant bearing on the potential that Platte River and its owner communities can achieve in a reliable and financially sustainable manner. Therefore, the results from the DER potential study discussed earlier should be considered a draft, with conclusion to follow completion of the DER strategic plan. Once the strategic plan is completed, Platte River and its owner communities will determine whether a new forecast of long-term DER potential is warranted within the next IRP cycle.

7 IRP supply-side assumptions

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

7.1 Inflation and discount rate

Staff used a 2% inflation and general escalation factor when estimating costs for potential new generating capacity. Fixed operation and maintenance costs for power generation facilities were escalated at 3.5%, which aligns with cost increases incurred for Platte River's current thermal generation fleet. In the future, two drivers will place fixed operating costs higher than the rate of inflation: shifting operational paradigms and resulting maintenance. Assets are aging and their usage will shift from baseload or peaking roles to a balancing role in which they follow intermittent, renewable generation. In addition, an escalation rate of 3% was used for the social cost of carbon.

Along with escalators noted above, staff used a discount rate of 5% for net present value calculations, which are in line with Platte River's long-term cost of capital. Present values are presented in 2020 dollars.

7.2 Regional import/export limits

Platte River transacts with three neighboring utilities – Black Hills Energy, Colorado Springs Utilities and Xcel Energy – through the JDA and on a bilateral basis. Outside of the JDA, Platte River may work with other utilities to buy and sell energy on a bilateral basis.

For IRP modeling, analysts assumed purchases or sales up to 200 MW in any hour, which is approximately 50% of Platte River's anticipated 2030 average hourly demand. The 200 MW transaction limit ensures market transaction volume remains realistic. For modeling purposes, total annual volume of imported energy was limited to not only mitigate risks associated with the market purchase of large quantities of low-cost power but also to better calculate carbon emissions (or lack thereof) from generating resources. To balance the opportunity to purchase low-cost energy without becoming overly reliant on outside generators, market purchases were unrestricted for the first five years when Platte River would have more price forecast certainty and then gradually reduced to only 5% of its annual energy needs in 2030 and later. No limit was placed on energy exports to maximize benefits to the owner communities through economic sales from Platte River's generation assets.

7.3 JDA modeling

As mentioned in Section 3.4, the JDA acts like a small-scale hourly energy imbalance market. As a participant in the JDA, Platte River can buy and sell power from its utility partners within the hour, following re-dispatches. These real-time transactions are separate from the bilateral market described in Section 7.2 and are modeled in Aurora as a unique resource. The quantity and pricing of JDA energy depends on the real-time imbalance of economic energy among the local participants, so it is difficult to forecast from a fundamental model in the same manner as the price forecast prepared by Siemens. Instead, pricing and volumes were forecasted based on historical data. Hourly historical data for both prices and volumes were reviewed with an emphasis on the most recent data. For each month, a typical week was developed that gave the model a maximum volume of energy and the expected price for every hour of the week. Based on those inputs the model can choose to buy energy to replace native generation. Since JDA energy re-dispatches units (replaces more expensive generation with lower cost energy), constraints are set to ensure JDA purchases only offset existing generation and cannot be used as additional energy. JDA sales were modeled in a similar manner. The only restriction on sales was the total hourly volume, which was designed to ensure future JDA sales volumes roughly align with historical results.

7.4 Commodity price projections

Commodity price projections are a key input to resource planning. Platte River engaged Siemens Energy Business Advisory (previously Pace Advisory or Siemens) to provide regional natural gas, power and CO_2 cost projections.

Coal prices were projected by Platte River based on unique coal supply plans for its coal fired generation fleet. Following subsections discuss these commodity price projections in more detail.

7.4.1 Natural gas prices

Siemens provided a monthly natural gas price forecast for the Colorado Interstate Gas (CIG) trading hub, extending through the planning horizon. In addition, Siemens also supplied a low gas price and a high gas price forecast to show a band of uncertainty around the base forecast. The high- and low-price projections reflect changes to the underlying fundamentals of the gas market such as production volumes, export volumes or changes in consumption. All three gas price projections are shown in Figure 7-1.

In addition to the above gas commodity prices, Platte River also pays a transportation charge to pipeline owners for natural gas delivered across their pipelines. This was priced at the actual value of $0.87/MBtu for 2020, rising at the rate of inflation.

For new gas fired power plants, two additional gas-related cost components were also included in the analysis. The first covers the construction of an additional pipeline spur needed to serve new generating resources and the second covers the cost of firm gas capacity reservation on interstate pipelines to ensure delivery during critical times. Those costs are discussed further in the supply-side resources section.

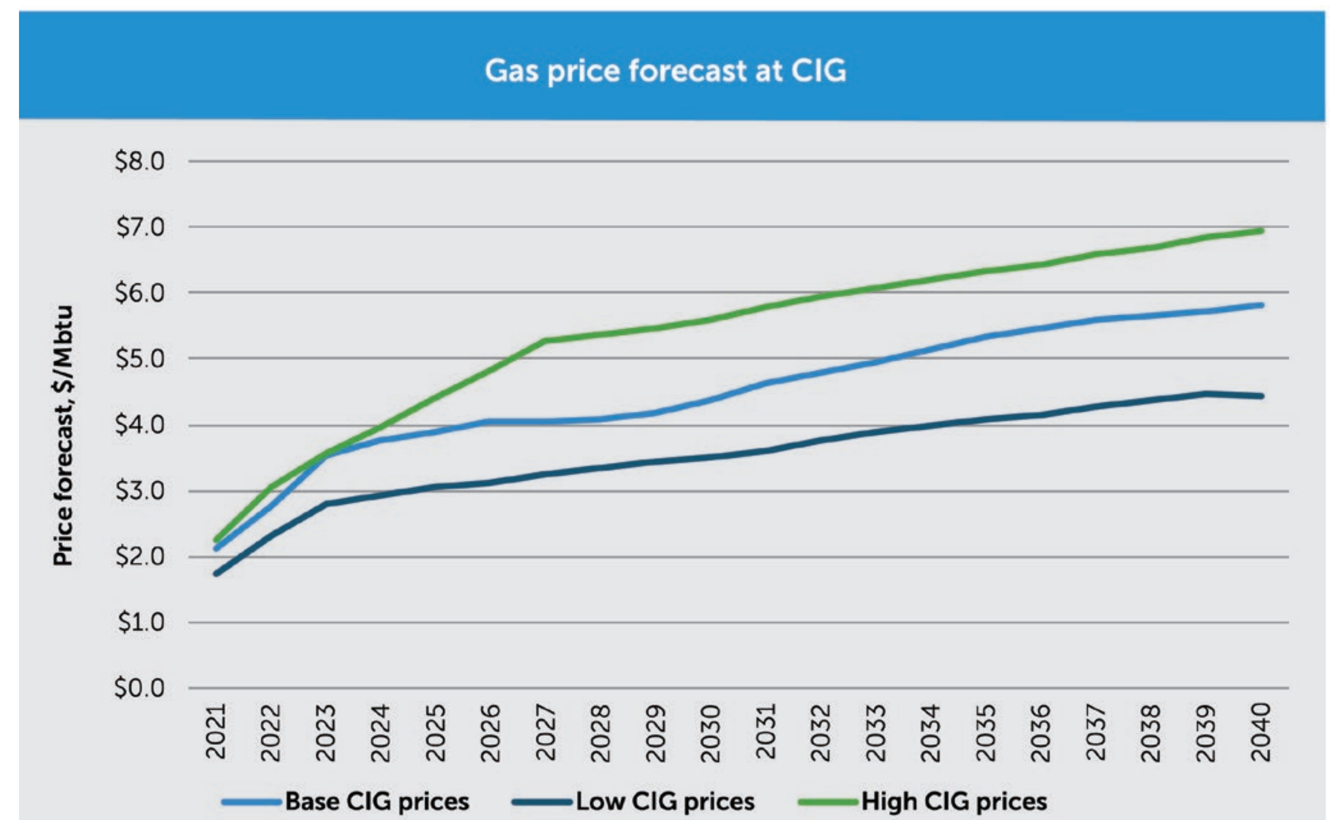


Figure 7-1

7.4.2 Regional power prices

Regional power prices impact the four portfolios discussed in this IRP because they allow for the purchase and sale of energy on an economic basis. During portfolio simulations, the Platte River system was allowed to buy power when the regional market price is lower than Platte River's marginal cost to produce electricity and allowed Platte River to sell excess power when the market prices are higher than its marginal cost. Margins from these transactions reduce the overall cost to Platte River's owner communities.

As Platte River's system and the regional electric grid evolve to integrate larger amounts of renewables, the linkage between power prices and renewable energy generation becomes more important. With more renewable resources on the regional grid, renewable energy becomes an even bigger driver of power prices. Siemens predicts that sunny on-peak hours, currently the highest-cost hours, will eventually become lowest-cost hours as solar energy saturates the region. This trend is clearly visible in Figure 7-2 which shows power price forecast in the Platte River area.

In the past, price forecasts were provided as monthly on-peak/off-peak values which were then used to produce an hourly price shape. For the 2020 IRP, Siemens provided an hourly price forecast and the renewable energy patterns used in their price forecasting models, which helped ensure consistent relationships between the price of intermittent wind and solar energy production levels. Because Siemens supplied the natural gas and emission prices forecasts, the ecosystem of assumptions was appropriately correlated down to an hourly level to ensure internal consistency among various projections.

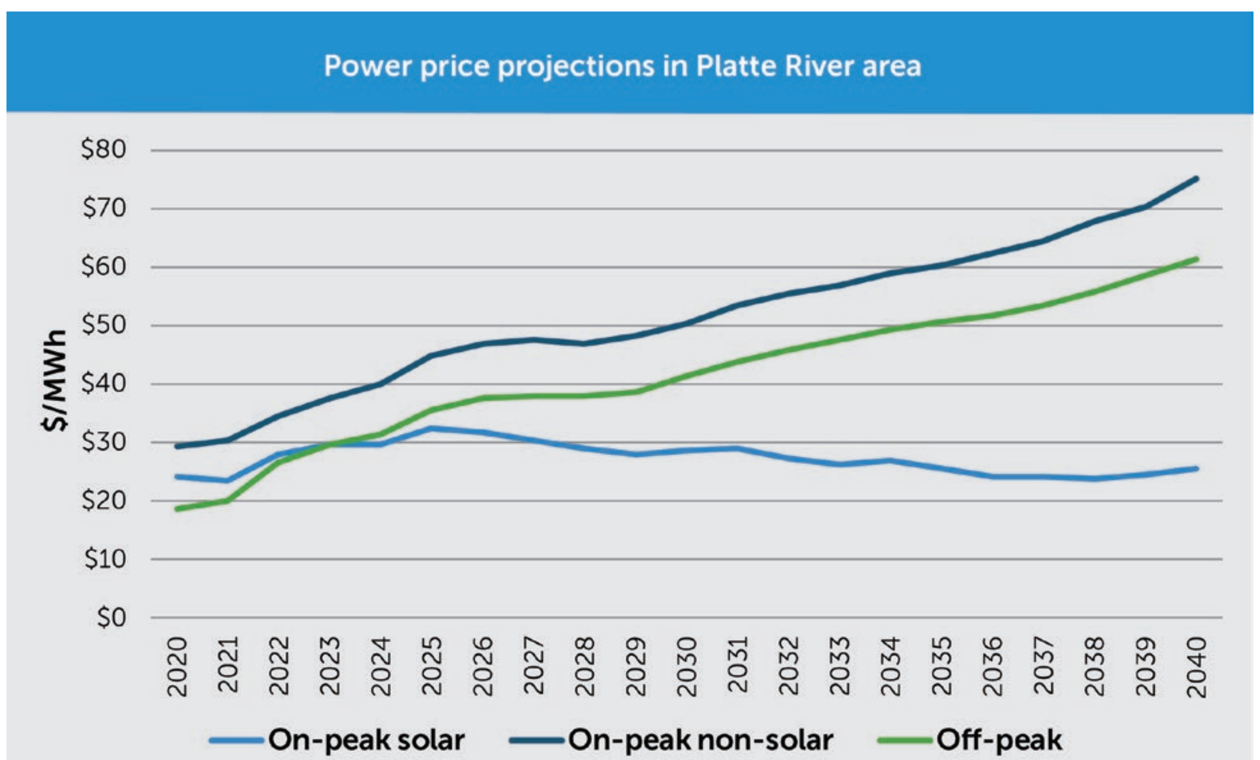


Figure 7-2

7.4.3 Coal prices

Each coal plant in Platte River's portfolio operates with a unique coal supply arrangement, so price forecasts for the two Craig coal units and Rawhide Unit 1 were developed separately. Rawhide receives coal from the Powder River Basin and its price forecast is largely based on broader market prices. Near-term prices reflect existing contracts and prices that have been locked in with the supplier(s) and near-term coal market assessments and indices. As locked-in quantities and/or the quantities with prices tied to market indices decrease over time, the remaining coal is priced at Siemens's forecast for Powder River Basin coal. By 2024 the price forecast is based entirely on the forecasted commodity price from Siemens. The commodity price is adjusted to reflect mine-specific pricing and additional costs Platte River pays for required dust suppressants. Transportation expenses, based on the current projections, are also added to forecast delivered coal price.

The overall Craig coal price forecast is based on price forecasts provided by the Trapper Mine, which is adjacent to the Craig plant. Platte River has a partial ownership interest in Trapper Mine and coal costs are determined on a "cash cost" basis, with no transportation costs incurred. Figure 7-3 illustrates the delivered coal prices for Platte River coal plants.

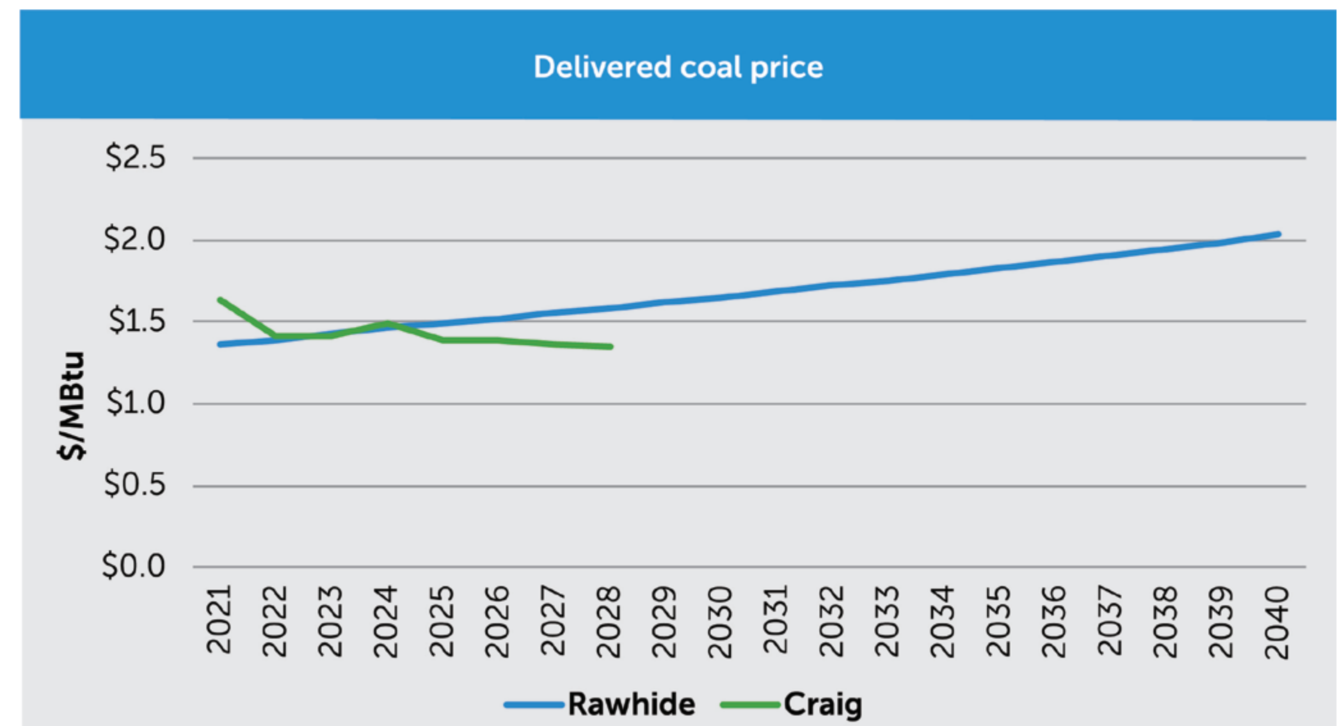


Figure 7-3

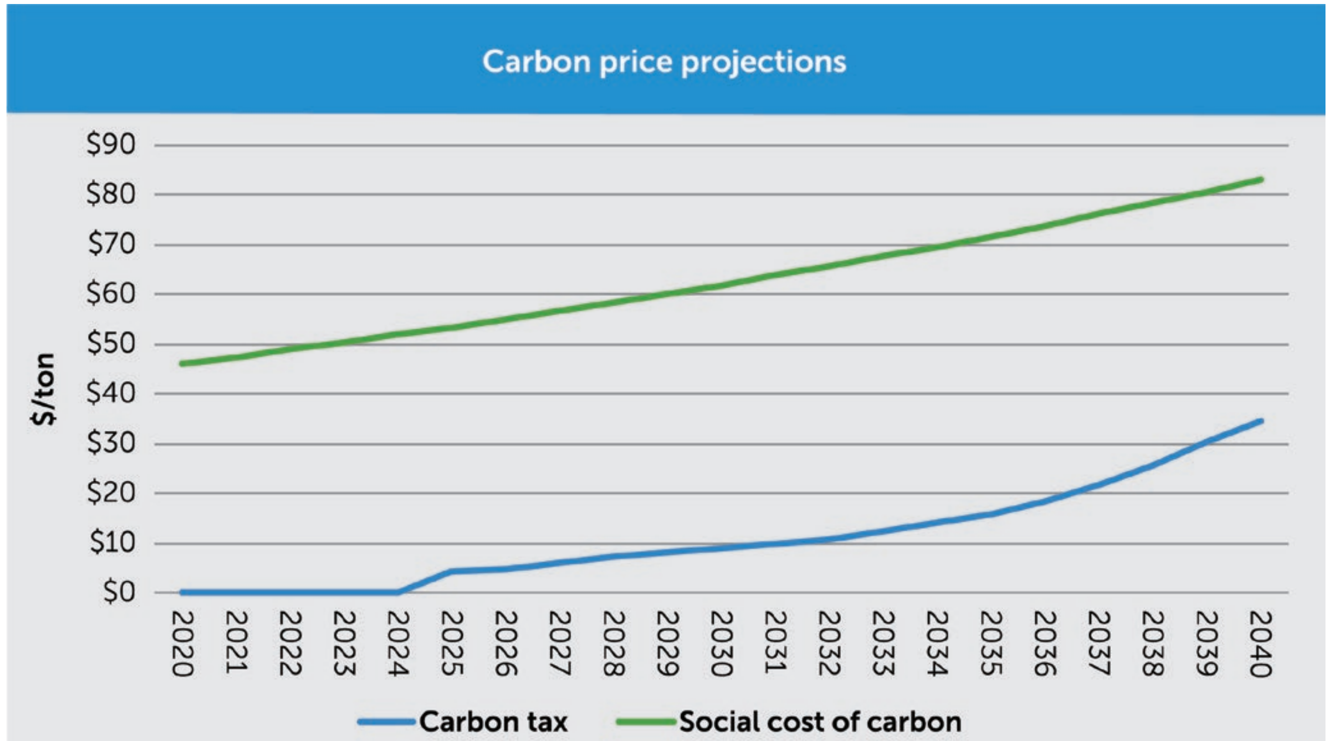


Figure 7-4

7.4.4 Carbon prices

Siemens supplied a carbon price (tax) forecast based on its expectations concerning public policy discussions and potential legislation, as shown in Figure 7-4. Platte River also evaluated portfolio outcomes using the social cost of carbon in the sensitivity studies. Unlike a carbon tax, which disincentivizes carbon emissions, a social cost simulates total direct and indirect costs to the society that would otherwise be externalized and quantifies potential inter-generational cost shifts. The specific costs used were based on language in Colorado Senate Bill 19-236, which references the 2016 report produced by the Interagency Working Group in Social Cost of Greenhouse Gases.

7.5 Supply-side generation resources

This section contains a discussion of all power generation resources considered by Platte River to meet its owner communities' future electricity needs beginning with a discussion of the resource screening process and a listing of the resources that were screened out and not considered in the IRP as candidates for investment. A detailed discussion follows concerning the resources (both renewable and traditional) that were considered for investment in the IRP. Finally, the section features a list of Platte River's existing resources including physical generation assets and contracted third party resources.

7.5.1 New resource screening

Platte River considered a large number of generating resources for this IRP. Some of the resources were screened out due to size, technology commercialization status and suitability for Platte River's system. These resources are listed here along with the rationale for their unsuitability. Platte River will continue to monitor the commercial viability of these resources as technology evolves and suitability for Platte River improves.

- **Conventional nuclear** – large reactor sizes, high costs, long construction durations and permitting challenges
- **Small modular nuclear reactors** – no commercially proven examples
- **Coal integrated gasification and combined cycle with carbon capture and storage** – high cost, immature technology
- **Pumped storage hydro** – limited regional resource availability, high cost, long permit and building timeline
- **Compressed air energy storage** – limited regional resource availability
- **Flow batteries** – few commercially viable options, high costs and lower efficiency compared to lithium-ion batteries
- **Geothermal** – limited regional resource availability
- **Biomass** – limited production potential, high costs
- **Municipal waste** – limited production potential, high costs
- **Solar thermal** – limited commercial penetration, high costs

The following is a list of technologies that were considered for inclusion in the IRP:

- **Wind turbines** – favorable resource availability, technological improvements, stable or declining costs
- **Solar photovoltaic** – favorable resource availability, technological improvements, stable or declining costs
- **Lithium-ion batteries** – peaking capacity and renewable energy integration, technological improvements and declining costs
- **Small thermal generation** –
  - **Combustion turbines Aero derivatives and 7F** – mature technology, suitable for load following and integration with intermittent renewables
  - **Combined cycles, 1X1 Aero derivative and 7F** – mature technology, suitable for load following and integration with intermittent renewables
  - **Reciprocating internal combustion engines (RICE)** – mature technology, emerging resource for load following and integration with intermittent renewables in small scalable sizes

Techno-economic data for the above four types of resources considered for inclusion was received from outside consultants such as Siemens and HDR Inc. New resources were used in different block sizes based on their design and suitability for Platte River's system. Wind and solar were added in 100 MW blocks of nameplate capacity while storage battery resources were added in 50 MW X 4-hour (200 MWh) blocks. Thermal resources were added at the standard sizes available in the market.

7.5.2 New wind resources

For the purpose of IRP modeling, 100 MW blocks of nameplate wind capacity were added through PPAs using a 30-year levelized annual payment instead of one-time capital expenditure. PPA payments compensate the developer or PPA counter party for capital costs (depreciation and returns), interest during construction, taxes (sales, property and income) and ongoing O&M costs.

Wind power plants were modeled with a 45% capacity factor; costs used in the model are shown in Figure 7-5. These are nominal values that increase at a lower rate than inflation due to technology maturation. The relatively sharp price increase in 2022 stems from the reduced production tax credit. Platte River received wind price data from Siemens and calibrated it to match recent market transactions in the area.

In addition to the wind PPA cost, Platte River also pays its transmission provider a fixed monthly cost for services associated with integrating variable resources, such as wind and solar. These charges are set by the Federal Energy Regulatory Commission and are known as “Schedule 3” and “Schedule 16” charges. These charges have remained steady over the last few years, therefore no escalation was assumed. The Schedule 3 charge is $0.16/kW/month and Schedule 16 charge is $0.91/kW/month applied to all nameplate capacity amount of wind.

Wind resource availability within Platte River's service territory is limited and future new wind resources will ultimately require new transmission capacity to be built or procured. Consequently, staff assumed any new wind capacity above the next incremental 100 MW block will require new transmission capacity. For planning purposes, an additional transmission wheeling cost equal to the average of WAPA and Xcel Energy transmission tariffs was used. Figure 7-5 shows wind costs, including estimated generator transmission interconnection costs, with and without third-party transmission wheeling costs. Figure 7-5 shows fixed payments for the duration of the PPA for the particular start year. For example, a wind project that begins commercial operation in 2021 is estimated to cost fixed $20/MWh over the 30-year PPA term and a project starting commercial operation in 2024 will have a fixed cost of $23.42/MWh for the duration of the PPA.

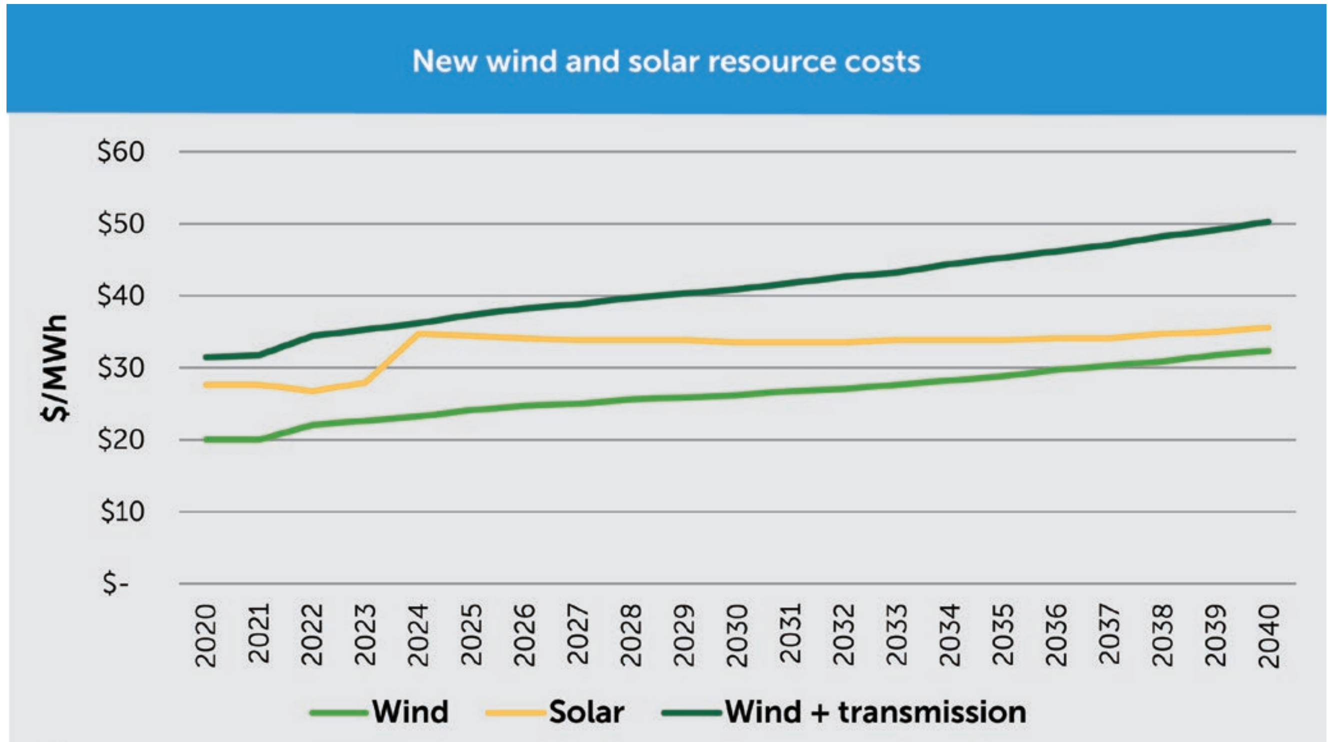


Figure 7-5

7.5.3 New solar resources

Like wind, new solar resources were considered as 100 MW block sizes priced at 30-year levelized PPA payments including transmission interconnection costs. Solar generation is assumed to have an annual capacity factor of 28%. Annual prices for solar resources were developed by Siemens and calibrated to reflect recent transactions in the area.

Staff assumed that new solar projects will be built within the existing Platte River transmission footprint. Consequently, no new transmission capital costs or third-party wheeling costs were assumed for solar generation. Figure 7-5 illustrates the cost of solar generation, declining slightly in nominal terms, indicating technology improvements over time. The sharp price increase in 2024 stems from the Investment Tax Credit reduction from 30% to 10%. Figure 7-5 shows fixed payments for the duration of the PPA from the particular start year. For example, a solar project that begins commercial operation in 2023 is estimated to cost a flat $28/MWh over the 30-year PPA term while a project starting in 2024 will have a cost of $35/ton for the duration of the PPA.

7.5.4 New battery storage

Platte River considered commercially available lithium-ion battery storage technology in 50 MW block sizes. Staff assumed 200 MWh of storage per battery, which would provide up to four hours of discharge capacity at a rate of 50 MW per hour. Other combinations of storage and capacity sizes can be built as well. For example, an equivalent 2-hour battery would still store 200 MWh but could charge or discharge at 100 MW per hour. An 8-hour battery that stores 200 MWh could only charge or discharge at 25 MW per hour. Each type of configuration has appropriate uses. A 2-hour battery provides superior flexibility but at an added cost of more inverters relative to the number of battery cells. In contrast, 8-hour batteries offer cost savings on non-battery equipment such as inverters, but their flexibility can become constraining as energy cannot flow into or out of the battery as quickly. For modeling, the 4-hour battery provides a balance of cost and flexibility. As with other candidate resources, once Platte River decides to install new battery storage resources, the full range of available options will be considered to ensure each project uses the best available option for the specific needs of the system at that time and location.

The batteries were assumed to have an 85% round trip storage efficiency. Like wind and solar, battery storage cost was modeled as a PPA-type payment to a developer or counter party for a 15-year term with all future battery storage projects sited within Platte River territory, thereby avoiding third-party transmission wheeling costs. Figure 7-6 shows the levelized battery costs for a 50 MW 4-hour battery over the 15-year term of the PPA. For example, a 15-year 50 MW 4-hour battery that begins commercial operation in 2023 is estimated to cost $10/kW-month over the entire 15-year term.

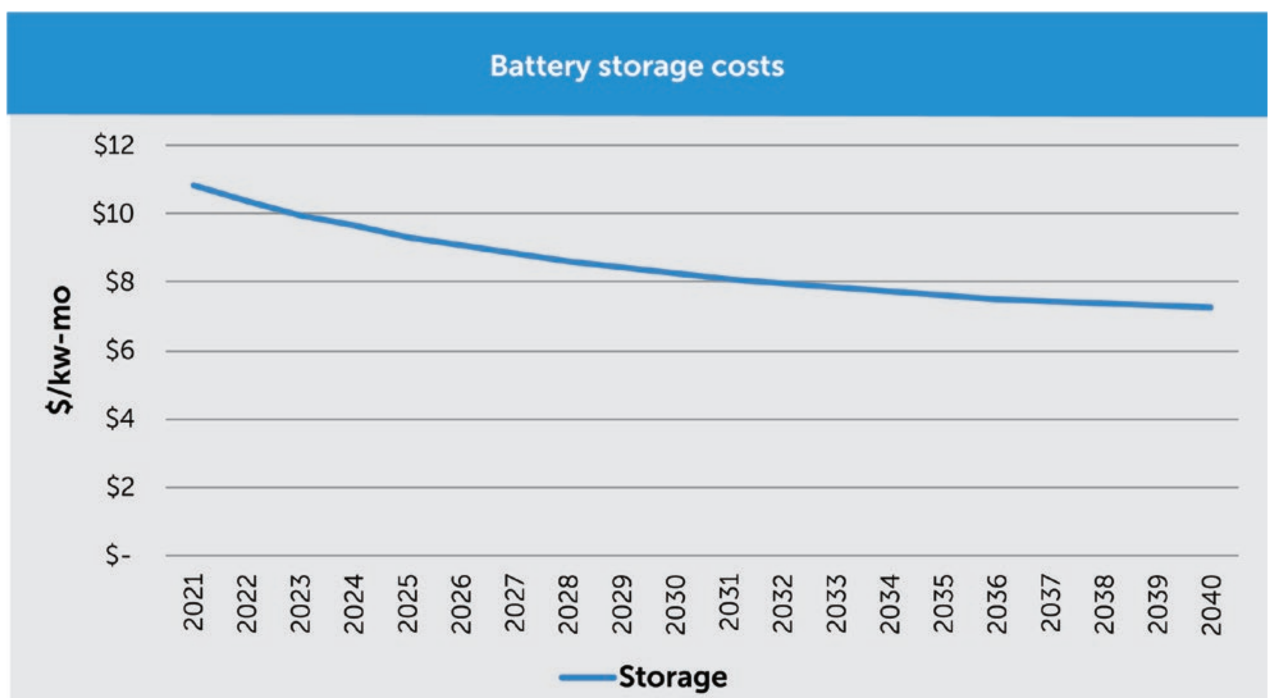


Figure 7-6

7.5.5 New thermal generation resources

Platte River screened a range of thermal generating options before advancing a limited portfolio of resources to the expansion planning model. Emphasizing decarbonization and integrating more renewable resources, the modeling focused on smaller, more flexible thermal generation resources, including aeroderivative combustion turbines, combined cycles and reciprocating internal combustion engines (RICE). Screening performed by HDR Inc. indicated that RICE units are competitive with other technologies and a good complement to intermittent renewable generation. The Aurora model developed new generation expansion plans, often selecting RICE as a least-cost solution. RICE units also offer significant operational advantages with their ability to run at low levels, start and stop frequently with little added cost impact and the potential option to operate on a variety of fuels such as natural gas or biodiesel. Their small size, modularity and scalability also makes them convenient to site and construct.

New thermal generation costs and operational details provided by HDR Inc. and used in Aurora are shown in Figure 7-7.

Since HDR supplied only a single year snapshot of costs, Platte River used Siemens' technology cost escalation methodology to adjust for future year prices. This adjustment is separate from the standard 2% inflation modification. It reflects cost trends for both mature and newer technologies.

Staff assumed any future thermal generation will be sited at the Rawhide Energy Station and would require the construction of an additional gas pipeline spur at a cost of $6.0 million. To ensure reliability, Platte River would also need to purchase firm gas transport capacity on the gas delivery system. Actual gas supply cost will vary depending on the consumption level, but the added cost averages $1.65/kW/month across all thermal resources.

New thermal generation resource data

Unit	Maximum capacity (MW)	Minimum capacity (MW)	Installation cost ($/kW)	Fixed O&M ($/kW-mo)	Variable O&M ($/MWh)	Efficiency	CO_2 emission rate (lbs./MWh)
Rice6x0	111	9	$1,252	$0.50	$5.42	41%	987
Rice3x0	55	9	$1,389	$0.91	$5.42	41%	987
Aero CT	83	21	$1,184	$0.78	$6.10	36%	1110
2x1 Aero CC	108	29	$1,748	$2.45	$4.81	47%	850
7FA Frame CT	194	98	$715	$0.39	$4.29	35%	1144
7FA 1x1 Frame CC	275	147	$1,322	$1.03	$4.74	50%	801

Figure 7-7

7.5.6 Platte River's existing resources

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

Platte River entered into some capacity and energy sale transactions to optimize its supply portfolio. These contracts were modeled in Aurora to ensure the generation necessary to supply the contracted sales is appropriately accounted for when making dispatch and resource optimization decisions. Figure 7-8 summarizes the committed transaction as of Jan. 1, 2020. Figure 7-9 shows all the existing generation resources.

Committed power transactions data					
Sale transactions	Nameplate capacity (MW)	Effective capacity (MW)	Type	Commercial operation	Normal retirement / contract expiration
25 MW sale from Craig	25	25	Baseload	2019	2024
25 MW sale from Craig	25	25	Baseload	2020	2022
Silver Sage	12	3	Wind	2018	2042
Spring Canyon II	32	7	Wind	2020	2030
Spring Canyon III	28	6	Wind	2020	2030

Figure 7-8

Existing generating resource data				
Thermal generation facilities	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation	Nominal retirement / contract expiration
Coal				
Rawhide Unit 1	280	280	1984	2046*
Craig Unit 1	77	77	1980	2025
Craig Unit 2	74	74	1979	2028**
Natural gas (simple-cycle CTs)				
Rawhide Unit A	65	65	2002	Indefinite
Rawhide Unit B	65	65	2002	Indefinite
Rawhide Unit C	65	65	2002	Indefinite
Rawhide Unit D	65	65	2004	Indefinite
Rawhide Unit F	128	128	2008	Indefinite
Other resources				
Wind				
Medicine Bow	6	1	1998	2033
Silver Sage	12	3	2009	2029
Spring Canyon II	32	7	2014	2039
Spring Canyon III	28	6	2014	2039
Roundhouse	225	50	2020	2042
Hydropower				
Loveland Area Project	30	30	1973	2054
Colorado River Storage Project	60	60	1973	2057
Solar				
Commercial solar power purchase program	4	2	Approved 2013	Varies
Fort Collins community solar	1	0.4	2015	2040
Foothills Solar (Platte River share)	0.5	0.2	2016	Indefinite
Rawhide Flats	30	13	2016	2040
Rawhide Prairie	22	6	2020	2040
New solar* **	100	26	2023	2040
Storage				
Rawhide Prairie Battery	1 MW x 2 hours	1	2020	2040

Figure 7-9

* This was the original retirement data for Rawhide Unit 1 at the time of modeling during fall 2019. With the announced retirement of Rawhide Unit 1 in 2030, this assumption has been superseded.

**We assumed a December 2028 retirement date for modeling purposes. Later on, a retirement date of September 2028 was announced which would not change the results of this IRP.

***Platte River is currently conducting a solicitation for 50-150 MW of solar to come online by December 2023. For modeling purposes, a 100 MW capacity addition was assumed, but later on a 150 MW project was approved.

8 Reliability planning and future portfolios

This chapter includes a discussion of two key IRP topics: planning for reliability with intermittent resources and the development of four portfolios to cover a wider range of future possibilities. These topics are discussed with the backdrop of Platte River's Resource Diversification Policy and the organization's foundational pillars of safely providing reliable, environmentally responsible and financially sustainable energy and services to its owner communities.

8.1 System reliability

Near- and long-term resource planning is the first step in ensuring reliability. Failure to plan for adequate energy supply may cause supply shortages, which, if sustained, can cause significant economic damage. For example, Electric Reliability Council of Texas (ERCOT) customers recently paid 300 times the average price of $30/MWh for energy (about $9,000/MWh) for a few hours due to supply shortages[9]. Fortunately, this episode lasted only for a few hours in the ERCOT market. If the demand was to go any higher, or if any generating unit was to breakdown during these super peak hours, ERCOT would have to resort to supply curtailment (or load shedding). In addition to the economic impacts, curtailments due to a lack of adequate supply will likely impact public health and safety.

To maintain sufficient resources to meet demand, referred to as resource adequacy, staff must account for electric demand that changes hourly and by season. Peak demand for electricity on the Platte River system during a hot summer day can be more than twice the demand during a spring or fall day. Platte River must always build or procure enough supply resources to meet this peak demand. Figure 8-1 shows Platte River's average hourly demand during a summer, spring, fall and winter day in 2018.

[9] https://www.reuters.com/article/us-texas-power-demand/texas-power-prices-nearly-triple-to-record-high-as-heat-bakes-state-idUSKCN1V61CG

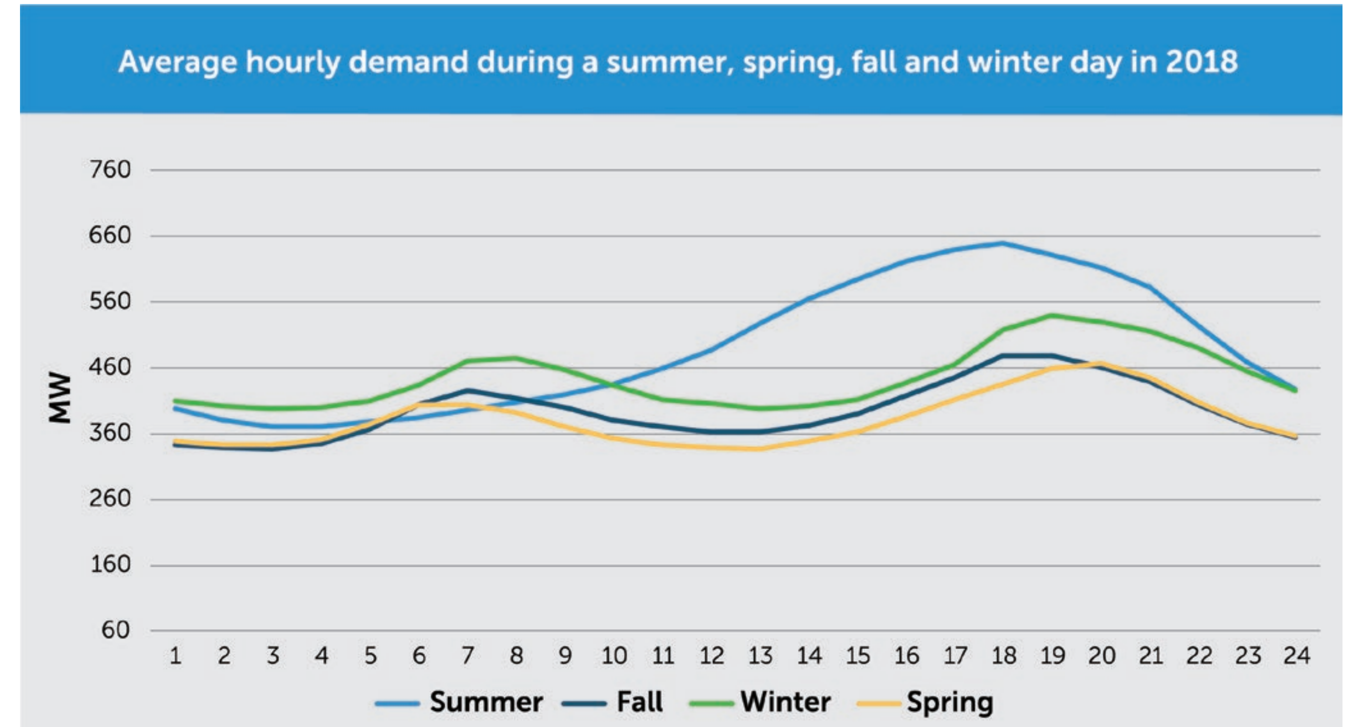


Figure 8-1

8.1.1 Reliability modeling with planning reserve margin

An electric utility ensures long-term resource adequacy by meeting the North American Electric Reliability Corporation (NERC) criterion of allowing just a single day outage within a 10-year period or 2.4 hours of outage per year. To meet this criterion, NERC recommends using a 15% PRM, which is additional capacity above peak demand expectation. If a utility is expecting a peak demand of 100 MW in a future year, for example, it should build or acquire 115 MW of generating capacity. This level of PRM is necessary to account for (1) forecast errors, (2) unplanned outages of generation resources and (3) transmission outages.

While a 15% PRM works well with dispatchable thermal resources, the inclusion of intermittent non-dispatchable renewable resources in the supply mix means additional considerations must be given to the probability of renewable resources being unavailable during peak demand periods. Due to the complexity of estimating the reliability contribution of renewable resources, Platte River hired an independent consultant, Burns and McDonnell, to recommend reserve margin guidelines. Their report describes different techniques they used to evaluate reliability, ultimately concluding a 15% PRM is still appropriate for Platte River as long as proper adjustments are made to the peak hour capacity contribution from renewable resources and battery storage as described below. The full report can be found on the Platte River website.

8.1.2 Reliability contribution of renewable and storage resources

Intermittent renewable resources such as wind and solar contribute to reliability in a probabilistic way so additional analysis is required to estimate their contribution to meeting the annual peak demand, known as effective load carry capability (ELCC). In general, ELCC of an intermittent resource is the equivalent MW contribution of a firm resource in meeting the peak demand. Figure 8-2 explains the concept of ELCC for Platte River's system for an illustrative day. Hourly load profile for the day is shown as a green line in the chart. The peak demand for the day is 700 MW. Installed capacity of wind is 228 MW and the installed capacity of solar is 50 MW in this example. Hourly load profile after reducing the load for available wind and solar is shown in blue color. The net peak demand after considering the available wind and solar that day is 627 MW.

Based on this data, the ELCC of 278 MW of wind and solar is (700-627)/278 = 26.3%.

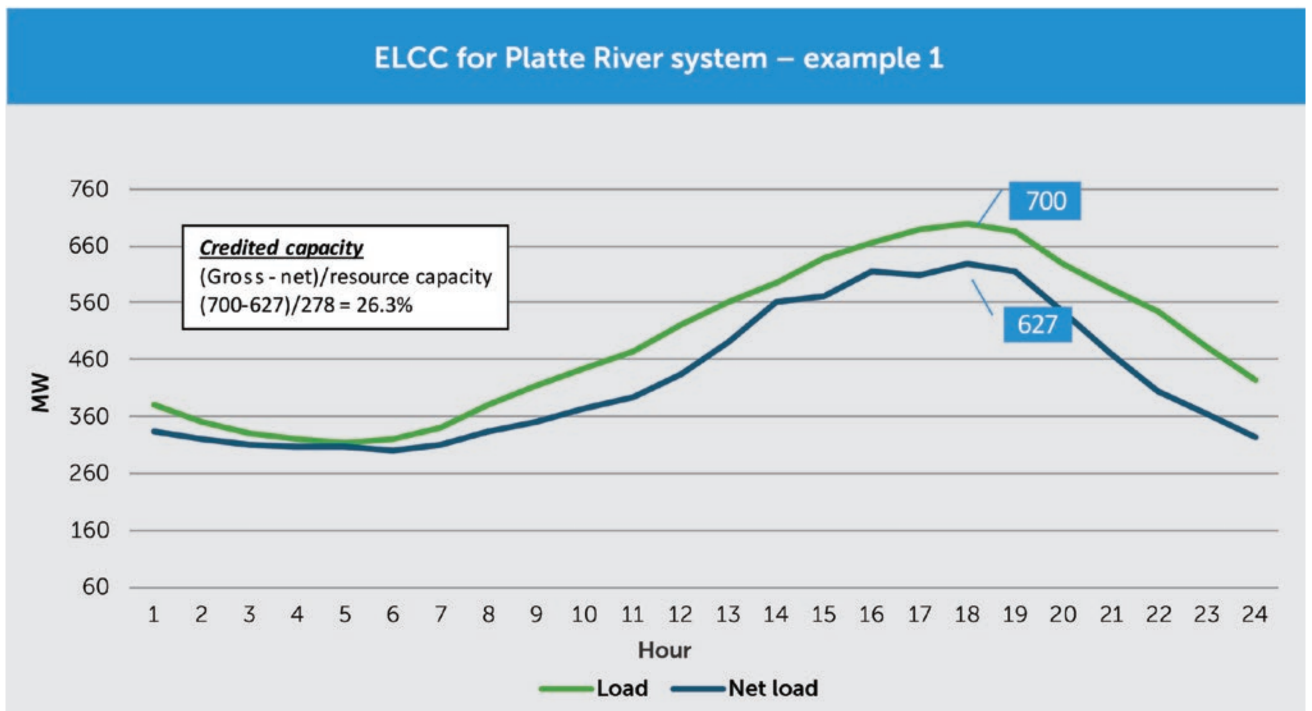


Figure 8-2

Now consider another wind and solar profile shown in Figure 8-3. In this case wind generation starts increasing around 4 p.m. and reduces the net demand to less than 600 MW at 6 p.m. The wind then starts slowing down and the contribution from solar also decreases. Net load at 7PM is 639 MW. This is the new net peak load and the peak hour has shifted from 6 p.m. to 7 p.m. In this case, the peak impact of wind and solar is 673 less 639, that is only 34 MW. The ELCC of wind and solar in this case is (673-639)/228 = 12.2% as show in Figure 8-3.

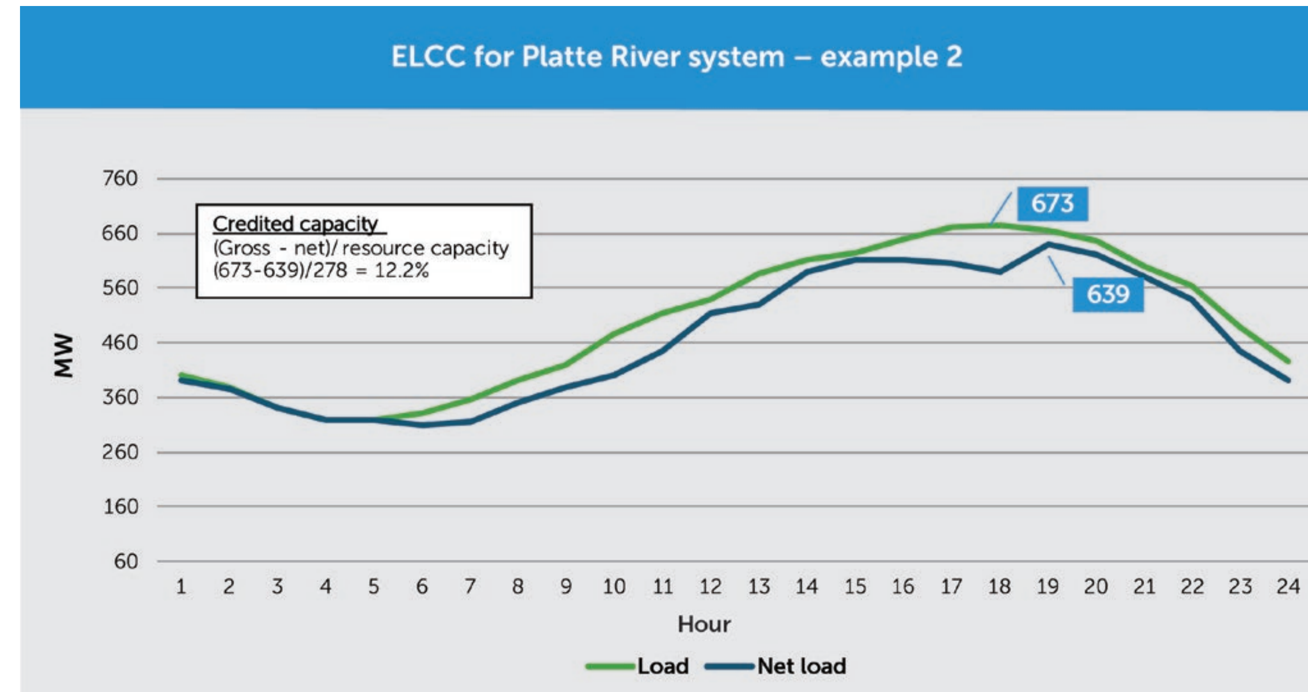


Figure 8-3

Renewable energy output tends to be geographically correlated (typically, it is windy or sunny across the region). The ELCC of additional renewable resources generally drops as more resources are added to the grid. For example, if the ELCC of the first 100 MW of a wind (or solar) project is 30 MW, the ELCC of a second 100 MW block of the same resource type in the geographic vicinity will be less than 30 MW.

Similarly, battery storage also contributes to reliability in a probabilistic manner because it is an energy-limited resource. Battery storage may be dispatched to meet load, but only for a limited duration and only if it is charged before the dispatch. As with wind and solar, the reliability contribution of incremental battery storage also drops as more and more storage is added to the system because of the lower probability of being fully charged at the time of peak.

Platte River's consultant Burns and McDonnell recommended declining values of ELCC with incremental resource additions for wind, solar and battery as shown in Figure 8-4. The figure 8-4 shows the average ELCC contribution from the existing wind is 22% and the existing solar is 42%.

For the next block of 100 MW of wind, the ELCC contribution drops to 14%, while the solar ELCC drops to 26%. The ELCC contributions from the next blocks of solar and wind are even lower. ELCC of the first block of 100 MW of battery is 77%, while the ELCC of the next 100 MW block drops to 54%. This declining pattern continues just like wind and solar.

The PRM reliability construct was developed for North America's generation system which is dominated by dispatchable thermal resources. With majority thermal resources providing firm capacity and some hydroelectric storage resources, a value of 15% PRM has been providing adequate reliability for North American utilities. This PRM construct breaks down in a 100% renewable system due to intermittency and non-dispatchability of supply and limitation of battery storage. As discussed earlier, the incremental contribution to reliability as measured by ELCC declines as more and more renewables and battery resources are added. Oversizing the resource base may reduce the risk, but the cost will go up and the risk of supply shortage will stay during occasional long periods of time without wind or sun. The utility industry is still developing resource adequacy criteria for a 100% renewable portfolio. Platte River will continue to work internally and track industry progress in developing a reliability metric for a 100% renewable portfolio. In the absence of any standards, Platte River used the criteria of minimizing unserved energy to select an acceptable resource mix for its 100% renewable portfolio.

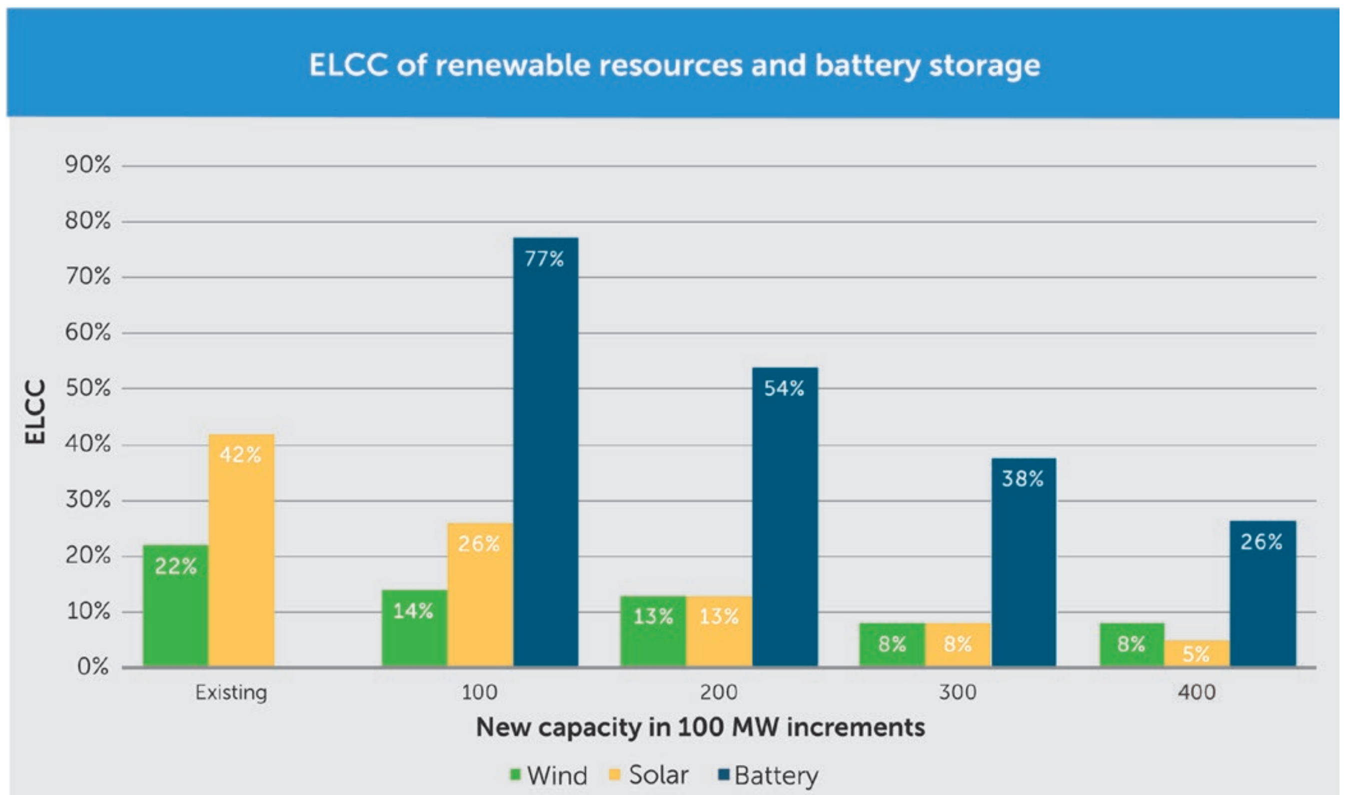


Figure 8-4

8.2 Need for new resources

The need for new resources can be assessed by reviewing future capacity and energy balance charts. The future capacity balance chart includes the forecasted annual peak demand plotted against the capacity contribution of each of the existing and committed resources. Figure 8-5 shows the capacity balance of Platte River for the duration of the planning period. It shows the forecasted capacity requirement and the capacity contribution of all existing resources. The capacity requirement shown by a thick black line includes the annual peak demand plus the 15% PRM required for reliability. On the supply side, summer capacity of all the available resources is shown as area charts. For thermal resources, their actual summer capacity is shown, while for renewable resources, their ELCCs are shown in the chart. It is clear Platte River does not need new capacity until both Craig units are retired by the end of 2028.

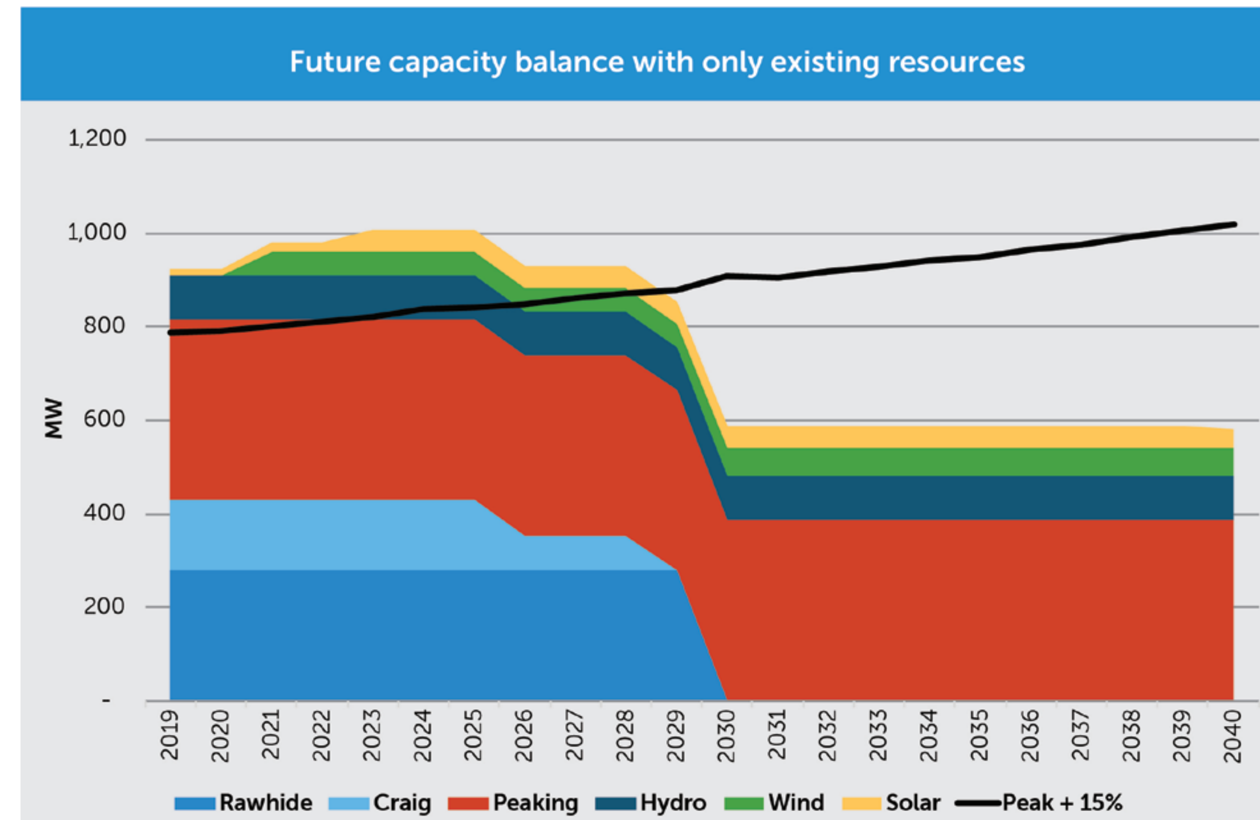


Figure 8-5

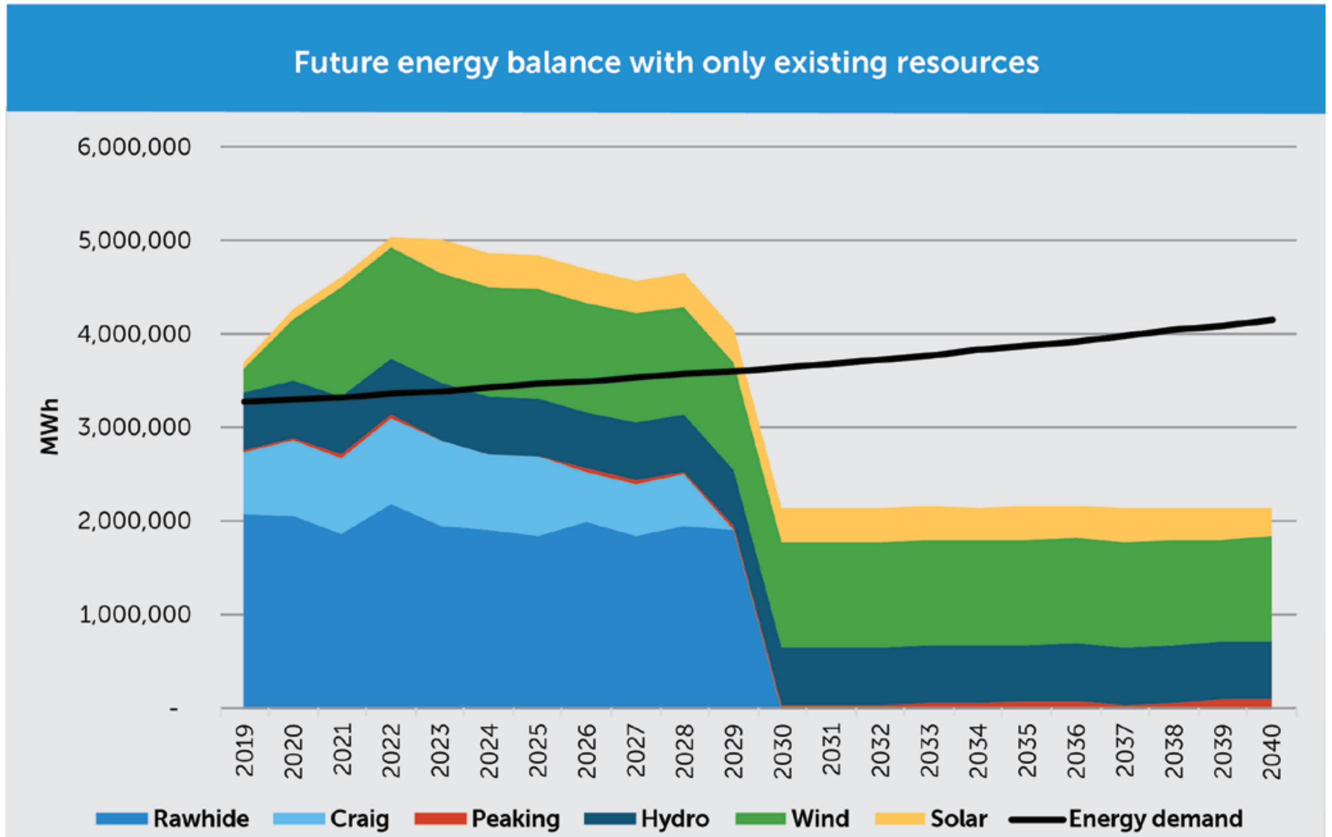


Figure 8-6

Platte River's expected energy balance over the planning horizon is shown in Figure 8-6. The energy demand in this chart is the net of DERs. On the supply side, solar, wind and hydro resources show their average generation while thermal resources produce at their expected economic levels. Figure 8-6 illustrates that for the next few years, Platte River will have excess energy available for export when wind and solar are producing at the average expected levels. After the retirement of coal-fired generation, Platte River will need new energy resources.

Platte River's Resource Diversification Policy calls for providing 100% noncarbon energy to its owner communities by 2030, subject to certain conditions being met. To achieve this goal, all thermal generation resources must be retired by 2030. Figures 8-7 and 8-8 show respective capacity and energy balance charts following the retirement of all carbon emitting resources by 2030. It is clear from these charts that significant amounts of renewable resources and battery storage will be required when thermal resources are retired.

Platte River's future energy and capacity needs, along with all the supply-side assumptions discussed in Chapter 6 were placed into the Aurora model (see Appendix D for more details of the model). This model develops an optimal resource plan, economically adding new resources or retiring existing resources to reliably meet Platte River's future electricity needs.

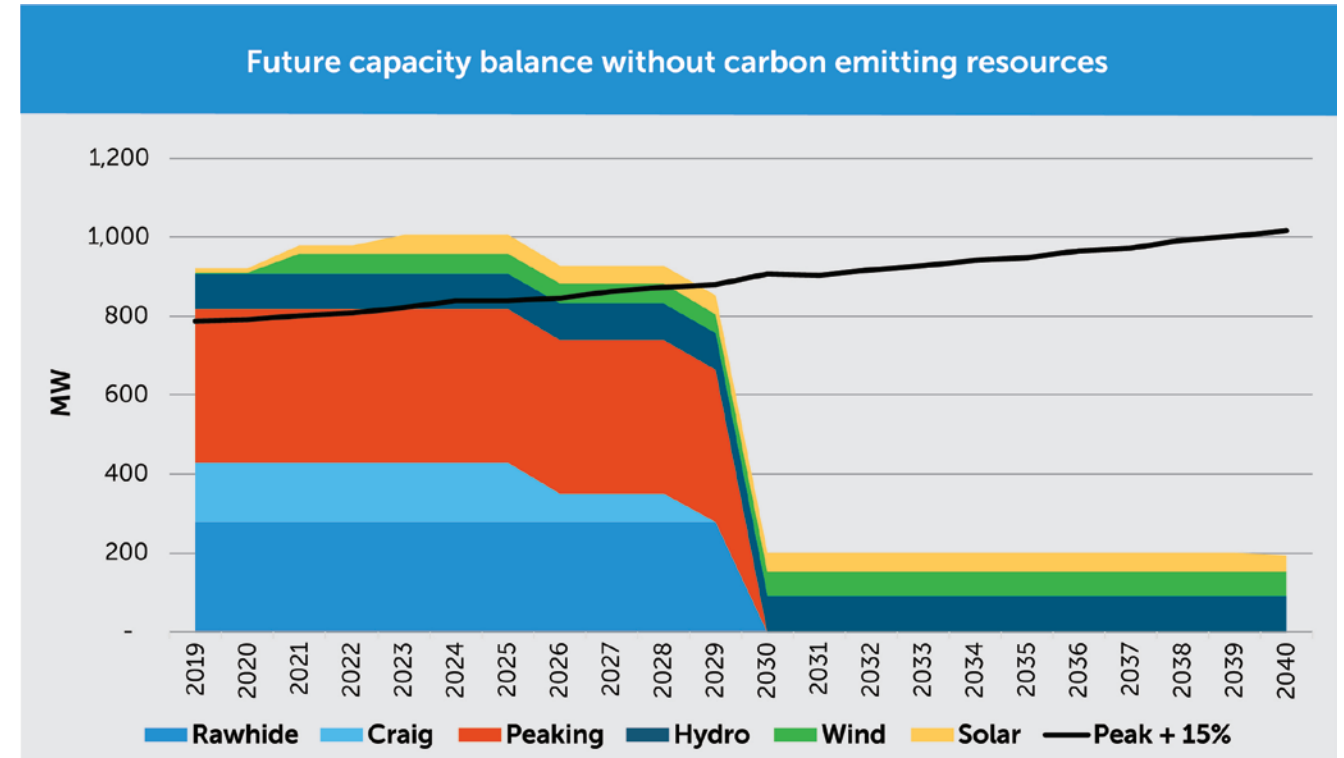


Figure 8-7

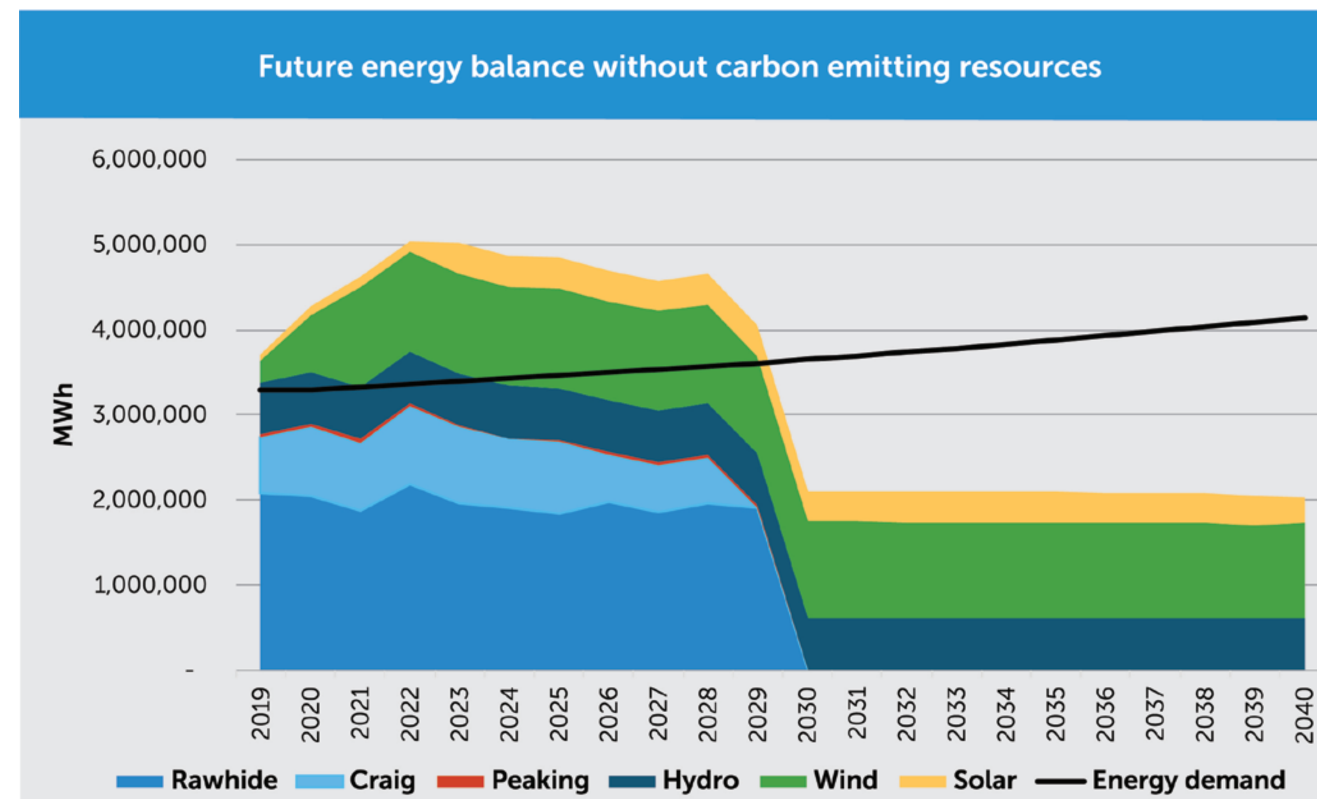


Figure 8-8

8.3 Development of future portfolios

Using various combinations of assumptions related to demand, supply, regulation and technology evolution, Platte River developed four different energy supply portfolios for this IRP, all of which consider the following inputs and assumptions:

- Commodity prices (gas, coal and power)
- Economic expansion in the communities and demand growth
- Pace of renewable and battery technology price evolution
- Pace of technology adoption by the suppliers and consumers of electricity
- Pace of DER adoption by customers
- Governmental policies regarding taxes, incentives and the environment
- Public expectations and adoption of noncarbon technologies
- Power market development in the region
- Development of the distribution grid and requirements of wholesale supply-side reliability
- Board's adopted Resource Diversification Policy

With these considerations in mind, Platte River selected the following portfolios for this IRP.

P1: continuity

This portfolio explores the path of continuing the current policy of reliably meeting owner communities' load obligations by adding new resources or retiring existing resources economically. Following the announcement of plans to retire Rawhide Unit 1 by 2030, the key assumption of no forced retirements has been superseded in this portfolio. However, this portfolio provides valuable baseline projections to measure the cost and environmental impact of assumptions and decisions in other portfolios.

P2: zero coal

This portfolio explores the path where Platte River retires all coal fired generation by 2030 while continuing the current policy of reliably meeting owner communities' load obligations. New resources are added economically while continuing to meet all current environmental regulations.

P3: zero carbon

This portfolio explores the path where Platte River retires all thermal generation by 2030 while continuing the current policy of reliably meeting owner communities' load obligations. New renewable resources and battery storage are added to develop a zero carbon supply portfolio.

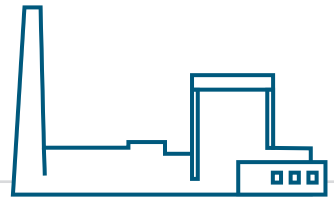
P4: integrated utilities

This portfolio explores a future where technology evolution accelerates and new technology costs drop faster than current projections. Consequently, renewables, battery storage, EV and DER penetrate at a faster pace. For example, the costs of solar, wind and battery technologies in this portfolio are 15-25% lower relative to the first three portfolios. Similarly, distributed solar and EVs reach double the level relative to portfolios 1-3. Finally, other DERs also penetrate at a higher rate. While this energy transition is manifesting at an accelerated pace, Platte River adheres to its core pillars of reliably meeting owner communities' load obligations with the lowest-cost resources.

Similar to P1, the key assumption of no forced retirements has been superseded in this portfolio following the announcement of plans to retire Rawhide Unit 1 by 2030. However, this portfolio provides valuable insight on the impact of faster electricity transition with lower cost of renewables and higher DER penetration.

A detailed summary of the individual portfolios with associated assumptions and challenges is provided in the following section.

8.4 P1: continuity



The continuity portfolio is the least-cost option. This portfolio provides important insight about which resources are the most valuable and how their value may change over time. The Aurora model minimized the total cost of the system by retiring existing units when beneficial and adding new thermal, wind, solar or storage when required.

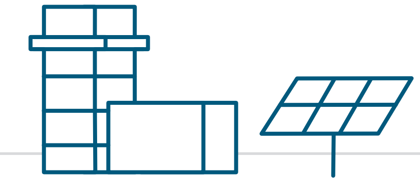
Modeling details

The Aurora model was run without any forced constraints on resource additions or retirements and an optimal portfolio was produced. That portfolio was then adjusted to reflect the expected retirement date of Craig 2 and reoptimized to give a least-cost solution while meeting the reliability requirement. Next, some early resource addition dates from this portfolio were adjusted to better coincide with the expected Craig retirement and a final optimization was run. As changes were made, the cost impact was monitored to ensure the portfolio still reflected a least-cost approach. The resulting portfolio is an actionable plan based on current expectations.

As part of the modeling process, additional demand-side resources were also tested. The medium DER potential proposed by HDR Inc. was not cost-effective, so the final portfolio reflects current base level of DER assumptions that were already included in the load forecast.

Finally, existing hydro and renewable resources were allowed to operate according to their schedules, without any change or retirement, over the full planning horizon.

8.5 P2: zero coal



The zero coal portfolio was designed to test the impact of retiring Rawhide Unit 1 earlier than its economic life. As a starting point, the model was allowed to retire the unit whenever economical during the planning period of 2021 through 2040. But the model didn't retire it, indicating that the early retirement was not the least-cost solution. Then the coal unit was forced retired at the end of 2029. Reliability was maintained through adherence to a 15% planning reserve margin and the balance of the portfolio was constructed to minimize costs. The model was allowed to economically add new gas-fired generation as well as wind, solar and battery storage resources.

Modeling details

For this portfolio, candidate capacity expansion plans were summarized across various metrics, including overall cost, renewable energy penetration, excess renewable energy that could not be sold to the market, the volume of surplus sales, and tons of carbon emitted. Balancing the benefits of higher renewable energy production and lower carbon against the risks of dumping excess energy and high volumes of surplus sales while minimizing costs required multiple iterations. The optimization process found the least-cost option that met the reliability criteria while keeping the excess energy sales at a reasonable level. With each iteration, the expansion plan was slightly altered to better balance the metrics followed by a new optimization test. Alterations were made to the year or size (or both) of the resources added. The goal was to use analytical judgment to test resiliency of P2 where necessary but rely on the model to optimize where possible. The resulting P2 was the least-cost option (among the various options tested) and was very competitive across every other metric. This portfolio also relied on the existing levels of DERs because higher levels were not economic when tested in the model.

8.6 P3: zero carbon

The zero carbon portfolio was designed to meet the goal of producing all energy from noncarbon resources starting in 2030. Consequently, all thermal units were retired and replaced with wind, solar and battery resources. Hydro allocations were retained so the noncarbon energy mix is a combination of wind, solar and hydro, along with batteries used to store excess energy during periods of high noncarbon production for use during periods when renewable resources cannot fully meet demand. In this portfolio, retirement of all thermal resources required significant additions of renewable resources and battery storage, with large amounts of excess renewable energy during hours of high wind and/or solar generation. While a PRM of 15% is sufficient for Platte River with a mix of thermal and renewable generation, with 100% noncarbon generation the reliability requirement needed additional analysis, as discussed later in this section.

Modeling details

Development of a 100% noncarbon portfolio was an iterative process. The criteria used to select a resource plan for this portfolio aligned with Platte River's three pillars. Reliability was measured by tracking the amount of energy that could not be served by a given combination of resources. If Platte River's wind, solar, hydro and battery resources were not able to provide enough energy to meet demand, then Platte River would need to procure that energy from neighboring systems. The plans with heavy reliance on neighboring systems were less reliable and less predictable than plans that were able to serve load with Platte River's own resources[10].

Environmental responsibility was implicitly assumed in this portfolio because all energy would be produced from noncarbon resources starting in 2030. Plans that produced significant amounts of excess energy were deemed less financially sustainable because excess energy not sold in the regional market would need to be curtailed. Without energy storage, this energy could be wasted. Plans with less excess energy were ranked as more environmentally and financially responsible than other plans. Net present values of total plan costs were also used to measure financial sustainability over time, with lower net present values representing better financial sustainability.

A grid search was performed on many combinations of solar, wind and battery resources to identify competitive energy mixes. Each combination was placed into a production cost model to measure its costs, reliability and excess renewable energy. Once these measures were recorded, the portfolios were compared based on these measures.

Challenges of zero carbon portfolio

Intermittency of wind, time-limited availability of solar and a finite amount of battery storage are the main challenges to reliably meet customer demand in the absence of dispatchable thermal resources. Ensuring reliability of supply during periods of extended cloudy days with low or no wind, also referred to as "dark calms," would require a very large bank of batteries which may become uneconomical. A dark calm experienced in Platte River's service territory during January 2018 is illustrated in the figure below.

Figure 8-9 displays output of wind and solar resources as a percentage of nameplate capacity over the course of five days. This data was used to test the amount of battery storage needed to serve load during periods of low generation. Due to low wind and solar generation in the first few days, battery discharging was required to meet load. The battery was unable to fully recharge due to continued low wind and solar generation, causing reliability challenges during the night between the fourth and fifth days when there was no solar or wind generation and the batteries were depleted. To reliably serve customer needs during extended low generation periods would require a very large battery bank. Staff currently do not have enough historical data to determine the worst-case scenario for wind and solar during similar shortages for multiple years. In the absence of such credible historical data, the NERC recommended generation reliability planning criteria of allowing no more than a one-day outage in 10 years or 2.4 hours in one calendar year would be hard to meet.

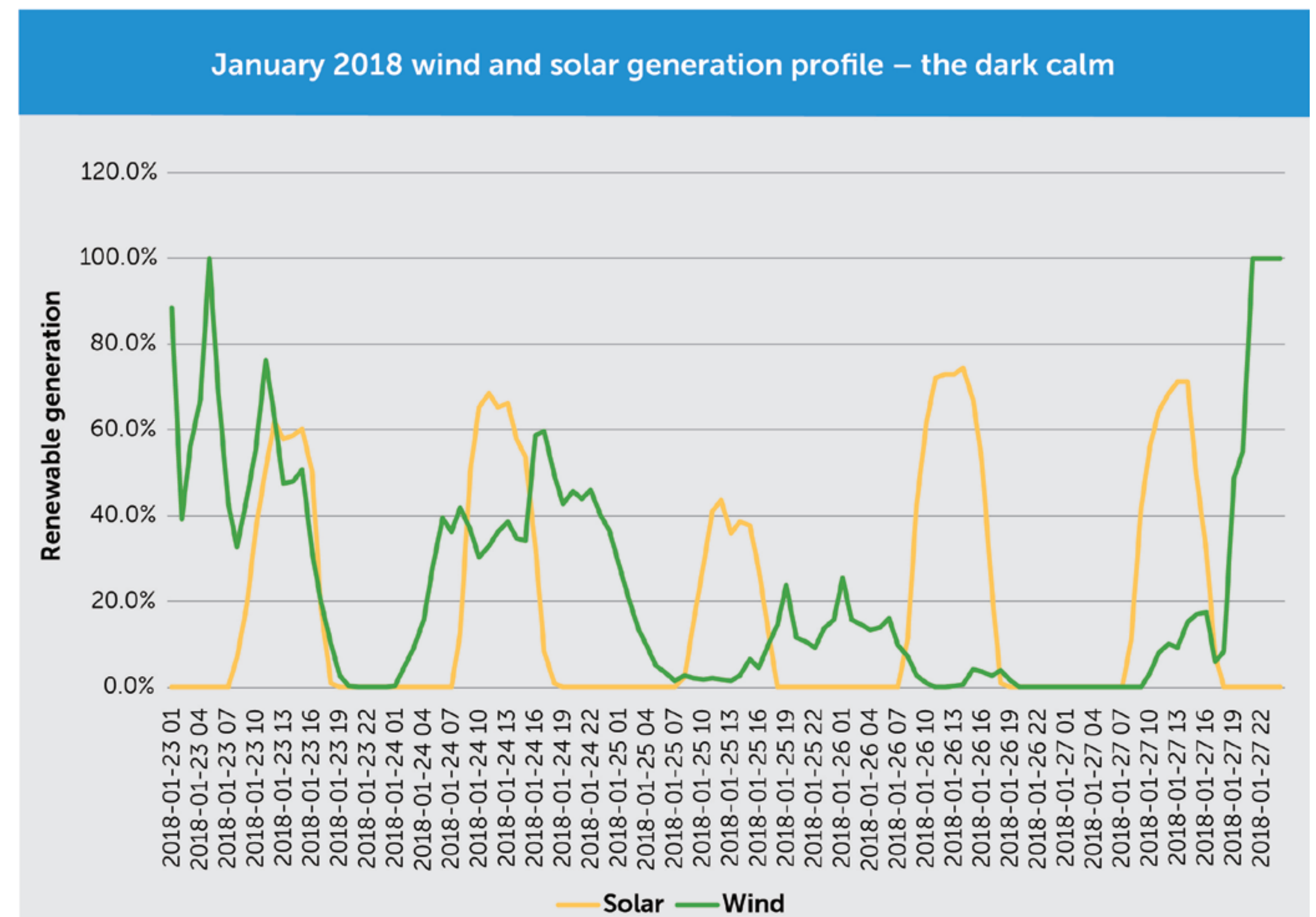


Figure 8-9

[10] In a 100% renewable scenario, availability of emergency energy from neighboring systems is less certain due to less diversity of weather patterns across neighboring areas. When a big weather system moves through the area, it can impact a large geographic region. For example, it could be cloudy in a large geographic territory, thereby reducing solar energy production across the region.

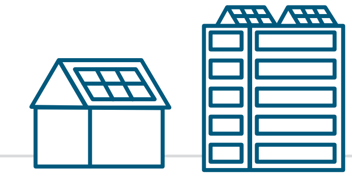
The zero carbon portfolio is highly dependent upon the renewable generation profiles assumed in the study. If wind and solar hourly generation profiles are averaged over multiple geographic regions, they are less susceptible to dark calms. Using broader geographical profiles also requires fewer storage resources to provide reliability through periods of low generation. With less geographic diversity, storage requirements drastically increase because single sites are more susceptible to long stretches of little wind generation versus a portfolio of generation spread across a larger region. This will be an area of focus in future studies to determine the cost effectiveness of more diverse renewable portfolios.

In a test example, switching from a diverse regional profile to a single site profile resulted in a more than 50% increase in the amount of storage required to serve load. This additional storage would have only served around 100 hours of load over the course of a year, meaning that most of the time the batteries could not have been used. This test example highlights the potential tradeoffs between the environmental cost of additional batteries compared to the environmental cost of thermal generation to provide reliability during occasional dark calms. Planning for a reliable portfolio with 100% renewable resources requires careful evaluation of the following assumptions:

- Can the renewable generation resources be spread over a large enough region for weather diversity to minimize the probability of dark calms?
- Can the market or neighboring utilities be relied upon to provide emergency support and reliability during dark calms?
- What is the maximum support expected from participating in a regional market?

Traditional reliability metrics like planning reserve margins do not adequately address reliability concerns with a 100% noncarbon energy portfolio. Reliability metrics need to be redefined and further analysis of renewable generation should be performed to measure the risk associated with dark calms. This work must also include a market study that examines how much a market can mitigate the risk of dark calms. Finally, future work should address the tradeoffs between the financial and environmental costs of a large new battery bank versus keeping the existing thermal peaking generation to provide reliability during periods of dark calm.

8.7 P4: integrated utilities



The integrated utilities portfolio assumes a faster rate of technological progress, accelerating the energy transition with higher distributed solar generation and EV penetration as well as the implementation of additional DER programs. This portfolio also assumes lower costs for wind, solar and battery resources relative to those used in portfolios 1-3. Figure 8-10 shows the cost of these resources in P4 relative to the cost in P1-P3. For example, cost of solar in P4 is 18% lower in 2030 and 20% lower in 2040 relative to the cost of solar in P1-P3.

P4 renewables and battery costs relative to P1-P3		
	2030	**2040**
Solar	-18%	-20%
Wind	-14%	-14%
Battery	-27%	-33%

Figure 8-10

Due to the lower resource price trajectories, the integrated utilities portfolio assumed twice the amount of distributed solar capacity and twice the number of EVs by 2040. These assumptions impact the load forecast in different ways as shown in the following two tables and discussed in detail in Appendix E. Figure 8-11 shows the impact of distributed solar, EVs, energy efficiency and demand response programs on the annual peak demand in 2030 and 2040 for P1-P3 and P4. It can be seen that distributed solar reduces peak demand by 3% in P1-P3 (from the base forecast) while it reduces the peak by 5% in the case of P4 due to higher distributed solar adoption. Similarly, EVs increase peak demand by 3% in 2040 for P1-P3 while the peak demand increase is 7% in the case of P4 due to higher penetration.

DER impact on peak demand forecast				
	P1-P3		**P4**	
	2030	**2040**	**2030**	**2040**
Distributed solar	-3%	-3%	-5%	-5%
EVs	1%	3%	2%	7%
Energy efficiency and demand response	-1%	-1%	-3%	-3%
Total	-2.7%	-0.3%	-5.6%	-1.0%

Figure 8-11

DER impact on energy forecast				
	P1-P3		P4	
	2030	2040	2030	2040
Distributed solar	-3.6%	-3.7%	-7.7%	-7.5%
EVs	2.1%	9.0%	4.4%	18.1%
Energy efficiency and demand response	-8.8%	-12.0%	-11.1%	-14.4%
Total	-10.4%	-6.8%	-14.5%	-3.8%

Figure 8-12

Figure 8-12 shows the change in energy consumption due to different DERs for P1-P3 and P4. It is interesting to note that the net change in energy consumption in P4 relative to P1-P3 is higher in 2030 (-14.5% vs. -10.4%) but lower in 2040 (-3.8% vs. -6.8%) due to higher EV penetration in P4.

Challenges and future work for integrated portfolio

P4, with a higher level of DERs, will require a complex interaction between the customers and the power suppliers, both at the distribution level and at the wholesale level. First of all, the traditional one-way flow from the suppliers to the customers will not hold true as some consumers may become prosumers (producers and consumers) on a regular basis. Managing distribution-level resources with renewable generation fluctuations at the wholesale level will require more integration and coordination between Platte River and its owner communities. A key facet of this integration will be the real time data sharing with customers whereby they can use flexible demand sources when higher levels of renewables are available. As discussed in Section 6.9, Platte River and the owner communities recently initiated a DER strategic planning process. Through this process, Platte River and its owner communities intend to address the key issue of integration and collaborate to develop a common vision and set of objectives and initiatives.

While there will be many operational challenges of integrating high level of DERs, a key challenge during the planning phase is to model customer behavior with future technologies where little or no data is available, i.e., EV charging. Data concerning how much charging can be curtailed when costs are high or how much charging load will be available during periods of high renewable energy generation is unknown at this time. Additional analysis is required to improve modeling of discharging EVs to meet load requirements and to improve forecasting expected energy storage from EVs. Also, it is unclear how the customers will change their usage patterns if new rate structures like time-of-day rates or real time market price-based rates are adopted by the owner communities.

Other challenges include modeling potential load growth driven by the adoption of beneficial electrification policies, such as switching to electric hot water heaters and heat pumps, currently under consideration in the owner communities. This additional load may also require the owner communities to upgrade some distribution circuits and transformers while Platte River would need to acquire additional supply side resources.

9 IRP results

This chapter evaluates IRP modeling results and important features of the four portfolios with a focus on Platte River's three pillars of reliability, environmental responsibility and financial sustainability. Modeling results, including new resource additions, CO_2 reduction and costs for each of the four portfolios are discussed first. This is followed by a sensitivity analysis to test the resilience of each portfolio under differing values of major input assumptions. A qualitative summary concludes this chapter, followed by recommendations in Chapter 10.

9.1 Portfolio expansion plans

The four portfolios discussed in this IRP were developed to cover a wide spectrum of future possibilities. These four portfolios represent four snapshots of unique paths into the future. The following pages compare the capacity additions and retirements for different resource types in each of the four portfolios. Resource types are presented in alphabetical order. When a resource type retires, its capacity is reduced to zero. Capacity resources added as part of this IRP are labeled with "(new)". For example, existing solar resources are labeled as "solar" while the solar resources added as part of this IRP are labeled as "solar (new)".

Due to relatively low demand growth, none of the four portfolios add any new resources through 2028. From 2030 through 2040, the four portfolios add different amounts of resources. While this IRP does not add new resources prior to 2028, Platte River staff will continue to evaluate options to progressively add economical new resources to advance toward a 100% noncarbon supply mix while maintaining three pillars of reliable, environmentally responsible and financially sustainable energy and services.

P 1: continuity
Capacity expansion plan

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CTs	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Craig	151	151	151	151	151	74	74	74												
Hydro	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
RH1	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278
Solar	55	55	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	135
Solar (new)																100	100	100	100	100
Storage									50	50	50	50	100	100	100	100	100	150	150	200
Wind	231	231	231	231	231	231	231	231	225	285	285	285	285	285	285	285	285	285	285	285
Wind (new)									100	100	100	100	100	100	100	100	100	100	100	100

Figure 9-1

The **continuity portfolio** adds 100 MW of wind and 50 MW of battery storage capacity[10] in 2029 following the anticipated retirement of Craig 2 in 2028[11]. Rawhide Unit 1 and the combustion turbines remain in service through the end of the planning horizon. No additional thermal resources are added into this portfolio. As load grows, more battery storage capacity and renewable energy resources will be added to meet reserve margin and incremental energy requirements.

[10] All battery storage units are modeled with 4-hour storage capability. So, a 50 MW battery storage block has 200 MWh energy capacity.

[11] For this analysis, Craig 2 was assumed to retire on Dec. 31, 2028. On July 8, 2020, owners announced the retirement date as Sept. 30, 2028. This minor difference will not change the results or conclusions of this IRP.

P2: zero coal
Capacity expansion plan

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CTs	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Craig	151	151	151	151	151	74	74	74												
Hydro	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
RH1	278	278	278	278	278	278	278	278	278											
RICE										104	104	104	104	104	104	104	104	156	156	156
Solar	55	55	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	135
Solar (new)										300	300	300	300	300	400	400	400	400	400	400
Storage									100	300	300	300	300	350	400	400	450	450	450	450
Wind	231	231	231	231	231	231	231	231	225	285	285	285	285	285	285	285	285	285	285	285
Wind (new)									100	200	200	200	200	200	200	200	200	200	200	200

Figure 9-1

The **zero coal portfolio** adds 100 MW of wind and battery storage in 2029 following the anticipated retirement of Craig 2 in 2028, but significant rebalancing occurs when Rawhide Unit 1 retires in 2030. At that time, the baseload unit is replaced with 104 MW of RICE, 100 MW of wind, 300 MW of solar and 200 MW of battery storage. Following this rebalancing, more resources are added to meet anticipated demand growth, including 52 MW of RICE, 100 MW of solar and 150 MW of battery storage in later years. Gas-fired RICE generation with high level of flexibility complements renewable intermittency and provides back up during low renewable generation to ensure high level of reliability to the customers. Based on today's projections, RICE generation is the least cost option to provide reliability. If there is a technological breakthrough and a lower cost alternative is available to provide the same level of flexibility and reliability before the investment decision is made, Platte River will consider it.

P3: zero carbon
Capacity expansion plan

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CTs	388	388	388	388	388	388	388	388	388											
Craig	151	151	151	151	151	74	74	74												
Hydro	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
RH1	278	278	278	278	278	278	278	278	278											
Solar	55	55	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	135
Solar (new)										750	750	750	750	800	800	800	800	800	850	850
Storage									100	2400	2400	2400	2450	2450	2500	2550	2550	2600	2600	2600
Wind	231	231	231	231	231	231	231	231	225	285	285	285	285	285	285	285	285	285	285	285
Wind (new)									100	550	550	550	550	550	550	550	600	600	600	600

Figure 9-1

The **zero carbon portfolio** adds 450 MW of wind, 750 MW of solar and 2,300 MW of battery storage capacity to replace all the thermal resources. This level of battery storage would approximately serve the average Platte River demand for a period of 24 hours. While this would be enough to cover the dark calm events experienced in 2018, it would not be able to provide the reliability that a thermal system can provide with 15% of PRM. More analysis is required to understand the reliability risks associated with this portfolio, including the potential reliance on outside purchases during dark calm periods when neighboring utilities could face energy shortages due to weather similarities. Because no broad energy market currently functions in the region and because neighboring utility plans concerning noncarbon resources are expected to be somewhat similar, it is difficult to model broader market dynamics.

P4: integrated utilities
Capacity expansion plan

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CTs	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Craig	151	151	151	151	151	74	74	74												
Hydro	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
RH1	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278					
RICE																104	104	156	156	156
Solar	55	55	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	135
Solar (new)																400	500	500	500	500
Storage									100	100	100	100	100	100	100	400	400	400	400	400
Wind	231	231	231	231	231	231	231	231	225	285	285	285	285	285	285	285	285	285	285	285
Wind (new)									100	100	100	100	100	100	100	200	200	200	200	200

Figure 9-1

The **integrated utility portfolio** shows how Platte River may progress in a rapid energy transition future. This portfolio sees aggressive transportation electrification, high level of DER penetration and accelerated technology improvements resulting in lower prices for renewable resources and battery storage. Like the continuity portfolio, this portfolio relies on the least-cost approach to planning with no forced constraints (in contrast to the forced retirements in P2 and P3). Under this portfolio, Rawhide Unit 1 is economically retired in 2036 due to rapidly falling renewable and storage costs. At that time, this portfolio behaves like P2 and adds 104 MW of RICE for ensuring reliability and adds renewables and batteries to provide lower-cost energy.

9.2 Portfolio costs

Figure 9-2 shows annual generation costs for each of the four portfolios. Generation cost includes fuel, O&M, power purchase costs and netted for sales revenue. These costs do not reflect the full annual revenue requirements Platte River must collect from its owner communities. As noted previously, supply portfolios remain the same before 2029, resulting in cost curves that are similar as well. In 2030, the cost curves diverge based on the resource mix of each portfolio. Clearly visible, the zero carbon portfolio costs are significantly higher due to mandated replacement of all thermal resources, which undermines Platte River's core pillar of financial sustainability.

Generation costs of the remaining three portfolios are relatively closer together and follow approximately similar trajectories as shown in Figure 9-3. Cost of the zero coal portfolio rises in 2030 due to the new investment required to replace Rawhide Unit 1. The integrated utilities portfolio also sees a cost increase in 2036 following the retirement of Rawhide Unit 1, but this increase is smaller due to the lower costs of solar, wind and battery storage in this portfolio. By 2040 costs of the three portfolios converge within a 3% range. Around that time, the cost of the continuity portfolio is rising at a higher rate relative to the other two portfolios due to the impact of CO_2 taxes and fuel costs.

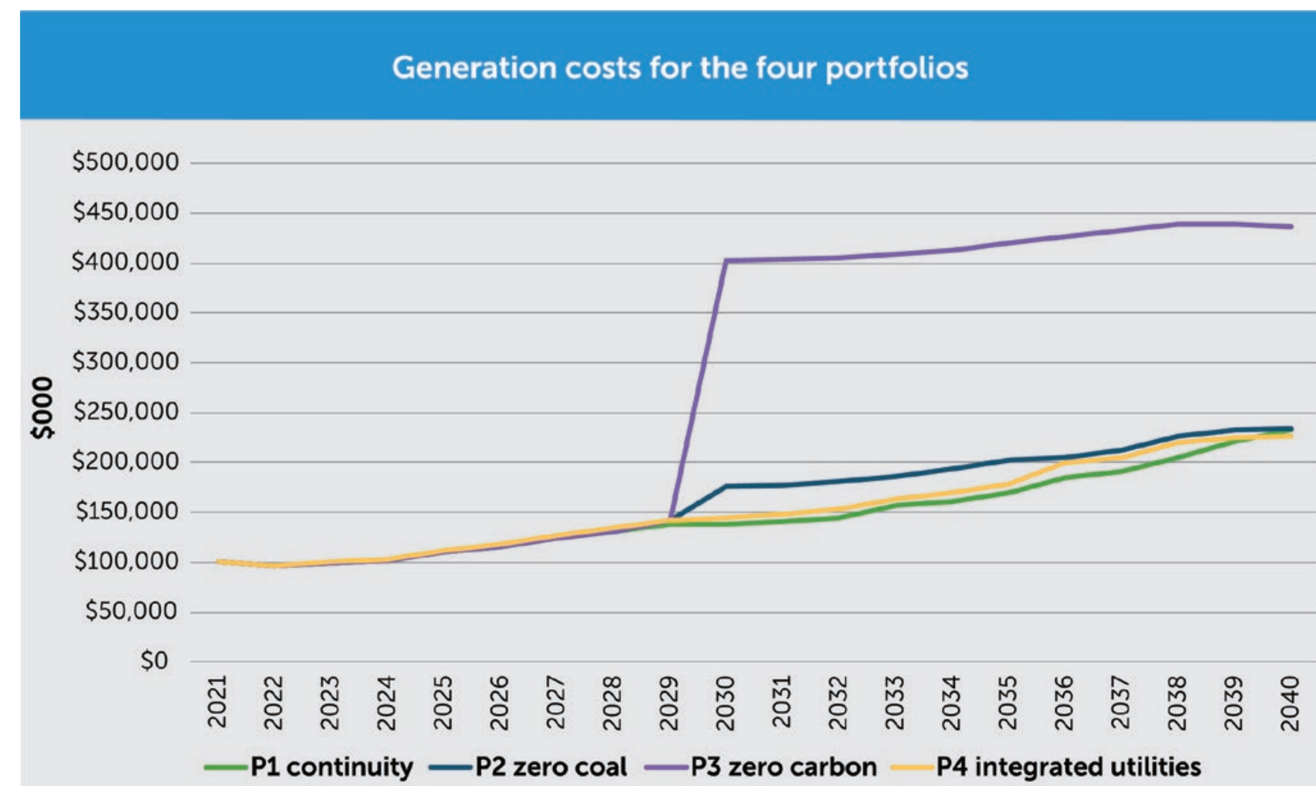


Figure 9-2

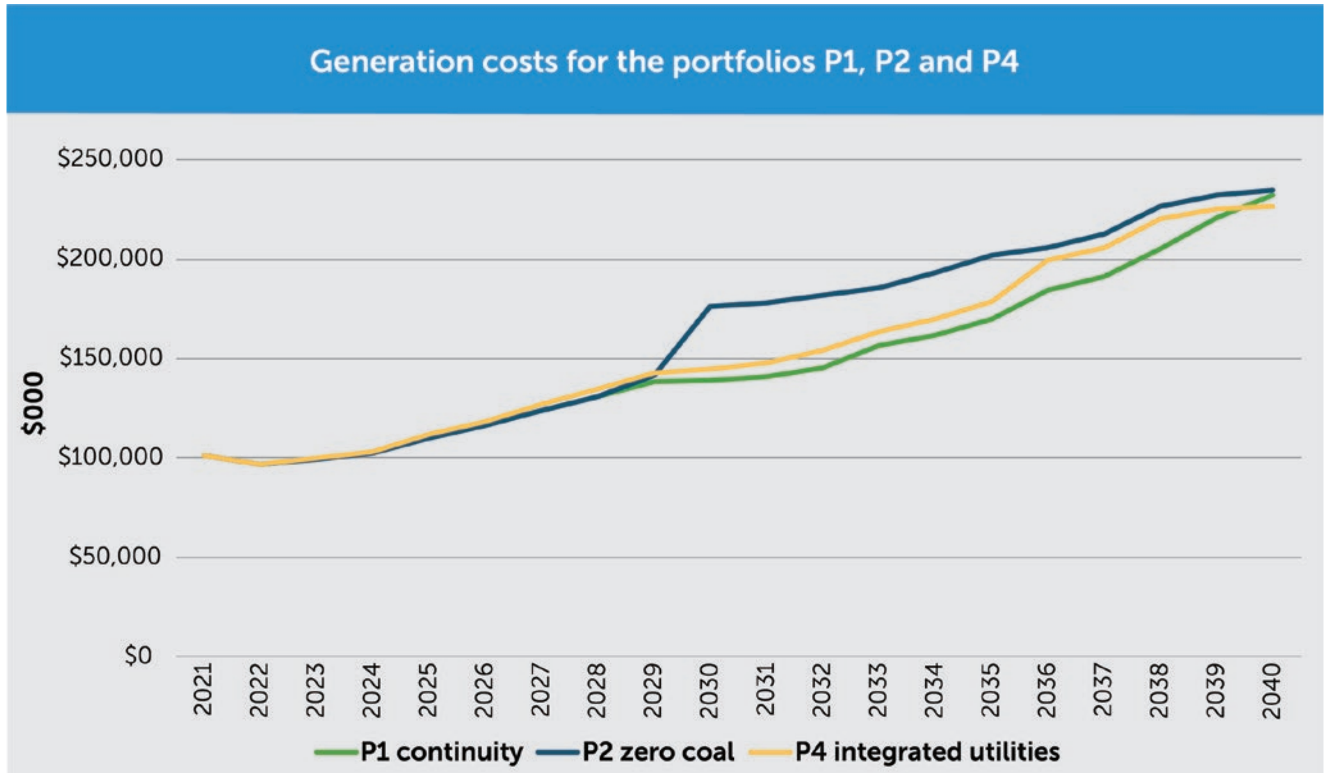


Figure 9-3

9.3 Portfolio wholesale 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, all aligned with its three pillars. Platte River's strategic financial plan (financial plan) provides a roadmap for long-term financial sustainability, financial risk management and support for Platte River's vision, mission and values. Platte River has established the following financial plan metrics in consideration of rating agency guidelines.

- Generate minimum 1.5 times fixed obligation charge coverage ratio
- Generate minimum net income equal to 3% of projected annual operating expenses
- Target debt ratio less than 50%
- Target minimum 200 days unrestricted cash on hand

The IRP rate analysis used a financial model that integrates the Aurora model outputs with other operating costs to project earnings, liquidity, debt and cash flows relative to financial plan targets over the IRP planning horizon. This process identifies future debt issuance and revenue requirements, thus projecting future rate increases. Key financial assumptions in the IRP rates analysis are as follows:

- PPAs were assumed for new wind, solar and battery storage additions.
- Battery storage PPAs were assumed to be a fixed obligation due to storage resources' nature as capacity resources with high fixed costs. Therefore, 1.5 times fixed obligation charge coverage ratio included battery storage PPA expense.
- Depreciation was accelerated for units retired before the end of their projected useful lives.
- Decommissioning costs for the Rawhide and Craig power plants were amortized annually until sites are decommissioned.
- Personnel transition costs were not included.
- Fossil fuel-based new resources were assumed to be owned and financed with debt when necessary to achieve financial plan targets.

Figure 9-4 shows future wholesale rate projections for the four portfolios. Rate smoothing strategies were incorporated into the rate projections to avoid large single-year rate increases or to accomplish specified financial objectives.

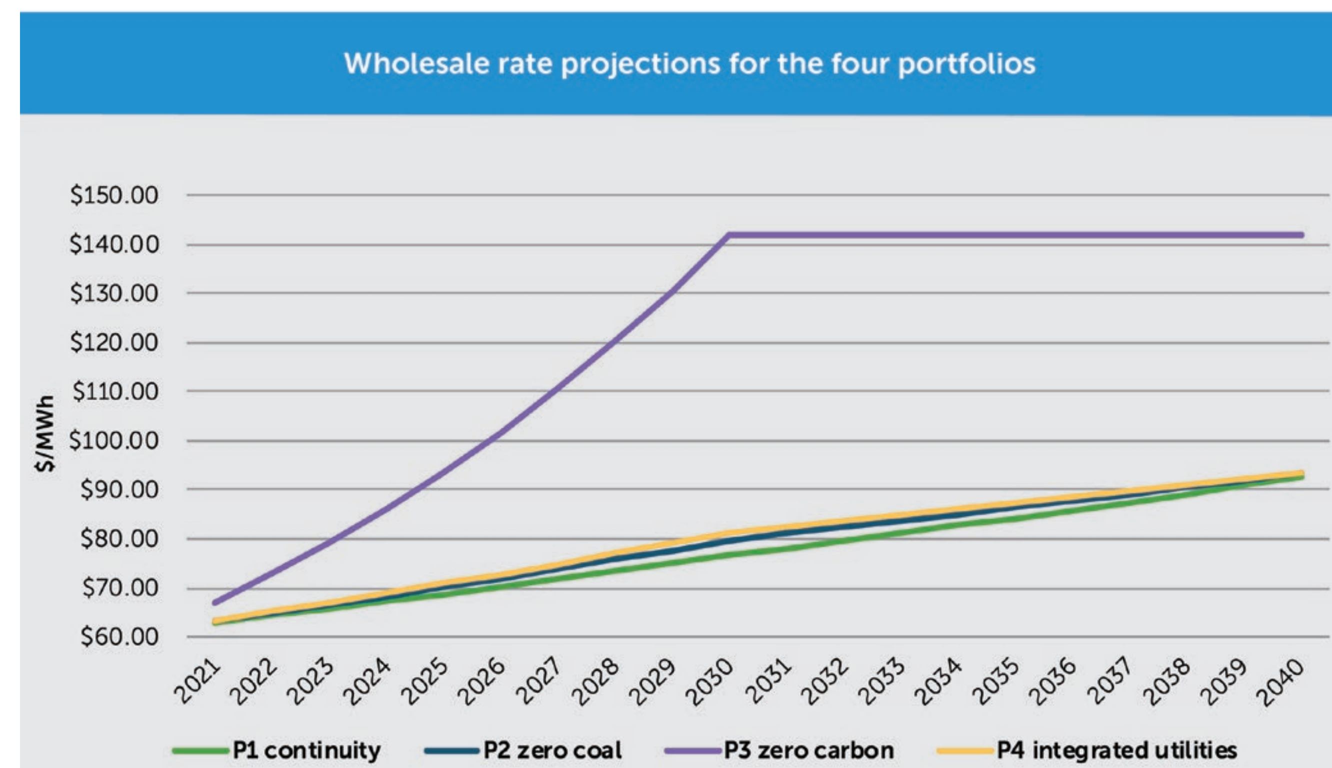


Figure 9-4

The **continuity portfolio** has the lowest projected rates over the long term. Rate drivers from 2020 to 2040 include purchased power expenses covering market prices and PPAs for wind, solar and battery storage resources. Additionally, CO_2 taxes contributed to rate pressure starting in 2025.

The **zero coal portfolio** retires all coal units but maintains the existing natural gas combustion turbines and projects RICE natural gas unit additions in 2030 and 2038 for reliability. These RICE units were assumed to be built and owned by Platte River. Purchased power is the most significant rate driver from 2020 to 2040, including increased wind, solar and battery storage. The average rate in the zero coal portfolio is roughly $3/MWh more than the continuity portfolio in 2030 and about the same in 2040.

The **zero carbon portfolio** eliminates all CO_2 operating emissions by retiring all coal and natural gas generation resources by 2030. Replacement energy and capacity resources include wind, solar and a significant amount of battery storage. To avoid a large rate increase in 2030, Platte River would begin implementing 8.7% average annual rate increases from 2021 to 2030. This increase leads to 2030 rates that are $65/MWh higher relative to the continuity portfolio. Although there are minimal rate increases after 2030, zero carbon portfolio rates in 2040 remain approximately $49/MWh higher than the continuity portfolio in 2040.

The **integrated utilities portfolio** assumes higher levels of DERs and lower wind and solar prices. Following the retirement of Rawhide Unit 1 in 2035, RICE capacity would be added in 2036 for reliability purposes. Increases in DER resulted in lower projected sales, thus requiring increased rates to recover fixed costs. For these reasons, 2030 rates would be $4/MWh higher than the continuity portfolio.

The rate impacts seen in Figure 9-5 are higher leading up to 2030 due to rate smoothing and the need to build reserves to meet the financial plan requirements. These rate projections show the zero coal portfolio would require a modest increase over the continuity portfolio. The integrated utilities portfolio would require slightly higher rates through the first half of the planning horizon but lower impacts in the later years, with an average rate increase on par with the zero coal portfolio. For the zero carbon portfolio, an average year-over-year rate increase of 8.7% is needed until 2030 and 0.0% increase from 2031 until 2040 for an average rate increase of 4.3% per year over the horizon of the study. Most of the rate increases in the zero carbon portfolio, relative to other portfolios, stem from the need to build a large amount of new, noncarbon generation and storage batteries to maintain reliability.

	Average annual growth rate			Cumulative growth rate		Rate	
	2021-2030	2031-2040	2021-2040	2021-2030	2021-2040	2030	2040
P1	2.2%	1.9%	2.0%	24.3%	50.1%	$77	$93
P2	2.6%	1.6%	2.1%	29.3%	51.5%	$80	$93
P3	8.7%	0.0%	4.3%	130.3%	130.3%	$142	$142
P4	2.8%	1.4%	2.1%	31.8%	51.5%	$81	$93

Figure 9-5 Wholesale rate comparison for the four portfolios

9.4 Portfolio CO_2 emissions

To measure environmental sustainability, Platte River reviewed CO_2 emissions from two different perspectives. First, reduction of CO_2 emissions relative to 2005 actual emissions, per Colorado standards, and, second, annual renewable energy as a percent of total annual energy supplied to the owner communities. These perspectives are discussed in sections 9.4.1 and 9.4.2. Section 9.4.3 gives a high level overview of recently enacted state legislation in Colorado; HB19-1261 and SB19-236.

9.4.1 CO_2 reduction relative to 2005 actual emissions

Figure 9-6 shows CO_2 reductions for the four portfolios relative to 2005 actual emissions. As in the case of generation costs, emission profiles of all the four portfolios are similar prior to 2030 because of similar resource mix. There is a steady decline in CO_2 emissions from 2021 through 2029 as the percent reduction relative to the 2005 baseline increases from 20% in 2021 to over 40% by 2029. This doubling of reduction is achieved through the gradual retirement of Craig coal units and addition of renewable generation. After 2029, P1 does not achieve any significant reduction. P2 sees emission reduction of above 90% in 2030 and beyond following the retirement of Rawhide Unit 1. P3 achieves 100% reduction with the retirement of all thermal generation in 2030. P4 experiences a large increase in emission reduction in 2036 following the retirement of Rawhide Unit 1.

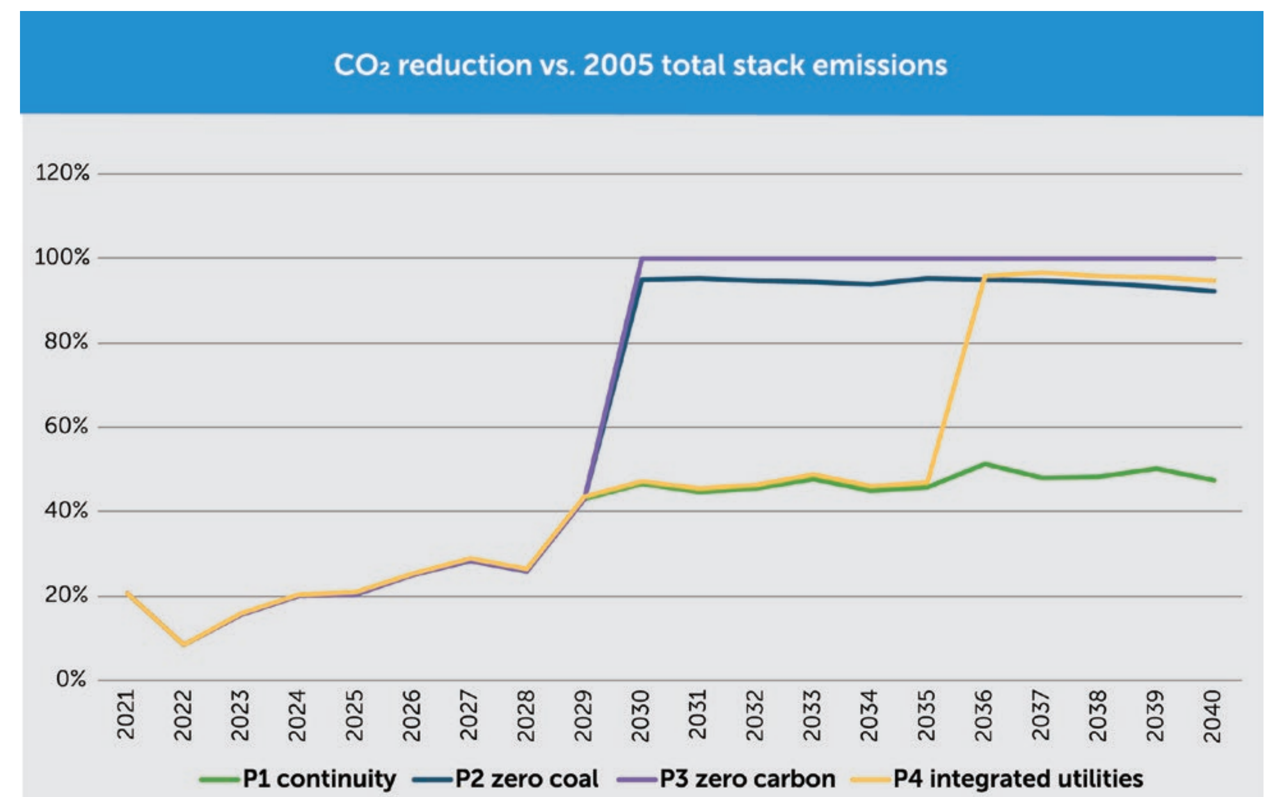


Figure 9-6

9.4.2 Percent renewable generation supplied

Figure 9-7 shows the amount of renewable or noncarbon generation as a percentage of total owner community load. All portfolios reach about 56% noncarbon supply by 2024, reduce slightly due to load growth and reach 65% by 2029 and then diverge. The continuity portfolio's noncarbon energy production percentage stays around 65% through the planning horizon, with minor changes due to load growth and new resource additions. The zero coal portfolio reaches 100% noncarbon generation by 2030 and then fluctuates around that value due to load growth and new resource additions. The zero carbon portfolio noncarbon generation rises much higher than 100% of owner community load due to the excess renewable resources required for reliability purposes. Finally, the integrated utilities portfolio follows the continuity portfolio until the retirement of Rawhide Unit 1 in 2036 and then stays above 100%.

As discussed in the supply-side assumptions chapter, 100 MW of new solar addition in 2024 was assumed from the currently on-going solicitation for 50-150 MW of new solar generation. From the initial review of the offers, it seems likely that 150 MW may be procured in this solicitation, increasing the level of carbon free energy initially assumed. Figure 9-8 shows the percentage of carbon free energy with 150 MW of new solar instead of 100 MW. With this increase, Platte River will be able to provide about 60% noncarbon energy by 2024, as seen in Figure 9-8.

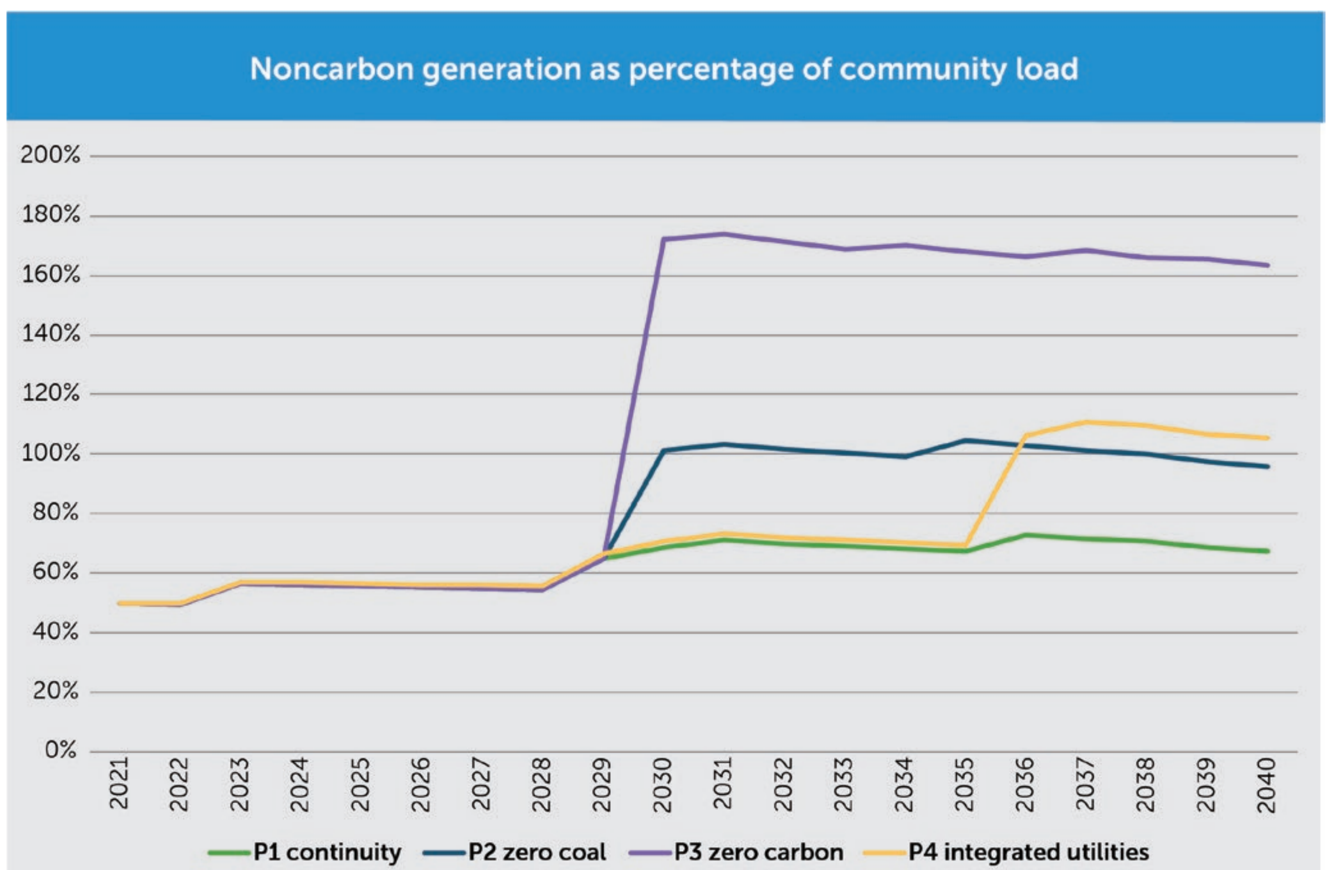


Figure 9-7

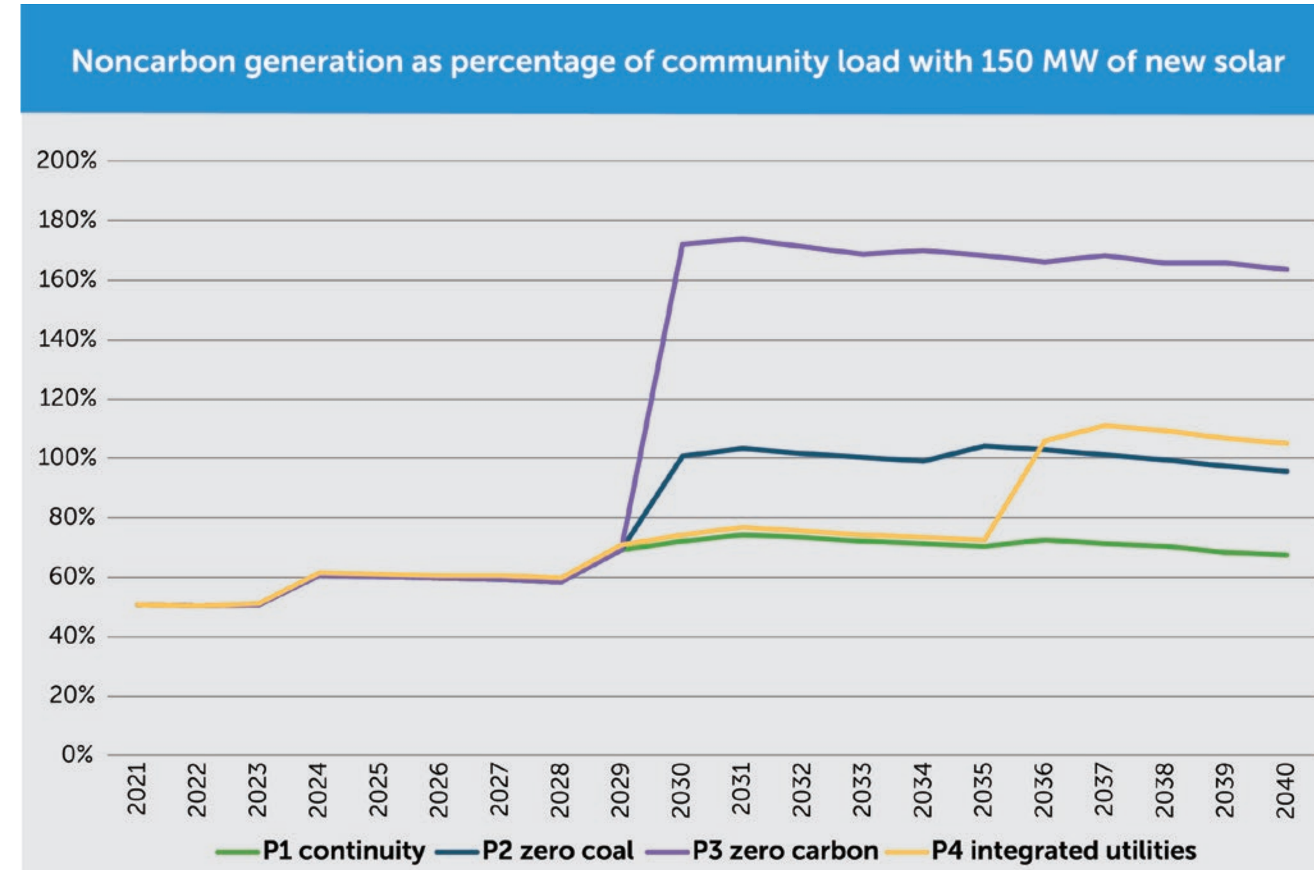


Figure 9-8

9.4.3 Colorado CO_2 legislation (HB19-1261 and SB19-236)

HB19-1261

Colorado House Bill 19-1261, titled Climate Action Plan to Reduce Pollution, establishes statewide goals to reduce 2025 greenhouse gas emissions by at least 26%, 2030 greenhouse gas emissions by at least 50%, and 2050 greenhouse gas emissions by at least 90% of the levels of greenhouse gas emissions that existed in 2005. It also specifies what the Colorado Air Quality Control Commission (AQCC) must consider when implementing policies and promulgating rules to reduce greenhouse gas pollution, including the benefits of compliance and the equitable distribution of those benefits, the costs of compliance, opportunities to incentivize clean energy in transitioning communities, and the potential to enhance the resilience of Colorado's communities and natural resources to climate impacts. In lieu of rulemaking, the bill permits utilities to voluntarily submit a clean energy plan (CEP) to the AQCC, as long as that plan commits to an 80% reduction in greenhouse gas emissions by 2030.

SB19-236

Colorado Senate Bill 19-236, also known as the Sunset Public Utilities Commission bill, requires among a host of other things, a qualifying retail utility to submit a clean energy plan, and allows any other electric utility to voluntarily submit a plan to the commission as part of its ongoing resource acquisition planning process to seek approval from the commission on how the qualifying retail utility plans to address clean energy targets established in the act.

As noted in section 9.4.1, P2 and P3 meet the requirements of voluntary reduction of CO_2 emissions by 80% by the year 2030 while P1 and P4 do not meet this voluntary requirement.

9.5 Sensitivity analysis

Sensitivity analysis refers to changing one or more assumptions used in developing the portfolio and analyzing resulting changes in different attribute of the portfolio. Sensitivity analysis is very important to test the robustness of portfolios under the circumstances when one or more key inputs or variables diverge from the assumed values. The sensitivity analysis considered the impact of two key assumptions: prices for CO_2 and natural gas.

9.5.1 Social cost of carbon sensitivity

The state of Colorado requires investor owned utilities to incorporate the social cost of carbon into resource planning decisions[12]. Following this guidance, Platte River analyzed the impact of adding the social cost of carbon for CO_2 emissions from thermal generation resources. To model this sensitivity, CO_2 tax of $4/ton starting in 2025 was replaced with the social cost of carbon of $46/ton in 2020 escalating at 3% per year. The social cost of carbon of $46/ton adds about $50/MWh to the dispatch cost which is more than three times the fuel cost of coal plants. With this large increase in cost, coal generation does not remain economical to operate. Consequently, all coal generation tends to retire when the social cost of carbon is added, provided enough renewables and other resources are available to reliably meet customer load. If this sensitivity was run unconstrained, all coal generation would retire in 2021, the first year of planning. Since it takes two to three years to plan, permit and construct new generation, for modeling this sensitivity, Rawhide Unit 1 was not allowed to retire before 2023. The Craig units were retired at their planned dates in 2025 and 2028 respectively, because Platte River cannot unilaterally retire them as a partial owner. The resulting least-cost portfolio with the social cost of carbon looks very similar to the zero coal portfolio but with an earlier transition to renewables. The portfolios are shown in Figure 9-9.

[12] Senate Bill 19-236 §40-3.2-106 (4)

Social cost of carbon sensitivity

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CTs	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Craig	151	151	151	151	151	74	74	74												
Hydro	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
RH1	278	278	278	278																
RICE					104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104
Solar	55	55	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	135
Solar (new)					100	200	200	300	300	400	400	400	400	400	400	400	400	400	400	400
Storage					100	200	200	200	300	300	300	300	350	350	350	400	450	500	600	600
Wind	231	231	231	231	231	231	231	231	225	285	285	285	285	285	285	285	285	285	285	285
Wind (new)					100	100	100	100	100	100	100	100	100	200	200	200	200	300	300	300

Portfolio 2: zero coal

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CTs	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Craig	151	151	151	151	151	74	74	74												
Hydro	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
RH1	278	278	278	278	278	278	278	278	278											
RICE										104	104	104	104	104	104	104	104	156	156	156
Solar	55	55	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	135
Solar (new)										300	300	300	300	300	400	400	400	400	400	400
Storage									100	300	300	300	300	350	400	400	450	450	450	450
Wind	231	231	231	231	231	231	231	231	225	285	285	285	285	285	285	285	285	285	285	285
Wind (new)									100	200	200	200	200	200	200	200	200	200	200	200

Figure 9-9 Expansion plan comparison; zero coal portfolio and the social cost of carbon sensitivity

Under the social cost of carbon sensitivity, Rawhide Unit 1 is replaced with 104 MW of RICE and 100 MW each of wind, solar and battery storage in 2025. As the Craig units are retired, additional storage and renewable resources fill in as needed until the portfolio reaches stability in 2030.

In terms of total generation cost and CO_2 reduction, the social cost of carbon sensitivity behaves like the zero coal portfolio except for the earlier retirement of the coal fleet, as shown in Figures 9-10 and 9-11.

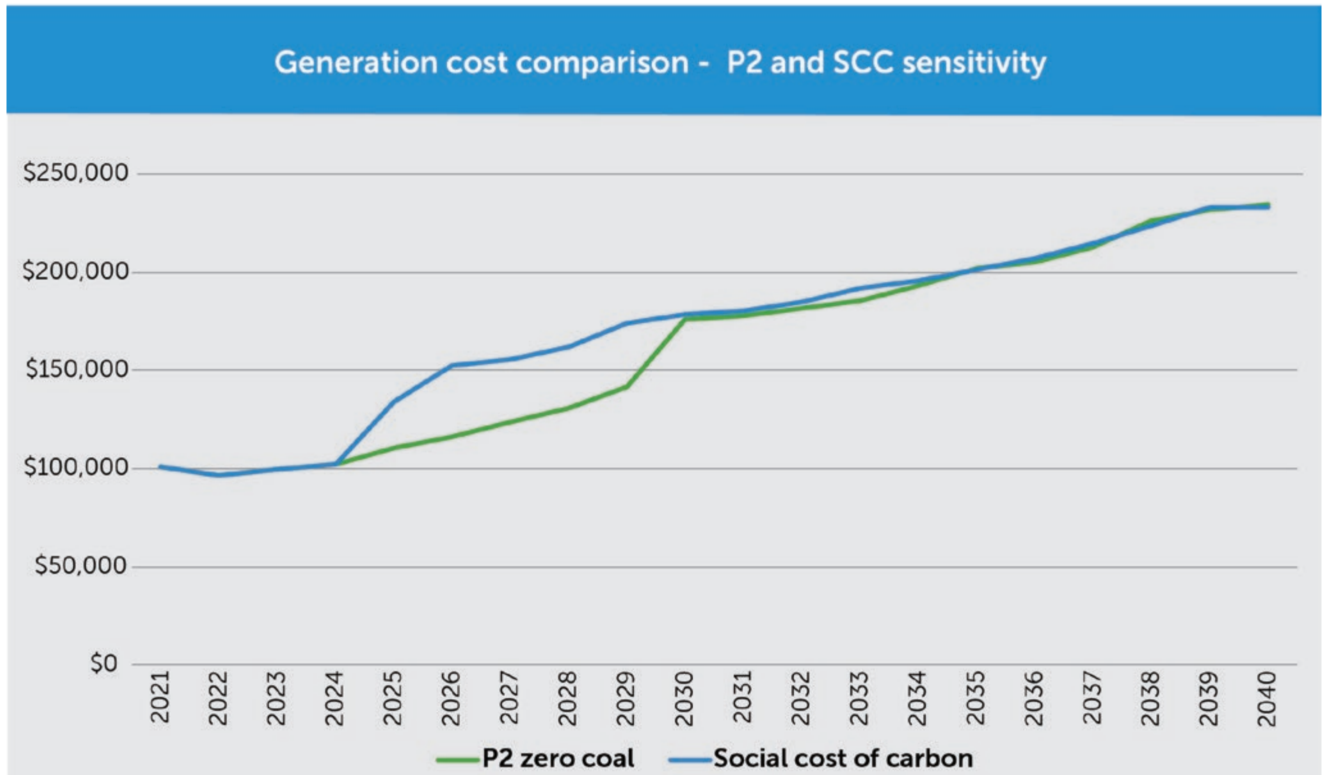


Figure 9-10

9.5.2 CO_2 cost sensitivity

As noted earlier, a CO_2 tax was included in all the portfolios. This CO_2 tax starts at about $4/ton in 2025 and escalates to around $9/ton in 2030 and $35/ton in 2040. Two sensitivities around the CO_2 tax were tested: a no carbon tax case and a tax equal to the social cost of carbon. The social cost of carbon starts in 2020 at $46/ton and escalates at 3% per year to reach approximately $98/ton in 2040. The results of CO_2 price sensitivity are shown in Figure 9-12.

The continuity portfolio with the highest level of coal generation shows the greatest risk exposure in terms CO_2 pricing, with an NPV cost reduction of about 10% in the no carbon tax case and a 90% increase in costs for the social cost of carbon case. The zero coal portfolio provides the lowest risk with a cost reduction of 3% in the no carbon tax case and a cost increase of about 50% in the social cost of carbon case. The integrated utilities portfolio risk profile falls between the continuity and zero coal portfolios with a cost decrease of 6% and an increase of 80%, respectively.

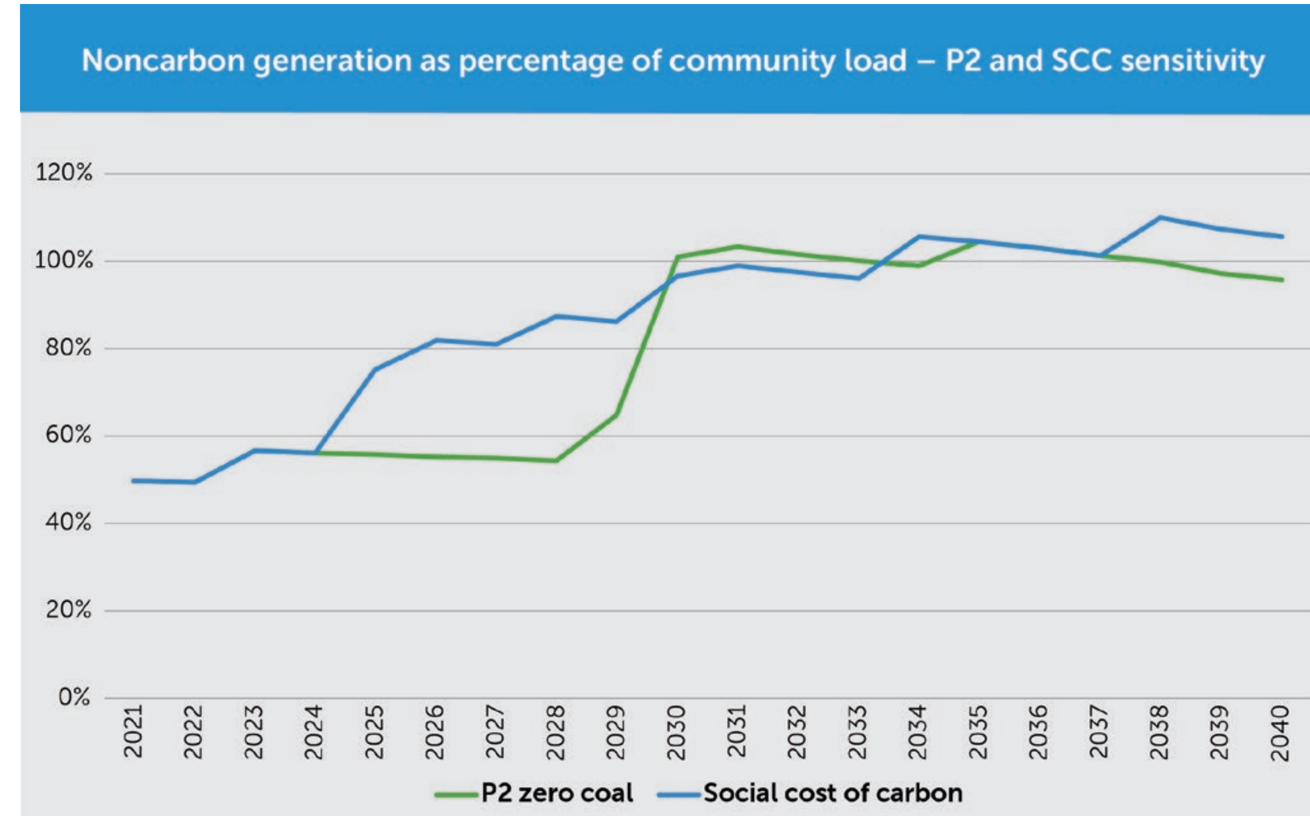


Figure 9-11

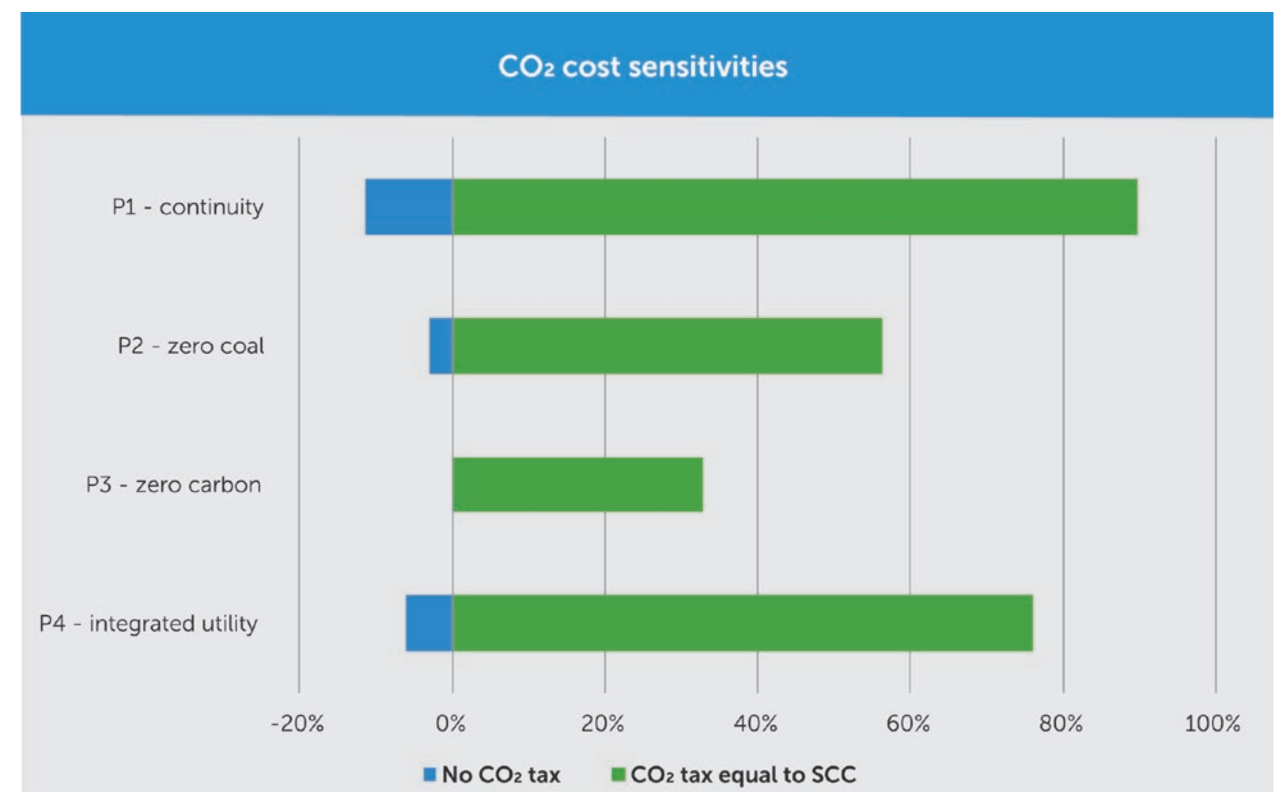


Figure 9-12

9.5.3 Gas price sensitivity

In addition to the base gas price forecast at CIG, two gas price sensitivities were considered: one representing high gas prices and another representing low gas prices. Gas price sensitivities, as well as the corresponding electricity market prices, were developed by Siemens. Base, high and low gas forecast price are provided in Figure 9-13.

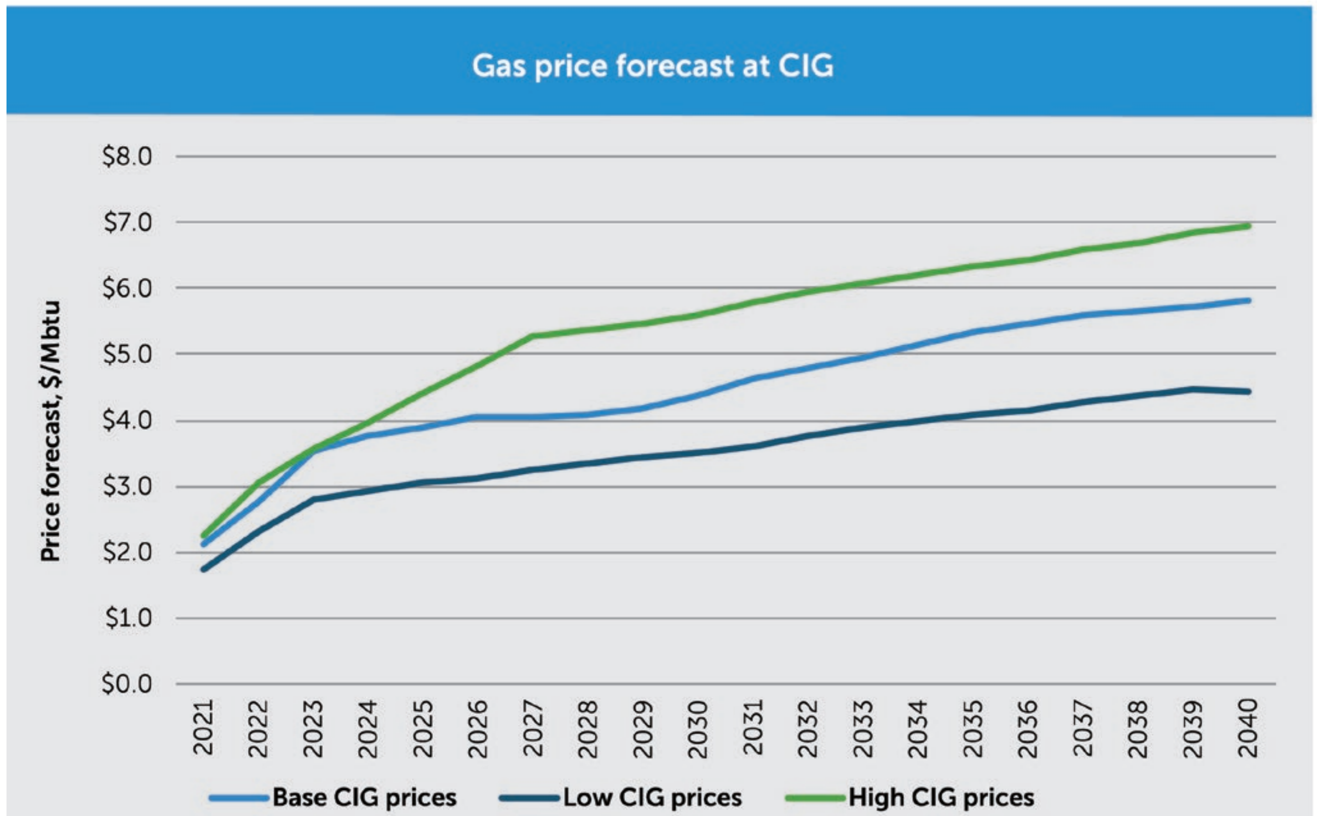


Figure 9-13

High gas prices typically lead to higher electricity market prices, which would enable increased opportunities for surplus sales from Platte River's coal and renewable generation fleet. Higher sales revenue generates greater margins, which lead to reduced costs for Platte River customers. Conversely, low gas prices suppress wholesale electricity prices, reducing surplus sales revenue and increasing customer costs. As shown in Figure 9-14, the continuity portfolio is the most sensitive to gas price changes, with a cost reduction of 3% in the high gas price case and a cost increase of 3% in the low gas price case. The zero coal portfolio is the least sensitive to gas price fluctuations, with a cost reduction of 1% and a cost increase of 1% for the high and low gas price sensitivities. The integrated utilities portfolio performs with less sensitivity than the continuity portfolio, with cost changes of about 2.5%. The zero carbon portfolio was not tested with gas price sensitivity because no gas would be used. Given these results, the continuity portfolio represents the largest cost risk associated with natural gas price variations.

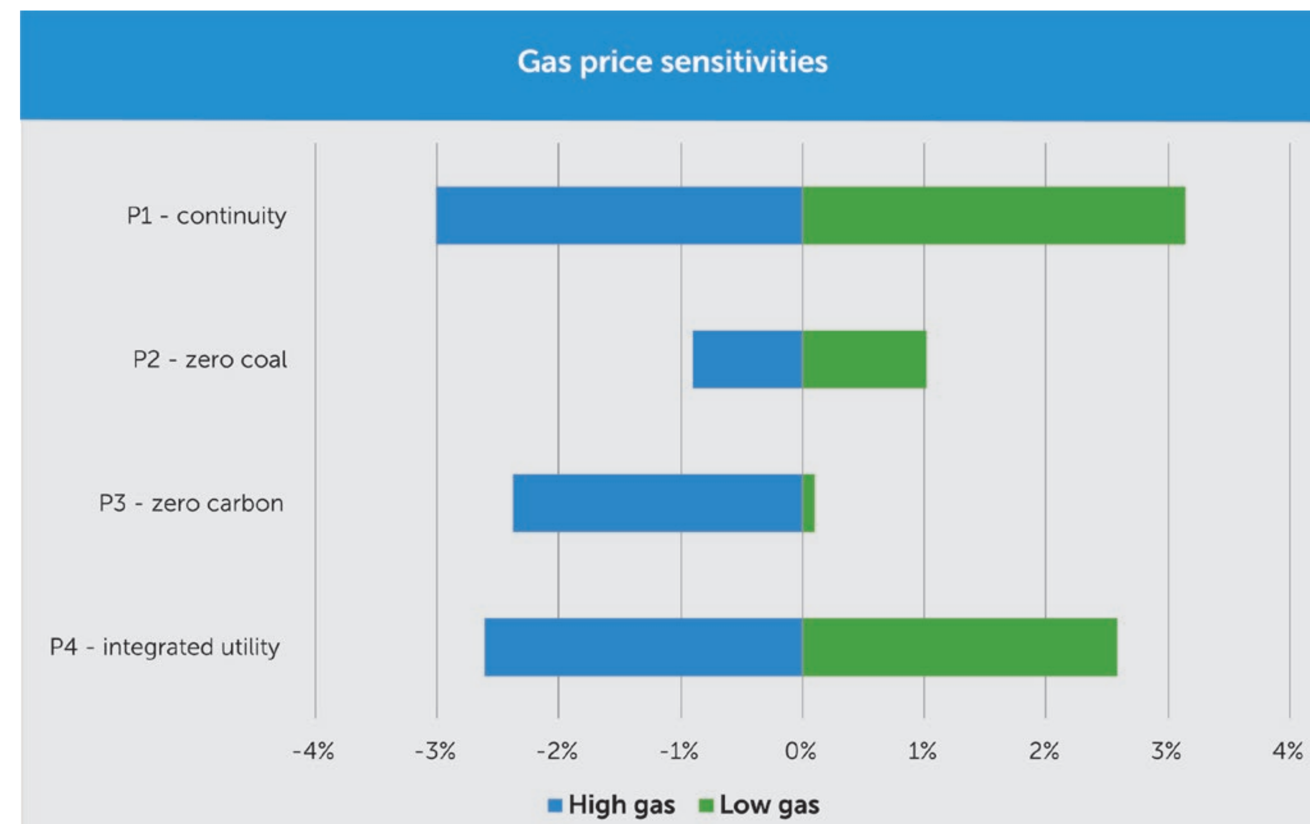
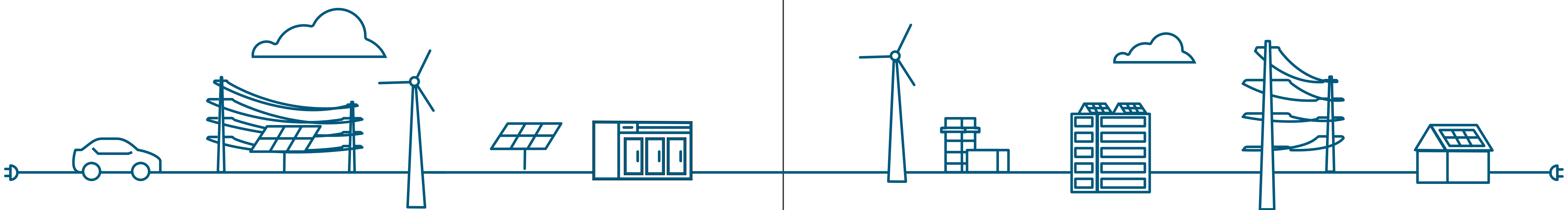


Figure 9-14

10 Recommendation



Portfolio 2: **zero coal**

Long term utility planning is a dynamic process, whereby the plans are updated regularly as technology evolves and new information becomes available. By developing four portfolios, this IRP illustrates four distinct futures out of an infinite number of possibilities.

The assumptions used in this IRP are based on the best available information at this time, but the industry is evolving quickly. To ensure timely decisions, Platte River will develop a generation supply plan before its next IRP, due in 2025, which will include updated assumptions and revised forecasts. Interim planning will allow Platte River to remain flexible, to take advantage of opportunities or respond to new developments.

To continue its journey toward a 100% noncarbon resource mix, **Platte River staff recommends the zero coal portfolio as the best option under the current assumptions.** With the announcement of the planned retirement of Rawhide Unit 1 by 2030, this portfolio represents a natural progression toward meeting the goals of the Resource Diversification Policy.

This portfolio significantly reduces emissions by relying extensively on renewable energy and using natural gas to maintain system reliability at a relatively low cost to the owner communities. Additionally, this portfolio meets the requirement of 80% CO_2 reduction from 2005 level and allows Platte River to file a voluntary CEP in compliance with state legislation (SB19-236 and HB19-1261). In addition to satisfying stakeholder desires for carbon emission reductions, the zero coal portfolio will ensure Platte River can meet future environmental requirements.

The recommended portfolio is a possible roadmap for the future and not a firm investment plan. Platte River staff is committed to modifying plans in line with the directions of the board and desires of the owner communities.

Staff will continue to refine this portfolio with new data and assumptions with a focus on evaluating battery storage and DERs to maintain reliability at a reasonable cost. With these refinements and improvements, Platte River will continue to advance toward a 100% noncarbon supply mix while maintaining the three pillars of safely providing reliable, environmentally responsible and financially sustainable energy and services.

11 Appendices

Appendix A. IRP checklist for WAPA[13]

Document section	Requirement	Included in this IRP	Section number
IRP portfolios	Does the IRP evaluate the full range of alternatives for new energy resources?	✓	7.9 – 7.14, 11.1, 11.3, 11.5
Ensuring system reliability	Does the IRP provide adequate and reliable service to the customer's electric consumer?	✓	8.1 – 8.4
Ensuring system reliability	Does the IRP take into account the necessary features for system operation?	✓	8.1 – 8.4
Existing DER programs and activities	Does the IRP take into account the ability to verify energy savings achieved through energy efficiency?	✓	6.7
Existing DER programs and activities	Does the IRP take into account the projected durability of such savings measure over time?	✓	6.7
IRP portfolios	Does the IRP treat demand and supply resources on a consistent and integrated basis	✓	6.8.2, 8.5
IRP portfolios	Does the IRP consider electrical energy resource needs? The IRP may, at the customer's option, consider water, natural gas, and other energy resource options.	✓	6.3
IRP assumptions – supply side	Does the IRP identify and compare resource options?	✓	7.9 – 7.14, 11.1
IRP portfolios	Does the IRP clearly demonstrate that decisions were based on a reasonable analysis of the options?	✓	9.3 - 9.7
IRP results and recommendations	Does the IRP include an action plan describing specific actions the customer will take to implement the IRP?	✓	1.2, 9.9
IRP portfolios	Does the IRP list the time period that the action plan covers?	✓	1.2, 9.9
IRP results and recommendations	Does the IRP include an action plan summary consisting of: Actions the customer expects to take in accomplishing the goals identified in the IRP? Milestones to evaluate accomplishment of those actions during implementation? Estimated energy and capacity benefits of each action planned?	✓	4.0

Document section	Requirement	Included in this IRP	Section number
IRP results and recommendations	Does the IRP, to the extent practicable, minimize adverse environmental effects of new resource acquisitions and document these efforts?	✓	9.6
IRP results and recommendations	Does the IRP include a qualitative analysis of environmental effects in a summary format?	✓	9.6
Community engagement	Does the IRP provide ample opportunity for full public participation in preparing and developing the IRP?	✓	5
Community engagement	Does the IRP include a brief description of public involvement activities?	✓	5
	Does the IRP document that each member based association (MBA) member approved the IRP, confirming that all requirements have been met?	NA	
	Does the IRP contain the signature of each MBA member's responsible official, or document passage of an approval resolution by the appropriate governing body?	NA	
Load forecast	Does the IRP contain a statement that the customer conducted load forecasting, including specific data?	✓	6.1 – 6.2
IRP results and recommendations	Does the IRP contain a brief description of measurement strategies for identified options to determine whether the IRP's objectives are being met?	✓	10
IRP portfolios	Does the IRP identify a baseline from which the customer will measure the benefits of IRP implementation?	✓	8.5
	Does the IRP specify the responsibilities and participation levels of individual members of the MBA and the MBA?	NA	

[13] This check list is available at https://www.wapa.gov/EnergyServices/IRP/Pages/review-checklist.aspx

Appendix B: IRP studies

Key findings of the nine studies conducted by Platte River's outside consultants and advisors as part of this IRP are discussed blow. Where appropriate, the full studies are available on the IRP microsite.

1. Generation technology review

Consultant: Pace/Siemens Inc.

The generation technology review (GTR) is a comprehensive study of resources that Platte River may evaluate in more detail during the 2020 integrated resource planning (IRP) process. The GTR helps to identify the most viable resource options to help meet the energy goals of the owner communities and their communities.

Key findings:

- Existing generation resources continue to provide reliable supplies until their respective retirement dates
- Should consider solar, wind, battery storage, distributed resources, energy efficiency, demand response and gas-fired fossil fuel generation to meet future energy needs

2. Regional economic impacts

Consultant: Colorado State University

The economic impact study estimates the impacts of a range of potential electricity price changes due to changes in the generation portfolio. Economic impacts were estimated for each of the four communities served by Platte River—The Town of Estes Park, and the Cities of Fort Collins, Longmont and Loveland. The impacts on both residential and commercial users were estimated as well. Multiple metrics, including changes in employment, household income, and local economic activity (called domestic supply), are used to measure the economic impacts.

Key findings:

- Rate increases will have
  - Higher impact on low income households
  - Potential negative impact on businesses through higher production costs

3. Energy storage technology assessment

Consultant: HDR Inc.

This report provides technology characteristics and an estimated cost comparison of several specific types of Energy Storage Systems that are suitable for use on Platte River's system. Characteristics of pumped hydropower energy storage systems (PHES), battery energy storage systems (BESS), and compressed air energy storage are discussed in this report. Life cycle cost estimates for PHES and BESS technologies are analyzed over a 30-year life cycle cost basis considering operations and maintenance costs, major maintenance, augmentation, purchased power, and capital recovery costs. Using these results technologies are compared on levelized costs.

Key findings:

- Lithium-ion batteries and pumped hydro storage are commercially proven technologies
- Lithium-ion batteries have the lowest life cycle cost estimate for four-hour storage requirements
- Pumped hydro storage has the lowest life cycle cost for 10-hour storage
- May take 8-10 years to build
- Environmental impacts/permitting challenges

4. Coal cycling

Consultant: Burns & McDonnell Inc.

This study examines the operational and economic impacts on the Rawhide coal unit as cycling increases to follow intermittent renewable energy generation. As more renewable resources are added to Platte River's portfolio and in the region, baseload coal units will need to cycle more than they have traditionally done in the past.

Key findings:

- Rawhide coal unit will have more starts per year to follow intermittent renewable generation
- Fixed operations and maintenance cost will increase

5. Thermal generation alternatives

Consultant: HDR Inc.

This report evaluates thermal generation options to support and allow for the integration of renewable generation. The purpose of this study is to characterize potential natural gas fired generation resources selected by the Platte River evaluation team in support of the IRP process. The information provided in this study includes generation performance estimates, emissions data, capital cost estimates, operations and maintenance cost estimates, and inputs to the Aurora electric market model for each of the potential generation options identified.

Key findings:

- Small gas turbines and reciprocating engines are viable backup thermal resources for Platte River to complement intermittent renewable resources
- Reciprocating engines can be installed in smaller increments
- Small gas turbines have lower capital cost

6. Resource adequacy review

Consultant: Burns & McDonnell Inc.

This report provides a review of reliability and planning regulations related to increased wind and solar penetration, reserve requirement metrics, and methods to determine adequate reserve margins. The goal for this review is gain a better understanding of the planning criteria needed to ensure reliability when relying on intermittent renewable generation and energy storage systems.

There are three reliability related metrics that are reviewed: a review of Effective Load Carrying Capability, a review of Platte River's Loss of Load Probability and an assessment of regulatory and policy requirements for today and in the future.

Key findings:

- Continue to use 15% planning reserve margin as recommended by the North American Electric Reliability Corporation
- Use declining curves for capacity contribution from wind and solar resources for reliability purposes

7. Market analysis

Consultant: PACE/Siemens Inc.

This report provides price forecasts for gas, power, renewables and emissions that are used as inputs to the Aurora model.

Key findings:

- Gas prices will stay depressed through 2023, before increasing due to increasing exports and consumption in the power sector
- A carbon tax will be levied within the next five years
- In the short run, solar and wind prices will increase due to tax incentive expiration in 2023
- Over the long run, solar and battery prices will continue to decline due to technological improvements

8. DER potential

Consultant: HDR Inc.

The purpose of this report is to evaluate DERs, including energy efficiency, demand response (including distributed energy storage and EVs) and distributed solar and to forecast how much DERs are cost-effective and achievable.

Key findings:

- May be able to increase annual energy efficiency results
- Demand response has potential to reduce peak hour electric demand
- Distributed solar is anticipated to grow

9. Life cycle carbon impact

Consultant: Colorado State University

This report provides estimates the lifetime carbon emissions of generation resources, including carbon emissions during manufacturing, construction and operation.

Key findings:

- Coal is the biggest source of CO_2 operating emissions with emission rate at 1150 kg/MWh. For coal fired plants, CO_2 emissions related to coal mining and transportation are approximately 10% of the stack emissions.
- Natural gas-fired generation operating emission rate (including extraction, fugitive and transport losses) is between 60% and 70% of the coal operating emission rates. Stack-only CO_2 emissions from new natural gas-fired generation are approximately 50% of the stack emissions of coal-fired generation.
- CO_2 emissions related to manufacturing, transportation, construction, commissioning and decommissioning are relatively insignificant as compared to operating emissions for all types of thermal generation.
- Lifetime average CO_2 emissions from solar, wind and battery storage are negligible while hydro power emission rate is 25 kg/MWh, which is small compared to thermal resources.

Appendix C: DER programs

Demand response measures

Residential			
HVAC programmable communicating thermostat (PCTs)	All residential	3	24
HVAC DLC	All residential	3	24
Water heater DLC	All residential	3	48
Battery and plug-in hybrid vehicles DLC - charging interruption during peak hours	All residential	4	260
BESS (5 kW) automated demand response	Single family	4	260
BESS (5-10 kW) automated demand response	Multi-family	4	260
Commercial / industrial			
HVAC automated demand response	Commercial / industrial	3	24
HVAC DLC and PCTs	Commercial / industrial	3	24
50 kW BESS automated demand response	Commercial / industrial	2	260
150 kW BESS automated demand response	Commercial / industrial	2	260
Industrial process - automated demand response	Industrial	3	48
Industrial process - manual demand response	Industrial	3	48
Lighting - luminaire, zonal and standard control options	Commercial / industrial	3	48
Refrigerated warehouse - automated demand response	Industrial	3	48
Other			
Voltage reduction	System	4	36

Residential energy efficiency measures

Heating	
Smart thermostat installation - electric heating*	All residential
Smart thermostat installation - gas heating*	All residential
Programmable thermostat installation - heating	All residential
Weatherization: air sealing	All residential
Weatherization: insulation	All residential
High efficiency windows	All residential
Installation of ENERGY STAR® storm windows/doors	All residential
Install heat recovery ventilation	All residential
Cooling	
Central air conditioner upgrade	All residential
Smart thermostat installation - cooling*	All residential
High efficiency air handler/rooftop units	Multi-family
Ventilation	
Electrically commutated furnace blower motor	All residential
Water Heating	
Heat-pump electric storage water heater	All residential
Lighting	
LED upgrade (interior)	All residential
LED upgrade (exterior)	Single family
Refrigeration	
ENERGY STAR® freezer	All residential
ENERGY STAR® refrigerator	All residential
Refrigerator recycling	All residential
Miscellaneous	
ENERGY STAR® pool pumps	All residential
ENERGY STAR® dishwasher	All residential
ENERGY STAR® clothes washer	All residential
ENERGY STAR® clothes dryer	All residential
ENERGY STAR® electronics (advanced power strip)	All residential
Faucet aerators	All residential
Low flow shower heads	All residential

* A smart thermostat is one physical device but impacts both heating and cooling. Therefore, the smart thermostat measures are broken down by end-use and customer heating type. During total resource cost test, the measures were appropriately combined to evaluate the economic viability.

Commercial & industrial energy efficiency measures

Heating	
Smart thermostat installation - heating*	All commercial categories
Cooling	
Air-cooled chiller upgrade	All commercial categories
Water-cooled chiller upgrade	Healthcare, industrial, and office categories
Evaporative pre-cooling installation on air-cooled condenser	Retail, education, healthcare, industrial, office and utility
High efficiency air handler/rooftop units	All commercial categories
Advanced RTU controller (ARC) retrofit	All commercial categories
Smart thermostat installation - cooling*	All commercial categories
Ventilation	
Electrically commutated motor-variable air volume	All commercial categories
NEMA super premium motors	Education, healthcare, industrial, office, utility
Lighting	
LED screw-in upgrade from CFL (interior)	All commercial & Industrial categories
LED linear upgrade from T8/T12 (interior)	All commercial & Industrial categories
LED high-bay fixtures (interior)	Industrial
LED upgrade (exterior)	All commercial categories
LED screw-in upgrade (exterior)	Industrial
LED area lighting upgrade (exterior)	Industrial
LED linear lighting upgrade (exterior)	Industrial
Smart lighting controllers / occupancy sensors	All commercial categories
Smart lighting controllers / daylight sensors	All commercial categories
Cooking	
Electric combination ovens	Food sales, food service and healthcare categories
Electric exhaust hood	Food sales, food service and healthcare categories
Refrigeration	
Refrigerator floating-head pressure controls	Food sales and food service categories
Refrigerator/freezer gaskets	Food sales and food service categories
Office equipment and computing	
Advanced power strips	All commercial & industrial categories
Miscellaneous	
Energy assessment retro-commissioning	All commercial & industrial categories
Energy management system with data analysis	All commercial & industrial categories

*A smart thermostat is one physical device but impacts both heating and cooling. Therefore, the smart thermostat measures are broken down by end-use and customer heating type. During total resource cost test, the measures were appropriately combined to evaluate the economic viability.

Appendix D: Aurora model

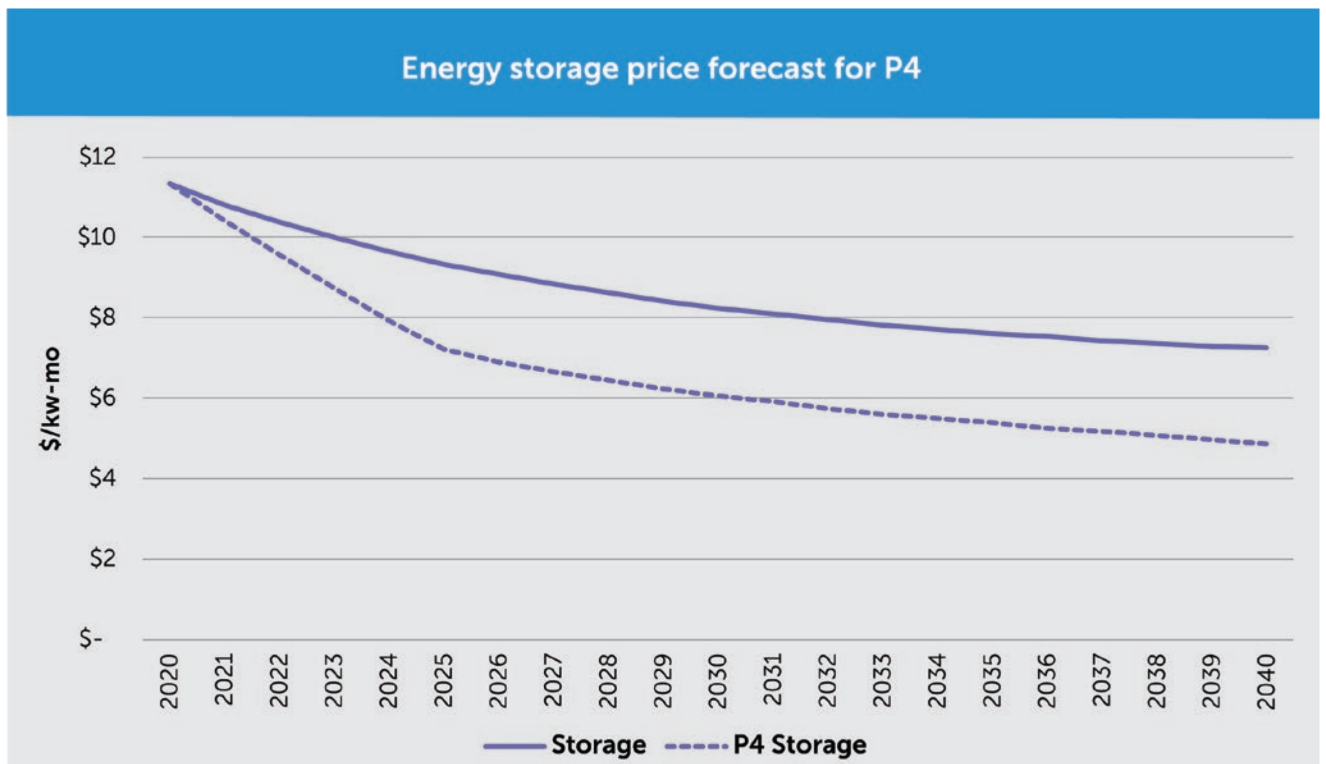
Aurora modeling software is an economic optimization tool. This model is used by Platte River for long-term capacity expansion planning, budget modeling and transaction analysis. The model economically dispatches each generation unit while respecting its operational constraints to meet hourly chronological load. For future years, when demand exceeds the existing resources, it selects the most economical next candidate unit (thermal, renewable or battery storage) to reliably meet future energy and capacity needs. While simulating the operation of Platte River system, the model allows buying and selling from an outside market to lower costs.

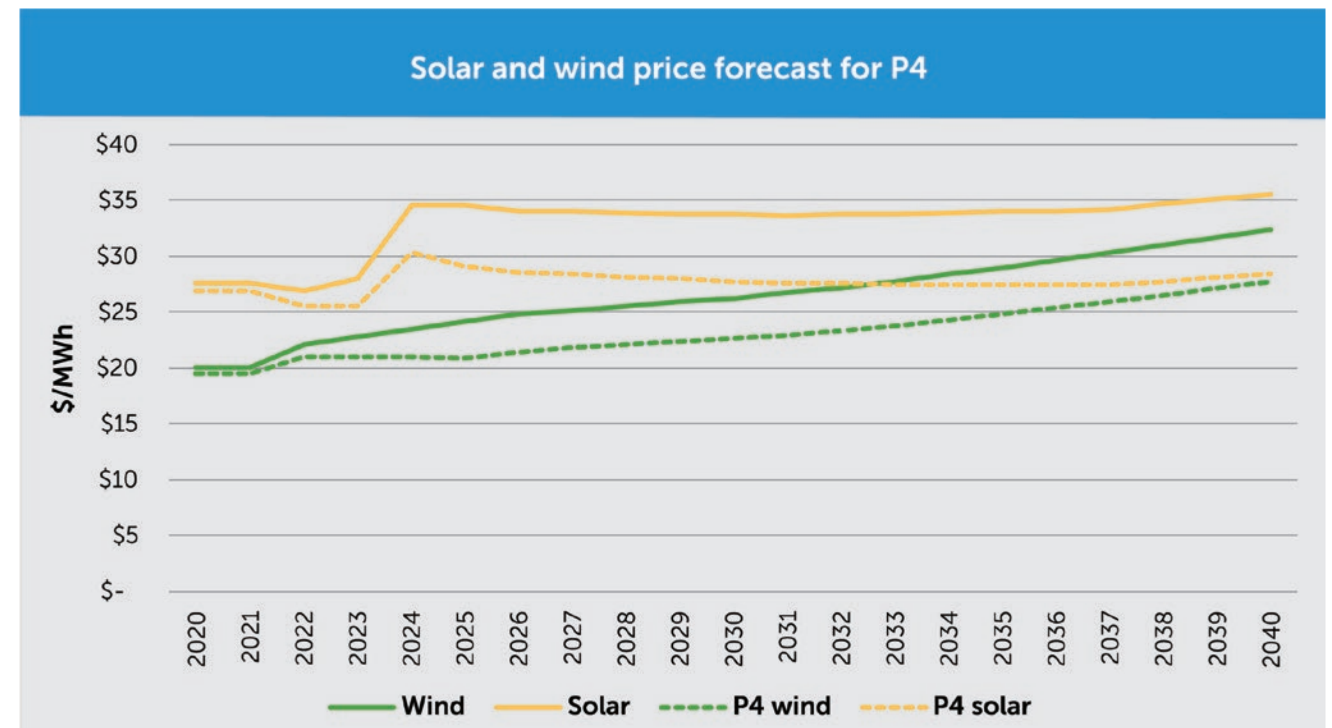
For capacity expansion planning, the model chooses from a menu of available candidate units including thermal units, noncarbon resources and storage. The expansion plan will weigh the economics of unit additions while ensuring enough firm capacity is built to maintain a planning reserve margin. The software can also economically retire units. An initial portfolio of units is chosen in the first run and then subsequent runs test resource additions and removals and modify the portfolio to reduce costs. When the software can no longer find a solution that is cheaper than the current candidate, it stops the iterative process. The final portfolio is reviewed and may be adjusted slightly to ensure it reflects a realistic plan. For example, the least cost plan may add storage a year after adding a renewable energy unit. This would be corrected to add both simultaneously even if the cost was slightly higher.

Expansion plans with high penetrations of renewable energy and storage are difficult to optimize in an iterative manner as modeled in the Aurora software. The value of renewable energy and storage are not strictly independent so testing their economics independently may not extract their full value. For these portfolios, additional runs were made using the least-cost plans developed by Aurora. Resource additions were moved earlier and later and the magnitudes where shifted up and down as well. The final portfolios reflect the least-cost solution resulting from both the Aurora optimization algorithm and expert judgment.

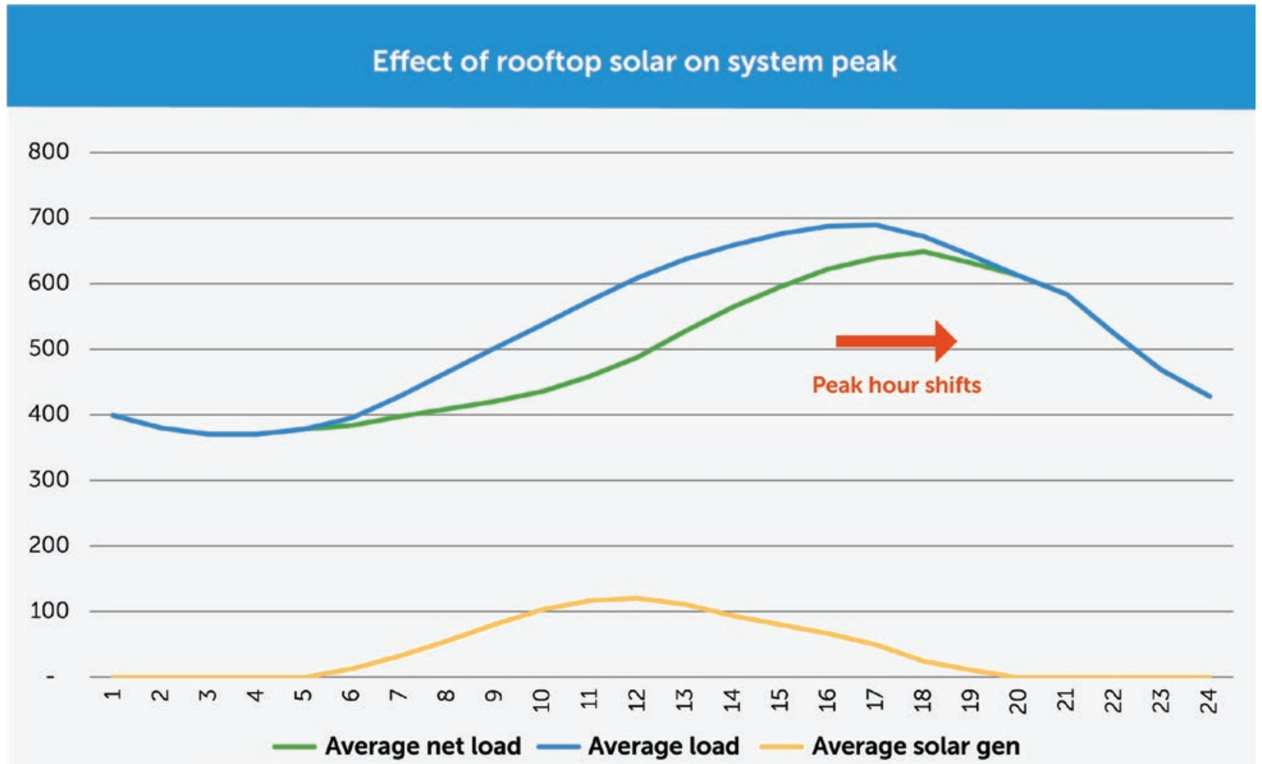
Appendix E: P4 assumptions

Lower bounds from the price forecasts were used to generate the price assumptions in P4. The cost of batteries is approximately 33% lower in 2040, while wind and solar are 14% and 20% lower, respectively. Of these three technologies, batteries have the largest opportunity for cost reductions due to technological and manufacturing advancements. The solar industry is more mature than the battery industry but still has opportunities to become more efficient and, in turn, reduce costs. The wind industry is believed to be mature with highly optimized designs and manufacturing and thus has few opportunities for additional efficiencies. As a result, the cost curve for batteries is declining over time, the solar costs are holding flat, and wind costs are rising due to inflation.

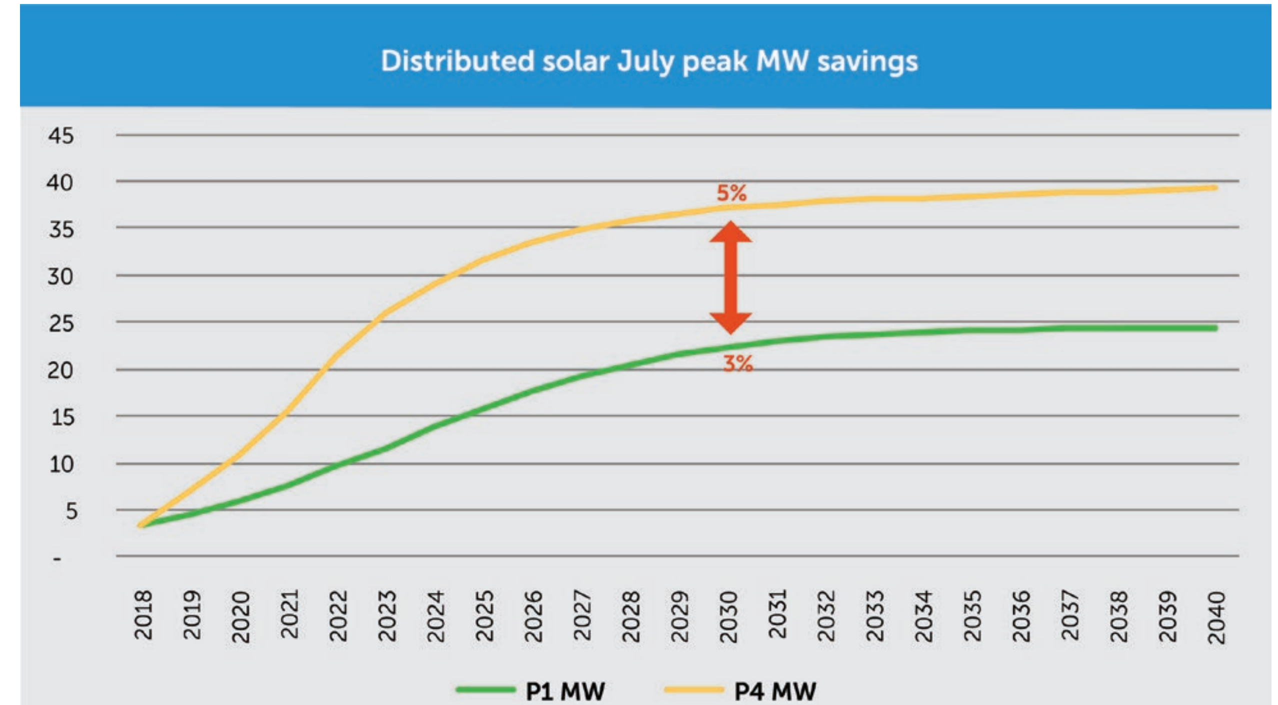




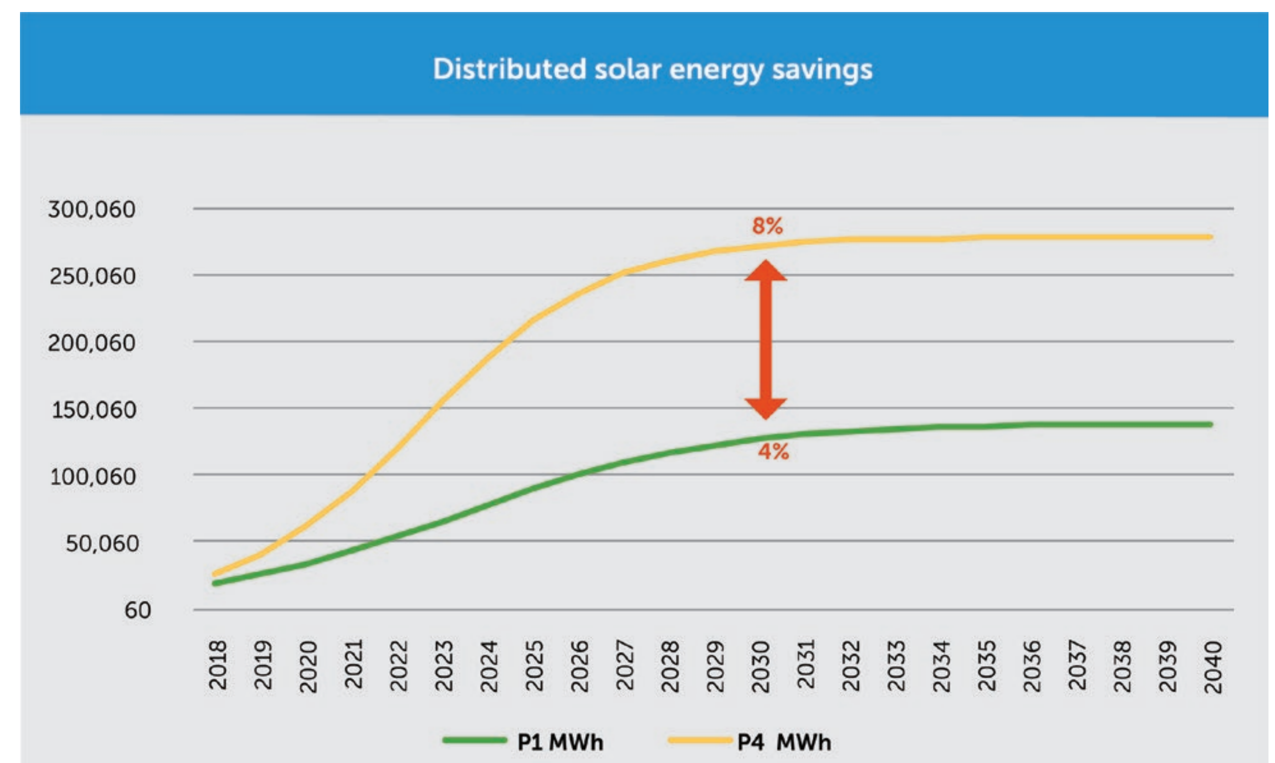
The lower cost assumptions in P4 lead to increased rooftop solar penetration, in fact, double the level of penetration in P1-P3. Doubling the number of rooftop solar panels doubles the amount of energy produced by them. Accordingly, the impact on Platte River energy is also doubled. The impact on Platte River peak demand is not doubled due to shifting of the peak hour with more distributed solar as shown in the following chart.



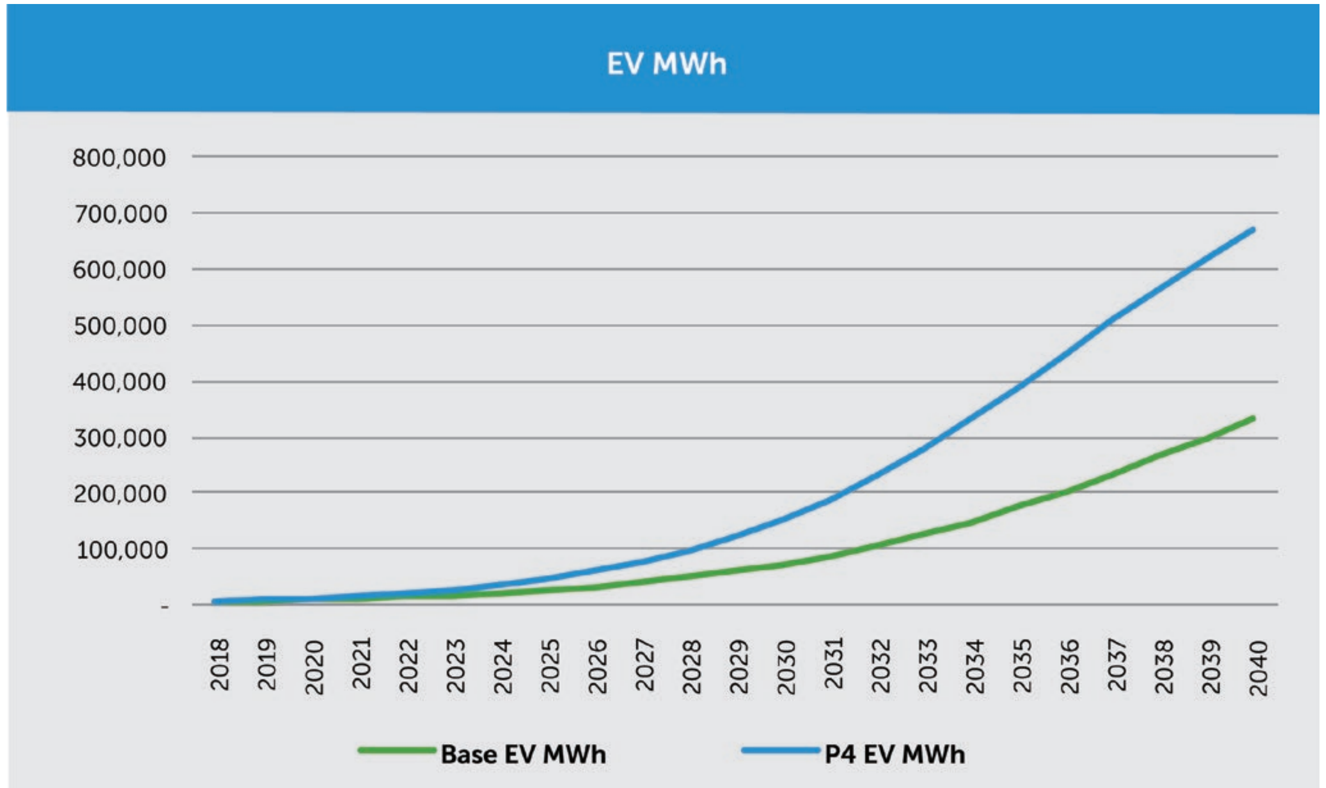
In the base assumption, distributed solar reduced peak demand in 2030 by around 3%, and after double distributed solar in P4 the peak demand was reduced by about 5% in 2030 as shown in the following chart.



Doubling of the solar generation also doubles the total energy reduction as shown in the following chart.



Similarly, EV penetration for P4 was double that of P1-P3. Total increase in energy demand due to EVs in the base case and for P4 is shown in the following chart.



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